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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

January 26, 2005

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on January 26, 2005, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 MEETING

5 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

6 (ACRS)

7 SUBCOMMITTEE ON THERMAL-HYDRAULIC PHENOMENA

8 + + + + +

9 WEDNESDAY,

10 JANUARY 26, 2005

11 + + + + +

12 ROCKVILLE, MARYLAND

13 + + + + +

14

15 The Subcommittee met at the Nuclear Regulatory

16 Commission, Two White Flint North, Room T2B3, 11545

17 Rockville Pike, at 8:30 a.m., Dr. Graham Wallis,

18 Chairman, presiding.

19 COMMITTEE MEMBERS:

20 GRAHAM B. WALLIS, Chairman

21 F. PETER FORD, Member

22 THOMAS S. KRESS, Member

23 VICTOR H. RANSOM, Member

24 STEPHEN L. ROSEN, Member

25 JOHN D. SIEBER, Member

1 ACRS STAFF PRESENT:

2 RALPH CARUSO

3 NRC STAFF PRESENT:

4 HERBERT BERKOW

5 ROBERT DAVIS

6 MICHELLE HART

7 STEVE JONES

8 N. (KALY) KALYANAM

9 RICHARD LOBEL

10 LOUISE LUND

11 KAMAL MANOLY

12 L.B. (TAD) MARSH

13 JAMES MEDOFF

14 SAM MIRANDA

15 KRIS PARCZIEWSKI

16 PAUL PRESCOTT

17 WILLIAM H. RULAND

18 ANGELO STUBBS

19 MARTIN A. STUTZKE

20 JAMES TATUM

21 JOHN TSAO

22 LEN W. WARD

23

24

25

1 ALSO PRESENT:

2 ROB ALEKSICK, CSI Technologies

3 JEFF BROWN, Westinghouse

4 PRASANTA R. CHOWDHURY, Entergy

5 JOSEPH CLEARY, Westinghouse

6 DAVID CONSTANCE, Entergy

7 STEVEN CYBERT, Westinghouse

8 THOMAS FLEISCHER, Entergy

9 JAMIE GOBELL, Entergy

10 MARIA ROSA GUTIERREZ, Entergy

11 ALAN HARRIS, Entergy

12 JERRY HOLMAN, Entergy

13 THEODORE LEONARD, Entergy

14 G. SINGH MATHARU, Entergy

15 JOSEPH REESE, Entergy

16 RALPH K. SCHWARTZBECK, Enercon

17 PAUL SICARD, Entergy

18 DON SISKA, Westinghouse

19 DAVID VIENER, Entergy

20 ARTHUR (GENE) WEMETT, Entergy

21

22

23

24

25

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1 P-R-O-C-E-E-D-I-N-G-S

2 8:31 a.m.

3 CHAIRMAN WALLIS: The meeting will now
4 come to order. This is a meeting of the Advisory on
5 Reactor Safeguards Subcommittee on Thermal-Hydraulic
6 Phenomena. I am Graham Wallis, Chairman of the
7 Subcommittee.

8 Subcommittee members in attendance are Tom
9 Kress, Victor Ransom, Jack Sieber, Steve Rosen and
10 Peter Ford.

11 The purpose of this meeting is to discuss
12 the extended power upgrade application for the
13 Waterford Steam Electric Station, Unit 3. The
14 Subcommittee will hear presentations by and hold
15 discussions with representatives of the NRC staff and
16 the Waterford licensee, Entergy Operations regarding
17 these matters.

18 The Subcommittee will gather information,
19 analyze relevant issues and facts and formulate
20 proposed positions and actions as appropriate for
21 deliberation by the full Committee.

22 Ralph Caruso is the designated federal
23 official for this meeting.

24 The rules for participation in today's
25 meeting have been announced as part of the notice of

1 this meeting previously published in the *Federal*
2 *Register* on December 21, 2004.
3 A transcript of the meeting is being kept
4 and will be made available as stated in the *Federal*
5 *Register* notice.
6 It is requested that speakers first
7 identify themselves and speak with sufficient clarity
8 and volume so that they can be readily heard.
9 We have not received any requests from
10 members of the public to make oral statements or
11 written comments.
12 I have an opening comment. I read hundreds
13 of pages of text, prepared both by the licensee and
14 the staff, and I still don't have a good grasp of how
15 this operate is achieved. I noticed some changes
16 which were very small in the temperatures of the cold
17 leg and hot leg, but they do not seem to be sufficient
18 to account for an 8 percent uprate. And there's no
19 mention whatever of what happens to the full rate
20 through the core.
21 In some way the power in the core is
22 increased and yet we're told that the linear heat
23 generation rate, actual linear heat generation rate is
24 reduced and the radiation to the core internals is
25 reduced, so something has presumably happened with the

1 fuel management, although we're told it's the same
2 fuel. But there's a mystery there I'd like to have
3 resolved.
4 So it will be very useful if someone could
5 explain just how the operators achieved and what the
6 consequences are for important parts of the system
7 such as the fuel and the cooling system. And maybe
8 this in the documents and I just couldn't find it, but
9 I'm still mystified by just exactly how the uprate was
10 achieved and what the consequences were. Otherwise,
11 most of the documentation was very readable and
12 explicit.
13 I'm sorry, Tad, to hold you up.
14 MR. MARSH: That's fine.
15 CHAIRMAN WALLIS: Please go ahead.
16 MR. MARSH: Thank you.
17 Good morning, Mr. Chairman. And I do hope
18 we address those questions either from the licensee
19 from the staff in terms of how this is actually taking
20 place in the reactor.
21 Good morning. My name is Tad Marsh. I'm
22 the Director of the Division of Licensing Project
23 Management in the Office of Nuclear Reactor
24 Regulation.
25 The purpose of our briefing today is to

1 present our review of Entergy's application for the
2 extended power uprate for Waterford Unit 3. If the 8
3 percent uprate is approved, it will be the largest
4 power uprate for pressurized water reactor in the U.S.
5 And Waterford 3 will operate at a core power level of
6 3716 megawatts thermal.
7 Our review of the proposed EPU for
8 Waterford is the first one to be completed using the
9 Review Standard RS-001. Throughout the development of
10 the Review Standard the staff was in communication
11 with the ACRS. First in the July 2002 time frame the
12 discussed an outline of the Review Standard with the
13 Committee and then presented the draft Review Standard
14 to the Committee in a meeting in December, 2002. At
15 that time the Committee encouraged the staff to issue
16 the draft review standard to the public for comment
17 and report to the resolution of those comments to the
18 Committee.
19 The staff presented the Review Standard
20 including incorporation of the public comment to the
21 ACRS Thermal Hydraulic Phenomena Subcommittee in
22 August of 2003, and the Review Standard was finalized
23 later that year.
24 The staff's review of the Waterford power
25 uprate application was challenging and required a

1 substantial amount of additional information from the
2 licensee to complete its review. And this was the
3 first review involving large transient testing for
4 PWR, and the staff set the standard high and followed
5 the new Standard Revenue Plan associated with large
6 transient testing. And you'll hear more about that.
7 The staff completed a thorough review of
8 the application for Waterford, but there are still a
9 few items remaining resolution. Our Project Manager
10 Kaly will describe those items to you as we go through
11 the presentation.
12 Stepping back a little from Waterford, in
13 particular, and going to power uprate in general this
14 is, as I say, the first application of the Review
15 Standard in a power uprate review. And we believe the
16 review standard is a very thorough, very complete
17 document which is guiding our technical staff in these
18 reviews. But we did notice that there was a lot of
19 RAIs associated with this application and with other
20 applications associated with the Review Standard
21 review. We believe that's because the staff is now
22 guided with some specifics in terms of reviews, so
23 it's an effort for complete and thorough documentation
24 and complete and thorough review of an application
25 which we believe is in part resulting in these RAIs.

1 We do intend on issuing a regulatory
2 issues summary, a RIS, to clarify to the industry what
3 we believe we need for a thorough and complete
4 application associated with the Review Standard. And
5 those lessons learned are coming from not only the
6 Waterford review, but from other power uprate reviews
7 which are ongoing.
8 We look forward to the dialogue with you.
9 We would like to get a sense from you the level type
10 of information that you would like in the context of
11 some of these open items. Because you will hear today
12 that we are not quite done with them. So we would
13 like a sense from you what you would like in terms of
14 follow on communications or a presentation at the full
15 Committee. But we would like a sense of that, too, as
16 you go through these presentations.
17 Well thank you very much. I'd like to turn
18 it over to Kaly who will give an introduction for the
19 presentation.
20 CHAIRMAN WALLIS: Just one moment. You
21 mentioned the use of the new standard.
22 MR. MARSH: Right.
23 CHAIRMAN WALLIS: I think that's very
24 evident in the SER.
25 MR. MARSH: Right.

1 CHAIRMAN WALLIS: The SER is very
2 comprehensive and thorough in a way that some of the
3 earlier ones didn't.
4 MR. MARSH: Right.
5 CHAIRMAN WALLIS: I think that the
6 standard, obviously, is having an effect.
7 MR. MARSH: I recall conversations with
8 you about thorough and completeness of the safety
9 evaluations and making sure that the basis was
10 apparent in the staff's review. And the Review
11 Standard will help us in that regard. But it is
12 causing more hours to be expended for these reviews
13 than we had anticipated. And what we're trying to
14 discern is this a level of completeness standard that
15 we need to articulate to the industry more clearly,
16 hence the RIS, or is this our staff you know being
17 guided thoroughly in the Review Standard itself. But
18 it is causing more review time, quite a bit more.
19 CHAIRMAN WALLIS: Well, it's the first
20 time. You're learning, too.
21 MR. MARSH: It is.
22 CHAIRMAN WALLIS: And also I think it's
23 appropriate with such a large power uprate for a PWR
24 that you do cover all the bases.
25 MR. MARSH: Right.

1 CHAIRMAN WALLIS: Maybe next time you can
2 do it a little quicker and more efficiently.
3 MR. MARSH: Maybe. But thorough and
4 complete is important, making sure that the staff can
5 make the right kind of safety findings.
6 CHAIRMAN WALLIS: Thank you.
7 MR. MARSH: Thank you.
8 Kaly?
9 MR. KALYANAM: Good morning. My name is
10 Kalyanam and I'm known as Kaly here. I'm the Project
11 Manager for Waterford 3, and I work in the DLPM.
12 Okay. Just to give you a little background
13 for the Waterford uprate.
14 The plant was originally licensed in 1985
15 for operational reactor core power not to exceed 3390
16 megawatts thermal units. And measurement uncertainty
17 recapture uprate was rendered in 2002 which gave them
18 a 1.5 percent increase, and the core power level was
19 not to exceed 3441 megawatt thermal.
20 Now the uncertainty power uprate which we
21 are discussing now, requests are in the case of 8
22 percent and the core level will not exceed 3716
23 megawatts thermal. And as Mr. Marsh said, this is the
24 largest PWR power uprate to date.
25 Now, some of the major plant modifications

1 are: The licensee upgrading the high pressure turbine
2 and rewinding the generator and provide the associated
3 auxiliaries; installing higher capacity generator
4 output circuit breakers; disconnect switches and
5 reworking on the bus; main transformers and
6 modifications, and; replace and upgrade the control
7 valves for the heater drain system, and; stake the
8 condenser tubes.
9 And the time table for the EPU
10 implementation is intended plants implement this
11 Waterford 3 EPU in one increment. And completion of
12 the plant modifications necessary to implement the EPU
13 is planned prior to the end of the refuelling outage,
14 which is commencing the spring of 2005.
15 With the approval of this license
16 amendment request, the plant will be operated at the
17 new power starting in cycle 14.
18 Some of this table giving the comparison
19 of operating parameters. And as it was pointed, there
20 is a slight increase in the hot leg temperature and
21 the cold leg temperature, it drops. And the RCS flow
22 increases slightly pound-mass per second.
23 And on the secondary site, the steam
24 generator pressure drops and the flow increases.
25 Further data on this will be provided by the

1 reviewers.

2 CHAIRMAN WALLIS: So it's the increase in
3 the flow as well, that's the one I didn't find in the
4 documentation. There is something peculiar in the
5 documentation. It says that this change in temperature
6 was equivalent to an enthalpy change going through the
7 core, which was 9 percent. But that's not true. If
8 you look at the steam tables, it just doesn't work
9 out. So maybe the licensee is going to explain all
10 that to us.

11 MR. KALYANAM: I am sure.

12 MR. MIRANDA: Could I attempt to answer
13 this question? My name is Sam Miranda from the
14 Reactor Systems Branch.

15 And this question came up before just
16 where this power increase is coming from. And I did a
17 few calculations to see where it is coming from. And
18 basically it's a change in the cold leg temperature
19 increasing the delta T through the core. That
20 accounts for the 8 percent increase in power. And
21 there's also an increase in steam flow and a change in
22 the feedwater temperature.

23 And if you do the delta H calculations of
24 feedwater, FOP -- the steam FOP at the new steam
25 pressure, that's also the 8 percent increase in power.

1 CHAIRMAN WALLIS: Sam, you didn't say
2 anything about the RCS flow rate?
3 MR. MIRANDA: The RCS flow rate, there is
4 a small change there but mainly that's due to the
5 density change in the cold leg.
6 CHAIRMAN WALLIS: Well, I think if you
7 calculate the enthalpy change for the hot leg/cold
8 leg, you're lucky to get about four something percent
9 just from the enthalpy change. So we're going to
10 revisit this. Do you have different steam tables from
11 mine, though, something just doesn't work out. It's
12 not just the enthalpy change in the RCS fluid. It's
13 also the flow rate you have to use. I think this flow
14 rate may do it, just looking at it.
15 MR. MIRANDA: It's deceptive to look at
16 just the flow rate because the flow rate is the
17 thermal design flow rate, and that can change
18 depending upon, you know, how they want to use it in
19 their thermal-hydraulic calculations as opposed to the
20 RCP rated flow rate.
21 If you just look at the volumetric flow
22 rate and take the density changes, there is an overall
23 change in the flow rate of about 2.9 percent of which
24 about 2.4 percent is strictly due to the change in
25 density in the cold leg. And the rest would be --

1 CHAIRMAN WALLIS: And so we'll revisit
2 page 105 of the SER sometime, this enthalpy --
3 MR. MARSH: Yes. We want to explain to
4 you, too, as best we can what's going on in the core.
5 You know, where's the power happening in the core and
6 the fuel itself. So it's not just an RCS loop, it's
7 also what's happening to the flux profiles, what's
8 happening to -- why don't we make sure that the
9 licensee really addresses that for you as well.
10 Okay. Kaly.
11 MR. KALYANAM: The staff approach for the
12 review was as Mr. Marsh said, this the first PWR EPU
13 to follow Review Standard 001. We replaced the
14 Standard Review Plan and acceptable core and
15 methodologies. We developed 20 or 25 requests for
16 additional information. And altogether we had about
17 30 supplements. And we have done audits and
18 independent calculations in selected areas and the
19 reviewers will discuss that in later detail.
20 And principal areas of review. Okay. I
21 have listed them.
22 The vessels and internals.
23 Okay. The metrics which we are referring
24 to is the Review Standard metrics and we have covered
25 all of them. I'm not going to go line by line, but

1 basically vessels internals, piping integrity, steam
2 generator integrity and so on.
3 And we have --
4 CHAIRMAN WALLIS: How about the fuel?
5 MR. KALYANAM: The fuel comes --
6 CHAIRMAN WALLIS: The fuel is going to
7 produce more power?
8 MR. KALYANAM: Pardon?
9 CHAIRMAN WALLIS: The fuel produces more
10 power, so presumably you had to review what happens to
11 the fuel. It gets hotter or --
12 MR. KALYANAM: Yes.
13 CHAIRMAN WALLIS: -- heat distribution is
14 different and so on.
15 MR. KALYANAM: Okay. I'm sure we'll be
16 able to address it in their respective sections.
17 CHAIRMAN WALLIS: What is it that limits
18 the operators? Is it the fuel?
19 MR. KALYANAM: I think Sam or --
20 CHAIRMAN WALLIS: Or was it accident
21 analysis?
22 MR. KALYANAM: What? Can you answer?
23 MR. SICARD: This is Paul Sicard. I'm the
24 lead safety analysis engineer for the Waterford
25 uprate.

1 Now the question is what is a limit as far
2 as the power. From a core and fuel analysis point of
3 what we saw as a limiting event was the performance
4 related tube, the small break LOCA ECCS analysis.
5 CHAIRMAN WALLIS: Thank you.
6 MR. KALYANAM: And this is the
7 continuation of the principal areas of review.
8 And the order of the NRR presentation
9 after the licensee presentation will be as shown here.
10 We have the reviewers from all the branches. And if
11 there is any question that comes up, you know we have
12 the experts in those areas to answer your questions.
13 And the few open items that Tad Marsh
14 referred to, let me briefly discuss them. There are
15 four issues or topics that are on a success path and
16 close to resolution.
17 One is submittal by the licensee on the
18 alternate source term is under review. The draft SE
19 which you have and you have seen, the flux test and
20 the issue of the EPU amendment will be contingent on
21 the issue of the alternate source term amendment.
22 And the reactor vessel internal
23 degradation monitoring program we had some discussions
24 with the licensee and we are on a success path there.
25 And there was an issue on the three second

1 time delay between the steam generator tube rupture
2 and loss of offsite power. And there also we are very
3 close to the resolution.
4 And, you know, these items will be
5 resolved before the license is granted.
6 And the last one is accounting the
7 instrument uncertainty for the tech spec parameters,
8 but are influenced by the EPU. That's one other issue
9 that we are on a success path and close to resolution.
10 With that, I will ask Jim Medoff to come.
11 MR. MARSH: Just building a little bit on
12 that last one, that's not really the methods reissue
13 that you and I talked about. This is another accuracy
14 issue associated with this petition, which we'll
15 describe.
16 DR. RANSOM: One question that I have is
17 I would like to see a pressure schedule for this
18 system because you have a higher flow rate through the
19 core, so a higher delta P across the core, apparently,
20 and some of the steam generator tubes are plugged as
21 well which means the delta P is increased across
22 there. So the horsepower to the pumps must have to
23 increase. And I'm wondering if that's been looked at?
24 MR. BARKOW: Just a correction. This is
25 Herb Berkow. I'm the Project Director for Region IV

1 plant.

2 The licensee's presentation is next.

3 MR. KALYANAM: I'm sorry. The licensee's

4 presentation comes.

5 MR. MARSH: But I hope we get at your

6 question. If not us, then the licensee. Okay. That's

7 pressure around the reactor, what's going on when the

8 flow drops, horsepower requirements for the reactor.

9 Okay. Mr. Chairman, we'd like to turn it

10 over to the licensee for his presentation.

11 CHAIRMAN WALLIS: Move on. Thank you.

12 Thank you.

13 MR. MARSH: Thank you.

14 MR. MITCHELL: Good morning. I'm Tim

15 Mitchell. I'm Engineering Director at the Waterford 3

16 plant. I've been in this position since about August

17 of last year. Prior to that one piece of my past

18 experience was as Operations Manager at Arkansas

19 Nuclear One for the Unit 2 power uprate. So I've seen

20 power uprates also from the operations side. And I

21 feel like that has given me a perspective coming in as

22 Engineering Director at Waterford to look at this and

23 follow up.

24 In this presentation, Mr. Chairman, we

25 will answer your questions. We'll answer all the

1 questions, but we'll make sure that we get to the ones
2 that have been introduced so far.
3 We have a number of people here to support
4 our presentation, people from Westinghouse, Enercon
5 and Entergy. I will be introducing the primary
6 members here.
7 We've built this presentation to cover a
8 number of items, some not effected by power uprate,
9 but they're areas of interest for the industry. So we
10 will try to address more than just what has been
11 effected by power uprate.
12 I am Tim Mitchell, again giving the
13 introduction.
14 Safety analysis will be presented by Paul
15 Sicard.
16 And each of these presenters will give a
17 little bit about their background when they come up.
18 Risk considerations will be given by Mr.
19 Jerry Holman.
20 Engineering plant impacts by Mr. David
21 Viener.
22 Then the Operations Impacts. First
23 training and procedures by Mr. Gene Wemett. And then
24 testing, Mr. David Constance.
25 And then we'll to the conclusions.

1 We have a lot of data to present. We will
2 present it as efficiently and answer your questions as
3 we can.
4 This h as been a significant project for
5 us with significant resource amendment. We think that
6 has helped our product. It has been over three years
7 of significant dedicated resources, and it's been a
8 multisite effort, not just Waterford, but all the
9 Entergy nuclear sites have contributed resources and
10 expertise to this effort.
11 We feel one of the benefits for Waterford
12 is it has improve our design basis. We've had a
13 strong focus while we went through this on margins.
14 We've eliminated some longstanding margin issues and
15 have plans to address more.
16 Focused oversight and rigor has been a key
17 element of managing this project. We have a director
18 level project lead, Mr. Ted Leonard. Design and
19 review committees have been used to provide oversight
20 throughout the process so that we have additional
21 rigor or oversight at the end to make sure that the
22 product that is being provided to the plant is the
23 best possible.
24 We've had some assessments, including
25 corporate lead assessments. We started the effort with

1 a large assessment to make sure that we learned from
2 the industry and in particular the Arkansas Nuclear
3 One Unit 2 upgrade. So we started on the right foot.
4 We had several other assessments. We had
5 a big one last October to review our readiness. It
6 was a 12 member team. Eleven people on that team had
7 previous upgrade experience, four were from outside
8 Entergy. And then we do periodic assessments of our
9 engineering quality also to make sure another depth of
10 review of done, to make sure the fire quality is good.
11 We've accounted for industry experience.
12 We've applied it where applicable and we have had a
13 rigorous -- and we appreciate that rigor because we
14 feel that it has given us a better product as well.
15 And as previously mentioned, this
16 submittal was prepared for the draft Review Standard
17 RS-001 for our efforts.
18 A high level description of the plant,
19 most of this has already been presented, but we are a
20 combustion engineering NSSS pressure water reactor. So
21 we did enter commercial operation in 1985, and Kaly
22 has already presented the rest of the information on
23 the slide, so I won't go through it again
24 MR. SIEBER: You have two steam
25 generators.

1 MR. MITCHELL: That is correct.

2 MR. SIEBER: And how many total tubes and

3 how many are plugged?

4 MR. MITCHELL: Do you have the actual

5 data, Alan?

6 MR. HARRIS: I'm Alan Harris with the

7 engineering department at Waterford.

8 There are normally 9,350 tubes per steam

9 generator. And number one steam generator, 571 tubes

10 are plugged. And in number two steam generator, 484

11 tubes. That's a total of 1,055 tubes.

12 Of those that are plugged, only 429 were

13 plugged due to actual indications. The other 626 were

14 preventively plugged early in plant life or prior to

15 commercial operations due to concerns with vertical

16 support ware at the bat wings.

17 Does that answer your question?

18 MR. SIEBER: Okay. Thank you.

19 DR. FORD: Could you go back one slide,

20 please? This whole presentation relates to the power

21 uprate, of course. I understand that you're

22 considering going for license renewal at some time in

23 the future. To what extent did your analyses for

24 power uprate take into account this future license

25 renewal?

1 MR. MITCHELL: We in all cases protected
2 our options to go for license extension, and we do
3 plan on going for license extension. The current
4 schedule would be roughly the 2008 time frame to be
5 prepared to go forward with that license renewal.
6 So we have every intention of proceeding
7 with license --
8 DR. FORD: So in the back of your mind
9 when you're going through these analyses, the changes
10 influx for instance, corrosion of various types but
11 also entered into your thinking?
12 MR. MITCHELL: That is correct.
13 Okay. I'll go through a little
14 introduction of the project team consisting of
15 Entergy, Westinghouse, Enercon and Siemen's-
16 Westinghouse. And as already mentioned, we have a
17 number of people from Westinghouse and Enercon here
18 with us today.
19 In closing my introduction, we plan to
20 show you that we've done a thorough and rigorous
21 project and that we are making the plant better as a
22 result of this project, and it is safe. The staff
23 review has challenged us and it has improved our
24 project.
25 And we thank the ACRS Subcommittee for

1 their time to be able to present this to you.

2 Thank you. I'll turn it over to Paul

3 Sicard, who will go over our safety analysis.

4 MR. SICARD: Good morning. My name is Paul

5 Sicard. I'm the lead safety analysis engineer for the

6 Waterford 3 extended power uprate project.

7 I started work at Waterford in 1988, and

8 I've been doing safety analysis work for Entergy since

9 that time. And I'm here to discuss the safety analysis

10 work that had been done to demonstrate that Waterford

11 will continue to operate safely under extended power

12 uprate conditions, and that we meet the required

13 acceptance criteria for this.

14 And my discussion is going to be focused

15 on the analytical side of safety analysis, the final

16 safety analysis report section, chapter 15 for

17 example. But I want to also stress that Waterford has

18 kept a focus on operational safety as part of our

19 uprate project, and we have kept our operations

20 department very involved in the project, as Tim has

21 said.

22 Next slide, please.

23 The scope of what we've looked at has

24 included looking at the fuel impacts, the emergency

25 core cooling system analyses, the analyses of non-LOCA

1 transient events, containment analyses and our
2 radiological analyses. This has been an extremely
3 thorough review. We have basically redone 90 to 95
4 percent of the analyses that fall into this
5 traditional realm of safety analysis. We have been
6 closely involved with Westinghouse in the development
7 of those computations. And this is a project that we
8 see as greatly improving the strength of the design
9 basis for the Waterford plant in terms of bringing all
10 of this up to date for our power uprate conditions.
11 Next slide.
12 Kaly has already gone over the
13 modifications associated with the power uprate. We
14 want to point out that we have not needed to make
15 significant changes to any of the safety systems.
16 There's no change, for example, to the safety
17 injection system associated with the uprate. Most of
18 these changes are related to the power conversion side
19 of the plant. We do have some changes in the control
20 systems and instrumentations, a couple of minor
21 setpoint changes and relatively minor changes to
22 control system setpoints that are associated with the
23 power uprate.
24 Next slide.
25 MR. SIEBER: A quick question, and you may

1 not be able to answer but I'm sure somebody will in
2 the course of the day.
3 I note the steam pressure goes down by
4 about 30 pounds and the steam flow goes up by about 8
5 or 9 percent. That tells me that the moisture content
6 has to increase. You are not planning, I presume, to
7 change the moisture separator path of the steam
8 generators. And if you don't, then I presume that
9 there will be an increase in erosion/corrosion of the
10 piping and also an increase in the wear rates of the
11 turbine blade. If that's the case, what steps has
12 Entergy taken to recognize that and alleviate it if
13 possible?
14 You probably aren't the guy?
15 MR. SICARD: No. I'm not the guy to get
16 into those details here. David Viener, who is our
17 lead mechanical engineer for the project, will be
18 addressing flow accelerated corrosion during his
19 presentation later, or do you want your answer --
20 MR. SIEBER: I can wait.
21 MR. SICARD: Okay.
22 MR. SIEBER: But if he could right is down
23 so that he makes sure he covers it.
24 MR. SICARD: Okay.
25 MR. SIEBER: Maybe I can ask a general

1 question about fuel management.

2 MR. SICARD: Yes.

3 MR. SIEBER: You intend to increase power

4 by about 8 percent. Will the cycle lengths remain the

5 same?

6 MR. SICARD: I will cover that in a slide

7 later, but yes we are going to keep the same 18 month

8 cycle length that we currently operate with.

9 MR. SIEBER: Do you intend to replace the

10 same number of assemblies at each refueling or a

11 greater number?

12 MR. SICARD: We anticipate replacing a

13 larger number of assemblies for each refueling. For

14 the upcoming refueling, our fuel cycle 14, we will

15 have 100 new assemblies as part of the reload compared

16 to 92 for the previous one.

17 MR. SIEBER: Is it your philosophy, I take

18 it, to minimize the increase in final burnup of the

19 fuel by increasing the amount that you --

20 MR. SICARD: We are looking to stay within

21 our current burnup limits by having larger batch

22 sizes. Also, by having slightly larger batch sizes

23 that allows us to lower the peaking on the fuel such

24 that under operating conditions there will not be a

25 significant difference in the environment seen by the

1 fuel assemblies for uprate versus what the highest
2 peaking assemblies see right now.
3 MR. SIEBER: Thank you.
4 CHAIRMAN WALLIS: You also have -- well,
5 I think it's in the staff's, lower gamma fluxes and so
6 on to the internals. Something has happened about the
7 flux distribution in the core?
8 MR. SICARD: That is basically an artifact
9 of conservatisms in the original analyses. The
10 original analyses were done, you know, with what was
11 viewed as a core design for the early 1980s. Since
12 then we have gone to a low leakage core such that even
13 when power uprate is considered, and we go and we
14 calculate what the fluence is towards the core
15 periphery, it is lower now than in those original
16 analyses.
17 CHAIRMAN WALLIS: So what's happened is
18 it's not as if it's actually decreased. It's
19 decreased not only because of the analysis --
20 MR. SICARD: It has decreased compared to
21 the values that it was designed for.
22 CHAIRMAN WALLIS: Physically it has
23 probably increased?
24 MR. SICARD: Pardon?
25 CHAIRMAN WALLIS: Physically it has

1 probably increased.

2 MR. SICARD: Physically it has probably

3 increased.

4 CHAIRMAN WALLIS: And that equates

5 decrease because there's less conservatism?

6 MR. SICARD: That is correct.

7 This slide presents some of the operating

8 parameters.

9 CHAIRMAN WALLIS: Well, this enthalpy

10 change we're talking about comes from using 541, is

11 it?

12 MR. SICARD: Let me speak to the --

13 CHAIRMAN WALLIS: I don't understand

14 having this range of temperatures. I mean, you're

15 talking about a specific power. You presumably have

16 a certain temperature?

17 MR. SICARD: Yes. And when one starts

18 talking about RCS flow, one gets into the situation

19 like the saying of the man with two watches never

20 knows what time it is. Because one has to define which

21 flow it is that you are considering and what are the

22 assumptions that go into those particular flows.

23 The technical specification minimum flow

24 is not being changed. That's a value of 148 million

25 pounds per hour. The maximum flow assumption that we

1 used in safety analyses is 115 percent of that value.

2 There is also a nominal flow which we used

3 in order to do analyses, for instance, of fuel burnup

4 and support fuel management and which is input into

5 items such as structural analysis.

6 A number that was presented in the slides

7 before shows the change in that nominal flow from what

8 had been our docketed operating point under the

9 Appendix K uprate compared to what the nominal flow is

10 that we are docketing right now for our extended power

11 uprate. And a complication in there is the fact that

12 Waterford had a miscalibration of its ultrasonic flow

13 meter which lead to that previous flow that was our

14 docketed flow upon which operating point calculations

15 were built being slightly low. You know, when we

16 discovered this issue, we entered into our corrective

17 action process. We have assessed it for impact on

18 current operations which was truly minimal. But it

19 does result in having to explain this difference in

20 between the flow rate for our Appendix K information

21 as docketed with the NRC versus power uprate.

22 Now, for the actual physical change due to

23 power uprate, you will see a slight change in the flow

24 because of the increase in density, because of the

25 slight decrease in temperature.

1 CHAIRMAN WALLIS: Well, what I'm trying to
2 get at is when you increase the power by 8 percent, is
3 6 percent of that due to temperature change and 2
4 percent due to flow change or is it a variable and
5 sometimes it's 5 percent 3, sometimes it's 7 percent
6 2, one or something? There's obviously these two
7 figure in the energy balance. And I couldn't figure
8 out by how much the flow rate had changed in order to
9 make up this energy out.
10 MR. SICARD: Yes.
11 CHAIRMAN WALLIS: Presumably there's a
12 range.
13 MR. SICARD: Yes. From our point of view
14 the major contributor to the increase in delta T will
15 be the increase in the power. We see the input from
16 the increased output of the core being the more
17 dominate factor to increasing what your delta T will
18 be.
19 CHAIRMAN WALLIS: Should I use 541 when I
20 try to check your calculations, or 543?
21 MR. SICARD: You should use 543 because
22 that is--
23 CHAIRMAN WALLIS: Then you have not quite
24 an increase in flow rate, and flow rate is a
25 significant part of the uprate?

1 MR. SICARD: Pardon?

2 CHAIRMAN WALLIS: Then the flow rate
3 change is a significant contributor to the uprate.
4 Because 543 you don't get close to it --

5 MR. SICARD: No. We are able to accomplish
6 this uprate without crediting an increase in the flow.
7 Because we have built this uprate based upon our
8 minimum technical specification flow which has not
9 change for the uprate. So we are having a fire
10 temperature rise across the core that for the same
11 flow rate as what we had previously.

12 CHAIRMAN WALLIS: That's true. But 2.6
13 degrees is not enough to give you that. So I just
14 wanted a simple energy balance calculation, that's all
15 I'm looking for because when I do it, it doesn't come
16 up to 8 percent. That's all I'm looking for.

17 MR. SICARD: We had questions and
18 discussions with the staff on the subject. This has
19 been documented in some of the responses to the
20 request for additional information that we did have
21 from the staff. And, you know, what is confusing here
22 is the fact that we had this error of approximately 3
23 percent in this nominal flow. Now I need to stress
24 again --

25 CHAIRMAN WALLIS: Basically what you guys

1 could do is you could prepare a one sheet explanation
2 that will make sense to a sophomore in engineering in
3 terms of heat balance and put it up on the screen
4 sometime today so I can understand it. You've talked
5 around it so much, I still don't understand how the
6 energy balance works. All I need is a simple equation
7 with some numbers that I could go over --
8 MR. SICARD: Sure.
9 CHAIRMAN WALLIS: and say, yes, I believe
10 it. That's all I'm looking for.
11 MR. HOLMAN: This is Jerry Holman from
12 Waterford 3.
13 And we'll try and put together that type
14 of slide. The other piece of the equation here that
15 I think is missing is the increase in steam flow from
16 the steam generator as a result of --
17 CHAIRMAN WALLIS: That has nothing to do
18 with what happens in the flow.
19 MR. SICARD: We do have that information,
20 and it was in our May 12th RAI response, last page of
21 that.
22 MR. MIRANDA: Excuse me. Name is Sam
23 Miranda.
24 Again, I'm back with this same question.
25 And referring back to my calculations. And I believe

1 that the 543 degree temperature in my calculations
2 accounts for only five percent of the power uprate.
3 If I go to the 541 degree temperature, that goes up to
4 the 8 percent.
5 CHAIRMAN WALLIS: Yes, that's right. Yes,
6 that's more like it.
7 MR. CARUSO: And you should have a table
8 there that--
9 MR. MIRANDA: Yes, I did a little
10 spreadsheet.
11 CHAIRMAN WALLIS: Maybe you could share
12 this with us at some time today? Maybe we should move
13 on now, but we'll come back and make this absolutely
14 clear at some point.
15 MR. SIEBER: The new delta T, the range of
16 it, would lead to a 6 to 9 percent increase in power.
17 So this, by the change in delta T, that accounts for
18 it in my mind.
19 MR. SICARD: Let me also explain what this
20 541 to 543 is. This is a gram of the nominal
21 temperature. We have a range for our cold leg
22 temperature technical specification. But a
23 temperature program for the plant, we're at zero power
24 conditions to control around 541 degrees, and that
25 raises -- that is increased to 543 for hot/cold power

1 conditions. And this is consistent with the original
2 design of Waterford 3. Waterford 3 originally was
3 designed with a temperature ramp going from 545 up to
4 553. And we changed that in 1992 to a flat
5 temperature profile of 545 due to concerns for
6 potential material issues such as the condition steam
7 generator 2. So that is some of the history of the
8 temperature and how it evolved over time.
9 You know, let me get back to so me of the
10 other--
11 CHAIRMAN WALLIS: I guess the reason that
12 this concerned me was because there are changes in
13 flow rate that wasn't evident in the documentation.
14 They have some consequences, and they never seemed to
15 be discussed. That's why it interested me was that
16 there are changes in the RCS flow rates and there are
17 some consequences in terms of --
18 MR. SICARD: The changes in those flow
19 rates are within the bounds of the existing analyses -
20 -
21 CHAIRMAN WALLIS: Well, they be legal, but
22 they still have some effect. And it's interesting to
23 discuss what the effects might be.
24 MR. CARUSO: Can I ask a question?
25 MR. SICARD: Yes.

1 MR. CARUSO: Are you changing anything
2 about the reactor coolant pump operations as a result
3 of this uprate?
4 MR. SICARD: No. We are not changing any
5 reactor coolant pump operation as a result of the
6 uprate.
7 MR. CARUSO: And you're not making any
8 hardware changes to the reactor coolant pump?
9 MR. SICARD: We are not making any
10 hardware changes to the reactor coolant pump.
11 MR. CARUSO: So if the reactor coolant
12 pump mass flow rate changes, it's entirely because of
13 -- you're not making any changes to the geometry or
14 the reactor coolant system or the pressure drop
15 behavior of the fuel, correct?
16 MR. SICARD: We are not making any
17 physical changes to the reactor coolant system. You
18 do have some slight change in the hydraulic resistance
19 as the number of tubes plugged increases.
20 MR. CARUSO: Right.
21 MR. SICARD: And there are some slight
22 changes associated with the acceleration of fluid
23 through the core due to the higher heat input. Those
24 are relatively minor.
25 MR. CARUSO: Okay. So any change in the

1 flow through the reactor coolant pumps is due to the
2 change in the density of the fluid as it's flowing
3 around the loop and as it's heated by the core?
4 MR. SICARD: Yes, that would be correct.
5 CHAIRMAN WALLIS: Don't you have some
6 control over that flow rate? You must have. You just
7 run the pump and get whatever flow rate you get?
8 MR. SICARD: Yes.
9 CHAIRMAN WALLIS: Then that's another
10 interesting consideration. How do you manage to make
11 it happen?
12 MR. SICARD: Well, we do perform analyses
13 of the pressure drop within the core and there are,
14 you know, extensive analyses in order to document what
15 the flow rate will be and that it will be within the
16 acceptable criteria.
17 Would Steve Cybert of Westinghouse want to
18 add anything to that statement. I think Steve would be
19 the best person. Is he there?
20 CHAIRMAN WALLIS: So I'm trying to figure
21 out how you get the operate. You simply take more
22 steam out of the steam generator and that makes the
23 water colder?
24 MR. SICARD: Right.
25 CHAIRMAN WALLIS: And this then has

1 effects on the flow rate and everything else which
2 somehow works out.
3 MR. SIEBER: But the primary effect is on
4 the delta T.
5 MR. SICARD: Yes.
6 MR. SIEBER: The flow rate really doesn't
7 mean anything.
8 CHAIRMAN WALLIS: So how do you manage to
9 get the flow rate coming out of the core hotter? You
10 raise the power level?
11 MR. SIEBER: You lower -- is the way you
12 do it.
13 CHAIRMAN WALLIS: So, I mean, you seem to
14 be very concerned about regulations, you say
15 everything's within regulations. But I'm just
16 wondering whether the physics works out and you can
17 actually do it. Maybe it'll work out. Maybe when you
18 do this thing it'll happen exactly as you planned.
19 MR. SIEBER: It does. It works out.
20 CHAIRMAN WALLIS: Okay. Okay.
21 MR. SICARD: Steve, you have something
22 you'd like to add?
23 MR. CYBERT: Steve Cybert, Westinghouse
24 Electric.
25 As far as we're looking at the numbers,

1 and on the operating point, Kal, it does show that the
2 T hot will be more closer to like 601.8, so there's a
3 little more there as far as the delta T.
4 CHAIRMAN WALLIS: That helps me, too.
5 Because I still have the discrepancy of the 601. So
6 if you have 600.2 you might as well get the other
7 numbers to the same accuracy so we can make a simple
8 calculation.
9 We should move on here. It just to me
10 there's some very simple questions I was asking and it
11 seemed to be difficult to get a very simple answer.
12 MR. SICARD: We can provide some
13 information on this later today to clarify the issue.
14 CHAIRMAN WALLIS: Sure.
15 MR. SICARD: Okay. Getting on to some of
16 the other parameters. You know, one of the objectives
17 that we had in our power uprate is that we did want to
18 maintain a hot leg temperature approximately the same
19 on a nominal basis as what it was before. That is, you
20 know, somewhere around 601 degrees over here. And
21 that is why we lowered what the cold leg temperature
22 was slightly compared to where it is previously in
23 order to not aggravate any materials associated with
24 nominal hot leg temperature.
25 We have not changed what our nominal RCS

1 pressure is. The steam generator pressure for the
2 full power conditions goes down slightly because of
3 that increase in power and the fact that we have no
4 increased what that hot leg temperature is and steam
5 flow, of course, increases in order to get the
6 increase in power.
7 One other operating parameter of note is
8 that we have expanded the safety analyses to allow for
9 a slightly more negative moderator temperature
10 coefficient than what we had previously included in
11 our analysis. And now we cover up to a minus 4.2 times
12 10 to the minus fourth value for the MTC as opposed to
13 a minus 4.0 previously.
14 CHAIRMAN WALLIS: So your steam flow goes
15 up by 8.6 percent. And that leads you to stiffen the
16 condenser tubes because you're concerned about
17 vibration. So there's a rather small change in flow
18 and you do something with the condenser. The small
19 changes in flow through the core don't lead you to any
20 concerns about what might happen?
21 MR. SICARD: We have fully analyzed the
22 impact of flow conditions on the core for power
23 uprate. The change in the flow associated with the
24 slight increase in density is well within the bounds
25 of the number that we have based our maximum analyses

1 on. You know, we feel like we have a focus on reactor
2 safety in that we have done the analyses to show that
3 the hydraulic performance of the core is acceptable
4 and that this change is within the bounds that we have
5 established for the acceptable.
6 MR. ROSEN: Would you go back to the
7 moderator temperature coefficient again?
8 MR. SICARD: Yes.
9 MR. ROSEN: Tell me more about that. How
10 long does that last through the cycle an what is its
11 profile?
12 MR. SICARD: The moderator temperature
13 coefficient is roughly linear through the cycle. It
14 starts out at a value which is fairly small. Our
15 technical specification limit, I believe, is minus
16 0.02 at start up. Am I recalling that number
17 correctly, Jerry?
18 MR. HOLMAN: Yes. This is Jerry Holman.
19 The MTC that Paul referred to is the minus
20 4 is an end of cycle MTC.
21 MR. ROSEN: And the beginning of cycle.
22 MR. HOLMAN: The beginning of cycle is
23 very slightly negative at 100 percent power.
24 MR. ROSEN: And it remains negative at a
25 100 percent power throughout the cycle.

1 MR. HOLMAN: That is correct. Yes.

2 MR. ROSEN: Does it remain negative at a

3 100 percent power, I mean does it remain negative at

4 zero percent power through the cycle?

5 MR. HOLMAN: At zero percent power it is

6 slightly positive at the beginning of cycle.

7 MR. ROSEN: How positive is that?

8 MR. HOLMAN: I don't have the exact

9 number.

10 MR. SICARD: The former limit which

11 hopefully we do not challenge on each core design, is

12 I believe plus 0.5.

13 Jeff Brown of Westinghouse, do you recall

14 for cycle 14 what our beginning of cycle moderator

15 temperature coefficient is?

16 MR. BROWN: It's about a minus .3 at full

17 power conditions at beginning of cycle.

18 MR. SICARD: And do you have the numbers

19 with you for what it is at lower powers?

20 MR. BROWN: At zero power it's about a

21 plus .5.

22 MR. ROSEN: And how long does that last

23 through the cycle?

24 MR. BROWN: Well, it's --

25 MR. ROSEN: As the boron burns out?

1 MR. BROWN: Right. As Paul said, it's more
2 a less monotonically a decreasing throughout cycle
3 from the value of minus .5 to the end of cycle value
4 18 months later of about minus 4. That's delta --
5 MR. ROSEN: So I would just guess that
6 maybe from those numbers and the monotonic information
7 that it's about 20 percent through the cycle, perhaps,
8 before you go to zero?
9 MR. SICARD: I'd say a little bit less
10 than that.
11 MR. BROWN: Well, at full power.
12 MR. ROSEN: I know, at zero power?
13 MR. SICARD: At zero power it probably
14 would be about -- my guess is, you're correct, about
15 20 percent of the cycle.
16 MR. ROSEN: Thank you.
17 MR. SICARD: And for the cycle 14 core in
18 particular, you know while we have expanded the range
19 of the MTC in most of the safety analyses to this
20 minus 4.2 value, our actual expected end of cycle MTC
21 for cycle 14, our first power uprate four that we will
22 be starting up in May or June is a minus 3.9 value. So
23 the minus 4.2 is the result of consideration for
24 providing an expanded range to accommodate the uprate
25 fours. But the first uprate four is within the bounds

1 of what we had previously assumed.

2 MR. ROSEN: And how many effective full

3 power days is the core loaded with for anything on

4 site?

5 MR. SICARD: Okay. Jeff, do you have your

6 number at your fingertips, number of effective full

7 power days?

8 MR. BROWN: Yes. It's 510 EFPDs.

9 MR. SICARD: And I'll compare that to our

10 cycle 13 core which was actually designed for a 524

11 EFPD cycle.

12 MR. ROSEN: Thank you very much.

13 CHAIRMAN WALLIS: While we're talking

14 about flow, the concern with flow-induced vibrations

15 in the steam generator, is that due to the steam flow

16 or water flow?

17 MR. SICARD: Let me refer that to one of

18 our support staff over here. I think Don Siska from

19 Westinghouse is the best person to answer that

20 question.

21 MR. SISKA: Yes. This is Don Siska from

22 Westinghouse.

23 The answer is both the two areas that are

24 most commonly see that flow-induced vibration are the

25 downcomer entrance to the tube bundle, which is

1 essentially saturated flow, maybe slightly subcooled,
2 and also in the upper tube bundle, the horizontal
3 section of tubing which is mainly a high quality steam
4 at that point or mid quality steam.
5 CHAIRMAN WALLIS: Are you going to cover
6 that later on?
7 MR. SICARD: That will be covered in David
8 Viener's presentation on the impacts to the plant.
9 Next slide.
10 We'll go on and discuss some of the
11 significant aspects of the uprate. As presented on
12 the previous slide, we're trying to maintain
13 approximately the same nominal hot rate temperature.
14 One of the significant aspects is that we are
15 crediting our steam generator atmospheric dump valves,
16 the ADVs, for secondary pressure control for the small
17 break LOCA event. Those are safety related valves that
18 have already been credited as a means of cool down for
19 the plant and we now have also credited them in this
20 particular analysis.
21 We have adopted the Westinghouse 1999
22 large break LOCA evaluation model for the ECCS
23 analyses.
24 We have moved to the Westinghouse CENTS
25 code as opposed to the CESEC code for the evaluation

1 of non-LOCA transients. The FSAR Chapter 15 type
2 events over there. And that is the case of moving to
3 a more moderate code that has increased capability.
4 It has slightly better modeling on the secondary side
5 and the steamline.
6 And we have also adopted the alternative
7 source term methodology for our dose calculations.
8 And that is something that we have done primarily in
9 response to the generic letter on control room
10 habitability.
11 I will mention that there is a precedent
12 for crediting the atmospheric dump valves on this
13 role. South Texas Project credits them in a similar
14 capacity.
15 Next slide.
16 These are a list of some of the technical
17 specifications of interest for the power uprate.
18 Because we are crediting the atmospheric dump valves
19 in the small break LOCA analyses, we have moved the
20 requirements that we have on them from the licensee
21 controlled technical requirements manual to our
22 technical specifications including the specification
23 of the setpoint for those valves.
24 We have raised what our minimum boric acid
25 concentration is in the boric acid makeup tank in

1 order to show acceptable shutdown margin. We have also
2 made more rigorous assumptions in that analysis than
3 the original calculations that supported those
4 technical specifications.
5 We have lowered the maximum liquid volume
6 in the safety injection tank. That was done for large
7 break LOCA purposes. What that does is it increases
8 the volume of the pressurized nitrogen at the top of
9 the tank which drives the safety injection flow into
10 the reactor coolant system with a better delivered
11 guides that flow in faster because of having more of
12 that gas pressure. Because of the lower steam
13 generator pressure associated with our uprate
14 conditions, we have lowered our setpoints on low steam
15 generator pressure to maintain operational margin.
16 As an enhancement we have moved the
17 controls on minimum containment temperature, which is
18 a parameter credited in the ECCS analysis from the
19 technical requirements manual to he technical
20 specifications. And --
21 CHAIRMAN WALLIS: Now why did you do that?
22 MR. SICARD: We had this parameter in the
23 technical requirements manual. And we had a discussion
24 as we were formulating our license amendment on this
25 parameter. And we felt that minimum containment

1 temperature because of it's role in ECCS performance
2 analysis merited under 50.36 being included in
3 technical specifications.
4 CHAIRMAN WALLIS: The focus has something
5 to do with NPSH?
6 MR. SICARD: This does not have --
7 CHAIRMAN WALLIS: It has no impact on it?
8 MR. SICARD: This has does not have impact
9 on NPSH. We do not credit containment over pressure
10 for our net positive suction head calculations.
11 And we have also changed our specification
12 for primary to secondary leakage for the steam
13 generator. We have based on discussions with the
14 staff adopted an operational leakage value. This is
15 similar to the operational leakage that is discussed
16 in NEI 97-06. And the industry as a whole is moving
17 based on discussions with the staff to adopting
18 operational leakage values for the steam generator.
19 CHAIRMAN WALLIS: But the previous slide
20 you mentioned control room habitability. We're going
21 to discuss that later on?
22 MR. SICARD: Yes. The end of my
23 presentation I have a discussion on the alternative
24 source term, analyses including the results of our
25 control room habitability tests.

1 CHAIRMAN WALLIS: And will there be some
2 discussion of the remote shutdown panel and
3 accessibility?
4 MR. SICARD: We had not included --
5 CHAIRMAN WALLIS: The time to perform
6 operations there and that sort of thing?
7 MR. SICARD: We have a discussion from our
8 operations support people here on what the operational
9 impact is of power uprate, including the impact on
10 procedures. Does that answer your question.
11 CHAIRMAN WALLIS: Well, maybe they will
12 cover that then, remote shutdown panel. I didn't find
13 anything about that in the documentation, which is
14 curious. So put that on the list of things to --
15 MR. SICARD: Somebody has that on the list
16 then.
17 DR. KRESS: Are you going to talk about
18 your calculations from the control room habitability
19 with the alternative source term?
20 MR. SICARD: I didn't catch the beginning
21 of your question.
22 DR. KRESS: Is it on the agenda to go over
23 the calculations that are on the alternative source
24 term --
25 MR. SICARD: I will present the results of

1 that and fully prepared to discuss that.

2 DR. KRESS: What code did you use for

3 that?

4 MR. SICARD: We used RADTRAD.

5 DR. KRESS: RADTRAD.

6 MR. SICARD: We have a couple of slides

7 presenting some of the analysis changes associated

8 with our power uprate effort. As noted before, we

9 have expanded the assumption on number of steam

10 generator tubes plugged for power uprate. Currently

11 our analyses support a maximum number of 700 tubes

12 plugged, and we for power uprate plus that number up

13 to 1,000 to give us more margin on that particular

14 parameter.

15 The next slide.

16 CHAIRMAN WALLIS: Are you going to discuss

17 the small break LOCA and things like that? Is someone

18 going to do that later on?

19 MR. SICARD: Yes. I am presenting kind of

20 the generic list of the analysis changes and I have

21 slides later on small break and large break LOCA.

22 CHAIRMAN WALLIS: Okay.

23 MR. ROSEN: Did you mention earlier that

24 you were planning to change the steam generators out?

25 MR. SICARD: No. We do not have any

1 definite plan for changing the steam generator. Ted
2 Leonard will speak to that.
3 MR. MITCHELL: Actually, I am Tim
4 Mitchell.
5 We have initiated studies for steam
6 generator replacement. Those studies indicate that it
7 will be sometime after the 2010 time frame before we
8 would be required. Probably more likely beyond 2012.
9 But we will be monitoring and updating that study
10 after each refueling outage following our inspection
11 scope and what we find. But right now, steam
12 generator replacement is something we anticipate in
13 the future, but it is a number of years off.
14 MR. ROSEN: What do you think it's impact
15 would be on the EPU depending the plant is granted an
16 extended power uprate?
17 MR. MITCHELL: That the steam generator
18 replacement would account for the extended power
19 uprate and we would factor in other variables such as
20 did we want to raise T_{hot} after steam generator
21 replacement, those types things. But, you know, none
22 of that design has been started as far as designing
23 the steam generators. But we would expect that all of
24 this power uprate and life extension would be factored
25 into the replacement steam generator uprate.

1 CHAIRMAN WALLIS: Did you get to the
2 lowest item yet?
3 MR. SICARD: Pardon?
4 CHAIRMAN WALLIS: Did you get to the
5 lowest item here yet?
6 MR. SICARD: No. I was just going to
7 mention that in passing, and we do have a slide on
8 that later, we have changed our analysis on the long
9 term cooling. We previously had credited the lower
10 plenum in the mixing volume as a result of lessons
11 learned or operating experience from the ANO power
12 uprate. We changed what that assumed volume was for
13 the analysis. We submitted such that we no longer
14 credit the lower plenum but instead credit a portion
15 of the upper plenum.
16 CHAIRMAN WALLIS: Is this making -- is
17 this now a more conservative analysis?
18 MR. SICARD: Yes. That is a more
19 conservative analysis because that gives you a smaller
20 overall mixing volume under the power upgrade
21 assumptions, which means that you get to the
22 concentration limit sooner.
23 CHAIRMAN WALLIS: And in the resolution of
24 GSI-185 we were convinced by the staff to accept a
25 well mixed lower plenum. So it just seems to be going

1 on the opposite direction here, but if it's
2 conservative that's okay.
3 MR. SICARD: It is conservative. And I
4 believe the staff is also going to discuss this
5 analysis.
6 CHAIRMAN WALLIS: I think they need to
7 because there's a very long discussion in the SER
8 about this matter, and I couldn't quite see how it got
9 resolved.
10 MR. SICARD: Continuing on. One aspect of
11 our uprate analysis is that we now predict and permit
12 fuel failure for the return to power main steamline
13 break analysis, one of the Chapter 15 analyses. There
14 are two analyses that are done for main steamline
15 break. This is the one for the longer term reactivity
16 control return to criticality. And we now allow a 2
17 percent fuel failure due to the DNBR departure from
18 nucleate boiling mechanism. There's a precedent in
19 terms of Florida Power & Light and Calvert Cliffs also
20 having fuel failure for that event.
21 I will point out that we do not have fuel
22 failure for any of the outside containment main
23 steamline break for Waterford. We have fully adopted
24 the method of statistical convolution for assessing
25 the amount of fuel failure for the Chapter 15 events,

1 and we have updated the ANSI standard upon which we
2 base our reactor coolant radioisotopic concentrations.
3 Let me also point out on this main
4 steamline break analysis, that is based upon a minus
5 4.2 MPC. And the amount of fuel failure would be
6 significantly reduced and we may not have any if we
7 looked at that based upon the minus 3.9 value that we
8 would actually have for cycle 14.
9 Next slide presents the analysis changes
10 that are pertinent to the dose analysis. We're
11 adopting the alternative source term methodology. We
12 are changing the primary-to-secondary leak rate
13 technical specification to an operational leakage
14 value, 75 gallons per day, per steam generator.
15 We have updated the calculation of our
16 atmospheric dispersion factors for use in both offsite
17 dose analyses and for the main control room. We are
18 using ICRP30 dose conversation factors.
19 And we have expanded the scope of the
20 control room doses that are reported in our final
21 safety analysis report to include all of the non-LOCA
22 transients analysis and the small break LOCA as well
23 as the large break LOCA and the fuel handling accident
24 which are the two events that we currently report for
25 control room dose.

1 The next slide. This is where are
2 addressing fuels issues related to the operating. And
3 I hope that we will answer the questions that you have
4 related to fuel here.
5 Our cycle 14 fuel design, there's no
6 change in the fuel mechanical design. It is a standard
7 16 by 16 Westinghouse/CE fuel design. It is a 18 month
8 fuel cycle. We continue to use Erbia as the burnable
9 poison in that design. We've been using Erbia for
10 several fuel cycles.
11 Out of the 217 total fuel assemblies in
12 the core, we will have a batch size of 100 fresh
13 assemblies for the upcoming cycle. We have done
14 analysis for the fuel rod corrosion and duty, and
15 demonstrated that we have acceptable performance
16 related to those parameters.
17 We've asked questions as far as how much
18 power we're getting out of the fuel. On a core
19 average linear heat rate basis, we will have a core
20 average linear heat rate that corresponds to 5.8
21 kilowatts per foot. That's just slightly larger than
22 the ANO conditions after they're operated at 5.7. And
23 that is not an outlier compared to other PWRs.
24 Prairie Island has a corresponding value, 6.2. Indian
25 Point has a value of 6.6.

1 CHAIRMAN WALLIS: It says in the SER that
2 the peak linear heat rate is actually reduced. So you
3 must have done something to change the heat generation
4 distribution.
5 MR. SICARD: Well, the peak linear heat
6 rate that is assumed as the input in the ECCS analysis
7 for power uprate is a value of 13.2 kilowatts per foot
8 which compares to a value in the current pre-rate ECCS
9 analyses of 12.9 kilowatt per foot.
10 CHAIRMAN WALLIS: So it's actually
11 increased?
12 MR. SICARD: On that basis it has
13 increased. We have been able to increase what the
14 value is that we can accommodate within the analyses.
15 You know, there are different -- you know, linear heat
16 rate enters into different analyses and with different
17 biases. And I do not want to comment on what's in the
18 SER because I'm not sure of the context in which that
19 was presented. But, you know, looking at this from
20 the ECCS performance analysis our power uprate
21 supports an increase in what that peak linear feet --
22 CHAIRMAN WALLIS: So should we think that
23 what's happening here is that a power generated in the
24 core is increased by 8 percent everywhere?
25 MR. SICARD: That would be a simplistic

1 way of looking at it. What we have, really, is a case
2 where more of the assemblies are sharing the power.
3 More of them are operating closer to the limit.
4 I'm going to ask Jeff Brown from
5 Westinghouse, who is --
6 CHAIRMAN WALLIS: So there is a change in
7 the distribution?
8 MR. SICARD: Yes, you could say there is
9 a change in the distribution --
10 CHAIRMAN WALLIS: Because in these power
11 uprates that we've seen before when there's a large
12 power uprate, the management of the fuel becomes very
13 important.
14 MR. SICARD: And --
15 CHAIRMAN WALLIS: And is often the key to
16 getting the high uprate.
17 MR. SIEBER: Yes. But at this point you
18 aren't designing in the final design on the long term
19 steady-state cores. You do that reload by reload as
20 you go along. So what you know most about is the
21 transition fuel.
22 I think a way to look at this, if there
23 were not a EPU, how many assemblies would you
24 typically add each refueling?
25 MR. SICARD: We had 92 assemblies for

1 cycle 13, which is currently operating compared to 100
2 assemblies for cycle 14 our first power --
3 MR. SIEBER: Okay. So you're increasing
4 it by about 8 percent?
5 MR. SICARD: Yes.
6 MR. SIEBER: Which is about the size that
7 you would use.
8 MR. SICARD: Yes.
9 MR. SIEBER: So the burnup will stay the
10 same, the enrichment is typical --
11 MR. SICARD: Yes.
12 MR. SIEBER: The first cycle enrichments
13 will be the same?
14 MR. SICARD: The increase in enrichment
15 from cycle 13 to cycle 14 is 0.07 percent. So it is
16 very small.
17 MR. SIEBER: It's basically the same.
18 MR. SICARD: Yes, it is basically the
19 same.
20 MR. SIEBER: Now you're using a low
21 leakage core?
22 MR. SICARD: Yes, we have a low leakage
23 core.
24 MR. SIEBER: Okay. So the second and
25 third burn assemblies on the outside, basically?

1 MR. SICARD: The third burn on the
2 outside, yes.
3 MR. SIEBER: Yes. Okay. So that's where
4 the power comes from, this additional assembly you
5 said, and it's right over --
6 MR. SICARD: We're trying to get more
7 assemblies sharing the load --
8 MR. SIEBER: Right.
9 MR. SICARD: -- so that they are all
10 closer together in terms of the power.
11 MR. SIEBER: Right.
12 MR. SICARD: Let me have Jeff Brown from
13 Westinghouse provide his perspective on this. Jeff?
14 MR. BROWN: Right. I just want to
15 mention, as Paul said, although the average power in
16 the fuel rods has increased, in fact the peak fuel rod
17 power has remained more or less the same because this
18 increase in batch size, feed batch size, but also the
19 fact that we added a more burnable absorber, the more
20 smoothed the power distribution. And it was one of
21 the goals going in that the peak rod power would not
22 substantially be -- you know, in terms of absolute
23 power, kilowatts per foot, relative to what the thing
24 is. And so we inspect under normal operating
25 conditions to have about the same margins for the fuel

1 limits as we currently do.

2 MR. SIEBER: Since you volunteered to

3 answer questions, let me ask another that relates to

4 what Mr. Rosen discussed before.

5 If you had added additional burnable --

6 you could actually lower the zero power temperature

7 coefficient which is now positive and make it

8 negative, correct, which from an operator standpoint

9 would be a more stable core. And the offset for that

10 is you would have to increase enrichment cycling and

11 those are dollar bills that you're putting in.

12 Some utility licensees try to keep the

13 moderator coefficient negative in all cases. Would it

14 be a worthwhile endeavor for this plant to do such a

15 thing from the standpoint of operational stability,

16 particularly in cycle life?

17 MR. HOLMAN: This is Jerry Holman.

18 That is the balance that we always have to

19 weigh. I should mention, though, that this is not the

20 first cycle that we've seen, the positive MTC at low

21 power. So the operators are used to seeing that and

22 dealing with that type of response.

23 MR. SIEBER: Is it the practice of Entergy

24 to try to maintain negative temperature coefficients

25 at all times and exceeding it and having it go

1 positive as an exception?

2 MR. HOLMAN: We look at the balance of

3 those two factors. As you mentioned, the operational

4 impact versus the impact of the fuel and putting the

5 extra enrichment in there.

6 MR. SIEBER: So the answer is no?

7 MR. HOLMAN: Our balance would allow us to

8 have a slightly positive MTC as zero power. We've

9 trained the operators to address that and they're

10 familiar with that type of core response.

11 MR. MITCHELL: This is Tim Mitchell.

12 And I can speak from our Arkansas Nuclear

13 One experiences with what would turn out to be a

14 similar core post uprate and the effects of positive

15 moderator temperature coefficient on the operators

16 even at low powers is very minimal. So that is

17 something we've trained extensively on. And if we saw

18 problems with that, that is something that we would

19 consider changing our philosophy.

20 MR. SIEBER: Well, during a transient then

21 coefficient does turn negative someplace in the course

22 of a power transient. On the other hand, it makes for

23 a unusual response from the operator's viewpoint.

24 MR. MITCHELL: We use a lot of just in

25 time training to make sure that they're prepared for

1 changes in --

2 MR. SIEBER: Well it always happens just

3 in time.

4 MR. CARUSO: Who does your core design?

5 Do you do your own core design or do you have

6 Westinghouse do it?

7 MR. SICARD: Westinghouse does our core

8 design. Entergy does maintain an intrusive role in

9 that process, both in terms of participation from our

10 site safety analysis and reactor engineering and

11 operations groups as well as our corporate support

12 staff located in Jackson, Mississippi which provides

13 core physics supports to all of the Entergy South

14 sites.

15 CHAIRMAN WALLIS: While we're on this

16 number of first assemblies, so there's a discussion in

17 the SER about maximum heat loads to the spent fuel

18 pool and the decay time required for reactor shutdown

19 before you can transfer the fuel. Presumably you have

20 -- you just have 8 percent more assemblies with the

21 same burnoff as before you're transferring. It doesn't

22 seem like much of an issue, does it? But why is it

23 mentioned in the SER then?

24 MR. SICARD: Well, David Viener will

25 discuss these issues as part of the --

1 CHAIRMAN WALLIS: Oh, that's going to come
2 later?
3 MR. SICARD: -- design input. As far as
4 that ultimate heat sink calculation, that is a case of
5 where the analysis of record was done, you know, back
6 in the start up days and was a very conservative
7 analysis such that when we have updated mass and
8 energy releases that go into that calculation we
9 result in a lower peak heat load on the ultimate heat
10 sink now under power uprate than under the previous.
11 CHAIRMAN WALLIS: So part of the way you
12 can get this power uprate is because your analysis is
13 now sharper than it was before on several of these
14 matters, it seems to me?
15 MR. SICARD: Yes. There area number of
16 cases where that is the case, where the calculations
17 as done originally had conservatism in them that can
18 easily accommodate an 8 percent power uprate.
19 David Viener, would you like to add
20 anything on the subject? He's standing there to say
21 something. Okay.
22 Are there any other questions regarding
23 fuel or is it okay if I continue on to discuss other
24 aspects?
25 MR. SIEBER: Well, let me ask just as part

1 of the roadmap through all the presentations, the work
2 that you do comes up with safety limits, right? The
3 work that you personally do?
4 MR. SICARD: Yes.
5 MR. SIEBER: Your responsibility, your
6 come up with safety limits. From safety limits
7 somebody goes through a scaling manual process to come
8 to safety systems settings which is what one puts into
9 the instruments to cause reactors to --
10 MR. SICARD: Yes.
11 MR. SIEBER: Will someone discuss the
12 methodology that Entergy proposes at Waterford to make
13 safety system settings? And if so, who will it be so
14 that I can --
15 MR. SICARD: No, we were not going to
16 present too much information on that topic since we
17 only have one of our setpoints, which is changing for
18 power uprate. That is our low steam generator --
19 MR. SIEBER: My questions is more generic
20 than that. My questions involves the use of ISA RP
21 67.04 Method 3 which is not allowed by the staff,
22 which you proposed to use. And I want to know where
23 you stand,
24 MR. SICARD: I think I have the answer to
25 your question, which is that we had proposed the

1 setpoint per Waterford's license methodology
2 originally. There have been some discussions with the
3 staff subsequently on that one setpoint. Based on our
4 discussions with the staff, we have conservatively
5 adjusted that setpoint. We raised that setpoint
6 slightly in order to satisfy the staff's concerns and
7 we can come to an agreement.
8 MR. SIEBER: Are you still using Method 3?
9 MR. SICARD: I'm going to --
10 MR. SIEBER: With an adjustment?
11 MR. SICARD: I am going to have our lead
12 instrumentation engineer for power uprate Tom
13 Fleischer step in and address this.
14 MR. FLEISCHER: My name is Tom Fleischer.
15 I'm the lead I&C instrumentation engineer for
16 Waterford 3.
17 Currently the answer is no we do not.
18 Currently the answer is yes, we do use methods for the
19 other NSSS setpoints at this time. The setpoint that
20 we touched for extended power uprate was derived based
21 on our technical specification basis. We added
22 additional margin to that setpoint per the staff's
23 request which, I hate to admit, makes it equivalent to
24 Method 1.
25 The reason I'm saying I hate to admit is

1 because the committee right now, ISA 67.04, of which
2 I'm a voting member, currently is having discussions
3 about the use of Method 3.
4 MR. SIEBER: That's tomorrow, right?
5 MR. FLEISCHER: Yes.
6 MR. SIEBER: Okay. The meeting is
7 tomorrow.
8 Well, the way things stand right now
9 Method 3 is not endorsed by the regulation. And
10 Waterford is not the only plant that's in this
11 situation because others have chosen that pathway. On
12 the other hand, I have an interest in that and I think
13 it needs to be resolved. And as a person with
14 infinite patience, I will wait for the staff to make
15 progress on that. But it's something that I will
16 follow. And I would have objected to the EPU on that
17 basis, had you insisted on using Method 3 without any
18 adjustment. But since you've made an adjustment and
19 the staff's approved that, I guess I will wait until
20 a more generic resolution of the whole issue occurs.
21 It is something that has to happen sooner or later.
22 Okay. Thank you very much.
23 CHAIRMAN WALLIS: We're running way
24 behind. And I suggest that you keep going until you
25 finish your presentation and we have a break.

1 MR. SICARD: Okay.

2 CHAIRMAN WALLIS: And I hope that happens
3 before lunch sometime.

4 MR. SICARD: Okay. We have some slides
5 presenting the results of some of our specific
6 analyses. We have revisited our containment analysis
7 for power uprate. Our current containment LOCA
8 pressurization analysis already accounted for power
9 uprate in terms of the mass and energy releases. We
10 generated new mass and energy releases for main
11 steamline break, rerun these analysis using the GOTHIC
12 code, which is our current license code for this. The
13 results show that we meet our 33 psig acceptance
14 limit. There's essentially no change in the LOCA
15 results and the main steamline break results have gone
16 down slightly due to the lower steam generator
17 pressure at full power conditions.

18 The next slide. As I mentioned, we are
19 transitioning to the use of the CENTS analysis code
20 instead of CESEC for non-LOCA transients. CENTS is a
21 code that has been generically approved by the NRC for
22 CE designed plants, and it has also received plant
23 specific approval also for ANO 2, San Onofre and Palo
24 Verde.

25 One aspect of our transient analysis is

1 that we are continuing to credit a three second time
2 delay between reactor trip and the time of loss of
3 offsite power for the steam generator 2 rupture. That
4 assumption had previously been included in the CESAR
5 analysis and is also an assumption which is common for
6 Westinghouse Pittsburgh plants to assume for various
7 Chapter 15 events.
8 We have basically, as I said, gone through
9 and rewritten all of the safety analysis that go into
10 Chapter 15 of the final safety analysis report. We
11 have demonstrated that we meet the acceptance criteria
12 for those events, be that it may depending on the
13 specific event a no fuel failure acceptance criteria
14 or a fuel failure that supports the limits for the
15 dose calculations.
16 Next slide presents the results on our
17 limiting pressurization events, which is the loss of
18 condenser vacuum and for a limiting fault event, the
19 feedwater line break. This shows that we continue to
20 meet what those acceptance criteria are.
21 The next slide, our large break LOCA
22 analysis has been updated. We based upon the 1999
23 evaluation model. We currently use the 1985 model.
24 Mentioned some of the changes that went into this
25 analysis such as lowering what the maximum liquid

1 level assumes for the safety injection tank is. Our
2 maximum peak clad temperature from this analysis is
3 2164 which meets the acceptance criteria of 2200.
4 DR. RANSOM: What was that before?
5 MR. SICARD: The value currently in our
6 license basis analysis today is 2177.
7 DR. RANSOM: One thing that hasn't been
8 clear from this presentation is you're getting more
9 power out of the core, you haven't changed the
10 velocity through the core because I think you're
11 arguing you both maintained the volumetric flow
12 constant, which means that -- and the heat transfer
13 coefficient hasn't changed as a result of that or very
14 much. And so it must come from an increase in
15 temperature from the fuel clad to the fluid. And I
16 know you've lowered the temperature of the incoming
17 flow, but not changed the temperature of the outgoing
18 flow. But what happens to the peak power region of
19 the core; it's sort of unclear. It'd be nice to see a
20 picture of the fluid temperature and the clad
21 temperature through the core.
22 MR. SIEBER: I think you'd have a flatter
23 distribution.
24 DR. RANSOM: And I'm surprised that you
25 wouldn't increase the peak clad temperature under the

1 loss of coolant accident.

2 MR. SICARD: Well, for the question of

3 normal operation, Jeff Brown attempted to address that

4 in terms of the lowering peaking on the hot assemblies

5 for power uprate result in a very similar

6 characteristic for the hot assemblies under power

7 uprate compared to the hot assemblies in today's core.

8 And that's because of spreading what the load is

9 amongst more of the assemblies.

10 Now, for the large break LOCA, we do have

11 an improvement in the performance of this analysis

12 associated with using the 1999 evaluation model and we

13 do see some improvement in terms of improved delivery

14 of the safety injection tank fluid to the reactor

15 fluent system because of that increased vapor volume

16 at the top of the take. Those are the reasons why for

17 power uprate we are able to demonstrate using that

18 change to the safety injection tank and to the

19 evaluation model that the peak clad temperature

20 remains roughly similar.

21 MR. LEONARD: But the short answer is that

22 the higher decay heat that would drive a higher peak

23 clad temperature in the large break LOCA event is

24 offset by the better model. So we're getting a lower

25 peak clad temperature because we're using the new

1 evaluation model.

2 DR. RANSOM: I was concerned about the

3 stored energy. The --

4 MR. LEONARD: Right. That's correct. But

5 the new model offsets that higher decay heat and the

6 stored energy and gives us slightly lower temperature,

7 heat clad temperature.

8 MR. SIEBER: The model that you're using

9 is not a realistic model.

10 MR. LEONARD: That's correct. Yes --

11 MR. SIEBER: If you use the realistic

12 model, your temperatures would be around 1500 or

13 something?

14 MR. LEONARD: Would be much lower than

15 what we have here, yes.

16 DR. DENNING: Do you get discharge of the

17 nitrogen into the system? Do you have more discharge

18 of nitrogen in the system or is there something that

19 prevents the discharge?

20 MR. SICARD: There are limits on the

21 maximum and the minimum amount of nitrogen in the

22 system. And we did not change anything dealing with

23 the maximum nitrogen volume.

24 Joe Cleary from Westinghouse will have

25 something to add.

1 MR. CLEARY: Yes. My name is Joe Cleary.
2 LOCA safety analysis, Westinghouse, involved with the
3 Waterford power uprate analysis.
4 Yes. In the large break LOCA calculation
5 the safety injection tanks do empty their liquid and
6 inject the nitrogen into the RCS. The tanks inject
7 the nitrogen at an RCS pressure of roughly psi or so.
8 And the large break LOCA evaluation model represents
9 the effect of that nitrogen discharge in the injection
10 section of the RCS piping.
11 MR. SICARD: Does that answer your
12 question?
13 DR. DENNING: It wasn't clear. But there
14 is a larger nitrogen volume injected then?
15 MR. CLEARY: Yes. In order -- by lowering
16 the -- the analysis does analyze a maximum SIT liquid
17 level as the most limiting condition, and therefore by
18 lowering that there is slightly more, by that same
19 amount, more nitrogen.
20 MR. SICARD: Let me move on to the small
21 break LOCA analysis. We have not changed the method
22 for that analysis. Waterford 3 continues to use the
23 S2M evaluation model. We have credited the automatic
24 operation of the atmospheric dump valves on the
25 secondary side for secondary pressure control for the

1 small break LOCA. Previously relied on the main steam
2 safety pressure that control pressure at a higher
3 pressure.
4 We have a 1040 psia analysis setpoint for
5 the atmospheric dump valves. What this functionally
6 means is that we're able to control the pressure in
7 the reactor coolant system slightly lower which gives
8 increased flow delivery from our high pressure safety
9 injection pumps for this event.
10 We had historically at Waterford credited
11 the charging pumps in the small break LOCA analysis.
12 Those have been removed from that analysis both for
13 today's conditions and for power uprate conditions.
14 And the results of our analysis show a peak clad
15 temperature of 2019 degrees, which meets the 2200
16 acceptance criteria.
17 CHAIRMAN WALLIS: In your SBLOLCA analysis
18 you present lots of the two-phase level in the core.
19 And a minimum two-phase level is about half way down
20 the core for 1,000 seconds or more. To me a two-phase
21 level means the top of a two-phase mixture, so that
22 would indicate that the half top of the core is dry.
23 I don't think that's what you mean, is it?
24 MR. SICARD: Joe, would you care to answer
25 that?

1 MR. CLEARY: Yes, that is what -- that the
2 picture is supposed to present. The upper half of the
3 core is dry steam that the cladding is being cooled by
4 steam, heat transfer to steam both convective and
5 radiation.
6 CHAIRMAN WALLIS: For that very long
7 period of time. It seems surprising to me that you can
8 steam cool for that long period of time.
9 MR. CLEARY: That amount of coolant
10 recovery is not unusual. It's very similar to other
11 analysis we've been doing with our evaluation model
12 from the very beginning. The p-cladding temperature
13 of 2000, low 2000 is a somewhat typical result for a
14 CE PWR using our methodology.
15 CHAIRMAN WALLIS: Maybe it's it all right.
16 I remember analyzing TMI, and when that went dry
17 things heated up pretty quickly. Maybe it's all right.
18 I'm just surprised. You got some much of the core dry
19 for so long with that small break LOCA.
20 MR. SICARD: You have removed the sensible
21 heat before that occurs and your decay heat has gone
22 done somewhat by that point in time. You know, we do
23 have an increase in the clad oxidation associated with
24 the small break LOCA for power uprate which probably
25 is tied to this phenomenon that you are referring to

1 here.

2 Joe, would you have any further comments?

3 MR. CLEARY: You've made a good point.

4 The time at temperature is what controls the cladding

5 oxidation and the cladding oxidation did go up but

6 still well below the acceptance criterion level.

7 MR. SICARD: Right. And if I remember our

8 boiler brethren, they basically look to try to keep

9 the core one-third covered in order to credit the

10 steam cooling for the top part of their cores. You

11 know, our fuel is of a different design, but one would

12 have the same phenomenon to some extent.

13 CHAIRMAN WALLIS: Some of these plots are

14 in terms of collapsed level, and that's not what

15 you're showing here. You're showing a two-phased

16 level?

17 MR. CLEARY: Yes, sir.

18 MR. SICARD: I'll go on, if I may.

19 On LOCA long term cooling,t his is the

20 boric acid precipitation analysis that is done for the

21 core. And this was analyzed per the approved CE

22 Westinghouse methodology. And with the change in the

23 mixing volume that I had presented in the earlier

24 slide where we assumed part of the outlet plenum but

25 no longer assumed the inlet plenum as the mixing

1 volume, the results of that analysis who that the
2 initiation of hot leg injection in a two to three hour
3 time frame after a loss of coolant accident shows that
4 you meet your solubility limit. We have a four weight
5 percent margin at the three hour time point to that
6 solubility limit. And this is a change which is
7 primarily due to the change in method, change in
8 assumed volume rather than one which is driven by the
9 power uprate itself.
10 CHAIRMAN WALLIS: This is an area where
11 the staff has not always agreed with you?
12 MR. SICARD: There have been some
13 discussions with the staff on that. Let's see, Jerry
14 Holman, I believe --
15 MR. HOLMAN: Yes. We have had some
16 discussions with the staff on concerns that they had.
17 We have come to resolution on those concerns. And
18 I'll let the NRC staff discuss that more in their
19 presentation.
20 CHAIRMAN WALLIS: What's the ultimate heat
21 sink?
22 MR. SICARD: The ultimate heat sink aspect
23 of the analysis will be discussed in Dave Viener's
24 presentation.
25 CHAIRMAN WALLIS: I understand it's

1 cooling towers?

2 MR. SICARD: We have a combination of wet

3 and dry cooling towers. Dave, would you care to

4 answer that?

5 MR. VIENER: My name is David Viener, and

6 I'm the power uprate mechanical engineering lead.

7 Ultimate heat sink consists of the

8 component cooling water system, aux component cooling

9 water system and the wet cooling tower basins. The

10 component cooling water system uses a set of dry

11 cooling towers. The aux component systems removes heat

12 from the component cooling water system using the wet

13 cooling towers.

14 CHAIRMAN WALLIS: The condenser water is

15 cooled by normal operation?

16 MR. SICARD: The condenser is cooled by

17 our circulating water system, which is a once through

18 system cooled by the river.

19 CHAIRMAN WALLIS: It's cooled by the

20 river? Yes.

21 MR. SICARD: Yes.

22 CHAIRMAN WALLIS: So I just wondered why

23 you needed cooling towers when you have one of the

24 biggest rivers in the nation running next door?

25 MR. VIENER: Well, the plant was

1 originally designed to use the river, but during
2 original licensing it was determined to have an
3 independent --
4 CHAIRMAN WALLIS: It case the river dried
5 up, is that it?
6 MR. SICARD: I understand that happened to
7 Beaver Valley once.
8 CHAIRMAN WALLIS: The Mississippi probably
9 wouldn't dry up, but it might get diverted under
10 flood.
11 MR. SICARD: We can address that in our
12 risk considerations portion of the analysis.
13 Let me go on to the AST dose analysis.
14 Waterford had documented control room dose previously
15 only for the large break LOCA and the fuel handling
16 accidents. While we were in our power uprate project
17 developing analysis in support to it, there was the
18 issuance of the NRC Generic Letter 2003-01 on control
19 room habitability. And as a result of that generic
20 letter, Waterford saw the need to add to its licensing
21 basis for the control doses for other events.
22 We conducted our trace gas test of the
23 plant in April of 2004, which was after the initial
24 submittal of our power uprate licensing application.
25 And we have made a subsequent related but separate

1 license amendment to adopt alternative source term in
2 order to address the control habitability issues for
3 the plant. That amendment is under staff review and is
4 one of the open items that Kaly had mentioned in his
5 introduction.
6 We have in those analysis bounded what our
7 control room inleakage is under both modes of
8 operation of our control room. Our control room will
9 go into what we call a recirculation mode on receipt
10 of a safety injection actuation signal or a high
11 radiation signal at the intakes. And that is a mode
12 where you recirculate and filter the air which is in
13 the control room.
14 There is also a pressurized mode which the
15 operators can select and can put the control room in.
16 And when they do that, there is approximately 200 CFM
17 of filtered intake flow that comes into the control
18 room to pressurize it.
19 Our analysis have assumed values that
20 bound the measured inleakage. We assume 100 CFM in the
21 recirculation mode. It bounds a 79 CFM measured value
22 and we assume a 65 CFM value in the pressurized mode
23 that bounds a 36 CFM measured value.
24 DR. DENNING: Can you help us a little bit
25 on that?

1 When these pressurized area, it's above
2 atmosphere?
3 MR. SICARD: Yes, it is above atmosphere.
4 DR. DENNING: But you're assuming that
5 there's still some inleakage even though it's above
6 atmosphere?
7 MR. SICARD: We have performed the tracer
8 gas test, which is consistent with the guidance of the
9 generic letter and the NEI industry guidance. And,
10 you know the result of that test gave a value of 36
11 CFM for the inleakage.
12 Part of the reasoning behind doing that
13 trace gas testing is that there may be certain areas
14 of the control room where the differential pressure
15 may be different than what the measurement is, the
16 isolated rooms that connect up to the control room,
17 for instance. And I would let the staff provide more
18 explanation on the logic of that this afternoon, if I
19 may suggest. But, you know, we have conducted the
20 analysis in order to bound the results that we have
21 over here.
22 The next slide. One of the concerns for
23 the Waterford dose analysis is that we do have
24 relatively high chi-over-Q values. The atmospheric
25 dispersion values do to the location of these

1 atmospheric dump valves to the control air intake for
2 most of the non-LOCA transient events. One is cooling
3 down the plant with the atmospheric dump valves, so
4 that is the point of the release for the transient.
5 That is why that is of interest for these analysis.
6 We have assumed a steam generator leakage
7 of 0.375 GPM per generator for steam generators under
8 faulted conditions such as for a main steamline break
9 or a feedwater line break condition. This is the
10 value which is supported by the operational
11 assessments that are done, each reviewing for the
12 steam generator consistent with NEI 97-06. We have
13 assumed the operational leakage value for steam
14 generators that are intact that have not been subject
15 to a large transient. We have assumed a 75 gallon per
16 day limit for the small break LOCA and all the other
17 events assume a 150 gallon per day value for that.
18 And we have credited the existing operator
19 actions for selecting the preferred control room air
20 intake when the operators go to pressurized mode
21 within the analysis.
22 CHAIRMAN WALLIS: How close is this
23 proximity that you have?
24 MR. SICARD: It is approximately 21 feet
25 from the closest atmospheric dump valve to one of our

1 control room remote air intakes.

2 CHAIRMAN WALLIS: That's not very far?

3 MR. SICARD: No, it is not. That is what

4 has--

5 CHAIRMAN WALLIS: So you will be ingesting

6 not just some radioactivity, but steam, presumably?

7 MR. SICARD: If one --

8 CHAIRMAN WALLIS: It gets pretty warm in

9 there, like a Turkish bath in the control room.

10 MR. ROSEN: When you switch to the

11 preferred intake, do you get much more distance?

12 MR. SICARD: Yes, we have a better

13 geometry with the preferred intake. The chi-over-Q

14 value goes down by a factor of two for that.

15 MR. ROSEN: How big is the separation?

16 You said it was 21 feet in the non-preferred intake?

17 MR. SICARD: I do not recall that number.

18 It is more than twice the 20 feet. The other intake

19 is also oriented in a different direction.

20 This presents the results for the limiting

21 events that we analyzed for alternative source term.

22 This shows that we meet the regulatory limits of Reg.

23 Guide 1.183 of the alternate source term 10 CFR 50.67

24 and the five rem GDC19 general design criteria

25 requirement on the control room dose.

1 MR. ROSEN: Usually we put units on tables
2 that were shown to us.
3 MR. SICARD: I apologize. These are rem
4 TEDE, total effective dose equivalent.
5 CHAIRMAN WALLIS: What is the requirement
6 --
7 MR. SICARD: The requirement is 5 rem for
8 all events.
9 CHAIRMAN WALLIS: So you're getting fairly
10 close to that?
11 MR. SICARD: Yes, we are. Fairly close on
12 a couple of events.
13 MR. SIEBER: If you had left the allowable
14 steam generator leakage at 150, you would have been
15 above five in your small break LOCA, I take it?
16 MR. SICARD: Under the analysis we did if
17 that was the only change we made, yes we would have
18 been above five for small break LOCA. We do have some
19 conservatisms in that calculation. Because of the
20 relatively small time that we had to work with in
21 between the tracer gas testing and wanting to get a
22 submittal into the NRC for that event, we have a
23 relatively conservative release calculation for small
24 break LOCA. We do have the option of going back and
25 performing a more sophisticated analysis of the

1 releases which has the potential of improving that
2 margin.
3 MR. SIEBER: Okay. Thank you.
4 MR. ROSEN: On line four you have the
5 steam generator tube rupture, an acronym?
6 MR. SICARD: Oh. That is for the
7 preexisting iodine spike. One assumes two different
8 iodine spike characteristics for events that do not
9 involve fuel failure of a preexisting iodine spike and
10 an accident generated iodine spike.
11 MR. ROSEN: So this is sort of with the
12 preexisting?
13 MR. SICARD: Yes, that is the worse of the
14 two scenarios for the steam generator tube rupture.
15 So we have demonstrated that we meet the
16 acceptance criteria for the alternative source term
17 and this supports our --
18 CHAIRMAN WALLIS: Well, let me go back to
19 the last one. You have a fuel failure of 100 percent
20 for the small break LOCA. What kind of a fuel failure
21 are you talking about that's a 100 percent?
22 MR. SICARD: That is a clad failure. That
23 is meant to be fuel failure, the same as --
24 CHAIRMAN WALLIS: Just the gas between the
25 clad --

1 MR. SICARD: Yes.

2 CHAIRMAN WALLIS: It's not the whole fuel?

3 MR. SICARD: No, it is not the whole fuel.
4 Because you would not be uncovering the fuel until
5 approximately 15 minutes into the event where the
6 decay heat would go down. You would not be subject to
7 the fuel melt for that event.

8 CHAIRMAN WALLIS: Well, that's reassuring.

9 MR. SICARD: And that is an analysis
10 assumption that is consistent with the dose analysis
11 for the small break LOCA that have been done in the
12 industry.

13 So that concludes my review of the safety
14 analysis aspects. And if there are no further
15 questions, Jerry Holman our manager of nuclear
16 engineering will present the risk considerations.

17 CHAIRMAN WALLIS: He's going to present
18 after the break. We're going to have a break now until
19 quarter to 11:00. And we'll try to catch up because
20 we're taking twice as long as we scheduled.

21 (Whereupon, off the record at 10:28 a.m.
22 until 10:45 a.m.)

23 CHAIRMAN WALLIS: Let's come back into
24 session.

25 We're looking forward to Jerry Holman's

1 presentation. We hope that he can get us back on
2 time.
3 MR. SIEBER: They said it's not risky --
4 MR. MITCHELL: This is Tim Mitchell. If I
5 could interject one minute. We are ready to talk about
6 the heat balance question as far as how we did and
7 what percentages of delta T if now is an acceptable
8 time?
9 CHAIRMAN WALLIS: Well, why don't you do
10 that right after lunch when we're in a good mood?
11 MR. MITCHELL: Okay. We can wait until
12 after lunch.
13 CHAIRMAN WALLIS: Yes, I think we should
14 go ahead with this now since he's up there.
15 MR. MITCHELL: Okay.
16 MR. HOLMAN: Okay. I'll go ahead and get
17 started. I'm Jerry Holman, manager of nuclear
18 engineering. I've been with Waterford for 22 years.
19 I'm going to discuss the risk impact of
20 the power uprate.
21 We looked at all the major elements of the
22 PRA model for its impact on power uprate. That
23 includes the initiating event frequencies, success
24 criteria. We looked at the failure rates. We've
25 particular concentrated on operator response times and

1 the human reliability analysis. We quantified the
2 core damage frequency and the large early release
3 fraction. And we also looked at external events and
4 shutdown risk.
5 DR. KRESS: Now you have your own PRA, I
6 take it?
7 MR. HOLMAN: That's correct.
8 DR. KRESS: And through the industry
9 review?
10 MR. HOLMAN: Yes. We have gone through a
11 owner's group certification process.
12 DR. KRESS: Yes.
13 MR. HOLMAN: And addressed those issues.
14 There are no change in plant operation
15 that would cause any new initiating events to be
16 included into the PRA model.
17 DR. FORD: What is your basis for saying
18 that?
19 MR. HOLMAN: There's --
20 DR. FORD: Your factual basis?
21 MR. HOLMAN: We've looked at the operation
22 of the plant after power uprate. There is no
23 significant procedure changes, there's no changes in
24 the way the plant is operated, operator actions. So
25 there's no impact on initiating events.

1 DR. FORD: And materials degradation
2 doesn't come under that sub-bullet?
3 MR. HOLMAN: No. In fact, what we would
4 look at is in any cases where there might be some
5 additional wear or degradation --
6 DR. FORD: Right.
7 MR. HOLMAN: -- we have monitoring
8 programs to ensure that we capture that wear and do
9 preventative maintenance prior to it getting to the
10 point where it would result in any failures or
11 initiating events.
12 DR. FORD: Well, you mentioned flow-
13 induced vibration. What would happen, you got a
14 higher flow rate going through the steam generator and
15 the steam generator internals will presumably vibrate
16 more and wear more on anti-vibrations bars, for
17 instance.
18 MR. HOLMAN: Correct.
19 DR. FORD: What happened if it went so
20 fast that you go through a tube wall within one
21 operating cycle?
22 MR. HOLMAN: Right. We have Don Siska
23 here, but I think we would not expect to see those
24 types of differences and changes where the wear rate
25 would increase to get failure within that one cycle.

1 DR. FORD: Well, that was the objective of
2 my question. What's your technical basis for saying
3 that it wouldn't? The reason why we're so sensitive
4 to that is, as you know in the BWRs, the steam dryers,
5 we've had this problem. And no problem, no problem
6 based on analysis there was a problem.
7 MR. HOLMAN: Yes.
8 DR. FORD: So what is your technical basis
9 that you're so sure that there will not be a problem
10 within one fuel cycle.
11 MR. HOLMAN: Right. Don?
12 MR. SISKA: I'm Don Siska from
13 Westinghouse.
14 I can speak to the issue of the flow-
15 induced vibration, particularly within the steam
16 generator.
17 We looked at the higher flow rates and did
18 a much more detailed type of analysis than we had done
19 originally for these steam generators. And all of the
20 stability ratios, if you will, and the critical areas
21 all remained well within the -- below an acceptance
22 criteria such that we would not predict any sort of
23 onset of instability or any kind of significant wear
24 at all, certainly much less than a structural limit of
25 a tube within one fuel cycle. And I believe Waterford

1 does 100 percent inspection of all active tube during
2 an inspection, so we don't anticipate any problems in
3 that area.
4 DR. FORD: What would the impact be if you
5 were wrong?
6 MR. HOLMAN: Well, we have had occasions
7 back in the original licensing of San Onofre and St.
8 Lucie 2 where we did have vibration in what we call
9 the diagonal bars or bat wings and actually had a
10 small leak in less than one cycle. However, these
11 were small controlled leaks and the plant was able to
12 shutdown without any significant issues. We
13 subsequently have done plugging in that region. And
14 in some cases put stabilizers in an area to make sure
15 that this doesn't continue to happen.
16 DR. FORD: Are there other combustion
17 engineering designs similar to yours which are
18 operating at similar conditions to this?
19 MR. HOLMAN: Similar to the outbreak
20 conditions you mean?
21 DR. FORD: Yes, correct.
22 MR. HOLMAN: Well, Palo Verde has very
23 similar designs. The actual support, tube supports in
24 the Waterford steam generator are more robust than at
25 Palo Verde. They have three partial supports at the

1 top of the two bundles as opposed to two. And the
2 supports in the supper two bundle on the vertical
3 grids connect directly to I-beams where at Palo Verde
4 they float. So we would expect at Palo Verde we would
5 have much more vibration problems than would
6 Waterford.
7 DR. FORD: Okay.
8 MR. MITCHELL: This is Tim Mitchell on
9 what if we're wrong.
10 DR. FORD: Yes.
11 MR. MITCHELL: We do follow the EPRI
12 guidelines on responding to indications of leakage
13 within the steam generators. Those indications would
14 have us shutting down much sooner than the 75 gallons
15 per day limits that we talked about earlier. So it
16 would be something that we would take very seriously
17 and respond to operationally and take conservative
18 action. So it's not anything that we expect, but our
19 procedures are built to make sure that that is
20 evaluated seriously and there is clear shutdown
21 criteria. I don't remember the exact criteria, but
22 it's well below any of analyzed numbers.
23 DR. FORD: Okay.
24 DR. KRESS: On your initiating event
25 frequencies, do you use the generic values for that or

1 do you have plant specific values?

2 MR. HOLMAN: Yes, we use a combination.

3 We start with the generic data. And for those events

4 where we have seen plant specific events, such as loss

5 of feedwater, we roll in the plant specific.

6 DR. KRESS: So the only way you can assess

7 whether there is a change in frequency is mostly

8 judgment. You just look at the things that might cause

9 the frequency to change?

10 MR. HOLMAN: That's correct. And when we

11 do model updates, we go back and look at actual

12 history and we will roll any experience into those

13 model updates and changes.

14 DR. KRESS: Okay.

15 MR. MITCHELL: This is Tim Mitchell one.

16 The one thing we did do as a result of

17 industry experience, it was within the scope anyway

18 but we expanded it, was to go look at where the

19 industry has experienced problems with components as

20 a result of changes in power uprates, even just valves

21 operating in a different region than what they did

22 before.

23 DR. KRESS: That's where I was leading

24 with my question.

25 MR. MITCHELL: We've tried to look at

1 those cases and even look at our maintenance practices
2 of what do we need to do from a maintenance standpoint
3 to make sure those aren't issues. But our final catch
4 is we have performance monitoring program within
5 system engineering that after all the testing is done,
6 we'll continue to monitor parameters, especially on
7 the secondary but the primary also, to look for deltas
8 over consistent conditions that we would have seen
9 prior to the update. And we'll go evaluate those as
10 part of our corrective action process if there are
11 any.
12 We do have some Arkansas Nuclear 1 that
13 tells us that even two or three cycles later you can
14 have problems with things like static water cooling
15 system. So our performance monitoring program will be
16 very detailed and very rigorous at looking at changes
17 and evaluating those changes and looking within
18 industry experience as a guide at what things should
19 we be concerned about as a result of those.
20 MR. HOLMAN: Okay. We also looked at our
21 success criteria. We ran the CENTS code to do some
22 analyses in order to confirm that the success criteria
23 for power uprate would not change. And we found that
24 it does indeed --
25 DR. KRESS: Your success criteria was

1 what, two out of the three pumps?

2 MR. HOLMAN: That's correct. It would be

3 things like one emergency feedwater pump required to

4 mitigate and prevent core damage versus two or how

5 many flow paths for safety injection.

6 Okay. The power uprate team did

7 comprehensive reviews of equipment for its impact due

8 to power uprate. We found that all the systems

9 operate within allowable limits. EPU will not

10 overstress any equipment or there was no impact on any

11 of the PRA failure rates as the result of power

12 uprate.

13 As we've mentioned before, we do have

14 existing monitoring programs that are in place to

15 capture and monitor for any increased degradation or

16 wear. We have a strong incentive to make sure we

17 catch that degradation prior to it actually turning

18 into equipment failures.

19 DR. KRESS: Do you use CHECWORKS or the --

20 MR. HOLMAN: We use CHECWORKS for the

21 flow-accelerated corrosion, yes.

22 Okay. We looked at operator response

23 times. We ran again the CENTS computer code in order

24 to determine times that are available for recovery of

25 offsite power and the time to core uncovery. In

1 general the higher decay heat as a result of a power
2 uprate reduced operator available action times.
3 The major impact is the PRA model was a
4 reduction in the time to recover from a loss of
5 feedwater and the time to recover from offsite power,
6 a loss of offsite power. Typically what we're looking
7 at is the time to uncover the core here and with the
8 higher decay heat, that is a little bit shorter.
9 CHAIRMAN WALLIS: This is where you have
10 these reductions from 40 minutes to 2 minutes?
11 MR. HOLMAN: That was result of more
12 rigorous analyses and looking at different brakes
13 sizes for that range, that's correct.
14 CHAIRMAN WALLIS: You concluded that two
15 minutes was too short that you'd assumed that they
16 failed?
17 MR. HOLMAN: In cases where the time frame
18 was too short to credibly have operators take action,
19 we just assumed that that action was taken.
20 Okay. So this slide shows the impact of
21 the dominate operator recovery actions before power
22 uprate and after power uprate and after power uprate.
23 The time to core uncovery before power uprate coming
24 out of the CENTS analysis was 82.6 minutes. And after
25 power uprate because of the higher decay heat, it's

1 reduced to 68 minutes. That shorter time available
2 translates into a small increase in the failure
3 probability or the nonrecovery probability. So that's
4 an example of the tech 92 that we're talking about for
5 power uprate.
6 CHAIRMAN WALLIS: You have aux feed. What
7 is this feedwater recovery? You got two sources of
8 feedwater.
9 MR. HOLMAN: Yes. We have our main
10 feedwater. We have three emergency feedwater pumps,
11 two motor driven and one is a turbine drive EFW pump.
12 We also have a separate pump that we call an auxiliary
13 feedwater pump. It comes off of the main condenser.
14 So those are the type of actions that we would be --
15 CHAIRMAN WALLIS: So what's being
16 recovered here? Which of those different sources of
17 feedwater is being recovered?
18 MR. HOLMAN: We'll step through a
19 progression of what the operators would do given a
20 loss of feedwater.
21 The first thing they would do would be try
22 and start emergency feedwater. If that does not work,
23 they'll go the next thing. If it continues not to
24 work, we've also got an action to depressurize the
25 steam generators and try and use the condensate pump.

1 So there's a progression of actions.

2 The only thing that's changing for power

3 uprate is the total amount of time that's available to

4 complete those actions before we reach core uncovery.

5 MR. SIEBER: This is a side question. You

6 now have declared your atmospheric dump valves as

7 safety related and they're required to be operable

8 above 70 percent power?

9 MR. HOLMAN: Correct.

10 MR. SIEBER: For mitigation of a small

11 break LOCA. Was the fact that you now need them, that

12 becomes a new event with a different frequency; is

13 that figured into your risk calculation?

14 MR. HOLMAN: The credit for the

15 atmospheric dump valve was required for the

16 conservative licensing basis small break LOCA model

17 that has the Appendix K conservatisms.

18 For the PRA model we're looking more at a

19 realistic small break LOCA. On a realistic analysis

20 basis we do not require that same automatic feature of

21 the ADV. So we did not have to change or in corporate

22 that ADV as part of our success criteria for the PRA

23 model.

24 MR. SIEBER: But you have some

25 documentation that it establishes the reasoning path

1 where you document that conclusion?

2 MR. HOLMAN: That's correct. That's part

3 of the CENTS analysis.

4 MR. SIEBER: All right. Thank you.

5 MR. HOLMAN: Okay. We quantified the core

6 damage frequency increase as a result of power uprate

7 and determined to be 3.5 times 10 to the minus 7.

8 That's a small increase that meets the Reg. Guide

9 1.174 guidance.

10 We also quantified the large early release

11 frequency to be less than one times 10 to the minus 7.

12 So at the end of power uprate our new core damage

13 frequency is 5.9 times 10 to the minus 6.

14 MR. ROSEN: Now have you had a peer review

15 of your PRA?

16 MR. HOLMAN: Yes. We did a peer review

17 coming out of the owner's group. For the power uprate

18 model we've addressed all of the major items that came

19 out of the peer review with the exception of three

20 significant ones. Those were all related to the level

21 two analysis model.

22 For this effort on power uprate we did not

23 use the full level two. We did a simplified alert.

24 MR. ROSEN: Now you're saying that peer

25 review looked at your power uprate calculations as

1 well?

2 MR. HOLMAN: No. The peer review was for

3 a previous version of the PRA model that we built the

4 power uprate off of.

5 MR. ROSEN: And the peer review had no

6 quarrel with 6E to the minus 6 for internal events at

7 Waterford?

8 MR. HOLMAN: That's correct.

9 MR. ROSEN: What in your opinion gives a

10 result that low? I would expect it would be twice

11 that or maybe three times of that in a PWR.

12 MR. HOLMAN: Right. Prior to the latest

13 update, LOCA frequencies, small break LOCA in

14 particular had dominated, had been a significant

15 contributor. The last update revised the initiating

16 event for LOCAs consistent with the latest NRC

17 guidance. And that reduced the core damage frequency.

18 The other thing is the convolution

19 approach that we take to recovery of loss of offsite

20 power, that was also a benefit.

21 Some detailed look at the different

22 combinations of recovery of offsite power. So, again,

23 it's a more improved and detailed analysis which has

24 given us that benefit.

25 MR. ROSEN: While I've interrupted your

1 talk, let me ask you a related question. Part of the
2 discussion here today will be about the large
3 transient testing and the desire on the part of
4 Entergy to not do the large transient tests at
5 Waterford.
6 Now in the attachment 5 to the supplement
7 testing, the startup testing supplement rather, there
8 is a statement I want you to help me understand. It's
9 talking about a SCRAM from full power, from the new
10 extended power. It says "A SCRAM or the potential for
11 a SCRAM from a high power level results in an
12 unnecessary and undesirable plant transient cycle on
13 the primary system. And the risk associated with the
14 intentional introduction of a transient initiator
15 while small, should not be incurred unnecessarily."
16 Now, that statement does not quantify what
17 the word "small" means. And I'd ask you to help me
18 with that. What is your view of the risk of a full
19 power SCRAM?
20 MR. HOLMAN: We have not quantified that
21 specific transient and the impact of doing that test.
22 I think it was meant to be a more general statement
23 that anyway time you initiate you reactor trip, there
24 is some consequence to that.
25 MR. CONSTANCE: Hello. I'm David

1 Constance. And I'm with Entergy, and I'll be
2 presenting testing later on day.
3 Jerry, we did get some of those numbers in
4 for the event specific risks for turbine trip. I don't
5 recall what the numbers were, but they were indeed in
6 our opinion small but should not be discounted.
7 MR. ROSEN: What do you mean by small?
8 You mean --
9 MR. CONSTANCE: Less than ten to the minus
10 6.
11 MR. ROSEN: Less than ten to the minus 6?
12 MR. CONSTANCE: Right.
13 MR. ROSEN: Okay.
14 DR. KRESS: Refresh my memory about this
15 Waterford site. What sort of population density does
16 it have around it, do you recall those numbers?
17 MR. HOLMAN: No, I don't recall those
18 numbers.
19 DR. KRESS: Is it near a big city.
20 MR. HOLMAN: Waterford is about 35/40
21 miles outside -- west of the city of New Orleans.
22 DR. KRESS: That would be a low population
23 density side.
24 MR. LEONARD: This is Ted Leonard, the
25 project lead.

1 The site's situated in a rather low
2 population area. There's a lot of industry on the
3 river, petro-chem industry on the river near the site.
4 Probably the largest town of LaPlace is about five
5 miles away from the plant as the crow flies. New
6 Orleans is like 50 miles away.
7 CHAIRMAN WALLIS: It's getting further
8 away. It says 35 miles in the SER.
9 MR. MITCHELL: It probably is 25 miles to
10 the suburbs for sure.
11 MR. SIEBER: It's a fluid situation.
12 MR. HOLMAN: Okay. This slide shows the
13 relative contribution of different sequences. As you
14 can see, the risk at Waterford is dominated by total
15 loss of feedwater and station blackout events.
16 MR. SIEBER: There was question about how
17 much fuel oil that you have to sustain the loop in
18 that. And it says you will increase the capacity of
19 your diesel tanks by the end of next year. What do you
20 plan to do? Install additional tanks or --
21 MR. MITCHELL: Yes. This is Tim Mitchell.
22 David Viener will talk about it in more
23 detail during part of his presentation. But we do
24 plan on adding additional tanks to address operator
25 concerns or our concerns about the operators tend to

1 fill the tanks so full with little room to the
2 overflow. Now the overflow is captured, but the fact
3 that after a surveillance we'll have prompt action to
4 go refill the tank each time. And the frequency of
5 doing that, we think we can improve our margin and
6 improve -- or harden ourselves against operator error
7 with respect to things like overfilling the tank.
8 MR. SIEBER: So you don't plan to put in
9 additional tanks. You just plan to keep it fuller?
10 MR. MITCHELL: No. I'm sorry. The
11 immediate is we will keep it fuller until we get the
12 additional added, which is by December of 2006. So we
13 are working on pursuing that design right now to add
14 that additional tank.
15 MR. SIEBER: Will that be an underground
16 tank?
17 MR. MITCHELL: It will probably be a tank
18 located in our cooling tower areas. Do we have an
19 exact spot picked? There's three spots.
20 MR. SIEBER: And that single third tank
21 will feed multiple diesel generators?
22 MR. MITCHELL: Yes. We have a cross
23 connect between the qualified tanks that this third
24 tank will be able to supply both tanks. But, Joe?
25 MR. REESE: This is Joe Reese with

1 engineering with Entergy at Waterford 3.

2 Currently we're completing a scoping study

3 to let an engineering contract on the design of the

4 tank.

5 The predominate location selected right

6 now is in our wet cooling tower area. And the

7 predominate design would be looking at a safety

8 related seismic tank that would have the ability to

9 feed either diesel generator storage tank.

10 MR. SIEBER: So it's a safety related

11 tank?

12 MR. REESE: That's correct.

13 MR. SIEBER: Okay. Thanks.

14 DR. KRESS: Could I see your previous

15 slide a moment? Could you tell me, is that the -- did

16 the sequences that contribute to the core damage

17 frequency at the extended power uprate condition, is

18 that what--

19 MR. HOLMAN: That's correct, yes.

20 DR. KRESS: Okay. When you do a delta

21 CDF, then do you just look at the dominate sequences

22 in your--

23 MR. HOLMAN: Yes, we quantified the entire

24 model so we captured all of the sequences.

25 DR. KRESS: Oh, you capture all of them.

1

2 MR. HOLMAN: Yes.

3 DR. KRESS: Okay. Okay. Thank you.

4 MR. SIEBER: What is the delta CDF between

5 non-uprate and uprate conditions?

6 MR. HOLMAN: The delta CDF due to power

7 uprate was 3.5 times ten to the minus 7.

8 MR. SIEBER: Okay.

9 MR. HOLMAN: Okay. We looked at external

10 events. There was a slight increase in the fire core

11 damage frequency as a result of the small decrease in

12 available recovery times. We quantified the delta CDF

13 for fire to be seven times ten to the minus ten.

14 There were no other impacts to any of the other

15 external events as a result of power uprate.

16 We also looked at the --

17 MR. ROSEN: What is the fire portion of

18 CDF? Not the delta, the total?

19 MR. HOLMAN: The percent?

20 MR. ROSEN: Yes.

21 MR. HOLMAN: I don't have that number off

22 the tope my head. It's --

23 CHAIRMAN WALLIS: Well, the fire risk I

24 have is 8.15E to the minus six, which is bigger than

25 your internal events CDF.

1 MR. HOLMAN: The fire risk value that we
2 calculate is based on the very conservative approach
3 in the FIVE methodology. So it's hard to make a
4 apples-and-apples comparison to the internal risk.
5 MR. ROSEN: But based on what our Chairman
6 just said, it would roughly equivalent --
7 MR. HOLMAN: Roughly equivalent.
8 MR. ROSEN: -- to the internal events
9 risk.
10 MR. HOLMAN: That's correct. And the
11 delta--
12 CHAIRMAN WALLIS: The delta is minute.
13 MR. HOLMAN: Right. That's correct.
14 MR. ROSEN: The change is minute because
15 of this. But an important contributor to fire, the
16 CDF effort is based on the FIVE analysis at Waterford
17 is fire?
18 MR. HOLMAN: That's correct.
19 MR. HOLMAN: Okay. We've looked at
20 shutdown risk. There were no unique aspects of power
21 uprate that would cause us to change the risk at
22 shutdown conditions. We looked specifically at
23 maintaining safety functions during shutdown. There
24 were no changes to our shutdown operations protection
25 plan.

1 We did look specifically at some of the
2 calculations that we have to determine time to boil
3 under shutdown conditions, and have made those updates
4 as a result of the higher decay heat, folded that into
5 operating procedures.
6 Therefore, overall we looked at all the
7 PRA major elements for its impact on power uprate.
8 There was a minor reduction in the available recovery
9 time for several operator actions dominated by the
10 recovery of offsite power.
11 Power uprate has a very small increase of
12 the risk, the 3.5 times ten to the minus seven.
13 So that concludes my presentation on risk
14 considerations. If there are no other questions, I'll
15 turn it to Dave Viener to talk about our engineering
16 impact.
17 DR. KRESS: You said your LERF calculation
18 was not the full level two, but just the simplified
19 methodology that the NRC uses?
20 MR. HOLMAN: That's correct. Yes. The
21 simplified LERF.
22 CHAIRMAN WALLIS: Thank you. And you've
23 gained us a little bit of time.
24 DR. KRESS: Yes. Thank you.
25 MR. HOLMAN: Thank you.

1 MR. VIENER: Good morning. My name is
2 David Viener. I'm the extended power uprate mechanical
3 lead on the project. I've been at Waterford for 14
4 years, all in the design organization. I'm here to
5 discuss the engineering impacts as a result of the
6 power uprate.
7 The project team reviewed all plant
8 system, components and structures the plant could
9 safely operate to the extended power uprate
10 conditions. If the design was inadequate, mods were
11 proposed and they were scoped and designed. If the
12 design margins were acceptable, the design basis was
13 clearly updated to demonstrate acceptance for power
14 uprate.
15 Some of the significant modifications for
16 power uprate includes the replacement of our high
17 pressure turbine steam path, that's due to the
18 increase in volumetric flow as a result of power
19 uprate.
20 We are rewinding the generator to accept
21 the new electrical load as a result of the thermal
22 power increase.
23 We are replacing our generator output
24 breakers and switching station and bus work and so
25 forth. That's again is to accept the new electrical

1 load as a result of power uprate.

2 We are replacing our alpha transformer and

3 increasing cooling in our bravo transformer. Again, to

4 increase the design to accept the new electrical load.

5 MR. ROSEN: David, your first bullet on

6 that slide, replacing the turbine steam path. Could

7 you be more specific? That's short of shorthand. Tell

8 me in some detail what you're actually doing.

9 MR. VIENER: The steam path replacement

10 includes a new full reaction rotor, the inner cylinder

11 and flow guides to the turbine. The valves are not

12 being replaced.

13 MR. ROSEN: Any piping changes?

14 MR. VIENER: No piping changes at all.

15 Just -- well the nozzles because we're going to a full

16 arc admission machine. Right now we're at a partial

17 arc admission machine. And we're going from that one

18 nozzle to four nozzles. So there will be some machine

19 work at the turbine for that.

20 MR. ROSEN: So some piping changes,

21 obviously to match up --

22 MR. VIENER: To match up with the new

23 turbine. That's correct.

24 MR. ROSEN: But no new valving?

25 MR. VIENER: No new valving.

1 MR. ROSEN: The valving will be upstream
2 of those piping changes, is that correct? The
3 existing valving?
4 MR. VIENER: The existing valving will
5 remain. There's no change to the steam chest at all as
6 a result of the steam path in place.
7 MR. ROSEN: And what about the position of
8 the valves, the control valves?
9 MR. VIENER: They are not moved. There's
10 no physical modification at all.
11 MR. ROSEN: Okay. But they will operate at
12 a different point.
13 MR. VIENER: That is correct.
14 MR. ROSEN: Because of the higher steam
15 flow?
16 MR. VIENER: The higher steam flow.
17 MR. ROSEN: Now how close to valves wide
18 open are you?
19 MR. VIENER: We have designed the
20 operating point for the turbine to accommodate a 1000
21 tubes plugged and also include a one percent valve
22 margin on top of that. So that's should roughly give
23 us about 12 pounds of margin from the steam outlet
24 moving forward with the power uprate. Our design
25 should assure us that we do not operate with valves

1 wide open.

2 MR. ROSEN: But you're close, it sounds

3 like.

4 MR. VIENER: We will be close. But our

5 current tube plugging is about 550 on one generator,

6 450 on the other. We're going to a 1000 on both

7 generators. Accommodating that pressure drop as a

8 result of that, as well as add another one percent of

9 margin on top of that.

10 MR. ROSEN: So when are you going to -- I

11 guess you'll have the experience of setting those

12 valves as you creep up towards full power? What's

13 your planning there?

14 MR. VIENER: The valve -- David Constance

15 is maybe better to answer this question.

16 MR. CONSTANCE: I'm David Constance and

17 I'll be doing the static testing at Waterford.

18 And two aspects of the turbine control

19 system that we'll be validating during startup is the

20 turbine valve curve, which is the megawatt to valve

21 position curve and also the megawatt to turbine first

22 stage pressure curve; both will be validated during

23 plant startup.

24 MR. MITCHELL: This is Tim Mitchell.

25 Valve setup will actually occur prior to

1 rolling the turbine the same time. So the validations
2 will occur after the turbine is on line. But the
3 biggest change with valve positions is going to the
4 full arc versus partial arc. Instead of having three
5 valves full open and one valve throttling, we will
6 have all four valves throttling even at 100 percent
7 power. And I believe the projection is that'll be
8 roughly 80 percent open. Is that close?
9 MR. CONSTANCE: Yes, sir. Approximately
10 80 percent open.
11 MR. SIEBER: I guess the only impact that
12 the governor valve position has is on the governor
13 action on an overspeed. And presuming that the
14 governors have some impact as they tried to close
15 before the throttle valves trips. But typically that's
16 not the deciding factor. And so that's the only safety
17 issue that I can see that comes out of that, other
18 than you may not be able to get the full power. If
19 you don't, that's the way it goes.
20 CHAIRMAN WALLIS: So you're only changing
21 one stage in the turbine?
22 MR. VIENER: It's a whole rotor change.
23 CHAIRMAN WALLIS: It's a whole rotor.
24 It's one stage though?
25 MR. ROSEN: High pressure.

1 MR. VIENER: High pressure and is eight
2 stages.
3 CHAIRMAN WALLIS: You have eight stages in
4 that one. Well, that makes more sense.
5 MR. VIENER: Right, eight stages in that
6 one.
7 CHAIRMAN WALLIS: I was puzzled by it. So
8 by a stage you mean eight stages --
9 MR. VIENER: That's correct.
10 MR. SIEBER: Five for him in the rotor
11 section.
12 MR. ROSEN: Now you're also not doing
13 anything to the low pressure end of the turbine? You
14 have two low pressure?
15 MR. VIENER: We have three.
16 MR. ROSEN: Three.
17 MR. VIENER: Low pressure and no changes
18 are required on the low pressure turbines.
19 DR. RANSOM: Does that mean the power
20 distribution among the high pressure and low pressure
21 turbines, all of the power increase is in the high
22 pressure turbine?
23 MR. CARUSO: I do not know the balance of
24 the way the power -- you know, between high and low.
25 High takes the majority of it, but --

1 MR. SIEBER: Since you're getting it by
2 more steam flow, it would be essentially divided
3 between high pressure and low pressure.
4 MR. VIENER: Yes. I'm not sure of the
5 balance.
6 MR. SIEBER: Because you've got more steam
7 flow.
8 MR. MITCHELL: This is Tim Mitchell.
9 Because of the HP turbine modification, it
10 will be carrying more load.
11 MR. SIEBER: Right.
12 MR. MITCHELL: But the LPs will be picking
13 up some portion of that load. I can't either tell you
14 the percentage or the percent change, but it will be
15 distributed over the entire turbine train. However,
16 the HP will be redesigned to be a more efficient rotor
17 and it will take the majority of the increase.
18 MR. SIEBER: Well, it's not evenly divided
19 anyway. The very first row of blades produces a lot
20 of horsepower compared to everything else.
21 MR. MITCHELL: That is correct.
22 MR. VIENER: Okay. We also are planning
23 some changes on our heater drain valves. We are going
24 to be doing some tube staking in our condenser to make
25 sure we do not have tube vibration movements with

1 power uprate.

2 And we do have some control system and

3 instrumentations which include setpoint, range and

4 scale changes. And results in about four transmitters

5 to be replaced.

6 MR. ROSEN: What's the material of

7 construction of the condenser tubes?

8 MR. MITCHELL: The condenser tubes are

9 stainless.

10 MR. VIENER: Stainless.

11 Okay. With the higher decay heat, it

12 didn't result in any physical changes to our safety

13 systems with the ultimate heat sink. The system will

14 still be capable of dissipating the heat loads the

15 normal shutdown and accident conditions.

16 The water sources are still adequate to

17 maintain cooling to the essential plant equipment. And

18 equipment operating times, this will increase post

19 accident which does impact our fuel oil. And I think

20 we did talk about some plans to increase margin at the

21 site on fuel oil.

22 MR. ROSEN: Let's go back to 41 again, the

23 previous slide.

24 MR. VIENER: Sure.

25 MR. ROSEN: What are these transmitter

1 that are being replaced and the setpoint, range and
2 scale changes. And what instrumentation are you doing
3 that on?
4 MR. VIENER: I'd like to turn that
5 question to Ralph Schwartzbeck, our BOP lead.
6 MR. SCHWARTZBECK: I'm Ralph Schwartzbeck
7 with Enercon Services.
8 The four transmitters that are being
9 replaced are two main steam pressure transmitters and
10 two boric acid makeup level transmitters.
11 The setpoint changes are basically
12 operating points for those transmitters. We had to
13 recalibrate some of the transmitters to give them
14 increased range of operation. We have to rescale some
15 of the board meters to show with the new operating
16 conditions.
17 The setpoints that we really did -- one
18 major setpoint was the low steam generator pressure
19 trip that was done in the reactor protective system.
20 But other than that, it was just minor movements
21 around just to make sure the controls worked like for
22 the feed pump turbines and things like that. Just to
23 make sure that they will operate within their design
24 conditions at uprated power.
25 MR. ROSEN: You said low steam generator

1 pressure?

2 MR. SCHWARTZBECK: Yes. That's the only

3 plant protective system setpoint that is being

4 changed. And that was discussed earlier.

5 MR. SIEBER: That's a pretty big change.

6 You go from 764 to 662. Why are you changing that

7 again?

8 MR. SICARD: This is Paul Sicard.

9 The reason why we are changing that value

10 is to provide operational margin for the plant. We

11 are lowering what the full power steam generator

12 pressure is based upon our operating point for the

13 power uprate conditions, therefore we wanted to lower

14 that setpoint such that it was not going to cause any

15 increase in probability of an inadvertent trip.

16 And we ran some analysis in order to see

17 where it would make sense to push that number looking

18 at various ramp rates and the impact on plant

19 temperature. As a result of that, we adopted the

20 analysis value that is associated with that number

21 that's approximately 100 pounds lower than that in our

22 safety analysis and we're able to demonstrate

23 acceptable performance in the safety analysis based

24 upon that value.

25 Does that answer your question?

1 MR. SIEBER: Yes.

2 MR. VIENER: Okay. Go the fuel slide.

3 DR. RANSOM: Let me go back to the pumps

4 for a minute. The main coolant pumps. As near as I

5 can, if I'm not wrong, they'll see about a three

6 percent increase in load. And there's been no

7 discussion of what effect that has on the system.

8 MR. VIENER: The limiting condition on the

9 reactor cooling pump is during startup.

10 DR. RANSOM: Is what?

11 MR. VIENER: Is during startup where

12 reactor coolant is actually cooler and higher mass

13 flow as a result during startup and provides more draw

14 on our motors.

15 DR. RANSOM: Right. The motors will take

16 that and --

17 MR. VIENER: We're not changing the

18 startup sequencing in the reactor coolant pump motors.

19 Once you get up to nominal T_{cold} temperature, they're

20 fine. They're operate well within the design limits.

21 MR. SIEBER: Most coolant pump motor

22 failures are when the plant's cold, and in particular

23 from the in rush when you first start the pump. Once

24 you're operating, they'll run for a long time.

25 MR. VIENER: Okay. On the emergency

1 diesel generator fuel oil, we are raising the minimum
2 capacity requirement in our storage tank to maintain
3 the seven day supply for our current licensing basis.
4 We do have a commitment to add additional storage.
5 That should be complete by the end of 2006. And Tim
6 described and Joe described what our plans were for
7 that.
8 MR. SIEBER: Now, there is actually no
9 additional fuel oil consumption caused by the EPU.
10 This was an error that's been around for a long time,
11 I take it.
12 MR. VIENER: There will be more
13 consumption as a result of EPU because our ultimate
14 heat sink equipment, some of it has to operate a
15 little bit longer as a result of extended power
16 uprate. Therefore, more fuel will be required.
17 MR. SIEBER: But those are those cooling
18 tower pumps, right?
19 MR. VIENER: That's the wet cooling tower
20 fans.
21 MR. SIEBER: Right.
22 MR. VIENER: And our aux component cooling
23 water pump.
24 MR. SIEBER: Okay.
25 MR. MITCHELL: This is Tim Mitchell.

1 But you're right. There was design and
2 issue with margins that existed for quite some time,
3 and this is predominately driven -- the modification
4 is predominately driven to eliminate really both
5 issues. But the significance of it is is preexisting
6 to EPU.
7 MR. SIEBER: Okay. Thank you.
8 MR. ROSEN: This commitment to add the
9 additional storage, that will be completed prior to
10 the EPU?
11 MR. MITCHELL: That additional storage
12 will be provided prior to December of 2006. Not prior
13 to EP, I'm sorry.
14 MR. VIENER: On our emergency feedwater
15 system, it was reviewed and our system flow is still
16 capable of mitigating against feedwater demand events.
17 And our normal and backup condensate
18 sources are still adequate to bring the plant to
19 shutdown cooling conditions.
20 On our shutdown cooling system, the system
21 still will be capable of achieving cold shutdown in
22 accordance with Reactor System Branch, Branch
23 Technical Position 5-1.
24 And our refueling technical specification
25 time limits to reduce shutdown flow will remain

1 unchanged as a result of power uprate due to the
2 conservatisms that were in the current analysis.
3 Fuel pool cooling, power uprate is
4 proposing a 1 and a half percent increase in decay
5 heat for the fuel pool cooling analysis. We reracked
6 in 1008 and the analysis assumed an 8 percent power
7 uprate at that time. This uprate is basically
8 captured in the Appendix K on recapture, margin
9 recapture.
10 Delay heat removal analysis does bound the
11 capacity of the fuel pool. We will still maintain the
12 licensing basis temperature limits as a result of
13 extended power uprate. And the bounding time to boil
14 analysis will remain unchanged as a result of power
15 uprates.
16 MR. ROSEN: How is that possible? I mean,
17 if you're putting more fuel into the pool and your
18 assumption in the time to boil analysis is set, you
19 lose cooling to the pool at the worst time, how do you
20 end up with the -- I would expect there would be
21 change of one and a half change?
22 MR. VIENER: The licensing amendment in
23 1998 used the ASB 9-2 decay heat and there's a typo in
24 that decay heat equation that was used at that time.
25 Calculating the decay heats used in that

1 typo provided very conservative results. Extended
2 power uprate easily masked those conservatisms, and
3 therefore the time -- the bounding analysis which is
4 the full core offload, will remain unchanged.
5 MR. ROSEN: I understood up to the point
6 where you said there was a typo. And the bounding
7 analysis of the EPU remains unchanged because of the
8 typo is taken out or not? I don't understand.
9 MR. VIENER: No. Well, moving forward we
10 used the correct ASB 9-2 equation.
11 MR. ROSEN: I see. okay. And the next
12 sentence remains unchanged because you changed the
13 analysis to correct a prior error?
14 MR. VIENER: That's correct. That's
15 correct.
16 MR. ROSEN: Okay. But "unchanged," you
17 mean it's not higher than it was?
18 MR. VIENER: It's not higher than it was
19 docketed before. It was roughly a little less than
20 three ops.
21 MR. ROSEN: And now we're confident that's
22 right?
23 MR. VIENER: I'm very confident that's
24 right.
25 As far as EPU impact on ongoing industry

1 issues concerning containment overpressure, currently
2 Waterford 3 does not credit containment overpressure
3 in the net positive suction head analysis on emergency
4 core cooling pumps. EPU will still maintain that
5 assumption.
6 As far as EPU has no impact on the safety
7 injection sump performance as discussed in the
8 recently released generic letter.
9 EPU has not proposed any system change
10 inside containment, as well as our minimum containment
11 sump level and our sump temperature in containment
12 remain really unchanged as a result of power uprate.
13 MR. SIEBER: What you say on this slide is
14 it doesn't tell the whole story, right? You increased
15 the minimum temperature of containment to make sure
16 you had enough pump suction head?
17 MR. VIENER: No. No. We do not credit
18 containment pressure at all for the NPSH analysis on
19 the emergency --
20 CHAIRMAN WALLIS: That's a mistake in
21 something that we got in our literature.
22 MR. SIEBER: Right.
23 CHAIRMAN WALLIS: That has given the
24 impression that there was a --
25 MR. SIEBER: Right.

1 MR. HOLMAN: This is Jerry Holman.

2 The change in minimum containment

3 temperature was the result of the large break LOCA

4 ECCS performance. It is not factored into the net

5 positive suction head analysis.

6 MR. SICARD: This is Paul Sicard.

7 Let me point out the change is to move the

8 existing requirement from our technical requirements

9 manual to the technical specifications. So it is not

10 a change in any analysis assumption, but merely in how

11 we are enforcing that assumption.

12 MR. SIEBER: I guess I need some

13 clarification, though. If you increase the

14 temperature of the containment and thereby the

15 potential stored energy there, why would you do it --

16 for what reason would you do it other than to make

17 sure you had enough pump suction at the sump? I'm

18 missing something here.

19 MR. SICARD: Okay. This is Paul Sicard.

20 For the NPSH analysis or prepower uprate

21 conditions as well as post power uprate conditions we

22 do not consider any increase in containment pressure

23 that occurs because of the loss of coolant in the mass

24 and energy release to the containment. That analysis

25 for net positive suction head and pump performance

1 assumes that the containment stays at its initial
2 pressure for the purpose of evaluating the pump
3 performance.
4 Now, when one gets into the loss of
5 coolant accident, there one does account for the
6 minimum containment response, minimum pressure
7 response. And that is part of the approved
8 Westinghouse LOCA methodology for determining peak
9 clad temperature.
10 CHAIRMAN WALLIS: So there is an effect of
11 containment pressure on net positive suction head?
12 MR. SIEBER: Well, it is in a way and it
13 isn't in a way.
14 CHAIRMAN WALLIS: Two separate
15 calculations.
16 MR. SICARD: If we had considered --
17 MR. HOLMAN: There are two analysis.
18 MR. SICARD: Yes. If we had considered
19 containment over pressure for net positive suction
20 head, that would give us improved margin because that
21 would give you more pressure to assist the pump. We do
22 not consider that additional term for the net positive
23 suction head analysis.
24 MR. SIEBER: You're not taking credit for
25 the LOCA pressure? You're taking credit for the

1 containment condition? Is that a way to state it?

2 MR. SICARD: We are taking credit for the

3 containment initial pressure of approximately one

4 atmosphere.

5 CHAIRMAN WALLIS: That's all.

6 MR. SICARD: And that is all.

7 CHAIRMAN WALLIS: That's easy to

8 understand.

9 MR. SIEBER: Well, yes. The --

10 MR. VIENER: We follow the reg. guide

11 requirements as far as design and the ECCS pumps. And

12 if I'm not mistaken, it's the containment pressure and

13 the vapor pressure you assume will cancel out. Okay.

14 So all you have is the NPSH required of the pump less

15 the pressure drop from the containment sump to the

16 ECCS pump and the elevation. That's the only factors

17 you credit in the NPHS analysis.

18 DR. KRESS: And what did you do about the

19 sump screen blockage in this analysis?

20 MR. VIENER: Power uprate does not impact

21 that sump blockage analysis at all.

22 MR. SIEBER: Yes, it's the same sump.

23 Same debris.

24 CHAIRMAN WALLIS: But you still have the

25 problem if there was one with sump screen blockage.

1 It doesn't go away.

2 MR. SIEBER: It doesn't get worse even.

3 MR. VIENER: Yes. We do plan on following

4 the guidelines of the generic letter that was issued.

5 And we have taken some actions and we've got future

6 actions that are upcoming.

7 CHAIRMAN WALLIS: What kind of insulation

8 do you have on your steam generators?

9 MR. VIENER: What I'd like to do is

10 introduce Maria Rosa Gutierrez. She's the one that's

11 our lead in this issue.

12 MS. GUTIERREZ: My name is Maria Rosa

13 Gutierrez. I work at Waterford 3 in design engineering

14 department.

15 The question was insulation on the steam

16 generators?

17 CHAIRMAN WALLIS: Yes.

18 MS. GUTIERREZ: We have reflective

19 encapsulated insulation and also some Nukon blankets.

20 CHAIRMAN WALLIS: So it's all reflective

21 metal?

22 MS. GUTIERREZ: No, not reflective metal.

23 The only place we have reflective metal insulation is

24 on our reactor.

25 CHAIRMAN WALLIS: So you have fiberglass

1 on the --

2 MS. GUTIERREZ: Yes.

3 CHAIRMAN WALLIS: -- steam generators?

4 MR. MITCHELL: And on the piping.

5 MS. GUTIERREZ: And on the piping also.

6 MR. ROSEN: Any calcium silicate?

7 MS. GUTIERREZ: No, we do not.

8 CHAIRMAN WALLIS: But you have those 70

9 truckloads of fiberglass or whatever it is that we

10 were talking about.

11 MS. GUTIERREZ: I wouldn't say 70

12 truckloads, but yes we do.

13 CHAIRMAN WALLIS: Okay. Well, that's

14 another question.

15 MR. ROSEN: For another time.

16 MR. SIEBER: Yes.

17 CHAIRMAN WALLIS: For another time. We'll

18 probably see you again.

19 MR. VIENER: Okay. Due to operating

20 experience, we looked at vibration pretty in depth. On

21 a steam generator Don Siska talked about we did do

22 extensive evaluations on our steam generator and

23 determined that we should not experience any problems

24 due to vibration.

25 DR. FORD: Could I just return to this

1 particular one? When you say "evaluated," you really
2 mean analyzed? You didn't do any experiences or
3 comparison with plant data, is that correct?
4 MR. VIENER: Let me turn that question
5 over to Don Siska?
6 MR. SISKA: As far as the tube bundle
7 evaluation, that was a full analytical evaluation, you
8 know building the models and based on test data,
9 coming up with analytical results.
10 DR. FORD: Can you tell me more about the
11 test data?
12 MR. SISKA: The test data for the tubes
13 were based on the tests that combustion engineering
14 had done back in the 1970s for that particular tube
15 bundle design. Triangular pitch, you know one inch
16 apart. And comes up with essentially constants that
17 fit into these Connor's equations and such to predict
18 flow induced vibrations.
19 DR. FORD: And those experiments, that
20 combustion covered conditions that you'll be having
21 under EPU?
22 MR. SISKA: That's correct. Yes.
23 DR. FORD: Okay. On the Palo Verde
24 design, the dry design. First of all, is the dryer a
25 safety related component?

1 MR. SISKA: No, we do not consider it
2 safety related.
3 DR. FORD: So if there's a loose parts of
4 that and it impacts on the main steam isolation valve,
5 does that not make it a safety component?
6 MR. SISKA: Well, one could postulate some
7 pieces. I mean, probably the biggest thing would be
8 the dryer bolts. Those are the only thing we've ever
9 seen actually fall apart from there. And in general,
10 those fall down onto the separator deck. But it's not
11 impossible to say something couldn't get into the
12 steam dryer or into the main steamline, but it would
13 seem very unlikely.
14 DR. FORD: Okay. Now the question at Palo
15 Verde design, it is not exactly the same, is it?
16 MR. SISKA: The dryer design is exactly
17 the same.
18 DR. FORD: The dryer? Okay. But the
19 steam flow will be different, won't it, because
20 there's different -- there's only one steam outlet at
21 Waterford and there's three at Palo Verde? So the
22 steam flow will be different?
23 MR. SISKA: The steam flow up in the upper
24 drum in particular, yes, it has higher steam flows
25 through Palo Verde. The dryer, it's unusual to say,

1 but the actual Palo Verde which runs at a little
2 higher power than the Waterford EPU actually has less
3 dryers because it's a smaller steam drum.
4 DR. FORD: So if you take the experience
5 that we're unfortunately learning from the boilers
6 where vibrations in the boiling water reactor steam
7 dryers, certain designs of them, gave -- and you can't
8 say therefore in your particular design at Waterford
9 that you could not get unexpected vibrations?
10 MR. SISKA: I will never say never, sir.
11 DR. FORD: Because you don't have anything
12 to compare it with, because you don't have data to
13 compare it against?
14 MR. SISKA: Yes. We actually have two
15 pieces of data. The initial testing that was done on
16 these dryers looked at pressures from 600 to about
17 1200 psi and 30 to 60 kilopounds per hour, which is
18 within this range. Now, again, that was not done from
19 a structural sense. That was done mainly to determine
20 moisture carryover capabilities. But, you know, it was
21 some rather significant testing.
22 And then secondly, Palo Verde which has
23 been operating for nearly 20 years with exactly the
24 same design and higher flow rates, in particular the
25 dynamic pressure through Palo Verde's dryers is about

1 15 percent, 18 percent higher than what we expect at
2 Waterford during EPU. So we would expect that that
3 type of work at Palo Verde would bound anything that
4 Waterford will see.
5 MR. MITCHELL: One other point. This is
6 Tim Mitchell.
7 The dryers on a boiler are vastly
8 different than what are in the steam generators. So
9 we have compared it to the best data that we have
10 available to the most stringent experience, which
11 would be the Palo Verde experience as well as the
12 original testing.
13 DR. FORD: Okay. And you're still
14 discounting that there could be any impact on the
15 operation of the main steam isolation valves if you
16 were wrong? The loose parts coming off and --
17 MR. MITCHELL: The loose parts from
18 industry experience would be captured within the steam
19 generators. I am not aware of any industry experience
20 at all with dryer problems ending up anywhere other
21 than, as Don said --
22 DR. FORD: Again, I come back from the
23 boilers. We were told no it could never happen, but it
24 did happen. And that's why we're pushing it.
25 MR. SISKA: I'll never say never, sir.

1 MR. ROSEN: Now you did talk about some
2 bolts coming loose. Is that your own experience?
3 MR. SISKA: Yes. We have gone in there on
4 occasion. There are a total of 16 half inch bolts that
5 hold these dryers together. I believe there's five on
6 each side that hold it to the dryer support -- or
7 excuse me. Three on each side that hold it to the
8 support and then five that hold it to another dryer on
9 each side. So there's upwards of 2,000 bolts in
10 there. And on occasion we find some. We go in there
11 to take some dryers out, and find one missing.
12 And to my knowledge we've never actually
13 found one that was missing. You know, it probably
14 ended up just getting beat up and it's just a carbon
15 steel, so it probably eventually just turned into
16 sludge.
17 CHAIRMAN WALLIS: Maybe it was never put
18 there in the first place.
19 MR. SISKA: That's entirely possible as
20 well.
21 MR. SIEBER: Look at your tube sheets.
22 MR. SISKA: Oh, believe me, we do a lot of
23 that.
24 MR. SIEBER: That would be the first place
25 I would look.

1 MR. SISKA: Yes.

2 DR. FORD: And the failure of those bolts

3 by what, fatigue or by what?

4 MR. SISKA: I have no idea really.

5 CHAIRMAN WALLIS: They never found them.

6 They have no idea.

7 MR. SISKA: And the reason there are so

8 many of these bolts in there is not really from a

9 structural standpoint. It's just to try to keep the

10 steal so that you don't get any of the moisture

11 seeping through there without going through the

12 chevrons.

13 DR. FORD: Okay. Thank you.

14 MR. ROSEN: But you didn't say anything

15 about the condition of the dryers. You said that the

16 bolts were found loose a couple of bolts, a few bolts

17 out of the 1600 that are in there. Well, what about

18 the condition of the dryers themselves? Had you

19 inspected them?

20 MR. SISKA: Waterford I know was looking

21 at that effect. That was something that they were

22 looking at doing. I don't know if it was this outage

23 or later on.

24 MR. LEONARD: This is Ted Leonard, the

25 project lead.

1 In our last refueling we performed a
2 rather thorough inspection of our steam generator
3 secondary side after we did a chemical cleaning of the
4 steam generators. Our dryers have corrosion, some
5 type of deposits on them. And we evaluated it quite
6 extensively, probably more from an aspect of trying to
7 quantify is there a pressure drop across the dryers.
8 Some of the dryers there was more build up on them
9 than on some of the others. And we couldn't even with
10 a lot of industry help, we couldn't quantify if we
11 would pick up anywhere from three to four pounds more
12 pressure if we took all the dryers out one at a time
13 and cleaned them. We decided to go through the next
14 outage and do an inspection, and go from there.
15 MR. ROSEN: Well, I'm really not
16 concerned--
17 MR. LEONARD: But they're not in like new
18 condition, but they're not structurally degraded. They
19 more have some deposits on them.
20 MR. ROSEN: Were you actually able to get
21 a fiberoptics probe in there or some other method to
22 have a look at them.
23 MR. LEONARD: It was mainly all the
24 exterior. Took photos.
25 MR. SISKA: Yes. These dryers are only 12

1 inches high. So, you know, you can see a good part of
2 them from right underneath.
3 MR. ROSEN: Although they have deposits on
4 them, they don't show any signs of distress?
5 MR. LEONARD: No. It was just the
6 deposit, and some of them more than others. I would
7 not -- wasn't -- they weren't all as dirty.
8 MR. MITCHELL: This is Tim Mitchell.
9 There was no evidence of any structural
10 issues at all with the dryers.
11 MR. VIENER: Okay. We also looked at heat
12 exchanger equipment in our secondary system, namely
13 the feedwater heaters, moisture separator and
14 condenser. And as mentioned earlier, the only impact
15 we have is that we do have to perform some tube taking
16 on the condenser. The feedwater heaters and moisture
17 separator, the heater will be fine moving forward with
18 the power uprate.
19 We do have a vibration monitoring program
20 ongoing. We do have probes on some key piping systems
21 that we're getting baseline data. That will remain
22 moving forward with power uprate. And, you know, if
23 there are some unexpected results, which we don't
24 expect, but if there are we will take compensatory
25 action --

1 MR. ROSEN: Can you tell me what the
2 extent of that is? Are you looking, for instance, at
3 the feedwater heaters or the condenser tubes? Where
4 do you have the monitoring program probes?
5 MR. VIENER: We will have a program
6 through our power ascension testing and our power
7 ascension testing lead --
8 MR. ROSEN: Well, let me tell you where
9 I'm going with that. Would you be able to detect
10 incipient conditions that could lead to failure in key
11 components or are we going to wake up one morning and
12 hear that you've had failures, or are you going to
13 write an LER that says you detected vibration and went
14 and stopped it ahead of time?
15 MR. VIENER: What I'd like to do is turn
16 that question over to our test lead, David Constance.
17 MR. CONSTANCE: Hi. I'm David Constance.
18 Based upon recent operating experience
19 we've extended our vibration monitoring during the
20 extended power uprate startup testing beyond what was
21 committed to in the testing submittal.
22 Our testing is going to -- our monitoring
23 is going to extend from the reactor coolant system
24 through the entire plant to the switchyard. It's kind
25 of a graded approach. The more important systems will

1 have a higher level of monitoring and closer level of
2 monitoring than the systems that are either less
3 impacted by EPU or have less of a safety impact.
4 And I do have a backup slide where I can
5 go over that monitoring in detail during my
6 presentation, if you would like.
7 MR. ROSEN: Yes. I would like to see that.
8 MR. CONSTANCE: I'll make sure that's
9 prepared.
10 MR. VIENER: Flow accelerated corrosion.
11 The power uprate effects have been evaluated using our
12 CHECWORKS model. We do not -- we have determined that
13 no component replacements are required as a result of
14 going up with power uprate.
15 We did increase outage inspection sampling
16 based on the EPU conditions. That's basically to get
17 some additional baseline data that we don't have.
18 And moving forward, our program will
19 continue to monitor and detect any deviation from
20 predicted wear rates.
21 On alloy 600, on the reactor cooling
22 system, our reactor cooling hot leg temperature is
23 going up approximately about 0.8 of a degree. Our
24 cold leg temperature is going up -- or going down
25 about 2 degrees. And the impact on crack initiation

1 due to PWSCC that we have determined is negligible as
2 a result of these operating condition changes.
3 MR. SIEBER: The two degrees on this slide
4 is not consistent with the larger degrees that you
5 show on other slides.
6 MR. VIENER: Yes. This two degree
7 decrease is basically hot full power at 543, it
8 doesn't include the ramp, not hot zero power spot 41,
9 which is the four degrees.
10 MR. SIEBER: All right.
11 DR. FORD: Could you remind us as to what
12 the situation about your inspections for the reactor
13 vessel head?
14 MR. VIENER: That's a good question. We
15 have Jamie Gobell here to entertain those questions
16 for you.
17 DR. FORD: Thank you.
18 MR. GOBELL: I'm Jamie Gobell, engineering
19 for Alloy 600 Entergy South.
20 And we are following the NRC order,
21 revised order 03-0009 and that is the volumetric
22 inspection of the nozzles. We performed a volumetric
23 inspection of the nozzles last outage. Did not find
24 any indications to make any repairs. We also performed
25 a visual inspection of the bare metal of the top

1 surface.

2 DR. FORD: And no indications?

3 MR. GOBELL: No indications. The head is

4 in good shape.

5 MR. ROSEN: What sort of access have you

6 got on the top for bare metal?

7 MR. GOBELL: They had blanket insulation

8 up there that we removed and we could put a crawler in

9 or go in with a baroscope. Except for the very center

10 of the head still has some of the metal insulation and

11 we have to lift that and go in with a baroscope to

12 inspect that.

13 MR. ROSEN: You did do that, because that

14 was at the famous plant I won't mention did not

15 inspect that area because it was hard to do.

16 MR. GOBELL: Yes, we did the full

17 inspection.

18 MR. ROSEN: Three sixty around each of

19 the--

20 MR. GOBELL: Yes.

21 MR. ROSEN: Good.

22 MR. VIENER: Okay. In our steam

23 generators, our NEI 97-06 program we continue to

24 ensure true integrity is maintained post EPU.

25 Grid stability. Short circuit, transient

1 stability and offsite voltage studies were reperformed
2 as a result of power uprate. Our short circuit study
3 determined that our main generator output breakers
4 were marginal and we are replacing those in this --
5 well, we replaced one in the last refueling outage,
6 and we're replacing the other one in this upcoming
7 refueling outage.
8 MR. SIEBER: What's the nominal increase
9 in interrupting capability that you expect to put in
10 there? Do you know?
11 MR. VIENER: What I'd like to do, I have
12 Singh Matharu who does have those details and he can
13 answer that question.
14 MR. SIEBER: Okay.
15 MR. MATHARU: My name is Singh Matharu.
16 I'm an electrical engineer at Waterford.
17 The original breakers that we had were oil
18 circuit breakers with a short circuit interrupter
19 rating of 63 kA. We have now gone to the SF6 type,
20 which now have an excess of 80 kA.
21 MR. SIEBER: Okay.
22 MR. MATHARU: The model that --
23 MR. SIEBER: So that's a pretty
24 substantial increase?
25 MR. MATHARU: That is correct.

1 MR. SIEBER: Yes. And they're OCBs?

2 MR. MATHARU: Excuse me?

3 MR. SIEBER: You say they're oil circuit

4 breakers?

5 MR. MATHARU: The original ones were oil

6 circuit breakers. The new ones are SF6.

7 MR. SIEBER: Okay. Thank you.

8 MR. VIENER: Okay. In conclusion with the

9 proposed modifications I've described Waterford 3's

10 plant design can safely operate at the proposed

11 extended power uprate condition.

12 And that concludes my presentation. If

13 there's no more question, what I'd like to do is turn

14 it over to Gene Wemett, he's our assistant operations

15 manager at Waterford.

16 CHAIRMAN WALLIS: Thanks.

17 MR. VIENER: Thank you for your time.

18 CHAIRMAN WALLIS: What I'd like to do is

19 hear this presentation, and then I think it would be

20 a good time to take a lunch break. We'll come back

21 for what remains, which is a rather small amount. And

22 at that time, you can have anything you wish to add,

23 additional information on any of the questions asked

24 this morning. And then you can wrap up and then we'll

25 hear from the staff.

1 And I assume it'll take maybe 20 minutes,
2 a half an hour up until lunch something like that at
3 most.
4 Please go ahead.
5 MR. WEMETT: My name is Gene Wemett,
6 Waterford 3. I'm the assistant ops manager at the
7 plant. And I have been with the Waterford operations
8 since 1980.
9 The first thing I'd like to do is address
10 the question I was asked earlier that had to do with
11 evaluation of the control room or promote shutdown
12 habitability.
13 The power uprate had no effect on actual
14 operations habitability at the area of the remote
15 shutdown panel. The only changes to their occurring
16 down there are basically banding of the meters due to
17 the new ranges for power uprate.
18 CHAIRMAN WALLIS: Does it change any of
19 the times that the operators have to --0
20 MR. WEMETT: No, sir.
21 CHAIRMAN WALLIS: -- go there or take
22 action and whatever that you know?
23 MR. WEMETT: No, sir.
24 CHAIRMAN WALLIS: It doesn't change
25 anything like that?

1 MR. WEMETT: That's correct.

2 On the first slide we have here is the
3 operations oversight slide. We assigned two full time
4 individuals from the operations staff were assigned to
5 the power uprate project.

6 MR. SIEBER: Sir, could you talk a little
7 louder, please.

8 MR. WEMETT: Two full time individuals
9 from the operations staff were assigned to the power
10 uprate project from the start. We assigned a third
11 senior reactor operator shift technical advisor was
12 assigned to review power uprate modifications and
13 evaluations. The responsibility that was given to
14 these individuals has been to identify and respond to
15 operations and training issues, identify and
16 coordinate revisions of operations procedures and to
17 support startup test development.

18 Operations management has received weekly
19 briefings of the project status from these
20 individuals. And that is still ongoing.

21 Underneath the training, it's in a three
22 phase program. Phase 1 was introduced last year. It
23 consists of seminars on the overall large overview of
24 power uprate effects on plant systems, technical
25 specifications and operations procedures. And that was

1 performed during the 2004 training cycle.

2 During phase 2 that's presently in

3 progress, which is cycle 1 of 2005, plant

4 modifications is presently being addressed to all the

5 operators.

6 In cycle 2 of 2005 is phase 3. This full

7 cycle is dedicated to power uprate training. In this

8 we will be training on operations procedures, setpoint

9 changes and technical specifications. During this

10 period of time the crews will all be evaluated on the

11 uprated plant simulator and the changes in procedures

12 and the setpoints and technical specifications.

13 MR. ROSEN: Now you said operator plant

14 simulator. I take that to mean that the simulator has

15 been modified to model the uprated plant, is that

16 correct?

17 MR. WEMETT: That's correct. Prior to

18 cycle 2 the completion of the changes that are being

19 brought by power uprate will be in place in the

20 simulator to train the operators.

21 The operators will be examined. They will

22 have an evaluated session on the simulator with the

23 power uprate. They will also have a written

24 examination that they will also take like procedures

25 and setpoints and technical specifications.

1 MR. ROSEN: What's the biggest impact you
2 see on operating during normal times?
3 MR. WEMETT: During normal times?
4 MR. ROSEN: Yes.
5 MR. SIEBER: Nothing.
6 MR. WEMETT: Huh?
7 MR. SIEBER: Nothing.
8 MR. ROSEN: Don't answer. Give him a
9 chance at it. Well, I'm sure you can answer.
10 MR. WEMETT: Well, there were three
11 concerns that I've had, and I think ops shares that.
12 One was the ability of the secondary plant
13 systems to adequately perform with the increase flow
14 rates that we're going to see with the steam flow and
15 the feedwater flow and condensate flow.
16 The other is the ability of core cooling
17 for decay heat removal on both normal plant shutdown,
18 shutdown cooling type conditions as well as with
19 underneath accident situations.
20 And as we go through here, all the
21 information I've received from the individuals that
22 have reviewed the modifications, the power rate that
23 have been with that, I think they have addressed those
24 concerns from an operations standpoint.
25 MR. SIEBER: You have no hardware changes

1 to the control room, right?

2 MR. WEMETT: There is one hardware change.

3 It's actually in the PAC system. And I'm going to get

4 to that in this, and I'll explain a little bit. It has

5 to do with atmospheric dump valve.

6 MR. SIEBER: Okay.

7 MR. WEMETT: They're going to add one card

8 to a PAC system.

9 MR. SIEBER: Okay.

10 MR. WEMETT: And I'll explain that a

11 little bit. They've allowed me to do that.

12 MR. SIEBER: But your meter readings will

13 be different and the transient times will be different

14 from an operator's standpoint?

15 MR. WEMETT: The meter reads? What do you

16 mean?

17 MR. SIEBER: Well, you know, a 100 percent

18 is a different number now.

19 MR. WEMETT: That's correct. It'll be

20 about 8 percent higher than what we're at right now.

21 MR. SIEBER: Right.

22 MR. WEMETT: But it'll look 100 percent

23 power to us.

24 MR. SIEBER: Yes. It'll still say 100

25 percent.

1 MR. WEMETT: All the banding and
2 corrections of the transmitter rescales will be done.
3 MR. SIEBER: Okay.
4 MR. WEMETT: All right. One of the things
5 that we have agreed to, all operations personnel will
6 be trained and evaluated on the power operated
7 training that we're giving right now prior to be
8 allowed to take a shift and operate the plant.
9 This is kind of getting to your point. On
10 the controls and displays, there are very minimal
11 changes that we've seen. One is to allow a more
12 precise setting of atmospheric dump valve. This is
13 the piece I was talking about, a hardware change.
14 They're adding a card, and what this will
15 allow us to do is perform a more precise setpoint
16 change to the atmospheric dump valve setpoint. And
17 basically what it's going to be, it's an interface
18 with our plant monitoring computer and it's just
19 visual only for indication. And then at the control
20 room will be able to adjust the setpoint. And that
21 setpoint actually provides impacts -- there is a card
22 being added for us to see that. And that's the only
23 hardware that I know of that's in the control room
24 that's being changed at this time.
25 The other is the main turbine valve

1 operation, which we talked earlier, is going to be
2 changed from a sequential valve operation to single
3 valve or partial arc admission type control. Our
4 present turbine has that capability and we do do that
5 during turbine valve test, and we go from sequential
6 to single valve. Stroker valves testing, and then we
7 go back into sequential valve. We also startup in
8 single valve and go to single valve.
9 MR. SIEBER: Again, that's not a hardware
10 change to the nozzle blocks. It's just different
11 settings in the --
12 MR. WEMETT: This is the valve programming
13 controller. Digital hydraulic program. Correct.
14 MR. SIEBER: Right.
15 MR. WEMETT: Technical specifications.
16 Changes to the technical specifications and the
17 operations procedures are changes in parameters due to
18 the higher decay heat, thermal power and secondary
19 flow changes that we're seeing.
20 There are going to be no new procedure
21 changes to the normal or off-normal procedures.
22 And the emergency operating procedures
23 there's really no change to the type and nature of the
24 actions that are in those, and there's actually no
25 action.

1 There is a change that is in there, and
2 they talked about it earlier, and that is just the
3 time frame which is kind of like a parameter change to
4 initiate hot leg injection.
5 MR. SIEBER: Right.
6 MR. WEMETT: It's going from two to four
7 hours to two to three hours. And operations feels
8 that's acceptable to be able to do that. That's just
9 based on a larger break loss of coolant accident.
10 And in conclusion, the power uprate has
11 worked really hard to minimize the impact of the plant
12 operations at Waterford. The result is the changes
13 brought about by power uprate to the units operation
14 are minimal and are found to be acceptable to the
15 operations department.
16 Our next priority is the post power uprate
17 power ascension testing to the new power level. To
18 address this priority, Operations had assigned a
19 senior reactor operator for whom this afternoon, I
20 assume after lunch, is David Constance. And he'll be
21 taking that up from me.
22 And that's basically all I have in my
23 presentation. If there's any questions?
24 MR. SIEBER: Why did you choose link the
25 change in partial to full arc admission to the EPU?

1 It's not part and parcel of EPU. You could have done
2 that anytime, right?
3 MR. WEMETT: That's correct.
4 MR. SIEBER: Why don't you do it now?
5 MR. WEMETT: Well, actually right now I
6 think the optimum valve position in our type of
7 turbine that we have in this present age, we actually
8 have better efficiency sequential valve than we do
9 with single operation.
10 MR. SIEBER: Well, when you go to full arc
11 admission the impulse stage efficiency goes down.
12 MR. WEMETT: That's correct.
13 MR. SIEBER: On the other hand, the reason
14 why you would want to do it is to minimize the
15 temperature differential around the nozzle block so
16 you don't get cracking. So you either got -- have
17 some symptoms of cracking or that you're willing to
18 trade for a couple of Btus someplace. But a lot of
19 people have changed and decided I'll waste the BTUs
20 and maybe a few kilowatts to avoid damage to the
21 turbine. I'm sort of wondering why you've linked it to
22 the EPU? It's a curiosity, it's not a safety issue.
23 MR. WEMETT: David Viener can probably
24 answer that a little bit better.
25 I do know that in the original discussion

1 it was an option, we could go either way.

2 MR. SIEBER: Yes.

3 MR. VIENER: I'm not an expert in turbine

4 design.

5 This is David Viener, EPU lead.

6 But right now our turbine has a control

7 stage followed by seven stages of reaction. The new

8 turbine is going with all reaction bladding. We're

9 not going to have the control stage.

10 MR. SIEBER: Oh, really.

11 MR. VIENER: And that's why we're going to

12 full arc admission.

13 MR. SIEBER: Thank you. Understand.

14 MR. WEMETT: All right. Are there any

15 other questions?

16 MR. SIEBER: Okay. Thank you.

17 MR. WEMETT: Thank you very much.

18 CHAIRMAN WALLIS: We've gained some time.

19 I wonder how much time will the next presentation

20 take?

21 MR. MITCHELL: Fifteen, 20 minutes I

22 believe is a fairly good estimate.

23 CHAIRMAN WALLIS: We could move ahead with

24 that and then maybe shorten the lunch break. Let's

25 see. Is that agreeable with the Committee? We just

1 move ahead with this one? Let's move ahead.

2 MR. WEMETT: All right. Then I'll present

3 David Constance.

4 MR. CONSTANCE: Hello. I'm David

5 Constance. I've been at Waterford for 17 years. I'm a

6 shift technical advisor and hold a senior reactor

7 operator license on the unit. I've been assigned to

8 power uprate full time for the past power. And I'm

9 performing engineering reviews and I'm responsible for

10 testing. And this segment I'm here to talk about

11 testing.

12 Power ascension testing consists of

13 reactor engineering tests and power verification,

14 transient and baseline steady state data records,

15 plant modification testing -- I'm sorry, post

16 modification testing, one plant maneuvering test from

17 100 percent to 90 percent to 95 percent, post 100

18 percent testing, data collection and surveys and

19 vibration monitoring.

20 Now part of that post 100 percent testing

21 will include a moisture carry over test where we will

22 find out what the impact on moisture carry over has

23 been due to extended power uprate.

24 MR. SIEBER: Will that be a sodium test,

25 sodium isotope test?

1 MR. CONSTANCE: Yes, it will be a tracer
2 injection. I don't know what the trace is going to be
3 used.
4 MR. SIEBER: Okay.
5 MR. CONSTANCE: The next slide here shows
6 our power ascension profile. You'll find seven power
7 plateaus followed by a plant maneuvering test from 100
8 percent to 90 percent.
9 CHAIRMAN WALLIS: How does this fit in
10 with your various shifts or actually in the control
11 room? It doesn't look like it's of the usual division
12 of time. So there's going to be overlap between these
13 ten hours?
14 MR. CONSTANCE: This testing extends for
15 five days. So it will go through multiple --
16 CHAIRMAN WALLIS: I know. But your steps,
17 they don't seem to be related to the shifts in the
18 control room in any logical way; that's my question.
19 MR. SIEBER: No, it's not.
20 CHAIRMAN WALLIS: It's not.
21 MR. MITCHELL: This is Tim Mitchell.
22 It is not tied to a time on shift to make
23 a power maneuver. At this point we do have --
24 CHAIRMAN WALLIS: But you don't want to be
25 doing something just as one shift is leaving or

1 something.

2 MR. MITCHELL: That is correct. Turnover

3 times will be observed and adhered to.

4 MR. CONSTANCE: What we have, is we'll

5 have during refueling outages we go to two operating

6 crews. And both operating crews will be trained on

7 this power ascension.

8 Next slide.

9 MR. SIEBER: Does that mean 12 hour

10 shifts?

11 MR. CONSTANCE: That's correct. Twelve

12 hour shifts.

13 MR. ROSEN: Is that a real hold at 50

14 percent power, very short?

15 MR. CONSTANCE: Right. The hold at 50

16 percent power is to recalibrate our excore nuclear

17 instruments. It typically only takes a couple of

18 hours. We'll just take that opportunity to collect

19 some steady state data recognizing it's not truly

20 steady state, not the steady state data that we need

21 for -- that we wish for for our other power plateaus.

22 CHAIRMAN WALLIS: What's that zigzag at

23 the 100 percent? Does that just mean it's

24 continuously 100 percent?

25 MR. CONSTANCE: No. That's actually meant

1 to represent the plant maneuvering tests from 100
2 percent to 90 percent. And it is not unrelated in
3 time to the power ascension.
4 CHAIRMAN WALLIS: Okay. Okay.
5 MR. CONSTANCE: Next slide.
6 A low power physics testing remains
7 unchanged for an extended power uprate. So the startup
8 will be the same as a normal refueling, which is still
9 very similar to our initial startup on the unit.
10 During power ascension following low power
11 physics testing, data sets will be collected very 10
12 percent from 20 percent to 100 percent. They'll also
13 be collected at seven different power plateaus.
14 Approximately 1000 parameters will be monitored. And
15 the data will be automatically collected, processed
16 and evaluated against predetermined acceptance
17 criteria.
18 CHAIRMAN WALLIS: So it will be evaluated
19 right then and there?
20 MR. CONSTANCE: That's correct. All the
21 data will dump to an Excel spreadsheet. It'll be
22 compared to the acceptance criteria.
23 CHAIRMAN WALLIS: So it's essentially
24 online? There's no delay while you do this
25 evaluation?

1 MR. CONSTANCE: That's right. There's no
2 delay determining which parameters meet the acceptance
3 criteria.
4 MR. SIEBER: Is this all stuff that comes
5 from your plant computer or do you install some
6 special instrumentation just for this test?
7 MR. CONSTANCE: All the data sets come the
8 plant monitoring computer. There will be a subset
9 which will have to be collected manually at each of
10 the power plateaus. That will be a small subset.
11 MR. SIEBER: By hand?
12 MR. CONSTANCE: Right.
13 MR. SIEBER: Okay.
14 MR. CONSTANCE: Moving on, the Plant
15 Safety Subcommittee will review a results report at
16 each power plateau graded in 68 percent. The results
17 report will include testing results, a list of
18 equipment out of service and the calculation of the
19 plant safety index.
20 The plant safety subcommittee recommends
21 continued power ascension. And the plant manager,
22 operations manager and test director approval is
23 required to commence or to recommence power ascension.
24 CHAIRMAN WALLIS: So he recommends
25 continue ascension no matter what?

1 MR. CONSTANCE: No. Their recommendation
2 is required for continued power ascension.
3 CHAIRMAN WALLIS: Or not to. Okay.
4 MR. ROSEN: Who is this Plant Safety
5 Subcommittee? A subcommittee of what? Of who?
6 MR. CONSTANCE: Of the Plant Safety
7 Committee. We call it the OSRC, they have different
8 names at different plants.
9 MR. ROSEN: And this is comprised of who
10 are those people? Not by name, but whether they're --
11 MR. CONSTANCE: Right. We'll have an
12 operations representatives. I'm sorry. An operations
13 representative, a system engineering representative,
14 a design engineering representative, QA representative
15 and at least one other OSRC regular member.
16 MR. ROSEN: So they're all site people on
17 the subcommittee, right?
18 MR. CONSTANCE: That's correct.
19 MR. ROSEN: What about the OSRC, who are
20 those?
21 MR. CONSTANCE: That is a site Safety
22 Review Committee.
23 MR. ROSEN: So you just gave me the
24 membership of the --
25 MR. SIEBER: Onsite.

1 MR. MITCHELL: This is Tim Mitchell.

2 Let me correct me. The Onsite Safety

3 Review Committee is a larger group that includes a

4 couple of additional people like projects and I'm not

5 sure I remember the full -- licensing's also on it.

6 Design engineering is on it. So this is a

7 subcommittee that reports to the OSRC on their review

8 of essentially the startup.

9 MR. ROSEN: And there is no offsite

10 corporate review during this testing?

11 MR. MITCHELL: During the testing there is

12 not a -- Safety Review Committee is what we call it in

13 the Entergy. They do not review online with the data.

14 They will review what we're doing beforehand and

15 review after hand. But it's not during the actual

16 power ascension profile.

17 CHAIRMAN WALLIS: Is there going to be an

18 NRC inspector observing what this safety subcommittee

19 does?

20 MR. CONSTANCE: Of course, we have our NRC

21 resident. And I have not yet spoke to him what his

22 information requirements are. But we'll provide him

23 with any information that he requires at whatever

24 points in the power ascension he desires it.

25 CHAIRMAN WALLIS: I think it would be

1 useful to have him around.

2 MR. CONSTANCE: Right.

3 CHAIRMAN WALLIS: While you're making

4 these decisions.

5 MR. ROSEN: Right. We can ask them when

6 they come up, and I'm sure they will point someplace

7 to observe.

8 CHAIRMAN WALLIS: They will find some

9 reason to be absent or something?

10 MR. SIEBER: Well, there's a lot of good

11 places for him to be during this phase.

12 MR. RULAND: If I could just add

13 something? My name is Bill Ruland, I'm the Project

14 Director for PD3.

15 There's a specific inspection module

16 associated with power uprates. It looks at both the -

17 -- some of the modifications that the licensee had and

18 also directs the inspectors to look at power ascension

19 testing, I believe. We'll confirm that for you later.

20 DR. DENNING: The 92.5 percent, is that

21 the old operating power and so you can do comparisons

22 with the familiar level? And then 95, 97 that's just

23 kind of creeping up; is that the logic?

24 MR. CONSTANCE: That's correct. 92.5 is

25 the previous license power level. And the other ones

1 are just intermediate levels that we selected as being
2 prudent.
3 MR. SIEBER: On slide 61 where will you
4 take your flux maps?
5 MR. CONSTANCE: The question is where will
6 we take our flux mapping. At each one of those power
7 plateaus, those are largely driven by what we
8 committed to in racked engineering testing. The
9 specific tests that are done at -- the racked
10 engineering tests that are done each plateau. I have
11 somewhere here in my documentation, but I don't have
12 it on the top of my head.
13 MR. SIEBER: But basically you're going to
14 do three or four?
15 MR. CONSTANCE: Yes. Many of the normal
16 startup tests that we do during power ascension will
17 be repeated multiple times during this power
18 ascension.
19 MR. SIEBER: Okay. Good enough.
20 MR. CONSTANCE: If I can go to my backup
21 slide now on vibration testing.
22 MR. CARUSO: You're going to have to flip
23 up the mirror. The other way.
24 MR. SIEBER: Perfect.
25 MR. CARUSO: Now focus.

1 MR. SICARD: All these backseat drivers.

2 MR. ROSEN: That's our job, Paul.

3 MR. SIEBER: Now you have to lay over this

4 one here.

5 MR. CONSTANCE: All right. For vibration

6 testing we have a fairly extensive detail vibration

7 monitoring plan that extends from the racked cooling

8 system and all the way through the plant to the

9 transformer yard. We've taken a graded approach based

10 upon the impact of power uprate on that specific

11 system and upon the importance of that system to

12 safety.

13 Basically what you're looking at is a

14 break up of systems based upon the level of detail of

15 monitoring. So the first set is the main steam and

16 main feed piping that is safety related. For that

17 we're doing a 100 percent baseline inside and outside

18 containment vibration collection using installed

19 vibration monitoring equipment which we've installed

20 full power upgrade. We'll be collecting that data at

21 92.5 percent, 95, 97.5 percent and the new 100 percent

22 and comparing it to prebaseline data.

23 For the main feed and main steamlines

24 outside containment that are seismic quality, which is

25 a larger set of main steam main feed piping, we'll be

1 taking data collection using hand held vibration
2 equipment at 100 percent power and comparing it to the
3 pre EPU baseline data. Visual inspections will be
4 performed at 92.5, 95 and 97.5. So for that piping
5 we'll be taking a data set only at 100 percent, the
6 new 100 percent.
7 For turbine building piping, we will be
8 performing a walkdown of the turbine building at 100
9 percent power prior to shutdown. The members of that
10 walkdown team are going to be our performance
11 monitoring engineer, civil engineer and two operators.
12 From that walkdown we will identify any areas that may
13 have additional vibration and either film them, take
14 video records of that piping and hand held vibration
15 data. Then we will re-perform those walkdowns with
16 those same personnel at 92.5, 95 and 97.5 percent.
17 Now for the main turbine feed pump at the
18 racked cooling pump we have permanently installed
19 instrumentation. It's spectral analysis
20 instrumentation. And the data will be reviewed at
21 92.5, 95, 97.5 and 100 percent power and compared to
22 pre EPU conditions.
23 For the equipment in the turbine building
24 we will perform rough data collection using hand held
25 vibration equipment at 95 percent and 100 percent.

1 That will be compared to the current data that we have
2 on that equipment from our performance monitoring
3 program.
4 Since we are crediting the atmospheric
5 dump valve -- we have more reliance on the atmospheric
6 dump valve, we have a plan to collect vibration data
7 on the atmospheric dump valve during a full stroke at
8 normal operating pressure, normal operating
9 temperature with steam.
10 And the condenser, we are going to perform
11 an acoustic survey of the condenser at 100 percent and
12 compare it -- at the new 100 percent and compare it to
13 pre EPU baseline data which will be collected prior to
14 shutdown.
15 We also have a valve and loose parts
16 monitoring system on the reactor cooling system. That
17 data will be reviewed at 92.5 percent, 95 percent,
18 97.5 percent and 100 percent power and compared to pre
19 EPU baseline data.
20 DR. DENNING: Could you tell me, is that
21 system that's in normal operation, what do you have
22 for monitoring and loose part monitoring during normal
23 operation all the time? Is it this last thing or how
24 much of this equipment is in effect all the time in
25 normal operation?

1 MR. CONSTANCE: Of this equipment normally
2 that's in service during normal operation, the valve
3 and loose parts monitoring system is always in service
4 and it's an alarm system. So it has preset conditions
5 which will provide a control room alarm annunciation.
6 We also have vibration monitoring installed on the
7 main turbine, on the feed pumps and on the reactor
8 cooling pumps. That's normally installed equipment.
9 We have installed some sensors for EPU
10 which will remain installed, but you have to go and
11 connect them and collect that data.
12 DR. FORD: Now you've got all these
13 monitoring systems in place. Is there any way of using
14 that data to determine what might be happening in an
15 unmonitored place like the dryer or the condenser
16 tubes and the steam generator tubes? Is that global
17 to local evaluation?
18 MR. MITCHELL: This is Tim Mitchell.
19 I can't tell you that we'd be able to pick
20 up something on a steam dryer in the steam generator.
21 But you can use this data to triangulate and point you
22 in a direction as far as something abnormal that is
23 occurring and where is that occurring.
24 DR. FORD: That's what I was getting at.
25 That's what I was getting at.

1 MR. MITCHELL: So this data, and we have
2 experience within Entergy Nuclear South we're doing
3 that because there were some feedwater vibration issue
4 at Arkansas Nuclear One Unit 2. And we actually did
5 a lot of that with similar type data to be able to
6 point us in which direction. You know, is it a feed
7 reg valve, you know that type of stuff that will help
8 us narrow it down if we see something abnormal.
9 DR. FORD: Okay. Thank you.
10 MR. CONSTANCE: Okay. Ready to go to the
11 next slide.
12 DR. DENNING: Let me ask you another
13 question, and that is would it be prudent to continue
14 to have an expanded monitoring program for a period
15 longer than just the power ascension? I mean like for
16 the first six months of operation or something like
17 that. Have you considered that?
18 MR. CONSTANCE: Yes, it's been considered.
19 Keith Kunkel is our performance monitoring individual.
20 He's not here today and it is not part of our plan.
21 We're not committing to it now. But we have discussed
22 that at approximately six months, every six months
23 through the next cycle we should do a turbine building
24 walkdown with those same personnel.
25 MR. MITCHELL: Yes. This is Tim Mitchell

1 again.

2 And that's something that I was referring

3 to earlier with the performance monitoring program

4 that system engineering does. We have a plan to

5 collect data prior to the outage or pre EPU conditions

6 and then to go through system-by-system methodically

7 identify any deltas after we reach full power

8 conditions.

9 So the performance monitoring program will

10 be a living ongoing thing that we'll continually look

11 for any deviations and then go evaluate what those

12 deviations might effect on other systems. But we've

13 also scheduled for ourselves an assessment with

14 industry participation for next June or July, I forget

15 which month, to bring them in and get industry

16 experience to look at the data that we're looking at

17 from a performance monitoring standpoint and get their

18 input. Like, for example, ANO 2 will certainly be a

19 part of that because they've gone through this same

20 type exercise.

21 MR. SIEBER: I note in your chart of

22 planned testing you don't have any provision for a

23 trip from full power. Why is that?

24 MR. CONSTANCE: The question concerns a

25 trip from full power testing, and I think I've best

1 addressed with the next two slides where we talk about
2 our testing considerations, what things we considered
3 in selecting the suite of testing that we're going to
4 do for extended power uprate. So, if I may continue.
5 All right. This next slide is testing
6 considerations. Some of the things that we considered
7 when selecting the suite of testing for post uprate
8 conditions is that the proposed modifications either
9 have no significant impact on transient response or
10 the effect on transient response has been evaluated
11 using a calculational model which is suitable for
12 predicting the effect on plant transient response due
13 to that modification.
14 We noted that there are no physical
15 changes to nuclear steam supply system, that there are
16 no new interactions that affect system response and
17 that there are no changes to controller algorithms.
18 All changes to controllers are being accomplished
19 through setpoint changes.
20 MR. SIEBER: However, you would agree that
21 if you trip from higher power level than your previous
22 maximum power level, the forces are greater on
23 structure systems and components like pump seals,
24 hangers, snubbers, dampers that the plant has never
25 experienced before. And that was not apparently one of

1 your consideration?

2 MR. CONSTANCE: Right. The question

3 concerns the structural integrity of the plant and its

4 ability to endure large transient. I --

5 MR. SIEBER: Sooner or later you're going

6 to have one.

7 MR. CONSTANCE: That's correct.

8 MR. SIEBER: And the question is would you

9 like to have instrumentation available and learn

10 something from it or just have one, you know which is

11 a different kind of thing.

12 MR. CONSTANCE: Well, the instrumentation

13 that we would have available, we currently have

14 installed. Most of the information that we would want

15 to gain from a transient test we would gain from the

16 data points that are monitored by the plant monitoring

17 computer.

18 MR. SIEBER: Well, you may want to think

19 about that because the movement of components on skid

20 plates and strain gauges on various structural members

21 of snubbers, hangers and so forth are not permanently

22 installed. So if you're interested in that kind of

23 stuff, you may want to think about that.

24 MR. MITCHELL: Okay. This is Tim

25 Mitchell.

1 We did go through and look at what the
2 effects would be from the higher power level. We've
3 used the LTC code to help us predict how system
4 performances would be. We validated that against past
5 operating experience both at Waterford during
6 transients and at other plants that have gone through
7 extended power uprate. And we believe that we
8 understand what the affects of 100 percent load
9 rejection or whatever the transient would be upon our
10 secondary with the testing that we are doing.
11 MR. CONSTANCE: Let me continue on with
12 these next two slides, and then I'll come back to your
13 question.
14 MR. SIEBER: Okay.
15 MR. CONSTANCE: Where we at? All right.
16 So our approach to testing is at the post
17 modification testing demonstrates that components and
18 systems will perform as designed. That the power
19 ascension data collection confirm acceptable
20 operation. That the maneuvering test provides further
21 confirmation and that we've used a benchmark
22 calculation model to evaluate postulated transient
23 conditions.
24 Two other things that we considered when
25 considering a large transient test is one is the

1 limitations of a large transient test. A large
2 transient test is a single test transient test. It
3 demonstrates a single transient and demonstrates that
4 at a single set of initial conditions. The majority
5 of our changes that impact transient response are to
6 control systems where they're changing our control
7 system setpoints so they control at the new operating
8 point. There is no clear maximum or minimum or
9 bounding condition for transient that we could select
10 to know that our control systems will interact
11 properly.
12 So the approach we used was to utilize the
13 LTC code, which is a computational method that has
14 been used since the early '80s, specifically in the
15 design of control system interactions. Using that, we
16 were not restricted to a single point test. Instead
17 we ran 38 cases from different transient from
18 different initial conditions.
19 The second consideration that we used
20 other than the limitations of a single point transient
21 test is that the risk -- and you quoted this earlier -
22 - the risk associated with the introduction of a
23 transient initiator, while small, should not be
24 incurred unnecessarily. So the question that we have
25 to answer is will the transient test provide us a

1 specific discrete piece of information that would make
2 our introduction of the transient initiator worth
3 doing.
4 MR. ROSEN: From our standpoint you've
5 already told us the risk of doing so is small. Less
6 than 1E to the minus six. So we have no nuclear safety
7 risk to do it.
8 MR. CONSTANCE: That's correct. It is
9 small, but it shouldn't be discounted. It is small,
10 and it's acceptable but it shouldn't be discounted.
11 So it's --
12 MR. ROSEN: There's no risk argument being
13 made or offered here. It's simply that Entergy
14 believes it's unnecessary.
15 MR. CONSTANCE: Right. It's not a risk
16 argument. It's an alternate methods argument, that
17 we've used alternate methods to validate that the
18 plant will operate properly during a transient at the
19 new operating point with the new control system
20 setpoint..
21 MR. ROSEN: That's the side of the glass
22 you're looking at. I'm looking at the other side
23 which says that Entergy offers no argument that it's
24 too risky.
25 MR. CONSTANCE: That's correct.

1 MR. ROSEN: You can SCRAM this plant or do
2 a turbine trip from 100 percent full power without
3 encountering any undue risk?
4 MR. SIEBER: If there was a significant
5 risk, then we would be remiss in allowing the EPU in
6 the first place.
7 MR. CONSTANCE: That's correct. We're not
8 arguing that it is an unacceptable risk. It is an
9 acceptable risk.
10 MR. SIEBER: You don't want to do it.
11 MR. ROSEN: So it's an economic argument,
12 not a risk argument.
13 MR. SIEBER: Yes, they don't want to do
14 it.
15 DR. DENNING: I still think there's a
16 safety argument. As a risk analyst I still think that
17 there is a consideration here. And I don't think we
18 want to push too -- there is a cost benefit question
19 here and I don't think you want to ever induce a trip
20 like this unless there is good reason. So there is a
21 cost benefit we really have to consider here. So I
22 wouldn't let them bull you too much here in saying
23 that ten to the minus six means that it's acceptable
24 for us to go ahead to do that.
25 MR. ROSEN: Well, he didn't say it was ten

1 to the minus six.

2 DR. DENNING: Yes.

3 MR. ROSEN: He said it was less than ten

4 to the minus six. Well I maintain there's no risk

5 argument to -- and I'm just recording your own words.

6 MR. CONSTANCE: Right. We do not intend to

7 forward a risk argument here. We intend to --

8 MR. ROSEN: So it's an economic argument.

9 MR. CONSTANCE: Well, we intend to forward

10 an alternate methods argument in that we can gain the

11 same information through an alternate method and we do

12 not need to incur the small but not insignificant

13 risk. The risk was on the order on eight times ten to

14 the minus seven. So it was less than ten to the minus

15 six.

16 MR. SIEBER: That's insignificant.

17 MR. ROSEN: We have to sit and listen to

18 a lot of stuff that's not all that thrilling, but this

19 stuff is interesting and we'll come back to it. We'll

20 come back to it, I'll guarantee you later today when

21 the staff presents. So I would suggest that maybe you

22 don't go away.

23 MR. CONSTANCE: Okay. I will certainly be

24 around.

25 CHAIRMAN WALLIS: Well, eight times ten to

1 the minus seven may seem small, but it's not small
2 compared to the ten to the minus six for a CDF we have
3 already, it seems to me. A significant perturbation
4 on your CDF for the year, isn't it? Or is it not?
5 MR. MITCHELL: This is Tim Mitchell.
6 We did look at it and we tried to evaluate
7 what the risks were. And I agree that the risks are
8 small. But there is, as stated, some amount of risk
9 even if it is small, and in this case we concluded we
10 were not going to get any significant value out of
11 doing a large transient test.
12 CHAIRMAN WALLIS: Let's take this up with
13 the staff this afternoon.
14 MR. ROSEN: Oh, yes, we will take it up
15 with the staff.
16 CHAIRMAN WALLIS: I think that Steve will
17 probably do that.
18 I'd like to take a break. And since we are
19 behind, would the Committee agree to come back here at
20 1:15. Take 45 minutes for lunch. So we'll take a
21 break until 1:15.
22 (Whereupon, at 12:30 p.m. the Subcommittee
23 was adjourned, to reconvene this same day at 1:17
24 p.m.)
25

A-F-T-E-R-N-O-O-N S-E-S-S-I-O-N

1:17 p.m.

CHAIRMAN WALLIS: Let's come back into session.

We'll finish the Entergy presentation and then we'll hear from the staff. And I believe Entergy is going to answer a few of the questions we had this morning that didn't get covered.

MR. SICARD: Yes. This is Paul Sicard from Entergy again.

CHAIRMAN WALLIS: Quiet please.

MR. SICARD: There were questions retarding RCS flow and the role of the increased density versus temperature rise in the power uprate. We have prepared a slide to try to address that, which we have on the screen right now comparing the current prerate conditions with the conditions for power uprate. And this comparison shows what the mass flow numbers are that correspond to those two different conditions and the corresponding enthalpy rise. This shows that out of the 8 percent uprate from those initial conditions over there to the uprate conditions that three percent of that eight percent is due to the mass flow component and approximately five percent is due to the enthalpy rise associated with those change

1 in conditions. And we hope that this illustrative
2 calculation does answer the question regarding how we
3 are achieving the increased power through the core.
4 And I will point out again that these are
5 nominal flow values. That the technical specification
6 minimum flow requirement of 148 million pounds per
7 hour is not being revised for power uprate. And that
8 these mass flows are in the middle of the range in
9 between that minimum flow and the 115 percent maximum
10 flow value that we use in analysis where a maximum
11 flow is called for.
12 So, I hope that this answers any questions
13 or if not, we will entertain them either now or
14 subsequent to the meeting as you desire.
15 CHAIRMAN WALLIS: Thank you.
16 So you have an enthalpy change, enthalpy
17 rise change of 3.6, I guess, which I agree that sounds
18 much more reasonable to compare with my calculations.
19 In the SER it says the average core
20 enthalpy rise goes from 81.5 to 88, which is quite
21 different from your numbers in the 70s. And it seemed
22 to be far too big a change. So something is
23 inconsistent about the staff's enthalpy numbers to
24 yours and mine.
25 MR. SICARD: I would suspect that the

1 staff numbers that they are reporting there are based
2 upon the minimum flow rate rather than a nominal flow
3 rate.
4 CHAIRMAN WALLIS: Well, these are BTUs per
5 pound. They've based on temperature. And I don't see
6 how they could ge so different. So there's something
7 to be sorted out between your numbers and the staff's
8 numbers for enthalpy change. And they're getting all
9 their eight percent out of the enthalpy change and
10 none of it out of flow rate, which again is not
11 consistent with what you have. So there's something
12 very different about what you're saying and what the
13 staff is saying about something which is so simple
14 that it just needs to be corrected, I'm sure.
15 MR. SICARD: And noted. And I would have
16 the question of is that based on the minimum flow
17 which is not changing. But --
18 CHAIRMAN WALLIS: But you're still not
19 going to get 88 BTUs per pound delta H without a much
20 bigger temperature rise. Even 541 I think doesn't do
21 it. But anyway, the staff can sort that out.
22 Thank you. That's been very helpful.
23 MR. SICARD: Okay. I will turn this over
24 to--
25 CHAIRMAN WALLIS: Will you put this in the

1 record so we have a copy of this.

2 MR. CARUSO: I have a copy on this

3 computer. Just leave it on the computer and I'll have

4 a copy of it.

5 MR. SICARD: Okay.

6 CHAIRMAN WALLIS: Thank you.

7 MR. SICARD: I will turn this over to Tim

8 Mitchell for concluding remarks.

9 MR. MITCHELL: Again, I am Tim Mitchell.

10 There was a flow accelerated corrosion

11 question this morning early in the presentation which

12 we said we'd get to it later. And we did present some

13 information on flow accelerated corrosion, but I

14 wanted to confirm. I don't even remember where the

15 question came from. But the effects on the secondary

16 from a flow accelerated corrosion standpoint are very

17 minimal, and we can go into more detail if you would

18 like. Okay.

19 First, I'd like to thank you for this

20 opportunity for us to come talk to you. We believe

21 that this power uprate project, like I started off

22 with, has improved Waterford as a plant, that it's

23 safe for us to go do and that we're actually improving

24 our design basis as part of it.

25 We appreciate the staff's challenges. I

1 believe they have challenged us in a number of areas
2 and approved our product as a result.
3 And I want to thank the Committee for this
4 opportunity to present again.
5 This does conclude our presentation.
6 We're available for any other questions. But I thank
7 you for the time. That's it.
8 CHAIRMAN WALLIS: Thank you.
9 Can we now move on to the staff's
10 presentation?
11 CHAIRMAN WALLIS: I think we're waiting
12 for the computer, is that what we're doing?
13 MR. KALYANAM: Sorry about that.
14 My name is Kaly, I am the Project Manager.
15 And we are going to start the presentation from the
16 staff side.
17 And the first presenter we have is Jim
18 Medoff who is the reviewer for the vessel. Jim?
19 MR. MEDOFF: Good afternoon, Committee
20 members. My name is Jim Medoff. I'm the materials
21 engineer with the Materials and Chemical Engineering
22 Branch of NRR. I was responsible for reviewing the
23 reactor vessel integrity and reactor vessel internals
24 integrity issues and to assess the impact of the EPU
25 on the integrity of these components.

1 Basically as part of my review we used
2 Matrix 1 of the Review Standard RS-001 and my review
3 responsibilities fell under sections 2.1.1 through
4 2.1.4.
5 The first area of interest that I looked
6 at was the impact on the 10 CFR Part 50 Appendix H
7 withdraw schedule for the facility. And what we
8 determined as part of the uprate is that the latest
9 capsule report for the facility had a new withdraw
10 schedule in it and the withdrawal schedule did not
11 include the impact of the uprate on the withdrawal
12 time for the final capsule for the vessel. They've
13 already pulled two capsules, they're required to pull
14 one more in accordance with their delta RTNDT for
15 their limiting material.
16 We determined that 10 CFR Part 50 Appendix
17 H requires you to follow ASTM standard E185-82 in
18 terms of the withdrawal schedule criterion. And the
19 final capsules to be pulled at a time between one and
20 two times the projected end-of-life fluence for the
21 vessel --
22 CHAIRMAN WALLIS: Can we take down this
23 transparency projector which is --
24 MR. ROSEN: This thing in front of it.
25 CHAIRMAN WALLIS: This thing in front.

1 MR. MEDOFF: What we determined is the
2 projected final withdrawal for the third capsule will
3 continue to be withdrawn in accordance with the ASTM
4 standard, and therefore we concluded that the impact
5 of the uprate did not impact conformance with the ASTM
6 standard in terms of the withdrawal time. And we found
7 that to be acceptable.
8 Section 2.1.2 of the impact requires us to
9 look at the impact upper shelf energy assessment for
10 the vessel and on the P-T limits. I'll get into the
11 upper shelf energy first.
12 Basically the staff uses the Charpy impact
13 upper shelf energies as a measure of the remaining
14 ductility in the vessel after you irradiated. And it
15 requires that the upper shelf energy for the limiting
16 vessel material remain above 50 foot pounds Charpy
17 impact absorbed energy at the end-of-life of the
18 plant.
19 The Waterford 3 reactor vessel is plate
20 limited. It's a low copper vessel and has sufficient
21 remaining margin even under the uprated conditions and
22 we made sure that we got approval of their fluence
23 methodology and fluence calculations by Dr. Lambros
24 Lois, who is my counterpart in the Reactor System
25 Branch of NRR.

1 We calculated an end-of-life upper shelf
2 energy of 71 foot pounds. And this jived with what the
3 licensee calculated under the uprated conclusions, and
4 that satisfies the 50 foot pound criterion in the
5 rule, so we found that to be acceptable.
6 MR. SIEBER: That's 40 years into the
7 life?
8 MR. MEDOFF: They're under a current 80
9 year design basis, so it's 32 effective full power for
10 40 year license life.
11 MR. SIEBER: Okay.
12 MR. ROSEN: And 80 percent capacity.
13 MR. MEDOFF: Capacity factor is what
14 they're using.
15 MR. SIEBER: But that's a lot of margin
16 anyway.
17 MR. MEDOFF: Right. They have --
18 MR. ROSEN: I don't suppose the Entergy
19 management would be real happy with 80 percent, but
20 nevertheless it's plenty of margin.
21 MR. MEDOFF: They have to make that call.
22 I can't force them to do it.
23 MR. ROSEN: We've had this debate before.
24 MR. MEDOFF: Right.
25 For the pressure temperature limits, they

1 did not propose new pressure temperature limits for
2 the EPU application. However, in a previous license
3 amendment application they did submit new heat up and
4 cool down curves for the unit. And what I did was Tom
5 McLennan in my branch was the reviewer for that
6 license amendment. And what I did confirm was that the
7 license amendment did include the upgraded fluences to
8 establish the P-T curves and therefore, we concluded
9 that his approval was based on the upgraded conditions
10 was acceptable.
11 The next one. The next slide us we look
12 at in 2.1.3 of the Matrix tells us to look at the
13 impact under 10 CFR 50.61 PTS assessment. Again, it's
14 limited by a copper material. And the criterion for
15 the limiting shelf plate is 270 degree F in accordance
16 with the rule. And we calculated a RTPTS or adjusted
17 reference temperature value of 49 degrees F. And this
18 has a wide margin in the --
19 CHAIRMAN WALLIS: It's amazingly low.
20 MR. MEDOFF: It's because it's a low
21 copper vessel.
22 CHAIRMAN WALLIS: How does it get to be so
23 low?
24 MR. MEDOFF: Low copper.
25 CHAIRMAN WALLIS: The low copper?

1 MR. MEDOFF: Usually the plants have --
2 low copper materials have better RTPTS values, lower
3 value.
4 So there's not much of an affect on the
5 RTPTS value by the upgrade. So we concluded that it
6 was acceptable against 10 CFR 50.61 criteria.
7 Okay. The next slide. And we also looked
8 at the impact on the structural integrity of the RV
9 internals. Currently the ASME code, which is invoked
10 by 10 CFR 50.55a requires visual inspection of these
11 components. But there is some -- we may anticipate all
12 of the Dresden/Quad City steam dryer issue, that some
13 of these power uprates may impact some cracking in the
14 component failure. So we looked at the impact on the
15 structural integrity of the RV internals.
16 When the applicant came in with its
17 application it basically assessed them on the gama
18 radiation. And if you Matrix 1 of the Review Standard,
19 there's a footnote on section 2.1.4 and it invokes a
20 couple of industry topical reports in assessing void
21 swelling and irradiated-assisted stress corrosion
22 cracking. And we used the Westinghouse topical as our
23 guideline, our topical report for this. And
24 Westinghouse establishes a threshold on cracking of
25 one times ten to the 21 neutrons per square

1 centimeter. And the energy is .1 MeV on the neutrons.

2 What we did was we asked them a question -

3 - a request for additional information on what the

4 fluences would be for their internals. And they came

5 back with something of the order three to five times

6 ten to the 22 neutrons per square centimeter. And

7 since that's above the threshold, the applicant is

8 willing to give us a commitment on participating on

9 the EPRI studies on internals and to implement the

10 activities that result from them. And they're going to

11 send in an inspection plan for review and approval.

12 We're ironing out the wording for the commitment, but

13 that will be resolved before the SE gets written.

14 DR. KRESS: Where do they stand on

15 inspecting their upper head?

16 MR. MEDOFF: On nickel alloy components?

17 DR. KRESS: No, just the upper head.

18 MR. MEDOFF: The upper head?

19 DR. KRESS: Yes.

20 MR. MEDOFF: I think if I'm not mistaken,

21 Entergy indicated that they just at their outage just

22 did a bare metal visual and the volumetrics and didn't

23 find anything.

24 But we're going to iron out the exact

25 wording of that commitment before the SE gets written.

1 CHAIRMAN WALLIS: So at the present moment
2 it's a conditional component ironing this thing out
3 before you issue the final SER, is that it?
4 MR. MEDOFF: Well, we incorporate the
5 commitment into the SE, so we're going to have to
6 alter a little bit. But pending the final wording
7 that we work out with Entergy, but that will go into
8 the final SE.
9 CHAIRMAN WALLIS: So if they don't meet
10 some requirement, it's okay to then join some
11 imitative?
12 MR. MEDOFF: Well, the way the initiatives
13 work, and Materials and Chemical Engineering Branch
14 encourages the industry to go out and do industry
15 initiatives studies on degradation and cracking of
16 vessel and internals components. And for PWR, the
17 EPRI/MRP is the organizations that's initiating the
18 studies on these components. We've already had a
19 number of assessments come in from the MRP on nickel
20 alloy cracking. And I think they're starting to
21 initiate the studies on the internals and with the
22 intent down the road that they would submit something
23 to us on what they're recommending for inspections on
24 a plant initiative basis for internal components. And
25 then we would look those over and have dialogues with

1 the EPRI/MRP to work out what a final approved program
2 would be. And that's sort of the way we've done this
3 for the BWR VIP with the boilers and we're trying to
4 initiate something similar with the MRP.
5 Are there any other questions on the
6 vessel and the vessel's internal components? Dr.
7 Wallis is pondering them. Any further questions.
8 CHAIRMAN WALLIS: That's okay. You can go
9 ahead.
10 MR. MEDOFF: Thank you very much.
11 Mr. Bob Davis will now address what the
12 impact of the EPO on the leak before break analysis
13 and the nickel alloy components integrity.
14 MR. DAVIS: My name is Bob Davis. And I'm
15 with the Engineering Materials Chemistry Branch in the
16 Piping Integrity and NDE Section. And I reviewed the
17 portion of the application that deals with reactor
18 coolant pressure boundary materials and leak before
19 break.
20 The increase in hot leg temperature only
21 being .8 degrees will have a minimal impact on the
22 Alloy 600. I think somebody asked about the upper
23 head. I believe they're scheduled to, in accordance
24 with the order, inspect their reactor pressure vessel
25 head this spring. I think other than maybe a small

1 relaxation from the order on coverage on their
2 nozzles, they are complying with the order for the
3 bare high susceptibility. So this small temperature
4 increase really doesn't do anything to change that.
5 And, of course, a decrease in temperature is obviously
6 advantageous as far as PWSCC goes.
7 So the staff concluded that the increase
8 in temperature will have only a minimal impact on
9 crack initiation and growth.
10 I did a gentleman this morning from
11 Westinghouse mention that the temperature increase in
12 the hot leg was actually 1.6 degrees rather than the
13 .8 degrees. So I think I will have to somewhere we'll
14 have to address that.
15 I think somebody this morning asked a
16 question and got a response, and the hot leg
17 temperature is a little bit more. Even at 1.6 degree
18 increase that will have a negligible impact on
19 increased susceptibility to PWSCC. They have a fairly
20 aggressive program. They've replaced some of their
21 nozzles already on their hot leg piping and their
22 initiatives are to replace a lot of their 600 with
23 Alloy 690 using Alloy 52 and 152.
24 CHAIRMAN WALLIS: With these questions
25 about what the temperature change actually is, is

1 someone going to find out what it actually turns out
2 to be so that after the EPU has been implemented we
3 can find out what it actually is?
4 MR. DAVIS: Yes. And part of my question
5 based on what the gentleman said this morning from
6 Westinghouse is the range. The .8 plus or minus,
7 point .8 plus or .8 plus or minus two and at what
8 point would they really need to come back and talk to
9 us if it was greater than a certain number?
10 Okay. Any other questions.
11 DR. FORD: Could I ask, it's more of a
12 general question than this specific one, to what
13 extent does the staff take into account emerging
14 issues with respect to cracking in this case for the
15 primary water site in a PWR? And I'm thinking
16 specifically in terms of the effect of ripple loading,
17 which might occur because you've got increased flow
18 rates and the effect that that would have on thermal
19 fatigue of some of these pipings. And it recognizes
20 an emerging issue because it's not in the rules, it's
21 not in bulletin, etcetera, right now. But at what
22 point does the staff become involved in addressing
23 those emerging issues?
24 MR. DAVIS: On that issue I don't have an
25 answer for.

1 MR. TSAO: This is John Tsao from
2 Materials and Chemical Engineering Branch.
3 To respond to your questions, the staff is
4 working with the industry to come up with some sort of
5 resolution of the issues, particularly we are looking
6 at the PWSCC, the primary water stress corrosion
7 cracking and leak before break. Right now the EPRI,
8 industry are trying to come up with some type of
9 inspection and enforcement guidelines. And the staff
10 also is trying to find out if we need some type of
11 generic communication to make sure that PWSCC is not
12 a potential degradation.
13 DR. FORD: Thank you very much.
14 And the reason why I bring it up is that
15 when you talk about thermally induced ripple loading
16 in piping, it falls between the cracks of the ASMI
17 corrosion fatigue evaluations and MRP stress
18 corrosion. It's between the two ends of the spectrum
19 and it's not addressed. And yet when you look at, for
20 instance, socket welds in these systems where you have
21 eddies associated with a socket weld, you could have
22 a potential decrease in the integrity of those
23 components.
24 But from your answer, this is ongoing. It
25 is not covered in this particular item because there

1 is not enough information, is that correct?

2 MR. DAVIS: Well, the PWSCC is what I

3 would be familiar with. And we are, as John

4 mentioned, there are a lot of ongoing issues and

5 discussions with industry. As far as the other issue

6 you brought up, I'm not aware.

7 DR. FORD: And as you point out, this is

8 not specific to Waterford. It is a generic EPU topic.

9 CHAIRMAN WALLIS: It only occurs at EPUs?

10 DR. FORD: Well, it occurs when you

11 increase the flow rate and now you're starting to put

12 in thermal fatigue issues, which are dominate in for

13 instance socket welds.

14 MR. MEDOFF: Dr. Ford?

15 DR. FORD: Yes.

16 MR. MEDOFF: So far for the cracking of

17 the nickel alloy components, Mechanical has been

18 looking at fatigue aspects and the Materials Branch

19 has been looking at PWSCC. We haven't considered

20 ripple loading, we will raise the issue with my

21 management and see what will be taken from there for

22 you. And we'll get back to you.

23 DR. FORD: Okay. Thank you.

24 MR. DAVIS: Any additional questions on

25 Alloy 600?

1 Okay. I also review the section on leak
2 before break. And the operating conditions under the
3 uprated conditions will not alter the conclusions of
4 the previous leak before break analysis for Waterford
5 3. It's still valid.
6 Are there any additional questions?
7 I'll turn it over to John Tsao.
8 MR. TSAO: I'm John Tsao from the
9 Materials and Chemical Engineer Branch. I reviewed
10 five sections; coding system, flow accelerated
11 corrosion programs, steam generator tube inspections,
12 steam generator blowdown systems and chemical and
13 volume control systems.
14 I will be talking about only two systems
15 here; flow accelerated programs and steam generator
16 tube inspections because they are more significant in
17 terms of power uprate.
18 For the flow accelerated corrosion
19 programs, this morning there was some issue as to how
20 much you increase. I have this backup slide.
21 The FAC program measure the wear rates in
22 terms of mils per year. And these are the changes
23 that would be due to power uprate conditions.
24 Also, I want to show you another slide
25 that gives the effectiveness of the FAC program. This

1 is provided by the licensee. And as licensee said, it
2 is more in the -- they used CHECWORKS. It's a
3 computer program that considers hydrodynamics, heat
4 balance, temperature in particular.
5 As you can see the predictive method is
6 conservative considered to actual measurement.
7 DR. FORD: I'm sorry. Could you explain
8 that?
9 MR. TSAO: Okay.
10 DR. FORD: It looks as though it's equally
11 scattered around the one to one line. So why are you
12 saying it's conservative?
13 MR. TSAO: Well, for example, you can see
14 -- let's see.
15 You can see just for example, this point
16 here the measurement is about 300 mils. The predict
17 value, let's say, from here to here is about 240 mils.
18 So what it says is that the methodology will predict
19 that the tube wall thinner than measured, therefore it
20 also indicated that the licensee may need to do some
21 monitoring or replacement of that pipe.
22 DR. FORD: But equally there are points on
23 the other side which are not, what you call it --
24 MR. TSAO: Well, that's true. Yes, that's
25 correct. But as you know this is only a prediction.

1 Predictions, hopefully -- well, from the data point
2 you can see they are scattered toward the conservative
3 side. And also the FAC program according to EPRI is
4 that it's a process. In other words, the licensees
5 would go out, make an inspection, UT or ultrasonic
6 measurements or the pipe thickness and then they will
7 come back and they input that data into the computer
8 code so that to make sure there is a certain accuracy
9 in their predictions.
10 Also predict that the -- in the prediction
11 method they include some safety factors.
12 DR. FORD: It seems to me as though
13 there's a huge amount of scatter around that one-to-
14 one line. And so the question immediately arises as
15 to what is the impact of that in terms of could you
16 get a through wall erosion event taking place when you
17 had predicted it would not have done so?
18 MR. TSAO: It could.
19 DR. FORD: Did you go through that sort of
20 "what if" argument? I mean if you look at that data
21 base, you don't really have too much confidence in
22 CHECWORKS.
23 MR. TSAO: Well, I wouldn't say they would
24 be relying on CHECWORKS per se. The licensees, not
25 only Waterford but other licensees, you know they

1 include other factors. For example, other industry
2 experience. You know if some plants have some problem
3 with FAC water lines, then they will consider --
4 DR. FORD: I recognize that.
5 MR. TSAO: Right.
6 DR. FORD: But this particular EPU is
7 putting a lot of basis on CHECWORKS to manage this
8 problem. And if this a general observation as to how
9 good CHECWORKS is, my confidence is a little bit
10 shattered.
11 MR. TSAO: I should point out that
12 Waterford is not unique. I did the review for license
13 renewal, and I also asked questions. And this is type
14 of plot that, you know, other licensee has shown me.
15 DR. FORD: Yes, I know.
16 MR. TSAO: In other words, I don't think
17 that licensee is depending solely on what prediction
18 is. They also, you know, include other experiences and
19 inspections. Not only the inspections for the fact,
20 but there are other SME code inspections they have to
21 perform.
22 DR. FORD: I'll ask again. Did you go
23 through the "what if" scenario?
24 MR. TSAO: I have Kris Parcziewski from my
25 branch to elaborate on this.

1 DR. FORD: With that amount of uncertainty
2 in your modeling capability and therefore your
3 management capability, do you not feel uncomfortable?
4 MR. TSAO: No.
5 DR. FORD: No?
6 MR. PARCZIEWSKI: Kris Parcziewski from
7 the Chemical Engineering Branch.
8 To answer your question, those points are
9 predicted. CHECWORKS predicts but in addition there
10 is a correction factor for each individual line which
11 is here at the top right hand side, line correction
12 factor which indicates that it is corrected for each
13 individual line all the points predicted in the line
14 are corrected by this line correction factor. And the
15 line is defined as a portion of the system which has
16 the same chemistry but not necessarily the same
17 temperature. If I answer your question.
18 So all those points are already corrected.
19 Ideally, if they were ideal, they would lie in the 45
20 degree line, the middle line. However, obviously,
21 there is some scatter.
22 DR. FORD: I understand the physics --
23 MR. PARCZIEWSKI: Yes.
24 DR. FORD: -- of the erosion process.
25 It's highly dependent on ph. High dependent on

1 temperature. Highly dependent on corrosion potential
2 and all of those things are interacting. So that if
3 you're a little bit off on your definition of one of
4 those parameters, then you're going to get a big
5 change. So I can understand why there is a scatter
6 there because you're not able to define your system
7 adequately enough, and therefore that's the physical
8 origin of your LCF. But I still feel uncomfortable
9 about that huge scatter and how you use it in
10 management from their point of view and in terms of
11 regulation from your point of view.
12 MR. TSAO: Okay. For regulation,
13 basically there's no regulation on FAC program.
14 DR. FORD: That's what worries me.
15 MR. TSAO: The FAC program is instituted
16 because of the bulletin. Back in the '80s it was
17 result of Bulletin 87-01 where Surry had a --
18 DR. FORD: Yes, sure.
19 MR. TSAO: -- a rupture. And Generic
20 Letter 89-08 that required the licensees to institute
21 some type of program, FAC program. And then the
22 industry, you know, with EPRI guidance come up with
23 this program. And so --
24 DR. FORD: I understand all that. I'm
25 just looking at what the history has been since then.

1 And, you know, a few months ago we had fatalities in
2 Japan because of this phenomenon, which was not
3 managed well. And you know if this is supposed to be
4 the state-of-the-art of prediction of management and
5 therefore regulation, I just don't feel comfortable.
6 MR. TSAO: Okay. Speaking of the
7 Japanese, again from my understanding is that Japanese
8 did not inspect, you know, the last 20, 30 years.
9 DR. FORD: Correct.
10 MR. TSAO: Where here under FAC program
11 the licensees will have to inspect at least they say
12 50 to 100 inspection points for their large bore
13 piping and small bore piping they probably sometime
14 inspect 100 percent. And so there's a constant
15 inspections going on to make sure that the --
16 DR. FORD: I understand that.
17 MR. TSAO: Right.
18 DR. FORD: All I'm pointing out is
19 everyone bows to CHECWORKS and says yes, yes that's
20 the best thing that's around. And I'm just
21 questioning it. Is it adequate?
22 MR. HOWE: This is Allen Howe.
23 And I'd just like to add in at this point
24 that we understand the question and we will be happy
25 to get back with you with a response on that.

1 DR. FORD: Thank you.

2 MR. TSAO: Okay. Next slide.

3 Next slide I will be talking about is the

4 related to steam generator tube inspections.

5 This morning you also raised about the

6 question that -- sorry.

7 Next slide. The power operator will effect

8 the anti-vibration tubes for locations. What it does

9 at the increase of feedwater flow will cause the tube

10 to vibrate a little bit more. And the possible

11 degradation is where the anti-vibration bar, they call

12 the bat wings on top of that square shape, hitting the

13 supports.

14 Now, we have the requirement in tech spec

15 that we have the leakage requirement, which the

16 licensee has reduced to 75 gallons per day of a steam

17 generator. This is pretty significant in that the

18 normal primary to secondary leakage limit is 150

19 gallons per day. And Waterford is willing to go down

20 to 75 gallons per day. And that it is very good

21 limits to detect any potential leakage. Because 75 for

22 tech spec translate into administrative limit.

23 Control probably would be at even lower. Therefore,

24 if there's any leak, you know they would probably go

25 into a special administrative control actions

1 additional monitoring. So that's one area that is
2 going to help Waterford.
3 The second one is in tech spec requirement
4 any flaws cannot exceed 40 percent through wall,
5 through a tube's wall. For the wear indication
6 usually the average is about 5 percent per cycle. In
7 other words, the crack growth for tube wear type of
8 indication usually it grows five to ten percent. So I
9 remember you mentioned the possibility whether the
10 crack can grow in one cycle and through wall. And that
11 is not likely.
12 DR. FORD: Why do you say that?
13 MR. TSAO: Because crack grows -- every
14 crack grows for tube wear is about five to ten
15 percent. So even if you have, let's say, 39 or 38
16 percent crack --
17 DR. FORD: Maybe I'm misunderstanding.
18 That statement there and from what I've understood
19 about the situation, you're looking at two distinct
20 degradation mechanisms. One is tube wear.
21 MR. TSAO: Right. Yes.
22 DR. FORD: And the other one is cracking.
23 Two entirely different atom degradation mechanism.
24 MR. TSAO: Okay.
25 MR. MEDOFF: And they may be

1 interconnected, but they don't necessarily have to be.
2 And so I'm trying to sort the two different
3 degradation mechanisms and trying to understand how
4 your control criteria of make it 75 gallons per day,
5 and you're saying that's great. I just don't follow
6 why is 75 gallons per day adequate when you've got two
7 different wear mechanisms operating under different
8 rate limiting steps? Why is it an adequate regulation
9 and manager?
10 MR. TSAO: Okay. You talk about the two
11 separate. Cracking. IDSCC, inside diameter stress
12 corrosion cracking.
13 DR. FORD: Yes.
14 MR. TSAO: And then PWSCC. Okay.
15 DR. FORD: Sure.
16 MR. TSAO: And then this tube wear it's a
17 -- I would say it was kind of pitting. You would say
18 pitting or some type of mechanical metal-to-metal
19 contact the cause.
20 DR. FORD: Sure.
21 MR. TSAO: Okay. Now the 75 gallons per
22 day it lower the threshold for licensee to do certain
23 administrative controls, and that is a big plus.
24 Because normal plant it is 150 gallons per day. So
25 there, you know -- because this is -- this leakage

1 limit is defense-in-depth. Wherever there is a crack-
2 -
3 DR. FORD: I'm hearing all the words. I'm
4 looking at what's on that paragraph there and what
5 I've read in the SER.
6 MR. TSAO: Right.
7 DR. FORD: I'm seeing at least two
8 different atomistic degradation mechanisms. I'm
9 seeing NEI 97-06, which takes into no account the
10 mechanism I'm aware of. And then I'm looking at 75 per
11 gallons per day. And I'm having a problem of
12 interconnecting all of these things that are on that
13 graph and trying to relate them to what is the danger
14 that I might expect to have a thorough wall hole
15 regardless of the mechanism in one fuel cycle. And I
16 don't have the data and I haven't seen the analysis.
17 MR. TSAO: The bottom line is that they
18 have a very good leakage limit. Regardless if they
19 pipe break or anywhere, they have 75 gallons per day
20 that would make sure that would make them to shutdown,
21 they have a shutdown if it goes up to 75. Some of the
22 plants they don't shutdown until 150 gallons per day.
23 Now as for NEI 97-06, that is the industry
24 guidelines that provide a descriptive guidance for
25 them to do inspections and to do certain controls.

1 DR. FORD: Okay. You sound as though
2 you're defending the licensee rather than questioning
3 the licensee. You're saying that they can do this.
4 And this is good for them.
5 MR. TSAO: Well, technically -- in fact,
6 I raise the question that their current tech spec is
7 720 gallons per day. And I questioned them. And then
8 I kind of twist their arm, so to speak, and they come
9 down to 75. And so I wouldn't defend them if --
10 DR. FORD: Okay.
11 MR. TSAO: In other words, I'm very happy
12 they come down to 75. I'm very surprised. And
13 actually I give, you know, a pat on back on that in
14 terms of tube degradation and terms of controlling any
15 potential leakage.
16 DR. FORD: Okay. Thank you.
17 MR. TSAO: Okay. This is pretty much
18 straightforward and this ends my talk.
19 DR. FORD: Is someone going to tackle this
20 question about the flow induced vibration in the
21 dryer? Is that going to be discussed by yourself,
22 well obviously not yourself, but is that going to be
23 covered later on?
24 MR. TSAO: Speaking of flow induced
25 vibration, I not review that section, but this morning

1 someone asked a question about loose parts.

2 DR. FORD: Yes.

3 MR. TSAO: Even if the bolts on a dryer

4 are forced down into the steam generator, usually the

5 licensee, including Waterford, they have the secondary

6 site inspection and they usually go through a foreign

7 object search and retrieval, the FOSR. And what they

8 do is they stick a optical camera down the secondary

9 site and they go down to a tube sheet to find any

10 loose parts. Also loose parts can be detect by the

11 bobbin inspections.

12 DR. FORD: Are you happy that you could

13 never get a loose part into the main steam isolation

14 valve, which was stated this morning?

15 MR. TSAO: Right. Now I have not heard the

16 cases of going to a main steam valve. Usually if there

17 are loose parts, it falls down --

18 DR. FORD: Usually.

19 MR. TSAO: Into bundles.

20 DR. FORD: Always?

21 MR. TSAO: I have not heard -- I have

22 heard of the loose parts come from regular internals

23 that flow into the steam generator on secondary side.

24 And then there are some feedwater gaskets that falls

25 into steam generator site. But I hadn't heard of loose

1 parts in the main isolation valve.

2 MR. MANOLY: Good afternoon. I'm Kamal

3 Manoly, the Section Chief in the Mechanical Branch in

4 NRR. And the lead reviewer for the Waterford power

5 uprate at an audit at Dresden in Chicago looking at

6 the work being done by Dresden/Quad on their dryers.

7 So I know this topic is dear to your hearts, and we're

8 still working on that aspect of it on the boilers.

9 So if you have any questions beyond what

10 I got from him, I'll take notes and we'll get back to

11 on that, because I don't have benefit of the questions

12 discussion with the licensee.

13 As typical we look at the -- there is some

14 overlap between our work and the Materials Branch

15 work. We focus primarily in the vessel internals on

16 the stress analysis and the fatigue usage factors.

17 And small loose vibration concentrations. But,

18 obviously you heard the Materials focus is different

19 than ours.

20 The same thing we do for the steam

21 generator components and the electrical pump.

22 Obviously, and the pressurizer and supports,

23 structural supports also we look at that, too. And

24 balance-of-plant piping and supports and the safety

25 related valves and we saw what we focus on in that

1 area.

2 Next slide.

3 We look at the methodology and the loads
4 that they used, that they're consistent with the
5 design basis, the stresses and the fatigue and the
6 agenda and the codes that they're committed to under
7 SER. And also look at the functionality of the valves
8 and their impact on the EPU based on the findings from
9 the Generic Letters 89-10, 95-06 and 96-06 for the
10 pressurization of segments of piping.

11 Next slide.

12 Okay. The next slide addresses the NSSS
13 and BOP piping and supports. We talk about the EPUI
14 evaluation that incorporates the approved leak before
15 break methodology for elimination of the primary loop
16 pipe breaks in the original design basis. So that's
17 a change from the original design basis for the
18 facility. And now that everything breaks out in the
19 branch piping, the largest branch piping from the main
20 steam and feedwater and otherwise.

21 Finite element analysis for the revised
22 loads. Understand that the change in temperature
23 obviously, as we all know, was very small in terms of
24 effect on the stress allowable. But apparently they
25 were doing that as part of the upgrade of their design

1 basis documents.

2 I guess until earlier today I was under
3 the impression that they meet the ASME limits for all
4 the allowables on all lines, except look at this
5 bullet on that slide. Due to EPU the licensee
6 discovered that the component cooling water shutdown
7 cooling, heat exchanges at the piping was operating at
8 a higher temperature than they initial thought. The
9 design basis is 175 degrees. They have done
10 evaluations for operability up to 225, which means
11 that they don't quite meet the ASME limits above 175.
12 So my understanding is that they will have to start by
13 50.59 utilizing Generic Letter 91.18 and supplement
14 the one with the nonconformance that they have to
15 ultimately correct to meet the code allowance.
16 Because when they start the 175 for that system, they
17 will be exceeding the ASME code limits.

18 The last slide is about flow induced
19 vibration. And I guess we have three bullets there.

20 One relates to the testing and
21 instrumentation on the feedwater at critical locations
22 to monitor during power ascension. And they would be
23 meeting the OM3 standards for monitoring of vibration.

24 The concern about flow induced vibration,
25 obviously on the dryer, is raised several times. And

1 I think the vigor lies on the applicant on the work or
2 on the operation of experience to Palo Verde, which
3 has more power than their plant after the power
4 increase. And I considered that operation of a plant
5 for many years probably is far more proof than just
6 testing for -- you know, limited testing. So we know
7 what Palo Verde's experience is and their dryers are
8 bigger, I believe, than Waterford dryer. So we did
9 not feel that there was real issues.
10 I just heard that during the licensee's
11 presentation that they found that some bolts had
12 broken off at Palo Verde and that's an aspect, I
13 guess, we're going to have to think about.
14 DR. FORD: What was also brought up this
15 morning was that Palo Verde is not the same design of
16 the steam in the upper plenum, because they have more
17 than just one steam exit point.
18 MR. MANOLY: I see. I know that the boiler
19 are much larger, because you have four steamlines and
20 the interplay between the four steamlines has a lot to
21 do with the loads on the plates. So the issue is not
22 as exacerbated as the boilers. But I think there's a
23 lot of reliance here on the Palo Verde experience.
24 And the concern about broken bolts is that they go,
25 you know, where they're not desired to be. So I think

1 we still need to think about the significance of that
2 in terms of operability.
3 On the steam generators, the analysis
4 shows that they meet the stability ratio below .8. So
5 the limit is one, and they basically also said that
6 the steam generators are more robust than the Palo
7 Verde. So I wouldn't expect that they would have an
8 issue there.
9 So that's basically the section on the
10 Mechanical part. If you have any questions, I'll be
11 glad to take it.
12 MR. ROSEN: Well, I think you hit on a
13 couple of good issues, Peter. And I wonder if we
14 could have a little more information at the full
15 Committee on this, especially on the reliance on the
16 Palo Verde experience which may or may not be
17 applicable, I guess.
18 MR. MANOLY: My understanding is that
19 their dryer is bigger than the Palo Verde dryer.
20 MR. ROSEN: But from our experience in
21 talking about the BWRs and specifically the problems
22 addressed in Quad and how that translates to the rest
23 of the fleet, there was discussion about the
24 differences in configuration are very important.
25 MR. MANOLY: Yes.

1 MR. ROSEN: And so I would draw from that
2 the same conclusion here; that the differences in
3 configuration between Palo Verde and Waterford may
4 also be very important. So using Palo Verde as a
5 stocking horse for Waterford may or may not be
6 appropriate. We need a more fundamental look at this
7 than just simply saying well it's kind of like Palo
8 Verde and they haven't had a problem. Not very
9 substantive.
10 MR. MANOLY: Well, yes. The power at Palo
11 Verde is higher than at Waterford after the power
12 uprate.
13 MR. ROSEN: Well, yes. But the question
14 really is about forcing functions for vibrations.
15 MR. MANOLY: Yes, I understand.
16 MR. ROSEN: Not just because the power is
17 higher doesn't necessarily mean that the flow induced
18 vibration is.
19 MR. MANOLY: But the geometry I understand
20 of the dryer at Waterford is very similar but it's
21 larger dryer. So --
22 MR. ROSEN: Maybe we could have some
23 pictures of Palo Verde's dryers and the Waterford
24 dryers.
25 MR. MANOLY: Okay.

1 MR. ROSEN: And at least quality of
2 discussion about where the --
3 CHAIRMAN WALLIS: I'd like to know also
4 because this morning some of the speakers seem to say
5 it was the same, these were the same dryers. They'd
6 also been tested at CE over a wider range of flow rate
7 and pressure. So maybe we could get this more
8 definite; are they same, are they not the same, have
9 they been tested or not been tested, has something
10 similar been tested or the same? You know, get it
11 absolutely straight.
12 DR. FORD: And also I the other aspect I
13 think, Graham, is this whole question what's going to
14 happen to the loose parts which are created if it does
15 fail or is it just a no nevermind?
16 MR. ROSEN: Well simply because the loose
17 parts that were talked about here were found down on
18 the top of the tube sheet doesn't necessarily mean
19 that's where they'll always go.
20 DR. FORD: Exactly.
21 MR. ROSEN: I mean, they may go down the
22 steamline.
23 DR. DENNING: But that's probably an
24 analyzable condition.
25 DR. FORD: Absolutely, but there hasn't

1 been, that's the point. We don't know it's been
2 asked.
3 MR. MANOLY: It was not supported --
4 MR. ROSEN: We're a little bit sensitive
5 on this issue because of history.
6 MR. MANOLY: Right. Any additional
7 questions?
8 CHAIRMAN WALLIS: So we've agreed that
9 before the full Committee you're going to have a --
10 MR. MANOLY: A comparison, I guess,
11 between the --
12 CHAIRMAN WALLIS: A more definite
13 comparison?
14 MR. MANOLY: Yes. The Palo Verde dryers
15 and--
16 CHAIRMAN WALLIS: Maybe besides that you
17 could actually provide my colleague here with a
18 written document which actually has pictures of things
19 so that rather than have the full Committee have to go
20 through all the details so that somebody here can go
21 by an certify --
22 MR. MANOLY: Yes, that's possible.
23 CHAIRMAN WALLIS: -- that he has seen
24 drawings, and indeed they are the same or they are
25 not, or whatever.

1 MR. MANOLY: Yes. That's more efficient I
2 think. Okay. Thank you.
3 CHAIRMAN WALLIS: Thank you.
4 MR. STUBBS: Okay. Good afternoon.
5 My name is Angelo Stubbs. And I'm a
6 reviewer with the Plant Systems Branch. And the
7 review that we performed was for the balance of plant
8 size, plant systems.
9 Go the next slide. Okay. We'll start off
10 with the scope.
11 We followed the Review Standard and
12 there's a detailed breakdown of the things that's
13 included in our review scope in Matrix 5 of the Review
14 Standard. I'm going to summarize here things that
15 were in our scope of review. And that included the
16 secondary plant systems; that was the secondary plant
17 waters systems, circulating water systems, the steam
18 heat water, condensate, the ultimate heat sink and
19 cooling water systems, the main turbine and protection
20 from pipe failures, floods, and internally generate
21 missiles.
22 Also the spent fuel pool cooling and
23 cleanup system, the emergency feedwater system,
24 fission product control and waste management systems
25 and the emergency diesel generator fuel oil storage

1 and transfer systems.

2 So for our review what we did was we began

3 by looking at what things in the uprate would impact

4 the balance of plant systems. And there were things

5 that we thought of that were of major concern. One,

6 the increase in decay heat associated with the EPI

7 operation. The second was a modification that they

8 were making on the main -- on their pressure turbine.

9 And the third was there could be changes in system

10 operating parameters, that is the pressure, the

11 temperature. There's an increase flow, steam flow by

12 8.5 percent.

13 Okay. Next. Okay.

14 I'm going to start off by talking about

15 the turbine. The change that was made to the turbine

16 was the physical modification of high pressure

17 turbine. And that modification included installation

18 of new high pressure turbine rotors with reaction

19 rating, I think they talked about that earlier. And

20 including the inner cylinder, stationary blades and

21 inlet flow guide.

22 The EPU evaluation was performed for that,

23 and what we found was the maximum rotor speed

24 following the reactor trip will still be less than 120

25 percent rates speed, so it will continue to provide

1 adequate protection against overspeed, turbine
2 overspeed.
3 Okay.
4 DR. RANSOM: Was the entire high pressure
5 and turbine replaced or did they just put a new rotor
6 in it?
7 MR. STUBBS: Okay. No -- okay. Go back to
8 the last one. The changes that were made was in the
9 turbine speed paths was in addition to the turbine
10 rotor there was also inlet flow guides, steam sealing
11 components that were replaced.
12 DR. RANSOM: How many stages around the
13 high pressure turbine?
14 MR. STUBBS: Does somebody want to -- I
15 don't recall.
16 MR. VIENER: This is David Viener from
17 Entergy.
18 There's eight stages.
19 DR. RANSOM: Pardon?
20 MR. VIENER: Eight reaction stages.
21 DR. RANSOM: Eight stages?
22 MR. VIENER: Eight stages.
23 DR. RANSOM: So you changed all the
24 staters and the rotors I guess in that?
25 MR. VIENER: That is correct.

1 MR. STUBBS: Okay. As I already
2 mentioned, as far as we're looking at it to see that
3 the overspeed protection, the overshoot would stay
4 within the design and the results were we still
5 maintained the overspeed to be less than 120 percent.
6 CHAIRMAN WALLIS: And 120 percent is okay
7 because of what? Why is 120 percent okay?
8 MR. STUBBS: Well, 120 percent is the
9 design overspeed that's currently water turbine. The
10 trip -- I think the trips are at 111, the control is
11 at 111 or 111 and a half. And there could be some
12 overshoot.
13 There was study done to confirm that 120 -
14 - that the 120 percent wasn't exceeded at the EPU.
15 That's the current overshoot for the current turbine
16 and its design overshoot that the plant is designed
17 for in terms of the turbine protection system.
18 MR. SIEBER: There actually should be very
19 little change in what speed you achieve because --
20 MR. STUBBS: Right.
21 MR. SIEBER: -- at a lower pressure, you
22 actually have less stored energy and you're getting
23 all of the additional output from higher steam flow,
24 which doesn't contribute to the overspeed.
25 MR. STUBBS: Right. And the reason we

1 looked at it is because you're actually making
2 physical changes and what we might do to change to
3 inertia in the turbine, we just wanted to make sure
4 that that was not --
5 MR. SIEBER: And those factors are going
6 to be small.
7 MR. STUBBS: That's right, it turned out
8 to be small.
9 MR. SIEBER: Yes.
10 MR. STUBBS: Okay.
11 DR. RANSOM: What happens on loss of load
12 in terms of overspeed.
13 MR. STUBBS: In terms of loss of load?
14 DR. RANSOM: Right.
15 MR. STUBBS: It still protects -- it's
16 still protect that same overshoot. The control will -
17 -
18 DR. RANSOM: Shut down?
19 MR. STUBBS: Particularly at 111 percent
20 and even after that, the overshoot will maintain it --
21 MR. ROSEN: Does this turbine have
22 electrical overspeed and mechanical overspeed both?
23 MR. STUBBS: Yes.
24 MR. ROSEN: So what are the setpoints for
25 the electrical overspeed protection and the mechanical

1 overspeed protection?

2 MR. STUBBS: I believe one is 111 and the

3 other is 111.5.

4 MR. SIEBER: Unless you have governor

5 valve action.

6 MR. SCHWARTZBECK: Yes. Ralph

7 Schwartzbeck with Enercon Services.

8 The electrical overspeed is 103 percent

9 and the mechanical is 111 percent.

10 MR. ROSEN: So the first thing that

11 happens is the control valves try to control it,

12 right?

13 MR. SIEBER: Right.

14 MR. SCHWARTZBECK: Yes. They close down.

15 MR. ROSEN: If they don't control it, then

16 you get electrical overspeed trip?

17 MR. SCHWARTZBECK: Yes.

18 MR. ROSEN: If that doesn't come in, you

19 get a mechanical overspeed trip at 111. And if that

20 doesn't control it, then you just --

21 MR. SIEBER: Run. Get out of the way.

22 MR. ROSEN: Well, then the turbine's

23 designed to -- if you have a loose part, it has to be

24 a very big one to come through the casing. And if so-

25 -

1 MR. SIEBER: Yes. They usually keep
2 everything inside.
3 MR. ROSEN: Yes, it's usually contained.
4 But not always and the orientation of the turbine is
5 looked at vis-à-vis safety related equipment and so
6 on.
7 MR. SIEBER: Right. And other turbines.
8 MR. STUBBS: Okay. We'll move on.
9 Okay. The next area that we looked at was
10 spent fuel pool. And the reason for this was because
11 there's increased decay heat associated with the EPU,
12 so the fuel being offloaded to the spent fuel pool
13 could -- if it was offloaded at the same time would
14 have higher decay heat associated with it.
15 There was a question this morning
16 concerning why there was discussion in the SE, the
17 extent of the discussion in the SE on this. And the
18 reason is we did our initial review of this and what
19 we saw was that the current analysis, there was very
20 little margin between the calculated peaks and the
21 pool limits. So as a result of that, we asked for
22 additional information from the licensee, and they
23 provided that information. And we wanted to be
24 assured that we weren't exceeding the pool
25 temperatures.

1 In the inlet what happened, what we found
2 out was or the way this is being controlled is they're
3 using administrative controls to control the amount of
4 decay heat that's actually in the spent fuel pool at
5 any given time after the offloads so that they be
6 control the decay heat to be below the heat removal
7 rate available from the spent fuel pool cooling
8 system.
9 This way they ensure that they stay below
10 the temperature limits of the pool and they ensure --
11 by staying below the temperature limits and having the
12 decay heat within -- below -- really at about the same
13 but slightly below what was used in the previous
14 analysis, the time to boil remains down by the current
15 analysis.
16 CHAIRMAN WALLIS: What does
17 "administrative control" mean? Does it mean that you
18 unload the stuff slower or something, or you unload --
19 MR. STUBBS: Okay. Administrative
20 controls, in this case it sets offload limits for the
21 total amount of fuel that could be in the fuel pool
22 for any given time after the reactor is shutdown.
23 The tech spec requires 72 hours before you
24 can start offloading fuel. In this case here it's
25 controlled so that the maximum heat load in a pool

1 will be -- for the normal offload will be 29 million
2 BTUs --
3 CHAIRMAN WALLIS: So you might wait longer
4 to offload, is that what you might do?
5 MR. STUBBS: Yes.
6 MR. SIEBER: That's one thing.
7 MR. STUBBS: Well, the rate at which you
8 offload --
9 CHAIRMAN WALLIS: Or offload at a slower
10 rate?
11 MR. STUBBS: -- may be slower. The one
12 thing, you can wait longer and begin to offload later.
13 That's also an option. But if you begin to offload at
14 72 hours after shutdown, you know, the rate of -- at
15 some point you're going to get to the point where you
16 would be approaching the maximum heat load and your
17 offload would have to be slowed so that you don't
18 exceed that maximum heat load allowable.
19 MR. ROSEN: Is that the licensee's answer
20 to that question?
21 MR. STUBBS: What?
22 MR. ROSEN: That you control the rate of
23 offload?
24 MR. VIENER: This is David Viener, again
25 from Entergy.

1 And Angelo described it perfectly.

2 CHAIRMAN WALLIS: Sot his increases your

3 time that you have to take to reload and everything?

4 MR. VIENER: No. What we would do is

5 control how many assemblies that we can offload based

6 on time after shutdown to control the amount of heat

7 that we can put in the pool.

8 MR. ROSEN: Well, I would say that's sort

9 of surprising. I think that may be the first time

10 I've heard that, that a plant is so limited with

11 respect to spent fuel pool heat rejection capacity.

12 MR. MITCHELL: Yes, this is Tim Mitchell.

13 There is typically a tech spec limit on

14 like at a 100 hour point on how many assemblies you

15 can have offloaded.

16 MR. ROSEN: Yes, I understand.

17 MR. MITCHELL: And it's really not that

18 we're going to slow down the offload, is that we might

19 either have to stop the middle because we have a

20 certain number of assemblies until we reach some hour

21 point post shutdown or you would start later, which is

22 more likely.

23 MR. ROSEN: Is that something you do now?

24 MR. MITCHELL: That is something that we

25 do now -- actually our current outage schedules have

1 not challenged it, so we haven't had to. But I have
2 seen it done at other plants within our system where
3 there is a specific evaluation and depending on things
4 like late temperature or cooling temperature that has
5 to be done on a per cycle basis to determine --
6 MR. ROSEN: It sounds like it's a pretty
7 marginal design to me.
8 MR. VIENER: We've had administrative
9 controls in place prior to even this submittal.
10 CHAIRMAN WALLIS: So this might increase
11 your outage time? You got elements to unload and
12 you've got to do it slower?
13 MR. MITCHELL: At this point we wouldn't
14 expect to increase our outage time. But there may be
15 a point where outage times if they are improved, could
16 be effected by it. It would be something that we
17 would have to evaluate.
18 CHAIRMAN WALLIS: So you increase the
19 power of the reactor, but then you increase your
20 outage times, so your net energy production stays the
21 same?
22 MR. MITCHELL: No. My answer actually was
23 right now it would not effect our current outage time.
24 CHAIRMAN WALLIS: But it seems that it
25 might.

1 MR. MITCHELL: It might if we shorten the
2 outage.
3 MR. ROSEN: Shouldn't you be increasing
4 the capacity of this heat rejection capability here
5 instead of being so marginalized?
6 MR. SIEBER: That's controlled by the
7 river temperature, right?
8 MR. ROSEN: Is it the river temperature
9 that's controlling it or your heat exchanger size and
10 pumping capacity?
11 MR. VIENER: It's controlled by our heat
12 removal component cooling water system and the size of
13 our heat exchanger.
14 MR. ROSEN: It sounds pretty marginal, as
15 I said.
16 MR. SIEBER: It's down south.
17 MR. VIENER: Yes, we're talking that we
18 can remove a partial offload at approximately five
19 days after shutdown. This is if we start to offload
20 at about 72 hours, then it becomes critical because
21 the decay heat is very high in the core three days
22 after shutdown. But the system can remove the whole
23 partial offload of 106 assembles assumed within about
24 five days.
25 MR. LEONARD: This is Ted Leonard.

1 And that's using all the worse case design
2 assumptions? And a train of cooling?
3 MR. VIENER: That is correct. That is
4 following the Standard Revenue Plan criteria of a
5 single failure which we lose a train of cooling.
6 MR. STUBBS: The analysis was performed
7 with a single failure and also bounding. I'm looking
8 at the last offload which would fill the pool to
9 capacity, so it bounds all their offloads in the
10 future.
11 CHAIRMAN WALLIS: Okay. So we'll move on.
12 MR. STUBBS: Okay. Another area that the
13 decay heat also effects -- the increased decay heat
14 also effects is the alternate heat sink in terms of
15 the long term cooling. So EPU evaluation were
16 performed and the results showed that wet and dry
17 cooling tower has sufficient capacity to accommodate
18 post-LOCA heat loads and sufficient water volume is to
19 continued to be available either in the one basin to
20 meet the 30 day heat removal criteria.
21 The conclusion that we drew for alternate
22 heat sink is pending resolution of how the licensee
23 account for measurement of certainty, which is one of
24 the issues I think that was introduced earlier in the
25 introduction.

1 CHAIRMAN WALLIS: So this 30 days is if
2 the cooling towers aren't used at all, they just cool
3 with the water basin, is that what that means?
4 MR. STUBBS: Excuse me. Can you repeat
5 that?
6 CHAIRMAN WALLIS: Is the 30 day heat
7 removal criteria, that means you just use the water in
8 one basin, you don't actually cool it with a cooling
9 tower?
10 MR. STUBBS: Well, if the water in one
11 basis is sufficient to meet that.
12 CHAIRMAN WALLIS: That is just a pool,
13 isn't it?
14 MR. STUBBS: Huh?
15 CHAIRMAN WALLIS: A basin is a pool?
16 MR. STUBBS: Yes. Yes.
17 CHAIRMAN WALLIS: A big basin is a pool.
18 MR. STUBBS: Yes.
19 CHAIRMAN WALLIS: And it means that you
20 just draw in that water without cooling that water
21 over the cooling tower, is that what it means?
22 MR. STUBBS: No. You still utilize the
23 cooling tower, but --
24 CHAIRMAN WALLIS: So it operates from the
25 cooling water, is that what it's making up?

1 MR. STUBBS: Yes.

2 CHAIRMAN WALLIS: Okay. How about the

3 river? The river doesn't count for all of this?

4 MR. STUBBS: Well, to meet their 30 day

5 requirement, their primary heat sink is a wet

6 cooling tower basin.

7 CHAIRMAN WALLIS: Well, why aren't they

8 allowed to use the Mississippi?

9 MR. SIEBER: They need two.

10 MR. TATUM: This is Jim Tatum from the

11 Plant Systems Branch.

12 The criteria that we look at, we rely on

13 seismically qualified capability for the design basis,

14 and so that's why the licensee has to rely on the

15 cooling tower. The cell that they're relying on is

16 seismic category one. And the intake structure, I

17 believe, is not seismically qualified.

18 CHAIRMAN WALLIS: I see.

19 MR. ROSEN: Now as a matter for follow up,

20 these places where the staff conclusion is incomplete,

21 is it planned that they'll come back to the full

22 Committee and give us a --

23 MR. STUBBS: Yes. Right now we're working

24 on -- I think Kaly mentioned this morning, resolution.

25 We think we have a path to resolution for the

1 measurement uncertainty. And as soon as that's
2 resolved --
3 MR. ROSEN: Well, there are a couple. The
4 other one is the AST, alternate source term. And
5 there are several other things that we've talked about
6 as being pending resolution. It seems to me we're
7 getting a little ahead of ourselves here where the
8 staff isn't done with the licensee and yet they're at
9 Subcommittee.
10 MR. BERKOW: This is Herb Berkow.
11 As Kaly indicated this morning, we have
12 agreement, conceptual agreement with the licensee on
13 these three issues. And they will be resolved before
14 we come to the full Committee.
15 MR. ROSEN: And you'll give us a brief of
16 how they were resolved?
17 MR. BERKOW: Yes.
18 MR. ROSEN: Okay.
19 MR. BERKOW: We will.
20 MR. STUBBS: Okay. Another area, again it
21 was a result of the increase in the decay heat, we
22 reviewed the impact on the emergency feedwater system.
23 And the initial water source for those are the
24 condensate storage pool with the backup source being
25 the cooling tower and basin. The evaluations so that

1 increased demand for the emergency feedwater for the
2 plant will continue to be met at operating conditions,
3 at the plant operation of operating conditions.
4 Okay. And the final one which we looked
5 at was the emergency diesel generator fuel oil storage
6 and transfer system. And because of the increased
7 decay heat, this required that some of the equipment
8 for decay heat removal operates for a longer period of
9 time. And that results in an increased demand on the
10 turbine in the four to seven day range and a slight
11 increase in the fuel oil requirements.
12 The licensee's current fuel -- the current
13 fuel oil levels did not support the seven day
14 operational requirements once the uprate was factored
15 in. It was only -- they were only supplying six and
16 three quarter days for the fuel oil supplier. So the
17 licensee has proposed change their tech spec to
18 increase the minimum required volume in the fuel oil
19 storage tank to meet the seven day criteria. And we
20 reviewed that and we found that the new tech spec
21 requirement added enough additional fuel to satisfy
22 seven day post -- seven day operation.
23 And as they mentioned this morning,
24 there's also a commitment to add additional fuel oil
25 storage capabilities to the plant by December of 2006.

1 Is there any other questions?

2 CHAIRMAN WALLIS: Does that bring it to

3 the end of your presentation?

4 MR. STUBBS: That would be the end of my

5 presentation.

6 CHAIRMAN WALLIS: I'm trying to look ahead

7 to the rest of the day here. Someone's going to talk

8 about LOCAs and transient and -- that's the next time,

9 huh?

10 MR. STUBBS: Rich Lobel is going to talk

11 about containment systems.

12 CHAIRMAN WALLIS: That includes LOCAs and

13 various transients?

14 MR. STUBBS: Yes.

15 CHAIRMAN WALLIS: Okay. Not from the

16 Appendix K standpoint.

17 Well, I think we should take a break.

18 Thank you very much for your presentation.

19 MR. STUBBS: Okay.

20 CHAIRMAN WALLIS: Five minutes to 3:00 we

21 need to be back.

22 (Whereupon, at 2:41 p.m. a recess until

23 2:56 p.m.)

24 CHAIRMAN WALLIS: Come back into session,

25 please.

1 We're now going to complete the NRR
2 presentation.
3 MR. KALYANAM: I have one question.
4 Before Rich Lobel goes, we have two experts, one of
5 the FAC CHECWORKS program, the other one on the steam
6 generator tubes. So we had some questions before the
7 break, and I'm sure they'll be able to provide their
8 response to that. Is that okay.
9 DR. FORD: Well, I've been bagging on the
10 head about this FAC business. I understand it
11 perfectly. The other members might enjoy having a
12 presentation on that.
13 MR. KALYANAM: Okay. Either way is fine.
14 CHAIRMAN WALLIS: If it's something we're
15 going to enjoy, I think we should do it.
16 MR. ROSEN: As many times as possible.
17 MR. SIEBER: That's one time.
18 MR. KALYANAM: I have Ken Karwoski from
19 EMCB
20 MR. KARWOSKI: I guess I understand this
21 morning there were questions from the steam generator
22 two integrity standpoints some questions about whether
23 or not the power uprate, what effect it would have on
24 wear and cracking along the length of the tubes as a
25 result of the increased flow through the steam

1 generator. And then there may have also been a
2 question about the adequacy of the 75 gallon per day
3 leakage link.
4 In terms of the effect of the power uprate
5 on the increased flow through the steam generator,
6 there is a potential effect on the amount of wear that
7 can happen at the various support locations, whether
8 it be at the vertical straps, the diagonal bars or at
9 the egg crate supports. There could be an effect on
10 the wear.
11 In addition, Waterford has exhibited
12 stress corrosion cracking at a number of locations
13 along their steam generator tubes. Both of those
14 mechanisms could be effected by the power uprate.
15 However, the change in the conditions in terms of the
16 flow, the temperatures and the pressures across the
17 steam generator tubes are relatively small and well
18 within the bounds of what exists at other plants. And
19 it's been our experience at the other plants which
20 have uprated power that these small changes have
21 negligible increases in corrosion rates, negligible
22 increases on wear rates. And by "negligible," I mean
23 that it's well managed from one inspection to the
24 next; that when they go in and do an inspection after
25 a power uprate or after an interval, that they still

1 have tube integrity. That the tubes have adequate
2 regulatory margin --
3 CHAIRMAN WALLIS: This is where? On the
4 inside of the tubes you're talking about?
5 MR. KARWOSKI: On the outside.
6 CHAIRMAN WALLIS: Are the tubes rattling
7 and wearing.
8 MR. KARWOSKI: Rattling and wearing. And
9 that happens at almost every --
10 CHAIRMAN WALLIS: These fluid interactions
11 are a little hard to predict, aren't they?
12 MR. KARWOSKI: Actually, they're quite
13 reliable. I mean there are some instances where some
14 tubes, and this is usually in the life of a steam
15 generator, where some tubes will wear quicker than
16 others because of the placement of the anti-vibration
17 bars or the diagonal straps in the case of Waterford.
18 So some tubes may wear more than others,
19 but in general these phenomenon are very predictable.
20 Plants leave wear scars in service, and in general
21 they're very predictable. The wear rates tend to be
22 very low and they're left in service for many cycles
23 before they exceed the tech spec.
24 MR. ROSEN: Do they tend to decrease in
25 rate because they kind of wear off whatever the

1 contact point and that's it?

2 MR. KARWOSKI: That has been the

3 experience, and I can't comment on the combustion

4 engineering data, but I know that that's definitely

5 been the experience at Westinghouse design steam

6 generators. But the wear rates decrease with time

7 because of the contact issue point.

8 MR. ROSEN: Now the question is brought up

9 how about the effect of vibration, vibrational

10 stresses on the kinetics of stress corrosion cracking?

11 MR. KARWOSKI: Once again, you know, it is

12 possible that that would increase the rate of

13 cracking, may even change the initiation of cracks.

14 But it's been our experience that any change that does

15 occur: (1) It's not readily measurable, and; (2) that

16 it can be managed within the normal frequency of in

17 service inspections. And certainly if there is a

18 change, we will detect that as we review the annual

19 reports that the plant sends in regarding their

20 inspections. And we would expect them to take

21 corrective action, and that would be something we

22 would followed up. But in general we have not

23 observed that. And in the case of Waterford, it's been

24 their practice that when they find a crack, they plug

25 that crack on detection. It's not like some of the

1 other plants which leave cracks in service and try to
2 manage cracks that --
3 MR. ROSEN: My questions on those two
4 issues.
5 MR. SIEBER: The displacements are
6 extremely small and the number of cycles is extremely
7 large. So if there is going to be failure, it would
8 show up fairly early, I would expect.
9 MR. KARWOSKI: That would be for like the
10 cycle type of fatigue failure.
11 MR. SIEBER: Right.
12 MR. KARWOSKI: In this case it's more just
13 the wearing of the tube, which it can be low cycle--
14 MR. SIEBER: But that's not fatigue
15 failure.
16 MR. KARWOSKI: No, that is not fatigue.
17 Yes, that's correct.
18 MR. SIEBER: Right. It's just wearing
19 out.
20 MR. KARWOSKI: That's just wear.
21 DR. FORD: Jack, there's a problem
22 discussed earlier on. It's not trangranular fatigue,
23 cracking you see.
24 MR. SIEBER: Right.
25 DR. FORD: And therefore it's not covered

1 by the ASME 3 code or anything like that. Similarly
2 it's just stress code in cracking that's been
3 accelerated.
4 MR. SIEBER: But wear phenomenon is
5 covered by the ASME code.
6 DR. FORD: Yes.
7 MR. KARWOSKI: Through the plugging limits
8 and what not and through the plant technical
9 specifications.
10 DR. FORD: Right.
11 CHECWORKS?
12 MR. KARWOSKI: I think Louise Lund was
13 going to talk about CHECWORKS.
14 DR. FORD: Maybe if I could just state
15 what my problem was, Louise, and that would make it
16 more efficient for you to answer it.
17 MS. LUND: Should I introduce myself first
18 for the record?
19 DR. FORD: Yes.
20 MS. LUND: I'm Louise Lund. I'm the
21 Section Chief for the Steam Generator and Integrity
22 and Chemical Engineering Section, NRR. And, anyway,
23 I was asked to come over and discuss the FAC program.
24 DR. FORD: My concern was that the way
25 that they're using CHECWORKS right now, it is

1 primarily a prioritization tool as to where you're
2 going to look in the carbon steel piping. From the
3 measures that were shown this morning, it's apparent
4 that CHECWORKS is not good on one-to-one correlation.
5 Therefore, it's quite possible that you may use
6 CHECWORKS to say that I should not look at that pipe
7 because of the particular operating conditions of that
8 pipe, but I should look at this pipe. But in fact that
9 pipe there might well be eroding at quite a large
10 rate, but you wouldn't look at it for one, two, three
11 cycles. In that time you could go through wall. So
12 that was essentially my worry that you're using a
13 model which is not precise to make prioritization
14 decisions.
15 MS. LUND: Right. And I just want to say
16 off the top, you know we have a very active interest
17 in the FAC programs. Specifically we've had generic
18 letters or generic correspondence that has asked
19 industry to put together these type of programs which
20 manage FACs and also have these predictive
21 methodologies. However, it's not a case of just using
22 the predictive methodologies blindly and looking at
23 information on one line or another; there's a number
24 of things that inform the decision as far as what's
25 inspected and how it's inspected. Because it is a

1 tool, but it's not a blind tool in that particular
2 way. And, in fact, this gentleman I believe is from
3 Waterford and he was mentioning, we had a kind of
4 offline discussion about it and that's why I asked him
5 to come up here and help discuss this, and
6 specifically for Waterford.
7 I also wanted to say that for these FAC
8 programs, I think that we have an interest in looking
9 at them through power uprate and license renewal in
10 that we ask that the licensee provide information on
11 their most susceptible lines with their measures
12 versus their predicted and whether it gave them
13 information such that they could replace the lines,
14 you know, in a timely manner. Because that's really
15 what we want to know is, is it giving you the
16 information at the time that you need it in order to
17 make the decisions you need to make good decisions
18 about running your plant.
19 So that's the kind of questions we ask. We
20 do not do a re-review of their CHECWORKS data. We do
21 not take all their raw data and subsequently do an
22 audit of it. Okay. So I just wanted to kind of
23 clarify what it is that we do, you know, in our review
24 process. Usually through a request for additional
25 information we usually will ask them for the most

1 susceptible lines.

2 MR. ROSEN: We call that a performance-

3 based regime?

4 MS. LUND: Right. Right. And when we put

5 out that generic letter where we asked the licensees

6 to put together a FAC program and also have these

7 predictive methodologies, we did inspections of those

8 programs at that time. Okay. In fact, to make sure

9 that these programs were in place and in fact doing

10 what we thought that they were doing. Okay.

11 Now, I now in license renewal, true

12 license renewal we've been asked to come and give a

13 presentation to the ACRS on FAC and FAC programs. And

14 we've actually been in contact with CHECWORKS user

15 script to ask them to come in and help present this

16 information such that you can look industry-wide at

17 how well these FAC programs are working, specifically

18 with the CHECWORKS program and give you a lot of sense

19 -- instead of looking at just one graph, kind of get

20 a sense for generically how this is working and where

21 it may be challenged in certain ways or another,

22 because they think that they have a very good story to

23 tell.

24 Now maybe if you could introduce yourself,

25 and then also explain how programmatically it's a much

1 lighter look at how you choose the lines and --
2 because there's a surrogate aspect to it where, you
3 know, if you see something you look at other things
4 that are like that. There are a lot of things that go
5 into the program that don't rely on just this
6 measurement.
7 So, anyway --
8 MR. ALEKSICK: Good afternoon. My name is
9 Rob Aleksick. I'm with CSI Technologies representing
10 Entergy today.
11 Real quick about my background. I've had
12 the opportunity to be involved with flow accelerated
13 corrosion since 1989 and in particular have modeled or
14 otherwise addressed approximately 20 EPU efforts in
15 the last two years.
16 Dr. Ford made a very good point earlier
17 when he said that the graph that we looked at did not
18 display a very good correlation between the measured
19 results and the predicted results out of CHECWORKS.
20 Programmatically -- well, let me back up a second.
21 That is certainly true in the example that we looked
22 at. That is not always the case.
23 CHECWORKS models are on a per line or per
24 run basis. The run --
25 CHAIRMAN WALLIS: Could we go back to that

1 graph that we saw? The graph was a plot of thickness
2 versus predicted thickness.
3 MR. ALEKSICK: That's correct.
4 CHAIRMAN WALLIS: Because if you looked at
5 amount removed versus predicted amount removed, it
6 seems to me the comparison will be even worse.
7 MR. ALEKSICK: That's correct. In fact --
8 CHAIRMAN WALLIS: That's what you're
9 really trying to predict is how much is removed.
10 MR. ALEKSICK: Yes, that is true. And my
11 point is that in some subsets of the model, the one
12 that we looked at here which was high pressure
13 extraction steam, the correlation between measured and
14 predicted is not so good. And in some subsets of the
15 model, the correlation is much better.
16 CHAIRMAN WALLIS: It looks to me that in
17 some cases it's predicting no removal whereas in fact
18 there's a lot of removal. So the error is percentage
19 wise enormous?
20 MR. ALEKSICK: Yes, exactly. Exactly.
21 Some runs results are imprecise and some more precise.
22 And we look at both accuracy and precision.
23 Programmatically we account for that, that reality, by
24 treating those runs that have what we call well
25 calibrated results, i.e., precise and accurate results

1 coming out of the model that are substantiated by
2 observations, we treat those piping segments
3 differently programmatically than we do areas where
4 the model is less good. If the model results do not
5 correlate well with reality, different actions are
6 taken primarily increased inspection coverage to
7 increase our level of confidence that those systems
8 can continue to operate safely.
9 In addition to the CHECWORKS results many
10 other factors are considered to assure that the piping
11 retains its integrity, chief among these are industry
12 experience as exchanged through the EPRI sponsored
13 CHUG group. Plant experience local to Waterford in
14 this case. And the FAC program owner maintains an
15 awareness of the operational status of the plant so
16 that, for example, modifications or operational
17 changes that occur are taken into account in the
18 inspection of the secondary site FAC susceptible
19 piping.
20 DR. FORD: And my final question on this
21 particular subject was given the uncertainties in the
22 model, changed by this performance based aspect that
23 you just talked about, is there any way that you can
24 come up with a quantification of the risk associated
25 with a failure of a specific pipe?

1 MR. ALEKSICK: There's currently no
2 accepted methodology to quantify that risk, no.
3 However, it is accounted for primarily on a judgment
4 basis through industry experience and information
5 exchange through the EPRI CHUG group.
6 DR. FORD: Okay.
7 MR. MITCHELL: Yes, this is Tim Mitchell.
8 Just to give you a feel for how we're
9 addressing for this upcoming refueling outage, we have
10 increased our scope for a couple of reasons. One to
11 get additional data and we always do more than just
12 exactly what CHECWORKS supports. So you're always out
13 validating and getting more data to be able to help
14 predict where do you need to be looking. But in
15 addition, we're taking some additional points to make
16 sure we have good baseline data for the next cycle to
17 ensure that those points give us a good indication
18 going forward after the EPU.
19 The analysis for flow accelerated
20 corrosion shows very minimal changes as a result of
21 power uprate. But we are taking seriously our
22 inspection program and expanding it for this upcoming
23 outage to ensure that we know what's happening not
24 just what we're predicting.
25 MR. ROSEN: Let me roll that back now,

1 Tim. Can you tell me like for the last three or four
2 outages have you done some actual replacement of
3 piping based on predictions of FAC from the CHECWORKS
4 code or have you never replaced anything? What are
5 you seeing at Waterford?
6 MR. MITCHELL: I can give you non-
7 Waterford data better than I can give Waterford to
8 ponder.
9 MR. CHOWDHURY: My name is Prasanta
10 Chowdhury and I'm working with Entergy design for last
11 20 years.
12 I was involved with FAC also for several
13 years in the past.
14 It's not the CHECWORKS model that
15 determines what replacement is to be done. We base it
16 on actual measurement we take during the refuel
17 outage. So we also project based on actual measurement
18 that what will be our future projected thickness in
19 next refueling outage. So you can survive until next
20 cycle. And then we do some evaluation based on our
21 criteria that makes the stress criteria -- or based on
22 the code requirement. Like make all the equation.
23 Now code allows to go thinning in local
24 area but the FAC is a local thinning. So we do some
25 local thinning evaluation to make sure that it goes to

1 the next cycle.

2 Does that answer your question?

3 MR. ROSEN: No.

4 MR. MITCHELL: Did we replace any piping

5 in the last three outages?

6 MR. CHOWDHURY: I don't recall. I don't

7 recall. But we did extensive modification on

8 extraction steamline in the past. But it changed to

9 crack piping or stainless steel piping or chrome moly,

10 which is more corrosion resistance piping. I don't

11 answer your question --

12 MR. ROSEN: You say you have made

13 extensive modifications --

14 MR. CHOWDHURY: In the past.

15 MR. ROSEN: -- you changed to chrome moly?

16 MR. CHOWDHURY: Several years back, yes.

17 MR. ROSEN: Okay.

18 MR. CHOWDHURY: So whatever we did, see

19 the corrosion of thinning, we took it out and made

20 modifications.

21 MR. ROSEN: Yes, well, that's typically

22 the plant's response. If you find substantial

23 thinning, then you just don't go back and put in

24 carbon steel back in the same place.

25 MR. CHOWDHURY: Right.

1 MR. ROSEN: Because what happened before
2 will happen again.
3 MR. CHOWDHURY: I mean we have also made
4 a procedural entry into this FAC that anytime we do a
5 replacement, we use a better corrosion resistant
6 material or EPRI guidelines.
7 MR. ROSEN: Okay. So you're saying you
8 have made those kinds of modifications.
9 MR. CHOWDHURY: Yes. But still we are
10 ongoing and doing things. If we see something we need
11 to change, we change it.
12 Does that answer your question, sir?
13 MR. ROSEN: It's a little better. Not a
14 100 percent.
15 MR. CHOWDHURY: Okay.
16 MR. ROSEN: I would prefer something, and
17 maybe for next meeting you can come back with some
18 real data that there are 11 locations that you changed
19 in the last five years or something.
20 MR. CHOWDHURY: Yes, we can do that.
21 Because I don't have the data with me. I can get in
22 touch with the FAC program engineer and get those
23 information. Thank you.
24 CHAIRMAN WALLIS: That would be excellent.
25 DR. FORD: Thanks very much indeed. I

1 appreciate it.

2 MR. KALYANAM: Next we have the

3 Containment Systems group Richard Lobel.

4 MR. LOBEL: Good afternoon. My name is

5 Richard Lobel. I'm with the Probabilistic Safety

6 Assessment Branch but in the Containment System area.

7 Next slide, please.

8 I wanted to talk about the review of the

9 analysis that were done for the containment accident

10 analysis. This slide lists the areas that were looked

11 at. Basically the analysis of containment response to

12 a LOCA both the mass release and the containment

13 response and the containment response to a main

14 steamline break, both mass and energy into the

15 containment and the containment response and

16 subcompartment analysis also, which is a type of LOCA.

17 Next slide.

18 CHAIRMAN WALLIS: You mean that PSA Branch

19 actually does this sort of thermal-hydraulic analysis?

20 MR. LOBEL: We're the orphan section. We

21 go to the branch meetings but don't understand what

22 they're talking about, because it's all acronyms

23 dealing with risk and we just sit there and listen.

24 But that's where they put us.

25 The mass and energy for the LOCA was

1 calculated using NRC approved Westinghouse methods,
2 Ceflash for the blowdown and Flood 3 for reflood and
3 Contrans for the long term mass and energy release.
4 The calculations for LOCA were previous
5 approved by the staff and the license amendment
6 issued, I think in Amendment 165 that had to do with
7 changing the number of operable fan coolers. And I
8 think that was issue around 2000. So the mass and
9 energy release and the containment response for LOCA
10 haven't changed for the Waterford EPU because the
11 analyses were initially done at EPU conditions.
12 A subcompartment is defined in the SRP,
13 for those who are familiar, as any partially or fully
14 enclosed volume within the primary containment that
15 houses a high energy piping and limits the flow out of
16 that volume so that the subcompartment pressurizes
17 faster than the global response to the containment.
18 And the item of interest is the structural integrity
19 of the walls of the subcompartment.
20 The license reexamined this and found that
21 there was significant margin to any limits. And used
22 approved methods.
23 The main steamline break analysis was done
24 using the NRC approved code, SGNIII that was approved
25 back with CESAR and calculates the mass and energy

1 release from a ruptured steamline into the
2 containment.
3 The containment response to both the LOCA
4 and the steamline break were calculated with the
5 GOTHIC code. The staff back in this Amendment 165 had
6 approved GOTHIC 5 for use by Waterford and the
7 licensee went to the more recent version of GOTHIC,
8 GOTHIC 7. The staff had reviewed GOTHIC 7 on another
9 docket and found it acceptable with some limitations
10 or restrictions that had to do with modeling of heat
11 transfer. The licensee used the code in a way that
12 didn't use any of the model that we found
13 unacceptable. So the calculations done with GOTHIC 7
14 were benchmarked to GOTHIC 5 calculations and found to
15 be very close.
16 CHAIRMAN WALLIS: So you accepted the
17 calculations made by the applicant?
18 MR. LOBEL: Yes, we didn't do --
19 CHAIRMAN WALLIS: You didn't any
20 confirmatory calculations?
21 MR. LOBEL: No, because of the fact that
22 the change wasn't all that much in terms of
23 containment and the licensee used methods, mass and
24 energy methods had been used for decades now for
25 analysis and CE designed plants. And like I said,

1 GOTHIC 7 we reviewed on another docket and the
2 licensee was asked to verify that they were using the
3 code consistent with that review, and they answered
4 that they had. So it really didn't qualify for
5 analysis that required an independent audit.
6 The environmental qualification analysis
7 the licensee stated that the containment pressure and
8 temperature for EPU conditions were bounded by the
9 existing plant accident profile except for the time at
10 elevated temperatures, which was slightly longer. And
11 the licensee confirmed that the electrical equipment
12 was still qualified for the longer time and the
13 containment flood level remained unchanged.
14 MR. SIEBER: It would seem to me that with
15 respect to the scored energy contained in fluids, they
16 would be equal to or perhaps slightly lower than the
17 current conditions at the plant. And the only thing
18 that's different is the decay heat of the core.
19 MR. LOBEL: Yes.
20 MR. SIEBER: And so whatever differences
21 you see are the result of the, perhaps, ten percent
22 higher level of decay heat, which would tell me
23 everything stays about the same.
24 MR. LOBEL: Yes. Basically these codes --
25 because typically when we do an audit calculation, we

1 ask the licensee -- which we didn't do in this case.
2 When we do, we ask the licensee for his mass and
3 energy calculations. So really this is just a heat
4 balance check.
5 MR. SIEBER: That's right.
6 MR. LOBEL: And a check of the heat
7 transfer models and that kind of stuff accounting for
8 the inventory of liquid, what's condensing on the
9 walls and what's falling in the sprays and what's in
10 the sump, and all that.
11 MR. SIEBER: Right. Right.
12 MR. LOBEL: So it's basically true.
13 There were slight differences in the
14 calculations, some assumptions, but really not --
15 CHAIRMAN WALLIS: But you could almost
16 estimate the change in pressure by a global energy
17 balance -- or put it into the containment and see what
18 happened. And you've come fairly close in terms of an
19 increment.
20 MR. LOBEL: Yes.
21 MR. SIEBER: That's why it's small.
22 CHAIRMAN WALLIS: Yes.
23 MR. LOBEL: Next slide, please.
24 CHAIRMAN WALLIS: So you do it on the back
25 of an envelop confirmatory calculation.

1 MR. SIEBER: Yes.

2 CHAIRMAN WALLIS: That's what I would do.

3 MR. SIEBER: You would not even need the

4 whole envelop.

5 MR. LOBEL: These are the results of the

6 calculations for the LOCA. Like I say, these were

7 done for a previous license amendment that the staff

8 approved. And the next slide for the steamline break.

9 Let me just point out there should have been change to

10 the slide. The numbers for the pressure and

11 temperature are very slightly different than what I

12 have here. This was from the licensee's original

13 submittal and they made a modification, which didn't

14 make it onto the slide.

15 The pressure, I think, was 41.87 instead

16 of 41.83. So not really significant.

17 CHAIRMAN WALLIS: These temperature

18 acceptance limits are so different because steam has

19 a different effect than water or something on --

20 MR. LOBEL: On a LOCA in the main

21 steamline break?

22 CHAIRMAN WALLIS: On equipment, is that

23 what it is or was it --

24 MR. LOBEL: Yes. We asked the license

25 about this and the licensee claims that the acceptance

1 level they've always used for main steamline break is
2 this high temperature, which is an environmental
3 qualification temperature. So we did ask the licensee
4 well how does that address the issue of structural
5 integrity of the containment. And the licensee came
6 back in response and said that they had looked at that
7 and they were calculating a temperature below the
8 structural temperature.
9 CHAIRMAN WALLIS: Well, did the
10 containment sprays come on during all this?
11 MR. LOBEL: Yes.
12 MR. SIEBER: Yes.
13 CHAIRMAN WALLIS: So why is the steam
14 break inherently different from a water steam break?
15 MR. LOBEL: Well, typically the --
16 CHAIRMAN WALLIS: Everything is wet and
17 soggy no matter what, isn't it?
18 MR. LOBEL: Well, typically the enthalpy
19 of the break is higher and the timing is different for
20 the steamline break.
21 MR. SIEBER: More mass.
22 CHAIRMAN WALLIS: But the environment is
23 wet and soggy in either case, and the temperature is
24 very different in the two cases. I can't understand
25 why equipment qualification or whatever should be so

1 different.

2 MR. LOBEL: Well, I can't answer what the

3 basis for that limit is. Maybe the licensee can. But

4 I'm sure it's based on --

5 CHAIRMAN WALLIS: Don't you set the

6 acceptance limit?

7 MR. LOBEL: Pardon?

8 CHAIRMAN WALLIS: Doesn't the agency set

9 the acceptance limits rather than the licensee?

10 MR. LOBEL: Well, we set the criteria, but

11 no the licensee typically sets the value because it

12 depends on the design of his containment and any

13 equipment in his containment. So --

14 MR. SIEBER: Generally the EQ profile, you

15 have a lot of electrical equipment in containment and

16 each one has an EQ profile that it has been tested to.

17 MR. LOBEL: Right.

18 MR. SIEBER: So you look at the most

19 restrictive of those, and that becomes the design

20 acceptance form below which you must keep the

21 containment response to a steamline break.

22 MR. LOBEL: It's a very conservative

23 calculation. For instance, the staff guidance allows

24 the licensee to take credit for what's called

25 revaporization where some of the liquid that is

1 condensed goes back into steam again and takes some
2 energy out of the system. But Waterford didn't take
3 credit for that.
4 DR. RANSOM: Are these results for LOCA a
5 large break LOCA?
6 MR. LOBEL: Yes. That's typically limiting
7 for containment.
8 MR. SIEBER: What's that, the LOCA?
9 Steamline break?
10 MR. LOBEL: Well, for a LOCA, the large
11 break LOCA is typically limiting for containment.
12 MR. SIEBER: That's right.
13 MR. ROSEN: The previous slide.
14 MR. SIEBER: Okay.
15 MR. LOBEL: In general, some licensee
16 predict that the steamline break is a higher
17 temperature and --
18 MR. SIEBER: Yes. I thought that
19 generally the case, that there's more energy release
20 from a steamline break than a LOCA.
21 MR. LOBEL: Yes.
22 CHAIRMAN WALLIS: Well, the SER is full of
23 all kinds of transients that were analyzed. And there
24 is nothing of interest in any of that, is that right?
25 It's just these few that are the limiting ones that we

1 worry about?

2 MR. LOBEL: For the containment, yes.

3 MR. SIEBER: It depends on who --

4 CHAIRMAN WALLIS: Well, for anything else.

5 I mean, for any other criteria, all these other

6 transients that are in the SER, that presumably you're

7 not going to talk about, were not interesting because

8 they never challenged any limits?

9 MR. LOBEL: Well, not containment limits.

10 DR. DENNING: Radiological. Some of them

11 are radiological.

12 MR. LOBEL: This review concentrates on

13 the structural capability of the containment.

14 CHAIRMAN WALLIS: Just on containment.

15 All those other things that were in the SER that we're

16 not going to discuss perhaps?

17 MR. LOBEL: Well, I think they're going to

18 be discussed after I'm done. We have people here to

19 discuss them. But it's not something I review.

20 CHAIRMAN WALLIS: Maybe they just

21 summarize in a minute or two or something all these

22 events. We're going to get to that next, are we?

23 MR. LOBEL: Yes.

24 CHAIRMAN WALLIS: Okay. So are you

25 finished?

1 MR. LOBEL: I'm finished.

2 CHAIRMAN WALLIS: Thank you very much.

3 MR. KALYANAM: Next we have Sam Miranda

4 from the Reactor Systems Branch.

5 CHAIRMAN WALLIS: We still have about half

6 of your slides to go through, is that real? I'm just

7 looking at the schedule and the mass of slides here.

8 MR. KALYANAM: And hopefully Sam will be

9 able to skip quite a few of them.

10 CHAIRMAN WALLIS: Okay. Thank you.

11 MR. MIRANDA: My name is Sam Miranda. I

12 work in the Reactor Systems Branch as a technical

13 reviewer. And could I have the next slide, please?

14 Our review areas are listed in the

15 following slides. They're based on Matrix 8 of the

16 Review Standard-001.

17 Okay. At this point in general, I could

18 summarize the review areas as those accidents or

19 transients that are sensitive or effected by the power

20 uprating or have been analyzed using different

21 methods. In the case, the principle change in the

22 non-LOCA accidents was the transition from CESEC to

23 CENTS.

24 As part of our review we have also done an

25 audit of several key analyses, a detailed review both

1 in-house and at Westinghouse's offices in Connecticut.
2 And we concentrated on these accidents for various
3 reasons.
4 For example, the loss of feedwater
5 analysis is a loss of heat sink event which would be
6 effected by the power uprating.
7 The feedline break analysis is one of the
8 more complicated non-LOCA events which requires a
9 detailed model of the secondary side.
10 Steamline break analysis in this instance,
11 we noticed that there was a change in the licensing
12 basis for the steamline break. Besides using the
13 CENTS code, there was -- the licensee was reporting a
14 fuel failure for the inside containment steamline
15 break with loss of offsite power and where they had
16 not been doing so in the past in the FSAR.
17 Furthermore, this fuel failure was due to
18 incipient centerline melting. And we discussed it with
19 the licensee and they agreed that in the future that
20 there would be fuel management and shutdown margin
21 available to prevent centerline melting of fuel.
22 However, they do predict two percent fuel failure due
23 to clad damage.
24 We also looked at the small break LOCA and
25 long term cooling, and Dr. Len Ward, my colleague,

1 will discuss this in further detail after me.

2 MR. SIEBER: As far as long term cooling

3 is concerned, it seemed to me that was where one of

4 the shortfalls was, slightly. And the question is do

5 you retain a coolable geometry for the long term?

6 MR. MIRANDA: I didn't get the first part

7 of your question.

8 MR. SIEBER: Well, it seemed to me that

9 one of the questions was the capability to do long

10 term cooling. And my question is does Waterford

11 retain coolable geometry for the long term period,

12 which is 30 days plus?

13 DR. WARD: Yes. I'm Len Ward from the

14 Reactor Systems Branch. I'm going to talk about that

15 right after this discussion in about ten minutes.

16 MR. SIEBER: Okay. All right.

17 DR. WARD: And it's in regard to boric

18 acid precipitation where you can block the entire core

19 with boric acid.

20 MR. SIEBER: Okay.

21 MR. MIRANDA: Yes, we have a detailed

22 discussion on that coming up.

23 These are some results of our calculations

24 we did. We did the details reviews, we did the audits

25 and Len Ward also did some independent calculations.

1 And this is a brief summary of those results. And
2 he'll be going into this in further detail later.
3 As you can see, we have the fuel clad
4 failure of 2 percent in the steamline break.
5 For the large feedline break, one of the
6 concerns is RCS over pressurization. And the licensee
7 predicts a peak pressure of 2753 psia and our staff
8 calculations predict 2709 psia.
9 The next slide.
10 CHAIRMAN WALLIS: And that 3000
11 parenthesis, that's an acceptable?
12 MR. MIRANDA: That is the limit for this
13 event, yes.
14 The loss of condenser vacuum, we also got
15 good agreement between the submittal and our
16 independent calculation, as well as the small LOCA. We
17 were predicting within half a foot of core uncovery.
18 Next slide.
19 CHAIRMAN WALLIS: And that's okay to have
20 the core -- the top half of the core uncovered for
21 over 1,000 seconds is okay? Maybe I've forgotten this
22 kind of thing, but it seems sort of surprising to me
23 to have it uncovered for so long.
24 MR. MIRANDA: Yes. This morning there was
25 a peak clad temperature reported for this break of

1 2018.

2 CHAIRMAN WALLIS: Right. That is

3 presumably because it's climbing up steadily during

4 all that time and it's dry.

5 MR. MIRANDA: These slides I'm going to go

6 through very quickly. I have them in case anyone

7 wants to ask questions or discuss them, but basically

8 what these are are a checklist or a worksheet that I

9 was using to be sure that all of the events were

10 addressed. And for a power uprating submittal, not

11 all the accidents really need to be reanalyzed. You

12 have to look at the ones that are effected by the

13 power uprating and the ones that are effected by

14 changes in methodology. And there are a lot of

15 accidents that are bounded by others. And you need to

16 be careful about reviewing the ones that are bounded

17 by others to be sure that you're comparing apples-and-

18 apples, that the same criteria apply for these events.

19 And that's where the ANSI Condition II, III and IV

20 come in. And this is an expansion you might consider

21 of Matrix 8 of the Review Standard where I'm looking

22 at these events to be sure that claims of one accident

23 bounding another really are valid.

24 So that's the rest of the slides.

25 CHAIRMAN WALLIS: Why do you need to

1 consider so many things? I mean, presumably very few
2 of them turn out to be significant?
3 MR. MIRANDA: Exactly. And some of them -
4 - many of them are not analyzed.
5 CHAIRMAN WALLIS: But you knew from
6 previous experience before the uprate that many of
7 them didn't come close to challenging the system.
8 MR. MIRANDA: Yes.
9 CHAIRMAN WALLIS: Yet you still have to go
10 through it all again for a relatively small change in
11 power?
12 MR. MIRANDA: Just to be sure that it was
13 looked at, yes. And a lot of them, as you'll see,
14 they're not even analyzed. They're bounded.
15 MR. SIEBER: Is that because of the way
16 the Review Standard is written?
17 MR. MIRANDA: Yes. The Review Standard
18 covers all of these, that's right.
19 MR. SIEBER: What's your opinion of the
20 Review Standard the way it is right now easy to use,
21 difficult to use, does it make more work for you, does
22 it have a value added to it?
23 MR. MIRANDA: I have used it. I do think
24 it has a value added. I think it's too long. But I
25 use the parts that I find useful, and the parts that

1 I found useful were the Matrix 8.

2 And, frankly, I think the Review Standard

3 should be used as a guide to revise the Standard

4 Revenue Plan, which need revision anyway. So this is

5 a good starting point for the revision, and we should

6 rely mainly on the Standard Revenue Plan which should

7 have provisions in each Standard Revenue Plan section

8 to deal with situations such as upratings. If you're

9 looking at uprating, consider decay heat, consider

10 power level, consider so on.

11 MR. SIEBER: It seemed to me that it did

12 allow the staff to produce pretty good SER. To me

13 it's one of the best that I've seen.

14 MR. MIRANDA: Thank you.

15 If there are no more questions, I'd like

16 to have Dr. Len Ward come up and discuss the

17 independent calculations and the long term cooling.

18 DR. WARD: My name is Len Ward. I'm in the

19 Reactor System Branch. And I just wanted to show you

20 some calculations that I did, some audit calculations.

21 The large feedline break. We looked at the limiting

22 small break LOCA and I looked at post-LOCA long term

23 cooling, and that's dealing with boric acid

24 precipitation.

25 And we picked these because when you have

1 increase in power like that, small breaks will uncover
2 deeper, they'll be exposed longer, you're really
3 taxing the ECCS. And this limiting small break I'm
4 going to show you is controlled by the high pressure
5 safety injection safety only, one HPSI pump.
6 Post-LOCA long term cooling is important
7 because you're putting in borated water into a system
8 that's boiling. You're building up boric acid. And
9 once you reach the solubility limit, you'll get
10 precipitation. So clearly what's CE/Westinghouse does
11 is they would provide a guidance document to the EOPs
12 to their customer, and they would recommend a time to
13 switch to simultaneous hot and cold side injection.
14 And that is initiated to control the boric acid and
15 prevent it from building up. And I'll show you the
16 results of some of some the calculations that we did
17 and --
18 CHAIRMAN WALLIS: You're going to have a
19 much higher concentration of boric acid, too?
20 DR. WARD: That's right. That's right.
21 The source is higher, the power is higher. I'll get
22 into it, but basically our calculations showed that --
23 I couldn't reproduce the results, and the reason was
24 there was an error in it. But we fixed it and I'll
25 get into the details later.

1 CHAIRMAN WALLIS: There was an error in
2 your calculations?
3 DR. WARD: No. There was an error in their
4 calculation.
5 CHAIRMAN WALLIS: Oh, okay.
6 DR. WARD: I was asked to speed this up,
7 do you want me to jump to the small break LOCA and the
8 boric acid --
9 CHAIRMAN WALLIS: Because yours may be one
10 of the more interesting presentations.
11 DR. WARD: Okay. Let me ask the Chairman
12 here, or the Committee, do you want me to talk about
13 feedline break -- okay. I mean, it's up to you.
14 CHAIRMAN WALLIS: These are important.
15 DR. WARD: Okay. The large feedline
16 break, basically I verified their peak pressure and to
17 get to the bottom line here, they really overwhelmed
18 this, they did it to death. They assumed the
19 feedline break was at the bottom of the tube sheet so
20 that they expelled all the liquid from the system in
21 about 20 second due to break. Now clearly, you know,
22 it's a boil off problem if you put the break up at the
23 actual location. You're going to have a heat sink
24 for a longer period of time and you're not going to
25 probably use your heat sink while you're at full

1 power. But I consider this analysis pretty much beat
2 to death, and so I didn't want to emphasize this too
3 long because I'd like to get to the small break
4 because of Dr. Wallis' concerns.
5 But the staff calculation are the circles.
6 And this is the cold leg pressure. And the I
7 calculated a pressure within 50 pounds pressure. And
8 basically what happens, as the next slide will show
9 you, when you put the break at the bottom of the tube
10 sheet, you basically drain the generator in about 20
11 seconds and so you degrade the heat transfer, you have
12 full power. Because you don't have full heat
13 transfer, the pressure goes up. And you hit -- the
14 safety valve opens, you get a trip. And the pressure
15 decreases and it slowly increases again later on
16 because the other generator, because of the
17 conservative assumption they made on aux feed, they
18 really delayed that. You start to pressurize again a
19 little bit at the end. But I was more focused on that
20 initial pressure and wanted to confirm that peak
21 pressure. Because this is an event that challenges the
22 design pressure of the plant.
23 Now, I mentioned small break LOCA.
24 DR. DENNING: Len, did you all assume
25 looking at water levels in the vessel and fuel

1 failure?

2 DR. WARD: No, I didn't look at that. I'm

3 just looking at the thermal-hydraulics. I'm looking

4 at peak pressure. I didn't look at -- or anything like

5 that. Well, I didn't get into that.

6 DR. DENNING: But this is the case, isn't

7 it, where there's two percent clad failure?

8 DR. WARD: You know, I can't remember. No,

9 I don't think so.

10 DR. DENNING: It's a different case?

11 DR. WARD: I don't think so.

12 MR. SICARD: This is Paul Sicard.

13 The feedwater line break is a

14 pressurization event. It does not challenge the DNBR.

15 There is no fuel failure for that event.

16 DR. RANSOM: Were these independent

17 calculations or were they using methods that --

18 DR. WARD: And I'd better mention that I

19 didn't have six months to set up RELAP5. We didn't

20 have a Waterford plant deck. So I used a model that I

21 had put together, that I had developed about 15 years

22 ago. I'm going to document that calculation as part

23 of this submittal that the staff will get. It's very

24 similar to what you saw on AP1000. It's basically the

25 same model, but I put drift flux in there. It's got--

1 and thermal dynamics. It solves a network, a
2 nodalization network simultaneously for pressure and
3 system flow rate, semi-implicit. The drift flux model
4 has been benchmarked against a lot of the data that
5 you've seen at low pressure as well at intermediate
6 pressures. It's got all of the required Appendix K
7 models in there; Henry-Fauske, critical flow. There's
8 a pump coastdown model.
9 I could probably spend an easy hour
10 describing it, but I would rather wait so that you
11 could see -- you'll see the documentation on this
12 later on when I document it. But you may have seen
13 most of the model documented in the AP1000 submittal,
14 the work that I did on that plant.
15 CHAIRMAN WALLIS: Why is there no credit
16 for accumulator injection?
17 DR. WARD: That is a conservative
18 assumption they made, and I'll show you. The primary
19 system pressure for this break decreased below the SIT
20 accutation pressure of about 580, but they didn't
21 credit it for this break.
22 The most limiting small break -- when you
23 have fairly low capacity HPSI pumps or HPSI pumps that
24 are SI pumps that CE has, their classic 2700 megawatt
25 plant Millstone/Calvert Cliffs, low capacity HPSI

1 pumps, 200 pound accumulators. So because of that you
2 get these long uncoveries. So this kind of uncovery
3 transient that you're seeing is very typical of a CE
4 type plant.
5 But I wanted to mention that that this
6 calculation is still conservative. And there is no
7 credit for the accumulator injection. If they took
8 credit for that, you would have terminated the
9 transient earlier and the P clad temperature a 100 to
10 a couple hundred degrees lower.
11 Now remember, too, we're assuming the
12 decay heat is 20 percent higher and there's a diesel
13 failure, which means you're only taking credit for
14 three-quarters of one high pressure pump.
15 The actual power distribution is TOC
16 skewed. When you expose the core for a small break,
17 you want to look at a shape with a peak in the top
18 because that'll heat up the worse. And this shape
19 happens to be -- it's not a shape that's going to set
20 for decay heat. It's a shape that was chosen from a
21 transient analysis that would be momentary. The actual
22 decay heat shape will be less skewed because you've
23 been operating, you know, for months with that kind of
24 power shape.
25 So I just wanted to list some of the

1 conservatisms in the analysis.

2 If we look at the pressure transient for

3 this break, this is an 0.055 square foot break at the

4 bottom of the discharge leg, and that's about a three

5 inch break. So it's pretty small.

6 When the break opens, the system

7 depressurizes, you lose the subcooling and you'll

8 establish a pressure plateau just over 1,000 pounds.

9 And that's because the break is too small to continue

10 to depressurize and so you have to rely on heat

11 removal through the generator.

12 The secondary side is sitting at the

13 relief valve setpoint. Actually, it's the ADV valve in

14 this case, and this is a good thing that CE did. They

15 qualified their ADVs to open at a lower pressure.

16 And so what does that do? That lowers the system

17 pressure from up here around 1200 down here, and that

18 means during this 1200 second tier, you're going to

19 get more injection into the system. So from a safety

20 standpoint, that was a good thing to do.

21 Now this is an Appendix K calculation, of

22 course, so there's 20 percent more decay heat.

23 This primary system is a giant U tube.

24 And the break in the cold leg, the fluid levels

25 drained down to the elevation of the break critical

1 flow of liquid going out of the system. Now once the
2 level drops down below the bottom of the cold leg,
3 you're going to get steam out. And so for the
4 remainder of the transient, it's a simple boiling pot.
5 You've got a head of water supporting a two phase
6 mixture on the core lower plenum side. And because of
7 the steaming rate going out the break, that that flow
8 is greater than the steaming rate in the core it
9 depressurizes. But at these higher pressures, the
10 high pressure pump cannot match boil off. So I'll
11 show you the level. The level is decreasing. And it's
12 a race so the pressure falls low enough so that the
13 high pressure injection can now match the decay heat
14 boil off and then the level will recover again.
15 And you can see the pressure. Small break
16 is a pretty simple transient. It's just a hydrostatic
17 fluid balance. The only mass in the system for the
18 majority of this event from 600 seconds out to an hour
19 is in the downcomer and in the core and lower plenum.
20 And to get steam elsewhere in the system, there's no
21 spacial variation in pressure. It's probably a tenth
22 of a psi pressure difference between the upper plenum
23 and the core. So you don't need a lot of cells to
24 model that. And that's why with the calculation I
25 did, it's basically got two volumes in the primary

1 system. But I have a drift flux model to calculate
2 the level swell.
3 And that's probably the single most
4 important parameter that one --
5 CHAIRMAN WALLIS: What does it matter
6 because if the top's dry, who cares what's happening
7 to the swelling below it?
8 DR. WARD: Well, I mean that's the point,
9 though. But you want to calculate the amount of
10 liquid mass that's in the core. You're voiding the
11 core --
12 CHAIRMAN WALLIS: What I'm worried about,
13 though, that dotted line at the top which says top of
14 the core.
15 DR. WARD: Right, right here.
16 CHAIRMAN WALLIS: It's exposed for 1500 or
17 2000 seconds or something.
18 DR. WARD: Right. And I guess, that's
19 from--
20 CHAIRMAN WALLIS: That's the worse.
21 DR. WARD: When you look at that, that's
22 kind of alarming, isn't it?
23 CHAIRMAN WALLIS: It is. Yes.
24 DR. WARD: But let's look at the reason
25 why that is. We've got 20 percent more decay heat

1 than is actually there. If you decrease the power by
2 20 percent, that's just like increasing the capacity
3 of the high pressure pump by the same pump.
4 If you increase the flow rate from the
5 pump by 20 percent of a 12 and a half foot core,
6 you're going to increase that level by another two and
7 a half feet. It's going to be up here. And the
8 temperature is going to drop by 500 degrees.
9 Now, the accumulator came on right about
10 here, but they didn't credit it. And that would have
11 jumped the level up anyway. And they could have
12 credited that and we have accepted it. But they wanted
13 to make this conservative because you want to show the
14 most limiting small break in this range is the one
15 when the system depressurized on that previous plot,
16 the primary system pressure hangs up just above the
17 accumulator pressure. So the only thing that's
18 controlling this break is HPSI flow, and at about this
19 point here the system has depressurized enough. So
20 three quarters of one high pressure pump is now
21 exceeding the boil off and it's slowing filling back
22 up.
23 So now there is two-phase nucleate boiling
24 in the bottom. And as long as the plant's tripped,
25 that's okay. The clad temperature is probably within

1 ten degrees of the sink temperature. But up here now
2 we've got steam in this part.
3 CHAIRMAN WALLIS: That's 40 minutes for
4 that time for when it's exposed?
5 DR. WARD: It's exposed for -- yes, the
6 peak is probably somewhere right about here.
7 CHAIRMAN WALLIS: Yes. But TMI --
8 DR. WARD: TMI drained completely.
9 CHAIRMAN WALLIS: -- was destroyed long
10 before 40 minutes.
11 DR. WARD: Yes. If this two-phase level
12 drops probably another foot, half a foot, it's going
13 to go over 2200 degrees. I mean with Appendix K
14 assumptions, they're probably at the limit -- they
15 probably can't drop that level too much more, like a
16 half a foot.
17 CHAIRMAN WALLIS: It's the fact that the
18 top's dry that --
19 DR. WARD: This is steam cooling now. You
20 can cool a rod with steam.
21 MR. SIEBER: It's not dry.
22 CHAIRMAN WALLIS: But you could drop the
23 level to zero, you still haven't changed what you're
24 doing to the top of the core.
25 DR. WARD: Then you're not producing any -

1 - there's no boil off. There's no steam flow. It'll
2 heat up very -- it'll melt.
3 CHAIRMAN WALLIS: Okay.
4 DR. WARD: So we're taking credit -- you
5 have --
6 CHAIRMAN WALLIS: So you need the depth to
7 make the steam.
8 DR. WARD: Right. If the two-phase level
9 is at the top, you're boiling at a 100 pounds per
10 second of this thing. If it's down here just above the
11 middle, it's about 60 pounds per second. Okay.
12 CHAIRMAN WALLIS: Okay.
13 DR. WARD: And so 60 pounds per second of
14 steam flowing up the top of that rod is enough. The
15 heat transfer coefficient is about 25 BTUs per hour
16 per square foot per degree F. And that includes
17 convection and radiation. The THTF test down at Oak
18 Ridge shows that thermal radiation to steam represents
19 about 20 to 30 percent of the heat transfer. So it's
20 pretty significant.
21 If they didn't credit that, the
22 temperature would be over 2200 degrees. But they
23 benchmarked against the G2 bundle uncovery data and
24 all the THTF data, we reviewed that. And they did a
25 good job.

1 I mean, so this core is uncovered for this
2 long, this is not best estimate. If this was a best
3 estimate CSAU calculation, I'd have a lot of heartburn
4 with this because I don't think they can calculate the
5 two-phase level over that period of time within a half
6 of foot out of 12 feet. But this has one HPSI pump,
7 three quarters of one pump, it's got 20 percent more
8 decay heat and they are also the steam super heats
9 right at the two-phase surface. And if you look at G@
10 data and THTF, it really doesn't super heat for about
11 six inches to a foot because you've got this froth and
12 it's throwing bubbles and it's closer to Tsat there.
13 So they don't credit that.
14 So, yes, it's a little alarming to see
15 something like this, but remember it's Appendix K. If
16 they made all best estimate assumptions and they only
17 had one HPSI pump, the two-phase level would be
18 somewhere up here. Temperatures would probably be
19 around 1500.
20 So I guess what I'm saying is, yes,
21 there's still margin there. You're getting this
22 response because of the conservatism in Appendix K,
23 and there's that margin.
24 MR. SIEBER: It goes beyond that. It's
25 self imposed conservatism --

1 DR. WARD: Well, plus the accumulator,
2 that's right, because that would even lower further.
3 MR. SIEBER: Right.
4 DR. WARD: They could take credit for
5 accumulator injection.
6 MR. SIEBER: Right.
7 DR. WARD: Because for that break size and
8 larger ones, accumulators are coming on. And the
9 accumulators are overwhelming the system. And the
10 accumulators are there not for large breaks, but for
11 small breaks, probably more so I would say. It keeps
12 the small breaks really low temperatures. Okay. So
13 accumulators are a good thing. They're your friend.
14 But they didn't credit it.
15 So that in itself, you know, I can say --
16 I can stand up here and say it's a conservative
17 calculation. You know, it's alarming to see a core
18 exposed like that for a three inch break but it's that
19 way for a reason and it's prescribed in the law. And
20 they have met that.
21 The next thing I looked at was the post-
22 LOCA long term cooling. And when I did that I couldn't
23 reproduce their results. And it turned out that when
24 I assumed -- now the mixing volume for mixing boric
25 acid in their model with the core and the upper plenum

1 below the elevation of the bottom of the hot leg. And
2 when I assumed that that was true liquid, I matched
3 their result. Let me show what I'm talking about
4 here, maybe if I could illustrate it.
5 MR. ROSEN: It would be better right side.
6 DR. WARD: Their mixing volume is
7 basically the core region and the fluid level up to
8 the bottom of the cold leg. They're about the same,
9 they're off set by half a foot, but it's right there.
10 What they assumed -- I calculated a void
11 fraction of 35 percent average at about three hours.
12 I put that in, and I precipitated it about an hour.
13 They're getting about four hours. So this initiated
14 some discussion with the vendors --
15 CHAIRMAN WALLIS: Yours sounds worse.
16 Yours sounds worse.
17 DR. WARD: Yes. I calculated an hour.
18 They corrected their model and put in 35 percent void
19 fraction and got basically the same thing. Let me
20 show you what that looks like.
21 Now this is the calculation I did --
22 CHAIRMAN WALLIS: They have one where it
23 turns around.
24 DR. WARD: Right. Well, I'll show you that
25 in a minute. Well, I'll get to that second, but let

1 me go through this first.

2 This is just pumping in borated water and

3 it's building up. And when you do that, they

4 calculated, you know, over four hours. And this is my

5 calculation but it also reproduced theirs. But this

6 is with the error. If you assumed the void fraction

7 is 35 percent liquid, this is a steam void, then it

8 precipitated in an hour.

9 CHAIRMAN WALLIS: So what appears in the

10 documentation that we saw --

11 DR. WARD: You see this curve right here

12 and then you see between three and four --

13 CHAIRMAN WALLIS: It's the wrong curve?

14 DR. WARD: Yes, it's the wrong curve.

15 Between three and four hours they initiate hot and

16 cold side injection, so when that happens -- all you

17 need to do is inject in excess of the boil off at

18 about 25 GPM you will -- you'll turn it over and it

19 will -- with their high pressure injection pump, it

20 was asymptotically reach a value somewhere down --

21 CHAIRMAN WALLIS: Now you're saying they

22 have to do this before an hour instead of the four

23 hours?

24 DR. WARD: No. You can't switch before

25 two hours because --

1 CHAIRMAN WALLIS: So --

2 CHAIRMAN WALLIS: Because when you split
3 half the injection between the hot and cold side, at
4 that point if you switch any earlier than two hours,
5 you'll uncover the core, you can't match the steam
6 rate.

7 CHAIRMAN WALLIS: So you're saying you're
8 going to plug up the core?

9 DR. WARD: Well, no. I'm just saying that
10 they need -- you know --

11 MR. SIEBER: They're overheat.

12 DR. WARD: What'll happen is if you
13 precipitate, yes, it'll block the core. I'm not going
14 to guess what's going to happen, but you'll fill the
15 core up with boric acid salt and it will block the
16 core. And then it will heat up and something else will
17 happen. So it's a long term cooling -- that's why you
18 don't -- that's why you want to switch to simultaneous
19 injection at some time enough earlier so that you can
20 control it.

21 CHAIRMAN WALLIS: Can you do it with the
22 real mixing volume?

23 DR. WARD: No, you can't do it this way.
24 They assume the pressure in the upper plenum is 14.7
25 which is basically the containment pressure. And with

1 that volume, it won't work. So what I had done is
2 some calculations to look what I would call basically
3 an envelop of where they need to be in for us to be --
4 for this to work.
5 And so what I did -- but what I did, I did
6 a calculation where I calculated the mixing volume.
7 Now the mixing volume will grow with time. It'll
8 start off in the core, this is a large break LOCA, and
9 it will grow as the steaming rate drops and the loop
10 pressure drops. You'll get more and more two-phase in
11 the system.
12 What I did is I calculated a two-phase
13 mixing volume that includes the core and the upper
14 plenum. And as it grew, I took credit for that
15 increase in the mixing volume until it got up to
16 within about a half foot of the hot leg and then I
17 didn't let it get any bigger because the steam that's
18 disengaging the two-phase surface and collecting in
19 the upper head, it's got to go somewhere. Where is it
20 going to go? It's going to go out the hot leg, so
21 that defines a pressure to drive steam around the loop
22 and it won't let the two-phase go any higher. So I
23 held it at that point.
24 And even if I did that, if I assumed 14.7
25 in the upper, I'm still precipitating at about an

1 hour. It didn't help very much. But if you assume now
2 that your upper plenum pressure is 20 pounds pressure,
3 which is what CD has done; they have changed from 14.7
4 to a 20 psi limit, and they are using a mixing volume
5 that is no greater than to a region near the top of
6 the hot -- if you do that now, you will precipitate at
7 somewhere in the neighborhood of near four hours. So
8 if they switch to simultaneous injection in the two to
9 three hour time frame, you know, this envelop suggests
10 they're okay.
11 Now, they just finished doing these
12 calculations in the last week and I haven't seen them,
13 but I talked to them on the phone. They're in the
14 envelop.
15 One of the things that we're going to have
16 to do is review -- they're going to submit their
17 containment analysis. They used GOTHIC. It's a
18 licensed methodology, too, and they ran it in a
19 minimum containment pressure mode where they maximize
20 the heat transfer on the surfaces, maximized -- made
21 all the assumptions pertinent to minimizing the
22 pressure. And they calculated at 4 hours 21 psia,
23 right? So, you know, I eager await that calculation
24 to take a look at it. And they're also going to
25 document their boric acid calculations that they did

1 that's consistent with my values at 20 pounds.

2 So the bottom line is they had to make

3 some -- they corrected the error. There is still

4 margin remaining to support this power uprate.

5 And I wanted to mention some of the other

6 things that would show that this is still

7 conservative.

8 The two-phase level is up into the -- it's

9 up into the hot leg region to the top of the hot leg.

10 I mean, the two-phase level after about two hours is

11 up in this region here. And there's a large volume

12 there. And that's not considered. They were able to

13 show the four hour precipitation limit with that

14 without crediting the hot legs. And I think the hot

15 legs are going to increase the mixing volume. That's

16 about another couple hundred cubic feet.

17 The other thing is this is a large break

18 LOCA. The steam that's coming off the core is in

19 entraining liquid and it's throwing out in the hot

20 legs in the generator. So it's removing liquid with

21 boric acid in it, so it's not really concentrating, at

22 least it's not going to concentrate at that level.

23 So did I show that? So anyway, I guess --

24 CHAIRMAN WALLIS: So if they had somehow

25 vented the containment and hadn't gotten this

1 pressure, then they would plug up the core?

2 DR. WARD: Then you let the containment

3 door open and you stayed 14.7, I guess you'd have a

4 problem.

5 MR. SIEBER: Nothing would come out.

6 DR. WARD: You know, I mean, containment

7 doors don't open that readily, so --

8 CHAIRMAN WALLIS: Where did this 20 psia

9 number come from?

10 DR. WARD: They did it. It was a

11 calculation that I had done that showed that it works.

12 They did a GOTHIC minimum containment pressure

13 calculation to show that they can justify 20 psi with

14 that. And that's a licensed methodology run to

15 minimize containment pressure, maximize condensation

16 on the walls, maximize energy removal, I think. Well,

17 all four --

18 CHAIRMAN WALLIS: Sounds like NPSH all

19 over again.

20 DR. WARD: Well, it does, doesn't it.

21 It's--

22 CHAIRMAN WALLIS: Well, this is

23 interesting. I'm very glad that you did some

24 independent calculations which lead you to find an

25 error, and then that you cleaned up the mess created

1 by the error.

2 DR. WARD: Right.

3 CHAIRMAN WALLIS: Helped to.

4 DR. WARD: And I think, you know --

5 CHAIRMAN WALLIS: Then the end of the

6 story seems to be happy, we think.

7 DR. WARD: Right. I couldn't say it any

8 better. And I guess we --

9 CHAIRMAN WALLIS: How many other

10 calculations you need to do independently.

11 DR. WARD: Excuse me.

12 CHAIRMAN WALLIS: How did you know to do

13 this one?

14 DR. WARD: Well, you know, I just -- you

15 know, you pick one.

16 CHAIRMAN WALLIS: Yes.

17 DR. WARD: The plant power levels going

18 up--

19 CHAIRMAN WALLIS: You picked one which was

20 important.

21 DR. WARD: Yes. I mean, there's 8 eight

22 percent power increase. I mean, you're going to build

23 up boric acid a lot faster, the sources are higher

24 concentration. I mean, you're going to get there

25 quicker.

1 And I consider this is important because
2 this phenomenon is consistent with any break size in
3 the cold leg where the system will not refill, so it
4 boils. If you -- if the break size is small enough and
5 eventually the high pressure injection system or the
6 ECC fills the system, you'll disperse the boric system
7 throughout the system. But this a break size probably
8 down in the neighborhood of two-tenths of a square
9 foot or larger where they never refill. And so all
10 you need is a break. I can't have as many HPSI pump--
11 the full -- that's all. You're going to be in this
12 region.
13 So it's important that the guidance that
14 CE gives -- excuse me. Westinghouse gives their
15 customer is a switch time to assure: (1) when they
16 switch you've got enough injection so the core won't
17 uncover but it's early enough so that you can control
18 the boric acid. And that's important. That's why I
19 wanted to look at this calculation.
20 MR. SIEBER: Let me ask a question about
21 that from an operator's viewpoint. The time that
22 you're predicting there, really depends on the way you
23 do your calculation and the assumptions that you make.
24 DR. WARD: That's right.
25 MR. SIEBER: Now the operator isn't going

1 to sit there looking at his watch saying no, it's
2 going to be time in 15 minutes to switch my injection
3 mode. He has to look at other parameters. What does
4 he look at to tell when it's the right time to make
5 that change?
6 DR. WARD: Well, he has that -- and it's
7 a large break, he has no other indication except a
8 time. And he's got to adhere to that. Hopefully,
9 there's usually one hour or more for him to do that.
10 They would be told at -- if they're told to switch to
11 simultaneous injection at 2½ hours, no later than 3½
12 hours, that two hours the guidance will say prepare to
13 line up the system because as early as but no later
14 than X you will be in simultaneous injection. And my
15 experience at Northeast Utilities when I was working
16 with the SRO there when we were modifying the
17 procedure, those guys follow it exactly.
18 MR. SIEBER: I know.
19 DR. WARD: This is a LOCA. In post TMI
20 days, now that was my experience at Northeast, that
21 this SRO is real sensitive to what that procedure
22 says. And he's not going to touch those pumps and
23 he's going to do whatever it says. And he's going to
24 do when it says it.
25 MR. SIEBER: Yes, there's no doubt that

1 the operator 99 percent of the time will do what he's
2 told to do.
3 DR. WARD: Right.
4 CHAIRMAN WALLIS: On the other hand, it's
5 not clear to me that what the analysis tells him to do
6 is going to match to the way the plant's responding at
7 a given time because of all these conservatisms and
8 assumptions and everything that are built into this.
9 And I'm having a little difficulty reconciling all of
10 that to what does the operator really do.
11 DR. WARD: Okay. Well, assuming he
12 follows his procedure, what -- within this envelop if
13 he follows it, if he was late by half an hour or an
14 hour, my gut feeling is -- I haven't done any
15 entrainment calculations, I haven't included the
16 mixing in the hot legs.
17 MR. SIEBER: Right.
18 DR. WARD: You know, we were trying to get
19 there so we could have this meeting.
20 CHAIRMAN WALLIS: You ought to put in some
21 uncertainties and you ought to show what's the spread
22 of likely results.
23 DR. WARD: Okay. Well --
24 CHAIRMAN WALLIS: And suppose he that he
25 injects at a time --

1 DR. WARD: There's 20 percent more decay
2 heat to secure, so if you get rid of that, it's going
3 to give you another 30 minutes. If you take credit for
4 entrainment, my guess is -- now that's going to move
5 it out at least another half an hour. I mean, I can't
6 speak -- I haven't done that calculation, but --
7 MR. SIEBER: He's probably hoping for
8 shift change.
9 DR. WARD: Yes.
10 MR. SIEBER: Let the other guy do that.
11 DR. WARD: Well, I don't want to go there.
12 But, I mean, there is conservatisms in this, too.
13 There isn't as much as there was before.
14 CHAIRMAN WALLIS: This is going to be
15 resolved unequivocally by the time of the full
16 Committee meeting?
17 DR. WARD: They have committed to document
18 everything they have done.
19 CHAIRMAN WALLIS: Is that going to resolve
20 everything unequivocally?
21 MR. SIEBER: Well, but this isn't unique
22 to the EPU condition, right? This will occur in any
23 plant that does this configuration?
24 DR. WARD: Well, that --
25 CHAIRMAN WALLIS: There will be a lot more

1 boric acid now.

2 DR. WARD: We're getting ready to send a

3 letter out. We're going to mention that we found a

4 nonconservatism in a vendor's model, please review

5 your long term cooling analysis and, you know, show us

6 that your model remains acceptable.

7 CHAIRMAN WALLIS: But this is work in

8 process?

9 DR. WARD: Right now.

10 CHAIRMAN WALLIS: Less than three weeks

11 before the meeting, or two weeks before?

12 DR. WARD: Well, their calculations are

13 done. They haven't documented them yet. And I'm

14 expecting to get them -- well, hopefully before the

15 SER goes out. I mean, there will be a reference. The

16 project manager can address that.

17 MR. KALYANAM: Before February 2.

18 MR. SIEBER: Can you hear that? You need

19 to talk into a microphone somewhere.

20 MR. KALYANAM: Okay.

21 MR. SIEBER: Pick one. You can talk into

22 his tie, if you want to.

23 MR. KALYANAM: I was saying that we have

24 the next meeting here on -- the full meeting on

25 February 10th. Before that we would -- unless these

1 calculations will be dockets.

2 CHAIRMAN WALLIS: Okay. So there's no

3 uncertainty in management decisions. There may be in

4 engineering, but there's never uncertainty in

5 management decisions.

6 MR. KALYANAM: I think we work in unison.

7 DR. WARD: Thank you.

8 DR. RANSOM: I think it's very good to see

9 calculations like this. The only difficult I guess I

10 have with it, it's not TRACE, it's not TRAC, it's not

11 RELAP5, but yet another methodology that presumably

12 has not been benchmarked and --

13 DR. WARD: Well, it has. I've benchmarked

14 it against LOFT, Semiscale, SO-710D is a Semiscale

15 test that has a long term core recovery.

16 MR. BROWN: Well, the point is I don't

17 believe you've documented that and --

18 DR. WARD: Well, you haven't seen it, but

19 I'm going to give it to you. I mean, there's only so

20 much I can do in a month, you know. If I could break

21 into three people --

22 MR. BROWN: Why are we developing TRACE

23 when you can do this?

24 DR. WARD: Well, we didn't have a plant --

25 we did not have a Waterford -- we don't have plant

1 decks for every plant, so we got to do the best we
2 can. The best I could do is I have a methodology that
3 I -- I mean, I did hand calculations, too, to verify
4 minimum levels and peak pressures, but I wanted to see
5 the transient. And if I've matched separate effects
6 data for two-phase level swell over a full range of
7 pressures and heat up data, I'm going to run that. In
8 lieu of doing nothing, I think what I have done
9 verifies their analyses. I've predicted the break
10 spectrum with that code for Millstone running a .5
11 square foot, .2 square foot, .05 -- I mean, a small
12 break is something easy to model. It's a boiling pot.
13 You don't even need to do a momentum
14 balance. And you can take the liquid mass, balance
15 them hydrostatically, off set the fluid levels by the
16 steam flow, which is decay heat in the loop, and
17 you're going to get the same thing that TRAC or RELAP
18 gets, only I'm going to get it in 15 seconds and I'm
19 not going to wait for five hours for the answer. And
20 I can run maybe 15 or 20 of these.
21 DR. RANSOM: Well, is the NRC going to
22 make this a part of their inventory of codes to use
23 and methods?
24 DR. WARD: Well, no. We haven't talked
25 about that. But anybody that, you know, in the branch

1 that wants to use the code, you know I will show them
2 how to use it.
3 DR. RANSOM: That's the only problem I
4 have with it, is --
5 CHAIRMAN WALLIS: Well, Vic, this isn't
6 going to be licensed based on his calculations.
7 MR. BROWN: No, I understand that. But
8 you use it as an audit.
9 DR. WARD: I mean, my calculation gave me
10 enough comfort it says that limiting 055 square foot
11 break, I didn't feel comfortable. When I saw that, I
12 was going like whoa.
13 CHAIRMAN WALLIS: It's not a code, is it?
14 It's just a one node --
15 DR. WARD: Well, no, it's three volumes.
16 There's one on the hot side, there's one on the cold
17 side, there's a pressurizer that's not equilibrium
18 because of that over pressurization event. I compare
19 it against the MIT pressurization tests that Pete
20 Griffith did very nicely. A whole slew of level swell
21 tests.
22 I mean, the most important parameter for
23 a small break to govern, to judge its performance is
24 two-phase level swell. And there isn't a level swell
25 test out there that I haven't run. And I have run --

1 CHAIRMAN WALLIS: Now when you get more
2 and more boron in there, doesn't the drift flux
3 change?
4 DR. WARD: Good question. I guess the
5 density changes.
6 CHAIRMAN WALLIS: Well, the interfacial
7 properties change when you got all this gop in there.
8 DR. WARD: That's right. I didn't --
9 CHAIRMAN WALLIS: It concentrates at the
10 interfaces, it changes whether or --
11 DR. WARD: You're right.
12 CHAIRMAN WALLIS: -- not the bubbles are
13 glommery. And I think the drift flux is going to
14 change as you get more and more boron concentrating.
15 Do we have any basis for knowing what it is?
16 DR. WARD: I have not done that
17 calculation. And that is a good --
18 CHAIRMAN WALLIS: I would think it would
19 froth up more as you --
20 DR. WARD: I think it would tend to retard
21 the steam velocity and it would froth it up. It would
22 swell more even in this small break --
23 CHAIRMAN WALLIS: Are there those studies
24 of level swell with concentrated boron --
25 DR. WARD: I've seen none in that area.

1 I mean, I'd like to see.

2 CHAIRMAN WALLIS: There should be.

3 DR. WARD: I haven't seen any tests that

4 says here's the mixing volume. Those don't even

5 exist.

6 CHAIRMAN WALLIS: Yes. But you're assuming

7 you could take a drift flux correlation for pure water

8 and apply it to boric acid, which is almost on the

9 point of precipitating?

10 DR. WARD: Well --

11 CHAIRMAN WALLIS: It's like taking --

12 DR. WARD: That's a good question.

13 CHAIRMAN WALLIS: It's like taking your

14 first correlation for boiling water and applying it to

15 boiling milk. And you know what happens when you boil

16 one or the other.

17 DR. WARD: Yes. Yes.

18 Well, if this saving grace, there's

19 Appendix -- there are conservatisms in there that say,

20 you know, I believe it's in the envelop but I have not

21 done that calculation with boric acid in there.

22 CHAIRMAN WALLIS: I don't think you can

23 believe anything about boric acid unless you --

24 DR. WARD: I mean what test data would I

25 compare it to?

1 CHAIRMAN WALLIS: You have to have a test.

2 DR. WARD: Right. I mean, you have a good

3 point. I mean, I didn't think of that. I guess that's

4 one of the good things about standing up here and

5 talking with you, too. You get some good input,

6 right?

7 CHAIRMAN WALLIS: And how long does it

8 take to resolve something like that?

9 DR. WARD: Gee, I don't know. I mean --

10 MR. ROSEN: Oh, probably a year or two.

11 DR. WARD: I mean, I'd like to see some

12 test data on what is the mixing volume? What does it

13 look like? What does the debris from the sump do when

14 it's in there? I don't know what that --

15 CHAIRMAN WALLIS: There's probably more

16 mixing in the lower plenum than they assume.

17 DR. WARD: No mixing in the lower plenum.

18 CHAIRMAN WALLIS: There probably is.

19 DR. WARD: I think there is.

20 CHAIRMAN WALLIS: Because at psi 184 it's

21 a completely --

22 DR. WARD: Right. I think it will mix down

23 there, because it's heavy, it's going to drain --

24 CHAIRMAN WALLIS: Well, you've also got

25 jets coming in through the colander. You got a

1 colander down there? Maybe not in this design.

2 DR. WARD: That's right. Well, there's a

3 -- there's a flow skirt. But, yes, there's a big

4 lower head. There's about ten, fifteen feet in the

5 lower plenum.

6 CHAIRMAN WALLIS: Well, there's some jets

7 of liquid coming in. It's not just a big --

8 DR. WARD: Yes, it's coming -- no.

9 CHAIRMAN WALLIS: It goes through

10 something like --

11 DR. WARD: It goes through a flow skirt

12 and then it's directed upward into the core. But your

13 --

14 CHAIRMAN WALLIS: You have a problem I

15 think though with drift flux through a concentrated

16 boric acid mixture. Maybe it throws it up more, which

17 would be better, wouldn't it?

18 DR. WARD: Yes. I think it would swell up

19 faster and it would mix it out into the hot legs and--

20 CHAIRMAN WALLIS: And it might actually

21 carry over more, which would be worse.

22 DR. WARD: Could be. And the entrainment,

23 don't forget there's an entrainment mechanism, too,

24 that's throwing liquid out in the hot legs even before

25 the two-phase level gets up there. So it's not really

1 going to concentrate in my opinion in the first hour
2 because if you look at the reflood test, for every
3 pound of steam exiting the core, there's two to three
4 pounds of liquid flying out of there. And I assume
5 that that all stayed in the core.
6 CHAIRMAN WALLIS: Well, what shall we do
7 with this? When you have -- you have to have a drift
8 flux to get the swell here.
9 DR. WARD: Right. Right.
10 CHAIRMAN WALLIS: And that's very
11 important for cooling core.
12 DR. WARD: Well, in this case --
13 CHAIRMAN WALLIS: It's not so important
14 for the boron concentration, because you're just
15 pulling it off.
16 DR. WARD: Provided the two-phase -- I
17 don't -- it's going to be a cooling problem if the
18 two-phase level drops back into the core.
19 CHAIRMAN WALLIS: But if the two-phase
20 level rises, then you're boiling it off faster and
21 you're concentrating faster. You have more heat
22 transfer. It rises, it covers more of the core. You
23 get more boiling.
24 DR. WARD: That's right. That's right.
25 CHAIRMAN WALLIS: And so it will

1 concentrate faster?

2 DR. WARD: You're right, it'll concentrate

3 a little faster provided there's no such thing as

4 entrainment.

5 CHAIRMAN WALLIS: I'm quite sure you'll

6 resolve this issue.

7 DR. DENNING: Graham, I would agree. I

8 mean, I think that it's really very interesting work.

9 I'd be curious whether the applicant has a comment at

10 this point. But how do we go forward with this issue

11 as it currently stands? You know, it's just too up in

12 the air.

13 DR. WARD: Well, we plan, as I mentioned,

14 we're going to issue a letter shortly and we're going

15 to ask them to re-review -- to look at this model and

16 tell us -- you know, demonstrate that your model --it

17 remains applicable. And there will be a laundry list

18 of other things that will be addressed.

19 CHAIRMAN WALLIS: Someone going to respond

20 to this drift flux question?

21 DR. WARD: Well, that's another question

22 on the list.

23 CHAIRMAN WALLIS: But we know that putting

24 contaminants in water easily changes the drift flux.

25 DR. WARD: Yes. I haven't looked at that,

1 to be honest with you. I have not done that.

2 MR. ROSEN: When did you plan to come back

3 to the full Committee? I mean --

4 MR. CARUSO: Two weeks.

5 MR. ROSEN: That's what I thought.

6 CHAIRMAN WALLIS: And the management has

7 stated everything is going to be resolved.

8 MR. ROSEN: Two weeks is hardly time for

9 us to finish up our business here, go home, change

10 clothes and come back.

11 CHAIRMAN WALLIS: Well, we can write a

12 letter which says you got to resolve this issue.

13 MR. SIEBER: Well, this issue is not

14 Waterford EPU specific.

15 DR. WARD: Yes, it's not specific to it.

16 MR. ROSEN: It also applies to Waterford.

17 DR. WARD: Well, it does.

18 MR. SIEBER: That's right.

19 MR. ROSEN: And we're asked to --

20 MR. SIEBER: And we have a couple of

21 those.

22 MR. ROSEN: -- recommend a license change

23 --

24 MR. SIEBER: We got two of those now. We

25 got the instrument issue, too.

1 MR. ROSEN: We got the what?

2 MR. SIEBER: Instrument issue, too, that

3 needs to be resolved and they're both industry wide.

4 CHAIRMAN WALLIS: Well, I think this is a

5 case history of where the staff by actually doing its

6 own analysis begins to review features which it

7 wouldn't review if it just reviewed what someone else

8 has done.

9 MR. SIEBER: That's right.

10 CHAIRMAN WALLIS: And it indicates how

11 important it is to do this sort of thing.

12 MR. HOLMAN: This is Jerry Holman from

13 Waterford 3.

14 We've talked with Len quite a bit about

15 these issues. We agree he's got some good concerns

16 and things that we need to look at. Overall, however,

17 we believe there are still some remaining

18 conservatisms in the calculations to show that we're

19 still conservative with the power uprate.

20 You are correct that this is not just a

21 Waterford 3 power uprate issue, it's more a generic

22 issue that applies to all the plants. And we'll be

23 looking forward to finally resolving this in a generic

24 basis and approving the model.

25 CHAIRMAN WALLIS: What concerns me is that

1 this may be fairly long discussion. If we get into
2 satisfying ourselves that this issue is resolved, it
3 may take an hour or two. We can't do that at a full
4 Committee meeting. We have to have another
5 Subcommittee meeting. We can't take the full
6 Committee through all the details of something like
7 this. There isn't time to do that.
8 DR. WARD: No. Maybe you could take the
9 approach that if you look -- although there are some
10 weaknesses, and we recognize that there are other
11 weaknesses in this method. But if you look at the
12 model collectively, are there enough overwhelming
13 assumptions that would ease your conscious a little
14 bit. And that's where I'm at. But, you know, you
15 mentioned the effect on drift velocity, and that's
16 something that I want to look at. Because now you've
17 spiked my interest in it.
18 CHAIRMAN WALLIS: Well, you could do
19 interesting tests. You could two vertical tubes, you
20 could put distilled water in one, you can put boric
21 acid about to precipitate in the other --
22 DR. WARD: And see what it does.
23 CHAIRMAN WALLIS: -- and bubble or boil,
24 whatever.
25 DR. WARD: Right.

1 CHAIRMAN WALLIS: One may go way up here
2 and one may just go up there.
3 DR. WARD: Yes.
4 CHAIRMAN WALLIS: Then you can say --
5 DR. WARD: Right.
6 CHAIRMAN WALLIS: -- there's obviously a
7 big change or there isn't. But that takes time. You
8 can't just do that overnight. Maybe you need a rest,
9 so you can do it over night.
10 DR. WARD: It's something to consider,
11 certainly.
12 DR. DENNING: So where are we, Graham?
13 CHAIRMAN WALLIS: I'm not convinced. I'm
14 just waiting for -- I don't know what they're going to
15 do. Something is going to happen between now and the
16 full Committee --
17 DR. WARD: Well, they're going to document
18 their calculations.
19 CHAIRMAN WALLIS: Well, how do we know?
20 We don't want to go to the full Committee meeting with
21 something which is half baked.
22 DR. WARD: Well, maybe there's something
23 that--
24 MR. HOLMAN: This is Jerry Holman again
25 from Waterford.

1 As Len showed and pointed out, there are
2 some remaining significant conservatisms in the model,
3 namely the entrainment, the mixing volume, those types
4 of things that we believe shows there's still margins
5 available for this issue.
6 MR. SIEBER: I think the difficulty you
7 have is that we're faced with recommending the
8 acceptance of the SER that the staff wrote, and in the
9 next two weeks they're not going to revise that SER.
10 So I'm not sure what it is we're going to do in two
11 weeks.
12 I think the work that's been done has been
13 very good. I just don't think that you can finish in
14 time.
15 DR. WARD: Yes, I don't think I could
16 address that one.
17 MR. SIEBER: So, we have to decide what
18 we're going to do next.
19 CHAIRMAN WALLIS: Well, ideally, we'd like
20 to give you more time to get the story together.
21 MR. SIEBER: Yes.
22 CHAIRMAN WALLIS: And say that we don't
23 want to come to the full Committee until everything is
24 up and done, in which case we have to put it off for
25 a month or something. And we're already putting off

1 things and we have nothing to do in February if we put
2 this off, too. That's okay, I suppose. We go home
3 earlier. There is a real question about whether or
4 not you should bring something like this to the full
5 Committee.
6 DR. WARD: Well, maybe there's some
7 sensitive -- there's some calculations that I can do
8 to show the sensitivity to it and maybe if it shows
9 that you need to get out into the time where it's
10 after you had switched to simultaneous injection where
11 it becomes important, that it would help alleviate the
12 concerns somewhat. But, you know, that's an approach.
13 I mean, I can do -- obviously, I'm not going to do any
14 tests, but we can do some calculations. And I can get
15 together with Westinghouse and maybe do a literature
16 search and take a close look at it and see what's out
17 there and see what we can do. I mean, there's a lot
18 of stuff in the chemical industry that might be useful
19 that, you know, I haven't tried to look into.
20 MR. SIEBER: On the other hand, if we all
21 rush to get done, the chances of making an error or
22 overlooking something becomes greater. And I don't
23 want to be in that situation.
24 CHAIRMAN WALLIS: Well, maybe you should
25 do an independent study of some of the other things.

1 MR. ROSEN: Especially some things that
2 are coming up in the near term.
3 CHAIRMAN WALLIS: No, I mean some other
4 aspects of this application.
5 MR. ROSEN: Oh. Yes.
6 DR. WARD: Okay.
7 CHAIRMAN WALLIS: We're going to move on
8 the rest of the presentation and we're going decide
9 what to do with this one.
10 MR. SIEBER: Thank you.
11 CHAIRMAN WALLIS: Let's hear the rest of
12 what the staff has to say.
13 Do we need a break or not? Can we last?
14 We're going to be behind, but do we keep going? Shall
15 we try keeping going and see where we get? Just take
16 breaks as you have to, okay?
17 MR. KALYANAM: Michelle Hart from our
18 Containment and Accident Dose Assessment Section.
19 MR. SIEBER: You have to talk to the
20 microphone.
21 MR. KALYANAM: Okay. The next speaker is
22 Michelle Hart from our Accident Dose Assessment.
23 MS. HART: Hi. I'm Michelle Hart. I'm in
24 the Probabilistic Dose Assessment Branch. I did the
25 design-basis accident dose analysis review.

1 The regulatory requirements for this
2 plant, because they are not an alternative source term
3 for the EPU when they first submitted it, we looked at
4 then versus 10 CFR Part 100 and GDC-19. And the
5 review was conducted in accordance with the applicable
6 SRP sections as noted in Matrix 9 of the Review
7 Standard.
8 The licensee's analyses followed all
9 applicable guidance. Any differences were justified
10 and found acceptable by the staff. And we did perform
11 confirmatory dose analyses, although the acceptance is
12 based on their analyses.
13 The design-basis accidents that were
14 evaluated for radiological analyses are the following
15 on this slide. It's the Chapter 15 type design-basis
16 accident analyses. And there is one draft SE open
17 item, it is the control room habitability. Why that
18 was an open item is when they originally submitted the
19 EPU control room dose analyses in their original
20 submittal, they only looked at the LOCA and the fuel
21 handling accident and compared it to GDC-19 for whole
22 body and thyroid. And they noted that the unfiltered
23 inleakage assumption for the control room was not
24 based on testing, but they would be doing testing and
25 they would update it as necessary.

1 When they came back with the tracer gas
2 test results, the analyses in the original submittal
3 did not bound the results. So they decided to submit
4 a separate full scope alternate source term
5 application. They did this in July of last year. And
6 it's been supplemented through October of this past
7 year as well.
8 All of the control room dose analyses in
9 the AST were for all of the accidents in the Chapter
10 16, not just the LOCA and the fuel handling accident,
11 included all of them. And it supplants all of those --
12 the only two that were in the EPU, which were the LOCA
13 and the fuel handling accident. And so that the
14 control room unfiltered inleakage assumptions bound --
15 that would bound the tracer gas testing.
16 And the ASTU review is currently
17 undergoing. I have finished most of the review and it
18 is scheduled for completion by the end of March.
19 Actually, by the middle of March. And I don't see any
20 technical issues at this time that would prevent its
21 approval.
22 DR. KRESS: Are you reviewing the chi over
23 Q values?
24 MS. HART: Another person in our branch is
25 reviewing those. They did have new chi over Q values

1 for the control room, and those have been reviewed,
2 yes.
3 DR. KRESS: And they look like they're
4 okay for that --
5 MS. HART: They look like they're okay.
6 There is the ABV release point, which was not looked
7 at previously in their current FSAR because they only
8 looked at the fuel handling accident and the LOCA, and
9 that was not a release point. Those ADVs are r close
10 to the control room intake. We have evaluated that
11 and determined that the valve, even though it's very
12 high, is reasonable and they take care of that by
13 selecting a more favorable intake at two hours into
14 the accident, for most cases.
15 DR. KRESS: You have a special code you
16 use for those that takes care of the building wakes
17 and the close in?
18 MS. HART: ARCON 96 is the control room
19 code that is used. And it does take account of
20 building wakes. It is not -- the models break down
21 under ten meters. It was not benchmarked under ten
22 meters, the distance between the intake and the
23 release point.
24 DR. KRESS: Okay. And these were closer
25 than ten meters?

1 MS. HART: There is one release point that
2 is, yes.
3 DR. KRESS: But the alternate release
4 point is a little further?
5 MS. HART: That is correct. That is
6 correct.
7 CHAIRMAN WALLIS: Well, this is going to
8 be resolved by March the 10th.
9 DR. KRESS: I think she said it's already
10 --
11 MS. HART: Yes. The alternative source
12 term amendment is under review right now. It's a
13 separate amendment. It includes offsite and onsite
14 control room.
15 CHAIRMAN WALLIS: So the approval by
16 February 10th should be contingent upon this working
17 out okay?
18 MS. HART: Yes. The EPU is not found
19 acceptable with respect to term habitability with the
20 current information in the EPU submittal itself. In
21 that the EPU would not be able to be implemented until
22 the AST is also implemented.
23 DR. KRESS: The site dose calculation uses
24 the worst two hours?
25 MS. HART: That's correct. The offsite.

1 DR. KRESS: Does the control room do that
2 also?
3 MS. HART: No. The control room is for the
4 30 day extent of the accident, or if it's a shorter
5 accident for the shorter time period. So it's the
6 entire duration.
7 DR. KRESS: It's the entire duration?
8 MS. HART: Right.
9 Next slide.
10 The exclusionary boundary and low
11 population zone doses with the EPU submittal comparing
12 it to the 10 CFR Part 100 does meet that dose criteria
13 and all of the dose criteria within the SRP sections
14 of Chapter 15.
15 The control room doses are not yet found
16 acceptable for the EPU, the AST which does use the EPU
17 conditions is under review and will be approved in the
18 near term.
19 DR. KRESS: What kind of leakage
20 containment do they have for the site dose? One
21 percent, one tenth of a percent for that?
22 MS. HART: I can't recall off the top of
23 my head. I'm sorry. Do you remember, Paul?
24 MR. SICARD: Yes. This is Paul Sicard.
25 The containment leakage that is assumed is

1 0.5 volume percentage per day for the first day and
2 0.25 after 24 hours.
3 DR. KRESS: Yes, that accounts for the
4 pressure that you get.
5 MR. SICARD: That is correct, that
6 accounts for the pressure.
7 CHAIRMAN WALLIS: So you're sure that
8 everything's going to be okay?
9 MS. HART: Until it is absolutely --
10 CHAIRMAN WALLIS: You don't know?
11 MS. HART: -- issued, we don't know that
12 for sure.
13 CHAIRMAN WALLIS: So this is a little like
14 the previous matter?
15 MS. HART: It is an open item, yes.
16 CHAIRMAN WALLIS: Okay.
17 DR. DENNING: Let me pursue that just a
18 little bit. When is the earliest that it could be
19 closed?
20 MS. HART: It is now aiming at March, the
21 middle of March.
22 DR. DENNING: The middle of March. So does
23 that mean if the ACRS doesn't review this until the
24 middle of March, it doesn't make any difference as far
25 as the moving forward?

1 DR. KRESS: We have reviewed things based
2 on what the staff tells us and what the preliminary
3 results are and say that pending closure of these
4 items, satisfactory matter, that we approve the SER.
5 We've done that before.
6 DR. DENNING: Yes. Where I was headed,
7 Tom, was really the previous issue. I mean, I
8 wouldn't have any problems with this particular issue.
9 The previous issue is the one that we're going to have
10 a hard time dealing with it two weeks.
11 MR. SIEBER: Right.
12 CHAIRMAN WALLIS: Well, this seems to be
13 based on understood physics, this alternative source
14 term, I hope.
15 DR. KRESS: Well, we've had extensive
16 hearings on the alternative source term. And we have
17 agreed in the past that it is an appropriate thing to
18 use.
19 DR. DENNING: You know there's another
20 element of it, too. And that is whether it's five rem
21 in the control room that they get, or 10 rem in the
22 control room, that's not going to make a whole heck of
23 a lot of difference to the world. If you melt down the
24 core, it's a different issue. Not that -- and also, we
25 know that there's a lot of conservatism in these

1 methods anyway. But it's just what are the
2 implications in the long term.
3 DR. KRESS: Well, I feel good about the
4 fact that they actually measured in the inleakage use
5 and the tracer gas. You have to repeat that
6 measurement at particular intervals or is it a one
7 time thing?
8 MR. SICARD: This is Paul Sicard.
9 Right now there is not a definite time
10 period that has been established for periodic testing
11 of the tracer gas testing. That is an item which is
12 being worked on by NEI on a generic industry basis.
13 And when there is agreement on how to proceed on that
14 periodic testing, such as the frequency, Waterford
15 will be consistent with that generic industry
16 approach.
17 DR. DENNING: I'm still curious as to how
18 with positive pressure they're getting inleakage,
19 although you can get it with wind pressure, I guess,
20 on the building. But it still is curious to me that if
21 they really go to a positive pressure, that they're
22 seeing inleakage.
23 DR. KRESS: I think you hit on it. It's a
24 delta P --
25 DR. DENNING: It's a delta P with the

1 wind?

2 DR. KRESS: -- at various local positions.

3 And that could vary inside and outside.

4 MR. SIEBER: You've got a lot of rooms

5 surrounding the envelop and some of them are

6 pressurized and some are vacuumed.

7 DR. DENNING: And some aren't.

8 MR. SIEBER: And it's a matter of delta P.

9 CHAIRMAN WALLIS: I think there may be

10 duct switch may have a different pressure from the

11 environment, too, go through that.

12 DR. KRESS: Yes. And they may have --

13 MS. HART: They have noticed in previous

14 in previous testing that there's been pressurized

15 ducts that have been pressurized higher than the

16 control room itself, and that's actually what caused

17 the pressurization in the control room, helped the

18 system itself pressurize the control room. So that's

19 what one of the issue that started off the whole issue

20 with control room habitability and unfiltered

21 inleakage and the testing and started us off on that

22 whole route.

23 CHAIRMAN WALLIS: It was also a big issue

24 that they do a test. Of course they prepare for the

25 test and everything is fine. But as you know when

1 sort of you're weather proofing your house and you're
2 weather proofing and a few weeks later there are
3 leaks.
4 DR. KRESS: Well, that's why I asked them
5 about the frequency.
6 CHAIRMAN WALLIS: Right. How often do
7 they test?
8 DR. KRESS: Well, they're going to wait
9 for NEI guidelines on that.
10 CHAIRMAN WALLIS: Oh, wait for NEI. Okay.
11 MS. HART: Are there any more questions on
12 the design-basis accident analyses?
13 Thank you.
14 MR. KALYANAM: Okay. The next presenter
15 is Paul Prescott, and he will discuss our test
16 program.
17 MR. PRESCOTT: Good afternoon, gentlemen.
18 My name is Paul Prescott. I'm with the Plant Support
19 Branch of NRR.
20 Up to this point ACRS has heard the
21 licensee's and staff's reasons for granting the EPU.
22 Underlying the safety conclusions is the fact that
23 SSCs are installed correctly. A large part of this is
24 that they undergo required post-maintenance tests and
25 that all tech specs surveilliances have been

1 completed.

2 We challenged the licensee and the

3 technical branches to ensure that they have considered

4 the need for any specific testing. This includes any

5 larger scale testing beyond routine post-maintenance

6 tests.

7 A specific area considered in SRP 14.2.1

8 is large transient testing per RG 1.68.

9 Next slide, please.

10 Per the SRP, the licensee may propose

11 alternatives to certain testing. The most justified

12 exclusion to EPU testing is for large scale testing.

13 Typically this is the main steamline isolation valve

14 closure and the generator load reject tests.

15 The alternate method argument related to

16 analytical methods, that is the method chosen by the

17 licensee.

18 In accordance with SRP 14.2.1 the staff

19 reviews the proposed EPU test program to adequate

20 demonstrate the performance of SSCs important to

21 safety, checks the performance of SSCs impacted by the

22 EPU related modes, and reviews the integrated effect

23 of the EPU modifications.

24 Next slide, please.

25 As you may be aware, Waterford 3 was the

1 first EPU that was conducted using the guidance
2 developed with SRP 14.2.1. However, it was not truly
3 the first EPU for large transient testing that was
4 considered by our group. Duane Arnold, which recently
5 came for license amendment, I applied the principles
6 behind this to review their license amendment to defer
7 their large transient testing.
8 The next slide, please.
9 CHAIRMAN WALLIS: So even if there were
10 really good arguments for doing large transient
11 testing, you'd have to fight your precedent of having
12 approved 12 EPUs without requiring it? You'd have to
13 then presume they give really good reasons why
14 something was different about Waterford, even if there
15 are good reasons for doing LTT?
16 MR. PRESCOTT: Not necessarily. I mean,
17 we still look at each one, at least I do. I still
18 look at each one individually.
19 CHAIRMAN WALLIS: You have to say what's
20 different about Waterford?
21 MR. PRESCOTT: What's different about each
22 one.
23 CHAIRMAN WALLIS: Yes. But then they're
24 going to come back and say you allowed 12 which
25 covered the range, why are you picking on us.

1 MR. PRESCOTT: Again, this wasn't --
2 that's not truly how we look at it. I look at it as
3 each one comes in, I review it for the SRP.
4 CHAIRMAN WALLIS: Yes.
5 MR. PRESCOTT: I consider what's happened
6 in the past and apply that to the review. I think I'm
7 justified in doing that. The SRP gives me that
8 guidance, as a matter of fact, to consider operating
9 experience. And this could be applied, you know, as
10 an example of a similar PWR that had done a power
11 uprate to a similar extent.
12 MR. CARUSO: How does the fact that they
13 put together ANO 2 properly tell you that they put
14 together Waterford properly?
15 MR. ROSEN: What do you mean put together?
16 You mean built it?
17 MR. CARUSO: Build it, made the
18 modifications of ANO 2 correctly. How does the fact
19 that that was done correctly at ANO 2 tell you that it
20 was done correctly at Waterford 3?
21 MR. PRESCOTT: All right. One of the big
22 discussions that we've had in the past is what gives
23 me assurance, what gives us, staff assurance of the
24 plant's adequacy for the modifications that they
25 performed for the power uprate.

1 I believe that guidance is there in 50.59,
2 in the post-maintenance tests that are performed per
3 the regulations. And then our tech spec surveillances
4 that are required to assure operability of systems
5 important to see. That's what I base that on.
6 MR. CARUSO: Are there any startup tests
7 or surveillance requirements that would require an
8 integrated assessment of whether all these systems
9 that are individually tested will actually work the
10 way they are expected to operate?
11 MR. PRESCOTT: To assist us in that
12 review, we break down the EPU really into two separate
13 parts; that is the low power physics testing portion
14 of it and then power testing that's done 80 percent
15 and above. So you kind of break it down in steps. And
16 as the licensee as stated previously, the low power
17 physics testing portion, there was no impact on that.
18 So now that really leaves me with what modifications
19 were done for the power uprate and what post testing
20 or analytical methods that they propose to use.
21 MR. CARUSO: So how does this tell you
22 that it's all going to work in an integrated fashion?
23 MR. PRESCOTT: Again, I believe that the
24 post-maintenance tests are adequate and the analysis
25 that have been approved by the -- not just approved

1 but reviewed by the staff give assurance that the
2 plant will perform at uprated power.
3 MR. ROSEN: Yes, but those are just words.
4 I mean, the post-maintenance test, I assume you mean
5 post-mod tests as well?
6 MR. PRESCOTT: That's correct.
7 MR. ROSEN: The modification that they've
8 done, the principle one, is on the high pressure end
9 of the turbine.
10 MR. PRESCOTT: That's correct.
11 MR. ROSEN: You can't test that at zero
12 power or low power because there's not steam flow. The
13 idea of the initial startup tests was to test that
14 component, that whole series of components out through
15 the turbine with a turbine trip from full power.
16 MR. PRESCOTT: Right. But you have to look
17 at what the modification is. The modification is the
18 replacement of a HP rotor. The HP rotor was there
19 previously.
20 MR. ROSEN: And that's why I questioned to
21 move out the valving and all of that. And I got
22 answers that said it's mainly the steam path and not
23 the valving. But you're still talking about the
24 principle component for which the turbine trip test is
25 done at full power; that is the response of the

1 turbine to the shut off of steam.

2 MR. PRESCOTT: That's correct.

3 MR. SIEBER: Yes, but none of that is

4 safety related.

5 MR. ROSEN: Oh, I know it's not safety

6 related.

7 MR. SIEBER: And it doesn't effect the --

8 MR. ROSEN: No, wait a minute. Wait a

9 minute.

10 MR. SIEBER: -- safety aspect of the

11 point.

12 MR. ROSEN: I know it's not safety

13 related. We've shown hundreds of times, if I could

14 find one example I could find a 100, where non-safety

15 related components have impacts on the plant. And, in

16 fact, the turbine of course is treated, in some

17 respects, as a safety related component with the

18 turbine missile strike probability analyses and all

19 the rest.

20 So to just say it's not safety related

21 doesn't really inform me a whole lot. I mean, it's

22 true, but it doesn't inform me a whole lot, nor does

23 it provide a basis for the decision making.

24 MR. PRESCOTT: That's correct.

25 MR. ROSEN: I still want to know what the

1 substantive basis is for not requiring the test at
2 full power, the new full power, just as the staff did
3 at the original full power. And so I probed this
4 morning is it a risk basis? No. Turbine trip and the
5 SCRAM that results is not a risky situation. We're
6 told that it's a very low risk, so it can't be risk.
7 So it's purely economic. So the staff must be
8 responding to a licensee's economic pressure
9 incentives, and I don't think that's appropriate. I
10 think you need to --
11 MR. PRESCOTT: I don't think that's the
12 staff intent here. The staff looks at-- we don't
13 narrow the purview of the review to safety -- just
14 important to safety equipment. We look at the overall
15 scope --
16 MR. ROSEN: Well, that's right.
17 MR. PRESCOTT: -- of the EPU that was
18 performed. And, again, you have -- at least I -- we
19 ask the staff to ask themselves what would it gain you
20 if you asked for the test to be performed. And so far
21 when we were writing -- obviously, when we were -- as
22 you know, this SRP is relatively new. You know, we
23 developed it within the last couple of years.
24 And as we went around -- and there was a
25 DPO involved with this also questioning whether or not

1 large transient testing should have been performed.
2 And there's also a requirement that we go back and
3 look at the other sites that had performed large
4 transient testing at a later date to review whether or
5 not they should perform it.
6 When we -- again, it's not just my
7 opinion, it's the staff's opinion. They have to come
8 forward with a technical justification as to why the
9 test should be performed. Is there something new --
10 MR. ROSEN: Well who -- the staff must
11 come forward with a technical justification as why the
12 staff -- the test should be performed, is that what
13 you just said?
14 MR. PRESCOTT: There has to be a basis to
15 ask for them to perform the test.
16 MR. ROSEN: Well see now, that's precisely
17 why the Review Standard was changed and the SRP was
18 changed to reverse the burden of proof. That's the
19 way it was, but shouldn't be now. The idea at least
20 was that intended was that the licensee should come
21 forward with a justification that people can agree to
22 for why the test should not be performed; otherwise
23 the test should be performed. And I think what you've
24 done is taken on the licensee's burden, and it's not
25 necessary.

1 The licensee in his application should
2 carry that burden. I don't think they have. And I
3 don't think you should have agreed to it.
4 MR. JONES: This is Steve Jones in the
5 Plant Systems Branch, Acting Section Chief.
6 We did look at this from the perspective
7 of what is the basis for not performing the test, the
8 large transient tests in particular, general load
9 reject and mainsteam isolation valve testing. Those
10 tests perform certain functions or at least the
11 initial test program had certain design criteria that
12 they were intended to demonstrate. And in this case,
13 they didn't really have anything to do with the
14 turbine performance.
15 What we did consider is: The extent of
16 the modifications associated with the power uprate and
17 the overall change in power of the plant; the
18 operating experience this plant has had; what
19 analytical models they could use to evaluate transient
20 response to the plant in an integrated fashion, and;
21 how those models were benchmarked.
22 When we looked at Waterford, this is just
23 barely over the threshold for an EPU, 108 percent and
24 we only consider EPUs above 107, a percent of original
25 license power. And then we're looking at the

1 modifications were largely outside of the areas that
2 would effect integrated response in those two large
3 transients tests in that the turbine response is
4 fairly independent and then the other factors like the
5 feedwater heater drain valve response is also
6 relatively small effect on the transient response of
7 the plant to those types of tests.
8 Also, in this case the licensee had models
9 that considered how each controller performed. And in
10 this case the controllers were, as the licensee
11 mentioned this morning, the algorithms of the
12 controllers weren't changed, just the setpoints. So
13 they were able to change that in their model and model
14 the response. And those models have been benchmarked
15 to both Waterford's experience with those types of
16 transients that already have occurred from their 100
17 percent of their current licensed power, and also
18 operating experience at the -- at a similar CE and
19 NSSS plant, ANO 2 at a higher than original license
20 power from a power uprate condition, effectively.
21 And on that basis we concluded that there
22 would be very little information gained from a large
23 transient test.
24 MR. CARUSO: Can I ask a hypothetical?
25 Suppose Entergy decided to build Waterford 4, and they

1 decided to build it just like Waterford 3? Would you
2 expect them to perform this test at the startup of the
3 new Waterford 4 plant?
4 MR. JONES: Yes.
5 MR. CARUSO: Why?
6 MR. JONES: One of the principle reasons
7 would be that Waterford 3 has already essentially gone
8 through the tests from what's 93 percent of their
9 uprated power level. They just haven't done it at 100
10 percent. And then --
11 MR. CARUSO: Well, why would you require
12 Waterford 4 to do the test?
13 MR. JONES: Because there are a series of
14 new components that have never been -- never responded
15 to a transient and may have other problems.
16 MR. CARUSO: But they would say well we
17 tested these components in the factory. This pump
18 worked, this control circuit behaved properly, we did
19 the individual tests before we even started up the
20 plant pumping water, opening the valves that all the
21 valves worked, the turbine was tested in the factory,
22 the overspeed was tested, the control valves were
23 tested. Why do I have to run one of these tests?
24 MR. JONES: New plants have a lot of
25 experience with things like foreign materials being

1 left inside components. And that's not going to --

2 MR. CARUSO: And operating plants don't?

3 MR. JONES: Within the scope of the area

4 that of the plant that plant systems is concerned

5 with, these modifications don't have any credible

6 likelihood of introducing those types of foreign

7 materials that would change a transient response.

8 MR. CARUSO: They don't do maintenance

9 during outages?

10 MR. JONES: Every plant does. Then we

11 would be talking about every plant doing transient

12 testing coming out of each outage. I think what we're

13 looking at is the delta and whether or not the extent

14 of the modifications has a credible likelihood of

15 introducing some type of new interaction that can't be

16 detected by the normal post-modification testing of

17 that individual component.

18 What we see at Waterford was a lot of

19 setpoint changes that are non-disruptive to the

20 controllers. And then the only really invasive mods

21 are downstream of the steam inlet valves to the main

22 turbine or pretty upstream with regard to the

23 feedwater heat drains. But from what I understand of

24 that modification, that's not a mod that's actually

25 invasive to the valve either. That's mainly a

1 controller setup.

2 CHAIRMAN WALLIS: It may happen by itself

3 anyway --

4 MR. SIEBER: Well, it certainly will

5 happen.

6 CHAIRMAN WALLIS: -- after operating for

7 a while.

8 MR. ROSEN: At 2:30 in the morning.

9 CHAIRMAN WALLIS: And the only question is

10 is whether you'd rather do it that way or do it now.

11 For the first time.

12 MR. JONES: For the first time, that's I

13 think the key.

14 What we're expecting is that the response

15 will be very similar to the last time it happened

16 based on what we've just discussed. And we're using

17 the criteria that were laid out in the Standard

18 Revenue Plan for determining that.

19 DR. RANSOM: Well, to some degree is the

20 ascension to power test a test of this type because if

21 any problems are encountered, I presume they shut it

22 down, you know, and restart the test after they've

23 resolved whatever problems are encountered?

24 MR. JONES: Certainly a large majority of

25 the test systems that Plant Systems Branch are

1 concerned with are tested during the normal operating
2 and power ascension portions, and the maneuvering
3 transient that's included in their power ascension
4 test.
5 DR. RANSOM: One thing I'm curious about
6 on the turbine and the generator, isn't it rotated
7 before they begin this power ascension testing? How do
8 they do that?
9 MR. PRESCOTT: Put it on turning gear.
10 MR. SIEBER: Rotate it.
11 DR. RANSOM: Drive it in some way?
12 MR. PRESCOTT: Yes.
13 MR. SIEBER: Oh, yes. The turning gear.
14 MR. PRESCOTT: Yes. The turning gear.
15 MR. SIEBER: There's a motor on it.
16 DR. RANSOM: Well, I would say that this
17 uprate given, as you suggests, it's borderline
18 percentage wise, but it is not borderline in the sense
19 that to the extent to which modifications have been
20 made or are being made. As we said the high pressure
21 turbine will be upgraded and replaced, generator's
22 going to be rewound, associate auxiliaries will be
23 changed, higher capacity main generator output circuit
24 breakers, disconnect switches and bus work will be
25 installed, control valves for the heat drain system

1 will be either upgraded or replaced, atmospheric dump
2 valve controls, we heard a little about them, will be
3 replaced.
4 MR. JONES: I believe no. The atmospheric
5 dump controls --
6 MR. ROSEN: They're going to be modified?
7 MR. PRESCOTT: To a finer setpoint.
8 MR. ROSEN: The setpoint changes.
9 MR. PRESCOTT: Yes, sir.
10 MR. ROSEN: Okay. Well -- lower steam
11 generator trip pressure setpoint, reheat system safety
12 valves will be modified, condenser modifications will
13 be performed staking the condenser.
14 I mean, that's a long list of stuff. And
15 my feeling about all that stuff is it has to work as
16 an integrated whole. And the only way to know that is
17 to do an integrated test, the large transient test at
18 the new EPU. And I wouldn't expect that to be done the
19 day the instant you get there, but at a reasonable
20 time after you get to the EPI conditions and after
21 you've taken steady state data, and at a time
22 convenient to the system and the plant when management
23 and all the control systems, the proper control
24 systems are in place, additional resources as
25 necessary both people and equipment. And it would

1 seem to be that that would be an appropriate time to
2 take it rather at some undetermined time in the future
3 decided by the plant, not by the plant management.
4 MR. MITCHELL: Yes. This is Tim Mitchell.
5 I guess I feel like we are testing each of
6 those components you listed. And we are doing LTC
7 code predictions on their performance. But things like
8 turbine valves, which would be the primary concern I
9 believe with everything along the turbine train, are
10 they capable of moving and closing, you know we will
11 demonstrate that they are capable of moving and
12 closing or opening as part of the power ascension
13 profile, plus the maneuvering from 100 percent power
14 to 90, to 95 also shows our ability to move those
15 valves from the new 100 percent power plateau.
16 So to me we are testing the plant.
17 MR. ROSEN: Individual, I agree.
18 Individual here, individual there. But your reliance
19 on calculations and analyses to predict the transient
20 response of a plant from full power at the extended
21 power conditions is purely analytical. And I don't
22 think we would have ever accepted that in the past.
23 And I see no reason to do so in the future.
24 You can continue to address this subject
25 and provide more documentation, but I've been through

1 all of the stuff that's been provided, I think, both
2 by the staff and the applicant. And I don't think
3 you've carried the burden. My reaction to it is well,
4 if that's the best you can say, why don't you just do
5 the test and get it over with.
6 CHAIRMAN WALLIS: Steve, I'm not sure that
7 this Subcommittee is going to take the position one
8 way or the other. I don't know how the members feel
9 about this, but we may turn out to be evenly split.
10 MR. ROSEN: Well, that may very well be.
11 That may very well be. And I was just feeling my
12 burden to let the applicant and the staff know.
13 CHAIRMAN WALLIS: Well, I'm saying if
14 we're going to go to the full Committee, it would be
15 good if we could go with a recommendation. You know,
16 we've actually gone through the arguments and as a
17 Subcommittee we recommend that they do or do not do
18 these tests.
19 MR. ROSEN: Well, we could take a soft
20 vote if you want. I felt my burden was to say how I
21 felt.
22 CHAIRMAN WALLIS: Yes, I think you should.
23 I think that's very good that you did.
24 DR. DENNING: I mean if we're going to get
25 to a soft vote, then I'd like to talk a little bit

1 more about it. Because my feeling is --

2 CHAIRMAN WALLIS: Well, I thought we'd

3 talk about it after they've finished their

4 presentation.

5 DR. DENNING: Sure. After. Absolutely.

6 CHAIRMAN WALLIS: When we start asking

7 ourselves whether or not we should go to the full

8 Committee and what are the issues and so on.

9 MR. JONES: This is Steve Jones in Plant

10 Systems. I just wanted to bring up one more point.

11 We have accepted in the past when during

12 initial startup tests when plants have had inadvertent

13 trips at lower power levels then initially plans, we

14 have accepted those as satisfying the startup test

15 requirement.

16 MR. ROSEN: Up to that power level, not

17 extrapolated beyond that power level?

18 MR. SIEBER: No, extrapolated.

19 MR. JONES: I mean, we've accepted those

20 as satisfying the generator load reject tests for 100

21 percent power if it occurred at 80 percent power.

22 MR. PRESCOTT: And we also accepted for

23 initial startup of plants, we also accepted as logic

24 for not performing certain tests at other plants that

25 were being constructed afterwards with the same

1 vintage or the same make, they're not performing a
2 certain test based on a test performed at other
3 plants.
4 MR. ROSEN: I understand.
5 MR. PRESCOTT: So NRC has long --
6 MR. ROSEN: I understand that you've told
7 me that you've accepted it at other plants and at
8 lower power levels in the past.
9 MR. PRESCOTT: Yes.
10 MR. ROSEN: We're talking about the
11 future, not the past here I thought. And so I would
12 prefer to talk about the future. And given the fact
13 that either you make a change here with the past or
14 you use the past essentially forever as prologue. In
15 other words, we give every licensee the signal that
16 they may rely on the past precedent of not requiring
17 this. Their burden has been reduced effectively to
18 zero, when in fact their purpose -- the change of the
19 standard was to transfer the burden to the licensee.
20 It was not the staff's job to argue with the agency
21 reviewers that the licensee could waive transient
22 testing, which was part of normal startup programs. It
23 was not the staff's job to do that. It was the
24 applicant's job to do that. To make that case
25 convincingly.

1 MR. PRESCOTT: And then the SRP covers
2 that. It gives them the option of supplying us
3 information analytically or performing the test. It
4 doesn't weigh the option for them.
5 MR. RULAND: Let me add about Duane
6 Arnold. As you probably are aware, Duane Arnold when
7 we approved their power uprate, they had a license
8 condition that required them to do large transient
9 testing.
10 Recently they came in for a license
11 amendment to eliminate that license condition. And
12 the staff basically said to the licensee -- but we
13 haven't issued this license amendment by the way, yet.
14 That they hadn't performed sufficient justification to
15 eliminate large transient testing at this point.
16 So what I'm arguing is that the staff has
17 shown that we're applying this as the Review Standard
18 has suggested on a case-by-case basis. And in fact, at
19 least at this stage in Duane Arnold they haven't
20 provided us sufficient justification to justify
21 eliminating the large transient testing. So that's
22 just an example.
23 MR. ROSEN: Well, I appreciate that.
24 MR. PRESCOTT: And there was a significant
25 RAI associated with this EPU at trying to address

1 large transient testing.

2 CHAIRMAN WALLIS: Can we perhaps move on

3 and revisit this later?

4 MR. PRESCOTT: Finally, this is just to

5 give a little more background on some of the things

6 that we take a look at, and we also take a look at

7 operator training and familiarization, any changes

8 that were done to the ELPs and the benchmarking of

9 analysis codes and models as extra consideration for

10 whether or not large transient testing.

11 Next slide, please.

12 Finally, this is just a conclusion slide

13 to give an overall view of that SRP 14.2.1 has options

14 available to a licensee for ways of justifying large

15 transient testing and testing in general. And that

16 there have been 12 domestic LWRs or light water

17 reactors that have implemented staff approved EPUs.

18 CHAIRMAN WALLIS: But at Duane Arnold you

19 are requiring?

20 MR. PRESCOTT: No, it's a licensed

21 condition right now that's on there to perform the

22 testing. They're doing their power uprate in phases

23 and they haven't reached the phase yet where they're

24 required to do the testing --

25 CHAIRMAN WALLIS: There have to be LWRs

1 where you have required large transient testing.

2 MR. PRESCOTT: I'm sorry.

3 CHAIRMAN WALLIS: You said there were 12

4 were you have not required large transient tests. Are

5 there other ones where you have required large

6 transient tests?

7 MR. PRESCOTT: No, sir.

8 CHAIRMAN WALLIS: No. So this is 12 of

9 12?

10 MR. PRESCOTT: Yes.

11 CHAIRMAN WALLIS: There's no example where

12 you have required them?

13 MR. PRESCOTT: No, sir.

14 And that's it.

15 MR. HOWE: This is Allen Howe. Let me

16 just clarify something.

17 Duane Arnold has a license condition which

18 requires them to do large transient testing. As the

19 context here, they haven't gotten to the point yet

20 where they would need to do it, and they've submitted

21 an application for removal of that license condition.

22 But, in fact, you could say the answer is that Duane

23 Arnold has been required or has a requirement to do

24 large transient testing.

25 CHAIRMAN WALLIS: Can we move into the

1 next item now?

2 Thank you very much.

3 MR. KALYANAM: The last presenter of the

4 day will be Martin Stutzke to talk about the

5 probablistic safety assessment.

6 MR. STUTZKE: Good evening, gentleman. I'm

7 Martin Stutzke from the Probability Safety Assessment

8 Branch. Unlike the two members of my branch

9 previously, I'm an actual PRA analyst.

10 MR. ROSEN: Rather than an orphan in the

11 PRA group, right?

12 MR. STUTZKE: I look at them as my foster

13 children.

14 MR. ROSEN: Well, that's nice.

15 MR. STUTZKE: We're reviewed the risk

16 evaluation that Waterford submitted to us, primarily

17 for two reasons. One, we want to make certain that

18 the risks are acceptable. And two, we want to

19 determine if special circumstances exists as defined

20 in the Standard Revenue Plan Chapter 19 Appendix D.

21 Special circumstances are items that could rebut a

22 presumption of adequate protection that's provided by

23 meeting current regulations.

24 The point behind this is that the

25 Waterford EPU application is not a risk-informed

1 application. So strictly speaking RG 1.174 does not
2 apply. However in the course of developing the Review
3 Standard RS-001 there, the staff has concluded in fact
4 that special circumstances may exist for all EPUs, and
5 hence we do a review for that purpose.
6 One of the things that's different when
7 you're looking at the risk of a nonrisk-informed
8 application, the focus on adequate protection means we
9 tend to look at the overall risk. We're not so
10 concerned about the change in risk, the delta risk
11 calculation, although you will see that we have in
12 fact looked at them.
13 Next slide, please.
14 The review scope basically consists of
15 examining the internal events, the following types of
16 external events.
17 Internal floods. The license has a
18 conservative screening approach that's used.
19 Internal fires where they've relied on
20 EPRI methodology, the fire induced vulnerability
21 evaluation approach.
22 Seismic events or where they've relied on
23 seismic margins analysis.
24 The so called HFO events; high winds,
25 external floods and other external events where

1 they've used NUREG-1407 screening. 1407 is the IPEEE
2 submittal guidance.
3 Their Level 2 PRA which is basically a
4 LERF calculation based on NUREG/CR06595.
5 A qualitative assessment of shutdown risk
6 based on questions out of the Standard Review Plan
7 Chapter 19.
8 And we've also examined the PRA quality.
9 I should point out with concern to PRA quality, the
10 Review Standard is basically -- I looked at Regulatory
11 Guide 1.174, the SRP Chapter 19 and section 19.1. As
12 you know for Regulatory Guide 1.200 has been issued
13 for trial use, which talks about industry peer reviews
14 and the ASMI PRA standard. I will confess that I
15 looked at this, but you will not see that I referenced
16 it. It is not the basis of my decision of adequate
17 quality for this license application.
18 Next slide.
19 The overall results are as shown on the
20 slide. I did not have them up on this slide because
21 the internal floods and internal fires, in fact, are
22 conservative approaches. In fact, I went ahead and
23 added them up over lunch. The total core damage
24 frequency is about two times ten to the minus five per
25 year, that's including all the internal events and

1 external events.

2 The change in core damage frequency is on

3 the order of four times ten to the minus seven per

4 year. When you do compare that to Regulatory Guide

5 1.174 you find they're in Region III, which means it

6 is a very small increase in risk.

7 DR. KRESS: Did you look at late

8 containment failures at all?

9 MR. STUTZKE: No, sir. No, sir.

10 MR. ROSEN: Say again what Region III is?

11 MR. STUTZKE: Region III equates to a very

12 small change in risk.

13 MR. ROSEN: You mean that's what's

14 allowed?

15 MR. STUTZKE: Yes.

16 MR. ROSEN: It's not no change?

17 MR. STUTZKE: It's not no change.

18 MR. ROSEN: Right.

19 MR. STUTZKE: The language is very small.

20 Region II is small.

21 MR. ROSEN: Allowed?

22 MR. STUTZKE: Right. And Region I is not

23 allowed.

24 With respect to their internal events PRA,

25 I focused on several things. One had to do with the

1 frequency of loss of offsite power because the power
2 of the plant was being increased and we had an event
3 in August of 2003 that blacked out large amounts of
4 power in this country, we needed to have a look at the
5 loop frequency. In fact, the licensee's approach to
6 estimating loop frequency is to take a list of offsite
7 power events, loss of offsite power events that have
8 occurred and screen out those that clearly don't apply
9 to their sites such as snow or ice or things like
10 that. Even though I'll note that it apparently
11 supposedly snowed in New Orleans a couple of week ago.
12 MR. ROSEN: For the first time, and in
13 south Texas.
14 MR. STUTZKE: And in south Texas.
15 MR. ROSEN: Eight inches in my back yard.
16 MR. STUTZKE: It's amazing how probability
17 sometimes come true.
18 MR. ROSEN: That was once in a 100,000
19 years.
20 MR. STUTZKE: I look at that loop
21 frequency and compared it to work that the Office of
22 Research has recently done in support of the staff's
23 action plan on grid related issues. And the Waterford
24 frequency is in fact higher. I'll also point out that
25 Waterford operates in a regulated environment and

1 there's no intention to become deregulated. Office of
2 Research and NRR has tentatively reached a conclusion
3 that regulation versus deregulation does have some
4 influence on the likelihood of loss of offsite power.
5 I like that.
6 In addition, I looked at success criteria.
7 We've talked about that earlier today. The fact that
8 that the deterministic conservative calculations
9 require or the atmospheric dump valves to mitigate
10 small LOCAs. The PRA calculation, realistic
11 calculation indicated that those valves were not
12 needed to mitigate the LOCA.
13 My conclusion goes all the way back to the
14 Commission's PRA policy statement, the third bullet
15 says "PRAs should be as realistic as practicable." So
16 in fact when I use a realistic one, the licensee used
17 a realistic calculation. He determined that the
18 valves were not necessary, and hence there was no
19 change to their success criteria between the pre and
20 the post EPU plants.
21 I think our branch continues to wrestle
22 this as we find indications where one applies the
23 traditional deterministic approaches and reaches one
24 conclusion and comes in with a PRA calculation that
25 may refute this.

1 In addition, the licensee recalculated
2 operator response times using the CENTS code. They're
3 pre-EPU PRA appears to be a mixture of some plant
4 specific analyses, some generic analyses and some good
5 old fashioned engineering judgment. What you found in
6 some cases that when they calculated using CENTS, the
7 operator had more time than before, even though the
8 power level had gone up. So I asked them to do a
9 sensitivity calculation where they left the loop
10 recovery probabilities the same and they changed only
11 the human errors in the model. And in fact the change
12 in core damage frequency only went down by ten to the
13 minus nine. So it's a negligible effect. So in fact
14 they adjusted the pre-EPU PRA to account for the
15 correct times out of CENTS, and then they bumped up
16 the power level and recalculated those. And I think
17 it's a reasonable calculation.
18 For seismic risk, in NUREG-1407 Waterford
19 was classified as a reduced scope plant. The licensee
20 has stated that an increase in power level is not
21 expected to affect equipment survivability or
22 response. There's no change in the safe shutdown
23 passways using the seismic margin analysis.
24 For HFO events, they were screened out in
25 IPEEE; there's no way that an increase in power level

1 will increase the frequency, the current frequencies
2 of HFO events. So there's no contribution from them.
3 For shutdown risk, the Standard Review
4 Plan Chapter 19 contains four questions to help us to
5 decide if impacts on shutdown risks could be
6 important. The questions are as follows:
7 Will the changes affect shutdown schedule?
8 As you see indicated here, the answer is no.
9 Will the changes affect the operator's
10 ability to respond? And remember we're talking about
11 responds to events while the plant is in fact
12 shutdown. The licensee maintains a shutdown
13 operations protection plan that maintains a variety of
14 important functions. And they would propose to
15 control the plant using the same way.
16 The third question is will the changes
17 affect the shutdown equipment reliability? Again, the
18 answer is no.
19 Or would it affect the availability of
20 equipment or instrumentation used for contingency
21 planning? And again the conclusion was no.
22 So the fact that all of the questions
23 resulted in no lead me to the conclusion that the
24 proposed EPU had no or small impact on shutdown risk,
25 and we didn't pursue it any further.

1 With respect to PRA quality, you'll see
2 dates and times of when the licensee submitted their
3 IPE and IPEEE and when the staff accepted them. As
4 stated earlier this morning, the licensee had an
5 owner's group peer review in January of 2000. My
6 impression is the licensee maintains a living PRA
7 program, and I think this is true for all the Entergy
8 plants. You can see there's been several PRA updates,
9 the latest being in June of 2003. They maintain their
10 PRA as quality records.
11 I would say in my experience that's about
12 half of the plants do that, actually maintain these as
13 formal engineering calculations like that.
14 So in order to confirm the quality of the
15 PRA, I looked at the resolution of the IPE, IPEEE and
16 peer review findings. They have addressed all but
17 three of the category A findings from their peer
18 review, and all but 19 of the category B findings.
19 To give you a flavor of what this means is
20 most of the category A findings pertain to the Level
21 2 PRA. For the EPU they didn't use their existing
22 Level 2 PRA. Instead they used NUREG/CR-6595 and so
23 it's not necessary to resolve the questions. There's
24 some comments on model documentation and things like
25 this.

1 So the conclusions are, the PRA has
2 technical adequacy. I think it's modeling the post-
3 EPU plant reasonably so we can have some confidence in
4 its results. The risks are acceptable because, in
5 fact, the licensee meets the Regulatory Guide 1.174
6 guidelines even though they didn't need to. And we
7 have seen nothing in our review that indicates the
8 proposed EPU creates special circumstances, so we have
9 no reason to rebut a presumption of adequate
10 protection based on my review.
11 Questions?
12 CHAIRMAN WALLIS: The CDF for this plant
13 is low enough that it's more adequate protection
14 compared with the average plant.
15 MR. STUTZKE: That's right.
16 DR. KRESS: Besides it's a large dry
17 containment.
18 MR. STUTZKE: It's a large dry
19 containment.
20 DR. KRESS: Those are two pretty good
21 things to --
22 MR. STUTZKE: Yes.
23 CHAIRMAN WALLIS: So does the staff have
24 any kind of summary to present. It's on the schedule
25 here.

1 MR. RULAND: Just one thing I owe you from
2 this morning's meeting had to do with what our
3 procedures said concerning the inspector witnessing of
4 initial power ascension testing.
5 Our inspection procedure, which is
6 specifically called power uprate, and this inspection
7 procedure requires the inspector to witness initial
8 power ascension after they implement the changes that
9 were made for the power uprate and to witness a review
10 test of any major plant tests. So those are what the
11 guidance we give our inspectors.
12 Secondly, you've heard of course a number
13 of our technical staff stating that this the first
14 time that we've completely used our RS-001 Review
15 Standard.
16 CHAIRMAN WALLIS: Right.
17 MR. RULAND: And as part of that program
18 we're going to solicit from the technical staff for
19 not only this power uprate for PWR, but for the next
20 BWR power uprate review, to take that input from the
21 technical staff to see how we need to revise it, if
22 any. I suspect there's a number of changes that we're
23 going to make as the staff actually used the Review
24 Standard. So that's also part of our process, and we
25 intend to do that.

1 But that concludes our presentation. I
2 think Allen, you got some closing remarks.
3 MR. HOWE: Yes. Thank you, Bill. This is
4 Allen Howe.
5 And first of all, I'd like to say that we
6 appreciate the opportunity to come before the ACRS and
7 to present the information related to the Waterford 3
8 extended power uprate.
9 The staff has done an extensive review on
10 this process. When we came in today we identified a
11 couple of open items that we have conceptual agreement
12 on the resolution of them. We need to nail down some
13 of the details, and we are going to be working
14 diligently to do that.
15 In addition, during the course of the
16 dialogue today I took some notes, and I know that
17 others took some notes on some other items that were
18 of interest that we should be prepared to discuss at
19 the ACRS full Committee. And we will be working to
20 manage that and assure that we address those issues at
21 the time that we come before the full Committee.
22 Thank you.
23 CHAIRMAN WALLIS: Thank you very much,
24 staff.
25 Is it appropriate, Ralph, we come off the

1 record at this time?

2 MR. CARUSO: I think so.

3 CHAIRMAN WALLIS: So we don't need the

4 transcript anymore. Thank you.

5 MR. MITCHELL: Chairman Wallis, I do have

6 some FAC data that was requested.

7 CHAIRMAN WALLIS: Let's go back on for

8 these bits of factual data.

9 MR. MITCHELL: Okay. The flow accelerated

10 corrosion, going back on the question of past outage

11 history. All of the items I'm going to talk about were

12 predicted either by CHECWORKS or by our program

13 itself. As I think everybody's probably aware,

14 CHECWORKS does not do small bore, so we rely on our

15 program to do small bore.

16 In refueling 10, which would have been

17 three outages ago, we did some weld buildup on

18 stainless steel overlay that was predicted by the

19 program. This is not CHECWORKS either. That's

20 outside the bounds of CHECWORKS.

21 RF 11, the next outage --

22 MR. ROSEN: Well, where did you do that

23 weld overlay? What system? You didn't say.

24 MR. MITCHELL: It's a cross under piping

25 on the turbine.

1 RF 11 extraction steam elbow, a 20 inch.
2 That was based on a CHECWORKS prediction from the
3 previous outage. And we went in and replaced that with
4 chrome moly.
5 Then in RF 12 there are two two inch main
6 steamlines that replaced based on data that we had
7 collected in previous outages in this predictions. But
8 those were not -- but those are small bore, they
9 weren't CHECWORKS. And that's it.
10 MR. ROSEN: So some cross under piping was
11 built up?
12 MR. MITCHELL: That's correct. One 20
13 inch elbow.
14 MR. ROSEN: One 20 inch elbow was replaced
15 with chrome moly.
16 MR. MITCHELL: Right. And two --
17 MR. ROSEN: That's a small bore piping.
18 MR. MITCHELL: And then two lines of small
19 bore piping.
20 MR. ROSEN: In the main steam system?
21 MR. MITCHELL: That's correct. And again,
22 all of those were predicted.
23 MR. ROSEN: All of those were predicated,
24 but not necessarily by CHECWORKS.
25 MR. MITCHELL: Just one was even in the

1 scope of CHECWORKS, that's correct. So the one that
2 CHECWORKS had an opportunity to predict, it did
3 predict. But that's the only one in the last three
4 outages that was within the scope of the CHECWORKS.
5 MR. ROSEN: Thank you.
6 CHAIRMAN WALLIS: Okay.
7 MR. MITCHELL: That's all my FAC data. We
8 could discuss some more on the boron precipitation
9 question that Dr. Ward presented if you would like,
10 but I'll leave that up to the Committee.
11 CHAIRMAN WALLIS: Well, you didn't have
12 any info when he was talking and maybe you should,
13 since that looks as if that might be a very important
14 issue.
15 MR. MITCHELL: We have looked at it and
16 Joe's going to talk about it in more depth, but in
17 summary we have gone back and done the calculations.
18 Those calculations have supported our position, that's
19 even with the conservatisms that Dr. Ward described.
20 And those conservatisms more than bound any open
21 issues with the calcs. Those calcs will be QA'd next
22 week, I believe. If that's not correct, Joe, please
23 correct that. But I'm going to turn it over to Joe
24 and let him talk about it as well.
25 MR. CLEARY: Yes. What we plan to do is

1 expand the calculation that we've done today to
2 address Len's concern to include as quantitatively as
3 possible or semi-quantitatively some other
4 conservatisms that we haven't discussed in the meeting
5 today and also some of the ones that we have.
6 We would start off that recalculation by
7 attempting to implement into the calculation the
8 affect of the increase in the boric acid density on
9 the phase separation model that will determine the
10 void fraction in the mixing volume.
11 CHAIRMAN WALLIS: Now, do you have a basis
12 for doing that?x
13 MR. CLEARY: To be honest, we do not have
14 a basis at this point in time. The intent of the
15 calculation would be to show that hopefully over a
16 wide range of void fractions after accommodating --
17 relaxing these other conservatisms, we would have a
18 bounding result that would cover any expected impact
19 that a more detailed and therefore time consuming
20 evaluation of the effect of boric acid --
21 CHAIRMAN WALLIS: Well, when you boil a
22 mixture close to saturation, the vaporization
23 concentrates this substance on the interface and you
24 will probably will tend to precipitate boric acid on
25 the interface of the bubbles. So you now have a

1 mixture which is not homogeneous. It has interfacial
2 characteristics which are different from the bulk and
3 which may actually involve precipitation of this
4 soluble.
5 MR. CLEARY: I can't argue --
6 CHAIRMAN WALLIS: That would change the --
7 it seems to me, that would change the drift flux or
8 have the potential to change the formability of the
9 drift flux and quite a few other of the hydraulic
10 characteristics of this mixture, the same way that you
11 boil certain things in the kitchen, when you boil
12 candy and so on, when you start to get conditions
13 where you're going to change the structure of the
14 stuff, you begin to get very different boiling
15 behavior of that material.
16 MR. CLEARY: I agree. And that's why the
17 purpose of these calculations would be to show that
18 once we start relaxing these very conservative
19 assumptions we would remain far enough below the
20 solubility limit that these effects would not
21 significantly enough change the answer to lead to the
22 expectation of boric acid precipitation.
23 In the longer time frame, there are test
24 data out there that can be brought into the
25 evaluation. The MHI has done tests on the Backus

1 facility. The Finnish have done some tests that the
2 NRC staff is aware of that can help bring more factual
3 information to bear on the issue.
4 CHAIRMAN WALLIS: So these tests would
5 include boiling of boric acid solution near the limit
6 of solubility.
7 MR. CLEARY: That's correct.
8 CHAIRMAN WALLIS: And the resultant drift
9 flux or whatever it is that's necessary to calculate
10 the void fraction?
11 MR. CLEARY: At this point I don't know
12 the extent of the instrumentation that was in these
13 facilities to know what could be brought to bear on
14 trying to benchmark current models --
15 CHAIRMAN WALLIS: Now, is this something
16 that can be done in two weeks?
17 MR. CLEARY: What I'm describing, bringing
18 in the results of these test studies, they certainly
19 cannot be done in two weeks. Again, the intent of the
20 work we would propose doing in the next two weeks is
21 to show that once we relaxed the very conservative
22 assumptions, that we would lower the maximum
23 concentration recalculate well below the solubility
24 limit to give a high degree of confidence that in the
25 long term on a generic basis Waterford as well as

1 other Westinghouse and GE-designed NSSSs would not
2 have a problem.
3 CHAIRMAN WALLIS: What would concern me
4 about going to the full Committee with this is that
5 you have this analysis, it looks important enough that
6 it would have to be examined very carefully and
7 critically. We'd have to probably have some written
8 material we could study. And this would be --
9 certainly it would have to occur at the Subcommittee
10 level. We couldn't expect the full Committee to
11 digest new technical material which they hadn't had a
12 chance, no one had a chance to fully critique.
13 So I wonder if we should go to the full
14 Committee with something like that?
15 MR. MITCHELL: I guess it is important to
16 note that this is not a Waterford issue, that it is a
17 generic issue that we will be pursuing pushing to
18 resolution.
19 CHAIRMAN WALLIS: You may have created a
20 generic issue, yes.
21 MR. CLEARY: I believe the staff has
22 recognized that it is a generic issue and the draft
23 SER talks about pursuing it on a generic basis.
24 Albeit this is before Len Ward's consideration of the
25 affect of the void fraction on the mixing volume. But

1 in general, the staff had these issues which they were
2 planning to pursue on a generic basis.
3 MR. SIEBER: Well, it's not particularly
4 helpful for Entergy or any applicant to believe that
5 an issue becomes a generic issue and therefore they
6 should get their application approved because this
7 issue moved to some other category. And it could well
8 be that the applicant would want to move rapidly to
9 resolve it, at least in their case, so that the EPU
10 would move forward. You know, just making it a
11 generic issue doesn't help.
12 MR. CLEARY: I could expand on it a bit
13 more, the type of work we can do within the two week
14 time frame.
15 MR. SIEBER: When you get to the end of
16 the two week time frame, you're going to have a
17 calculation that's probably not been reviewed, is not
18 QA, not part of the application, not reviewed and
19 reviewed by the staff, not a part of the SER. And I'm
20 not sure how we can deal with that. I mean, there's
21 more that has to be done than I think is possible to
22 do in two weeks.
23 MR. RULAND: Clearly, Jack, at this stage,
24 you know, I think the staff needs an opportunity to go
25 back and talk to the applicant, talk to our management

1 and get back to you very rapidly about what we see as
2 our approach out of this problem.
3 MR. SIEBER: Promptly.
4 MR. RULAND: And promptly. Yes, sir.
5 MR. SIEBER: I'm not saying that anybody
6 did anything wrong. I congratulate both the staff and
7 the applicant for reaching the point that they've
8 reached. It's just that I think that we need to
9 resolve it and document it to a greater detail than
10 you can do in two weeks.
11 CHAIRMAN WALLIS: I think really from my
12 point of view, the desirable process would be for you
13 folks and the staff to work hard on this and come back
14 to the Subcommittee.
15 MR. SIEBER: Yes.
16 CHAIRMAN WALLIS: And when we're
17 satisfied, we can say it's ready to go to the full
18 Committee.
19 MR. SIEBER: right.
20 CHAIRMAN WALLIS: I don't see that
21 happening between now and February 10th. This will
22 upset the management that wants to get something out
23 of the way of the ACRS by the February meeting, but I
24 don't quite see how we're going to do that. That's
25 the feeling I have. Maybe my colleagues have a

1 different feeling about it.

2 MR. SIEBER: I agree.

3 MR. ROSEN: Are we on the record still.

4 CHAIRMAN WALLIS: We're still on the

5 record. We can go off the record, if you like.

6 We stayed on the record because we were

7 getting input from the applicant. If we have ceased

8 getting input from the applicant and the staff, then

9 I think we should go off the record and discuss among

10 ourselves.

11 Are we really ready to go off the record

12 now? In that case, I'll thank everybody who has

13 contributed to it. Thanks very much.

14 And go off the record.

15 (Whereupon, at 5:36 p.m. the Subcommittee

16 was adjourned.)

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CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards Thermal Hydraulic Phenomena Subcommittee Meeting

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Rebecca Davis

Rebecca Davis
Official Reporter
Neal R. Gross & Co., Inc.