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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

May 4, 2006

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on May 4, 2006, 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.

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

532nd MEETING

+ + + + +

Thursday, May 4, 2006

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The meeting came to order at 8:30 in room T2B3
of 2 White Flint North, Rockville, MD, Dana A. Powers,
Chairman, presiding.

PRESENT:

GRAHAM WALLIS	CHAIRMAN
WILLIAM J. SHACK	VICE CHAIRMAN
GEORGE E. APOSTOLAKIS	MEMBER
J. SAM ARMIJO	MEMBER
MARIO V. BONACA	MEMBER
RICHARD DENNING	MEMBER
THOMAS S. KRESS	MEMBER
OTTO C. MAYNARD	MEMBER
DANA A. POWERS	MEMBER
JOHN D. SIEBER	MEMBER AT LARGE
JOHN LARKINS	DESIGNATED FEDERAL OFFICIAL

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Adjourn	

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M-O-R-N-I-N-G S-E-S-S-I-O-N

8:30 a.m.

CHAIRMAN WALLIS: On the record. The meeting will now come to order. This is the first day of the 532nd Meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following: the Final Review of the License Renewal Application for the Brunswick Steam Electric Plant; the Final Review of the Extended Power Uprate Application for R.E. Ginna Nuclear Plant; the Final Review of the Extended Power Uprate Application for the Beaver Valley Nuclear Plant; Proposed Revisions to 10 CFR Part 52 "License, Certifications and Approvals for Nuclear Power Plants;" and the Preparation of ACRS Reports.

I would like to remind the members that we have several reports to write, so do not leave until we have finished writing them on Friday.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Dr. John T. Larkins is the Designated Federal Official for the initial portion of the meeting. We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions.

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1 A transcript of portions of the meeting is
2 being kept and it is requested that the speakers use
3 one of the microphones, identify themselves and speak
4 with sufficient clarity and volume so that they can be
5 readily heard. I would now like to turn to the first
6 item on the agenda and I invite my colleague, Jack
7 Sieber, to get us started. Jack.

8 MEMBER SIEBER: Thank you, Mr. Chairman.
9 The first item on the agenda, of course, is the Final
10 Review of the License Renewal Application for the
11 Brunswick Steam Electric Plant and I would like to
12 call on Louise Lund of NRR to introduce the speakers
13 and to move forward with the presentation.

14 MS. LUND: Thank you very much and good
15 morning. For the record, I am Louise Lund. I'm the
16 Chief for the License Rule Branch A of the Division of
17 License Renewal and I'm going to introducing Sikhindra
18 Mitra and also Maurice Heath who will be making the
19 presentations this morning to you and the staff has
20 completed the final safety evaluation of the Brunswick
21 Steam Electric Plant, Units 1 and 2, the license
22 renewal application and we will be giving a
23 presentation today with the assistance of the support
24 of the staff and also we have, I understand, Coudle
25 Julian from the region that's on the speaker phone

1 this morning. Coudle Julian was the Inspector Team
2 Leader at Region 2.

3 MEMBER SIEBER: Yes. Why don't we see?
4 Coudle, are you there?

5 MR. JULIAN: Yes, I am. Good morning.

6 MEMBER SIEBER: Welcome and good morning.

7 MR. JULIAN: Thank you.

8 MS. LUND: Okay. And also we have the
9 support of the License Renewal Branch C who is
10 responsible for the audit activities for this project.
11 We received the license renewal application October of
12 '04 and there was a draft safety evaluation issued in
13 January of '06 and the final safety evaluation was
14 issued in March '06. And with that, I will turn it to
15 S.K.

16 MR. MITRA: I am S.K. Mitra. I'm the
17 Project Manager for Brunswick Steam Electric Plant,
18 Unit 1 and 2. But first, a presentation will be done
19 by the Carolina Power and Light and Mike Heath is my
20 counterpart in CP&L. Thank you.

21 MR. HEATH: Good morning. I am Mike Heath
22 and we're here to talk about the Brunswick Steam
23 Electric Plant license renewal application. The
24 agenda is as we have shown here. We're going to give
25 you a short overview of the application itself. We've

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1 been asked to discuss specifically in terms of
2 operating experience our drywell liner and vibrations
3 associated with power uprate. We'll be discussing our
4 major equipment replacements and repairs, discussing
5 exceptions to GALL and then we'll be discussing our
6 commitment process.

7 The Brunswick Steam Electric Plant is
8 located in Southport, North Carolina which about 30
9 miles south of Wilmington at the mouth of the Cape
10 Fear River. The Cape Fear River is our ultimate heat
11 sink for the plant. We are a dual unit, GE BWR 4 with
12 a Mark 1 reinforced concrete containment. That
13 containment is unique in the industry and Mr. Overton
14 will discussing that in more detail in just a moment.
15 Both units have achieved 120 percent power uprate.

16 CHAIRMAN WALLIS: Usually we refer to the
17 power uprate as being the change. So this would
18 normally be called a 20 percent power uprate.

19 MR. HEATH: Yes sir.

20 CHAIRMAN WALLIS: Okay. Otherwise, it's
21 remarkable.

22 MR. HEATH: It is a remarkable plant. Our
23 current license expiration for Unit 1 is September of
24 2016 and for Unit 2 is December of 2014. This
25 application was prepared using the Class of 2003

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1 format. The information in our application was
2 developed using our plant calculations. We used the
3 plant calculations so that our process would confirm
4 with our plant Appendix B's Quality Assurance Program.
5 The application address all the ISGs 1 through 20. We
6 identified 34 aging programs and the SER when issued
7 in December had no open items and no confirmatory
8 items.

9 Mr. Overton will discuss our drywell liner
10 operating experience.

11 MR. OVERTON: Good morning. My name is
12 Tom Overton. I'm the Lead License Renewal Civil
13 Engineer for the Brunswick plant and I will be
14 presenting a brief overview of our containment design
15 and our operating experience.

16 The Brunswick containment is unique in the
17 industry. It's the only Mark 1, steel lined
18 reinforced concrete containment. We have no annular
19 space between the metallic liner and the reinforced
20 concrete. Our concrete is poured flush with the liner
21 and as such, we have no sand pockets, no sand bed
22 regions.

23 This is the overview of our containment
24 structure. Our liner on this side is backed by six
25 feet of reinforced concrete for the majority of the

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1 structure and in the upper reaches, it's four feet of
2 concrete. The liner and the concrete work in
3 conjunction to provide an impervious barrier, a
4 pressure boundary. The liner and the concrete work
5 together to perform or provide the pressure boundary.

6 The upper areas of the drywell, I'm going
7 to focus on that a little bit because I wanted to talk
8 about the bellows region. There's been a lot of
9 discussion with the bellows and I wanted to explain
10 how our bellows region is designed and the bellows
11 region is in this area right here and it goes and
12 attaches to the vessel. (Indicating.)

13 This is a blown-up picture of the bellows
14 area. The reactor vessel is right here. The reactor
15 building is right here. (Indicating.) This area
16 above would be flooded during a refuel operation. The
17 head would be removed and there would be water in this
18 area right here, demineralized water.

19 If we had a leakage of our refueling
20 bellows which are these bellows right here, the water
21 would go into the reactor building. It would not go
22 behind the liner. As you can see from this picture,
23 the concrete is flush with the liner and it would have
24 to pass through this metal plate to get behind the
25 liner which we inspect. This is part of our IWE

1 program. So these components are inspected.

2 MEMBER SIEBER: Is there any opportunity
3 under any circumstance for water to get between the
4 concrete and the liner?

5 MR. OVERTON: No.

6 MEMBER SIEBER: Do you have any evidence
7 through your in-service inspections that that has
8 occurred?

9 MR. OVERTON: No, we do not. In the next
10 slide, I'll talk about our operating experience right
11 now. We've had -- I'll talk about three events we've
12 had. In 1993, we had some corrosion at the liner
13 concrete interface right here. (Indicating.) This is
14 where our moisture barrier is located. In 1993, we
15 had corrosion along the perimeter of that interface.
16 We removed the moisture barrier, excavated the
17 concrete in that area, cleaned, repaired the liner
18 where required, recoated, placed the concrete back and
19 put an enhanced moisture barrier in and this moisture
20 barrier is a high density silicon elastomer and it's
21 actually shaped to direct the water away from the
22 liner. So we've had no more problems in this area
23 right here.

24 In 1999, we had three through-wall events
25 of our containment liner. One event was associated

1 with some foreign material that was behind the liner.
2 It created a bulge in the liner and the inspectors
3 identified it and it was a through-wall event. The
4 other two were events from corrosion from inside the
5 containment going through the liner back towards the
6 concrete.

7 In all three events, they did a local leak
8 rate test to determine whether we had containment
9 integrity and in all three cases, we were still
10 acceptable for our L_a limits for containment
11 integrity. So we didn't lose containment integrity in
12 any of those cases and in fact, in one of those cases
13 the inspectors had actually opened the hole up,
14 probed, removed corrosion before we did our tests. It
15 was in a much worst case situation.

16 MEMBER SIEBER: Now the liner itself is
17 carbon steel.

18 MR. OVERTON: It's a carbon steel liner
19 5/16th of an inch thick through the majority of the
20 containment. The penetrations in the torque, it's
21 3/8th of an inch thick.

22 MEMBER SIEBER: What kind, if any,
23 protective coating is there on the liner?

24 MR. OVERTON: We have a Class 1 coating on
25 the liner.

1 MEMBER SIEBER: Paint.

2 MR. OVERTON: Yes, it's paint.

3 MEMBER SIEBER: Both sides or just on the
4 inside.

5 MR. OVERTON: Just on the inside.

6 MEMBER SIEBER: And so there is no
7 protective coating on the concrete side.

8 MR. OVERTON: Well, the concrete is
9 effectively the protective coating. Highly alkaline
10 concrete will provide the protection. As a result of
11 these events, we've enhanced our IWE program. We've
12 included the inspection of bulges in the program and
13 now when the IW inspectors do their inspections, if
14 they identify a bulge by procedure, they're required
15 to grid the area and perform ultrasonic testing,
16 thickness measurements in the area.

17 Those results are attached to the
18 inspection report and sent to the IWR responsible
19 engineer and he'll review it and determine whether
20 there's an issue with this particular case. They also
21 included or enhanced the criteria to look for
22 inclusions in the paint which is basically blisters
23 and that's what we attributed to the two through-walls
24 from the containment side to the concrete side. So
25 they look for these blisters when they do their inspections.

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1 MEMBER SIEBER: Now the containment like
2 all Mark 1 containment is inerted during operations.

3 MR. OVERTON: Yes, it is inerted.

4 MEMBER SIEBER: Okay.

5 MR. OVERTON: The third event was a
6 bulging of our liner in the personnel access hatch and
7 in this area, it was identified again through the IWE
8 and we identified the bulge. We did the UTs and we
9 found material loss. They did weld overlays, repaired
10 these areas.

11 And they looked in the other areas where
12 this had occurred and we attributed it to a failed
13 EPDM wrapping around the barrel of the penetration.
14 They believe there was a tear in the coating that
15 allowed moisture into it and it just through the years
16 began to corrode and bulge the liner out in those
17 areas. Those are three main events.

18 CHAIRMAN WALLIS: I don't understand the
19 bulge. The bulge is presumably pushed from behind.

20 MR. OVERTON: That is correct.

21 CHAIRMAN WALLIS: So it's just the rust
22 which is pushing it.

23 MR. OVERTON: Yes. The corrosion
24 products.

25 CHAIRMAN WALLIS: A lot of rust to have a

1 noticeable bulge.

2 MR. OVERTON: There's a lot more volume of
3 rust than there is the original material and --

4 CHAIRMAN WALLIS: The bulge presumably is
5 how big? A inch or something? How much does it stick
6 out?

7 MR. MITRA: This is S.K. Mitra. Can you
8 show -- You have some pictures of the bulge. Can you
9 show how the bulge looks like?

10 MR. OVERTON: We do have a slide that
11 shows --

12 CHAIRMAN WALLIS: If you're going to see
13 a bulge, it has to be somewhat prominent presumably.

14 MR. OVERTON: You csn see -- The way the
15 inspectors look for them, they look for them like they
16 look for defects in drywall at your home. They put a
17 flashlight against the wall and they look for shadows.

18 CHAIRMAN WALLIS: Look for anything, yes.

19 MR. OVERTON: And if they see shadows.
20 Now here, there's a bulge right here.

21 CHAIRMAN WALLIS: Yes, it looks like a big
22 bulge.

23 MR. OVERTON: Yes, it's pronounced. It's
24 pronounced and a little bit here.

25 CHAIRMAN WALLIS: There are really bulgy

1 areas there.

2 MR. OVERTON: Yes.

3 CHAIRMAN WALLIS: Might not look at this
4 too long.

5 MEMBER SIEBER: You might have to shut
6 down.

7 MR. OVERTON: That being the case, let's
8 go to the gridded area. I have a slide. The next --
9 There we go and this is the same bulge where we had
10 cleaned the liner. We gridded it, did ultrasonic
11 thickness measures and I think in a couple of cases we
12 did some weld overlays to enhance the thickness.

13 VICE CHAIRMAN SHACK: How thin was it?

14 CHAIRMAN WALLIS: Well, see. His finger's
15 underneath the level there. So it's presumably at
16 least as thick, as big, as his finger.

17 MR. OVERTON: I'm not exactly certain how
18 much material was loss.

19 CHAIRMAN WALLIS: Your finger underneath
20 that. Right? So is it a half inch bulge sticking
21 out?

22 MR. OVERTON: Probably. I don't know.
23 They're not required to measure the depth of the
24 bulge. They are required to do ultrasonic to
25 determine the depth of the material, but I'm not sure

1 how high the bulge is.

2 MEMBER DENNING: What are we actually
3 seeing here? What are the black marks in this grid?

4 MR. OVERTON: The black dots are the grid.
5 When they identify a bulge, the inspectors will grid
6 the area.

7 MEMBER DENNING: I see. So they put those
8 in there.

9 MR. OVERTON: Yes, and then they'll do
10 ultrasonic thickness measures in each of these grids
11 and then these grids will be mapped on the inspector
12 report and it will be sent to the responsible engineer
13 to evaluate. In the last IWE inspection which was a
14 month ago, they identified, I believe, eight bulges in
15 the lower area of the containment. They did the
16 gridding. They performed ultrasonic thickness
17 measurements and they found there was no material loss
18 on any of these areas.

19 MEMBER ARMIJO: What's the mechanism
20 that's causing these bulges? Water must be getting
21 behind the paint and why would that happen?

22 MR. OVERTON: In these cases, these bulges
23 were not caused by water. They were from original
24 construction and that's what they were attributed to.
25 When we did the ultrasonic measurements, no material

1 loss was found there. In these bulges, we believe
2 there was water from original construction that had
3 caused the corrosion process to begin. That was many
4 years ago and it's just been a slow process that
5 allowed it to reach this point.

6 MEMBER BONACA: You said before that on
7 the bottom you had corrosion that you had to repair.

8 MR. OVERTON: That's correct.

9 MEMBER BONACA: Was that water intrusion
10 that caused the corrosion also from the original
11 construction?

12 MR. OVERTON: That water was on the inside
13 of containment. That wasn't --

14 MEMBER BONACA: Inside. Okay.

15 MR. OVERTON: That wasn't behind the
16 liner.

17 MEMBER POWERS: Could you go again this
18 argument that these bulges are due to original
19 construction?

20 MR. OVERTON: Yes. In the last
21 inspection, we identified bulges in the containment.
22 Those bulges were gridded. Ultrasonic measurements
23 were made. Thickness measurements were made of it.
24 There was no material loss associated with any of
25 those areas. So they have attributed the bulges to

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1 just construction defects.

2 CHAIRMAN WALLIS: Is there a void behind
3 the bulge then?

4 MR. OVERTON: No.

5 CHAIRMAN WALLIS: Or is there containment
6 concrete everywhere?

7 MR. OVERTON: No. It's just the natural
8 of the construction process. We had an effectively
9 thin plate with a lot of concrete pressure against it.
10 It could have been a natural bulge in the material
11 from the weld in the studs in the backside.

12 MEMBER SIEBER: So you should have found
13 them the very first day that plan was reading for
14 operation. Right?

15 MR. OVERTON: And it's possible they saw
16 them then, but the IWR inspections didn't, we didn't
17 start inspecting for bulges until later on in the
18 plant life and most of these things -- We're getting
19 a lot better with the IWE program. They've identified
20 these things in the past, but they haven't kept
21 records of them. Following these events, we started
22 to maintain an accurate record of these, so we won't
23 duplicate a lot of work in the inspection process.

24 MEMBER BONACA: When you go to repair them
25 and you cut them, you find behind rust or it's simply

1 the formation due to the original construction. I'm
2 trying to understand if the mechanism is intrusion of
3 moisture at the time of construction. That stays
4 there and then causes corrosion to develop or if it is
5 a different mechanism.

6 MR. OVERTON: What we found in the areas
7 where we have removed the liner, it's been a dry
8 powdery, what we've classified as inactive corrosion.
9 The concrete has been fine. There is no staining on
10 the concrete and they've identified no radioactive
11 particles or anything that would have indicated that
12 water transgressed from the fuel pool down to those
13 areas.

14 MEMBER SIEBER: Well, it would seem to me
15 that if you are classing these bulges as inactive
16 corrosion.

17 MR. OVERTON: No, we were classing them as
18 original construction.

19 MEMBER SIEBER: Okay. That means that if
20 you find a new one, that argument is not longer valid
21 if you find a new bulge that you haven't previously
22 identified.

23 MR. OVERTON: And that's why we do
24 ultrasonic measurements. If we identify a new bulge
25 it's possible that it just wasn't identified in a

1 previous inspection. So we would do --

2 MEMBER SIEBER: Or it may have grown.

3 MR. OVERTON: Exactly.

4 MEMBER SIEBER: And in fact if it did
5 grow, that means you have active corrosion or some
6 active mechanism going on that deserves your
7 attention.

8 MR. OVERTON: And our process would
9 identify that. We would do our ultrasonic
10 measurements and if there was material loss, then we
11 would take the appropriate action.

12 MEMBER MAYNARD: I'm hearing two or three
13 different examples here that we may be getting
14 confused. One, you have some bulges from original
15 construction. Those there is no void behind that.
16 There's no corrosion behind those. So those are still
17 attached or in contact with the concrete.

18 MR. OVERTON: That's correct.

19 MEMBER MAYNARD: You have some others that
20 was some corrosion from inside the containment that
21 started and that you do have a few that were corrosion
22 between the liner and the concrete.

23 MR. OVERTON: There were two cases of
24 corrosion from the backside. In one case, there was
25 a foreign object against the liner. It was actually

1 a glove from original construction and it had we
2 believe held enough moisture to create a corrosion
3 process and that created the bulge in the through-
4 wall. In the other case, we believe a tear in the
5 EPDM wrapping around the barrel of the liner in the
6 event allowed moisture in and allowed the corrosion to
7 start, but those two are one of foreign object and the
8 other a construction issue.

9 The majority of the containment liner does
10 not have this wrapping around it. These wrappings
11 were effectively a bond breaker between the barrel and
12 the liners that pass through. The majority of the
13 liner is flush with the concrete.

14 MEMBER SIEBER: Maybe I can ask one last
15 question on this and allow you to move on. When you
16 do the thickness measurements that's a ultrasonic
17 measurement.

18 MR. OVERTON: Yes.

19 MEMBER SIEBER: What's the minimum wall
20 that's acceptable under your code?

21 MR. OVERTON: Well, under IWE, ten percent
22 is normally the level that brings it to attention. We
23 will do a calculation if anything exceeds that.

24 MEMBER SIEBER: And that's based on the
25 nominal thickness of --

1 MR. OVERTON: Of the 560.

2 MEMBER SIEBER: -- the liner as installed.

3 MR. OVERTON: Yes, that's correct.

4 MEMBER SIEBER: Okay.

5 VICE CHAIRMAN SHACK: I have one. When
6 you find an event, does that change the frequency of
7 your subsequent inspections?

8 MR. OVERTON: Yes, it does and it depends
9 on how the event was evaluated. If we find an issue,
10 say these bulges that we identified in a previous
11 inspection and we check the thickness and they were
12 found to have no material loss, the frequency of those
13 would not change. If we found one where we actually
14 had corrosion where we were experiencing degradation,
15 that would go into an augmented program under IWE and
16 augmented inspections would be performed in those
17 areas.

18 VICE CHAIRMAN SHACK: Just locally then?

19 MR. OVERTON: Yes.

20 VICE CHAIRMAN SHACK: How about an area
21 expansion? If you find something in one place, do you
22 look harder elsewhere?

23 MR. OVERTON: Certainly, and the case with
24 the personnel access hatch, when we found the bulges
25 in these areas, we looked at other areas that we had

1 wrapped with this felt EPDM wrapping to see if we had
2 some bulges in those areas.

3 VICE CHAIRMAN SHACK: Now is it mandated
4 that you do that or you just did it?

5 MR. OVERTON: I'm not sure that it's --
6 That is exactly how we would handle the process. I'm
7 not sure that there is a requirement to expand it.

8 MEMBER BONACA: When you expand it, you
9 expand it visually just to look for bulges or do you
10 expand the UT?

11 MR. OVERTON: We would expand it logically
12 based on the circumstances of the event we found. In
13 the case of the wrapping material, we looked at all
14 materials that had the wrapping material. In the case
15 of the inclusions in the paint where we created a
16 through-wall, we started looking more actively for
17 these inclusions in the paint.

18 MEMBER MAYNARD: I would assume that your
19 overall corrective action program requires you
20 whenever you find a problem, part of the evaluation,
21 is any generic implications or do you need to go look
22 at other places whether it be for this or for other
23 things?

24 MR. OVERTON: That's correct and it also
25 forces us to look at the other unit too to see if we

1 had and in fact, that's what we did with these. Our
2 corrective action process basically drove us to
3 inspect the other areas in the other unit for the same
4 issues.

5 MEMBER SIEBER: I would point out that the
6 process of getting liner bulges is not unique to this
7 plant. Large dry containments that have a steel or a
8 liner particularly in the subatmospheric containments
9 where you put a vacuum in there and try to suck the
10 liner off the concrete and you can actually do it,
11 there has been in a lot of those containments bulges
12 like this and not necessarily indicative of corrosion,
13 just a phenomenon that occurs. So even though the
14 containment is unique for a BWR, the process is not
15 unique.

16 MEMBER BONACA: But the bottom -

17 CHAIRMAN WALLIS: But you can get a big
18 bulge.

19 MEMBER SIEBER: Yes.

20 MEMBER BONACA: But the bottom line for
21 license renewal is what's your plan.

22 MR. OVERTON: We will be managing our
23 liner with the IWE in Appendix J programs. We've
24 committed to that through the period of extended
25 operation.

1 MEMBER SIEBER: Maybe we can move on
2 because we're --

3 MEMBER POWERS: I'll help you get a little
4 farther behind time here.

5 MR. OVERTON: Okay.

6 MEMBER POWERS: You've discussed the
7 bellows up at the top. Do you have a bellows on your
8 downcomers into your suppression pool?

9 MR. OVERTON: Yes.

10 MEMBER POWERS: And how do they look?

11 MR. OVERTON: They haven't been -- There's
12 a liner. They are not inspected typically -- They are
13 in our IWE program, but we've just completed an ILRT
14 which effectively inspects them. It provides a
15 pressure boundary check and they are fine based on our
16 ILRT.

17 MEMBER POWERS: That means that you
18 pressurized them and they didn't vent.

19 MR. OVERTON: And they didn't leak, yes.

20 MEMBER POWERS: That doesn't mean they're
21 corroding.

22 MR. OVERTON: Right.

23 MEMBER POWERS: Do you think they are
24 corroding?

25 MR. OVERTON: I do not believe they are

1 corroding.

2 MEMBER POWERS: Can you imagine that
3 they're not?

4 MR. OVERTON: Well, they're in a dry,
5 inerted environment and they're made from stainless
6 steel. So based on our understanding of aging effects
7 associated with that material in that environment, we
8 do not believe there's corrosion.

9 MEMBER POWERS: Faith is a wonderful
10 thing. Confirmation would be useful.

11 MR. HEATH: Any other questions?

12 MR. OVERTON: All right. I'd like to turn
13 this over to Mr. Mark Grantham for discussing
14 vibration of extended power uprate.

15 MR. GRANTHAM: Good morning. I'm Mark
16 Grantham. I'm the Superintendent of Design
17 Engineering. I'll be discussing our vibration
18 experience associated with our extended power uprate.
19 I'll also be going over some of the major equipment
20 replacements and refurbishments that we've done over
21 the last few years.

22 Part of EPU we did instrumented vibration
23 monitoring on our main steam and feedwater piping,
24 particularly in the inaccessible areas of our drywell
25 and MSIV pit. We were monitoring main steam and

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1 feedwater because there was roughly a 15 percent
2 increase in flows associated with that. This
3 monitoring was conducted in accordance with Part 3 of
4 the ASME Operation and Maintenance Code which covers
5 pre-op and start up vibration testing.

6 To determine where we monitored, we did do
7 a modal analysis of the piping to determine sensorial
8 locations. We used accelerometers at those locations.
9 We did observe an increase in the vibration levels in
10 that piping with increasing flows and increasing
11 power. But the vibration levels were maintained well
12 below the allowable stresses.

13 We looked at essentially a case study here
14 for main steam piping and this was the worst case we
15 saw. At a particular location, the max vibration, and
16 this is at a 420 power, was only 15.5 percent of the
17 Code allowable for steady state vibration stress and
18 again this is the worst case.

19 CHAIRMAN WALLIS: This is for the piping
20 itself. It's not being used to diagnose what's
21 happening in the dryer or anything like that.

22 MR. GRANTHAM: That is correct.

23 MEMBER SIEBER: What of your inspection
24 results? What are the results for your dryer?

25 MR. GRANTHAM: For steam dryer, we've

1 inspected our dryer essentially all along, I guess,
2 our implementation of uprate. We implemented uprate
3 over two cycles. We just in March had a refueling
4 outage on Unit 1 which was after two full years of
5 operation at 120 percent.

6 The steam dryer inspections revealed no
7 new degradation. We have had some old degradation
8 that's been there for years, IGSEC type degradation,
9 but no new degradation, no crack growth and again, we
10 inspected at the beginning of uprate and every cycle
11 along the way through implementation and again, after
12 a cycle of full uprate, we saw no new degradation.

13 MEMBER SIEBER: Do the Mark 4 dryers for
14 the ones with the slope?

15 MR. GRANTHAM: That is correct. We have
16 the slanted dryer hood arrangement which is if you
17 look at the stresses given a constant loading on the
18 dryer, the dryers that had failed post EPU our stress
19 levels would be roughly a quarter of what those
20 stresses would be in the square hood type dryer.

21 MEMBER SIEBER: That dryer though did have
22 a weakness at the bottom at the right angle weld.

23 MR. GRANTHAM: Correct.

24 MEMBER SIEBER: Have you repaired that?

25 MR. GRANTHAM: We did do modifications to

1 our dryer as part of uprate. The cover plate weld
2 which was the initial failure that occurred at Quad
3 Cities, we did beef-up that weld from 1/4 inch to a
4 3/8ths inch weld. We did add a stiffener to the hood
5 face that came down and joined at the top of the cover
6 plate and we also replaced the tie bars at the top of
7 the dryer which there's been a lot of industry OE with
8 those bars failing as well.

9 MEMBER SIEBER: Is the dryer in scope?

10 MR. GRANTHAM: That is correct. It is in
11 license renewal scope.

12 MEMBER SIEBER: What's your aging
13 management program for the dryer?

14 MR. GRANTHAM: There is a BWR/VIP document
15 that now covers dryer inspections. It's BWR/VIP 139
16 as well as a GE seal which we're implementing which is
17 seal 644 which covers inspections and the general
18 inspections are a baseline inspection. If you do have
19 degradation, monitor the dryer for each outage after
20 you identify any existing flaws to confirm that you're
21 not seeing crack growth and once you establish that,
22 every other refueling outage do an inspection and this
23 is a VT-1 inspection.

24 MEMBER SIEBER: Thank you.

25 MR. GRANTHAM: All right. Moving along to

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1 feedwater piping and this is typical of our feedwater
2 piping. All of the vibration levels were extremely
3 low in feedwater. For this particular case, the
4 vibration was actually about one percent of the
5 allowable stress and again, that's typical of what we
6 saw in feedwater for both our units.

7 MEMBER POWERS: Is there any small
8 diameter piping where I might expect bigger changes?

9 MR. GRANTHAM: Generally, the criteria for
10 small bore piping has been as long as the large bore
11 piping is maintained less than 50 percent of the
12 allowables, you generally don't consider the smaller
13 bore piping. I'm getting ready to talk about it here
14 in a second, but we have had some small bore piping
15 vibration issues primarily with socket weld type
16 joints. There's a lot of industry OE with those type
17 failures. We had OE at Brunswick before extended
18 uprate and we've taken some actions in those areas
19 where we have had failures and were concerned about
20 the vibration.

21 VICE CHAIRMAN SHACK: But you don't
22 actually monitor the locations that have failed.

23 MR. GRANTHAM: That is correct.
24 Continuing, I guess, with that discussion, over on our
25 BOP side and again this piping is really not in the

1 scope of license renewal, we did have a couple of
2 failures on our EHC return lines from our main turbine
3 control valves.

4 We did, as I mentioned before, do uprate
5 in a two step fashion. So after our initial uprate at
6 an intermediate power level, our main control valves
7 were not in their final position, design position. So
8 we did get more movement than you would normally
9 expect at that power level. There is quite of bit of
10 industry OE with failures of this line and again it is
11 a socket weld type connection and we have since
12 modified that piping to get a flexible connection
13 design.

14 As I mentioned we did have a number of
15 failures on socket weld type joints. This was
16 primarily around our feedwater heaters. Again, we've
17 had a lot of previous operating experience prior to
18 uprate. We did go in to susceptible locations and
19 change the joint design for that socket weld to a more
20 fatigue tolerant configuration.

21 We also went through and did pretty
22 extensive walkdowns on our BOP piping at all power
23 levels up to 120 percent as part of uprate. We did
24 identify a couple of BOP lines, on extraction steam
25 line and a small bore main steam line that or main

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1 steam drain, excuse me, that were exhibiting some very
2 low frequency vibration, low frequency movement. All
3 of that piping was rod-hung piping. There was no
4 lateral support and we did go in and add lateral
5 supports to those.

6 MEMBER MAYNARD: What has the feedback
7 been from the operators, if any, in their plant
8 walkdowns? Do they hear more noise in some of these
9 areas or have they identified any areas you've had to
10 go look at?

11 MR. GRANTHAM: None that I can recall and
12 again, following the uprate we went through a pretty
13 extensive test program and we had hold points at the
14 various power levels as we went up and we had
15 engineering walkdowns, operation walkdowns and we had
16 management review at each of those hold points. So
17 nothing out of the ordinary was reported or observed.

18 VICE CHAIRMAN SHACK: Is your FAC
19 experience after the uprate consistent with what you
20 would expected from the uprate?

21 MR. GRANTHAM: I'll be quite honest.
22 We're still developing that. We got data following
23 this past outage which we had one year of operation.
24 The data did not show anything out of the ordinary,
25 but I'm not sure just a two year operating cycle is

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1 enough really to completely get a good idea of what
2 you're seeing. But we are monitoring it. It is very
3 much an inspection based program. We rely heavily on
4 inspections and less on predictions from our check-
5 works models. Any other questions on vibration before
6 I move on?

7 All right. Next we're looking at major
8 equipment replacement and repairs. Again, this is
9 over really about the last four years. Some of these
10 were related to uprates. Some were not. We have
11 replaced our power range neutron monitoring system,
12 the complete system, replaced our main power
13 transformers, replaced our high pressure turbines. We
14 reround our main generator statters. We've replaced
15 six feedwater heaters, five on Unit 1, one of Unit 2.
16 We've replaced our reactor feed pump turbine.

17 VICE CHAIRMAN SHACK: Why did you replace
18 those?

19 MR. GRANTHAM: It's primarily tube
20 plugging, looking at the higher flows associated with
21 uprate. We did an assessment of all our feedwater
22 heaters in accordance with the HEI standards as far as
23 flow, pressure drops and some of those heaters we
24 would have replaced even without uprate, the tube
25 plugging. One of them we had, I think it was up on

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1 the order of 18 percent tube plugging. So some of
2 them would have been replaced anyway.

3 VICE CHAIRMAN SHACK: What was the
4 original material?

5 MR. GRANTHAM: I believe it was 410
6 stainless steel. Reactor feed pumps, we installed new
7 governors on our reactor feed pumps as well as
8 replaced the pump rotating assemblies. We replaced
9 our condensate pumps and motors. We completely
10 replaced our isophase bus cooling units and we're
11 currently about halfway through a major project to
12 completely replace our fire detection system, new
13 sensors and everything. Any questions?

14 All right. With that, I'll turn it back
15 over to Mike Heath.

16 MR. HEATH: Thank you. I want to talk now
17 about exceptions to GALL. When we prepared the
18 application, our goal was to comply with GALL in every
19 place that we could. There are some cases where
20 existing programs satisfy our program needs and we'll
21 be discussing a few of those here.

22 For fire protection program, NUREG 1801
23 calls for a visual inspection of ten percent of each
24 type of penetration once every refueling outage. Our
25 existing program at Brunswick has us doing visual

1 inspections of a statistical sample once every 18
2 months.

3 GALL also calls for testing of halon and
4 CO₂ every six months. At Brunswick, we do testing of
5 halon annually and we test CO₂ every 18 months.

6 For fuel oil chemistry, GALL calls for
7 internal --

8 MEMBER POWERS: There must be a rationale
9 for those times.

10 MR. HEATH: That's based on our own
11 operating experience in the plant. Six months. We're
12 talking about the halon and the CO₂.

13 MEMBER POWERS: Right.

14 MR. HEATH: Yes, the halon and CO₂ every
15 six months, we've had no experience that we have any
16 problems in that system and that seems to be a very
17 reasonable time for us.

18 MEMBER POWERS: So it's chosen because
19 it's convenient. I mean if there are no problems
20 might as well do it every five years. Right?

21 MR. HEATH: Well, you try to get the most
22 optimum time period on those. There are some things
23 that you can't even look at because of your outage
24 frequency. This would not be one of those cases. But
25 you're still looking at those things on an optimum

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1 basis. We see no value in doing it less than that and
2 our current operating experience suggests that's a
3 pretty good number.

4 MEMBER POWERS: What was the rationale for
5 the NUREG that called for every six months.

6 MR. HEATH: I don't know that.

7 MEMBER POWERS: It seems extraordinarily
8 frequent.

9 MR. HEATH: I know there's been a good bit
10 of discussion about changing that, but I'm not sure
11 what the rationale was.

12 MEMBER SIEBER: It seems to me that the
13 six month interval was inconsistent with what the fire
14 insurance companies were requiring which was annual
15 tests.

16 MEMBER POWERS: I mean it does -- Six
17 months sounds very, very frequent.

18 MEMBER SIEBER: Yes, especially for halon.
19 Halon, you aren't supposed to be playing with halon.

20 MEMBER POWERS: Well, you could understand
21 for halon just because of the halon corrosion
22 potential that you do have there. But I mean it just
23 sounds enormously frequent.

24 MEMBER SIEBER: Yes.

25 MEMBER POWERS: I mean 18 months doesn't

1 sound an extraordinarily cavalier time either
2 especially if you've had no difficulty there. I'm
3 just wondering what the rationale was and it sounds
4 like in your case it's convenience.

5 MR. HEATH: And it's what we've been doing
6 all along.

7 MEMBER POWERS: Yes. I mean if it's what
8 you're used to, no reason to change it.

9 MR. HEATH: Right.

10 MEMBER SIEBER: Okay.

11 MEMBER BONACA: And what's the basis for
12 the requirement in NUREG 1801? Maybe the staff could
13 comment on that.

14 MR. MITRA: This is SK Mitra. This issue
15 was addressed by the staff and as already remembered,
16 there was an RAI on this and I don't have the staff,
17 the engineer, who did the review, but as far as I
18 remember, this issue is not unique for Brunswick and
19 this being raised and as a matter of fact, there is
20 an, I say, action item to change the six months
21 inspection to 18 months. But I am not quite sure how
22 far that went.

23 MEMBER POWERS: If there's no rationale
24 for six, is there a rationale for 18?

25 MR. MITRA: That's the industrial

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1 standard. That's what most of the plants are doing is
2 18 months.

3 MEMBER BONACA: One of the issues that
4 during the past review of 1801, one of the goals was
5 to reduce or eliminate prescriptiveness which is
6 unnecessary because otherwise you have these kinds of
7 disagreements that are not a disagreement really and
8 maybe that was not implemented.

9 MR. CHAN: This is Keng Chan from License
10 Renewal. The GALL specified an acceptable alternative
11 of addressing those issues. Like six months is
12 acceptable. But GALL does not exclude any applicant
13 using the plant-specific experience or reasoning to
14 deviate from the six months or basis. It tends to be
15 a little conservative, but I cannot answer the
16 question regarding to whether the GALL will be
17 modified to increase.

18 MEMBER BONACA: But if everybody does it
19 every 18 months, assume every plant does it every 18
20 months and it's acceptable.

21 MR. CHAN: Yes.

22 MEMBER BONACA: Why would you have a
23 requirement for six months when you have no basis? I
24 mean you would look at the experience, determine that
25 18 months is appropriate because it doesn't seem to

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1 create a problem and simply modify GALL to reflect 18
2 months. I think otherwise you're going to have
3 exceptions like this which are really not relevant and
4 require additional RAI and every time a discussion of
5 the discrepancy when you don't need that.

6 MR. CHAN: Yes. As I said, I cannot tell
7 you exactly whether we are changing it or when we are
8 changing it. But certainly we include that in our
9 GALL update maintenance program for future
10 considerations.

11 MEMBER KRESS: What would you say if
12 someone wanted to have a 36 month inspection schedule?
13 How would you judge that?

14 MEMBER BONACA: Well, I think the only
15 thing that I can say is that there has been so much
16 operating experience behind these plants and some
17 assume that most of them do it every year or 18 months
18 and that seems to be an appropriate frequency. I
19 think you would just leverage the experience because
20 you have no other basis.

21 MEMBER POWERS: It looks like to me that
22 it's just a completely arbitrary experience.

23 MEMBER ARMIJO: Is there a failure rate
24 for these things built into the fire PRA?

25 MEMBER POWERS: It seems to me that

1 there's just a huge number of these systems operating
2 throughout the United States and surely there is some
3 basis for deciding how often they ought to be
4 inspected or tested or something with that.

5 MEMBER KRESS: It would have to be how
6 often they're inoperable or not functioning properly.

7 MEMBER POWERS: Something to do with their
8 failure mode I would think and any number that comes
9 up -- I don't object to the plant saying we do it
10 every 18 months and they have no difficulty. That's
11 great.

12 MEMBER KRESS: That could give you a
13 basis.

14 MEMBER POWERS: But the staff
15 recommendation for six months seems or 18 months or 36
16 months, any number that's pulled out of the air seems
17 to me just completely capricious and arbitrary and
18 it's going to generate this kind of --

19 MEMBER KRESS: Unless there's a fire PRA
20 with a failure rate built into it and that's based on
21 the 18 month inspection because that's the operating
22 experience.

23 MEMBER APOSTOLAKIS: The same question you
24 can raise about any inspection interval, right, that
25 has been established in other context and that's why

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1 there are risk-informing regulations to try to come up
2 with a more rational way of determining those things.
3 So this is not unique.

4 MEMBER POWERS: No, it is not unique, but
5 it is certainly a good example.

6 MEMBER APOSTOLAKIS: Yes.

7 MEMBER KRESS: George, so long as the
8 failure rates you build into the PRA are consistent
9 with the inspection period, wouldn't that be
10 sufficient unless these things dominate some.

11 MEMBER APOSTOLAKIS: Or you could go the
12 other way. You determine the inspection frequency
13 from the PRA calculation.

14 MEMBER KRESS: That's hard because you
15 have to link inspection frequency to failure rate.

16 MEMBER APOSTOLAKIS: Right.

17 MEMBER KRESS: And you don't have that
18 database.

19 MEMBER POWERS: It don't see why you can't
20 get it, Tom.

21 MEMBER APOSTOLAKIS: They do.

22 MEMBER POWERS: I don't see why you can't
23 get it. This is --

24 MEMBER KRESS: It may be possible, but it
25 seems to me like the consistency argument is a lot

1 easier to come by.

2 MEMBER POWERS: I can understand why you
3 would have the consistency argument, but you have a
4 bit of "the chicken and the egg" problem here.

5 MEMBER KRESS: Oh, yeah.

6 MEMBER POWERS: Is like George says. This
7 is a system where you would like to use the PRA to
8 tell you how often to inspect something.

9 MR. KUO: This is PT Kuo. I believe this
10 fire protection issue was an IC topic. We have an
11 issue in IC and I'm not totally sure if this is the
12 requirement of NAPPA (PH) and we are going to take a
13 look into that. There has to be some basis. I don't
14 think the staff will make a requirement without a
15 basis, but I'm not sure whether this is a NAPPA
16 requirement or not. But it was in IC.

17 MEMBER SIEBER: Okay.

18 MR. HEATH: Okay. The other exception we
19 had involved internal surface inspections for main
20 fuel oil tanks. We have committed to doing internal
21 surface inspection for our main oil fuel tank. That's
22 the only fuel oil tank we have that's accessible to
23 the internal surfaces. When we do that inspection if
24 we need to, we'll clean the tank as well. Our smaller
25 tanks we've committed to doing UTs at that bottoms of

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1 those tanks from the outside.

2 MEMBER SIEBER: I take it an example of a
3 smaller tank would be like the day tank on these.

4 MR. HEATH: It would be the day tanks.
5 Yes.

6 MEMBER SIEBER: Okay, and these just sit
7 in the air.

8 MR. HEATH: They sit up in the air and the
9 bottoms are accessible for us.

10 MEMBER SIEBER: Okay.

11 MR. HEATH: We move on then to commitment
12 tracking. We commit, we do, our tracking for license
13 renewal commitments the same way we do our tracking
14 for all other commitments at Brunswick and that's
15 using our corrective action program. The one
16 exception we have for license renewal commitments is
17 that we've developed an implementation plan for each
18 of those and that implementation plan then identifies
19 everything that we have to do to implement that
20 commitment.

21 All those actions, if it's a procedure
22 change or the writing of a PMR or a work ticket, are
23 tied back then to that commitment through the
24 corrective action program. Each of those actions has
25 an owner and each one of them has a date for

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1 completion.

2 We also are in the process of developing
3 a license renewal program procedure. That procedure
4 then lists all those individual activities. So it
5 lists each commitment and all the procedures and PMS
6 and work tickets and other action items associated
7 with it and we'll do periodic assessments of that
8 procedure to assure that all of those activities are
9 being completed in a timely manner and are still
10 effective.

11 We are currently planning to complete all
12 those document updates that we can this year. We
13 expect to complete most of them prior to the end of
14 this year. Any questions on commitment?

15 If there are no further questions, I would
16 like to conclude just a few comments on the review
17 auto process. At Brunswick, we found that to be very
18 effective. It was to our advantage to have staff
19 onsite early in this process. We came to learn what
20 the problems and concerns were and we were able to
21 identify those very early in the process and we think
22 that contributed directly to the SER coming out with
23 no open items and no confirmatory items. Are there
24 any other questions for us?

25 MEMBER SIEBER: Yes, I do have a question.

1 MR. HEATH: Yes sir.

2 MEMBER SIEBER: When I read the
3 application and the SER and look at the NRC's website,
4 I hear different names for your company and I'd like
5 to know who is, what is the name of the entity that
6 holds the license. Is it Carolina Power and Light or
7 Progress Energy Carolina or what?

8 MR. HEATH: I'll Lenny Beller, our
9 Licensing Supervisor, to give you the complete and
10 true answer on that.

11 MEMBER SIEBER: You could just whisper it
12 to me if you'd like.

13 MR. BELLER: Good morning. My name is
14 Lenny Beller. I'm the Licensing Supervisor. Carolina
15 Power and Light is the holder of the license.
16 Progress Energy is the parent company. But Carolina
17 Power and Light is the entity that owns that license.

18 MEMBER SIEBER: Okay. Thank you and Tanny
19 was right. Okay/

20 MR. HEATH: Any other questions? Thank
21 you.

22 (Discussion off the microphone.)

23 MS. LUND: Okay. At this time, we're
24 going to do the staff's presentation and it's going to
25 be SK Mitra and Maurice Heath that are going to be

1 making the presentation for the staff.

2 CHAIRMAN WALLIS: You're not related to
3 the other Heath? There's a Heath on the other side,
4 too, isn't there?

5 MR. MITRA: Good morning. I'm SK Mitra.
6 I'm the Project Manager for the Brunswick Steam
7 Electric Plant Units 1 and 2 license renewal
8 application. To my right, Mr. Maurice Heath, Project
9 Manager, who helped me to prepare and issue the SER
10 report and from now on I think he will be the project
11 manager because I am going and working on some other
12 projects.

13 As we mentioned before, Mr. Coudle Julian
14 is on the telephone line. He's listening to us and if
15 you have any question on inspection, he will be glad
16 to answer that. Also present in the audience are the
17 technical reviewers, most of them. I could find my
18 fire protection engineer there, but most of them are
19 there who contributed to the ACRS to answer any
20 questions regarding the evaluation.

21 This is what we'll cover in this
22 presentation. I will just skip this because already
23 the Applicant had gone through that. So go to the
24 next slide. Each unit generates 2923 megawatt thermal
25 which is about 1007 megawatt electric. That includes

1 20 percent extended power uprate. The NRC approved
2 five percent power uprate in 1996 and an additional 15
3 percent on May 2002 and steam dryers by the way are
4 within the scope of license renewal.

5 The second bullet, the Applicant committed
6 to review plant and industry operating experience
7 relevant to aging effect caused by operation at power
8 uprate. The revelations will be submitted to NRC
9 review one year prior to the period of extended
10 operation. This is a direct result of the commitment
11 made in response to SER letter of September 16, 2004,
12 on license renewal application on Dresden and Quad
13 Cities.

14 The SER was issued on December 20, 2005
15 and as the Applicant said, there was no open-end
16 confirmatory items and also I acknowledge that the
17 staff's audits and inspections helped us resolve a lot
18 of issues and we issued the final SER on March 31,
19 2006. And it's the usual 3 license condition we have
20 that the FSER update following the issuance of renewed
21 license and commitment completed in accordance with
22 the schedule and the third one is the reactor vessel
23 service (PH) program and implement staff approved
24 BWR/VIP into the vessel service (PH) program and
25 obtain the NRC staff review and approval for any

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1 changes to the schedule.

2 CHAIRMAN WALLIS: There are no conditions
3 on the liner for the containment.

4 MR. MITRA: No.

5 CHAIRMAN WALLIS: You are satisfied about
6 the bulges and all that.

7 MR. MITRA: The staff is satisfied with
8 the bulges and all that. And these are the few items,
9 the components, that bring into the scope and subject
10 to MR was switchyard breakers. You know these are the
11 result of the review. Service order intake structure
12 fan, dampers and condensate storage tank piping
13 created for SBO station blackout.

14 This is the first time on Brunswick
15 license renewal review the staff has used the balance
16 of plant scoping review for two-tier process. The
17 staff presented this concept to SES (PH) full
18 committee on March 4, 2005 and explained the review
19 process at that time and essentially the two-tier
20 process, the Tier 1 is the screened review of the
21 license renewal application FSAR and identify system
22 for inspection.

23 Tier 2 review is slightly more detailed
24 than Tier 1 review. Tier 2 review concerns the review
25 of boundary drawings, other licensing basis documents

1 in addition to the application and FSAR. Typically,
2 the other licensing basis documents including plant
3 specific licensing action like relief request, etc.

4 And two-tiered scoping will be based on
5 screening criteria, mainly safety importance and risk
6 significance. Systems susceptible to common cause
7 failure, operating experience indicating likely
8 passive failures and previous LRA experience of
9 omissions and all electrical system and structure
10 continue to have Tier 2 review.

11 And groundwater environment is all under
12 the limit and this groundwater monitoring is done at
13 a frequency of annually. I think the next few slides
14 will be done by Maurice.

15 MR. MAURICE HEATH: Yes. Good morning.
16 Like SK said, my name is Maurice Heath, Project
17 Manager also with him on this project. What I want to
18 go over is just a brief highlight of a couple changes
19 or additions, not changes, additions, to the SER from
20 the first SER to the final SER.

21 The first highlight I want to go over
22 deals with Commitment No. 22 and that is with Reactor
23 Vessel Internal Structure Integrity Program and we
24 added -- There was additional information added to the
25 commitment based on top guide inspection and what we

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1 want to do is just lay out the same information that
2 was written in the SER and put in the commitment as
3 well so that it's a clear understanding of our sample
4 size and our inspection frequency.

5 The next one I would like to go over would
6 be the Applicant already did with Mark 1 steel lined
7 reinforced concrete containment. The Applicant
8 credits the Section 11 IWE along with the Part 50
9 Appendix J to manage the drywell liner. Both the IW
10 and Appendix J requires 100 percent inspection per
11 period and --

12 MEMBER BONACA: There are three period
13 inspections. Is that right?

14 MR. MAURICE HEATH: Yes, it is.

15 MEMBER BONACA: So that depends on the
16 bulges.

17 MR. MAURICE HEATH: Yes, it does. So
18 based on the history and the current programs that the
19 Applicant uses, it gives confidence to the staff that
20 they will effectively manage the drywell throughout
21 the period of extended operation.

22 The next slide I want to discuss was the
23 TLAA and based on the reactor vessel and upper shelf
24 energy and this was a lessons learned from the
25 subcommittee meeting and the question from the

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1 subcommittee meeting was conclusions. They were not
2 clear in our Section 4.22. So from the lessons
3 learned from that, we took that and took our chart
4 that we presented and actually put that in a final SER
5 so there is more of a sequence and you can follow the
6 conclusions and as you can see, we have our acceptance
7 criteria and then we have the calculations that the
8 staff did for the 54 EFPY and then the accepted and
9 the reason why which guidance it follows. It's
10 acceptable with I, II, III and that is also shown on
11 the next slide.

12 With that, I want to conclude as for the
13 staff presentation and on the basis of this evaluation
14 of the license renewal application, the NRC staff
15 concluded that the requirements of the 10 CFR 54.29(a)
16 have been met. With that, I would like to open it up
17 to any questions from the members.

18 MEMBER BONACA: So I understand now the
19 issue of relying purely on the visual for the liner is
20 based on the fact that they cannot get water during
21 refueling between the liner and the concrete. Right?

22 MR. MITRA: Yes.

23 MR. MAURICE HEATH: Yes.

24 MEMBER BONACA: Okay. So I understand
25 this is becoming an ISG and so the condition is

1 different. However, you're going to still require
2 ultrasonic testing. So this is the basis. In this
3 particular design, you have concluded that you don't
4 have moderate penetration.

5 MR. MAURICE HEATH: I'll get Hans actually
6 to address that.

7 MR. ASHAR: ISG is presently --

8 MR. MITRA: Hans, please identify
9 yourself.

10 MR. ASHAR: Oh. Hello, I am Hans Ashar.
11 ISG specifically excludes the application to the
12 Brunswick, just one plant, because there is reinforced
13 concrete steel liner on it. ISG applies to all the
14 other Mark I containments.

15 Now in the case of Brunswick, I'm aware of
16 everything that Tom Overton spoke to you about, all
17 the three holes that he had experienced we had
18 followed them through our inspection because every
19 time something happened, the Region II inspector had
20 called me up, I know and at that time, we had talked
21 about the three holes that they found, one hole from
22 the other side and everything. We talked about it.
23 We imposed certain more requirement on the Applicant,
24 at that time licensee. It was on the current
25 licensing basis.

1 So I'm aware of, but in general, there is
2 a lot of discussion here about the bulging and it is
3 true that a number of PWRs with liners as thin as
4 quarter inch liner and they are bulging between the
5 anchors which starts anchoring to the concrete and
6 they are bulging between the two and it's not really
7 unusual to find that kind of a thing.

8 In case of prestressed concrete
9 containments, it is not happening as bad. It
10 generally should happen bad, much more robust than
11 that because of the creep and shrinkage of concrete
12 that would influence the bulging. But what happens in
13 the construction with the wisdom of the engineers,
14 they had put the T sections or angle sections on it so
15 that the bulging is almost not there in many of the
16 prestressed concrete containments.

17 But in reinforced containment, you will
18 see bulging a number of places just because of the
19 dead load and the shrinkage that is caused between it.
20 Any other questions on that?

21 VICE CHAIRMAN SHACK: No thank you.

22 MEMBER SIEBER: Maybe I could make a
23 comment because the containment design in this plant
24 has been a concern at least to me and others in the
25 staff and my way of looking at it is that this Mark 1

1 containment differs from all the others in that the
2 steel liner is not a structural member. It's just a
3 member to prevent leakage in the structural of the
4 concrete and the reinforcing bars and so forth. So it
5 holds a different status than all the other drywells
6 in Mark 1 containments in where the liner is the
7 structural entity there and of course, it's two and a
8 half times as thick.

9 So it seemed to me based on what I know
10 about large dry containments that are steel lined
11 concrete and leak tightness that the kind of
12 inspections that are proposed and that have been done
13 are reasonable and consistent with what one would do
14 with a large dry containment that's basically a doomed
15 cylinder. Otherwise, I think if it were actually the
16 strength member of the containment as opposed to just
17 a barrier to leakage, I think the concern would be
18 quite a bit different and greater.

19 MEMBER MAYNARD: It also appears to me
20 that even if there was some localized corrosion that
21 even through-wall you really haven't lost the
22 containment function. The concrete failures still
23 have compressor retaining capability there.

24 MEMBER SIEBER: And you're right. You do
25 and, in fact, I'm reviewing right now the containment

1 tests that Sandia and others did which shows some
2 interesting results in failures of large dry
3 containments. They don't just fall apart. They just
4 start to leak. In this case, at the design
5 conditions, the limiting factor would be the Part 100
6 leakage limits in an accident and that's the
7 integrated leak rate tests are designed to show. So
8 I come away from the review and everything that
9 everyone has done, both the Applicant and the staff,
10 with the conclusion that the aging management program
11 which was proposed is adequate for this application.

12 Are there any other questions?

13 MEMBER ARMIJO: I have a couple of
14 questions on the table on the reactor vessel upper
15 shelf energy. Yes, that first row there, the
16 calculated value or analyzed value for the drop in the
17 upper shelf energy comes out to be 21 percent as
18 opposed to an acceptance of 23.5 percent. That's
19 pretty close.

20 What I'd like to ask is does the staff do
21 independent calculations or analyses to come up with,
22 to verify that the Applicant's numbers are right.
23 What happens if it turned out to be 24 percent? Is
24 that the end of the world? How close are we to --

25 MR. MAURICE HEATH: I'll get Jim Medoff to

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1 address that.

2 MR. MEDOFF: This is Jim Medoff with the
3 Division of Component Integrity. At the time of the
4 review, I was working for the Vessels and Internals
5 Integrity branch. I was responsible for doing all the
6 time limiting aging analyses on neutron radiation
7 embrittlement including those for the upper shelf
8 energy assessments.

9 Yes, we do do independent calculations,
10 but before we do anything, any independent
11 calculations, we make sure that the neutron fluence
12 methodology and the values provided by the Applicant
13 are reviewed by Dr. Lambrose Lois of the Division of
14 Safety and Safeguards. They renamed it, but it's
15 basically the Systems division and he's in what used
16 to be the Reactor Systems branch. He's our expert on
17 neutron fluence methodology. So I get his approval of
18 their values and then we use the values, if he
19 approves them, we use the values provided by the
20 Applicant in their applications and we compare our
21 values to their values.

22 MEMBER ARMIJO: So those would be the
23 fluences on the next chart.

24 MR. MEDOFF: Well, no.

25 MEMBER ARMIJO: For forging.

1 MR. MEDOFF: The reason there are two
2 slides is for the upper shelf energy and equivalent
3 margins analysis. For the reactor shell plates and
4 shell welds, we used the VIP guidance. But they had
5 a commitment to do a plant specific equivalent margins
6 analyses for their nozzle forgings and so I think it
7 was in '99, I evaluated that and approved that
8 equivalent margins analysis for the nozzle forgings
9 and I think we approved them down to about 30 foot
10 pounds.

11 For the FTLA, they had to just either
12 demonstrate that the fluence was still bounding or
13 that the recalculated value would remain above 30 foot
14 pounds and they chose the former approach. I had had
15 an oversight in not doing the welds. So we corrected
16 that for the license renewal application. So for the
17 nozzle welds, we used the generic VIP criteria to do
18 the equivalent margins analysis.

19 MEMBER SIEBER: Any other questions? I
20 think before we close I would point out to both the
21 staff and the Applicant that in my review of this
22 application and the accompanying SER I came away from
23 it, from that review, as concerning both the Applicant
24 and the staff to have done a really good job in
25 putting together the application that was concise and

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1 direct to the point and a safety evaluations report
2 that that was very well done.

3 I would think that there is a learning
4 curve in license renewal applications and there
5 obviously is and this is the result of maturity of
6 that learning curve. But I also think that both the
7 staff and the Applicant did a good job of being
8 conscientious and paying attention to the details to
9 get it right the first time. So that's my personal
10 opinion. I think that both the Applicant and the
11 staff did a good job on this.

12 If there are no further questions, I
13 appreciate the presentations by both and, Mr.
14 Chairman, I'll give the meeting back to you.

15 CHAIRMAN WALLIS: Thank you. We've
16 continued our tradition of being ahead of time.

17 MEMBER SIEBER: You can count on me, sir.

18 CHAIRMAN WALLIS: We're not allowed to
19 start ahead of schedule with the next presentation.
20 So we will take a break until 10:15 a.m. Thank you
21 very much.

22 MR. MITRA: Thank you very much. Thank
23 you, Dr. Sieber. I took the compliment on behalf of
24 the staff and I am sure that the Applicant also
25 appreciated your comment. Thank you.

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1 MEMBER SIEBER: Thank you.

2 CHAIRMAN WALLIS: Off the record.

3 (Whereupon, the foregoing matter went off
4 the record at 9:42 a.m. and went back on the record at
5 10:15 a.m.)

6 CHAIRMAN WALLIS: On the record. Please
7 come back in session. Next on the agenda is the Final
8 Review of the Extended Power Uprate Application for
9 R.E. Ginna Nuclear Plant. I invite my colleague, Rich
10 Denney, to lead us through this one.

11 MEMBER DENNING: All right. The request
12 here is for 17 percent power uprate. We've had three
13 subcommittee meetings. A focus of a lot of our
14 concern had to do with margins and so you'll see quite
15 a bit of discussion of that. I will point out that as
16 I look at the number of view graphs that are planned
17 for presentation here and I mentioned this to Mr.
18 Milano is there are just too many and so we're going
19 to have to move. It would be okay if we didn't have
20 an advisory committee, but the advisory committee is
21 going to ask questions. So if I see us getting
22 delayed in areas that don't seem to be important, I'll
23 try to press you. So I then turn it over to Mr.
24 Milano to make the preliminary introductions.

25 MR. MILANO: Good morning, Mr. Wallis and

1 other members of the ACRS staff. We're here today as
2 Mr. Denning said to review the 17 percent extended
3 power uprate for the R.E. Ginna Station and the
4 Constellation Energy's safety assessment of the uprate
5 and the staff's evaluation of that.

6 Again, my name is Patrick Milano. I'm the
7 NRR Licensing Project Manager with responsibilities
8 for the Ginna Station. Today Constellation, the key
9 members of the Constellation team are Mr. David Holm,
10 the Plant Manager for the Ginna Station and Mr. Mark
11 Finley who's the Project Director for the uprate.

12 Just quickly, these are the basic topics
13 that both Ginna and the staff are going to follow and
14 in the interest of time, I'm going to go without going
15 through these to try to explain any of this stuff.
16 I'm going to turn it over to Mr. Holm who is going to
17 going to start the presentation for the licensee.
18 Thank you.

19 MR. HOLM: Good morning. On behalf of
20 Constellation Energy, we're very pleased to present
21 our application for power uprate this morning. With
22 me today in addition to Mr. Finley, the Project
23 Manager, we have Roy Gillo (PH) who is an Operations
24 Shift Manager. From our Engineering Services
25 Department, Gord Verdin, Jim Dunne and Joe Pacer, our

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1 PRA consultant, Rob Cavedo, our Licensing Engineer,
2 George Wrobel and a host of Westinghouse support. I'm
3 going to provide some brief facts about the Ginna
4 Station and then I'll turn the presentation over to
5 Mr. Finley.

6 Ginna is a Westinghouse, 2-Loop
7 pressurized water reactor 1520 megawatts thermal by
8 design. The plant initially started commercial
9 operations in 1970 and was originally licensed at 1300
10 megawatts. However, in 1972, the license was
11 increased to the original design power of 1520
12 megawatts. In this application we seek to raise the
13 thermal wet megawatt rating to 1775 megawatts. Of
14 note, the Kewaunee station which is a very similar
15 NSSS design to Ginna Station uprated approximately two
16 years ago to 1772 megawatts and has been operating
17 successfully over that period of time.

18 Some of the activities that have led up to
19 this application, in 1996, Rochester Gas and Electric
20 replaced both steam generators at the Ginna Station.
21 Those steam generators were oversized in anticipation
22 of and to leave the options for a future uprate. In
23 2003, the reactor vessel head was replaced, thus,
24 eliminating any Alloy 600 concerns. In 2004, shortly
25 before Constellation Energy closed on the purchase of

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1 Ginna station we put together an experienced project
2 team consistently of not only Constellation Energy
3 engineers but Westinghouse, Stone & Webster and
4 Siemens.

5 Throughout that period of preparation, we
6 have had an executive oversight committee providing a
7 challenge process consisting of Constellation
8 Corporate, vendor representatives and industry
9 experts. We are prepared to implement the
10 modifications, testing and operating procedures
11 necessary for this uprate in our October 2006
12 refueling outage.

13 Mark Finley will now review the major
14 modifications, plant parameters and license changes to
15 implement this uprate.

16 MR. FINLEY: Thank you, Dave. Good
17 morning. My name again is Mark Finley and I've been
18 at Ginna now for about two years and three months as
19 the Project Director for the power uprate. Before
20 that, I was at Calvert Cliffs for 19 years and worked
21 in the Licensing, Outage Management and most recently
22 in the Fuel and Safety Analysis area. So after I talk
23 about the plant changes, I'll also talk some about the
24 safety analysis and again there's a lot of material
25 there. So I'll really leave it up to the Committee if

1 you have questions and then we'll spend more time in
2 those areas.

3 First, I'd like to talk about the
4 operating parameter changes that we're going to go
5 through to implement the uprate and then I'll talk
6 about the major modifications and the license
7 amendments.

8 With respect to the plant parameter
9 changes, this is a busy slide here, but one of the
10 learnings we took away from the meeting that you all
11 had with Waterford was to show you how we're actually
12 achieving the power uprate and if you look at the top
13 line here, it shows the power change, the core thermal
14 power change, from 1520 megawatt thermal to 1775
15 megawatt thermal. That's actually 16.8 percent.

16 Of note is we're increasing the average
17 coolant temperature from 561 degrees to 574 degrees.
18 However, that's not a temperature that Ginna hasn't
19 seen in the past. Before we replaced steam generators
20 in 1996, we actually operated as you see in the
21 footnote there at 573.5 degrees. So we're actually
22 going back to an average coolant temperature similar
23 to what we had before we replaced steam generators and
24 of course, the reason for the increase in average
25 coolant temperature is to increase the steam generator

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1 pressure to provide a higher pressure at the main
2 turbine inlet.

3 Also of note on this slide is if you look
4 at the coolant mass flow, there's really no change or
5 a minor change in the coolant mass flow rate. It
6 actually decreases slightly 0.7 percent. The
7 volumetric flow actually increases slightly. But why
8 that's important is essentially the way we're getting
9 the power is with a constant flow in the reactor
10 coolant system we're increasing the core ΔT ,
11 increasing the heat out of the fuel and increasing the
12 core ΔT . That's how we're getting the power.

13 With respect to the major modifications to
14 implement the power uprate, before I go down the list,
15 I'd like to just state that our design objective
16 throughout for these modifications was to maintain the
17 overall reliability and safety of Ginna and that was
18 the basis for driving these modifications. As an
19 example, we're maintaining the number of installed
20 spare pumps and fans in the plant to maintain that
21 level of redundancy and again reliability.

22 The first two modifications there are
23 safety related modifications. The remainder of the
24 modifications on the list are balance of plant
25 modifications and this is just a reflection of what

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1 Dave Holm said earlier about the Kewaunee plant, a
2 sister plant of Ginna with a very similar NSSS design.
3 They've uprated to 1772 megawatts thermal and our NSSS
4 is very similar to theirs and really no need to make
5 many modifications to the NSSS or safety related
6 systems with the exception of the fuel assembly. We
7 are incorporating the standard updated Westinghouse
8 design fuel assembly, the 422 V+ design with slightly
9 longer rods and fatter pellets that allows us to get
10 the additional uranium in the core that we need for
11 the uprate.

12 The other significant safety related
13 modification is we're adding an actuator to manual
14 main isolation valves in the feedwater system and
15 these valves will close automatically on a safety
16 signal and stroke faster than our current backup
17 valves do. It provides additional margin for steam
18 line break analysis for containment response.

19 In addition to that, we have these balance
20 of plan modifications, most significant of which is
21 we're replacing the high pressure turbine rotor.
22 That's, of course, to get the additional flow past
23 through the high pressure turbine and the power out of
24 the turbine. We are replacing the main feedwater pump
25 impellers and main feedwater pump motors, in addition

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1 replacing the condensate booster pumps and booster
2 pump motors. We're upsizing those pumps, of course,
3 to handle the additional flow and also replacing the
4 feed regulatory valve and the bypass valve internals
5 associated with that feed regulating valve.

6 In terms of the electrical side of the
7 system, we are increasing the cooling for the main
8 generator. We're replacing a heat exchanger that
9 provides the cooling water to the hydrogen coolers on
10 the main generator again to remove the heat that's
11 associated with the higher electric current passing
12 through the generator.

13 For the main step-up transformer, we
14 replaced the high side voltage bushings and added a
15 fifth cooler bank. Another example of our design
16 objective to maintain the same level of reliability
17 and redundancy, we currently have four cooler banks on
18 the transformer. We could have done the uprate with
19 just those four, but we would not have had an
20 installed spare on that transformer. So we're going
21 to add the fifth cooler bank to maintain that level of
22 redundancy.

23 And for that isophase bus duct, we're
24 adding a third fan, again to provide the additional
25 installed spare for that system and for the

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1 underground oil cables that transfer the power from
2 the plant to the switchyard, those are oil-filled
3 cables, we're going to recirculate that oil.
4 Currently, it's a static system and we're going to
5 just dynamically recirculate that oil as part of the
6 uprate.

7 For the moisture separator reheater relief
8 system, we're making modifications there again to
9 handle the higher steam flow rates. We need
10 additional capacity through this relief system.

11 And last but not least, we did learn
12 through our PRA process and Rob Cavedo will speak to
13 this in more detail when he talks about PRA, we took
14 some good learnings away from that process that we
15 then factored back into the design plans for the
16 uprate and examples of that are we're going to add a
17 system to back up the normal air supply to the
18 charging pumps such that if we lose our normal air
19 supply, we have a backup. We're also adding some
20 additional controls for the charging and turbine-
21 driven aux feedwater pump and this will enhance
22 operator response to fire scenarios. Again, this was
23 a learning that we uncovered from the fire portion of
24 the risk evaluation.

25 I won't spend a lot of time with this

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1 slide, but this is a listing of the license amendments
2 that we have submitted to the NRC. Several of these
3 have been approved already, but we did obviously need
4 to increase the license core thermal power. We are
5 changing our LOCA methods to the updates best estimate
6 LOCA methodology from Westinghouse. We'll revise the
7 actual offset control method to the standard updated
8 Westinghouse relaxed actual offset control design.

9 We need to increase the boron
10 concentration to provide additional ability to have
11 more boron in the RCS for reactivity holddown. A
12 minor change to the accumulator volume, that's really
13 not driven by the uprate, but we wanted to get some
14 margin to the uncertainty analysis for the accumulator
15 level indicator. Condensate storage tank volume
16 increase that slightly. Basis for that volume in the
17 tank is remove at least two hours of decay heat.

18 CHAIRMAN WALLIS: This is the volume of
19 water, not of the tank and the accumulator.

20 MR. FINLEY: That's correct.

21 CHAIRMAN WALLIS: You haven't changed
22 anything. You just put more water or less water in.

23 MR. FINLEY: That's correct. They have
24 not modified the tank, just raised the minimum
25 required level.

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1 And the feed isolation valve that I
2 mentioned, the stroke time for that valve is an
3 improvement. It will be 30 seconds in the technical
4 specifications as compared to 60 seconds currently.
5 And there were some changes to other RPS and
6 engineering safety feature set points and I'll mention
7 those later. Any questions about the plant changes,
8 modifications or amendments?

9 MEMBER MAYNARD: Just real quick on feed
10 isolation valve you say the tech spec will say 30
11 seconds. In practice, what do you expect the close
12 time to be?

13 MR. FINLEY: Okay. The question is the
14 tech specs will say 30 seconds. We expect -- We're
15 purchasing the valve with a specification of less than
16 25 seconds and we expect the valve will stroke in the
17 15 to 20 second range. Other questions?

18 Okay. I'll move right into safety
19 analysis where I'm going to talk about the safety set
20 point changes like I mentioned. We factored in some
21 new control settings. We optimized control settings.
22 And, of course, you have to factor that into the
23 impact on the safety analysis. I'll talk about the
24 methods that we changed. I'll talk some about non-
25 LOCA where a significant amount of discussion was had

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1 at the subcommittee meetings with respect to margin
2 and briefly discuss LOCA results where there's more
3 margin and then talk about the long-term cooling
4 analysis for Ginna and there was significant
5 discussion there again at the subcommittees.

6 First with respect to the safety set
7 points that were changed and these again are
8 controlled by the technical specifications, they're
9 also the analytical set points used in the safety
10 analysis. Of course, as you know, these are bounding
11 with respect to the actual field set points. We did
12 lower the high flux trip set point as a percentage of
13 the full power from 118 to 115 percent. Both the
14 high-high steam isolation and the high steam isolation
15 set points associated with the engineering safety
16 feature systems were increased to account for the
17 higher steam flow rates.

18 Pressurizer safety lift setting was
19 reduced slightly two pounds there, not a big change,
20 but necessary for the acceptable results in the safety
21 analysis. Safety injection and containment spray, the
22 set points there, the second and third from the
23 bottom, those are small changes, not really required
24 again by uprate but changes that we wanted to make
25 while we were revising the safety analysis to provide

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1 additional margin in the uncertainty calculations done
2 for those set points.

3 And at the bottom there, that PA
4 permissive set point, that's the set point below which
5 we can operate with a single loop and we don't, our
6 operating procedures don't actually allow us to
7 operate single loop, but we have a tech spec set point
8 for single loop operation and that was lowered from 50
9 percent to 35 percent.

10 Again, not to spend a lot of time on the
11 control system settings, but just to give you a flavor
12 for how the control grade system settings were changed
13 and the fact that these were all factored into the
14 safety analysis, pressurizer level range from hot zero
15 power to hot full power was increased. The new EPU
16 settings will be 20 percent to 56 percent. As
17 compared to before, we had a range of 35 percent to 50
18 percent.

19 Obviously, the reason we had to do that is
20 now our full power T_{avg} is higher than the zero power
21 T_{avg} . So the increase in temperature as you come up
22 from zero power to full power now is greater. You
23 have to allow for that in terms of pressurizer level
24 change say for a trip and post trip change in
25 temperature. So that's what we did with pressurizer

1 level. And I mentioned T_{avg} . The program T_{avg} changes
2 now to get us to the higher T_{avg} at full power.

3 We optimized the settings on both rod
4 control and steam dump. These are the control systems
5 that would guide the plant for power mismatch
6 scenarios automatically. And at the bottom there, we
7 are adding a filter on the T hot indication signal and
8 the reason there as other plants have seen, other
9 pressurized water reactors have seen, we have small
10 oscillations in indicated hot light temperature and
11 putting this filter on that signal dampens out those
12 oscillations. It provides a more steady signal.

13 MEMBER SIEBER: Have you ever gotten a
14 trip from spurious T hot signals?

15 MR. FINLEY: The question is have we ever
16 gotten a trip from spurious T hot signals? The answer
17 is no, not to my knowledge. We have gotten alarms
18 such that we know the margin is not what we want it to
19 be, but no automatic plant trips.

20 MEMBER SIEBER: Okay.

21 MR. FINLEY: With respect to the methods
22 used in the safety analysis, the non-LOCA analysis
23 were performed with the RETRAN code not new to the
24 NRC, just new for Ginna in the non-LOCA area. We had
25 previously used LOFTRAN. In addition, along with

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1 RETRAN we changed the thermal hydraulic code that's
2 used as part of these analyses to the VIPRE Code.
3 That's just the most recent analytical method that
4 Westinghouse uses for DNB. We previously had used the
5 THINC Code coupled with LOFTRAN. So that's part and
6 parcel to the RETRAN change.

7 I mentioned previously for large break
8 LOCA we updated to the most recent best estimate LOCA
9 methodology. For small break LOCA, there was no
10 change in method. We use the NOTRUMP Code previously
11 and use that for EPU. Similarly for the control
12 system transients, we continue to use LOFTRAN for
13 that.

14 For the containment analysis, we
15 previously used the GOTHIC Code for the LOCA response.
16 We continue to use that for EPU. However, for steam
17 line break, there was an older method call COCO
18 Westinghouse methodology. We've updated that now to
19 GOTHIC, the newer containment analysis method.

20 And for the dose assessment area, actually
21 in 2005, we gained approved of the alternate source
22 term methodology. That was done prior to EPU. We
23 also upgraded our control room ventilation system at
24 that time. So no real significant changes to the dose
25 methodology or to the way we operated the control room

1 ventilation.

2 As I mentioned, we'll talk in some more
3 detail about the non-LOCA analyses that were done and
4 in particular, about the margin in these analyses.
5 But before I do that, I'd like to talk about the
6 approach that was used at Ginna as a backdrop to that.
7 First of all, a very conservative inputs, essentially
8 the same inputs that were used in the pre-EPU
9 analyses, we attempted to stick with those, where
10 possible, for the analyses done for the EPU.

11 However, here were certain limiting EPU
12 analyses that weren't successful with those very
13 conservative inputs. We, therefore, adjusted the
14 inputs, in other words, constrained our operating
15 windows with more restrictive inputs until we achieved
16 successful results for the limiting analyses. But we
17 didn't attempt to demonstrate additional margin beyond
18 that point. So several of the results as you'll see
19 in the next slide are close to the acceptance limits
20 based on this approach. But we do understand that
21 there's a large amount of conservatism not only in the
22 methods and the inputs that are used but also in the
23 safety limits that we're required to meet by the
24 approved NRC methodology.

25 And this is the slide that Dr. Wallis

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1 specifically asked that I bring back to the full
2 committee. So, Dr. Wallis, dutifully I'm leaving this
3 slide in the presentation. But this shows the
4 limiting non-LOCA events for Ginna and categorized as
5 overheating, overcooling and reactivity addition. But
6 this demonstrates the point that I brought out
7 previously that some of the results are close to the
8 criteria although they are acceptable and I'll walk
9 through an example here in a minute just to
10 demonstrate why this is acceptable and what the
11 additional margins are in the analysis to make us feel
12 comfortable that this is safe.

13 As you can see for the overheating events,
14 loss of flow and locked rotor, those are the reduced
15 primary cooling events and the results that they have,
16 i.e. DNBR of 1.385 for the result with the criteria
17 being 1.38. I'm going to talk about that one in more
18 detail in just a second. Overheating events where we
19 have reduced secondary side cooling include the loss
20 of load in the feed line break analysis and those
21 demonstrated acceptable results.

22 On the over cooling side for the steam
23 line break or the condition four event, again we
24 demonstrated acceptable results for DNBR and linear
25 heat rate. And for reactivity addition, the most

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1 limiting events were the rod withdrawal at power and
2 the rod ejection events.

3 Let's take a look at an example on the
4 next slide.

5 MEMBER POWERS: Do you think your fuel can
6 tolerate 178 calories per gram?

7 MR. FINLEY: The question is do we think
8 our fuel can tolerate 178 calories per gram. The
9 answer is yes.

10 MEMBER POWERS: Do you have experimental
11 data to show that?

12 MR. FINLEY: Do we have experimental data
13 to show that? Let me ask Westinghouse in the
14 audience, Chris McHugh, with respect to the rod
15 ejection event and the basis for the 200 calorie per
16 gram limit.

17 MEMBER SIEBER: In this particular case,
18 history is bonk.

19 MR. HUGLE: This is Dave Hogle. I work
20 for Westinghouse. The question was regarding the
21 calorie per gram and I think most of the committee
22 members are aware of the tests that were conducted in
23 France that showed failure rates at rates much lower
24 than what we're meeting here and the methodology that
25 we used to analyze the rod ejection here for Ginna is

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1 based on the 1B approach. Westinghouse has done
2 analysis using a 3-D methodology where we've shown
3 that we can meet failure rates at a much, much lower
4 consistent with the test data that was presented as a
5 result of the test that were done by the French. And
6 as I think the committee that the NRC is currently
7 investigating what would be a new and proper limit to
8 be used for the rod ejection event.

9 When we did look at the rod ejection event
10 using a 3-D methodology what we found is if you take
11 into consideration the actual rod insertion limits and
12 conditions in the core what we find is we don't even
13 get to a condition where you have DNB. So we are
14 still investigating that, what is an appropriate limit
15 to use going forward and I think the staff again is
16 aware that that is out there. But since this was the
17 older methodology that we're using, we feel that this
18 is an acceptable approach for looking at the rod
19 ejection and again we did present information where we
20 showed with a 3-D analysis.

21 MEMBER POWERS: I just don't know what to
22 do with this. This is you come in here. I can show
23 you experimental data that shows fuel won't tolerate
24 these kinds of power inputs and on the face of them
25 experimental data says will not tolerate this kind of

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1 power input, cannot be an acceptable basis for
2 operating a reactor. You come in and you tell me you
3 did an analysis that's not part of the licensing
4 application, not reviewed and say everything's okay.
5 What am I supposed to do with this?

6 MR. HUGLE: That's I think because the
7 staff has not come to an agreement as far as what is
8 acceptable.

9 MEMBER POWERS: Well, the staff, I don't
10 know where to go. If the staff hasn't come to an
11 agreement is another problem I have. I don't know
12 where to go. Here is a clear case that says this
13 power uprate cannot be tolerated because you will
14 violate things. I can show experimental data of the
15 Code the fuel cannot tolerate.

16 MR. HUGLE: But I think we've also showed
17 Westinghouse --

18 MEMBER POWERS: You haven't shown that.
19 You've argued that.

20 MR. HUGLE: -- has presented information
21 to the NRC that we can meet limits that are consistent
22 with the failure rates that were shown based upon the
23 French data and that we can meet lower limits if we
24 were to look at it in a 3-D manner.

25 MEMBER POWERS: Well, you're going to have

1 to show them to me because this is clearly a
2 conundrum.

3 MR. FINLEY: Just to clarify, Dave,
4 correct me if I'm wrong, we have done a 1-D analysis
5 that demonstrates this result here meets the
6 acceptance criteria.

7 MR. HUGLE: That's correct and we also
8 have presented data that shows if you use a 3-D
9 approach and we even presented what we believe are
10 acceptable limits to use going forward for the rod
11 ejection event, but as I understand that I don't think
12 that there has been agreement as to what is an
13 appropriate limit moving forward. So this analysis
14 methodology as Mark has stated is based upon a 1-D
15 approach and we believe --

16 MEMBER POWERS: I don't care what --
17 Either it's an inadequate analysis or it is a clear
18 case that we can't approve this power uprate.

19 MR. HUGLE: We believe that it is an
20 adequate analysis based upon our clear understanding
21 of what happens in a rod ejection event. Again, if
22 you were to analyze the rod ejection event, full power
23 conditions based upon --

24 MEMBER POWERS: We're getting nowhere
25 here. I understand what you're saying. That's not

1 the argument that's presented here.

2 CHAIRMAN WALLIS: Can we get somewhere
3 please? I think that you're claiming that there is a
4 criterion of 200 calories per gram.

5 MR. HUGLE: That's correct based on the
6 current methodology.

7 CHAIRMAN WALLIS: Presumably approved by
8 the NRC.

9 MR. FINLEY: That's correct.

10 MR. HUGLE: That's correct.

11 CHAIRMAN WALLIS: And you have shown that
12 you come up with a smaller number.

13 MR. FINLEY: Yes.

14 CHAIRMAN WALLIS: Now there may be
15 experimental evidence which puts this criterion in
16 question.

17 MR. FINLEY: That's correct.

18 CHAIRMAN WALLIS: But there still is the
19 existing criterion. Is that right?

20 MR. HUGLE: That's right.

21 MEMBER POWERS: But my job, Graham, is to
22 say whether this is safe or not and it clearly
23 diverges from available experimental data. I don't
24 care what the criterion is. It diverges from the
25 available -- The fact of the matter is, the pure and

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1 simple fact of the matter is, that fuel will not
2 tolerate this kind of power input.

3 MR. HUGLE: Also stated, analysis based
4 upon actual conditions will show you won't even get
5 into DNB and that's with conservative assumptions.

6 MEMBER POWERS: Then you should have
7 presented that analysis here.

8 MEMBER DENNING: I do have another
9 question.

10 MR. HUGLE: We have not taken that
11 approach because we have not gotten agreement from the
12 staff as far as what is an appropriate limit to meet
13 and that's part of the problem.

14 MEMBER DENNING: With regard to the
15 current condition, the current operating condition,
16 what is the result of analyses for the current and
17 what's the criterion for the current?

18 MR. FINLEY: The criterion is the same,
19 the 200 calories per gram.

20 MR. HUGLE: The same. The criterion has
21 not changed.

22 MEMBER DENNING: What's the result?

23 MR. FINLEY: But the result, I'm not aware
24 of the result offhand. I don't know if Chris McHugh
25 from Westinghouse or Dave. We can certainly get you

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1 that result.

2 MEMBER POWERS: What difference would it
3 make? Then you can't tell me the physical reality has
4 changed because of the previous analysis.

5 MEMBER DENNING: No, Dana, I think
6 difference is a matter of -- I don't think there's any
7 question.

8 MEMBER POWERS: Absolutely.

9 MEMBER DENNING: There is an issue on rod
10 ejection and whether the existing criteria that people
11 have been using is really satisfactory. For EPU,
12 there is a question of does it make any difference the
13 fact that they're at higher power as to what the
14 result is. I suspect that the increased power makes
15 it a worse result.

16 MEMBER POWERS: Whether it does or not
17 doesn't change the fact that we cannot go around
18 approving things that are in defiance of physical
19 fact. I mean that's silly to do that.

20 MEMBER DENNING: I understand your point.

21 MEMBER BONACA: Well, this at least raises
22 the question of why did you use 1B model when you know
23 that if you use a 3D neutronic model most likely
24 you'll get a much lower --

25 MR. HUGLE: Again, we don't even predict

1 DNB for the rod ejection event.

2 MEMBER BONACA: I understand that.

3 MR. HUGLE: And failure is not an issue.
4 But again, we've gotten the methodology approved and
5 we have done the calculations for several plants
6 where, as I understand it and I'm not an expert in rod
7 ejection, I apologize, but there is some question
8 moving forward is what an appropriate limit to use for
9 the failure of the fuel. If 200 is too high, what is
10 appropriate? I know that we have done conservative 3-
11 D analysis and shown that, I think, were in the range
12 of 50 calories per gram in terms of the limit.

13 MEMBER BONACA: Incredible.

14 MR. HUGLE: I know that they're well under
15 in using a 3-D approach, but again, since that has not
16 been resolved, we still rely on this conservative 1-D
17 methodology that we have used for all the Westinghouse
18 fleet for doing reloads and for doing uprates and for
19 doing all kinds of analysis and continue to meet the
20 existing limit and that's what we've done here for the
21 uprating analysis.

22 MEMBER DENNING: What I think we should do
23 right now is clearly we have to come back to this with
24 staff. Let's not do that right now because I don't
25 want to bounce them up and down. Let's go through

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1 this and when the staff makes their presentation,
2 we'll definitely hit this item again and we may need
3 more input from you. But I think -- We've heard the
4 input. Now the question is what do we do with it and
5 part of that is what the staff has agreed. Dana,
6 we'll come back to this hard when we talk to the
7 staff.

8 MR. HUGLE: But it is definitely an issue
9 out there.

10 MEMBER DENNING: Okay.

11 MEMBER BONACA: Before you go forward, on
12 the previous slide, I had a question on 19. Now for
13 example for the overheating, you get the results of
14 2747 psi which is like three psi below the limit. Oh,
15 2500, it's 2750. Doesn't this number depend on your
16 high pressure trip set point and why didn't you adjust
17 it down to prevent to be so close to limits?

18 MR. FINLEY: As I said earlier, we did
19 adjust pressurizer safety valve set points and other
20 inputs to achieve acceptable results here. We did not
21 attempt to demonstrate additional margin to the
22 acceptance criteria. But as I'll demonstrate here on
23 the next slide and the slide after, that was with the
24 knowledge that again these methods are very
25 conservative and our inputs that bound the operation

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1 of the plant are also very conservative. So a more
2 realistic result is a quite a bit lower in terms of
3 pressure.

4 MEMBER BONACA: What was the volume before
5 you had the uprate?

6 MR. FINLEY: For the loss of load?

7 MEMBER BONACA: Yes.

8 MR. FINLEY: 2737.

9 MEMBER BONACA: So you open the safeties
10 even in that case.

11 MR. FINLEY: That's correct. That's
12 correct and that's a good point because it's really
13 the safety valve set point that determines what the
14 peak pressure is for this event. You do have some
15 overshoot above the set point, but that's not very
16 sensitive to the power level.

17 MEMBER BONACA: Okay. So mechanically you
18 cycle the safties before too.

19 MR. FINLEY: That's correct.

20 MEMBER BONACA: So you do the same.

21 MEMBER DENNING: But there is another
22 point here that goes beyond this particular one in
23 which you didn't do and that is one of the things that
24 really struck the subcommittee was how much the
25 criteria had changed because particularly if you look

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1 at the DNB, I don't remember exactly what it was, like
2 1.62 or something like that, was the criterion
3 previously. So clearly there's a significant change
4 in margin. Then the question is is the residual
5 margin still acceptable.

6 CHAIRMAN WALLIS: I think we should
7 explain to the full committee that this criterion for
8 DNBR is not set by the agency. It's set by the
9 licensee and we went through this with the
10 subcommittee.

11 MEMBER BONACA: There is a minimum that
12 you cannot exceed.

13 CHAIRMAN WALLIS: There is a minimum which
14 is less than that which is really the --

15 MR. FINLEY: Let me ask to go to the next
16 slide because I think that will lead us through this
17 discussion with respect to DNBR and these are the
18 results and the criteria that apply to the loss of
19 flow analysis in particular. That was one of the
20 limiting non-LOCA events you saw in the previous
21 slide. If you start at the top and essentially by
22 definition, critical heat flux is the 1.0 for DNBR and
23 of course, we bound that by looking, by doing
24 extensive testing and bounding that test data with a
25 more restrictive 1.17 criteria.

1 Then we establish a design limit of 1.24.
2 The purpose there is bound the variation in parameters
3 such as temperature, pressure, flow and geometry
4 information. Then beyond that, we establish the
5 safety analysis limit and this is done as Dr. Wallis
6 mentioned by Westinghouse as part of the methodology
7 in the fuel design, but it's reviewed and approved by
8 NRC as well and for Ginna, we consider this an NRC
9 approved limit that if we were to exceed or go below
10 this with respect to DNBR, we would come back to the
11 NRC to gain approval of that analysis.

12 So whereas it is set by Westinghouse based
13 on experience, it is approved by NRC and we consider
14 the safety limit, if you will, for this event. That's
15 1.38 and that --

16 MEMBER DENNING: Safety analysis limit, I
17 think we have to be very careful about safety limits.

18 MR. FINLEY: That's correct. Safety
19 analysis limit. Thank you. Safety analysis limit.

20 CHAIRMAN WALLIS: That's for Ginna because
21 other plants have other numbers.

22 MR. FINLEY: And this applies to Ginna.
23 That's correct and this provides additional margin to
24 the 1.24 design limit and that's to provide us some
25 margin for cycle-to-cycle changes in parameters that

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1 would affect DNBR. So that's a stack up of the
2 uncertainties in the margins that we have just in the
3 safety analysis limit itself.

4 Then below that just to give you an
5 example for how conservative the non-LOCA analysis
6 itself is, you see the result there 1.385, just above
7 the safety analysis limit. That uses a very
8 conservative time delay for the --

9 CHAIRMAN WALLIS: Please. You keep using
10 "very" to qualify "conservative." I think you ought
11 to just say conservative because what's "very
12 conservative" is somewhat subjective.

13 MR. FINLEY: Understand. I agree. Uses
14 a conservative time delay of 1.4 seconds.

15 MEMBER BONACA: You have to use
16 conservative. You do have extreme value there and so
17 you could use that.

18 MR. FINLEY: That's correct and this gets
19 back to the approach that we used. We had a
20 conservative time delay in our previous analysis prior
21 to EPU and we had significant margin there more so
22 than for the EPU analysis. When we did the EPU
23 analysis, we did not change that input just like we
24 didn't change many other inputs because we had
25 acceptable results.

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1 The time delay that was used in the
2 analysis was 1.4 seconds timing to reach the low flow
3 condition before you would get a reactor trip. Based
4 on one-time test data, we're comfortable that 1.0
5 seconds is an actual, still bounding, but conservative
6 time delay for this event.

7 MEMBER BONACA: I understand.

8 MR. FINLEY: And if we were to use 1.0
9 seconds versus 1.4, you see the improvement here, a
10 slight improvement in the result. In addition to
11 that, the methodology used for this analysis did not
12 credit the fact that pressure will increase during the
13 transient and in fact, at the time of minimum DNBR,
14 the pressure has increased approximately 75 psi. Of
15 course, that's beneficial in DNBR space.

16 MEMBER BONACA: I guess the way I was
17 going with my questioning was I understand you have
18 margin. Typically, you stay away from the limits
19 because if you have any real changes taking place in
20 the plant, you have to evaluate those values since you
21 are so close to the margin. I was trying to
22 understand the logic.

23 MR. FINLEY: Actually, that's a very good
24 point and let me elaborate. Your point actually helps
25 to justify the approach that we used. In other words,

1 we maximized the operating envelope that we have such
2 that when we do make changes cycle to cycle that we
3 don't have to revise the UFSAR analysis and go back to
4 the NRC staff to gain approval. So one of the reasons
5 for maximizing our operating windows is to avoid
6 having to revise the limiting analysis cycle to cycle.

7 MEMBER BONACA: So you apply that margin
8 really to parameters that affect the results. Okay.

9 MR. FINLEY: That's exactly right.

10 MEMBER BONACA: All right.

11 MR. FINLEY: We apply the margin to
12 operating parameters that we now control.

13 MEMBER BONACA: Okay. Thank you.

14 MR. FINLEY: Other questions on DNB? Next
15 slide. With respect to pressure, similar argument or
16 stack-up if you will of the design limit in this case
17 and the more realistic results below. Ginna's been
18 analyzed through the anticipated transient without
19 SCRAM event to be able to withstand a pressure as high
20 as 3200 psig with no deformation to the plant pressure
21 retaining components. Above 3200 psig there is some
22 potential for deformation, not likely a catastrophic
23 failure, but for example, perhaps elongation of
24 bolting on the reactor vessel head phalange where you
25 might get leakage as opposed to failure.

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1 We've done a hydrostatic pressure test
2 under cold conditions to 3100 psig. The design limit
3 is 110 percent of design pressure. Design pressure
4 being 2500 psia results in design limit of 2748.5
5 psia.

6 The safety analysis result for the loss of
7 load event which I believe we talked about previous
8 was close, 2747. We do open the pressurizer safety
9 valves, but they are successful in maintaining the
10 pressure below the --

11 CHAIRMAN WALLIS: This is really set by
12 the set point on the valves, the relief valves.

13 MR. FINLEY: That's correct. There is a
14 small effect on the overshoot after the safety is open
15 but predominantly this peak pressure is set by the
16 safety valve set point.

17 But if you, for example, look at a more
18 realistic transient in the plant and we talked about
19 control systems, control grade control systems,
20 previously, both the steam dump system and the
21 pressurizer spray system would typically operate in
22 this transient. These are very reliable systems. We
23 maintain them to be reliable. Taking credit for those
24 would result in a better-than-100-pound improvement in
25 the peak pressure.

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1 CHAIRMAN WALLIS: I guess I would say that
2 at subcommittee we said it's all very well you can say
3 this, but we don't know what's the probability of
4 these things and if you did a PRA type thing, you
5 would say we know that the steam dump and the
6 pressurizer spray are going to work with the
7 reliability of 99 percent or something and you go
8 through this and say the probability of ever getting
9 close to the limit is minute.

10 MR. FINLEY: Yes.

11 CHAIRMAN WALLIS: You actually have some
12 numbers.

13 MR. FINLEY: Yes, and actually --

14 CHAIRMAN WALLIS: But here you're just
15 talking qualitatively.

16 MR. FINLEY: To illustrate that point,
17 again look at the bottom bullet there. The Ginna
18 design is to have a reactor trip essentially
19 immediately following a turbine trip. By design, the
20 turbine trip will electrically cause a reactor trip.
21 This is a very reliable configuration. Either one of
22 two relays being energized as a result of the turbine
23 trip would then cause a reactor trip and I've talked
24 with our PRA folks about this and we believe the
25 probability of success with respect to the reactor

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1 trip on turbine trip is between 99.9 and 99.99
2 percent. Extremely reliable.

3 MEMBER SIEBER: Wasn't there within the
4 last month a failure in an operating plant of reactor
5 trip on turbine trip? It seems to me I read that in -
6

7 MR. FINLEY: I'm not aware of one.

8 MEMBER SIEBER: I'll look it up.

9 MR. FINLEY: But that's very important to
10 this event because what drives this event is the power
11 mismatch, essentially the delay between the turbine
12 trip where you stop your heat removal and the reactor
13 trip later. But the plant is designed to have
14 essentially simultaneous trips and again it's very
15 reliable. If you were to take credit for that reactor
16 trip on the turbine trip, then it really becomes a
17 very benign transient altogether and in fact, this is
18 demonstrated by actual plant data. We don't, for
19 example, even lift the PORVs in addition to not
20 lifting the safeties.

21 MEMBER BONACA: That was an objective that
22 came after TMI anyway that you would stay below the
23 PORV so you wouldn't actuate them. That's -- Okay.

24 MR. FINLEY: That's correct.

25 MEMBER BONACA: You went a long way, but

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1 we go to the bottom line. That's good.

2 MR. FINLEY: Yes.

3 MEMBER SIEBER: Let me ask another
4 question since you seem to want to discuss this. Is
5 the actual turbine trip device and the circuitry that
6 connects the turbine trip to the reactor trip, is that
7 all safety grade?

8 MR. FINLEY: No and that's --

9 MEMBER SIEBER: Then you can't take credit
10 for it.

11 MR. FINLEY: And that's in fact why we
12 don't in the safety analysis, why we don't --

13 MEMBER SIEBER: So it doesn't meet the
14 general design criteria.

15 MR. FINLEY: That's correct.

16 MEMBER SIEBER: Okay.

17 MR. FINLEY: And that's the reason why we
18 don't analytically in the approved safety analysis
19 take credit for that.

20 MEMBER SIEBER: Yes, and that's the way
21 the rules read and you're doing what the rules say.
22 It's not worth too much of a discussion to say if we
23 actually took credit for something that you can't take
24 credit for, it would be even better.

25 MR. FINLEY: But I think it is important

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1 in terms of how the plant will really operate and with
2 respect to margin, these trips will be here.

3 MEMBER SIEBER: Yes, but it doesn't have
4 the pedigree.

5 MR. FINLEY: I understand.

6 MEMBER SIEBER: Why don't we just move on?

7 MEMBER BONACA: One other thing that's
8 important to know is that if it already works,
9 whatever the problem may be, they have a target there
10 that is below the PORVs.

11 MR. FINLEY: Yes.

12 MEMBER BONACA: And so this kind of a
13 transient will not cause most likely the PORVs to be
14 actuated and that's a significant issue.

15 MR. FINLEY: Right.

16 MEMBER SIEBER: That's a good thing
17 because most of the failures are failures to close as
18 opposed to failures to open.

19 MR. FINLEY: Right.

20 MEMBER BONACA: That's why it's really
21 there to prevent in fact those things from happening.

22 MR. FINLEY: That's correct. Yes.

23 MEMBER DENNING: Continue.

24 MR. FINLEY: Just to sum up with respect
25 to non-LOCA, all of the non-LOCA results meet

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1 acceptance criteria and there is margin in both the
2 methods and in the inputs as well as margin and
3 conservatism in the limits themselves.

4 I'll real briefly touch on the results for
5 loss of coolant accident analysis for the Ginna EPU.
6 The large break result was 1870 as compared again to
7 the criterion you know of 2200.

8 MEMBER SIEBER: 2200.

9 CHAIRMAN WALLIS: There are three
10 criteria. You don't show the other ones.

11 MR. FINLEY: I don't have the other
12 criteria. We are well within the other, all five
13 criteria actually for 10 CFR 50.46.

14 CHAIRMAN WALLIS: You're well below the
15 other criteria.

16 MR. FINLEY: Yes.

17 CHAIRMAN WALLIS: I don't remember.

18 MEMBER SIEBER: Oxidation was very small.

19 MR. FINLEY: Yes.

20 CHAIRMAN WALLIS: Well below. Okay.

21 MEMBER POWERS: But that depends on how
22 they use the fuel. Right?

23 MEMBER SIEBER: It's like one percent
24 versus 17. It's zero so they come in very low.

25 MR. FINLEY: Right. We did look at both

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1 the transient oxidation and the oxidation pre-
2 transient and the combination is below, for the LOCA
3 oxidation limit, below 17 percent.

4 MEMBER SIEBER: With a lot of margin.

5 MR. FINLEY: With a lot of margin, yes.
6 Now we did, as I said before, revise the BE-LOCA
7 methodology here for the large break analysis. That
8 was a necessary thing to do for us in order for us to
9 demonstrate acceptable results for the large break
10 analysis, but that large break --

11 MEMBER SIEBER: That's why you got such a
12 low number.

13 MR. FINLEY: That's correct. That BE
14 ASTRUM type analysis that Westinghouse has approved
15 provided the margin that we needed to demonstrate
16 acceptable results for the EPU.

17 With respect to small break as I
18 mentioned, we haven't changed the method there. It's
19 the NOTRUMP method, but you can see by the much lower
20 peak clad temperature that we are a large break
21 limited plant and not a small break limited plant,
22 1167 for the peak clad temperature and again all of
23 the criteria associated with the 10 CFR 50.46 were met
24 with a good deal of margin.

25 MEMBER SIEBER: Now you're using the old

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1 decay heat curve.

2 MR. FINLEY: With respect to the best
3 estimate, that does not use the Appendix K decay heat
4 curve. It uses a more realistic decay heat curve.

5 MEMBER SIEBER: So the 20 percent margin
6 that was built into the old Appendix K is not here.

7 MR. FINLEY: That's correct. That's not
8 in the best estimate methodology.

9 MEMBER SIEBER: Okay.

10 MR. FINLEY: Okay?

11 CHAIRMAN WALLIS: It is there in your
12 probabilistic assessment, isn't it? You're bringing
13 up realistic assessment of the uncertainties in this
14 decay heat.

15 MR. FINLEY: That's a good point. Yes,
16 certainly -

17 CHAIRMAN WALLIS: -- the margin
18 completely.

19 MR. FINLEY: Certainly. Decay heat
20 uncertainty is one of the many uncertainties in the
21 best estimate methodology that's accounted for. Yes.

22 MEMBER SIEBER: But there was a tremendous
23 margin pad on the old Appendix K which later even
24 though you account for uncertainty, the margin is much
25 smaller.

1 MR. FINLEY: Yes.

2 MEMBER SIEBER: Justifiably so in my
3 opinion.

4 MR. FINLEY: Okay, and the last --

5 MEMBER BONACA: I have a question on this
6 just because I couldn't find the information in the
7 material. If you have a large break LOCA and you have
8 everything works, no single failures. How long does
9 the operator have to switch to recirculation? I mean
10 that depends on how large is your RWST, but I couldn't
11 find the information. I don't think it's that large,
12 is it?

13 MR. FINLEY: If everything works and we
14 have absolute maximum flow rates with all the pumps,
15 higher than what is really realistic, 24 minutes is
16 the time to establish recirculation. In other words,
17 the refueling water storage tank would then be pumped
18 down to the point that we had to establish
19 recirculation.

20 MEMBER BONACA: How large is this RWST?

21 MR. FINLEY: How large is the RWST?

22 MEMBER BONACA: One thousand. 330, okay.

23 MEMBER SIEBER: How big was that?

24 MR. GILLOW: I'm Ron Gillow, Shift
25 Manager. Three hundred thirty thousand gallons is the

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1 -- We keep about 315,000 in the RWST at any one time.

2 MEMBER BONACA: All right. Thank you.

3 MR. FINLEY: With respect to the long-term
4 cooling analysis, again there was a significant amount
5 of work and several questions from the staff and good
6 questions from the staff that were responded to with
7 new analysis in the long term cooling area. So we had
8 some discussion about that in the subcommittee meeting
9 and I'd like to spend a little time with that.

10 MEMBER DENNING: I don't think you have to
11 spend a lot of time on this frankly.

12 MR. FINLEY: I understand. Thank you.
13 First, with respect to the Ginna design, we have high
14 head safety injection pumps aligned to the cold legs
15 that would automatically inject when RCS pressure
16 initiates the safety injection system and pressure
17 decreases below about 1400 psi. That's the shutoff
18 approximately for these pumps.

19 We also have low head safety injection.
20 We call it residual heat removal pumps or RHR pumps
21 and those are lower pressure obviously. Shut off
22 pressure around 140 psi. But Ginna is a two-loop
23 Westinghouse design and unique to that design is what
24 we call upper plenum injection. Those low head safety
25 injection pumps are aligned directly to the upper

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1 plenum via nozzles in the reactor vessel itself and
2 inject just above the core in the upper plenum. This
3 is a very robust design with respect to this concern
4 for long term cooling.

5 MEMBER SIEBER: You should also point out
6 that you have big accumulators that operate at pretty
7 high pressure.

8 MR. FINLEY: That's correct. We also have
9 large accumulators that are pressurized to about 700
10 psi which is a relatively high pressure which benefit
11 in loss of coolant as well.

12 The point I want to make on this slide is
13 that we essentially -- When pressure lowers below the
14 shutoff of the low head SI pumps, we automatically
15 have simultaneous injection to both the hot side and
16 the cold side through these two sets of pumps and for
17 a large break LOCA, obviously that's what happens.
18 RCS pressure decreases rapidly below the shutoff of
19 both the high head and the low head pumps. So we get
20 simultaneous injection both to the cold side and to
21 the hot side and no matter which side of the reactor
22 coolant system the break is on, we get flushing flow
23 through the core to prevent increase of the
24 concentration.

25 Now I will say and the question came up

1 previously --

2 MEMBER BONACA: You don't have to switch
3 to hot leg.

4 MR. FINLEY: Actually, let me speak. I
5 will say though that's for the injection phase of the
6 event. Okay. When the RWST as was pointed out before
7 is pumped down, we do need to switch to the
8 recirculation phase. Now when we switch to the
9 recirculation phase, by procedure we turn off the high
10 head safety injection pumps and the basis for that is
11 that Ginna was not designed for simultaneous injection
12 in the recirculation phase and initially in the
13 recirculation phase the sump temperature as high as it
14 is would challenge the NPSH margin on those high head
15 safety injection pumps. So procedurally we actually
16 turn those pumps off in the recirculation phase and we
17 recirculate with the low head pumps initially.

18 We do do an analysis, a very conservative,
19 I used that word "very" again, Dr., a conservative
20 analysis to --

21 MEMBER SIEBER: Very, very.

22 MR. FINLEY: A conservative analysis
23 assuming that when we turn those high head safety
24 injection pumps off that we now begin to get
25 concentration in the core region and, of course, in

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1 that case it would have to be a hot side break that
2 would then carry all of the upper plenum injection
3 flow out the break without any significant mixing in
4 the core region. That's we feel a very conservative
5 assumption.

6 CHAIRMAN WALLIS: "Very" again.

7 MR. FINLEY: I do think "very" applies in
8 that. So --

9 VICE CHAIRMAN SHACK: It's not one word.

10 MEMBER SIEBER: Hyphenated.

11 MR. FINLEY: So we do calculate and this
12 is where in response to staff questions with regard to
13 what precisely is the mixing volume in that core
14 region and what is the void fraction in the coolant in
15 that core region. The staff asked those questions and
16 previously using the simplified method that
17 Westinghouse provided, those issues weren't addressed
18 as rigorously as we are now and we actually did an
19 analysis using the Westinghouse Cobra Track Code to
20 calculate the void fraction and the mixing of the two-
21 phased level through the course of this event and
22 input that into the boron concentration analysis.

23 May I ask you just to click on that slide
24 right there. Go one more. Just to demonstrate the
25 conservative nature of this analysis, you see a dotted

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1 line here on this slide which describes the core
2 mixing, the boundary, if you will, of the core mixing
3 volume in this concentration calculation. What we do
4 is we assume that most of that upper plenum injection
5 flow actually gets carried out the break and this
6 break is on the hot side as we've said; where in
7 actual fact, we feel there would be tremendous amount
8 of mixing across that boundary volume to dilute
9 essentially that core region.

10 Because we have not completely
11 demonstrated that level of mixing and gotten that
12 approval through the staff, we did not take credit for
13 that. All we take credit for is enough of the upper
14 plenum injection flow to essentially replace the mass
15 that's boiled off in the process. But with this
16 assumption, we calculated a time to concentrate during
17 this accident.

18 MEMBER DENNING: Let me interrupt you
19 because unless the Committee really wants to go into
20 this. I think that if you look at this slide you see
21 that part of this is that essentially all the safety
22 injection in the upper plenum is assumed to go out the
23 break in this analysis.

24 I think that we have greater concerns
25 about the more traditional non upper head injection

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1 plants and what happens there. I think this is -- I
2 frankly it's more artificial here. You've gone
3 through the analyses. People can read them. Since
4 we're going to come back and have with the staff some
5 significant discussions on an earlier issue, what I'd
6 like you to do unless people object I'd like to move.

7 MEMBER BONACA: I just had one question.

8 MEMBER DENNING: Go ahead.

9 MEMBER BONACA: Does it imply that you
10 have a pooling up there of water and then it comes
11 through the side?

12 MR. FINLEY: Not a pooling, but of course
13 what you have is rigorous boiling in the core and you
14 have entrainment of some of that injected coolant out
15 the break.

16 MEMBER BONACA: Okay. I don't want to --
17 It was more for curiosity. You go ahead.

18 MEMBER DENNING: Okay. If you don't mind
19 then, I think that you should jump to the conclusions
20 of the safety analysis and move on to the rest of the
21 presentation.

22 MR. FINLEY: All right. Thank you and,
23 yes, just to conclude with respect to safety analysis,
24 all of the safety analysis for the EPU for Ginna were
25 completed and meet the approved acceptance criteria.

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1 Our nuclear steam supply system is robust and our
2 engineered safety features are robust and these
3 results are consistent with the analyses that were
4 done for the Kewaunee plant again that operates at a
5 similar power level to what Ginna is requesting.

6 Any other questions for me in the safety
7 analysis area? Okay. I would like to introduce Jim
8 Dunne. He's the Project Lead Engineer and he'll
9 discuss some mechanical impacts.

10 CHAIRMAN WALLIS: Which are not safety
11 related?

12 MR. FINLEY: I'll let Jim answer that.

13 MR. DUNNE: Good morning. My name is Jim
14 Dunne. I hold the position of Engineering Consultant
15 to the Constellation organization and I'm at Ginna.
16 I've been in the Engineering Department at Ginna for
17 15 years and for the past three years, I've been Lead
18 Mechanical Engineer for the uprate project.

19 Basically what I'm going to go over
20 briefly is to discuss the impact of the EPU on some
21 various mechanical systems and components.
22 Specifically I'll go over the impact on steam
23 generator vibration, balance plant heat exchanger
24 vibration, the vibration monitoring program that we
25 plan on using for the piping due to EPU and also the

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1 impact of the EPU on the flow accelerated corrosion
2 program that's in place at Ginna.

3 With regard to the steam generators, it
4 was previously stated that we replaced our generators
5 in '96 with new generators. The design basis for the
6 new generators included a detailed vibration analysis
7 of the tube bundle for the impact of the operating
8 conditions, specifically looked at vibration potential
9 in the area of the tube bundle that saw cross flow
10 which would be the U-band region and the downcomer
11 entrance into the bottom of the tube bundle.

12 The parameters that were investigated as
13 part of the design of the replacement generator were
14 fluidelastic instability, vortex shedding in the tube
15 bundle region, random turbulence excitation and tube
16 wear in the U-band region. So basically the original
17 design in the generators had acceptance criteria that
18 we had to satisfy in the design of the new generators
19 for all four of those areas.

20 With the EPU, we went back to the OEM
21 which in this case is BNW Canada and asked them to
22 revise their vibration analysis for the EPU operating
23 conditions. So they basically repeated their analysis
24 that they did for the original design and looked at
25 the impact of uprate on these four areas and their

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1 conclusions where that basically the steam jointed
2 (PH) tube bundle design was adequately supported to
3 prevent any flow induced vibration due to EPU
4 operating conditions.

5 VICE CHAIRMAN SHACK: Have you have any
6 experience with frettings with the new generator?

7 MR. DUNNE: We haven't seen any real
8 indications of fretting with the new generators at
9 all.

10 The second issue that we believe probably
11 the ACRS is interested in based upon the BWR
12 experiences, a potential for vibration damage due to
13 steam separators in our case based upon the BWR steam
14 dryer issues. Basically, we think our design is
15 appreciably different than the BWR dryer design and
16 therefore is not really susceptible to any flow
17 induced vibration problems.

18 Our steam separators with the new
19 generators, we basically have 85 primary/secondary
20 modules that are basically in parallel. The number of
21 modules is controlled basically by the size of our
22 upper steam shell region. We can stuff has many
23 modules in the upper shell as possible and with our
24 design that came out to be 85.

25 Both the primary and secondary separators

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1 are a centrifugal type separator in comparison to our
2 original design which had three swirl vein primary
3 separators and then a chevron design for the secondary
4 separation. Because of the design, the flow through
5 the separators is basically axial in nature. So there
6 is no minimal cross flow velocity across the separator
7 modules that could cause vibration.

8 Additionally, the separate design is a
9 rigid design. All the separator modules are
10 interconnected with each other by separator ties that
11 get welded to the adjacent modules so that any one
12 module trying to move is going to transmit its load to
13 the entire separator bundle, if you will. So it's
14 basically a honeycomb structure. As such, we believe
15 it's a very rigid design.

16 Other things to note is that because we
17 have modules and can put 85 of them, the design for
18 those modules plus primary and secondary which based
19 upon actual full scale testing of the modules for
20 steam and flow at operating pressures that bound where
21 the plants would typically operate. With that, at
22 uprate, we are going to steam flow that is still
23 bounded by the original testing, the full scale
24 testing, that was done on the modules. The modules
25 have been tested for steam flows up to 58,000 pounds

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1 per hour steam flow and at uprate, we're going to be
2 going from around 38,000 pounds per hour up to around
3 45,000 pounds per hour. So we're still well below
4 where the modules were tested.

5 And we will be the lead B&W unit at uprate
6 for steam flow through an operating unit. However, we
7 are not that far apart from some other B&W replacement
8 generators that have done power uprates. I think our
9 flow is going to be approximately five percent higher
10 than the steam flow that both Bryon and Braidwood have
11 gone to with their uprates. So we don't believe we
12 are basically pushing the window on steam flow through
13 the modules.

14 To try and visualize the differences
15 between the BWR dryers and the actual Ginna steam
16 generator separator modules, we have this cartoon, if
17 you will, which is this is our understanding of how
18 the BWR steam dryers are set up where you have flow
19 coming out and then a lot of -- flow going over the
20 steam nozzle where they basically had problems at Quad
21 Cities.

22 The Ginna design, we have all these
23 modules stacked across here. This portion up here is
24 our secondary modules. So we basically have flow
25 coming out of all these 85 modules and then basically

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1 approaching the main steam nozzle and controlled by
2 the curvature of the upper head itself. So as such,
3 we have a much simpler flow pattern in our steam
4 generator upper head than you would see in the BWR
5 steam dryer design. And there really are no -

6 MEMBER POWERS: I'm not sure I disagree
7 with you, but what this actually shows that you've
8 drawn simpler arrows. It doesn't show that you have
9 a simpler flow pattern. I could have drawn a set of
10 arrows on the graph that suggests there is some
11 complexity in your flow. Are the arrows drawn based
12 on anything other --

13 MR. DUNNE: It's my hand drawing. They're
14 not --

15 MEMBER POWERS: You could imagine all
16 kinds of complexity in the corners and things like
17 that.

18 MR. DUNNE: You are going to get some
19 imbalance of flows between separators over in this
20 region versus in the middle. But in general, you're
21 going to have a flow pattern that's going to try and
22 follow the contour of the head of the generator and we
23 think that's a more simple flow pattern than coming
24 out here and having to turn around and approach this.

25 MEMBER POWERS: The problem I have is that

1 when the folks from Quad Cities came in and made
2 arguments on this, they drew arrows on figures and
3 they said they firmly believe they had no problem.
4 Okay. You can draw figures here and say I firmly I
5 believe I have no problem. It does not mean you're
6 not going to have a problem.

7 MR. DUNNE: The operating experience to
8 date on the B&W design --

9 MEMBER POWERS: Power uprate level is a
10 little thin.

11 CHAIRMAN WALLIS: You don't give numbers
12 on velocities. So your velocities I think are much
13 lower than BWR steam velocities.

14 MR. DUNNE: The velocities I think through
15 the steam separators themselves are on the order of 40
16 to 50 feet per second and then I think one of the
17 issues that Quad Cities was that they had high steam
18 velocities in their main steam piping in comparison to
19 the rest of the BWR fleet. Basically, our main steam
20 piping velocities are going to be going from 135 feet
21 per second up to around 160 feet per second and we
22 don't believe those are inordinately high steam
23 velocities for a steam piping system.

24 MEMBER DENNING: Okay. Proceed.

25 MR. DUNNE: The next area where we've

1 looked for uprate the impact of vibration is on the
2 balance of plant heat exchanges, specifically the
3 major heat exchangers in the power conversion cycle
4 which would be the feedwater heaters, the moisture
5 separator reheaters and also the impact on the higher
6 exhaust flows to the condenser on the condenser
7 tubing.

8 Basically, we have two trains of feedwater
9 heaters and we have five feedwater heaters in each
10 train, four low pressure and one high pressure. We
11 went to basically a feedwater heater manufacturer,
12 asked them to assess our feedwater heater and MSR
13 design at the EPU conditions for both vibration
14 thermal performance and erosion due to increased
15 velocities. The manufacturer we chose was the
16 manufacturer that was directly responsible for the
17 tube bundle design on six of our FIV feedwater heaters
18 that are presently installed and also responsible for
19 the design of our MSR tube bundles and they also had
20 access to design information for our other four fuel
21 heaters.

22 So they did their assessment of the EPU
23 conditions. They concluded there were no FIV issues
24 with the EPU. They identify that we would have on a
25 large number of inlet nozzles higher velocities than

1 which we typically design heat exchanges to if you
2 were going to design them to the uprated conditions
3 and they viewed that as being a potential long-term
4 erosion concern and basically recommended that we
5 monitor all those nozzles going forward which is
6 basically what our plan is. So we've added those
7 nozzles into our erosion/corrosion program. We'll get
8 baseline reading for where they are before EPU and
9 then monitor them going forward.

10 The other areas on the condenser tubing,
11 when we replaced our condensers or retubed our
12 condensers in '95, we replaced Admiralty tubing with
13 stainless steel tubing and at that time we staked our
14 entire tube bundle. Because our tube bundle was
15 staked in '95, evaluation on the tube bundle indicated
16 that the condenser was acceptable. If we had not
17 staked in '95, we would have had to have basically
18 staked the condenser tube bundle for EPU.

19 The other area on vibration monitoring we
20 have is a vibration monitoring program to assess the
21 impact of the EPU conditions on piping vibration
22 basically in the power conversion piping systems where
23 we are increasing flows and that similar to other
24 plants that have done EPUs, we are basically going to
25 do a pre EPU walkdown at full power to baseline the

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1 existing vibration levels in the plant and then after
2 we come up and do our full power condition at post
3 EPU, we will repeat that and assess if there's any
4 adverse increase in vibration at any part of the
5 system.

6 The vibration program is basically two
7 phased. The first part is to do a visual walkdown of
8 all of the systems which for the pre EPU we have
9 completed. Based upon that visual walkdown, we are
10 identifying select areas within piping systems where
11 we want to go back and actually get actual vibration
12 data with vibration monitoring equipment that we can
13 have a baseline for comparing the post EPU results and
14 that's basically what we plan on doing during our
15 power escalation testing which would be to do the
16 visual walkdowns to identify if there are any new
17 areas that are vibrating at post EPU conditions and
18 also revisit those areas where we got vibration data
19 pre EPU, repeat the data and quantify what the deltas
20 are and assess whether there are conditions that we
21 need to address.

22 The final area I would like to quickly go
23 over is the impact of EPU on our Flow Accelerated
24 Corrosion Program. Like most of the nuclear industry,
25 we do have a Flow Accelerated Corrosion Program to

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1 monitor long term wear of piping systems' components
2 and it's basically a combination of analytical tools
3 developed by EPRI in combination with actual field
4 data to assess predictive wear rates going forward and
5 determine when we need to reinspect and to when we may
6 need to do repairs. So we have gone through and used
7 the analytical tool that EPRI has for assessing
8 vibration levels, compared the calculated vibration
9 levels with the pre EPU flows and thermal dynamic
10 conditions in the various systems and then
11 recalculated them at the EPU flows and thermal dynamic
12 conditions to assess analytically what we expect the
13 change in erosion rates to be.

14 It varies from system to system. But the
15 numbers we've seen are typically varied from increased
16 erosion rates anywhere from two to three percent up to
17 20 to 25 percent. We've reviewed that data to see
18 based upon where we are presently in our erosion plan
19 whether there are any components that need to be
20 replaced prior to EPU due to a potential for increased
21 erosion rates. We have not identified any components
22 that need replacement prior to EPU.

23 We also have added new components to our
24 program. Some of them are the feedwater heater
25 nozzles that I talked about and we also have piping

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1 that before was exempt from the erosion/corrosion
2 program or FAC program because of thermal dynamic
3 conditions that now no longer screen out.
4 Specifically the piping between our No. 2 feedwater
5 heater and the No. 3 feedwater heater was below 212
6 degrees Fahrenheit, so it screened out of the FAC
7 program. At EPU, we're going from slightly below to
8 slightly above. So now it screens in and we're going
9 to add that piping to the program and for all the new
10 components, we're getting baseline readings prior to
11 implementing EPU.

12 So basically our first outage after the
13 uprate, we plan on going in and doing increased
14 inspections, a piping over what we would normally do
15 basically to get feedback as to what we're seeing in
16 the actual erosion rates to determine whether any of
17 the calculated values to each are adjusted according
18 and then continue to assess the piping systems going
19 forward by periodic monitoring of the programs similar
20 to what we do right now. That's all I have.

21 MEMBER DENNING: Anything else here?
22 Okay. Let's move to PRA and let's hold the PRA to ten
23 minutes.

24 MR. DUNNE: I'd like to introduce Rod
25 Cavedo who's from our Corporate PRA Group in

1 Annapolis.

2 MEMBER DENNING: I'll sit on George here
3 and see if we can move quickly through this.

4 MR. CAVEDO: My name is Rob Cavedo and I'm
5 here to present the -- I've been working in the PRA
6 field for 17 years. I'm here to present the results
7 of the PRA and insights. I'm here to talk about the -
8 - That's okay.

9 The PRA we've had a lot of discussion on
10 margins here and the PRA is our tool to quantify what
11 the actual impact to the margin is. We look at
12 everything that can be affected. We look at the
13 changes to the initiating event frequency. We look at
14 success criteria changes. We look at equipment
15 failure rate changes. And we look at the operator
16 response time changes which that is what drove the
17 change in risk associated with the power uprate, the
18 reduction amount of operator response time. We also
19 identified risk beneficial plant changes. We
20 calculated this using internal, external and shutdown
21 events.

22 For the initiating event frequency, we had
23 not new PSA initiators. So that doesn't mean that
24 there weren't any changes in the initiating event
25 frequency. That just means that the PRA already

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1 evaluates such a large range of initiators that there
2 were no new categories that needed to be developed.
3 But we did adjust based on the engineering evaluations
4 numerous initiating event frequencies. As Jim
5 mentioned, based on flows beyond recommendations, we
6 increased the initiating event frequencies for those
7 areas.

8 MEMBER SIEBER: What criteria did you use
9 to make those adjustments?

10 MR. CAVEDO: It was purely based on the
11 engineering reports. So as Jim gave a great example
12 for the heat exchanger, if you were designing a new
13 plant and you would allow a flow of X if the flow
14 actually went beyond that in EPU conditions, we
15 increase the failure rate for the initiating event
16 frequency.

17 MEMBER SIEBER: By how much and what's the
18 basis for the increase?

19 MR. CAVEDO: As we discussed in the
20 subcommittee meeting, that's a good question. There
21 is no concrete tool to determine exactly how the
22 initiating event frequency is going to increase as a
23 result of the EPU conditions. So what we did is we
24 took a best estimate as what the change in the
25 initiating event frequency would be and then we did

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1 sensitivity evaluations to say let's say the frequency
2 doubles or let's say it's half as much as we thought
3 and we looked at what that range of impacts were and
4 assessed whether it was still acceptable based on
5 those sensitivity studies.

6 MEMBER SIEBER: Sounds like a lot of
7 engineering judgment.

8 MR. CAVEDO: It is. Yes, PRA has a lot of
9 engineering judgment in it.

10 MEMBER SIEBER: Yes.

11 MR. CAVEDO: Until you have empirical
12 evidence for what's going on, you can't say with
13 certainty what's going to happen in the future.

14 MEMBER SIEBER: Well, the fact is that PRA
15 doesn't model effects like how much margin you have
16 and what that means as far as failures.

17 MR. CAVEDO: It does measure that. That's
18 the whole premise of what the -

19 MEMBER SIEBER: It's built into the
20 frequencies.

21 MR. CAVEDO: Right, it's built into the
22 frequencies. So you look at what the flow rate is
23 initially and if it's going to go up and if it's going
24 to go beyond these recommended limits from a design
25 perspective, then the failure rate has a chance of

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1 increasing. We plan on putting programs in place to
2 try to mitigate that as much as possible, but there is
3 no guarantee. So we increase the failure rate
4 initially and maybe 20 years from now, the failure
5 rate will go back to what it was because we'll find
6 out that our program has totally compensated for any
7 changes to the plant.

8 The other main area that we evaluated is
9 success criteria changes and we used the Thermal
10 Hydraulic Code to evaluate all of our success criteria
11 changes and we did have to adjust the bleed and feed
12 timing had to be adjusted and the number of PORVs
13 depended on the timing also was affected by the EPU.
14 So that was one of the significant thermal hydraulic
15 changes.

16 MEMBER SIEBER: But your success criteria
17 are still go/no go criteria.

18 MR. CAVEDO: The success criteria, it's a
19 very similar approach to how we do all these design
20 type calculations. You keep on adjusting the timing
21 of recovery until it becomes a go or no go. So you
22 say, okay, if you have two PORVs available, then you
23 might have 30 minutes to initiate bleed and feed. But
24 if you have one PORV, then you keep on doing the
25 thermal hydraulic calculation until you have just one

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1 PORV and maybe for one PORV you might have to get it
2 done in 15 minutes.

3 So it's by the nature of the calculation
4 just like the design calculations. You keep on
5 adjusting the time until you get either success or
6 failure as defined by some criteria. So it's a very
7 similar approach.

8 We did the comprehensive reviews of the
9 equipment and that was based on the design
10 calculations. The systems operate within allowable
11 limits and post trip because these were only mild
12 degradations, we didn't think the equipment failure
13 rates post trip would be changed significantly.

14 But the main change as I mentioned before
15 was in the operator response time and, of course,
16 because these's higher decay heat and you have the
17 same inventory and the RCS in the steam generators,
18 then you're going to have reduced amount of time for
19 the operator to respond.

20 MEMBER APOSTOLAKIS: Do you have any
21 examples of the difference there?

22 MR. CAVEDO: Yes, I actually think it
23 might have been taken out for this presentation. But
24 for the subcommittee, we gave a full chart and in the
25 submittal, it has all the different timing changes and

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1 I have a chart here. It's Table 2-13 and it shows you
2 what the time is before EPU and the time is after. So
3 if you have a specific human action in mind --

4 MEMBER APOSTOLAKIS: What's the largest
5 change?

6 MR. CAVEDO: I don't remember for
7 percentage what the largest change was, but we also
8 had a sensitivity change. You would think that it
9 would be something like 17 percent. Right? That's
10 the power change.

11 MEMBER APOSTOLAKIS: Not percent. In
12 actual minutes.

13 MEMBER DENNING: He means minutes.

14 MEMBER APOSTOLAKIS: What's the allowable
15 change?

16 MR. CAVEDO: That's what I'm saying. You
17 would think that it would be along those lines, but
18 because there is some base amount of time for the
19 operator to respond to take the actions, then you're
20 looking at the Δ time for a diagnosis. Since there's
21 that base time X and you have some Δ time Y, the
22 percentage can actually be greater than the power
23 uprate change. But there is a chart in here that has
24 the percentages for those changes. Last time, he
25 helped me out. Isn't that the chart? I don't

1 remember what page it's on, but is this it?

2 MEMBER APOSTOLAKIS: (Inaudible.) I don't
3 see a chart.

4 MR. HARRISON: Yes, this is Donnie
5 Harrison of the staff. I think the chart you're
6 looking for is on page 22 through 25 of the licensee's
7 submittal. It's Table 213-13. It gives the base
8 times and the EPU times. But I think just to make a
9 simple example would be the one that you up before
10 talking about going from having to reestablish cold
11 leg injection shifted from originally they had 19
12 hours and it shifted all the way down to about six and
13 a half hours. So it was a huge reduction in time.
14 However, you still have six and a half hours.

15 MEMBER APOSTOLAKIS: When you have six
16 hours.

17 MR. HARRISON: And that was the
18 observation.

19 MEMBER APOSTOLAKIS: Is there anything
20 that is closer?

21 MR. CAVEDO: The nice summary chart that
22 has all the decay heats in terms of percentages, Table
23 2.13-12 and you can see stuff like if you're talking
24 about operator fails to manually start a motor driven
25 pump with no auto start signal, the EPU time available

1 is 65 minutes and it was 84 minutes. And there's a
2 summary for all the broad categories of changes. So
3 it has bleed and feed timing that changed and it has
4 the bleed and feed timing. That's was one of the
5 largest changes that we had. It went from 32 minutes
6 available pre EPU to 15 minutes available post EPU.

7 MEMBER APOSTOLAKIS: So the probability
8 that is calculated.

9 MR. CAVEDO: Based on the reduction and
10 diagnosis time.

11 MEMBER APOSTOLAKIS: What model are you
12 using for that?

13 MR. CAVEDO: We're using the EPRI Human
14 Action Calculator.

15 MEMBER APOSTOLAKIS: A calculator is not
16 a model. It has four models. A calculator is a just
17 a computer program. So which one of the four are you
18 using?

19 MR. CAVEDO: For the specific human
20 action, I'm not sure. It automatically selects what
21 is done based on the type of action that you select.

22 MEMBER DENNING: There is no question what
23 the focus of what's important in this risk assessment.
24 Why don't you go ahead now. Let's see the results on
25 that as far as changes are concerned, but all those

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1 changes come from there are changes in the human
2 reliability.

3 MEMBER APOSTOLAKIS: If you go down to 15
4 minutes from what, thirty something.

5 MEMBER DENNING: Yes.

6 MR. CAVEDO: Yes, all the human actions
7 went down significantly enough that we didn't credit
8 them anymore.

9 MEMBER BONACA: And bleed and feed is a
10 very important contributor.

11 MR. CAVEDO: Yes, that reduction in human
12 action time was the largest contribution to the change
13 in risk.

14 MEMBER DENNING: That's you're about to
15 see. If you go to that table, let's just see the
16 changes.

17 MEMBER BONACA: Are those PORVs qualified
18 to bleed and feed?

19 MR. CAVEDO: Could you say that again?

20 MEMBER BONACA: Are those PORVs qualified
21 to bleed and feed?

22 MR. CAVEDO: Qualified from a design
23 perspective you mean?

24 MEMBER BONACA: Yes. Sure.

25 MR. CAVEDO: No, that's not a design

1 possibility. The PRA, just to take a step back,
2 credits anything that in reality would work at the
3 plant. So like for Mark's example where you're
4 talking about the loss of load, all of the secondary
5 equipment is credited in the PRA. It's just assigned
6 to failure likelihood based on normally historical
7 evidence.

8 MEMBER BONACA: Has anybody gone to the
9 vendor and asked the question "Can you pass water
10 through these valves for an extended period of time?"

11 MR. DUNNE: This is Jim Dunne from Ginna.
12 Basically, the Ginna PORVs were part of the EPRI post
13 EMI testing where they did water discharge and steam
14 discharge and transition from steam to water discharge
15 testing and basically for the PORVs specifically, our
16 PORVs are basically capable of passing low level water
17 discharge. We also use them for our LTOP over
18 pressure protection which is a water discharge
19 scenario.

20 MEMBER DENNING: Yes. Let's go to the
21 results -

22 MR. CAVEDO: To the results. So for the
23 results, you can see what the change -- First, let me
24 give a summary for our approach as a site for this.
25 As Mark mentioned and going back to Slide 11, we

1 looked at everything from a system's standpoint and a
2 number of pieces of equipment available. We ensured
3 that that margin remained the same. So that of course
4 factors into the risk results.

5 But our management asked us to go beyond
6 that and beyond just preserving the systematic success
7 criteria. They wanted us to look for risk beneficial
8 modifications to help to offset the risk associated
9 with the power uprate. So we took a look at that and
10 if you look at where it says "Base Pre EPU" so the
11 first --

12 MEMBER DENNING: As you do this, you're
13 going to have to still talk in the mike.

14 MR. CAVEDO: Okay. So as you look at the
15 first row that's here, you can see what the baseline
16 core damage was pre EPU and you can see what the
17 change is post EPU and you can see what the change to
18 LERF (PH) is. But what we did is that we said let's
19 say that we do additional modifications to help to
20 offset this risk and we looked at several of them.

21 One is making sure that all of the safety
22 injection piping equipment during a fire could be used
23 to mitigate that from an Appendix R type scenario. We
24 looked at the shutdown AOVs to make sure that on loss
25 of air or power that the failure of those won't go to

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1 a point where it will cause cavitation of the RHR
2 equipment. We're actually adding accumulators for the
3 charging -- Normally, the charging pumps will go at 60
4 gallons per minute, but when they lose air they go
5 down to a low speed and that's not as good for bleed
6 and feed and those type of actions. So we're going to
7 get longer amount of time where the charging will run
8 at the higher flow rate and that's very beneficial for
9 the bleed and feed because obviously that's a time
10 critical action. So that gives you extra margin and
11 then this is just a combination of the three
12 scenarios. So you can see that by implementing all of
13 these plant changes we actually end up with a lower
14 core damage post EPU than we did pre EPU without the
15 modifications.

16 MEMBER BONACA: Now this is a total CDF,
17 right, including external events?

18 MR. CAVEDO: Yes. This is including
19 everything.

20 MEMBER BONACA: For your internal event
21 CDF, how much was it originally?

22 MR. CAVEDO: I don't remember off the top
23 of my head what the --

24 PARTICIPANT: 1.51. 1.3 pre uprate.

25 MEMBER BONACA: How good is your PRA?

1 Just a question I have. How good is this PRA? I know
2 it was originally an IPE and IPEEE.

3 MR. CAVEDO: Yes, it's been updated
4 several times since the IPE.

5 MEMBER BONACA: Updating means to verify
6 that all the initiators --

7 MR. CAVEDO: I guess I should say it's
8 been revised because we have changed human action
9 methodologies and we've done multiple changes to the
10 PRA to increase the fidelity.

11 MEMBER APOSTOLAKIS: So which one is it?

12 MR. CAVEDO: For this specific --

13 MEMBER APOSTOLAKIS: What is the core
14 damage frequency now?

15 MR. CAVEDO: If we would implement all
16 these, then it would go down.

17 MEMBER DENNING: It's going to be that
18 bottom one.

19 MEMBER APOSTOLAKIS: 585?

20 MEMBER DENNING: Yes.

21 MR. CAVEDO: We'll implement all the
22 changes.

23 MEMBER BONACA: So you are reducing it
24 even from the pre?

25 MEMBER DENNING: Yes. Correct. By these

1 non EPU --

2 MEMBER APOSTOLAKIS: (Inaudible.) 585.

3 MEMBER DENNING: Right. It's essentially
4 the same.

5 MEMBER BONACA: You say if we implement.
6 Are you implementing or are you not implementing?

7 MR. CAVEDO: Yes, management is planning
8 on implementing these modifications.

9 MEMBER BONACA: So that's a commitment
10 they made to the NRC.

11 MR. FINLEY: This is Mark Finley again,
12 Project Director for the uprate. Yes, these are
13 commitments as a part of our license amendment.

14 MEMBER BONACA: Thank you.

15 MEMBER DENNING: Okay. Now this is not a
16 risk-informed modification and I would question some
17 of the things you said about the ability of a PRA to
18 even evaluate the impacts of margins. But
19 nevertheless, we're going to accept where you are
20 right now and I don't think you need to use your
21 conclusion statement. We can read that if we may
22 because what we'd like to do right now if there is no
23 objection is I think we'd like to have the staff come
24 up. Thank you very much and we'll let Mr. Holm
25 complete his final words at the end if that's okay.

1 Just leave it there. I'm not sure whose
2 it is. I don't think it's ours. And, Pat, we're
3 going to let you get through a few introductory
4 slides, but let's get right into the issue as quickly
5 after that as we can that Dana has raised. Okay?

6 (Discussion off microphone.)

7 MR. MILANO: Okay. Getting right into it,
8 the predominant area for the EPU review was the
9 reactor systems analysis and I'm going to be touching
10 on some of the other areas later on. Again, these are
11 from the review Standard RS001 for Reactor Systems
12 Review. These are the predominant areas we look at,
13 fuel and nuclear systems designs, ECS and associated
14 systems, the non-LOCA transients, LOCA transients and
15 ATWS.

16 Again, from the review standard, the NRC
17 confirms basically as Constellation had indicated in
18 their review. They used NRC approved codes and
19 methods and the staff evaluated those in terms of the
20 plant specific application. We looked at compliance
21 with any limitations and conditions on the use of
22 those codes. We verified a number of input
23 assumptions such as steam generator plugging, what the
24 10 percent plugging limit and the licensee's
25 evaluation of any vendor service advisories like N-

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1 cells in the case of Ginna with Westinghouse that
2 there were appropriate analytical assumptions made and
3 inputted into the analyses and whether the results met
4 applicable requirements and then we looked at whether
5 the processes to ensure that these analyses bound the
6 as-operated conditions that the plant will be operated
7 at and then again, we looked at foreign precipitation
8 in particular in long-term cooling.

9 Skip through the designs since you've
10 already heard it. They're going to 14 X 14 422
11 Vantage Plus and these things. We've already talked
12 about the VIPRE versus THINC, that there will be a
13 transition core and the use of transition core
14 penalties and then the use of the revise in the
15 standard thermal design procedures and we talked about
16 the design, the DNBR limits.

17 Getting right into the non LOCA transients
18 wherein you're going to have your major questions,
19 again the staff followed in particular the guidelines
20 in the Review standard. Most of these events, the non
21 LOCA events, were analyzed by the licensee using
22 RETRAN and VIPRE, both of which again were NRC
23 approved codes. We've already looked at the important
24 assumptions that went into the analysis and
25 evaluations that took place. When I say analysis and

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1 evaluations, over about three-quarters of the
2 transient analysis were reanalyzed by Constellation
3 and its vendor. Some were just evaluated.

4 And the staff found that the results
5 satisfied the applicable requirements and the design
6 limits and you mentioned that before. In the case of
7 Ginna, those safety limits are actually in Tech Spec
8 Section 2.1.

9 MEMBER DENNING: Okay. Right now then,
10 let's get into the question. Two hundred calories per
11 gram has been accepted in the past. There's evidence
12 of that. Now we're dealing with a power uprate.
13 What's the regulatory position on how we handle that?

14 MR. MILANO: With that, I'm going to turn
15 it over to Mr. Paul Clifford from the Fuels and
16 Nuclear Performance branch who is going to answer
17 those questions. Paul.

18 MR. CLIFFORD: Is there a host of
19 questions that need to be answered?

20 MEMBER DENNING: No, there is just one
21 question and that is how do you justify accepting 200
22 calories per gram or something that's approximating
23 that as far as the analysis that we have here when
24 there is experimental evidence that would indicate
25 that we should be reconsidering that 200 calories per

1 gram.

2 MR. CLIFFORD: Okay. It's important first
3 to note that there's three criteria and they all have
4 different limits for the rod ejection case. The first
5 is RCS peak pressure and I don't think there's any
6 dispute about that. The second is a coolable geometry
7 which goes back to GDC 28 and the third is offsite
8 dose or control room dose.

9 Let's start with the coolable geometry GDC
10 28. That was set at 280 calories per gram in Reg
11 Guide 1.77. For many years, the staff has known that
12 the 280 calories per gram isn't conservative. The
13 real number is 230 calories per gram and that came out
14 around 1980 when McDonald did an investigation based
15 upon PBF test results and some SPIRT test results. So
16 the real number is 230 calories per gram to ensure
17 there's not a loss of raw geometry. Since then, since
18 1980, there's been tests at various facilities, CABRI
19 and SRR, etc., where they've shown that there's been
20 clad failure below the previously expected 170
21 calories per gram.

22 So that goes to my next subject and that's
23 the dose. The dose is based upon the amount of fuel
24 rod cladding that fails. Today we use two methods to
25 determine clad failure. For BWRs, we assume 170

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1 calories per gram and for PWRs, we use DNB. If they
2 predict DNB to occur, they assume the clad fails and
3 then the fissure product inventory that's in the fuel
4 clad gap is released and that's used in the dose
5 assessment.

6 For clarification, the CABRI test, none of
7 the CABRI tests were done at higher than 200 calories
8 per gram and they were predominantly looking to
9 determine when PCMI clad failure occurred. The French
10 weren't really targeting to determine when there was
11 a loss of coolable geometry. The loss of coolable
12 geometry was really dictated by the PDF test in the
13 United States back in the '70s and there they had a
14 reactor that was capable of putting that sort of
15 energy deposition into the fuel rods and actually
16 melting the fuel and melting the clad.

17 I don't believe that the French at CABRI
18 or NSR or anyone really wants to melt the fuel and
19 melt the clad. So they are really not trying to
20 determine the loss of coolable geometry criteria.
21 They're trying to determine the PCMI clad failure. So
22 the coolable geometry failure limit of 230 calories
23 per gram, the Westinghouse analysis is assuming 200
24 calories per gram which is below the 230 calories per
25 gram. So that's conservative.

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1 For their dose calculation, they're
2 assuming a calculated DNB. Now I'm not that familiar
3 with this case, but in a previous life when I worked
4 for a utility out in Arizona, we used to assume DNB
5 failure and we also used to assume a calories per gram
6 failure for clad failure of 170. Even though it was
7 determined to be the value for BWRs, we adopted it
8 just to be conservative.

9 And just to give you a point of reference,
10 we would calculate eight or nine percent of the fuel
11 rods were in DNB, but we wouldn't calculate one rod
12 was above 170 calories per gram. So DNB is much more
13 limiting from a perspective of predicting or
14 estimating how many pins fail, much more conservative
15 than calories per gram.

16 So I think there's a little mix up between
17 the 200. The 200 that was mentioned earlier although
18 I wasn't in the room, but I've been told, the 200
19 calories per gram relates directly to coolable
20 geometry and not to failure. The failure is based o
21 n DNB.

22 MEMBER DENNING: I think at least from my
23 view point the safety concern is the coolable geometry
24 one but then there's the question of whether these
25 most recent tests really are below this level where

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1 one would be concerned about coolable geometry or not.
2 Dana, do you want to jump in here?

3 MEMBER POWERS: Yes, the presumption that
4 coolable geometry is lost only when you melt is wrong.

5 MEMBER DENNING: That is true.

6 MEMBER POWERS: All you have to do is
7 expel fuel and you've probably lost coolable geometry
8 and what we see is a variety of tests demonstrating
9 that that threshold for where you will get both fuel
10 cladding failure and beyond that expulsion of fuel
11 decreases with increasing burn-up. And after one
12 cycle, it's all below certainly to 100. It's probably
13 below 150. Arguable, but very low.

14 So the question is the Applicant comes in
15 and says I get 178. That would suggest that he's
16 vulnerable to a rod ejection accident. He goes on and
17 says, when that's raised, he says, "I've done other
18 calculations that are presumably not part of the
19 application that show that it's even less than that."
20 Well, that's good and I'm happy and I even actually
21 probably believe those calculations, but nevertheless
22 it's not part of the application.

23 So we're being asked to accept for power
24 uprate something that any member of the public can go
25 look and pull an article out of *Nuclear Safety* and

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1 say, "Gee, they accepted something that will fail if
2 there's an accident." Why did we do that?

3 MEMBER DENNING: Okay.

4 MEMBER POWERS: Why should we do that?
5 How would we defend ourselves in front of an energetic
6 interrogation by a member of the public? I don't
7 think I could.

8 MEMBER BONACA: And I would like to add
9 that it's 30 years that very simplistic methods are
10 being used like 1D calculation or whatever because it
11 was licensed once against this criteria and since the
12 members haven't been changing the books, they're still
13 using this very rough calculation when all of them,
14 the vendors, have much better methodology that they
15 could use and apply to the -- Actually calories per
16 gram would be much less than what they're calculating.

17 So we are left in this limbo here,
18 indecision, because simply the better methods are not
19 being used and the reason why they're not being used
20 is the criteria that they are forced to are
21 unreasonably high, 200 calories per gram, 280. I mean
22 these are huge numbers.

23 CHAIRMAN WALLIS: This is not a power
24 uprate issue. It's a more generic issue, isn't it?

25 MEMBER BONACA: I agree.

1 CHAIRMAN WALLIS: And we've known it for
2 some time.

3 MR. CLIFFORD: Can I say something here?
4 The staff is aware of this and just two months ago
5 with the RIC we unveiled a strategy for dealing with
6 this. We are going to by sometime this fall put out
7 interim criteria which will be significantly below the
8 280 calories per gram which is currently in the Reg
9 Guide and that will be based on an evaluation of all
10 the test data that's available today and then we'll be
11 doing a more thorough evaluation to revise Reg Guide
12 177 by the end of next year and that will include some
13 very important tests that are going on this year that
14 I hope will fill in some of the gaps that we have in
15 the empirical database.

16 But to go back to what was said earlier,
17 the 230 calories per gram, there's a lot of evidence
18 that shows that's the right value at zero power as was
19 mentioned and as you go up in burn-up that changes.
20 Now today we're relying upon two things. The first
21 thing is REAL (PH) 0401 which is published in 2004 by
22 Research is essentially state of the art operability
23 assessment which looked at all the data and came up
24 with very conservative acceptance criteria which were
25 based upon they collapsed the coolability line all the

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1 way down to the clad failure line.

2 So it went from, hold on one second. I
3 have it right here. They assumed in this REAL 150
4 calories per gram at zero and then it dropped all the
5 way down to about 60 calories per gram with burn-up
6 and then they did a detailed three dimensional
7 neutronics calculation to show that you just couldn't
8 achieve that sort of change. So the conclusion was
9 that not only would you not have an issue of coolable
10 geometry taking into account all the burn-up effects
11 and the corrosion effects, but you wouldn't even fail
12 clad.

13 MEMBER BONACA: Yes.

14 MR. CLIFFORD: So we're relying upon that
15 and we're also relying upon a fundamental
16 understanding of the core in the sense that, yes, when
17 you get a heavily corroded rod you lose ductility. So
18 you're more susceptible to PCMI failure. However,
19 when you reach that state in core life or in rod life,
20 you just don't have enough power left in that rod to
21 get that sort of impulse. The fresh rods are going to
22 be the rods that give you the highest power pulse and
23 those the cladding is very fresh. There's very little
24 corrosion. It's very ductile. It can expand and
25 absorb the fuel swelling.

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1 MEMBER POWERS: The problem is when you
2 have a corroded assembly next to a fresh assembly
3 around the high worth rod. That's when you get into
4 trouble here.

5 MEMBER SIEBER: So what do you expect the
6 Applicant to do for this power uprate? He seems to be
7 following whatever he thought was the correct
8 procedure.

9 MR. FINLEY: This is Mark Finley again,
10 Project Director. Let me just interject because the
11 question was asked earlier what the result was for the
12 pre EPU rod ejection analysis and I'd like Chris
13 McHugh from Westinghouse to speak to that.

14 MR. McHUGH: This is Chris McHugh from
15 Westinghouse. The pre EPU for the exact same case
16 that Mark presented that gave 178 calories per gram,
17 the result pre EPU was 176.3.

18 MEMBER MAYNARD: I think we have two
19 issues here. One, I think that Applicant has clearly
20 shown that and demonstrated that they have met the
21 current requirements and I think that's through the
22 staff review they've seen that and I don't believe
23 that for power uprates that we're to be using generic
24 issues to realize. If we think we have a real safety
25 issue, a generic safety issue, then I think that falls

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1 into another category and I believe that from what
2 I've heard and from what I understand with the
3 conservatism, I think this is an issue that definitely
4 needs to be pursued. But I'm not sure it's one that
5 demands going outside the current regulatory process.

6 MEMBER DENNING: Why don't we --

7 MEMBER POWERS: So you're going to walk up
8 to a member of the public and say, "Okay, here's this
9 experimental data published in the open literature
10 absolutely contradicts what I've accepted" and you're
11 going to defend that. How? How do you persuade
12 somebody that this is even a rational thing to do?

13 MEMBER DENNING: We're going to have this
14 discussion later. Let's move on at this point because
15 we know what the staff is saying. We know now what
16 they're thinking and we'll have to really discuss
17 later in detail as a committee just what we do about
18 it. But at the moment, I think we know what all the
19 positions are.

20 Agreed, Dana? There's no more that we're
21 going to get out of the Applicant or the staff right
22 now. We have to decide based upon that how we
23 proceed. Okay? Why don't you go ahead then and move
24 quickly through the balance of your presentation then.

25 MR. MILANO: Okay. I'm going to skip over

1 the large break LOCA because we've already heard it
2 and we also know that it's not limiting or excuse me,
3 It is the limiting 1870 PCT and stuff and we've
4 already talked about the fact that they've gone to
5 what we consider to be the state of the art, the
6 Westinghouse ASTRUM methodology.

7 Small break space, the staff reviewed the
8 short-term behavior. They found that for small break
9 that the results of the licensee's analysis were
10 within the limits of the 50.4060 (PH) Appendix K
11 results and we did do some confirmatory calculations
12 in this area using the staff's RELAP Mod 5 Code and
13 then we also had had a lot of interface with
14 Constellation regarding the post LOCA long-term
15 cooling. With that, I don't feel that there's
16 anything more that we need to say since the licensee
17 did go through it in a lot of detail and we did concur
18 with that.

19 Mechanical impacts, again I'll go through
20 this relatively quickly because we did evaluate the
21 areas of both accelerated corrosion and fuel induced
22 vibration. In this area, we did look at and we spent
23 a lot of time looking at for specific systems, the
24 systems that we felt, that the staff felt, most
25 susceptibly. We did take a look at the temperatures,

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1 flow velocities, moisture content, etc. in those
2 systems and compared those with industry norms for
3 that type of system such as condensator feed or
4 whatever and then we looked at what the licensee
5 through its program expected, what components were
6 expected to be affected by the increased EPU
7 conditions and the fact that they were put into their
8 FAC program.

9 We did look at the results of the
10 licensee's CHECWORKS program and the models that are
11 going to be updated based on implementing the EPU and
12 we felt that at EPU conditions the FAC program does
13 remain consistent with those industry guidelines such
14 as the EPRI standards and stuff that were mentioned.

15 Flow induced vibration, as Constellation
16 indicated, there was a lot of assessment done in this
17 area. The staff did focus quite a bit both on the
18 main steam and feedwater and condensate systems and
19 noted that those systems are going to be instrumented
20 at critical locations to monitor the vibration levels.
21 Both was done at current power level and will be done
22 during the power ascension testing.

23 The vibration monitoring was evaluated in
24 accordance with the standard ASME Operating
25 Maintenance Code 3 and then in particular and both

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1 Constellation discussed today and it was discussed
2 during the last subcommittee meeting, we spent a lot
3 of time on the steam separator portion of the
4 replacement steam generators and also on the U-tube
5 portion of the tube bundle to make sure that nothing
6 would be expected and this next slide just summarizes
7 the staff's assessment of that area and the fact that
8 although BNW Canada, their testing was done
9 predominantly to looking at moisture carryover and was
10 done just on a single separator module and stuff, as
11 was indicated by Constellation, the flow rate that was
12 tested for that by BNW Canada was well in excess of
13 what the expected mass flow rate would be through a
14 module at EPU conditions at Ginna.

15 And then going into the staff's review -
16 Excuse me. If there isn't anything in the vibration
17 and flow and corrosion areas, I'll go into the risk
18 evaluations. For the risk evaluation, Ginna has used
19 a PSA Level 1 which covers as we indicated before
20 internal events including internal floods, external
21 events and also shutdown operations. And it also uses
22 a simplified containment event tree to evaluate WURF
23 (PH) and then you'll follow NUREG CR 6595 for PWRs
24 with large dry containments.

25 The staff did note with some pleasure the

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1 fact that the Ginna EPU risk evaluation did gain a
2 number of insights and that those insights were
3 translated into proposed plant modifications and other
4 operational risk improvements that could reduce risk.

5 To further supplement your question that
6 you posed to Constellation about the commitments,
7 indeed Constellation did make a commitment and the
8 staff has codified that in its safety evaluation and
9 indeed as part of the recommended areas for inspection
10 prior and post implementation of the EPU, that will be
11 one of the areas that we're going to sample to make
12 sure that all of those commitments were indeed
13 accomplished. The staff's amendment process will
14 indicate also that implementation, a full
15 implementation of the EPU, will indeed be contingent
16 on the completion of those commitments.

17 We've already talked in some detail about
18 those five risk and cost beneficial changes that the
19 licensee had made. So there's no need to go over
20 those unless you have another question of the staff.
21 And again, the PRA conclusions, licensee adequately
22 modeled and addressed the potential risks. The risks
23 are acceptable and in accordance with SRP Chapter 19,
24 the staff believes that there is nothing in the
25 proposed EPU that creates any special circumstances

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1 and that the licensee did identify potential changes
2 that will be implemented that will reduce the risk
3 that would be incurred by the uprate.

4 MEMBER BONACA: Did you do any
5 verification with the SPAR model?

6 MR. MILANO: Donnie.

7 MR. HARRISON: There were a couple areas.
8 This is Donnie Harrison from the PRA staff. There
9 were a couple areas where we ran SPAR models primarily
10 in looking at their seismic analysis. We did a couple
11 of manipulations just to confirm that we would expect
12 to get similar answers as the licensee got. We also
13 did some things dealing with the seismic vulnerability
14 that would affect shutdown operations just to show
15 that it would be a small risk increase as well during
16 shutdown. Yes, there were a couple places where we
17 did that.

18 MEMBER BONACA: But you've gained some
19 familiarity with their model or just compared some of
20 the numbers or you don't know?

21 MR. HARRISON: It's a -- Any time you run
22 a SPAR model or any kind of PRA model, you're going to
23 get some familiarity with the plant and what kind of
24 consequences you get from certain actions. So there
25 was some gain in that.

1 MR. MILANO: I'm going to end up the
2 staff's presentation with talking about what I would
3 say are other key areas, not to say that those areas
4 were key to our actual decision for acceptance. These
5 were what I would say areas where we had a major
6 focus, balanced plant, operator reactions, that's the
7 human factors area, testing and then finally I'd like
8 to talk a little bit about, because it came up last
9 time, the proposed inspections during the actual
10 implementation of the EPU.

11 In the balanced plant area, it was done in
12 accordance, the staff's review was done in accordance,
13 with Matrix 5 of the Review Standard which looked at
14 a number of these areas as indicated here. In
15 particular, the staff looked at the areas that would
16 be affected by the increased decay heat loading, spent
17 fuel pool cooling, the service water system and the
18 auxiliary feedwater system noting that the service
19 water system is important to cooling of the RHR heat
20 exchangers and also the fact that the auxiliary
21 feedwater minimum flow rates were going to be raised
22 somewhere because of the EPU based on the transient
23 and accident analysis. And then we spent a lot of
24 time looking at operational considerations with regard
25 to the feedwater and condensate systems.

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1 Staff's results of this was the decay heat
2 load will not exceed the cooling capability of the
3 systems that are being relied on. Balanced plant
4 systems don't pose an increased challenge to the
5 reactor safety systems and that albeit I'm going to
6 talk a little bit about the Power Ascension and
7 Testing Program later, the review in the balanced
8 plant area did have a lot of interface with the groups
9 doing the power ascension testing. They provided a
10 lot of input into that to make sure that that testing
11 would encompass any of the issues that they were
12 concerned about.

13 MEMBER DENNING: Incidentally, I would
14 like you to jump now to 22 and talk about power
15 ascension test program. The other two view graphs are
16 pretty straightforward.

17 MR. MILANO: Okay. Again, the staff's
18 review used SRP Section 14.2 which codifies the
19 guidance that was provided in Reg Guide 1.68 for
20 review of power ascension and testing. In terms of
21 this, usually what's mentioned is large transient
22 testing. The staff does not believe that there needs
23 to be large transient testing done to assess the EPU.
24 The EPU test program that will be instituted by the
25 licensee does include sufficient testing to

1 demonstrate that the structure, systems and components
2 perform satisfactorily and the staff did consider and
3 discuss on several occasions with the licensee and its
4 vendor what was done in the original power ascension
5 testing in the early '70s and the effect of the EPU on
6 plant-related modifications that are being done now,
7 how those would be tested and incorporated into the
8 start-up test program.

9 The one thing of note in the power
10 ascension testing that the licensee does plan to do is
11 a manual turbine trip at 30 percent of the EPU power
12 level to verify the plant's dynamic response and to
13 also verify the control system settings such as
14 pressurizer level and pressure controls, steam
15 generator water level, and the rod control systems.
16 And the --

17 MEMBER DENNING: I think that they did
18 make a pretty good case that that 30 percent manual
19 trip really is more important as a test than a full
20 power trip as far as testing control system behavior.

21 MR. MILANO: That's correct and that
22 pretty much is what the basis of our conclusion was.
23 I did want to -- Although this is not really part of
24 the review itself, it's a resultant of the staff's
25 review. The staff will be conducting through

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1 utilization of the resident inspectors and regional
2 specialist, they will be reviewing a number of things
3 that the NRR staff recommends to verify the adequate
4 implementation of the EPU. The regional staff will be
5 using Inspection Procedure 71.004 which describes
6 those things that are necessary for power uprate
7 evaluations and it provides guidance to them with
8 regard to how to conduct those inspections.

9 The staff did make a number of
10 recommendations for areas of inspection, not to say
11 that every single thing in there will be, every single
12 recommendation will be fully implemented. We are in
13 the process right now of discussing these
14 recommendations and how they will be factored into the
15 region's implementation of the inspection procedure,
16 what portion of it needs to be samples, what levels
17 will be sampled. That is ongoing right now.

18 They are considered to be recommendations
19 as I said that will be used when selecting the sample.
20 They don't constitute inspection requirements per se
21 and I'd like to just mention a few items as an
22 example. You know Constellation had indicated that
23 there are some changes that are going to be made to
24 the turbine bypass system, to the flow rates for both
25 AFW and standby AFW and stuff. We have recommended

1 that when those systems are being tested that that
2 testing be monitored, that the results be reviewed and
3 evaluated and stuff to make sure that the results
4 substantiate the bases that the staff utilized in
5 making its assessment, so those areas.

6 We're also going to look at other things
7 like the actual mechanical overspeed trip of the main
8 turbine and making sure that that overspeed trip test
9 is going to be done at about 20 percent power and that
10 is one of the areas that we're going to ask. Again,
11 there are roughly -- And as you can see in the draft
12 safety evaluation that was provided to you, there's
13 about 12 areas with a number of subsets of them where
14 we're recommending that the regional staff consider
15 putting those into its inspection program.

16 With that, that basically concludes that
17 staff's presentation.

18 MEMBER DENNING: Thank you. Do we have
19 any other questions for the staff? Yes.

20 MEMBER ARMIJO: I have a couple of
21 questions about the fuel. We didn't talk about that
22 this morning.

23 MEMBER DENNING: No.

24 MEMBER ARMIJO: But the first question is
25 this fuel, the 422 V+ design. Is that a new or unique

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1 fuel design? Is this the first time that's been used
2 in -

3 MEMBER DENNING: I think that --

4 MR. VERDIN: This is Gord Verdin, a
5 Principal Engineer at Ginna responsible for fuel. The
6 422 V+ product is actually a proven product. We have
7 made some Ginna-specific enhancements and changes.
8 Ginna has nine grids whereas the other plants that use
9 422 V+ fuel have seven grids. We've made some other
10 changes, but all those changes are based upon
11 improvements that have been done since the original
12 422 V+ product. So, no, it is a proven product.

13 MEMBER ARMIJO: Okay. The second part of
14 my question is I know you've added a lot, stuffed a
15 lot more fuel in there, more fuel length, more surface
16 area, but have you increased the linear heat
17 generation rate of the fuel assemblies or either peak
18 rods?

19 MR. VERDIN: As a result of uprate
20 obviously, the linear heat generation rate does
21 increase. In order to mitigate a lot of these
22 effects, we've done several things. The fuel assembly
23 has substantially higher internal plenum volume for
24 rod internal pressure issues. It's obviously a larger
25 diameter rod which gives you the additional inventory

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1 plus it also gives you some DNB enhancement. But
2 lastly, the fuel stack height itself has increased by
3 1.58 inches. That gives you obviously some mitigating
4 in terms of peaking factors from our current fuel
5 stack height.

6 MEMBER ARMIJO: So the peak linear heat
7 generation rate hasn't gone up proportional to the
8 uprate. It's gone up a little bit much but not much.

9 MEMBER SIEBER: Not the peak.

10 MR. VERDIN: It has gone up, but it is not
11 proportional exactly to the uprate.

12 MEMBER ARMIJO: Okay. Thanks.

13 MEMBER SIEBER: Generally, those kinds of
14 fuel designs, the idea is to get more pins to approach
15 the peak and level things off which is what they did.

16 MR. MILANO: And one of the other things
17 that was mentioned during one of the subcommittee
18 meetings also was the pin diameter is going up and it
19 is going up to a diameter that was consistent with, I
20 believe, the RFA assemblies that --

21 MR. VERDIN: Actually the 422 pin diameter
22 is consistent with the original Westinghouse standard
23 fuel that was used at Ginna in Cycles one through
24 eight and so there are some similarities to our
25 previous fuel assembly.

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1 MEMBER ARMIJO: Thank you.

2 MEMBER DENNING: Any more questions to the
3 staff?

4 MEMBER SIEBER: We move from Vermicelli to

5 --

6 MEMBER DENNING: Mr. Holm, would you then
7 give us a wrap-up from your side? Let me ask you a
8 question and it's a joint question for you and
9 Westinghouse and it doesn't imply that we're really
10 going to ask for this. But if we were to --
11 Westinghouse had implied that have done analyses with
12 improved methods that show that in the rod ejection
13 accident you'd have much lower heat content of the
14 fuel and that they would not go to DNB. If we were to
15 ask for that information, would you be able to provide
16 it to us in a short period of time? I don't mean
17 today.

18 MR. HOLM: I'm going to ask for a member
19 of my staff to support me on this.

20 MR. FINLEY: Yes. Mark Finley and I'm
21 going to ask Westinghouse to tell me what was done to-
22 date and then I can respond to what time it would take
23 us.

24 MR. HUGLE: This is Dave Hugle,
25 Westinghouse, and what I can do is over the lunch

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1 break or as soon as we break here, I can contact the
2 Pittsburgh office and see what might be available to
3 present to you today.

4 MEMBER DENNING: Thank you.

5 MR. HUGLE: And if we can't present
6 something today, certainly we'll see what we can do.

7 MEMBER DENNING: I'm not sure that we
8 actually even can today. Could we today if we wanted
9 to?

10 CHAIRMAN WALLIS: We can if you want to.

11 MEMBER DENNING: Yes, we can. Sure.

12 MR. HUGLE: I know we've presented results
13 to the staff because obviously this was a big issue.
14 We wanted to assure the staff that everything was okay
15 in terms of, since all the plants out there, all the
16 Westinghouse fleet, are using the 200 calorie per gram
17 as a limit. So this is independent of Ginna or even
18 the Ginna uprating here.

19 MEMBER DENNING: Very good. We'll expect
20 to at least here back from you whether it would be
21 possible.

22 MEMBER SIEBER: It's really not an EPU
23 issue either.

24 MEMBER DENNING: Well, I think that's
25 still to be -- That's something we're going to have to

1 debate.

2 MEMBER SIEBER: If you change the power
3 level, the calories per gram doesn't change very much.
4 You may end up saying if I want to meet some vastly
5 lower limit better not run your plant and you can say
6 that to 30 or 40 plants.

7 MR. FINLEY: Yes.

8 MEMBER DENNING: Please proceed.

9 MR. HOLM: I would like to thank the
10 Committee for the opportunity to present our
11 application today. We've completed many detailed
12 comprehensive reviews and they will continue through
13 our construction and operating periods through our
14 oversight processes. We've identified no new safety
15 issues and a comprehensive testing plan and operator
16 training plan will be performed in support of this
17 uprate.

18 We're confident that Ginna's safety and
19 reliability will be maintained as a result of our
20 modifications, our procedure changes and operator
21 training and oversight processes. And thanks to the
22 Committee for the opportunity.

23 MEMBER DENNING: Thank you very much. Any
24 other questions for the utility? Then thank you and
25 again, I'd like to thank you for your presentations

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1 and your staff and also to the staff of the Nuclear
2 Regulatory Commission for their presentations. Thank
3 you very much. Back to you.

4 CHAIRMAN WALLIS: We will now take a break
5 until the schedule for the next presentation which is
6 at 1:15 p.m. I want to keep us on schedule because we
7 have a lot of work to do and we have a short meeting.
8 So we'll have a slightly shorter lunch but not much
9 shorter. 1:15 p.m. Off the record.

10 (Whereupon, at 12:25 p.m., the above-
11 entitled matter recessed to reconvene at 1:16 p.m. the
12 same day.)

13 CHAIRMAN WALLIS: On the record. The
14 next item on the agenda which is another extended
15 power uprate, this time an application from Beaver
16 Valley Nuclear Plant.

17 MEMBER DENNING: Do we know anything about
18 this plant?

19 MEMBER SIEBER: Where?

20 CHAIRMAN WALLIS: Rich Denning will again
21 lead us through the process. Rich, are you ready?

22 MEMBER DENNING: Yes. Now we're going to
23 be considering two smaller uprates at the two units at
24 Beaver Valley and I'm going to turn it over to Tim
25 Colburn to lead us off here. Thank you.

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1 MR. COLBURN: Dr. Denning, Dr. Wallis.
2 My name is Tim Colburn. I'm a Project Manager in the
3 Division of Operating Reactor Licensing assigned to
4 the Beaver Valley Power Station, Units Nos. 1 and 2.

5 MEMBER SIEBER: Could you pull the
6 microphone a little closer to you? Thank you.

7 MR. COLBURN: Yes, I'm sorry. I'm here to
8 discuss the Beaver Valley extended power uprate of
9 eight percent and the agenda topics we'll be
10 discussing this afternoon will be licensing
11 introduction. Lead speaker for the licensee is Pete
12 Sena, the Director of Site Engineering. With him with
13 be Mark Manoleras, Ken Frederick, Mike Testa and Colin
14 Keller who will discuss PRA. We're discussing plant
15 modifications, safety analysis, mechanical impacts,
16 risk assessment, implementation and summary remarks.

17 The licensee had several amendments as pre
18 application amendments necessary to support the power
19 uprate. These included containment conversion to the
20 atmospheric conditions for both units. This involved
21 approval of MAAP DBA, computer code for mass energy
22 release. Beaver Valley 1 relies on containment
23 overpressure protection for pumps. Beaver Valley 2
24 does not. Staff performed independent mass energy
25 release calculations and had good agreement with the

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1 licensee results and steam generator replacement for
2 Beaver Valley 1 only was also accomplished.

3 The October 4, 2004 application had
4 numerous supplements in response to staff REIs and
5 included a request for full alternative source term
6 implementation. The staff review followed the Review
7 Standard RS 001 Rev 0. At this point, I would like to
8 turn it over to Pete Sena from the Licensee Staff to
9 begin their presentation.

10 MR. SENA: Thank you, Tim. Good
11 afternoon, Mr. Chairman and distinguished members. I
12 am Pete Sena. I'm the Director of Site Engineering at
13 Beaver Valley. This morning I would like to provide
14 a brief introduction and some background to the Beaver
15 Valley power uprate.

16 Our desired outcome is to provide you with
17 sufficient information and answer all relevant
18 questions regarding the Beaver Valley power uprate so
19 that you may form the appropriate positions and
20 recommendations to the NRC Commissioners. We've built
21 this presentation to cover a number of areas affected
22 by the uprate and areas that we believe are of
23 interest to the Committee in fulfilling the desired
24 outcome of these procedures.

25 Today's agenda has already been covered by

1 Mr. Colburn and the members of Beaver Valley. So I
2 will not reiterate that. I will be covering the
3 Beaver Valley history with respect to our power
4 history, the Beaver Valley comparison with our peer
5 units with regard to our power and our preparations
6 for the uprate.

7 Beaver Valley units are a three loop
8 Westinghouse PWRs that achieve commercial operation in
9 1976 for Unit 1 and 1987 for Unit 2. The original
10 core license power level was 2652 megawatts thermal.
11 The 1.4 percent current uprated power of 2689
12 megawatts credited the improved feedwater flow
13 measurement uncertainties. The larger power uprate
14 approximately eight percent was initiated in mid 2000
15 and used an initial scoping phase to determine the
16 best approach and the optimum target license power
17 level. As a result of the scoping evaluation, a
18 target reactor power level of 2900 megawatts was
19 selected.

20 As you can see, this target value aligns
21 us very well with our peer three loop Westinghouse
22 units that have previously uprated. We benchmarked
23 closely these units' approach to uprate and their
24 operating history since their implementation. We feel
25 that collectively using the experience of these

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1 stations gives us confidence in the approach that we
2 have chosen.

3 As you can see here and Mr. Colburn
4 already covered this, but there were several license
5 amendments which preceded the uprate application. Two
6 key components of the uprate are the containment
7 conversion and the best estimate LOCA amendments.
8 These amendments were approved by the NRC in the first
9 quarter of this year.

10 The atmospheric containment provided an
11 industrial safety improvement to allow for frequent
12 and safer containment entries while at power. The
13 Beaver Valley containment design pressure of 45 psig
14 is not being changed nor is the containment structural
15 design temperature of 280 degree being revised. The
16 containment conversion project incorporated all
17 changes due to the EPU application and the steam
18 generator replacement projects at Unit 1.

19 Also the best estimate LOCA methodology
20 was applied to the EPU. This is the same model
21 currently in use by other stations throughout the
22 country such as Braidwood, Byron and Indian Point.
23 BELOCA and that's the code retract methodology is the
24 preferred methodology for Beaver Valley needed to
25 support the uprate.

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1 BELOCA and containment conversion have
2 been implemented at Unit 1 during this past Unit 1
3 spring outage and will be implemented at Unit 2
4 following our Unit 2 fall outage. Finally, the
5 replacement steam generator amendment was implemented
6 this past spring.

7 As you can see from this picture, at Unit
8 1, we have just replaced our steam generators with
9 Model 54F units and these units were designed for the
10 uprate application. The reactor head was also
11 replaced with a simplified, modified design.
12 Additionally, new control rod driver mechanisms were
13 installed. This outage was recently accomplished as
14 I said about two or three weeks ago and was completed
15 in a 65 day time period.

16 Again, this was a Beaver Valley site-led
17 project. The ownership remained with us at the site.
18 All of our speakers are site individuals. We provided
19 the overall management and direction. Beaver Valley
20 reviewed and approved the design inputs and performed
21 detailed owner acceptance of each vendor calculation.
22 Our support teammates of course did include
23 Westinghouse and Stone & Webster, many of whom are
24 here today as subject matter experts and may be called
25 upon.

1 Our corporate offices provided oversight
2 for the project to make sure that we met quality
3 assurance requirements. Additionally, independent
4 assessments of our safety analysis were completed by
5 MPR and Associates. That completes my introductory
6 remarks. Next I would like to introduce Mark
7 Manoleras. Mark is our Manager of Design Engineering
8 at Beaver Valley.

9 MR. MANOLERAS: Thank you very much, Pete.
10 As Pete had mentioned, I've been at Beaver Valley for
11 the past 18 years. I've been the Design Manager at
12 Beaver Valley since 2002. My department has ownership
13 of the safety analysis and modification packages
14 associated with this power uprate. I'd now like to
15 discuss those modification packages.

16 We replaced our charging safety injection
17 pump rotating assemblies at each unit. This is going
18 to extend the pump burnout flow limit and will improve
19 our high head flow capacity to improve small break
20 LOCA PCT results. We added new feedwater isolation
21 valves at Unit No. 1. This reduces our containment
22 pressure and temperature falling of main steam line
23 break inside containment. This brings our Unit No. 1
24 up to the same design as our Unit No. 2.

25 We added aux feed cavitating venturis at

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1 Unit No. 1. Again, this brings our Unit No. 1 up to
2 our Unit No. 2. This will minimize mass addition
3 input into the containment and reduce aux feed flow on
4 a feed line break and will maintain the minimum flow
5 to the intact steam generator.

6 We are adding a reactor cavity drainage
7 port at both units. This will facilitate post
8 accident draining of the cavity to improve NPSH
9 performance of the pumps that draw from our
10 containment sump. And we replaced our steam
11 generators at Unit No. 1.

12 For secondary side modifications, we are
13 replacing our high pressure turbine at Unit No. 1 and
14 Unit No. 2 with an all-reaction design. We are going
15 to install stakes in our main condenser in Unit No. 2.
16 We already have those stakes at Unit No. 1. We are
17 raising the set pressure of our MSR relief valve set
18 points at both units. We are increasing the Cv of our
19 main feedwater control valves. At Unit No. 1, we made
20 control valve trim changes and at Unit No. 2, we're in
21 the process of replacing those control valves.

22 We replaced our turbine generator rotor
23 and statter at Unit No. 1. The existing rotor had a
24 short and we replaced that. We wanted to replace it
25 prior to power uprate and we've completed that

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1 modification. Additionally, we replaced several
2 instrument sets and we replaced these instrument sets
3 due to the higher flow range required needed to take
4 a look and be able to monitor the parameters.

5 If there are any questions, I'll take
6 those at this time.

7 MEMBER DENNING: No, I think we're fine.

8 MR. MANOLERAS: I would like to now
9 introduce Ken Frederick who will talk about the plant
10 safety analysis.

11 MR. FREDERICK: Thank you, Mark. As Mark
12 said, my name is Ken Frederick and I'm the Lead Safety
13 Analyst at Beaver Valley plants. I have been at
14 Beaver Valley for 27 years and for about 24 years,
15 I've worked in the Engineering Department primarily in
16 the safety analysis area and for the last five years,
17 I've been involved with the containment conversion and
18 the uprate projects.

19 For the safety analysis discussion here,
20 I guess the criteria or the objectives here are to
21 basically demonstrate that the analyses meet the
22 regulatory limits and that Beaver Valley will operate
23 with adequate safety margins at the EPU conditions.

24 So for this discussion reduced from the
25 last meeting we had, we had a lot more detail, but

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1 we'll go over again the operating parameters at the
2 EPU condition, touch on the methods and the
3 methodology changes that have been part of this
4 project and look at some of the results for non LOCA
5 and LOCA events as well as the long term cooling and
6 touch on the containment analysis. Again, the
7 containment and also the large break analyses were
8 actually part of separate submittals which have been
9 approved earlier this year.

10 This slide shows the nominal operating
11 parameters for Unit 1. Again, these are more best
12 estimate type in our target values for our operation
13 at the EPU conditions. We've actually analyzed over
14 a range of T_{avg} from 566.2 to 580 degrees. So that
15 establishes our operating window. But again, our
16 intent is to operate at these conditions primarily
17 because this is what we've optimized our high pressure
18 turbine replacement at the steam pressure shown here.

19 The flow here from pre EPU to EPU does not
20 change the thermal design flow. It remains at the
21 current value, so the increased output from the core
22 as a result of increased temperature rise.

23 These are our similar values for Unit 2.
24 One thing to note here is that we're actually planning
25 to reduce T_{avg} a couple degrees and this is to keep our

1 hot line temperatures below 610 and this is primarily
2 material concerns since we do still have Alloy 600
3 tubes in the Unit 2 steam generators.

4 MEMBER SIEBER: So the enthalpy rise
5 across your reactors is about the same.

6 MR. FREDERICK: No, it will actually
7 increase about seven or eight percent.

8 MEMBER SIEBER: Or eight percent.

9 MR. FREDERICK: Right.

10 MEMBER SIEBER: Okay.

11 MR. FREDERICK: This slide shows the
12 methodologies that we used for the safety analyses and
13 you can see there the change from the current, the
14 ones that have changed, rather the large break where
15 we're using BELOCA methodology now. This is the
16 original Westinghouse methodology, not ASTRUM. That's
17 the more updated one.

18 For non LOCA, we've switched the DNBR
19 calculation to the NRC approved VIPRE code.
20 Previously, we used THINC. Then we have gone on to
21 MAAP as part of the containment conversion program.
22 I'll discuss that a little bit later.

23 In the dose assessment area, we've gone to
24 a full implementation of alternative source term as
25 well as using ARCON 96 for the chi over Q's. In the

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1 non LOCA area, it lists here the condition to
2 acceptance criteria, key ones being DNBR limits, heat
3 generation limits, RCS and secondary pressure limits
4 at 110 percent and criteria that Condition 2 should
5 not escalate into a Condition 3 or 4 event.

6 Condition 3 and 4 criteria are a little
7 less stringent. Some fuel damage is accepted and dose
8 results need to remain within the limits. I might
9 note that for the EPU program none of the events have
10 changed categories.

11 This slide shows the DNBR margin in kind
12 of a pictorial representation. Again at the bottom
13 1.0 for DNBR is critical reflux and the correlation
14 limit which is a number that's actually in our tech
15 specs is 1.14. The Beaver Valley design limit is 1.22
16 and that's adding in the process uncertainties for
17 pressure flow, temperature. And our safety analysis
18 limit that we used for Beaver Valley for the EPU was
19 1.55. So you can see there's about 21 percent margin
20 retained between the safety analysis limit and our
21 actual design limit.

22 And primarily that is because when we
23 started this program we were in a transition on our
24 fuel. So we had some transition core penalties which
25 have since gone away since we're all in the RFA fuel

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1 now. At this point, we have a fair amount of margin
2 in our safety analysis which is good considering that
3 we do have results that are fairly close to the limit.
4 We see here the DNBR events which are events which for
5 DNBR is a primary limit.

6 Some of these use different correlations
7 and those things depend on what kind of event it is.
8 If it's a zero power, for example, we would use a
9 different correlation than WRB-2M. WRB-2M is
10 associated with the RFA fuel and this is the first
11 application at Beaver Valley. That was part of the
12 licensing change and that takes advantage of the IFM
13 to the immediate fuel mixers on the RFA fuel
14 assemblies which provides some thermal hydraulic
15 margin and for that reason, we did regain margin with
16 these analyses that EPU has taken away.

17 MEMBER SIEBER: I take it you could not
18 have done an uprate of this size had you not changed
19 the fuel.

20 MR. MANOLERAS: Limited in thermal
21 hydraulic space?

22 MEMBER SIEBER: Yes.

23 MR. MANOLERAS: I'm not sure. Chris
24 McHugh.

25 MEMBER SIEBER: It doesn't look like you

1 have a lot of excess margin.

2 MR. MANOLERAS: Probably did not while we
3 were doing the transition.

4 MEMBER SIEBER: Right. Okay.

5 MEMBER DENNING: But notice that their
6 criterion here is 1.55 versus 1.38 that we discussed
7 the last time. So there's something there.

8 MEMBER SIEBER: Yeah, but in licensing
9 space, you don't count that margin, you know. It's
10 deterministic. 1.55 is it and to get more room to
11 operate you have to reapply to the agency to change
12 the safety limit.

13 MEMBER DENNING: I don't quite understand
14 what you're saying, Jack, because I mean the 1.38 was
15 at the choice of --

16 MEMBER SIEBER: Ginna.

17 MEMBER DENNING: Ginna.

18 MEMBER SIEBER: Right. This is their
19 choice here.

20 MEMBER DENNING: And that's their choice.
21 Right.

22 MEMBER SIEBER: Right. But once you chose
23 it and the staff approves it, that becomes a firm
24 number and to change the number the staff has to
25 approve the different one.

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1 MR. MANOLERAS: As noted here, the
2 limiting event is the rod withdrawal power at 1.57 for
3 Unit 1 and the other note here is that the steam line
4 breaks which are actually Condition 4 events are
5 analyzed to Condition 2 criteria as a conservative
6 measure.

7 This slide shows some of the events which
8 the challenge the pressure limits and here for the
9 Condition 2 events which are noted by the pressure
10 limit of 2748.5 psia the limiting event is the loss of
11 load and we'll talk about that a little bit more. And
12 the locked rotor has a limit of 120 percent design
13 which is a Level C criteria or ASME level C and that
14 also has the specific limit associated with it and the
15 analyses show that we meet these limits.

16 Discussing the loss of load, we actually
17 had a loss of load event recently in early April and
18 if you look at the blue line on the slide there,
19 that's the actual plant data. The red line is
20 actually a LOFTRAN. That's the thermal hydraulic code
21 that we use for non LOCA events. That analysis is
22 crediting all the control systems which are not
23 normally credited in the safety analysis. So the
24 safety analysis result shows in increase in pressure
25 of around 500 pounds. If we credit control systems

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1 and run the analysis the pressure goes up about 100
2 psi.

3 CHAIRMAN WALLIS: Do you have anything
4 about this calories per gram issue and rod ejection
5 loads coming up?

6 MR. MANOLERAS: Yes, the next slide.

7 CHAIRMAN WALLIS: Okay. I just wanted to
8 know.

9 MR. MANOLERAS: The point of this slide
10 was to demonstrate the level of conservatism in this
11 particular non LOCA analyses contrasting essentially
12 no pressure increase at all with the 500 pound
13 increase predicted by the Code and that's the effect -
14 -

15 CHAIRMAN WALLIS: In strange units here,
16 BTUs per pound. What is that?

17 MR. MANOLERAS: Chris, could you jump in
18 here? The conversion from BTU per pound to calories
19 per gram that would work to about 180 calories per
20 gram for the results here of 326.8.

21 MR. McHUGH: The question was asked this
22 morning about the pre EPU value for Ginna. The pre
23 EPU for Beaver Valley was 180 and the post is 181.6.

24 MR. MANOLERAS: The other note on this
25 slide --

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1 MEMBER POWERS: So I burn up fuel clear
2 across the coolant. Right? Roughly speaking.

3 MR. MANOLERAS: Was there a question
4 there?

5 MEMBER POWERS: Not really.

6 MR. MANOLERAS: Okay.

7 MEMBER DENNING: It's a statement.

8 MEMBER POWERS: One hundred eighty
9 calories per gram will blow your -- up, your third
10 cycle fuel completely off, bust the clad and --

11 MR. MANOLERAS: And this is again a
12 conservative 1D analysis. The other events listed on
13 this slide --

14 CHAIRMAN WALLIS: Well, it doesn't sound
15 very conservative if it's going to challenge the fuel.

16 MEMBER DENNING: He said the analysis was
17 conservative. He didn't say the criterion was
18 conservative.

19 MEMBER POWERS: It's only a prediction.

20 MR. MANOLERAS: The pressurizer --

21 MEMBER POWERS: -- pounds of fuel to 180
22 calories per gram is not a prediction.

23 VICE CHAIRMAN SHACK: That's true.

24 MEMBER SIEBER: If it got there.

25 MR. MANOLERAS: We look at the pressurizer

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1 filling for several events as listed here. For the
2 spurious safety injection, we actually see the
3 pressurizer fill and we talked about this event in
4 some detail at the last meeting. But essentially what
5 that causes us to do is to make sure that the safety
6 valves and the power operator relief valves will be
7 able to pass water and successfully reclose following
8 reset of the pressure signal.

9 To conclude for the non LOCA, as we showed
10 the DNBR, the limits, safety analysis limits have some
11 substantial margin between the design and the actual
12 safety analysis limit that we use. The analysis that
13 we do to look at peak pressures in the system are very
14 conservative and we're comfortable with the results.
15 And again, all the acceptance criteria for all the
16 Conditions 2, 3 and 4 events are met at EPU
17 conditions.

18 Moving on to LOCA, summarized are all the
19 PCT values here for both large break and small break
20 as well as the pre EPU values that are shown there and
21 you see that EPU does not demonstrate a substantial
22 increase in the temperatures and primarily this is
23 because of the modifications that we made in the
24 plants. For the large break, this analysis tends to
25 be very sensitive to containment back pressure. In

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1 the containment conversion program, we've actually
2 raised the initial pressure containment around four
3 pounds. So there is some benefit there as well as
4 going to BELOCA technology. It also shows us some
5 benefit.

6 In the small break area, again we've
7 increased the safety injection flow from our high head
8 system by approximately five percent by changing out
9 the pumps and that provides us some offset of the
10 change due to EPU.

11 VICE CHAIRMAN SHACK: Now are these both
12 calculated with the new best estimate model?

13 MR. MANOLERAS: No, the small break is
14 done using the current NOTRUMP.

15 VICE CHAIRMAN SHACK: But in the large
16 break, the current and EPU. Now are they both --

17 MR. MANOLERAS: No. The current is
18 actually using the Appendix A models.

19 CHAIRMAN WALLIS: Are you the folks who
20 came close to Co Y (PH) oxidation limit?

21 MEMBER DENNING: Yes.

22 MR. MANOLERAS: Yes, for the core -- we
23 were close.

24 CHAIRMAN WALLIS: Are you going to show
25 that? I don't see a slide on that.

1 MR. MANOLERAS: I don't have that in my
2 slides.

3 CHAIRMAN WALLIS: That seemed to be
4 remarkably --

5 MEMBER DENNING: Do you happen to remember
6 those values because I think we ought to mention
7 those?

8 CHAIRMAN WALLIS: Who asked you about
9 that?

10 MR. MANOLERAS: Yes, we can pull them up
11 here real quick.

12 MEMBER DENNING: Okay. I think for one
13 thing it was clear and that was the percent hydrogen
14 was one percent which was essentially the criterion.
15 But we were presented with some discussion by
16 Westinghouse that indicated that the reason it was one
17 percent was the result of a very conservative analysis
18 and because it was so conservative they didn't press
19 it.

20 MR. MANOLERAS: The results could be lower
21 if we pursued it further I guess is the way it was.

22 MEMBER DENNING: And I think that's pretty
23 obvious that that was the case.

24 MR. MANOLERAS: Yes. For the large break,
25 the local cladding oxidation is 8.7 percent for Unit

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1 1 and 6.7 for Unit 2. Again 17 percent is the
2 criteria there. For the core wide for Unit 1, it's
3 0.98 percent and for Unit 2, it's 0.91 and again this
4 is typically the way the analysis is done is we
5 perform a very conservative analysis and if the
6 results come in within the acceptance it's not pursued
7 further even though there are margins that could be
8 put in there if we did further work.

9 CHAIRMAN WALLIS: You guys are also very
10 conservative, are you?

11 MEMBER DENNING: They seem to be careful
12 up until that last "very." But one thing that's clear
13 is that these guys have always been sitting in on the
14 Ginna presentations so they always know the things
15 that --

16 CHAIRMAN WALLIS: I'm just wondering if
17 they are only conservative if they would be
18 acceptable. They would have to very conservative.

19 MEMBER SIEBER: Or very, very
20 conservative.

21 MEMBER POWERS: You're being difficult,
22 Graham.

23 MR. MANOLERAS: Moving on to long term
24 cooling, similar to Ginna, we had some questions from
25 the staff that we needed to address and we had to

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1 essentially redo the analysis to take into
2 consideration the issues listed here, core voiding,
3 system effects and pump -- that we were going to
4 credit --

5 CHAIRMAN WALLIS: This is another area
6 where we have some feeling that the staff ought to
7 sort things out better, isn't it?

8 MEMBER DENNING: Yes. There is high
9 reliance here on the BACCHUS experiments as indicative
10 of a mixing that occurs with some fraction of a lower
11 plenum and all the analyses that we're seeing take
12 that credit without doing a very good analysis of the
13 BACCHUS experiment or using tools that one could use
14 in a more realistic way to better analyze this is my
15 impression.

16 MR. MANOLERAS: I'm not sure if anybody
17 from Westinghouse mentioned it but the PRAs owners
18 group has a program approved to actually work with the
19 staff to --

20 CHAIRMAN WALLIS: That's right. That's
21 another one of those things where the staff is working
22 on doing things better and we want to see it happen.
23 But now we're asked to approve this without knowing
24 what is going to come out of this new evaluation.

25 MR. MANOLERAS: Yes, this analysis has

1 credited 50 percent in the lower plenum based on the -
2 -

3 CHAIRMAN WALLIS: It's the number between
4 zero and one.

5 MR. MANOLERAS: Yes.

6 MEMBER POWERS: Fifty percent is not
7 between zero and one.

8 CHAIRMAN WALLIS: Yes it is. Fifty
9 percent is a half.

10 MR. MANOLERAS: So the results for Beaver
11 Valley we show the switchover time required to go to
12 hot leg injection for Unit 1 is 6.5 and for Unit 2
13 it's six hours and for small breakers, we've also done
14 analyses to address an additional question to
15 basically show that the systems are capable of cooling
16 down and depressurizing within the required switchover
17 time.

18 In the containment area, again we have
19 recently got approval for our containment conversion
20 program and essentially what that does is allows us to
21 operate the containment at about four psi higher,
22 still slightly subatmospheric. This analysis
23 benefitted from some modifications we made in the
24 plant, the replacement of steam generators for Unit 1.

25 CHAIRMAN WALLIS: You've told us the

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1 subcommittee that this was entirely for the benefit of
2 the personnel who had to go into the containment.

3 MR. MANOLERAS: That is certainly one of
4 the major benefits.

5 CHAIRMAN WALLIS: There was no technical
6 reason.

7 MR. MANOLERAS: That does actually give us
8 some PSH margins.

9 MEMBER SIEBER: It helps the pumps in PSH.

10 CHAIRMAN WALLIS: Does it work? It does
11 not help. Doesn't it make it worse?

12 MEMBER SIEBER: No.

13 MR. MANOLERAS: It actually improves the
14 PSH margin.

15 CHAIRMAN WALLIS: Because you get a higher
16 pressure when you -- Okay.

17 MR. MANOLERAS: We put new feedwater
18 isolation valves as Mark said that eventually helps
19 out with our steam line break and the drainage port
20 helps out with the inventory in the sump.

21 CHAIRMAN WALLIS: That means that you get
22 water from the reactor cavity into the sump.

23 MR. MANOLERAS: Yes. Previously we were
24 holding up 25 gallons or something.

25 CHAIRMAN WALLIS: And then there's

1 something about the probability of blocking that hole.

2 MR. MANOLERAS: Pardon me?

3 CHAIRMAN WALLIS: Did you know something
4 about the probability of blocking that drainage?

5 MR. MANOLERAS: It's about a one foot
6 diameter. Is that right?

7 CHAIRMAN WALLIS: The hole doesn't have a
8 screen on it or anything.

9 MR. MANOLERAS: There is no screen on it.

10 CHAIRMAN WALLIS: A big hole?

11 MR. MANOLERAS: It's basically a hole that
12 we did deliberately skew it so that we don't have
13 streaming problems from radiation. But it's basically
14 just an open hole, yes.

15 All the analyses again show that we remain
16 within the current design pressure of 45 psig in the
17 design temperatures. For Unit 1 for the recirc spray
18 pumps we do credit containment overpressure and that
19 is part of the current licensing basis as well.

20 MEMBER DENNING: And you should mention
21 what the duration is that's required in the magnitude
22 of the overpressure.

23 MR. MANOLERAS: Right. The overpressure
24 is required for the first 20 minutes after the pump
25 starts.

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1 MEMBER DENNING: That's pretty small.

2 CHAIRMAN WALLIS: As I recall, that's
3 exactly the same curve as you had before the uprate.
4 There's essentially no change in the --

5 MEMBER SIEBER: Right.

6 CHAIRMAN WALLIS: What you're asking for
7 is close to what you had before, isn't it?

8 MR. MANOLERAS: Right. The time duration
9 only increased I think it was around a minute and the
10 pressure a pound.

11 CHAIRMAN WALLIS: What are the green and
12 red here?

13 MR. MANOLERAS: The green and the red are
14 the required containment overpressure for inside and
15 outside recirc spray pumps.

16 MEMBER DENNING: And the blue is what's
17 available.

18 MR. MANOLERAS: The blue is --

19 CHAIRMAN WALLIS: I thought you have a
20 curve of what you had before the uprate but maybe you
21 don't.

22 MR. MANOLERAS: I did not include those
23 slides in this package.

24 CHAIRMAN WALLIS: But it's very much the
25 same, isn't it?

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1 MR. MANOLERAS: Yes, they are very
2 similar.

3 MEMBER DENNING: And you should also
4 mention the tests that were performed on the pumps and
5 their ability to pump without failure.

6 MR. MANOLERAS: Right. We actually have
7 run the pumps at degraded MPSH conditions in our test
8 program dating back to the late '70s. Actually, they
9 were North Anna pumps, but ours are identical and that
10 test showed that the pumps could operate at reduced
11 MPSH down to, we ran them down to about four feet
12 available and the pumps ran in a stable condition and
13 post-run tear-down showed no damage to the pump. So
14 even under reduced MPSH conditions, we're confident
15 that the pumps will operate.

16 MEMBER KRESS: Were they cavitating
17 severely?

18 MR. MANOLERAS: They were cavitating, yes.

19 MEMBER POWERS: And how long did you run
20 them?

21 MR. MANOLERAS: I think most of those runs
22 were around a half hour.

23 In conclusion, all acceptance criteria for
24 the safety analysis are shown to be met at EPU
25 conditions and the effects of some of the plant

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1 modifications, we may benefit the analyses and help to
2 offset the change in safety margin that would occur
3 from EPU.

4 CHAIRMAN WALLIS: What do you mean by
5 "maintain safety margin"?

6 MR. MANOLERAS: Well, for example, in the
7 case of large break LOCA, we see PCTs that are not
8 changing much from pre EPU to EPU and again those are
9 benefitted by some of the modifications.

10 CHAIRMAN WALLIS: By safety margin, you
11 mean the difference between 2200 and whatever you
12 predict.

13 MR. MANOLERAS: That's correct, yes.

14 CHAIRMAN WALLIS: That was using a new
15 technique.

16 MEMBER DENNING: Yes, that's really a
17 selection of examples.

18 MR. MANOLERAS: A better example might be
19 the small break analysis because that one really does
20 benefit from direct changes we've made to both the
21 charging pumps and the accumulator pressures.

22 CHAIRMAN WALLIS: Actually if you'd use
23 the BASH method you've shown that you didn't have the
24 safety margins.

25 MR. MANOLERAS: Potentially yes.

1 CHAIRMAN WALLIS: This "maintain safety
2 margin" is a term that's used rather loosely I think
3 and you have to be careful about its use. At least
4 you're below the limits. That's what matters. If we
5 started really checking what you'd changed in margin,
6 we'd be here for a long time I think.

7 MR. MANOLERAS: Any other questions?

8 MEMBER KRESS: Have to develop some new --
9 to do that.

10 MEMBER DENNING: Any more questions
11 related to safety analysis?

12 MR. MANOLERAS: I would like to introduce
13 Mike Testa. He'll go over the mechanical impacts.

14 MR. TESTA: Yes. Thank you, Ken, for that
15 introduction. I would also like to thank the
16 Committee for the opportunity to be here today. As
17 Ken said, my name is Mike Testa. I'm the Extended
18 Power Uprate Project Manager for Beaver Valley. I've
19 been at Beaver Valley for 24 years. I came up through
20 the Design Department. I've been assigned as the PM,
21 Project Manager, for the last five or six years and
22 also I manage the related submittals that were put in
23 place to lead up to the uprate.

24 Today I'll be discussing the mechanical
25 impacts. I'll talk about steam generator vibration,

1 piping and component like the balance of plant heat
2 exchangers vibration and flow accelerated corrosion.

3 The first thing here is the steam
4 generator two bundle region that was evaluated. As
5 was discussed earlier in the presentation on the Unit
6 1 just this spring a few weeks ago, we replaced the
7 steam generators from a Model 51 to a Model 54F.
8 Steam generators are designed for the uprate
9 condition.

10 For Unit 2, we're continuing to utilize
11 the existing Model 51 steam generators. They were
12 reviewed for flow induced vibration effects which
13 showed acceptable results. We also looked at
14 unsupported U bends for increased fatigue and under
15 this evaluation, there were six tubes that were
16 required to be plugged or taken out of service and
17 that was already done. And we also looked at increase
18 in tube wear at the anti-vibration bar interface which
19 was evaluated and also shown to be acceptable.

20 VICE CHAIRMAN SHACK: What's the material
21 on your Model 51?

22 MR. TESTA: Six hundred.

23 VICE CHAIRMAN SHACK: ET or 600?

24 MR. TESTA: I'll let Greg Kammerdeiner
25 answer that.

1 MR. KAMMERDEINER: This is Greg
2 Kammerdeiner from First Energy. It's Alloy 600 low
3 temperature milled.

4 MR. TESTA: Going on, as far as the steam
5 generator, steam dryer for the secondary steam dryer,
6 we are aware of the issues with the BWR dryers. Now
7 what we did here was look at the secondary separators
8 for our Model 51 and 54 steam generators and I think
9 the bottom line, the conclusion there, is that the way
10 that the steam flow comes up through the secondary
11 dryers, the velocities are low. They are on the order
12 of 3.5 to 4 feet per second; whereas the BWR they are
13 on the order of 100 feet per second in the area or in
14 the region where they've had problems with cracking.

15 Again the comparison between the Model 51
16 and 54, the 54 is comparable velocity and basically,
17 the bottom line is that the PWR secondary steam dryers
18 have not exhibited any operational issues in the
19 industry.

20 As far as the balance of plant exchangers
21 again we looked at the increased flow, change in
22 parameters, thermal dynamic parameters through the
23 heat exchangers. It shows that the feedwater heaters,
24 moisture separator reheaters, were acceptable. As far
25 as the condenser, it was mentioned previously that our

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1 Unit 1 condenser was previously staked. We will doing
2 that on Unit 2 before we increase power.

3 Vibration monitoring, secondary piping
4 systems, we're going to monitor the secondary systems
5 pre EPU and that's going to include a baseline
6 walkdown for each of the plants which we have done
7 that at the 100 percent pre EPU level. Areas of
8 interest will be targeted for inspection and what
9 we're doing here is we're going to utilize the
10 guidance from ASME OM-3. Going forward as we escalate
11 power, we're going to collect and review data at each
12 power ascension plateau. We will augment the
13 inspection with the vibration monitoring equipment as
14 required and just the last bullet here is just a note
15 that we have large equipment, for example, the reactor
16 coolant pump and the turbine which is continuously
17 monitored with the existing installed plant
18 instrumentation.

19 Just a final thing here to wrap up on flow
20 accelerated corrosion, we have evaluated the impact of
21 the uprate on our flow accelerated corrosion program.
22 The EPU effects were evaluated using CHECWORKS. Just
23 a second bullet here, just a note, turbine extraction
24 steam teeth, one in each unit at comparable locations
25 were replaced and that was done proactively.

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1 The next item here is the post uprate
2 outage inspection sampling will be increased based on
3 the EPU and piping systems impacted will continue to
4 be monitored to detect any deviation from predicted
5 wear rates.

6 MEMBER POWERS: I'm puzzled just a bit
7 about bullet number two. You did that because you
8 detected something in CHECWORKS that was bothersome.

9 MR. TESTA: Yes. We're going to let Dave
10 Grebski. He's our program.

11 MR. GREBSKI: Yes, Dave Grebski, First
12 Energy. The MSR relief valves set point was increased
13 to 260 pounds. Therefore the design pressure
14 increased in that system. So the margin between the
15 measured thickness and the required was cut into. So
16 as Mike said, we proactively replaced that. Upgraded
17 with chrome mollie material because it was undergoing
18 some thinning.

19 MR. TESTA: Okay. If there are no other
20 questions, that concludes my part of the presentation.
21 I would like to introduce Colin Keller. He's our
22 Supervisor of our PRA group. Colin.

23 MR. KELLER: Mike, thank you for that
24 introduction. As Mike said, my name is Colin Keller
25 and I'm the Supervisor of the PRA group at Beaver

1 Valley. Today I'd like to talk about the elements of
2 the PRA model that were reviewed for EPU conditions,
3 initiating event frequencies, success criteria,
4 equipment failure rates and also operator response
5 times and also discuss the changes that resulted in
6 core damage frequency and large early release
7 frequency.

8 CHAIRMAN WALLIS: You're going to use CDF
9 from LERF. This is a plant which is closer to a
10 population center than almost all other plants. Isn't
11 that?

12 MR. KELLER: I don't know. I can't speak
13 for all other plants. We are relatively close to the
14 Pittsburgh area.

15 CHAIRMAN WALLIS: It's pretty close to.
16 Yes, so this isn't really part of what you have to
17 evaluate. It's just my curiosity. How close is it to
18 Pittsburgh because this is obviously some element of
19 risk associated with it?

20 MR. KELLER: I believe it's approximately
21 35 miles.

22 CHAIRMAN WALLIS: Thirty-five miles.

23 MR. KELLER: Somebody can correct me.

24 MEMBER SIEBER: Thirty.

25 CHAIRMAN WALLIS: Thirty. So the center

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1 of Pittsburgh which is a fairly big city.

2 MEMBER SIEBER: It's getting smaller.

3 MR. KELLER: Okay.

4 (Several are speaking at once.)

5 MEMBER POWERS: Moved out. It may become
6 more attractive now.

7 MEMBER SIEBER: Went down by two not too
8 long ago.

9 MEMBER POWERS: The age increased when
10 Jack left.

11 CHAIRMAN WALLIS: But if people are all
12 moving to the suburbs then they would be closer to
13 this reactor, wouldn't they?

14 MEMBER SIEBER: So did the ugliness
15 factor.

16 CHAIRMAN WALLIS: Okay. We'll move on.

17 MR. KELLER: Looking at our initiating
18 events as a result of our review for the extended
19 power uprate, there were no new initiating events
20 identified and also there were no significant
21 increases in the initiating event frequencies due to
22 the extended power uprate.

23 For our success criteria, we used the MAAP
24 code to perform the analysis to establish that
25 criteria and also identified that there were no

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1 accident sequences that resulted from the extended
2 power uprate. Our component and system reliabilities
3 with comprehensive reviews of the equipment was
4 performed. We found that the systems will operate
5 within the allowable limits and that the impacts on
6 PRA failure rates, there was no impact on the PRA
7 failure rates or results. In the area of operator
8 response times, again we used the MAAP analysis to
9 determine operator action time available and did find
10 that as a result of the higher decay heat that some of
11 those times had reduced for operator actions.

12 This is a table for Unit 1 showing the
13 resulting changes from pre EPU to post EPU for total
14 core damage numbers as well as internal, external and
15 fire and also for total LERF. As you can see, the
16 changes in risk were relatively small compared to the
17 original risk.

18 VICE CHAIRMAN SHACK: There are nominally
19 changes in risks though. They're just changes in
20 frequency.

21 MR. KELLER: There were some additional
22 modifications that were made especially at Unit 1
23 where you added additional equipment like cavitating
24 venturis fast acting feedwater isolation valves. so
25 there were some additional failure probabilities due

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1 to those equipment, but those overall impacts were
2 very small.

3 MEMBER POWERS: There's also an increase
4 in the inventory of releaseable radionuclides that
5 amounts to about eight percent. That's not reflected
6 in those numbers.

7 MEMBER SIEBER: Yes.

8 MEMBER POWERS: Why are they meaningful to
9 us? I mean if we do a power uprate and we look at the
10 change in risk, we don't look, the one that that's
11 absolutely guaranteed to go up.

12 MEMBER KRESS: Number 1, the inventory
13 would affect the LERF that you think is a surrogate
14 for the QHO.

15 CHAIRMAN WALLIS: That's right.

16 MEMBER KRESS: And Number 2, the percent
17 increase in fission products means the societal risk
18 is increased by that much.

19 MEMBER POWERS: But that's not reflected
20 in these numbers.

21 MEMBER KRESS: Not in any of these
22 numbers, that's right.

23 MEMBER DENNING: Which is a good reason
24 why we don't use PRA to these in a risk inform.

25 MR. KELLER: This is not a risk informed

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1 application. It's kind of a --

2 MEMBER DENNING: Because I don't think PRA

3 --

4 MEMBER POWERS: I'm not terribly concerned
5 about his application right now. I'm concerned about
6 what our responsibilities are to advise the Commission
7 on what its responsibilities are and here we're going
8 up and we're advertising to the world that we're
9 making something like a one percent change in risk
10 when in fact we're making almost ipso facto, a
11 guaranteed eight percent change in risk. Without any
12 analysis at all, I can come up with roughly eight
13 percent here. We're just kind of lying here, aren't
14 we?

15 CHAIRMAN WALLIS: I usually call it change
16 in CDF and LERF.

17 MEMBER DENNING: We should certainly --

18 MEMBER SIEBER: These numbers reflect the
19 risk but the consequence.

20 MEMBER DENNING: No, I wouldn't say so.
21 I think that Dana is right. I mean the risk is --

22 MEMBER SIEBER: To an individual.

23 MEMBER KRESS: Two plants is on the site
24 so it's 16 percent.

25 CHAIRMAN WALLIS: No.

1 MEMBER POWERS: No, it's still eight
2 percent. An eight percent increase totally.

3 MEMBER SIEBER: Only one at a time is
4 melting.

5 CHAIRMAN WALLIS: This is a point we've
6 made many times before I think.

7 MEMBER DENNING: Yes, it is and I think
8 that you can move on.

9 CHAIRMAN WALLIS: It's worth making every
10 time this comes up.

11 MR. KELLER: I'll move on to the summary
12 of the Unit 2 results again identifying the changes
13 there. Relatively small pre EPU risk for each of the
14 categories identified.

15 CHAIRMAN WALLIS: There's also a change in
16 benefit if we're going to talk generalities here which
17 is also proportionate.

18 MEMBER KRESS: That's true.

19 CHAIRMAN WALLIS: So the risk/benefit
20 balance is presumably about the same.

21 MEMBER POWERS: The question is first and
22 foremost is whether we're impacting the adequate
23 protection of the public health and safety.

24 MEMBER DENNING: That's right.

25 MEMBER POWERS: And we don't get to count

1 benefit until we've satisfied ourselves on that.

2 MEMBER KRESS: And that's what these
3 numbers are trying to persuade us.

4 MEMBER DENNING: No.

5 CHAIRMAN WALLIS: We would be doing this
6 forever.

7 MR. KELLER: It's not intended for that
8 purposes. You would use the radiological analysis
9 really as your measuring stick for measuring health
10 and safety for the public.

11 CHAIRMAN WALLIS: But if there were no
12 benefit.

13 MEMBER DENNING: We've been through
14 comparisons with the criteria of acceptability.
15 That's where we make our decisions on. They meet the
16 various standards that are established
17 deterministically and that's how we make our
18 decisions.

19 MEMBER POWERS: Those standards are
20 reliable as 200 calories per gram. Right?

21 MEMBER DENNING: At least.

22 MEMBER SIEBER: Even more so.

23 CHAIRMAN WALLIS: I thought, Dana, you
24 were a great advocate of saying if they meet the
25 regulations then they're safe enough.

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1 MEMBER SIEBER: It's what the law says.

2 MEMBER POWERS: When did I say that? I
3 must be countering some arguments you were making.

4 CHAIRMAN WALLIS: I thought you said it
5 was very skillful of the staff to define adequate
6 safety as meeting the regulations.

7 MEMBER POWERS: Oh yeah.

8 CHAIRMAN WALLIS: I thought you were sort
9 of endorsing it.

10 MEMBER POWERS: I think that's an absolute
11 --

12 CHAIRMAN WALLIS: But you don't
13 necessarily endorse that point of view then.

14 MEMBER DENNING: I think this is a good
15 time for the conclusions on the PRA.

16 MR. KELLER: In conclusion, we'll state
17 that all the elements of the PRA model were reviewed
18 for extended power uprate impacts and the increase in
19 risk due to the extended power uprate for Units 1 and
20 2 is small compared to the current overall threshold.

21 CHAIRMAN WALLIS: You have increases in
22 frequencies again.

23 MEMBER DENNING: Thank you.

24 MEMBER POWERS: What is it in fire PRA
25 that changes the power uprate?

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1 MR. KELLER: What had changed in the --

2 MEMBER POWERS: Yes, what is it that
3 causes an increase in fire risk?

4 MR. KELLER: I'll ask Bill Etzel to answer
5 that question.

6 MR. ETZEL: This is Bill Etzel from First
7 Energy. Just basically we change human error rates
8 and as a consequence of that, any initiating event
9 also increased in frequency.

10 MEMBER POWERS: So it's just a time they
11 have available to respond before they uncover the
12 core.

13 MR. ETZEL: That is correct. Right. Or
14 other program measures.

15 MR. KELLER: Are there any other
16 questions? Okay.

17 MEMBER POWERS: In the PRAs, the fact that
18 your water is a little hotter and flowing a little
19 faster, there's no way to account for increased
20 corrosion or anything like that in the PRA.

21 MEMBER SIEBER: No.

22 MR. KELLER: No, not in the PRA. No sir.

23 MEMBER POWERS: So the PRA is kind of a
24 void of anything in it that would tell us.

25 MEMBER SIEBER: That's right.

1 MEMBER DENNING: Yes, it is very poor. I
2 mean the way we do PRA makes it a very poor tool to
3 evaluate the acceptability of an EPU. Thank you.
4 With that --

5 MEMBER SIEBER: Would you say that when
6 George is here?

7 MEMBER POWERS: It -- and the frequencies
8 are done improperly.

9 MEMBER DENNING: So what else did you want
10 done improperly?

11 MR. COLBURN: My name is Tom Colburn.
12 I'll be continuing on with the staff's presentation.
13 The staff in the area of reactor systems analysis
14 looked at fuel and nuclear system design changes and
15 determined there were no significant changes to the
16 fuel or the methodologies used in the design analysis.
17 The non LOCA analysis and transients, the LOCA
18 analysis and that was considerations, ECCS boron,
19 precipitation and long term cooling.

20 The staff review used Matrix A, the Review
21 Standard RS 001. As I said, there were no changes
22 from the NRC's approved codes and methodologies, no
23 changes to the fuel design. No DNBR transition
24 penalties were needed. Uncertainties were applied to
25 initial conditions in a conservative manner and

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1 conservative analyses methods and transient
2 assumptions were used and staff determined that all
3 applicable acceptance criteria were met. There were
4 acceptable margins in the safety analysis limits and
5 in the safety analysis results.

6 Staff review looked at the ECCS systems in
7 their approach to control boron precipitation, large
8 break LOCA analyses, post LOCA long term cooling for
9 boron precipitation, small break LOCA analysis for the
10 short term behavior and post LOCA long term cooling.
11 The staff conducted independent analyses on their own
12 to confirm licensee results and conducted audits at
13 the Westinghouse offices of the licensee analysis and
14 calculations.

15 MEMBER DENNING: Incidentally, I should
16 comment for both this application and the previous one
17 although the staff didn't do a lot of independent
18 analyses, the staff that made the presentations
19 definitely showed an understanding of these analyses
20 and they clearly looked into them in great detail and
21 clearly understood where the sensitivities were. I
22 thought that they gave very good indication of the
23 understanding. Even though there were some points
24 where there were independent analyses, in general
25 there weren't many independent analyses. But again,

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1 for the whole thing they really indicated their
2 understanding of where the insensitivities were in the
3 analyses that were provided to them.

4 CHAIRMAN WALLIS: Would you tell the
5 Committee what independent analyses were performed
6 because this is just a general statement here? Could
7 you indicate which the more important ones were
8 performed?

9 MR. COLBURN: I'll defer to Dr. Sam
10 Miranda.

11 DR. MIRANDA: In the LOCA, there were
12 independent analyses performed extensively in the
13 small break LOCA and in the non LOCA area, we did a
14 sample.

15 CHAIRMAN WALLIS: Similar of running a
16 code to evaluate the sequence of events and the
17 temperatures and so on.

18 DR. MIRANDA: Yes, for the small break
19 LOCA, RELAP was used.

20 CHAIRMAN WALLIS: RELAP?

21 DR. MIRANDA: Yes. And for the non LOCA
22 analyses, we used LOFTRAN.

23 CHAIRMAN WALLIS: But you didn't use
24 TRACE.

25 DR. MIRANDA: No, we didn't.

1 MEMBER KRESS: It didn't have a deck for
2 this reactor.

3 CHAIRMAN WALLIS: I thought these decks
4 were transferrable from RELAP to TRACE.

5 MEMBER SIEBER: No.

6 MEMBER POWERS: Transferrable is kind of
7 an on/off switch, isn't it? I mean it either is or
8 isn't.

9 MR. COLBURN: For the non LOCA transients,
10 the staff review followed the guidelines in Review
11 Standard 0001. The events were analyzed with LOFTRAN
12 and VIPRE. Analysis considerations were the power
13 level of 2917.4 megawatts thermal was assumed in the
14 analysis.

15 CHAIRMAN WALLIS: The staff used?

16 MR. COLBURN: I'm sorry. The licensee.

17 CHAIRMAN WALLIS: All right.

18 MR. COLBURN: The analyses considerations,
19 the licensee used 2917.4 megawatts thermal and that
20 was assumed in the analyses. The actual power level
21 increase is 2900 megawatts thermal.

22 The Beaver Valley steam generators were
23 replaced in the spring 2006 for fueling outage. The
24 licensee qualified the peak pressurizer safety relief
25 valves water relief during the inadvertent safety

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1 check --

2 CHAIRMAN WALLIS: I think it's 2910
3 megawatts thermal, isn't it, that they're asking for?

4 MR. COLBURN: 2910 is the NSSS number.
5 Actual license thermal power level is 2900 megawatts
6 thermal.

7 CHAIRMAN WALLIS: Where does it say 2910
8 on their slide six then?

9 MR. COLBURN: That's the NSSS.

10 CHAIRMAN WALLIS: I don't understand what
11 you mean by that.

12 MR. FREDERICK: This is Ken Frederick.
13 The 10 megawatts is the RCP heat input.

14 CHAIRMAN WALLIS: Oh. Okay. All right.
15 Thank you.

16 MR. COLBURN: Staff determined that the
17 results satisfied applicable acceptance criteria for
18 peak clad temperature, DNBR and reactor coolant system
19 pressure.

20 CHAIRMAN WALLIS: Again, this DNBR is
21 something found by the licensee.

22 MEMBER SIEBER: Yes.

23 MEMBER POWERS: Plant specific let's say.

24 CHAIRMAN WALLIS: Okay.

25 MEMBER SIEBER: That's another way of

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1 saying it.

2 MEMBER KRESS: Not if it's bigger than
3 1.24 --

4 MEMBER DENNING: Go ahead, Chris.

5 MR. COLBURN: For the large break LOCA
6 analysis, licensee used the BELOCA methodology with
7 COBRA-TRAC. Cold leg break was limiting for boron
8 precipitation. Licensee initiated simultaneous
9 injection before boron precipitation occurs. They
10 increased the minimum accumulated pressure and
11 containment operating pressure which partially offset
12 the increase in power effects for the review and staff
13 determined that they met the 10 CFR 50.46 acceptance
14 criteria for ECCS performance, PCT and cladding
15 oxidation.

16 For the small break LOCA analysis the
17 licensee modeled their analysis using NOTRUMP.
18 Initially the application assumed even integer break
19 sizes. This was later expanded during the review to
20 include a broader spectrum of break sizes. The
21 initial model assumed a broken loop seal clears for
22 all small break LOCA. Licensee reanalyzed this to
23 assume only that the loops cleared only for certain
24 small break LOCAs in response to the staff's
25 questions.

1 The licensee increased the accumulated
2 pressure and safety injection flow to gain margin in
3 the analysis and the staff independent calculations
4 agreed with the licensee results. The short term LOCA
5 analysis and small break LOCA analysis and small break
6 and large break long term cooling analogies were
7 determined to meet the 10 CFR 50.46 acceptance
8 criteria.

9 CHAIRMAN WALLIS: If they identified the
10 need for EOP changes, were the changes that were made
11 satisfactory?

12 MR. COLBURN: Yes, these were typically
13 changes in operator response time.

14 CHAIRMAN WALLIS: They also checked that
15 the changes were appropriate and satisfactory.

16 MR. COLBURN: Yes, the changes for the EOP
17 --

18 CHAIRMAN WALLIS: Having finding there's
19 a need for something doesn't mean to say you've met
20 that need satisfactorily. So that is okay.

21 MR. COLBURN: Yes, it is.

22 CHAIRMAN WALLIS: Probably said that's
23 what they did.

24 MR. COLBURN: The need for EOP changes
25 resulted in change to operator actions to compensate

1 for the need to perform actions in a more timely
2 fashion. The staff review also confirmed the timing
3 for boron precipitation.

4 With regard to mechanical impacts for flow
5 induced vibration, the main steam and feedwater piping
6 is instrumented at critical locations. Licensee
7 collected data and evaluated that in accordance with
8 ASME OM-3. A flow induced vibration on the steam
9 separator typically increases at EPU conditions.

10 (Telephone ringing.)

11 MR. COLBURN: The flow induced vibration
12 on the steam separators is minimized due to its high
13 stiffness and low flow velocity. Flow induced
14 vibration on U-bend tubing is within the allowable
15 limits. The fluid elastic instability ratio is less
16 than one and the peak stresses are less than the
17 material endurance limit. The potential for fuel
18 induced vibration was determined not to increased for
19 the steam separators and steam generator tubes at EPU
20 conditions.

21 The flow accelerate corrosion program, the
22 EPU conditions will change the temperature, flow
23 velocity and moisture content for some components.
24 The licensee used an updated CHECWORKS computer model
25 which will help determine future inspection and repair

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1 replacement plans. The flow accelerated corrosion
2 program, the scoping criteria, are consistent with
3 industry guidelines for temperature and moisture
4 content, component alloy content and the amount of
5 usage at EPU conditions.

6 Licensee also looked at the risk
7 evaluation. The full power PRA model was used
8 including internal events, flooding, seismic, internal
9 fires and PDF and LERF. A qualitative approach was
10 used by the licensee for other risks, high winds,
11 external floods and other external events screened per
12 NUREG 1407. Shutdown risk questions in Standard
13 Review Plan Chapter 19 were addressed.

14 MEMBER DENNING: Let me -- Let's press on.
15 I mean although we don't really think that the risk
16 assessment isn't an important element of this review.
17 As we look at the internal events for Unit 1 for
18 example at 6×10^{-6} per year, this is a awfully low
19 internal events core damage frequency. Does the SPAR
20 model indicate that that really is a credible number
21 and the fires at 5×10^{-6} per year, those are really
22 small.

23 MR. LAUR: This is Steve Laur from the
24 Division of Risk Assessment. The SPAR, let's see. I
25 have to find it here on this cheat sheet. Yes, Unit

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1 1 is just under $3E^{-5}$ per year and Unit 2 is a little
2 less under $3E^{-5}$ per year in the SPAR model.

3 MEMBER DENNING: So the SPAR models are
4 fairly significantly higher than what's being quoted
5 to us.

6 MR. LAUR: They are the -- They are
7 actually closer to the total risk including fires and
8 seismic that the licensee has.

9 MEMBER DENNING: Okay.

10 MEMBER BONACA: Do you have an
11 understanding of the differences, where they are
12 coming from?

13 MR. LAUR: I do not know. I did reach the
14 benchmark report. We actually, other individuals in
15 the Division of Risk Assessment have gone to every
16 plant to benchmark the significance determination
17 process phase II worksheets and they do that by taking
18 the worksheet, the SPAR model and the licensee's PRA
19 and the conclusion was there's good agreement. That
20 doesn't mean an numerical agreement. Usually what
21 that means is the order of magnitude risk profile and
22 the ability to get a similar result on a significance
23 determination finding.

24 MEMBER DENNING: You can comment.

25 MR. ETZEL: Bill Etzel from First Energy.

1 I believe the major differences in the RCP CL LOCA
2 modeling between the SPAR model and our plant specific
3 PRA.

4 MEMBER DENNING: And your belief is that
5 your reactor pumps seal model is more realistic.

6 MR. ETZEL: Yes, we use the Westinghouse
7 WCAP methodology.

8 MEMBER DENNING: A newer methodology.

9 MR. ETZEL: And I'd like to comment that
10 they are going to be revising the SPAR model. We just
11 did a PRA model update for Unit 1 and we will be
12 giving that to INEEL so that they can update their
13 SPAR model.

14 MEMBER DENNING: Have your values always
15 been this low like 6×10^{-6} ? Those are really low
16 numbers for an older plant.

17 MEMBER SIEBER: Yes.

18 MR. LAUR: No.

19 MEMBER DENNING: No. And what has
20 improved? Have there been changes in the plant design
21 or have there been changes in the methodology?

22 MR. LAUR: Changes in the methodology
23 primarily. We now take credit for dedicated aug
24 seawater pumps in reducing our RCP seal LOCA. We did
25 a best estimate MAAP runs, ran out to 48 hours with

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1 SBO conditions and found out that we would not uncover
2 the core. Therefore, those small seal LOCAs, 76 gpm
3 and less, as long as we maintain aug seawater we do
4 not uncover the core. So those accident sequences are
5 now going to success state.

6 MEMBER BONACA: But now it sounds like
7 that SPAR model, I mean the LOCA contribution to CDF
8 from SPAR is very high and that's --

9 MEMBER DENNING: Fractionally.

10 MEMBER BONACA: Fractionally. But I
11 didn't hear that from the gentleman behind there that
12 said that there was reasonable agreement between the
13 contributors and the outlier and distributional risks.

14 MR. LAUR: Yes. What I said was
15 reasonable agreement in terms of core damage frequency
16 profile, in other words, distributed but not the
17 absolute numbers.

18 MEMBER BONACA: Yes.

19 MR. LAUR: And in fact, the SPAR models
20 are, they're very good plant to plant because they are
21 standardized and they all use generic data for
22 example. But that's one place that where a licensee
23 can use basically update to use their actual operating
24 experience to get a lower number.

25 MEMBER DENNING: Again, I think that this

1 is a good application of SPAR regardless of who is
2 right because nobody is really right.

3 MEMBER BONACA: Yeah.

4 MEMBER DENNING: But I think that having
5 these kind of base generic models allows you to look
6 and see why is it that they're getting lower values
7 than the NRC is. Again, it's a little bit of a
8 digression here because I don't think it makes a lot
9 of difference to our decision here as to whether it
10 started out at 6×10^{-6} in the internal events or $3 \times$
11 10^{-5} . So thank you and Chris, you can continue.

12 MR. COLBURN: Staff conducted an onsite
13 audit in October of 2005 to check the quality of the
14 licensee's PRA and EPU risk assessment. The staff's
15 review determined that there were minor impacts on the
16 success criteria, time to recover offsite power,
17 auxiliary feedwater flow for ATWAS as in fact the
18 cavitating venturis, containment accident pressure
19 credit for net positive suction head. There was less
20 time available for some operator actions, post EPU,
21 CDF and LERF MAAP timing.

22 The staff review validated important short
23 time available actions and performed a human
24 reliability sensitivity analysis. The staff
25 determined that important operator actions that had

1 short term available were depressurizing the reactor
2 coolant system and implementing feed and bleed
3 cooling.

4 MEMBER BONACA: Did you reach any
5 conclusion regarding quality?

6 MR. COLBURN: The staff determined that
7 the licensee's analysis and risk assessment were of
8 sufficient quality that we didn't have any concerns.

9 MEMBER BONACA: Right.

10 CHAIRMAN WALLIS: Were you not concerned
11 about the short time for initiating feed and bleed?

12 MR. LAUR: This is Steve Laur, Division of
13 Risk Assessment. The short time for feed and bleed as
14 well as depressurizing the RCS, those are
15 proceduralized operator actions that are frequently
16 trained on by the operating crews in the simulator.
17 They are in response to symptom-based procedures and
18 so it's really more a factor of when you get to that
19 physical step in the procedure because the actual
20 steps you take to perform the action are simple and
21 take between two and ten minutes or ten minutes is
22 probably an outside number. So what we asked the
23 licensee to do is to validate via simulator or a
24 walkthroughs or talkthroughs that the reduced amount
25 of time available did not preclude any operator

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1 action.

2 CHAIRMAN WALLIS: Well, it's now down to
3 15 minutes or something like that.

4 MR. LAUR: I believe -- No, I think that
5 was the licensee this morning. I think it was 29.

6 CHAIRMAN WALLIS: It was the people this
7 morning that was 15 minutes.

8 MR. LAUR: It was 29 minutes. Help me out
9 here, Bill or somebody.

10 MR. KELLER: This is Colin Keller from
11 First Energy. Yes, for Unit 1 it was 29 minutes and
12 I believe for Unit 2 it was 42 minutes.

13 MR. COLBURN: Conclusions with the risk
14 assessment, licensee assessed the potential risk
15 impacts of the EPU. Changes in the core damage
16 frequency were determined to be very small. Changes
17 in large early release frequency were also determined
18 to be very small. The power uprate did not create
19 special circumstances, but the presumption of adequate
20 protection and the risk of the power uprate
21 implementation were actually addressed by the licensee
22 and are considered acceptable by the staff.

23 In terms of licensee implementation of the
24 power uprate, the licensee indicated that they are
25 going to do a two phase implementation for both units.

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1 Beaver Valley 1 will increase power by three percent
2 for the remainder of this operating cycle and will
3 implement the remainder of EPU next operating cycle.
4 All balance of plant modifications necessary to
5 support the power uprate have been completed, but I
6 think the fuel loading completed during the most
7 recent refueling outage that occurred in April would
8 not allow them to operate for the entire cycle at the
9 uprated power.

10 Beaver Valley 2 has some more balance of
11 plant modifications to implement. They're going to
12 implement some of those during the fall of 2006
13 refueling outage and then they're going to increase
14 power by three percent during the following operating
15 cycle. They will implement the balance of plant
16 modifications including the all reaction high pressure
17 turbine modification during the spring 2008 refueling
18 outage and then implement the remainder of the power
19 uprate increase during that following operating cycle.

20 In summary, the staff review, the licensee
21 proposed a power outage against the criteria that NRC
22 Review Standard RS-001. The licensee supplemented the
23 application numerous times in response to the staff's
24 request for additional information. The review was
25 kept on track in large part by some staff audits that

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1 helped expedite the reviews and at the end, the staff
2 determined that the licensee met all applicable review
3 criteria in the review standard for the uprate
4 conditions. What I would like to do -- Are there any
5 questions?

6 MEMBER DENNING: Any further questions for
7 staff?

8 MR. COLBURN: What I would like to do now
9 is turn the presentation over to the licensee so that
10 they can provide their concluding remarks.

11 MR. SENA: Thank you. Again, this is Pete
12 Sena. Again, Beaver Valley would like to thank the
13 Committee for their time and consideration for our
14 uprate application. We believe we have performed
15 detailed and comprehensive reviews. No safety issues
16 had been identified and again, Beaver Valley Power
17 Station will be operated safely and reliably through
18 our modifications, procedure changes, our training and
19 our adherence to our technical specifications and
20 operating license. With that, I would like to open up
21 the floor to any subsequent questions for the Beaver
22 Valley staff.

23 MEMBER DENNING: I don't think we have
24 any. I would like to thank you very much. Excellent
25 presentations by your staff today and also at the

1 earlier meetings. I'd also like to thank the
2 Regulatory staff for their presentations as well and
3 I think they did a very good job of reviewing this
4 application. So thank you very much.

5 Now I was wondering, Graham, whether we
6 ought to ask Westinghouse whether from this morning's
7 presentation whether they had an opportunity to
8 determine whether there was any additional information
9 they might present still today.

10 CHAIRMAN WALLIS: Yes.

11 MEMBER DENNING: I think they are looking
12 around to see if he's in the men's room.

13 MEMBER SIEBER: They went back to
14 Pittsburgh to increase the population.

15 MR. FINLEY: This is Mark Finley from this
16 morning, Ginna's Project Manager. Yes, Westinghouse
17 has some additional information.

18 MEMBER DENNING: And this looks like a
19 good time, Mark.

20 MR. FINLEY: If you have time now, that
21 would be good.

22 MEMBER DENNING: Yes, we do. We have to
23 stay in session here then.

24 MR. FINLEY: Okay. Good. He'll be in in
25 just a moment.

1 MEMBER DENNING: So you can stand at your
2 seat and stretch if you would like to.

3 CHAIRMAN WALLIS: Is this seventh inning
4 stretch or something like that?

5 (Discussion off microphone.)

6 MEMBER DENNING: I think we're ready to
7 start here again, guys. Is it easier for you to move
8 a little further that way?

9 MR. HUGEL: Whatever you want me to do.

10 MEMBER DENNING: Does that light in your
11 eyes really bother you? Or hadn't you noticed it
12 until I mentioned it?

13 MR. HUGEL: It really doesn't matter.

14 MEMBER DENNING: It's okay with you if you
15 want to stay there. That's fine.

16 MR. HUGEL: As long as I'm not blocking
17 anybody's view.

18 MEMBER BONACA: No, you're not.

19 MEMBER DENNING: It's pretty good.

20 CHAIRMAN WALLIS: I think we're on the
21 record. Does anyone say anything else? We can always
22 come off the record if you want to.

23 MEMBER DENNING: No, I know we're on the
24 record and we're now back discussing the Ginna Nuclear
25 Power Plant and Westinghouse is going to make a

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1 presentation related to the 3-D rod ejection analysis.
2 Please go ahead.

3 MR. HUGEL: Yes. My name is Dave Hugel.
4 Again, I work for Westinghouse. The question came up
5 regarding the limit that we're using for the rod
6 ejection event. I did contact Pittsburgh and talked
7 to some of our experts and they sent me some slides
8 that I hope will help demonstrate that when you employ
9 a 3-D methodology and we do have this 3-D methodology
10 that was approved. 15806 was the priority version of
11 the methodology, 07 the non PORV in February of '02.

12 And in this methodology, we transitioned
13 from the 1B analysis methodology that Westinghouse has
14 employed for the last 30 years.

15 CHAIRMAN WALLIS: Get it clear what the
16 first bullet means.

17 MR. HUGEL: I'm sorry.

18 CHAIRMAN WALLIS: You mean the NRC has
19 approved this methodology.

20 MR. HUGEL: Yes.

21 CHAIRMAN WALLIS: And now you are
22 licensing it to the plant.

23 MR. HUGEL: Well, we haven't done that.
24 We have a number of utilities who have contacted us
25 and have requested that we do this analysis for them,

1 but we don't -

2 CHAIRMAN WALLIS: What does Westinghouse's
3 license mean here? What does it mean?

4 MR. HUGEL: The methodology, in other
5 words, the approach of analyzing the rod ejection
6 event has been reviewed and approved by the NRC.

7 CHAIRMAN WALLIS: -- has a license. Okay.
8 I thought you were talking about you licensing
9 something.

10 MR. HUGEL: No. That would be something
11 new.

12 CHAIRMAN WALLIS: License it to the
13 licensee. I mean you could let them use it in that
14 sense.

15 MR. HUGEL: True.

16 CHAIRMAN WALLIS: So it's ambiguous.

17 MR. HUGEL: That's true.

18 CHAIRMAN WALLIS: So you've cleared it up.
19 Thank you.

20 MR. HUGEL: I'm sorry. Yes, the NRC
21 approved the 3-D rod ejection methodology but we have
22 not implemented it on any of the plants since the
23 industry EPRI, the NRC --

24 CHAIRMAN WALLIS: But there was no need to
25 do so?

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1 MR. HUGEL: No, because I guess they're
2 still not -- Agreement is still --

3 CHAIRMAN WALLIS: So it's still 200
4 calories per gram.

5 MR. HUGEL: Right. There is no agreement
6 as to what the new limit should be and that's I
7 believe being pursued and they're trying as Paul had
8 mentioned to resolve that and once that is resolved,
9 then I expect that plants will employ this
10 methodology.

11 CHAIRMAN WALLIS: So maybe we should do
12 something to push this along.

13 MR. HUGEL: I want to make sure that
14 whatever is decided in terms of a limit is acceptable
15 to everybody and is appropriate for use in the rod
16 ejection event.

17 CHAIRMAN WALLIS: Well, it's undesirable
18 to have the kind of questions that my colleagues
19 present.

20 MR. HUGEL: That's true. Good point.

21 CHAIRMAN WALLIS: And have it not
22 resolved.

23 MR. HUGEL: Yes. What I'm going to be
24 showing you is just a few slides comparing some of the
25 important parameters for this transient, the 1-D

1 results versus the 3-D method. This plot here is for
2 the zero power case. The zero power case was
3 presented because it results in a prompt neutron
4 condition. You get the biggest rapid increase in
5 power and you see the biggest delta change in your
6 fuel enthalpy and therefore, it's of highest concern
7 in terms of your limit.

8 MEMBER DENNING: Now this is turned by
9 Doppler. Is that's what's going on here?

10 MR. HUGEL: That's right. Yes, it's the
11 Doppler you --

12 CHAIRMAN WALLIS: The message here is that
13 the two methods are about the same over the period of
14 -

15 MR. HUGEL: And that just shows you that
16 we are still using a conservative approach even though
17 we are using a 3-D methodology. We are using
18 conservative assumptions in this 3-D analysis.

19 CHAIRMAN WALLIS: Why does this show that
20 you're being conservative?

21 MR. HUGEL: Because you're getting a very
22 comparable spike in the nuclear power for both the 1-D
23 and the 3-D method.

24 MEMBER BONACA: What's the difference
25 between the 3-D and 1-D?

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1 MR. HUGEL: I'm sorry.

2 MEMBER BONACA: What's the difference
3 between the two methods? I mean I would like to
4 understand. You say 1-D. Is it the point kinetics
5 calculation with a peaking factor assigned to it for
6 a thermostatic calculation?

7 MR. HUGEL: Yes.

8 MEMBER BONACA: Versus 3-D being what? A
9 neutronic calculation --

10 MR. HUGEL: Yes. In the 3-D method, we
11 are modeling all three directions. So you're taking
12 credit for your Doppler feedback effects that you
13 would have in a 3-D approach where the 1-D we just
14 estimate what those would be in the radial direction.

15 MEMBER BONACA: I'm surprised that you're
16 matching the spike.

17 MR. HUGEL: Okay.

18 MEMBER BONACA: I would expect the 3-D not
19 to give you that kind of a severe spike.

20 MR. HUGEL: Okay.

21 CHAIRMAN WALLIS: 3-D refers to how you're
22 modeling the core.

23 MR. HUGEL: That's correct.

24 CHAIRMAN WALLIS: Not how you're modeling
25 the particular piece of fuel that's getting

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1 overheating.

2 MR. HUGEL: That's correct. Here is the
3 Fq. The 1-D as you can see, we don't have the 3-D
4 effect. So it just remains, we go from some initial
5 Fq up to a very high transient Fq and it remains at
6 that transient Fq for the duration of the transient
7 where in the 3-D approach you do see a drop in the Fq
8 due to the increase in the power.

9 And here is the change in the fuel
10 enthalpy in comparing the 1-D versus the 3-D method
11 and you can see --

12 CHAIRMAN WALLIS: Why is there such a huge
13 difference?

14 MR. HUGEL: The huge difference is due to
15 --

16 CHAIRMAN WALLIS: Same peak. You got the
17 same peak.

18 MR. HUGEL: Right, and you have the same
19 peak in terms of the nuclear power, but in terms of
20 the effect on the heat, you do get the effect of the
21 3-D feedback which over the duration of the transient
22 results in a lower total integrated heat that added to
23 the fuel.

24 CHAIRMAN WALLIS: They cut it off at a
25 different time. So they go up and they level off.

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1 They follow about the same trajectory for the
2 beginning and then when they get to around 40, one of
3 them just gives up and flattens out.

4 MEMBER DENNING: Go back to the Fq.

5 MR. HUGEL: Sure.

6 MEMBER DENNING: Let's go back to the Fq
7 and discuss it.

8 CHAIRMAN WALLIS: Is it the Fq that does
9 that?

10 MR. HUGEL: Yes.

11 CHAIRMAN WALLIS: Okay.

12 MEMBER BONACA: The confusion here in part
13 is because they switched the colors. In this slide,
14 the red is 1-D.

15 MR. HUGEL: Sorry.

16 MEMBER BONACA: And the next slide the red
17 is 3-D.

18 MR. HUGEL: Oh, you're right. Sorry about
19 that.

20 MEMBER BONACA: You have a confusion
21 there. All right.

22 MEMBER DENNING: Back to the Fq and
23 explain to us what Fq is as far as a peaking factor.
24 What is that peaking factor?

25 MR. HUGEL: In the 1-D method what we do

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1 or what the core designer will do is they'll start
2 with the nominal peaking that you would see just based
3 upon a steady state condition and then what they do is
4 they would look at your rod insertion limits, how far
5 your rod are inserted into the core and then a static
6 calculation is performed where different rods of high
7 worth are ejected and then you look and see what the
8 resulting F_q would be due to the ejection of the high
9 worth rod.

10 MEMBER BONACA: So you have no benefit for
11 Doppler.

12 MR. HUGEL: That's right.

13 MEMBER BONACA: For Doppler feedback.

14 MEMBER DENNING: I'm not sure that that's
15 it. Isn't really a matter that here you've distorted
16 your flux in the region of where you've ejected it.
17 The neighboring rods get multiplied by a multiplier
18 which is the F_q .

19 MR. HUGEL: Right.

20 MEMBER DENNING: Because of the spatial
21 distortion of the flux.

22 MR. HUGEL: Right.

23 MEMBER DENNING: We saw the power earlier
24 which is an integral thing.

25 MR. HUGEL: Right and --

1 MEMBER DENNING: This is now the local
2 factor times the flux.

3 MR. HUGEL: That's right.

4 MEMBER BONACA: But what they do they take
5 the point kinetics calculation and then they multiply
6 by the peaking factor. So in the point kinetics, you
7 get very little Doppler effect resulting from it.

8 MEMBER DENNING: No, I think you get the
9 Doppler effect.

10 MR. HUGEL: Yes, you get the same Doppler
11 effect that you see in the nuclear power transient.

12 MEMBER DENNING: This is just the thermal
13 hydraulic.

14 MR. HUGEL: Right. This is the thermal
15 effect.

16 MEMBER BONACA: It's the thermal. Okay.

17 MEMBER DENNING: And here we see that what
18 it does is that it drops down. There's a very brief
19 period where it's high.

20 MR. HUGEL: Right. So what you're doing
21 is you're knocking down your total integrated energy
22 that's added to the fuel at the hot spot which is
23 reflected in the resulting fuel enthalpy.

24 MEMBER BONACA: And probably the
25 integration of the --

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1 MR. HUGEL: Right. Which is integrated
2 power effect at the hot spot and it's primarily driven
3 by what you see in the Fq due to the 3-D feedback
4 effects.

5 CHAIRMAN WALLIS: This is a typical
6 calculation. This isn't a Beaver Valley or Ginna
7 calculation.

8 MR. HUGEL: That's correct.

9 CHAIRMAN WALLIS: So we're near 180
10 calories per gram that we're talking about.

11 MR. HUGEL: Correct. But you would expect
12 to see a similar type of benefit if you were to apply
13 the approach --

14 CHAIRMAN WALLIS: No. I don't know what
15 I would expect. You have to say what you would
16 expect.

17 MR. HUGEL: Based upon the results that
18 we've done for the full power case, yes, we've seen a
19 similar drop in the peak fuel enthalpy for the full
20 power case. But the full power case I'm told is not
21 of as big a concern because you don't see --

22 CHAIRMAN WALLIS: This is a license
23 method.

24 MR. HUGEL: Yes.

25 CHAIRMAN WALLIS: And are we arguing about

1 -- Is the criteria going to be changed when you change
2 the method? Is that the other thing? The criterion
3 is going to be changed.

4 MR. HUGEL: That's my understanding. The
5 200 is deemed to not be acceptable for this event and
6 if we're going to use a 3-D methodology, then we're
7 going to need to go to some more appropriate limit.

8 CHAIRMAN WALLIS: Is it going to be very
9 different from 200?

10 MR. HUGEL: I don't know if Paul can
11 addressed what the latest numbers are or I'm told it's
12 somewhere around 100.

13 MEMBER BONACA: But the limit is not based
14 on the calculation.

15 MR. HUGEL: That's correct. The limit is
16 not based upon the calculation. The limit is based
17 upon looking at all the test data and trying to decide
18 what is an appropriate limit based upon the test data
19 taken into consideration that the conditions that the
20 test data were taken under and other factors to make
21 sure --

22 CHAIRMAN WALLIS: Test data says you ought
23 to come down from 200 to 100 and now developed --

24 MEMBER POWERS: Let's be very careful.

25 MR. HUGEL: Yes.

1 MEMBER POWERS: There's quite a little
2 controversy over how you interpret the data because a
3 substantial body of the data were taken at Japanese
4 reactor with cold water.

5 MR. HUGEL: Right.

6 MEMBER POWERS: And consequently, the clad
7 is much more brittle in that cold water case than it
8 would be in a normal reactor case. The really
9 offensive data points were taken in liquid sodium. On
10 the other hand in all of those transients the energy
11 is input to the fuel well before the clad even knows
12 about it.

13 So there's no cooling effect in there and
14 then you worry about things like how much strain you
15 put on the cladding and that's where the esteemed Dr.
16 Shack and I get into a little cat fight over how you
17 fit data. He's just absolutely dead flat wrong. And
18 EPRI is advancing a point of view on how to analyze
19 that based on the total amount of strain that goes
20 into the cladding and they come up with something
21 around 150 roughly that's fairly insensitive to burn
22 up after you get beyond to 20 to 30 gigawatt days per
23 ton.

24 The NRC looks at the data and it's a
25 combination of the stand of clad oxidation that's

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1 taking place and then amount of burn up that's taking
2 place and they come up with numbers that are like 100
3 maybe descending down to 80 as you approach to the
4 burn up limit right now. Those are rough numbers. So
5 there is some controversy over it. The one thing that
6 nobody disagrees with is that 178 exceeds everybody's
7 criterion.

8 CHAIRMAN WALLIS: Doesn't it matter how it
9 being cooled at the time, whether or not?

10 MEMBER POWERS: Sure. It makes the
11 difference what the temperature is.

12 CHAIRMAN WALLIS: Right.

13 MEMBER POWERS: And it makes the
14 difference -- There are lots of things that make a
15 difference. For instance --

16 CHAIRMAN WALLIS: If it goes to the DNB,
17 then presumably it goes up at a much higher
18 temperature.

19 MEMBER POWERS: No, none of those things
20 are -- Everything is taking place way too fast for
21 that to affect it. But one of the problems you get
22 into is selecting what is the limiting control rod
23 that does this. If I have a high burn-up fuel
24 assemblies all around a rod assembly, then it doesn't
25 matter. You can take a control rod, throw it away,

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1 stomp on it, burn it because there's no power.

2 CHAIRMAN WALLIS: It's the cooling.

3 MEMBER POWERS: But if you have very fresh
4 assemblies next to high burn-up assemblies, then you
5 get into a world of trouble.

6 CHAIRMAN WALLIS: But when the clad heats
7 up, it could heat up by enough --

8 MEMBER POWERS: Everything is over by
9 then. You've blown the clad apart at this point or
10 not.

11 CHAIRMAN WALLIS: So all that matters is
12 what's happening inside.

13 MEMBER POWERS: Yes. Everything is very
14 fast.

15 CHAIRMAN WALLIS: And it's a rapid
16 expansion of things rather than the heating of the
17 cladding.

18 MEMBER POWERS: Yes, everything takes
19 place before you really get any heat into the cladding
20 at all. The action is over at that point.

21 CHAIRMAN WALLIS: You're heating up all
22 the fission products and everything else that's in
23 there and expanding the gases.

24 VICE CHAIRMAN SHACK: Thermal expansion of
25 the pellet.

1 MEMBER POWERS: It's really thermal
2 expansion of the pellet that drives it. Now there are
3 lots of other things that occur. In the Japanese
4 tests, they get a prompt release of fission gases on
5 the order of 20 percent of the fuel inventory which is
6 a very big number, four or five times what we
7 ordinarily think of for one of these events whether
8 you've expelled the fuel. That has consequences with
9 things like control room operations and stuff like
10 that.

11 CHAIRMAN WALLIS: But to go back to the
12 regulations, I understand the present regulations say
13 200 calories per gram is acceptable using a 1-D method
14 and that's what the licensee has to do is to meet the
15 regulations.

16 MR. HUGEL: And that's what we've done.

17 MR. CLIFFORD: The current regulation says
18 280 calories per gram for a coolability limit.

19 CHAIRMAN WALLIS: Yes, and that seems
20 extraordinarily high.

21 MR. CLIFFORD: We know the numbers will be
22 230 is the correct value at zero burn-up and it's a
23 higher burn-up as you worry about accumulation of
24 fission gas. It will drop.

25 CHAIRMAN WALLIS: We've had this sort of

1 presentation from you guys before. I didn't make
2 sense then, the 280, and yet nothing seems to have
3 been done about it. We've been talking about this for
4 several years it seems to me.

5 MEMBER DENNING: Did you have any more -
6 Is that the end of the information?

7 MR. HUGEL: Yes, I think that's it.

8 MEMBER DENNING: Thank you very much. I
9 think it does help us get some feeling as to what the
10 margin relative to the calculations.

11 CHAIRMAN WALLIS: So we should say then
12 that if Ginna and Beaver Valley had done this this
13 way, that it got numbers somewhat belong 100. Is that
14 your speculation?

15 MR. HUGEL: Yes.

16 CHAIRMAN WALLIS: No 45 because this is
17 the high heat.

18 MEMBER SIEBER: We don't know what these
19 numbers mean.

20 MR. HUGEL: Right. Yes, we would expect
21 to see numbers under 100 if we were to do it using a
22 similar approach.

23 MEMBER KRESS: Eighty.

24 CHAIRMAN WALLIS: But you haven't done it
25 for them. You've haven't specifically done it for

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1 them this way.

2 MR. HUGEL: No, but I do know that I'm
3 told that the analysis that we did here and I hate to
4 use the word "conservative."

5 MEMBER DENNING: How about "very
6 conservative"?

7 MEMBER POWERS: Conservative is perfectly
8 okay.

9 MR. HUGEL: They attempted to use numbers
10 that hopefully will bound what we would expect to see
11 in terms of an ejected rod worth, in terms of the
12 peaking, in terms of the linear heat rate, in terms of
13 etc. because we don't want to present results
14 necessarily that are considered to be generic and then
15 find out when we employ this in a plant specific basis
16 that all of a sudden we get a different result. So
17 I'm told that we selected the numbers to try and
18 ensure that they would bound. Anything would expect
19 to be --

20 CHAIRMAN WALLIS: This is a so much better
21 method and you've had it for some time, four years or
22 something. I forget the number.

23 MR. HUGEL: Yes. We submitted it like --

24 CHAIRMAN WALLIS: Why hasn't it been used
25 and the NRC hasn't found a way to --

1 MR. HUGEL: Westinghouse and our utilities
2 would love to use it.

3 CHAIRMAN WALLIS: But you just don't use
4 it because the NRC doesn't know what to do with it
5 when you do use it. Is that right?

6 MR. HUGEL: I don't want to paint anybody
7 into a corner.

8 CHAIRMAN WALLIS: Well, it seems to be
9 clear.

10 MEMBER BONACA: This comparison, this
11 data, from other vendors has been available for 30
12 years, but they never went to it because they need to
13 spent the money to --

14 MR. HUGEL: There was no need.

15 MEMBER BONACA: Because the limit stated
16 280. So therefore, why spent the money to go to a
17 detail calculation when you do a point kinetics and
18 have -- channel with that one. So you have less
19 Doppler feedback and then multiply peaking factor and
20 get the result and then it's 280.

21 MR. HUGEL: Actually the running comment
22 at Westinghouse for years was if you analyze rod
23 ejection in 3-D it would go away.

24 MEMBER BONACA: Yes. In fact, it almost
25 does.

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1 MEMBER POWERS: I think there is some
2 substantial controversy between the staff and
3 Westinghouse on that point.

4 MR. HUGEL: That was before the French
5 data.

6 MEMBER POWERS: No, I think it has to do
7 specifically with these analyses and how fast the
8 transient actually is.

9 MR. HUGEL: Okay.

10 MEMBER POWERS: Okay. One of the
11 challenges that the experimentalists have had for some
12 time is how to simulate the power impulse and how
13 broad it should be and I believe over the last decade
14 we have come pretty much full cycle from at being a
15 very narrow pulse to a very broad pulse and back to a
16 very narrow pulse. I can't remember all the details,
17 but I believe from now narrow pulse is in. Right?

18 MR. HUGEL: It's narrower.

19 MEMBER POWERS: Narrower, yes. Not as
20 narrow as it once was. There's a threshold here that
21 really what matters is whether you get any energy loss
22 to the cladding or not in the course of the pulse and
23 along as your pulse is narrow enough that you don't it
24 could be any narrower.

25 CHAIRMAN WALLIS: I think we have a little

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1 time here. You referred to a published paper which
2 some member of the public was going to read and ask
3 questions about. What were the conclusions of that
4 paper?

5 MEMBER POWERS: The conclusions of the
6 paper were that when they do experiments on reactivity
7 insertion and the radiated fuel with the high burn-
8 ups, they get failures at relatively low energies,
9 down as low as 36 calories per gram.

10 MR. HUGEL: But I'm told that the one case
11 that it was at a low was from a liquid sodium reactor
12 and therefore wouldn't necessarily be applicable to a
13 PWR. That it was outlier in terms of the data.

14 MEMBER POWERS: That's -- The sodiumness
15 doesn't have anything to do with it because there's no
16 power.

17 MR. HUGEL: It was an outlier in terms of
18 the looking at all the test data.

19 MEMBER POWERS: What they have concluded
20 and I'll have to admit the details of this often
21 allude me that in the course of preparing the sample
22 they accentuated a flaw in the cladding so that it was
23 more susceptible to rupture than would be ordinarily
24 the case. Now the challenge, the thing that really
25 challenges me on this, of course is not all cladding

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1 is pristine. So how much of a flaw does it take? But
2 in general, depending on how you look at it, either 36
3 calorie or 18 calorie per gram failure rate is
4 generally excluded from the database, but there's a 50
5 calorie per gram experiment there that doesn't get
6 excluded. So I mean argue 50, 36. I don't care.
7 More important is how you make the change from the
8 fact that you're doing the test at one temperature;
9 whereas you want to do the analyses at a different
10 temperature.

11 CHAIRMAN WALLIS: It would seem that what
12 we need is the proper experiment or series of
13 experiments.

14 MEMBER POWERS: The challenge is that a
15 reactor for doing these experiments is a fairly rare
16 device.

17 CHAIRMAN WALLIS: We're obviously doing
18 experimenting any time there's a rod ejection, aren't
19 we?

20 MEMBER POWERS: The waiting time, the
21 dwell time, between experiments is long and the
22 instrumentation seems to be generally poor in those
23 events. What they are trying to do is set a hot water
24 loop at CABRI to do some confirmatory experiments but
25 those really are confirmatory experiments. The

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1 database exists now. There are challenges in the
2 interpretation, but again, no matter how it gets
3 interpreted 178 is well over anybody's threshold and
4 the challenge that faces this committee is how do we
5 explain to an interested member of the public why you
6 would approve something that manifestly is
7 contradicted by experimental data.

8 CHAIRMAN WALLIS: There is no change --
9 There's very little change in terms of the uprate and
10 this 176, 178, or 180 or 182 or whatever it is,
11 there's hardly any change. This is the problem if
12 there was one was there before. It's not the uprate
13 that's caused it. So it would seem that we would have
14 to separate about the uprate and what we say about
15 this issue.

16 MEMBER DENNING: I think we can let David
17 go now. Is that true?

18 CHAIRMAN WALLIS: Unless you have anything
19 to say.

20 MEMBER DENNING: We do appreciate that.

21 MR. HUGEL: Thank you.

22 CHAIRMAN WALLIS: Is there anything more
23 that you would like to be able to say? Do you have
24 any more information from Pittsburgh or is this the
25 end? There's nothing more you can say.

1 MEMBER DENNING: There's not much you can
2 say until you do an analysis that's specifically
3 oriented, has the right rod worth.

4 MR. HUGEL: Yes, unless we wanted to delve
5 into specific assumptions and stuff which I think is
6 beyond what we're trying to accomplish here.

7 CHAIRMAN WALLIS: For a different time.
8 Thank you very much.

9 MEMBER DENNING: That's right.

10 MR. HUGEL: You're welcome to come to
11 Pittsburgh any time, Dr. Wallis and discuss it.

12 CHAIRMAN WALLIS: It's too close to --

13 MEMBER POWERS: We understand the town is
14 getting smaller all the time though.

15 MEMBER SIEBER: The population.

16 MEMBER DENNING: Graham, then I'll turn it
17 back to you.

18 CHAIRMAN WALLIS: Thank you very much.

19 MEMBER POWERS: There will be lots of
20 hotel rooms there.

21 CHAIRMAN WALLIS: I'm glad we made use of
22 our extra time. Thank you. We still have some extra
23 time. Is it your wish that we take a half hour break
24 because we can't start? We have draft letters on all
25 the subjects we have to write letters on. So you have

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1 plenty of things you could do if you're twiddling your
2 thumbs in the break. We'll take a break until 3:30
3 p.m. 3:30 p.m. we will meet again. Off the record.

4 (Whereupon, the foregoing matter went off
5 the record at 1:16 p.m. and went back on the record at
6 3:02 p.m.)

7 CHAIRMAN WALLIS: Please come back into
8 session. This is the last formal presentation of the
9 day -- last but not least. And because we may need
10 some guidance on how to respond to it, we have chosen
11 a particularly skillful member of the Committee, Tom
12 Kress, to lead us through it. So, Tom, would you
13 please do so?

14 MEMBER KRESS: Well, I'm not sure how much
15 skillful guidance I am going to give you. This is the
16 second attempt to update Part 52, Certification Rule.
17 The staff has noted that there was some need for
18 making conforming changes to make it conform better
19 with the usual 10 CFR 50. And to clarify some of the
20 requirements like which parts of 50 apply.

21 And to just basically improve the rule so
22 that they can implement it more effectively and more
23 efficiently. And they are going to include some
24 lessons learned from the early site permitting
25 process.

1 I can't go into any detail about what
2 these changes are. There are a lot of them being
3 made. Most of them are procedural. Some of them are
4 not. And simultaneously, I think they are already out
5 for public comment and we are getting a substantial
6 number of those.

7 This is an interesting subject. I don't
8 know how the staff is going to deal with it in the
9 hour and a half that we have allocated. And so with
10 that as the challenge, I guess I will turn it over to
11 Eileen and let her introduce herself.

12 MS. McKENNA: Thank you, Dr. Kress. My
13 name is Eileen McKenna. My permanent position is as
14 a Branch Chief in the Financial Policy and Rulemaking
15 Branch of the NRR. But I've recently been asked to
16 take on a special role as a team leader for a group to
17 bring a number of rulemakings that are of particular
18 importance to new reactors to completion over the next
19 several months.

20 And one of the focal points of that effort
21 is, of course, the Part 52 rule which establishes the
22 framework under which many of these new reactor
23 applications will be submitted and processed.

24 We're happy to be here to brief you on the
25 status of our activities. And I would like to at this

1 point turn over the meeting to Jerry and Nan who will
2 walk you through the presentation.

3 MEMBER KRESS: Are you looking for a
4 letter from us Eileen?

5 MS. MCKENNA: We are not requesting a
6 letter. I think, as you will hear through the
7 discussion, we feel that the major aspects of the rule
8 are, as you indicated, to discuss process and
9 procedure.

10 There are some that deal more in some of
11 the safety requirements and we will focus on those in
12 our briefing but we are not specifically requesting a
13 letter although, of course, the Committee is, of
14 course, free to offer whatever comments they choose.

15 CHAIRMAN WALLIS: We don't usually
16 interfere in process and procedure unless it has some
17 kind of impact on safety and technical matters.

18 MEMBER KRESS: Yes, that's why I asked.

19 CHAIRMAN WALLIS: Thank you.

20 Well now, are we ready to proceed then?

21 MS. GILLES: Good afternoon. My name is
22 Nanette Gilles and I am a Senior Project Manager in
23 NRR's Division of New Reactor Licensing. With me is
24 Jerry Wilson, one of the co-authors of the Part 52
25 proposed rule. Jerry is also a member of NRR's

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1 Division of New Reactor Licensing. The other co-
2 author of the rule is Geary Mizuno from the Office of
3 the General Counsel.

4 The purpose of today's briefing is to
5 familiarize the Committee with the key objectives of
6 this rulemaking and to provide you with a general
7 overview of the changes to Part 52 as well as other
8 parts of 10 CFR with a focus on the changes that are
9 related to safety requirements.

10 The Part 52 proposed rule was published in
11 the Federal Register on March 13th of this year. The
12 public comment period ends on May 30th of this year.
13 No comments have been received to date.

14 This rule supercedes a previously proposed
15 rule that was published on July 3rd, 2003. And the
16 revised proposal results from comments on that 2003
17 rule as well as lessons learned during reviews of the
18 first three early site permit applications, during the
19 review of the AP1000 design certification, and during
20 numerous meetings with industry on the combined
21 license process.

22 CHAIRMAN WALLIS: So let's go back. You
23 said that the public comment period has already ended
24 I thought.

25 MS. GILLES: No, it will end May 30th.

1 CHAIRMAN WALLIS: Oh, 30th, okay. I'm
2 sorry. I thought you said the 3rd.

3 MEMBER KRESS: And you haven't had any
4 comments yet?

5 MS. GILLES: No. We know they are coming,
6 likely on May 30th.

7 CHAIRMAN WALLIS: Sorry. Thank you.

8 MS. GILLES: The rewritten Part 52
9 contains five subparts. Subpart A addresses early
10 site permits. An early site permit is, of course, a
11 license that allows an applicant to bank a site for
12 possible future construction of a reactor or reactors.

13 MEMBER KRESS: For ten years?

14 MS. GILLES: Pardon me?

15 MEMBER KRESS: They bank aside for what --
16 ten years?

17 MS. GILLES: Up to 20 years.

18 MEMBER KRESS: For 20 years.

19 MS. GILLES: Subpart B addresses standard
20 design certifications which is the process that allows
21 an applicant to attain preapproval of a standard
22 nuclear power plant design through rulemaking.

23 Subpart C addresses the combined license
24 process. Combined license is a combined construction
25 permit and operating license with conditions. A

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1 combined license can reference an early site permit,
2 a design certification, both or neither.

3 A new subpart, Subpart E is the standard
4 design approvals. This is a subset of the standard
5 design certification process. It essentially does not
6 include the certification rulemaking. A standard
7 design approval represents the staff's review of the
8 design application without the hearing or the
9 Commission review.

10 MEMBER POWERS: And what goo dis it?

11 MS. GILLES: Well, the applicant -- if the
12 applicant did not want to wait for the rulemaking
13 process for a design certification, they could
14 reference the design approval and they would at least
15 have finality as far as the staff's review goes. In
16 other words, the staff would not have to re-review
17 that design information. But that would still be
18 subject to the hearing and to review by the
19 Commission.

20 MR. WILSON: And I would add that we have
21 a long history with design approvals. We have been
22 issuing them since the 70s. And it is probably the
23 most used part of our licensing process. And so we
24 felt it was important to maintain that process.

25 MEMBER BONACA: What does it mean

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1 standards? I'm sorry. I'm trying to understand the
2 word standard.

3 MR. WILSON: From the standpoint of we're
4 trying to approve a design that would be referenced
5 many times -- using the same design.

6 MEMBER BONACA: Okay.

7 MR. WILSON: So it is standardization from
8 that context.

9 MEMBER BONACA: So there is still -- yes.

10 MEMBER KRESS: It is all the staff's
11 review of the certification process without the legal
12 parts of the sign-off.

13 MEMBER BONACA: Yes.

14 MEMBER KRESS: It gets that over with and
15 they can just reference it in the certification.

16 MEMBER POWERS: Yes but there is no
17 proscription against re-raising issues here.

18 MEMBER KRESS: I wouldn't think so. Not
19 by the staff. The Commission could.

20 MEMBER POWERS: The Commission can
21 presumably direct the staff to.

22 (Laughter.)

23 MEMBER ARMIJO: But apparently it must
24 have some value because people use it. They request
25 it.

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1 PARTICIPANT: I think it is matter of
2 profile.

3 MR. WILSON: Let me add on to that. Prior
4 to the creation of the design certification that was
5 our design approval process separate from an
6 application so it was frequently used there.

7 In the future, I think the issue is going
8 to be one of timing and whether a prospective combined
9 license applicant, as Nan said, wanted to wait that
10 additional time for the rulemaking to be completed to
11 achieve that additional finality. Or if they wanted
12 to just reference the design approval in the hopes
13 that they could get through the hearing and get their
14 construction underway sooner.

15 So different applicants may have a
16 different judgment on that issue. And we want to
17 provide these alternatives.

18 MEMBER BONACA: But if I understand it, I
19 mean on the rulemaking, okay, pretty much the design
20 is approved in its entirety. And then it cannot be
21 reopened.

22 MR. WILSON: That is correct.

23 MEMBER BONACA: And in this case, design
24 approvals -- at least the process in the past was the
25 anybody -- I mean there could be a reopening of the

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1 approval.

2 MEMBER KRESS: Yes, as Dr. Powers was
3 mentioning, subsequent to a design approval, if it is
4 referenced, it could be challenged in the hearing. Or
5 in an appeal, the Commission could reopen something
6 whereas in the design certification process in order
7 to get that additional finality, the rulemaking takes
8 the place of those two things.

9 And the Commission approves the rule and,
10 therefore, they have, in effect, signed off on it.

11 MEMBER BONACA: Yes, okay.

12 MS. GILLES: The fifth subpart in the
13 reviewed Part 52 is the manufacturing license process.
14 This was formerly an appendix in Part 52. This
15 provides a licence to manufacture one or more
16 reactors. The sites for construction of those
17 reactors are not identified in a manufacturing
18 license.

19 The proposed rule does provide a slight
20 difference from the current rule in that it actually
21 provides greater finality at the manufacturing license
22 issuance stage than is offered in the current rule,
23 very similar to the finality you would get in a design
24 certification in that the final design is approved at
25 issuance of the manufacturing license.

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1 MEMBER KRESS: What goes into deciding?
2 Because you can give a license to somebody to
3 manufacture one of these. What are the criteria?

4 MR. WILSON: One of the key parts is the
5 approval design and also qualifications of that
6 particular perspective licensee to build -- design and
7 build a nuclear power plant.

8 MR. WILSON: The standard design holder
9 could also be the manufacturing licensee? Is the
10 licensee -- I think the best way to explain this is to
11 talk about the one manufacturing license we have
12 issued in the past.

13 There is a company, Offshore Power
14 Systems, which is a subsidiary of Westinghouse. It
15 got a manufacturing license to build floating nuclear
16 power plants that they were going to deploy at various
17 locations.

18 So their plan was to build that plant at
19 a facility they were planning to build in
20 Jacksonville, Florida, have the whole plant completed
21 and then some perspective licensee who would site it
22 off their coast would purchase it, ship it out to that
23 site.

24 CHAIRMAN WALLIS: Well, this is
25 interesting to me because we approved something like

1 AP1000, let's say, but I don't recall that we went
2 into the details of how you are to going to make it
3 and whether you can with adequate controls and so on,
4 whether there are places which are capable of welding
5 large vessels any more with suitable quality control
6 and so on.

7 So in that scenario, a combined license
8 who references the AP1000 design, they would have to
9 demonstrate that they could do the things that you
10 just talked about.

11 MS. GILLES: The only appendices that
12 remain in the revised Part 52 are the four certified
13 designs. Appendix A is the General Electric advanced
14 boiling water reactor. Appendix B is the CE System 80
15 Plus. Appendix C is the Westinghouse AP600. And
16 Appendix D is now the Westinghouse AP1000.

17 During its revision --

18 MEMBER KRESS: You get a new appendix each
19 time you get a new design certified?

20 MS. GILLES: That is correct. That is how
21 it was structured. That that rulemaking, once it was
22 completed, would become an appendix to Part 50.

23 CHAIRMAN WALLIS: This happens after
24 design certification?

25 MS. GILLES: Yes.

1 CHAIRMAN WALLIS: This is sort of a
2 collection of the rules that are applicable to this
3 design then once it has been certified?

4 MS. GILLES: Yes. During its revision of
5 Part 52, in this proposed rule the staff took two
6 actions that account for the vast majority of the
7 changes in the proposed rule. The first was with
8 regard to Part 52 itself. We standardized the
9 organization and content of each of these five
10 subparts.

11 The second action was that we made
12 conforming changes throughout the rest of 10 CFR to
13 make sure that all of the other various technical and
14 procedural requirements recognized that the licensing
15 process in Part 52 existed and we tried to be explicit
16 as to which requirements applied to each of these five
17 processes.

18 Generally in making these changes, we
19 tried to keep the technical requirements where they
20 currently exist in Part 50, Part 100, and the other
21 parts and keep the procedural requirements in Part 52.

22 And there was a concerted effort on the
23 part of the staff working with the proposed rule not
24 to change those technical requirements that existed in
25 the other parts unless a change was necessitated by

1 virtue of the structure of the Part 52 licensing
2 process being different from the old construction
3 permit operating license process.

4 There are a couple of main objectives with
5 regard to this proposed rule. First, we feel that the
6 revised rule will enhance our effectiveness and
7 efficiency when we are implementing the Part 52
8 licensing process in the future. And we also believe
9 that it will provide both the staff and perspective
10 applicants clarity regarding the applicability of
11 these technical and procedural requirements to each of
12 the regulatory processes.

13 With regard to some of the key rule
14 proposals that effect safety requirements, the first
15 area of focus would be in the emergency planning area.
16 And the majority of these requirements are those
17 issues that fell out of lessons learned during the
18 early site permit process.

19 First of all, regarding a provision in the
20 early site permit subpart that requires an early site
21 permit applicant to identify physical characteristics
22 unique to the proposed site that could pose a
23 significant impediment to the development of emergency
24 plans, in the proposed rule, the staff has proposed to
25 add a requirement that if such physical

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1 characteristics are identified, the applicant also
2 must identify mitigation measures which, when
3 implemented, would mitigate that impediment to the
4 development of emergency plans.

5 MEMBER KRESS: A couple of questions about
6 that. How does one know what is a significant
7 impediment? Is that a judgment on the applicant? Or
8 is it a judgment on your part? Or do you two
9 negotiate that? Or do you get involved in the
10 emergency plans?

11 MS. GILLES: Yes. Both at the early site
12 permit stage and the combined license stage there is
13 a review of the emergency plans. Of course the
14 initial decision on what a significant impediment is
15 would have to be made by the applicant. But the staff
16 would certainly, in doing that review of emergency
17 planning, take a look at the site, take a look at the
18 physical characteristics and determine whether they
19 agreed with the applicant's --

20 MEMBER KRESS: You might identify a
21 significant yourself?

22 MS. GILLES: Certainly.

23 MEMBER KRESS: And the change is that --
24 it has always been in there --

25 MS. GILLES: Yes.

1 MEMBER KRESS: -- but now you are saying
2 they have to identify a way to fix the impediment?

3 MS. GILLES: A way to fix it, correct,
4 because it was sort of left up to the imagination as
5 to what would happen in this situation where a
6 physical impediment was identified.

7 MEMBER KRESS: And then the ITAAC would
8 insure that when it got to the COL stage that this fix
9 was made?

10 MS. GILLES: Well, let's be clear here for
11 a minute. There are actually three options with
12 regard to emergency planning under the early site
13 permit. The first option is that you -- and the least
14 work for an applicant -- is that they identify such
15 significant impediments.

16 There is no ITAAC associated or proposed
17 to be associated with that level of emergency planning
18 review. And I expect that in a situation where an
19 applicant had done that minimum level of -- provided
20 that minimum level of information in their
21 applications and they had identified a significant
22 impediment and proposed mitigation measures, those
23 most likely would show up as a permit condition in the
24 early site permit. That would be my guess as to how
25 it would work.

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1 MEMBER APOSTOLAKIS: Is emergency planning
2 a defense in depth measure that should be established
3 independently of what the reactor is, what the risks
4 are, and so on? Because it seems to me that
5 identifying impediments either by saying you have to
6 be able to evacuate, for example, or it can be done in
7 a different context where you are actually looking at
8 the reactor itself and what the frequency of various
9 releases are. And then you identify possible
10 impediments if there are any in the context of that
11 particular reactor.

12 So is there flexibility there? Or is it
13 just a defense in depth measure and you have to
14 demonstrate that you are able to handle emergencies
15 independently of what reactor you put there?

16 MS. GILLES: Remember at the early site
17 permit stage, the applicant is not required to
18 identify the exact design that they plan to build at
19 that site. So our review of emergency planning at
20 that time is independent of the design that will be
21 put there.

22 MEMBER APOSTOLAKIS: But what if they
23 don't have an ESP. They are free at the COL not to
24 refer to an ESP, right?

25 MS. GILLES: Correct.

1 MEMBER APOSTOLAKIS: And at that time,
2 they might come and tell you we are going to put this
3 reactor there which has the following characteristics.
4 Therefore, our emergency planning will be a minimal
5 thing, you know.

6 MS. GILLES: Yes, at the combined license
7 stage, they only have one option with regard to
8 emergency planning. There is not the requirement to
9 address significant impediments. The requirement at
10 the combined license stage is to provide the complete
11 emergency plan.

12 MEMBER APOSTOLAKIS: That would depend on
13 the kind of reactor you put there? Or is it
14 independent of that?

15 MR. WILSON: There is some flexibility on
16 that issue. And I believe the Committee is aware that
17 there is a special provision on emergency planning
18 zones with gas-cooled reactors. But in general, and
19 we're back to the scenario that Nan was talking about
20 in the early site permit, this is a siting decision.
21 And so we are looking at the site and whether it is
22 suitable for a nuclear power plant.

23 And so the focus of these significant
24 impediments are in siting issues. So an obvious
25 example is you are planning to put a nuclear plant on

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1 an island and the question is could other people
2 living on the island get off the island if there was
3 a need for an evacuation.

4 CHAIRMAN WALLIS: Is this referring to
5 Long Island?

6 (Laughter.)

7 MR. WILSON: No, I'm thinking of smaller
8 islands than that.

9 MEMBER POWERS: I'm struggling to
10 understand why this is a major issue at the ESP stage.
11 By identifying mitigations for significant
12 impediments, certainly none of the ESPs that we looked
13 at had major impediments. And so there was -- it
14 never excited us.

15 Why did this particular issue come to the
16 fore? I mean we had major problems with emergency
17 planning and ESPs but it was not this. It had more to
18 do with your second bullet which you don't seem to
19 have solved our problem for us.

20 MR. WILSON: Let's back up a little bit
21 and understand the difficulty that Nan and I have with
22 this presentation. As Dr. Wallis and Dr. Kress were
23 discussing earlier, this is primarily a procedural
24 rule. And in the past, this Committee hasn't been
25 interested in procedural rules.

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1 So we are struggling to pick out some
2 issues here that may have safety significance that the
3 Committee may want to be aware of, and we're not
4 claiming that this is a significant issue but it does
5 touch in that area of safety.

6 MEMBER POWERS: I want to know why it came
7 up. I mean --

8 MS. GILLES: I can tell you what I recall
9 is that it came up out of some internal staff
10 discussions about -- as we were preparing for early
11 site permits, about well what would we do if an
12 applicant identified a significant impediment.

13 And there was more than one opinion about
14 whether the rule would have required the Commission to
15 reject such an application because it didn't state
16 that there was an avenue to go forward with an
17 application that had a significant impediment.

18 So to avoid that situation, we felt that
19 it was better to clarify that the applicant needed to
20 provide an -

21 MEMBER POWERS: I can see what it is but
22 I would have thought you would just go through and say
23 look, they are required to outline their major
24 features of their emergency planning, including if you
25 had a major impediment, that would be a major feature.

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1 Now major features, we had real problems
2 with because we ended up with people counting hospital
3 beds, which is ridiculous. That's not a major
4 feature. I mean there we had problems. But I think
5 that had more to do with the review standards than it
6 did with the rule itself.

7 MS. GILLES: Yes, I would agree. And the
8 second bullet here really addresses the other two
9 options under the early site permit and that is to
10 provide major features or to provide a complete and
11 integrated emergency plan.

12 MEMBER KRESS: I presume this is aimed at
13 an early site permit that doesn't already have an
14 emergency plan and doesn't already have an existing
15 plant there? Otherwise, they don't have emergency
16 plans.

17 MS. GILLES: Well, but remember, even
18 though there is an existing site, the early site
19 permit applicant is a separate applicant from the
20 licensee who operates that plant. And it is their
21 choice to use that plan and submit it as the early
22 site permit plan or to go with one of these lesser
23 options. This is not --

24 MEMBER KRESS: Does he have to project 20
25 years into the future for these significant

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1 impediments?

2 MEMBER POWERS: Sure. Yes, you have to.
3 When you come to the ACRS you will be asked that
4 question.

5 (Laughter.)

6 MEMBER POWERS: But I suspect that the
7 major -- the major impediment I can imagine for an
8 existing site was a change in the political
9 administration of the region.

10 MEMBER KRESS: Wow. How am I going to
11 predict that?

12 MEMBER POWERS: Well, you are not required
13 to predict accurately. Responsibly but not
14 accurately.

15 MR. WILSON: Well, for the benefit of the
16 audience, I'd like to clarify that point. Major
17 impediments are physical features that we are looking
18 at.

19 MS. GILLES: With regard to the second
20 bullet, as you mentioned there were quite some fairly
21 large struggles with how to deal with major features
22 at the early site permit stage. And so we've actually
23 undertaken a couple of actions in the proposed rule.

24 One is we have posed a specific question
25 to ask whether the Commission should try to further

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1 define what a major feature is and provide some higher
2 level of finality associated with the major feature to
3 make it more useful to a perspective COL applicant.
4 And along with that, that increased finality with
5 major features we have required that. An ESP
6 applicant that submits a complete plan or major
7 features of a plan, that they include the inspections,
8 tests, and analysis, and acceptance criteria that
9 would be needed at the combined license stage to
10 finalize those plans.

11 So that will allow the staff to make the
12 same reasonable assurance finding at the early site
13 permit stage that it could make for a combined license
14 applicant that had ITAAC with --

15 MEMBER POWERS: I really struggle with
16 this. I mean it seems to me that the emergency
17 planning aspects that we just ran into all -- every
18 time we went to anything beyond the most high-level
19 statements on the emergency plan we ran into -- and we
20 can't do anything right now so we will have to move
21 back to the COL stage.

22 And there always seemed to be good reasons
23 for saying we can't do anything about that. I mean it
24 seems to me that enhancing it at the early stage, that
25 is not what I would have expected you to do. I would

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1 have expected you to downgrade what is in the existing
2 rule. Or make it very clear what you were looking for
3 rather than asking for more detail. Nobody can do it.

4 MS. GILLES: Well, the industry has
5 expressed interest in having flexibility regarding
6 emergency planning at the early site permit stage.

7 MEMBER POWERS: Yes, they want
8 flexibility. They don't want to get locked into
9 anything.

10 MS. GILLES: Well, I will point out that
11 we have reached agreement with the industry on a set
12 of emergency planning ITAAC that have been sent to and
13 approved by the Commission. So we actually have made
14 fairly good progress with regard to ITAAC in the
15 emergency planning area.

16 MEMBER POWERS: I don't think anybody
17 wants to do those at the ESP stage. I mean I think
18 they will just -- everything will just get -- it will
19 just be a condition in the ESP. I mean you are kind
20 of wasting your time here.

21 MS. GILLES: I think time will tell
22 whether that is true. We have heard applicants say
23 they are interested in pursuing this option although
24 we have yet to see that.

25 MEMBER POWERS: Yes. I mean I can only

1 speak from experience that all these things, they just
2 kind of throw up their hands and say there is nothing
3 I can do right now because I don't have a plant, I
4 don't know when I'm going to do anything, I don't know
5 what the future is going to really look like. And I
6 don't know how many hospital beds I need.

7 And so we just -- I mean we did have
8 people counting hospital beds and doing a lot of
9 things that they felt was useless. That they were
10 just simply going to have to redo it again.

11 Now maybe the next ESP will come in and
12 say he wants to lay out his emergency plan out to six
13 significant digits. But I'm not betting on it.

14 MS. GILLES: We will find out fairly soon
15 here.

16 Another requirement related to emergency
17 preparedness that appeared both in this proposed rule
18 on the previous 2003 proposed rule was the requirement
19 that combined license applicants that referenced an
20 early site permit update and correct the emergency
21 preparedness information that was provided in the
22 early site permit.

23 This was actually suggested as an
24 alternative to a proposal by one of the states several
25 years back that applicants be required to update the

1 information throughout the life of their early site
2 permit. And the industry proposed this as an
3 alternative: that they have a one-time update
4 requirement at the time that application is referenced
5 in a combined license application.

6 In addition to identifying this new
7 information, the applicant must discuss whether the
8 information would materially change the basis for
9 compliance with any NRC requirements so that the
10 Commission can determine that it needs to modify the
11 permit based on this updated information.

12 MEMBER MAYNARD: Could you clarify for me
13 what you are talking about with emergency preparedness
14 information? Are you talking about population or
15 bridges or what is in the area?

16 MS. GILLES: Well, it could be any
17 information that was provided at the early site permit
18 stage. And remember we just discussed the applicant
19 basically has three choices as to what level of
20 information they can supply at that stage.

21 MEMBER MAYNARD: Okay.

22 MS. GILLES: So it could be anything --
23 related to anything that was supplied at the early
24 site permit stage.

25 MEMBER POWERS: If we are in, for

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1 instance, one of the concerns is that military bases
2 either get installed or de-installed at a facility
3 which -- I mean de-installing it can effect your fire
4 protection planning. Installing it can effect all
5 kinds of things. But I think that effectively is in
6 the rules anyway. I think it is in Part 50.

7 MS. GILLES: Another area where some of
8 the technical requirements were changed in this
9 revised proposed rule relates to quality assurance
10 requirements for early site permit applicants. We
11 placed a explicit requirement in this rule that the
12 Appendix B quality assurance requirements apply to
13 early site permit applicants.

14 MEMBER KRESS: Can they really do that?
15 Suppose you have an ESP applicant who doesn't even
16 reference a certified design or any kind of plant, can
17 he do this QA requirement?

18 MS. GILLES: Well, we believe they can do
19 it and remember we are talking about them applying the
20 QA requirements as they would apply to the siting
21 activities that are going on during their application
22 and the review of this application for the early site
23 permits.

24 MEMBER POWERS: You've got a huge amount
25 of stuff coming in as far as well-testing data,

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1 drilling, things like that.

2 MEMBER KRESS: Oh, that's the QA
3 requirement you are referring to?

4 MS. GILLES: Yes.

5 MEMBER KRESS: You are not talking about
6 SSCs?

7 MS. GILLES: No.

8 MEMBER POWERS: I mean there is a huge
9 body of data that supports these things. And I don't
10 think this -- the QA requirement, I don't think they
11 pose an unusual burden. I mean I think people in the
12 nuclear industry are relatively used to handling data
13 in that kind of fashion.

14 MS. GILLES: Another area in the technical
15 requirements where we have made some changes in this
16 proposed rule relates to the applicability of 10 CFR
17 Part 21 and the related requirements in 10 CFR 5055(v)
18 to entities that hold a permit or a license under 10
19 CFR Part 52.

20 These changes would address an omission in
21 the existing regulations and ensure that requirements
22 in Part 21 and 5055(E) apply to applicants for and
23 holders of early site permits, design approvals,
24 design certifications, combined licenses and
25 manufacturing licenses and suppliers of basic

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1 components to such applicants and holders.

2 The proposal is based on the thought that
3 the extension of NRC's reporting requirements that
4 implement Section 206 of the Energy Reorganization Act
5 should be consistent with three key principles.

6 The first principle is that NRC regulatory
7 requirements implementing Section 206 should be a
8 legal obligation throughout the regulatory life of an
9 NRC license approval or certification.

10 The second principle is that defects
11 should be reported whenever the information on
12 potential defects will be most effective in ensuring
13 the integrity and adequacy of the NRC's regulatory
14 activities under Part 50 and the activities of
15 entities subject to the Part 52 regulatory regime.

16 The third principle is that each entity
17 conducting activities within the scope of Part 52
18 should develop and implement procedures and practices
19 to ensure it accurately and timely fulfills its
20 Section 206 reporting obligations.

21 The applications of these three principles
22 to each of the five subparts of Part 52 is described
23 in detail in the Federal Register notice that
24 transmits the proposed rule. This is one of the areas
25 that the staff found that there were really some

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1 extensive conforming changes needed in another
2 regulation to make sure that it addressed all of the
3 Part 52 licensing and regulatory processes.

4 The final area I will discuss regarding an
5 area that relates to some of the technical
6 requirements is in the area of PRA. There is an
7 existing requirement in Part 52 for design
8 certification and combined license applicants to
9 submit a probabilistic risk assessment with their
10 application.

11 However, in the staff requirements
12 memorandum that the Commission sent the staff after it
13 had reviewed the rule, the Commission asked the staff
14 to pose a specific question and request comments on
15 that question regarding the need for a living PRA
16 requirement.

17 The staff asked whether the Commission
18 should adopt in the final rule a new provision that
19 would require combined license holders to update the
20 PRA, submit it with the combined license application
21 periodically throughout the life of the facility on a
22 schedule either similar to that for the FSAR updates
23 or perhaps with every other refueling outage.

24 The Commission has asked for stakeholder
25 feedback on whether such a requirement should be added

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1 in the final rule. And if so, what update periodicity
2 should be associated with that requirement?

3 MEMBER KRESS: So what did you decide to
4 put in the rule?

5 MS. GILLES: We haven't decided yet
6 because we are still in the public comment period.

7 MEMBER KRESS: You are waiting for that.

8 MS. GILLES: Yes. We will have a specific
9 section that addresses this question and the comments
10 we received in answer to this question. And then the
11 staff's and the Commission's decision with how to go
12 in the final rule regarding this issue.

13 MEMBER APOSTOLAKIS: Is the issue only one
14 of having a living PRA? Or also what kind of a PRA?

15 MS. GILLES: In the rule that the staff
16 sent to the Commission, there was some attempt to
17 address what kind of PRA should be in the rule. And
18 the Commission directed the staff to take that
19 language out of the rule and to address those issues
20 in the regulatory guidance associated with Part 52.

21 So to my knowledge, there will be no rule
22 language that addresses the type of PRA. That will be
23 contained in regulatory guidance.

24 MEMBER POWERS: The question of
25 periodicity of updating anything, it is difficult to

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1 come up with.

2 MS. GILLES: It is but we do have some
3 model to follow with the FSAR update procedure which
4 is why we linked the question to that.

5 MEMBER POWERS: I know and it has been a
6 frustration. I mean that has not been a bed of roses
7 itself.

8 MS. GILLES: I will be the first to agree
9 with you that there are difficult issues to tackle in
10 this rulemaking.

11 MEMBER POWERS: I don't know how you come
12 up with it.

13 MEMBER APOSTOLAKIS: What would be the
14 purpose anyway? Let's say you are asking them to do
15 it every two years. Then what? I mean are they going
16 to give it to you or -- okay, they update it. Now
17 what? I mean there is no requirement for them to use
18 it.

19 MS. GILLES: No, the idea -- I'll tell you
20 what we stated in the question is that the PRA update
21 submittal would be required to contain all changes to
22 reflect information and analysis submitted to the
23 Commission by the licensee or prepared by the licensee
24 pursuant to a Commission requirement since the
25 submittal of the original PRA, or since the last

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1 update. It's really, in my mind, the way the question
2 was posed. It is simply a way for the staff to have
3 an updated version of the PRA for every plant.

4 MEMBER APOSTOLAKIS: For what purpose?

5 MEMBER KRESS: Does that make the PRA part
6 of the licensing basis then?

7 MR. WILSON: I don't think so. And we
8 tried to clarify that point to a certain extent in
9 this proposed rule where we pointed out that PRA is
10 part of the application but not part of the FSAR. But
11 back to Dr. Apostolakis's question in terms of how you
12 would use it, we have a couple of members of the PRA
13 branch in the audience. And I looking out there to
14 see if one of them would want to offer some views on
15 that point.

16 MEMBER POWERS: For one thing, the staff
17 is always in the position to ask for the risk of any
18 change -- associated with any change that the
19 applicant wants to make. I mean you can always do
20 that as part of the license amendment process. And so
21 presumably you would want that to reasonably reflect
22 any changes that have occurred in the plant.

23 And in some respects, it may happen
24 whether there is a rule or not. But I assume that you
25 would want some assurance that the PRA was up-to-date

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1 that was used there.

2 MEMBER APOSTOLAKIS: It seems to me though
3 that the most important issue is what kind, what scope
4 the PRA would have rather than how frequently you
5 update it.

6 MEMBER POWERS: Well, I agree with that
7 but, you know, we haven't figured out how to enforce
8 what scope yet.

9 MEMBER APOSTOLAKIS: Because my
10 understanding is that people more or less agree that
11 you have to have a good internal event up power PRA.
12 Now I hear that we've sort of agreed to have a good
13 fire PRA. But other than that, I'm not so sure. I
14 mean shutdown is still up in the air. Other external
15 events, losing some bounding techniques and all that.

16 I mean I don't know how -- why not do a
17 shutdown PRA, too? I don't understand that.

18 So you will issue regulatory guides that
19 will have this kind of information? I mean I don't
20 understand how that would work.

21 MEMBER KRESS: Who is going to speak? Go
22 ahead and use the mike.

23 MR. TESTA: Mike Testa, Division of Risk
24 Assessment Deputy Director. I think the intent of the
25 requiring the PRA updates was as we evolve in the use

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1 of risk, it is becoming more and more a part of day-
2 to-day operations with the maintenance rule, with the
3 ROP. And the requirement to submit a periodic update
4 of the PRA would be nothing more than insurance to the
5 staff that the licensee was maintaining it in a state
6 that could be used for those types of applications.

7 So where now there is no specific
8 requirement to update, you know, the NRC does have
9 some type of expectation that were the PRA to remain
10 a viable tool to use for these applications that it is
11 updated.

12 So I think it is basically a more explicit
13 statement of what expectations are for the way people
14 operate right now.

15 MEMBER APOSTOLAKIS: My understanding is
16 that the regulatory guide cannot impose any
17 requirements. No matter what you say in the guide --

18 MR. TESTA. Right. I thin we are talking
19 on different issues. I mean I was talking about the
20 requirement to submit a periodic update.

21 I think the Commission was -- it was my
22 interpretation of a message they were sending back to
23 the staff is that, you know, we are a little bit in
24 the state of flux with what we were going to require
25 for a PRA because if there aren't standards in place,

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1 you know it makes it a little bit more difficult to
2 say for a licensee that you need to have all these
3 different all modes, internal/external event, PRA out
4 there for use but the standards yet haven't been
5 developed yet. And haven't been concurred on by the
6 NRC.

7 So I think the message to the staff was
8 figure out at the time how to work your way through
9 that issue. And that is better fitted in a regulatory
10 guide rather than regulation.

11 MEMBER APOSTOLAKIS: Still, though, in a
12 regulatory guide, you cannot require anything.

13 MEMBER KRESS: But you can require an
14 update.

15 MEMBER APOSTOLAKIS: A what?

16 MEMBER KRESS: You can require an update
17 in the rule.

18 MR. WILSON: Could I clarify this point?

19 MEMBER APOSTOLAKIS: Oh, another two,
20 three year process just to change that. I thought the
21 whole idea was not to revise the rules --

22 MEMBER MAYNARD: But typically with a reg
23 guide, the licensees either expect it to commit to it
24 or show how they are -- what method they are using to
25 accomplish the same thing. The reg guide doesn't

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1 impose a specific requirement on you but the licensee
2 either got to commit to it or to demonstrate how they
3 are going to meet the same objections.

4 MR. WILSON: Let me clarify this. They
5 have a requirement to submit a PRA. We are talking
6 about adding a requirement to update that PRA. The
7 issue of the reg guide is how do you meet that
8 requirement to submit a PRA? In the reg guide is
9 going to be guidance on what type of PRA You have to
10 submit. But these is a requirement to submit one as
11 part of your combined licensed application and you
12 application for design approvals.

13 MEMBER APOSTOLAKIS: Well, the thing that
14 comes to my mind is at the last meeting, we reviewed
15 the regulatory guide, attempting to risk inform the
16 fire -- an FBA 805 implementation. And we were
17 struggling with the issue of talking about the PRA
18 when the rule does not require it.

19 We were told very explicitly that you
20 cannot say that the PRA is needed because the rule
21 doesn't say that you need it. So we have to dance
22 around it.

23 MR. WILSON: I understand. But remember -
24 -

25 MEMBER APOSTOLAKIS: I don't understand

1 why we have to create these issues.

2 MR. WILSON: In the scenario you are
3 talking about, you are talking about operating plants.
4 There is no requirement for operating plants to submit
5 a PRA. The requirement we are talking about is the
6 requirement for future combined license applications
7 or for design certification applications. That
8 requirement has been on the books since 1989.

9 And the reg guide would just be what type
10 of PRA do you need to submit to meet that requirement.
11 So we wouldn't have the problem you are talking about
12 with the operating plants.

13 MEMBER APOSTOLAKIS: Well, I don't
14 remember exactly how 50.40 something --

15 MR. WILSON: 50.48.

16 MEMBER APOSTOLAKIS: Forty-eight.

17 CHAIRMAN WALLIS: Can I go back to what
18 our role is in this whole process here? Eileen, you
19 indicated that maybe we didn't need to write you a
20 letter. But then do you want us to -- there are
21 various things we might do. I mean you might just
22 look at the transcript and say they said various
23 things. That's all we need at this stage.

24 But do you expect us to have some
25 interactions with you again before the final rule?

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1 MS. MCKENNA: Well, let me give you the
2 schedule of what we are on so you kind of have an
3 appreciation of the picture. As was indicated, the
4 comment period ends the end of May. The SRM that the
5 Commission sent us on the proposed rule said that they
6 wanted the rule back to them in October of this year.

7 There is not a whole lot of time between
8 the end of May and October for us to turn around a
9 final rule and have additional interactions with the
10 Committee. We really would like to have a sense from
11 now as to whether You would like to hear more or You
12 feel that You don't need to hear more?

13 CHAIRMAN WALLIS: Well, in terms of that,
14 we have no major issues with what You are doing. Do
15 You still expect to come back to us sometime between
16 now and October?

17 MS. MCKENNA: I don't think we envisioned
18 there is time between now and October to come back.

19 CHAIRMAN WALLIS: So this is our chance to
20 say something --

21 MS. MCKENNA: This would be your chance,
22 yes.

23 CHAIRMAN WALLIS: -- if we wish to do it?

24 MS. MCKENNA: This would be your chance,
25 yes. Yes.

1 CHAIRMAN WALLIS: And if we don't wish to
2 say much or anything, then we never say anything
3 again. Is that your view?

4 MS. McKENNA: Well, we would hope that
5 would be the case. I mean normally when we go to the
6 Commission, we include in the rule package, we include
7 a paragraph that describes what level of coordination
8 we have had.

9 CHAIRMAN WALLIS: You might want to let us
10 --

11 MS. McKENNA: Or a memo that says we've
12 had this meeting.

13 CHAIRMAN WALLIS: You seem to be on the
14 right track and that's it.

15 MS. GILLES: You know then maybe you don't
16 --

17 CHAIRMAN WALLIS: I mean if we are silent,
18 does that just give consent?

19 MS. McKENNA: Well, is you are silent,
20 then the approach we would most likely take is when we
21 go to the Commission with our final rule package in
22 October, we would include a sentence in the
23 coordination section that says we met with the
24 Committee on thus and so date. And the Committee did
25 not choose to send any comments.

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1 CHAIRMAN WALLIS: We could say we see no
2 major problems with what you are doing. And we don't
3 really see how we would add value by, you know --

4 MEMBER APOSTOLAKIS: Or we say nothing.

5 CHAIRMAN WALLIS: Or we say nothing at
6 all. But that sort of leaves it equivocal doesn't it?
7 If we say nothing at all?

8 MEMBER APOSTOLAKIS: No, it means we don't
9 object.

10 CHAIRMAN WALLIS: No, I don't think we
11 should say -- yes, we could do that. We would say if
12 we can't add value at this stage, we will just say
13 nothing.

14 MEMBER DENNING: I mean can't we take an
15 intermediate position in terms of -- I mean say
16 nothing at this point but make it clear that we want
17 the ACRS staff to take a look at it? See right now
18 what we are seeing is all of the things that we would
19 be interested in would be in the regulatory guides.
20 As, you know, they are pointing out, this is just kind
21 of structure.

22 CHAIRMAN WALLIS: Right.

23 MEMBER DENNING: You know the things that
24 we are really interested in are still to come. There
25 are going to be regulatory guides. But you don't know

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1 until after that. You know so can't the staff review
2 it at some point and then say yes, the Commission --
3 I'm sorry -- the ACRS wants to hear it? Wants to talk
4 with you about it?

5 MEMBER APOSTOLAKIS: Before the rule is
6 issued you mean? Before when?

7 MEMBER DENNING: Yes, before the rule is
8 issued. After they have drafted it, don't we get a --
9 I mean it seems to me we send a lot of Larkins-grams
10 that say yes, we want to look at it. Or no, we don't.
11 I mean can't we be in that position there where the
12 staff takes a look at it and says there is nothing in
13 here that the ACRS is really going to be -- I mean our
14 staff -- can't we do that?

15 CHAIRMAN WALLIS: Or we may have reached
16 that decision already.

17 MEMBER DENNING: Well, we may but we don't
18 know yet.

19 CHAIRMAN WALLIS: All right.

20 MEMBER DENNING: I mean that is the --

21 MEMBER APOSTOLAKIS: What you want to
22 prevent is us coming back in four months with a whole
23 lot of criticisms.

24 MS. McKENNA: Absolutely because we would
25 not bel able to deal with it at that point in time.

1 I think the point, too, is that if your issues are in
2 the reg guide, then that is something we can handle in
3 a different manner because what we need to send up to
4 the Commission and the rule and the resolution of
5 comments and some recognition of at least non-
6 objection by the Committee to proceeding with the
7 rule.

8 VICE CHAIRMAN SHACK: One substantive
9 issue is the update.

10 MEMBER KRESS: Yes, that would one we
11 would want a copy of I think.

12 VICE CHAIRMAN SHACK: Yes, that seems to
13 be something we certainly might want to comment on.

14 MEMBER APOSTOLAKIS: And we don't know
15 whether the public comments will address any of the --

16 MEMBER DENNING: Well, they are looking
17 for stakeholder input. We are stakeholders.

18 CHAIRMAN WALLIS: Are we?

19 MEMBER KRESS: Yes.

20 CHAIRMAN WALLIS: Lab material. We are
21 advisors. We don't have any stakes at all.

22 MEMBER DENNING: I would certainly like to
23 see what NEI thinks about these things?

24 MR. FREDERICK: Yes, it would be nice to
25 know.

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1 MEMBER SIEBER: And another meeting is
2 going to add a month to the schedule.

3 CHAIRMAN WALLIS: Do we want to have
4 another look at this thing?

5 VICE CHAIRMAN SHACK: Graham, we are going
6 to have the opportunity to hear from NEI during this
7 presentation sometime.

8 CHAIRMAN WALLIS: Are we going to hear
9 from NEI again -- on this thing again?

10 VICE CHAIRMAN SHACK: Well, they are here
11 today to get our comments.

12 CHAIRMAN WALLIS: Okay, okay. I see.

13 VICE CHAIRMAN SHACK: Maybe we ought to
14 hear it.

15 CHAIRMAN WALLIS: Let's hear from NEI.
16 Has the staff finished its presentation?

17 MEMBER KRESS: I'm not sure.

18 MS. GILLES: Yes, that concludes our
19 presentation.

20 MS. MCKENNA: I might just remind the
21 Committee that what was in the Commission's SRM on
22 this particular rule, in fact they spoke specifically
23 about the Committee. I don't know if you are aware of
24 this.

25 What they said is in the manner that

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1 supports the schedule, the staff should seek advisory
2 Committee on reactor safety on feedback on technical
3 issues, if any, during the public comment period. And
4 that is exactly what we are doing.

5 CHAIRMAN WALLIS: I remember that. I
6 remember that. Right.

7 MS. McKENNA: During the public comment
8 period. And that is exactly what were doing it.
9 During the public comment period is the worst.

10 CHAIRMAN WALLIS: They sat on technical
11 issues.

12 MS. McKENNA: On technical issues, that is
13 correct. That is our purpose here today.

14 CHAIRMAN WALLIS: So should we hear from
15 NEI? Is that the plan?

16 MS. McKENNA: Yes.

17 CHAIRMAN WALLIS: Let's do that.

18 MEMBER KRESS: You have an NEI
19 presentation?

20 CHAIRMAN WALLIS: Ralph is going to stay
21 around so that we come back to it whenever we ants to.
22 Thank you.

23 Now we also don't have the role of referee
24 between NEI and the NRC. No, and that is not our job
25 if there are issues like that.

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1 MEMBER KRESS: But we are welcome to speak
2 out on those issues.

3 MR. BELL: Some of you know me. I'm
4 Russell. I'm with the Nuclear Energy Institute. And
5 it is a pleasure to be back with the Committee.

6 We were shocked at the extensiveness of
7 this rulemaking when we first saw it last fall. It
8 was coming at a time when it had been delayed several
9 times and at the same time, progress towards COL
10 applications was being accelerated.

11 So we were faced with the situation of
12 dealing with the extensive rulemaking at the same time
13 moving forward with applications, moving forward with
14 COL application guidelines, and what we would have
15 preferred and what we recommended to the Commission in
16 a briefing and in a letter in December is a skinnied-
17 down rulemaking that focused just on the necessary
18 changes, the beneficial changes. And the clear
19 lessons learned from the interactions we have had to
20 date on design certification and NESP.

21 Ultimately, a majority of the Commission
22 decided to proceed with the rulemaking so here we are.
23 And I can tell you it is difficult to do justice to
24 the rulemaking while applicants are focusing on
25 writing their applications and getting them done by

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1 the end of next year. But we are trying to stay
2 focused on that and do our jobs and respond to the
3 rulemaking.

4 To be sure, there are a number of good
5 things in the rule. Unfortunately they were
6 overwhelmed by the magnitude of things we either
7 didn't understand or didn't agree with or didn't think
8 were necessary. But there are some conforming changes
9 to NRC regulations like 50.59 which was completed in
10 1999 so it wasn't reflected in the earlier
11 certifications.

12 Conforming changes in the Energy Policy
13 Act, terminology clarification, consistent use of
14 terminology, these are all good things. The notion of
15 completing ITAAC early if you can at the COL
16 application and review phase rather than just prior to
17 operation, just prior to fuel-up. That is a good
18 idea. And that is in the proposal.

19 But there was a great deal more that
20 concerned us, particularly the extensive cross
21 references to Part 50 that were inserted in Part 52.
22 It made it very hard to tell what was going on and to
23 be sure about what is going on. And to be sure we
24 fully understand it.

25 And again, it created an air of

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1 uncertainty at a time when applicants were trying to
2 move forward based on the rules they had come to know
3 and love.

4 As I said, the Commission directed the
5 staff to proceed almost as they had proposed. We were
6 glad to see that they had redirected the staff on the
7 scope of the PRA and they had the language taken out
8 that you were just discussing, the full scope, all
9 modes language. So that's not in there.

10 I think it is a question for another day
11 what that scope is. But it is more appropriate to
12 deal with that in guidance land and not rule land.
13 And we will be discussing that with the staff, I would
14 guess, in the next couple of months, again in the
15 context of the COL applications guidelines that the
16 staff is preparing.

17 That was the single -- if you had to
18 isolate the single biggest concern about the staff
19 proposal, that was it. And we were glad to see that
20 addressed.

21 So we are now addressing the rule that was
22 published on March 13th. Comments are due -- oh, my
23 word --

24 MEMBER APOSTOLAKIS: Excuse me, Russell,
25 when you say there are some licensees that are already

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1 writing COLs.

2 MR. BELL: Yes.

3 MEMBER APOSTOLAKIS: What kind of guidance
4 are they following? Is there any guidance right now
5 for that?

6 MR. BELL: No. There is draft guidance
7 that NEI prepared. There is much we know and much we
8 understand about the process. And the company are
9 proceeding on that basis.

10 MEMBER APOSTOLAKIS: So these regulatory
11 guides that we were discussing with the staff, when
12 will they come out?

13 MR. BELL: I won't speak for the staff but
14 -- do you want to go, Bill?

15 MR. BECKNER: This is Bill Beckner. I'm
16 Deputy Director of the Division of New Reactor
17 Licensing. We have a commitment to put out a draft in
18 June of this year.

19 MEMBER APOSTOLAKIS: Of this?

20 MR. BECKNER: Of the content, yes.

21 CHAIRMAN WALLIS: Could you clarify
22 something you said? I think you said that this
23 requirement for a full scope, the staff had backed off
24 from that? Is that true?

25 MEMBER APOSTOLAKIS: No, they were

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1 directed to back off.

2 CHAIRMAN WALLIS: They were directed to?
3 So they have backed off from that? Okay.

4 MR. BELL: Wait a second. Let's make sure
5 we understand. It is not in the rule. It is not
6 going to be in the rule. But it could very well be in
7 the regulatory guide.

8 CHAIRMAN WALLIS: It could be in the
9 guide, yes.

10 MEMBER APOSTOLAKIS: Yes, but they were
11 directed to take it out.

12 CHAIRMAN WALLIS: Because it is not in the
13 rule, okay.

14 MEMBER APOSTOLAKIS: The language.

15 MR. BELL: We would have the same concern
16 if it appeared in a guideline. Of course somebody
17 mentioned earlier a guideline is not a requirement.
18 Nonetheless, it is not good guidance to ask for
19 something that no one knows how to do and that there
20 are not standards to provide. So that is the point we
21 would make.

22 CHAIRMAN WALLIS: That's like saying we
23 want to go to the moon.

24 MEMBER KRESS: How do you feel about the
25 potential requirements for periodic updates of the PRA

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1 that you have?

2 MR. BELL: Folks are doing that now.

3 MEMBER KRESS: It is not a big imposition
4 is it?

5 MR. BELL: We are going to do it in the
6 future consistent with the standards. I don't think
7 that is the issue. I think it is an issue whether
8 that needs to be submitted to the staff either
9 initially or every cycle or every other cycle.

10 I share some of the questions that the
11 Committee was raising. I don't know what the staff
12 will do with that. And, again, it is not consistent
13 with what has been determined to be appropriate for
14 today's --

15 MEMBER POWERS: Wouldn't you anticipate
16 that what they really want is okay, if risk issues
17 come to the fore, new licensees should have available
18 at your site for me to inspect a PRA that is
19 reasonably up-to-date with respect to your plant
20 rather than submit it because the staff doesn't have
21 the manpower to review the PRAs that it has now let
22 alone new ones coming in.

23 But a requirement that says look, if you
24 are going to use risk or invoke risk somehow, I need
25 to come and look at the details of what you have got

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1 there.

2 MR. BELL: I would see no problem. We are
3 going to maintain those things on site. The staff can
4 come at any interval or frankly any time they choose
5 to come see the latest update, examine your process
6 for your update. And again, there are standards for
7 that.

8 So I believe that would be the nature of
9 our response to the question that is in the notice of
10 proposed rulemaking. And whether that translates --
11 I haven't thought this through -- I'm not familiar
12 with our draft preliminary comment on this -- whether
13 that translates to a rule requirement of some sort to
14 have it maintained, I'm not sure. But certainly the
15 periodic submittal, I don't think it is something that
16 we would comment against.

17 MEMBER POWERS: This requirement, what do
18 you do with them? It's a big pile of papers that
19 nobody is going to look at.

20 MR. BELL: And is it paper or is it the
21 decks and codes? So there is a question in my mind
22 what do you mean when you say submit the PRA? I think
23 --

24 CHAIRMAN WALLIS: Well since the time
25 isn't the issue, the issue is that when you need to

1 make a decision based on risk, you should have an
2 effectively up-to-date PRA. And if nothing has
3 changed, maybe you don't need to update it. But as
4 soon as something significant changes which will
5 effect the PRA, You really ought to incorporate it
6 into it.

7 MR. BELL: In fact, that's -- as I
8 understand the current standard, that is exactly what
9 the plants are doing. At a periodicity, they assess
10 the need to update. And if things have changed to a
11 certain degree, the update is made.

12 MEMBER KRESS: How do you view the
13 requirement of radiological consequence analysis?

14 MR. BELL: I don't like ti.

15 MEMBER KRESS: At the ESP stage?

16 MR. BELL: Yes, I was going to mention
17 that one. We saw this in 2003. We see it again in
18 2006. And I think it points up that sometimes we and
19 the staff perhaps took away different lessons learned.
20 We talk about a lessons learned rulemaking.

21 The lesson we learned on this one is that
22 it makes no sense for an ESP applicant who doesn't
23 know yet what he wants to build to try and provide
24 detailed radiological consequence analyses, which
25 requires a great deal of design information, source

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1 term, mitigation systems, and so forth.

2 They only have to be -- they will have to
3 be repeated again at the COL stage using the design-
4 specific information. So we will be making a
5 different proposal in our comments on that area.

6 It's not unlike -- I was just reminded,
7 the emergency planning information. The decision was
8 made, and I think appropriately, it makes no sense for
9 an ESP applicant to update that periodically. What if
10 nobody ever references the ESP?

11 The same kind of thing -- there is no need
12 at the ESP stage to do something that has to be --
13 only comes into play at the COL.

14 MEMBER KRESS: Could you also comment on -
15 - there was a provisions for being able to go ahead
16 and operate the plant at a level of about five percent
17 power even though there might have been impediments to
18 the emergency plan brought forth by FEMA? Could you
19 comment on whether that is advisable or not? Or how
20 you feel about it?

21 MR. BELL: As I understand it, that was an
22 agreement that we and FEMA and NRC arrived at
23 together. And it is based on current practice near as
24 I can tell. And Bruce is back there and can correct
25 me.

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1 If there is a FEMA issue, so that is a
2 problem -- some sort of open item on the off site
3 portion of the emergency plan, I think the theory is
4 that there is -- the company could proceed up to five
5 percent power while addressing that concern.

6 MEMBER KRESS: Yes.

7 MR. BELL: And that that is just a
8 practical issue and not -- for the company to be able
9 to efficiently deal with that and that there is not a
10 safety issue or an emergency planning concern because
11 of the low power issue.

12 MEMBER MAYNARD: Thank you. Typically
13 there is about a four- to six-month period at low
14 power for a lot of testing on a brand new plant.

15 MEMBER KRESS: Which is plenty of time to
16 fix the problem.

17 MR. BELL: To resolve those kinds of
18 things. I think we have also agreed that anything --
19 any problems identified with the on site plan would
20 have to be addressed prior to fuel load. So we are
21 just talking about the off site piece. And I believe
22 there is consensus on that point.

23 I'd highlight a couple other things while
24 you are thinking of other questions for me. We've got
25 comments large and small on the package. Of course,

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1 it is over 650 pages.

2 MEMBER KRESS: Yes, we noticed.

3 MR. BELL: I'm trying to make sure that
4 our comments come in at fewer than that. But I'm not
5 making any promises. We are concerned about the
6 reporting requirements under Part 21 being extended to
7 ESP applicants, and design certification applicants,
8 and ESP holders.

9 MEMBER KRESS: That's the QA?

10 MR. BELL: This is reporting defects to
11 the NRC --

12 MEMBER KRESS: Oh, yes.

13 MR. BELL: -- under Part 21. I think
14 there is a change that is needed to Part 21. I don't
15 think it is the change that the NRC staff has
16 proposed.

17 There can be no reportable situation under
18 Part 21 if the ESP hasn't been referenced by a COL
19 applicant or if a design certification hasn't been
20 referenced. So I think the change that is needed
21 needs to reflect that nuance. And so we are working
22 on that one.

23 The new requirement for applicants to
24 address international operating experience, we are not
25 sure how that --

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1 MEMBER APOSTOLAKIS: In general or --

2 MR. BELL: -- would be done.

3 MEMBER APOSTOLAKIS: -- from limited -- I
4 mean what does that mean?

5 MR. BELL: Well, exactly to what extent,
6 how do we become aware of that. I mean generally the
7 NRC is a player in other, you know, agencies worldwide
8 and is a source of that information. There is WANO
9 and, of course, INPO's participation in that. But it
10 is not clear to us that that is an appropriate
11 requirement or a necessary one.

12 I'm not sure there is a problem here.

13 CHAIRMAN WALLIS: It might be appropriate
14 and some of these reactors might well be first built
15 in other countries.

16 MEMBER APOSTOLAKIS: Yes, but my question
17 is this limited to that or is it general?

18 MEMBER POWERS: The question is are they
19 responsible for discovering these problems or
20 responding to them once they are discovered. And I
21 can't see what -- I just can't see any efficiency in
22 waiting for a licensee to discover a problem.

23 MR. BELL: I might add -- well, I'll skip
24 that one. There are also some areas where the NRC's
25 proposals perhaps didn't go far enough. There is a

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1 change to the design certification change process
2 where You could make generic changes that -- or NRC
3 could that reduced regulatory burden. So this would
4 be a slight expansion of the ability to change design
5 certification through a notice and comment rulemaking.

6 But what is really needed is a process by
7 which a vendor who is continually learning more about
8 his design and is now implementing his design may
9 identify changes that boy, I wish we would have done
10 that and put that in the design certification. I sure
11 wish there was a process for folding that back in
12 there.

13 Well, there isn't. So what we think is
14 that in addition to what the staff proposed, a
15 provision that would allow changes that would enhance
16 or extend standardization, which is, of course, a
17 fundamental goal of this rule, is appropriate. So we
18 will be making a proposal in that area.

19 Westinghouse, I believe, as I understand,
20 has some generic changes to their design certification
21 of this sort. And it would be nice to address those
22 through a -- one time through a notice and comment
23 rulemaking and not each time on every docket for a COL
24 applicant.

25 Doing it up front one time is the best way

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1 to assure that -- well, it is efficient, it is the
2 best way to ensure standardization as well. So that
3 is an interesting one.

4 There is an area that wasn't addressed at
5 all in the rulemaking that I think cries out for it.
6 There is another change process issue. The design
7 certifications, of course, also include features to
8 address severe accident issues. In particular, You
9 know, what happens in the unlikely event where
10 material leaves the vessel and it is out where it
11 shouldn't be.

12 So these types of things were considered
13 in the design certification. They are built in there.
14 And there is a process for controlling them so that
15 they are preserved. The problem is the current
16 criteria, there are questions about the scope of what
17 those criteria are focused on.

18 The criteria use terms like substantial
19 increase and credible accident. These terms aren't
20 defined. And we're frankly struggling with --
21 remember we're in the phase where we are actually
22 proceeding. We need to know how to implement every
23 part of this regulation, especially the change
24 process.

25 We are having trouble writing or even

1 proposing guidance in this area so we're still on two
2 paths. Whether we can work with the criteria and come
3 up with the proper guidance or our comments may
4 actually propose alternative criteria.

5 We wrote these together with the NRC 12
6 years ago, maybe more. I think we are a lot smarter
7 now. And we might have done it differently if we were
8 doing it today. And, You know what? We are doing it
9 today. So I mean we have that opportunity today.

10 There are -- the only other thing I would
11 add is there are a couple of policy issues I would
12 highlight and we will highlight in our comments. The
13 first is another area where the rule, You know, barely
14 touches upon but there is a great need. And it is the
15 ability for a COL applicant to proceed with pre-
16 construction activities.

17 Currently, you seek a limited work
18 authorization from the NRC staff. And it might be so
19 granted following the completion and issuance of a
20 final environmental impact statement. And a ruling by
21 the ASLB on this matter.

22 Those milestones occur too late in the
23 process. In order for the companies and the vendors
24 to efficiently construct these plants, moving from one
25 phase to the next, there is a need to begin these pre-

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1 construction activities.

2 We're talking about site preparation,
3 clearing the trees, building the roads, support
4 buildings -- this is non-safety-related stuff --
5 sooner than they would be able to under the current
6 requirements.

7 So, in fact we sat with the staff and
8 tried to do some out-of-the-box thinking on this at a
9 meeting April 18th. And we are polishing our ideas
10 and our recommendations in this area. And plan to
11 provide that this month as part of our comments on the
12 rulemaking.

13 There is a great need, again, from a
14 business perspective for these companies to be able to
15 efficiently move from one phase to the next and
16 construct these things and start building on time and
17 finish on time. The other -- and I call it a policy
18 issue because as we've discussed with the NRC staff,
19 it is going to be a different way of doing business
20 than before so that kind of, by definition, we are
21 calling it a policy issue.

22 Another one is a -- it is a concern that
23 we have about the finality at COL of information
24 contained in an early site permit. As we read and
25 understand more what the staff intends by the language

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1 in the rule, we are concerned that the staff intends
2 to essential redo the environmental review that was
3 done at ESP at the time of COL.

4 Our understanding is, based on the rules,
5 based on NEPA which everybody says is different and
6 I'm learning more than I ever cared to about the
7 National Environmental Policy Act -- I can tell you it
8 is different but what isn't different is if you have
9 resolved an issue once and there are no changes or no
10 significant new information, then it doesn't need to
11 be reviewed again.

12 We are concerned about some of the things
13 we are hearing or expectations of the staff in this
14 regard. And so I think we are going to seek some rule
15 clarifications in this area so that the value of the
16 ESP doesn't go to zero. A lot of people are putting
17 a lot of hard work into these things and we want it to
18 stand up.

19 Obviously if there is significant new
20 information effecting a prior conclusion about an
21 environmental impact, there is a mechanism for dealing
22 with that. But no need to review all the issues that
23 were previously reviewed. So we will be highlighting
24 at least those two very significant issues.

25 And I touched upon a couple others that I

1 thought -- certainly some of my favorites and I
2 thought might be yours -- and Dr. Kress, You picked
3 out the one -- certainly one I was going to mention
4 because the Committee has been interested in dose
5 analysis.

6 MEMBER KRESS: Yes, that's one of my issues.

7 MR. BELL: Did I give you enough time to
8 think of a couple more questions?

9 MEMBER KRESS: Well, let me ask you, there
10 was some question -- comment from the earlier versions
11 that I saw where industry would like to retain the
12 flexibility for a combined license COL submittal not
13 to have to reference either an early site permit or a
14 certified reactor design. What's the purpose of
15 needing that flexibility? And could you comment on
16 how that helps you out having that flexibility?

17 MR. BELL: Well, in general, you know,
18 flexibility is a good thing.

19 MEMBER KRESS: Yes, yes.

20 MR. BELL: And we don't rule out any
21 licensing scenario.

22 MEMBER KRESS: Combined, the COL may come
23 in and say here is my site. We don't have and ESCP.
24 We don't have a reactor in mind yet. But we want to
25 get this site approved.

1 MR. BELL: So he's likely to come in with
2 an ESBWR which doesn't have a design search yet.

3 MEMBER KRESS: Yes, okay. Then what is an
4 ESBWR like? You are saying --

5 MR. BELL: That is, of course, a real
6 scenario --

7 MEMBER KRESS: Yes.

8 MR. BELL: -- that is actively being
9 discussed. It is hard to imagine this other scenario.
10 There is such a premium on the design certification
11 reviews.

12 MEMBER KRESS: Yes.

13 MR. BELL: The staff portion and then the
14 rulemaking. That's why you see every company planning
15 to go forward only with at least the staff review in
16 hand.

17 But might there be a scenario where for
18 some new design you would go straight to the COL
19 application, I guess that was the PBMR case. At the
20 end of that process, they were also going to get not
21 only a license but a certification for that design.
22 So again there is a priority on the certification.

23 MEMBER KRESS: Yes.

24 MR. BELL: But there was a serious
25 interest at that time in going straight to the COL.

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1 But I know of no -- I certainly don't know of anybody
2 who is thinking about that now.

3 MEMBER KRESS: There doesn't seem to be
4 any difficulty in providing that flexibility.

5 MR. BELL: And no down side.

6 MEMBER KRESS: No down side.

7 MR. BELL: I see no down side in it.

8 We were consistently impressed and
9 gratified at the flexibility that the rule displays.
10 The framers, whether they were lucky or good, it has
11 accommodated, as you have seen, and read in the
12 papers, a number of different approaches.

13 And I think it needs to because there are
14 a number of different regions of this country,
15 business situations, regulated, non-regulated. So I
16 think it needs to be flexible. And I think it is.

17 MEMBER KRESS: I think I've had my
18 questions answered.

19 CHAIRMAN WALLIS: I'm glad you ended on a
20 positive note there.

21 MR. BELL: I hope I wasn't too dour.
22 There are a number of good things about this
23 rulemaking. We're certainly going to highlight those
24 as well and support those. But I think a number of
25 ways that it can be improved.

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1 CHAIRMAN WALLIS: Thank you very much.

2 MR. BELL: Thank you.

3 CHAIRMAN WALLIS: That's been very helpful.

4 MR. SNODDERLY: Excuse me, Graham, I just
5 wanted to take a moment to thank Jerry Wilson and Nan
6 Gilles for coming over and giving us this
7 presentation. I think it really helps us to
8 understand what the rule covers and doesn't. And it
9 will aide us in our upcoming review of the COL
10 guidance and its importance in helping us to prepare
11 for future ESP and COL reviews. So thank you.

12 MEMBER APOSTOLAKIS: The regulatory guide
13 you said will be in the draft form at the end of June?

14 MR. FISHER: Yes, actually there has been
15 an ongoing series of workshops already. And we have
16 sections already posted on our external website.
17 There has been extensive interaction with external
18 stakeholders already with the goal of a draft by this
19 June.

20 MEMBER APOSTOLAKIS: Is the ACRS going to
21 get involved at some point?

22 MR. FISHER: I think the answer to that is
23 yes, George. But I think the draft that Bill Beckner
24 is talking about is a goal of having the draft
25 sections on the web in June. So I don't think there

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1 is going to be a hard copy -- to my knowledge, there
2 is not going to be a hard copy of it available for an
3 ACRS review at that point. At least that is what Joe
4 Colaccino told me, Bill.

5 CHAIRMAN WALLIS: We can always print it.
6 What's wrong with that?

7 MEMBER APOSTOLAKIS: We can always print
8 it, yes.

9 MR. FISHER: I know that Dave Matthews
10 signed out a letter today which I think lays out a
11 more detailed schedule also. My point though was it
12 is going to be very draft at that point.

13 MEMBER APOSTOLAKIS: Once it is issued,
14 there will be a letter from the ACRS?

15 MR. FISHER: That is correct.

16 MEMBER APOSTOLAKIS: Okay. There has to
17 be? I don't know. They say yes.

18 CHAIRMAN WALLIS: Any other points? While
19 everybody has been thanking everybody, I thank
20 everybody again for your participation enlightening
21 us.

22 We are going to take a break. We don't
23 need the transcript any more. Thank you very much.

24 (Whereupon, the above-entitled meeting was
25 concluded at 4:55 p.m.)

CERTIFICATE

This is to certify that the attached proceedings
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Reactor Safeguards
532nd Meeting

Docket Number: n/a

Location: Rockville, MD

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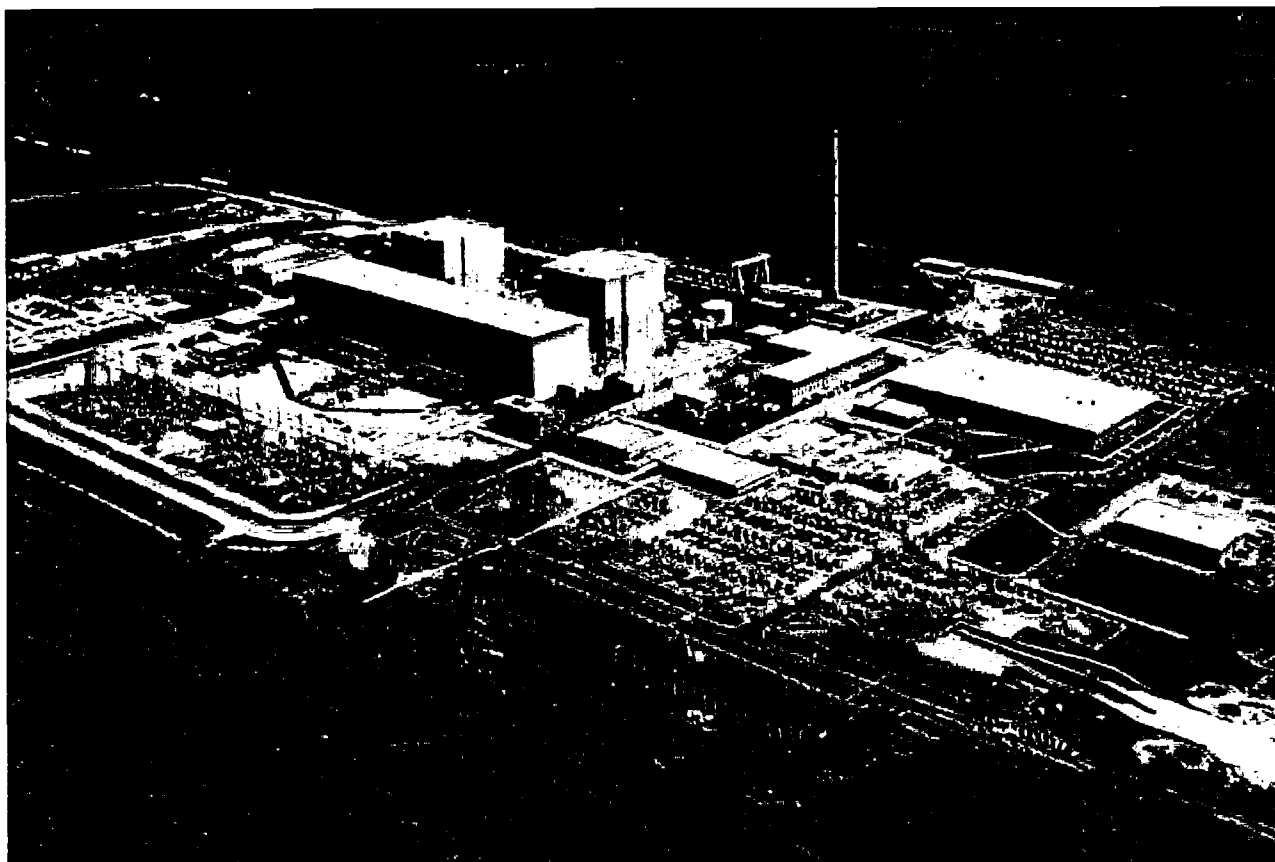
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Brunswick Steam Electric Plant Units 1 and 2



**Brunswick Steam Electric Plant
Units 1 and 2**

License Renewal Presentation to ACRS



Agenda

- A. Overview of License Renewal Application
- B. Operating Experience
 - ▶ a. Drywell Liner
 - ▶ b. EPU Vibration
- C. Major Equipment Replacements/Repairs
- D. Major Exceptions to the GALL Report
- E. Commitment Tracking

INDEX



Description of BSEP

- Located in Southport, NC
- Cape Fear River is Ultimate Heat Sink
- Dual unit GE BWR 4 with Mark I Reinforced Concrete Containment
- Both units have achieved 120% power uprate
- Current License Expiration
 - ▶ Unit 1 September 2016
 - ▶ Unit 2 December 2014

INDEX



Application Background

- LRA used Class of 2003 Format – May 2003
- Information in the LRA was developed in plant calculations
- Addressed ISGs 1 through 20
- 34 Aging Management Programs Identified
- No Open Items or Confirmatory Items

Drywell Liner Operating Experience

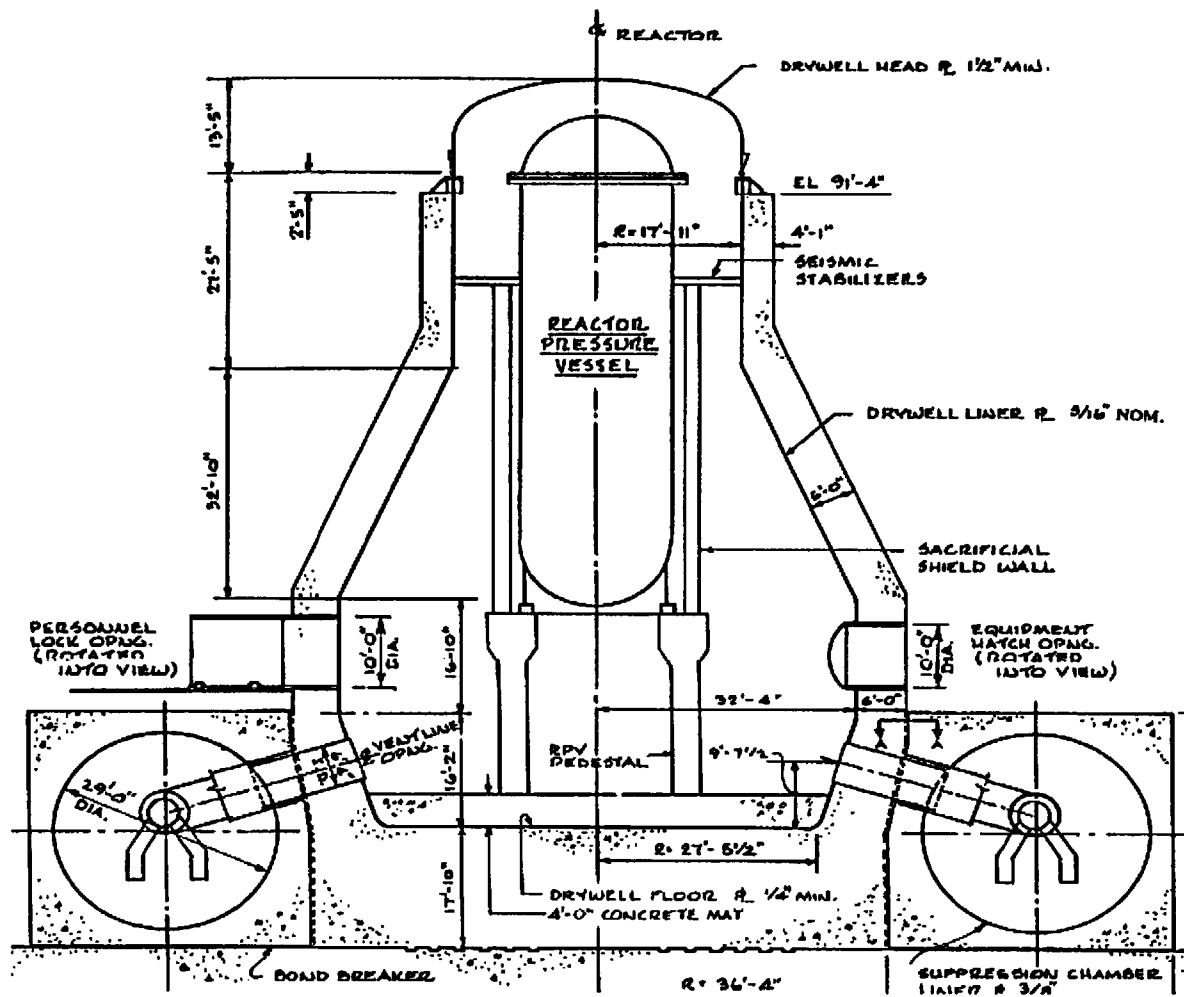
Tom Overton



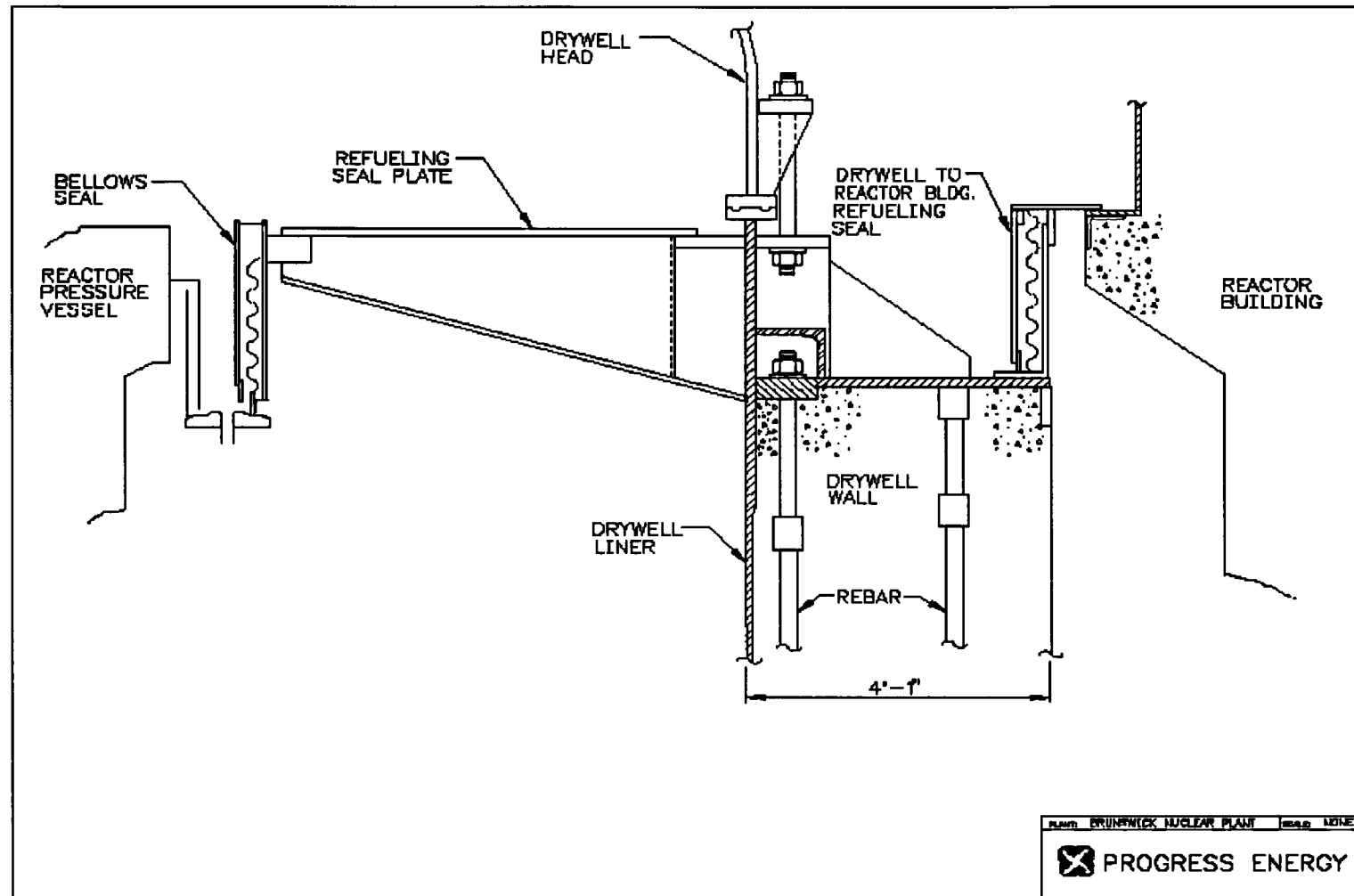
BWR Mark I Steel Lined Reinforced Concrete Containment

- Only BWR Mark I steel lined, reinforced concrete containment
 - ▶ No annular space between the metallic liner and the reinforced concrete
 - ▶ No sand bed region

Brunswick Mark I Steel Lined Reinforced Concrete Containment

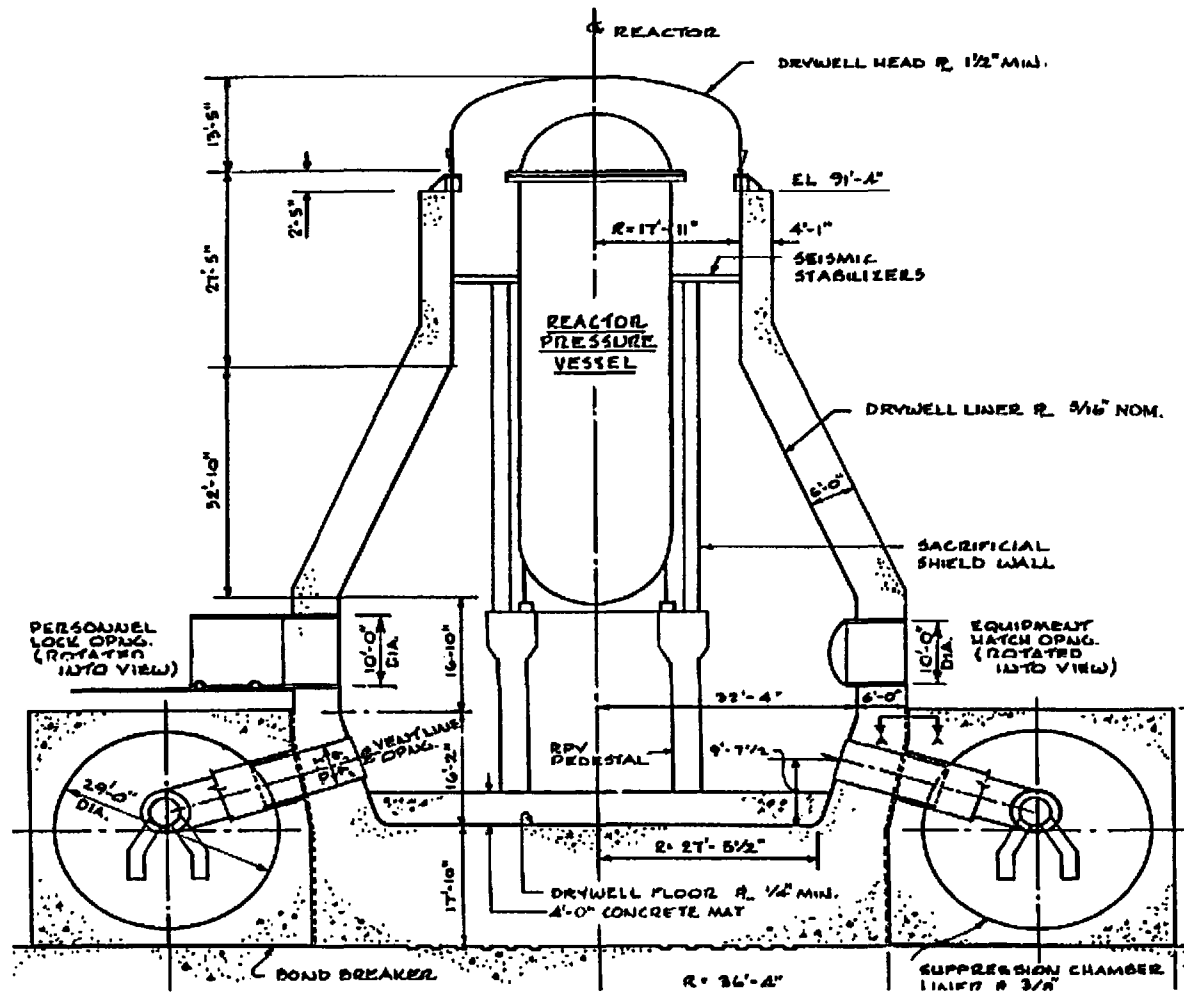


Refueling Bellows



Brunswick

Mark I Steel Lined Reinforced Concrete Containment



Power Uprate Vibration Operating Experience

Mark Grantham



EPU Vibration Experience

- Main Steam and FW Vibration Monitoring
 - ▶ Based on ASME/ANSI OM Part 3
 - ▶ Modal analysis performed to determine sensor locations
 - ▶ Vibration levels increased as part of EPU implementation, but remain well below code allowable stresses

EPU Vibration Experience

Main Steam Line Piping

- Acceleration Study for Unit 1 Main Steam Node 26

Channel Number	Measured Acceleration at EPU (g)	Allowable Acceleration (g)	Percent of Allowable (%)
11	0.126	1.014	12.4
12	0.108	0.698	15.5

EPU Vibration Experience Feedwater Piping

- Acceleration Study for Unit 1 Feedwater Node 37

Channel Number	Measured Acceleration at EPU (g)	Allowable Acceleration (g)	Percent of Allowable (%)
27	0.020	2.155	1.0
28	0.021	2.364	1.0

EPU Vibration Experience

BOP Piping

- Fatigue failure of EHC return line for main turbine control valves
 - ▶ Interim power level was likely a contributor
 - ▶ Industry OE with these types of failure exists
 - ▶ Piping modified to a flexible connection
- Socket welded drain line failures
 - ▶ Previous industry and BSEP OE with these types of failures
 - ▶ Changed socket weld configurations to a more fatigue tolerant design

EPU Vibration Experience

BOP Piping

- Rod Hung BOP Piping
 - ▶ Low frequency vibration
 - ▶ Modified to add lateral supports

Major Equipment Replaced or Repaired

Mark Grantham



Major Equipment Replacement/Repair

- Replaced Power Range Neutron Monitoring System
- Replaced Main Power Transformers
- Replaced High Pressure Turbines
- Rewound Main Generator Stators
- Replaced FW Heaters
 - ▶ Unit 1 - 5 FW Heaters
 - ▶ Unit 2 - 1 FW Heater
- Replaced Reactor Feed Pump Turbines, Governor, and pump rotating assemblies

Major Equipment Replacement/Repair

- Replaced Condensate Pumps and Motors
- Replaced Isophase Bus Cooling Units
- Fire Detection System (in progress)

Major Exceptions to GALL

Mike Heath

Major Exceptions to GALL

Fire Protection Program

NUREG 1801:

- Visual Inspection of 10% of Each Type Penetration Once Every Refueling Outage.

BSEP:

- Visual Inspection of a Statistical Sample Once Every 18 Months.

Major Exceptions to GALL

Fire Protection Program – continued

NUREG 1801:

- Test Halon/CO2 Every 6 Months.

BSEP:

- Test Halon Annually/Test CO2 Every 18 Months.

Major Exceptions to GALL

Fuel Oil Chemistry Program

NUREG 1801:

- Internal Surfaces of Tanks are Cleaned and Inspected.

BSEP:

- Only Main Fuel Oil Tank Internal Surface is Inspected and Cleaned if Needed. Smaller Tanks Have External UT of Tank Bottom.

Commitment Tracking

Mike Heath



Commitment Tracking

- All Commitments are Tracked by the BSEP Corrective Action Program (CAP)
- Each Commitment Has an Implementation Plan
 - ▶ Each Implementation Plan Identifies all required actions
 - ▶ All actions are linked to the CAP
 - ▶ All actions have a due date and owner
- LR Program Procedure Tracks LR Activities
- Most Document Updates Scheduled for 2006

Conclusion

- The New Audit Process Effective
- Early Identification of Concerns Allowed Early Resolution

Questions?





Brunswick Steam Electric Plant (BSEP) Units 1 and 2 License Renewal Final Safety Evaluation Report

Staff Presentation to the ACRS Full Committee
Sikhindra (SK) Mitra, Project Manager
Maurice Heath, Project Manager
Office of Nuclear Reactor Regulation
May 4, 2006



Introduction

- Overview
- Highlights of the Review
- Time-Limited Aging Analyses (TLAAs)
- Conclusion



Overview

- LRA submitted by letter dated October 18, 2004
- GE Boiling Water Reactors, Mark 1 design containments
- BSEP located at the mouth of Cape Fear River in Brunswick County, NC, two miles north of Southport, NC
- Unit 1 expires September 8, 2016, Unit 2 expires on December 27, 2014
- Request operating license extensions 20 years beyond the current expiration dates



Overview (continued)

- Each unit generates 2923 MW thermal, 1007 MW electrical – Include 20% Extended Power Uprate (EPU)
- Applicant committed to review plant and industry operating experience, relevant aging effects caused by operation at power uprate. The evaluation will be submitted for NRC review one year prior to period of extended operation (Commitment # 31)



Overview (continued)

- SER issued on December 20, 2005
 - No Open or Confirmatory Items
- FSER issued on March 31, 2006
 - Staff Conclusion: BSEP LRA has met the requirements of 10CFR Part 54



Highlights of Review

- Three (3) license conditions
 - FSAR update following the issuance of renewed license
 - Commitments completed in accordance with schedule
 - Reactor Vessel Surveillance Program
 - Implement Staff approved BWRVIP Integrated Surveillance Programs (ISP)
 - Obtain NRC staff review and approval for any changes to the capsule withdrawal schedule



Highlights of Review

- Items Brought into scope and subject to AMR
 - Switchyard Breakers
 - Service Water Intake structure fan, dampers, bird screen
 - Condensate Storage Tank Piping Credited for SBO



Highlights of Review

- Tier 1: Screen, Review (LRA, FSAR), Identify Systems for Inspections
- Tier 2: Review (Boundary Drawings, and Other Licensing Basis Documents in Addition to LRA, FSAR)
- 39 out of 62 Mechanical Systems are BOP (Most Auxiliary and Steam and Power Conversion Systems)
- 15 BOP Systems Selected for Tier 1 Review
- 24 BOP Systems Selected for Tier 2 Review



Highlights of Review

- Two – Tier Scoping Review Based on Screening Criteria
 - Safety Importance/Risk significance
 - Systems Susceptible to Common Cause Failure of Redundant Trains
 - Operating Experience Indicating Likely Passive Failures
 - Previous LRA Review Experience of Omissions
- 8 Total Electrical Systems and Structures Continue to Receive Tier 2 review



Highlights of Review

	Aggressive Limit	BSEP
pH	<5.5	6.4 – 7.5
Chlorides	>500 ppm	11 – 49 ppm
Sulfates	>1500 ppm	2 – 66 ppm

- Ground water phosphate level at 0.12 ppm
- Below grade environment is non-aggressive
- Annual groundwater monitoring frequency for concrete structures



Highlights of Review

- Commitment # 22 defines which BWRVIP reports are included in the scope of the Reactor Vessel and Internals Structural Integrity Program (RV&ISIP) and additional specific augmented activities that will be taken by the applicant
- Added sample size of the augmented inspection for top guide that will focus on the high fluence region



Highlights of Review

- BSEP is Mark I Steel Lined Reinforced Concrete Containment
- BSEP Credits ASME Section XI, Subsection IWE and 10 CFR Part 50, Appendix J for management of Drywell Liner
- Both IWE and Appendix J requires 100% inspection per period, there are 3 periods per interval, and each interval is ten years.



TLAA - Reactor Vessel (RV) Upper Shelf Energy (USE)

RV Beltline Component	Acceptance Criterion for USE	Component Value for 54 EFPY	Acceptable (Y/N)
Brunswick 1 Lower Intermediate Shell Plate (Heat No. B8946-1)	Percent Drop <23.5 percent drop in the USE ft-lb value	21.0 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21(c)(1)(ii)]
Brunswick 1 Circumferential Weld FG (Heat No. 1P4218)	Percent Drop <39.0 percent drop in the USE ft-lb value	14.1 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21(c)(1)(ii)]
Brunswick 2 Lower Shell Plate (Heat No. C4500-2)	Percent Drop <23.5 percent drop in the USE ft-lb value	17.0 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21 (c)(1)(ii)]
Brunswick 2 Circumferential Weld FG (Heat No. S3986)	Percent Drop <39.0 percent drop in the USE ft-lb value	13.3 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21 (c)(1)(ii)]



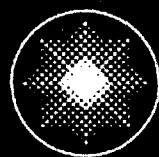
TLAA - Reactor Vessel (RV) Upper Shelf Energy (USE)

RV Beltline Component	Acceptance Criterion for USE	Component Value for 54 EFPY	Acceptable (Y/N)
Brunswick 1 and 2 N-16 Instrument Nozzle Forgings	Neutron Fluence $<1.6 \times 10^{18} \text{ n/cm}^2$ ($E > 1.0 \text{ MeV}$)	Neutron Fluence $= 1.38 \times 10^{18} \text{ n/cm}^2$ ($E > 1.0 \text{ MeV}$)	Yes [TLAA satisfies 54.21 (c)(1)(ii)]
Brunswick 1 and 2 N-16 Instrument Nozzle Welds	Percent Drop <35.0 percent drop in the USE ft-lb value	12.0 Percent Drop in USE ft-lb	Yes [TLAA satisfies 54.21 (c)(1)(ii)]



Conclusion

- On the basis of its evaluation of the license renewal application, the NRC staff concluded that the requirements of 10 CFR 54.29(a) have been met



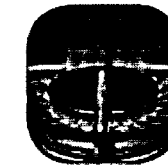
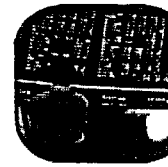
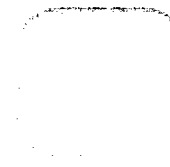
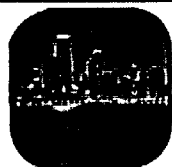
Constellation Energy

Ginna Extended Power Uprate

ACRS Full Committee Meeting

May 4, 2006

The way energy works.™





Ginna Extended Power Uprate

Dave Holm
Ginna Plant Manager
Introduction/Agenda Review



Agenda

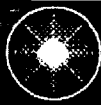
- Introduction
- Plant Changes
- Safety Analysis
- Mechanical Impacts
- PRA
- Conclusion

Dave Holm
Mark Finley
Mark Finley
Jim Dunne
Rob Cavedo
Dave Holm



Introduction - Agenda

- Design and Operating History
- Preparations for Uprate



Introduction - Design and History

- Westinghouse two-loop 1520 MWt NSSS design
- Commercial operation in 1970
- 1300 MWt original licensed power
- 1520 MWt licensed in 1972
- 1775 MWt Extended Power Uprate ⁽¹⁾

⁽¹⁾ Kewaunee is operating at 1772 MWt



Introduction - Preparations for Uprate

- Replaced steam generators 1996
- Replaced reactor vessel head 2003
- Experienced project team:
Westinghouse, Stone & Webster, Siemens
- Executive oversight:
corporate, vendor, industry experts



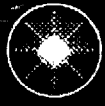
Ginna Extended Power Uprate

Mark Finley
Project Director
Plant Changes



Plant Changes-Agenda

- Operating Parameters
- Major Modifications
- License Amendments



Plant Changes-Operating Parameters

	EPU		Pre-EPU		
	Condition	Enthalpy	Condition	Enthalpy	Change
Core Power (MWt)	1775		1520		+16.8%
Taverage	574°F		561°F ⁽¹⁾		+13°F
Tcold / h cold (BTU/lb)	541°F	536.1	532°F	525.1	+9°F
Delta T	66°F		58°F		+8°F
Delta h		87.1		74.0	+17.5%
Thot / h hot (BTU/lb)	607°F	623.1	590°F	599.1	+17°F
Coolant Mass Flow (lb/hr)	6.96E+07		7.01E+07		-0.7%
Pressurizer Pressure	2250 psia		2250 psia		
SG Power (MWt)	1781		1526		+16.8%
FW In / h in (BTU/lb)	432°F	410.5	425°F	402.9	+7°F
Delta h		788.8		797.2	-1.2%
Stm Out / h out (BTU/lb)	798 psia	1199.4	770 psia	1200.1	+28 psia
Stm Mass Flow (lb/hr)	7.71E+06		6.53E+06		+18.0%

⁽¹⁾ Taverage was 573.5°F prior to SG replacement in 1996



Plant Changes - Major Modifications

- Fuel assembly
- Feed isolation valve actuators
- High pressure turbine and turbine control valves
- Main feedwater and booster pumps, feed regulating and bypass valves
- Cooling for main generator, step-up transformer, isophase ducts and underground oil cables
- Moisture Separator Reheater relief system
- Risk beneficial modifications:
charging pump backup air, charging and TD AFW controls



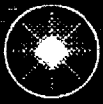
Plant Changes - License Amendments

Change	EPU	Current
Core Thermal Power	1775 MWt	1520 MWt
LOCA Methods	BE LOCA/ASTRUM	BE LOCA/SECY-83-472
Axial Offset Control	RAOC (Relaxed)	CAOC (Constant)
Max Boron - Accumulator / RWST	3050 ppm	2600 ppm
Min Volume - Accumulator	1090 ft ³	1111 ft ³
Min Volume - Condensate Storage Tank	24350 gal	22500 gal
Feed Isolation Valve (Back-up Valve Stroke Time)	30 sec	60 sec
Safety Setpoints	Later in 'Safety Analysis'	Later in 'Safety Analysis'



Ginna Extended Power Uprate

Mark Finley
Project Director
Safety Analysis



Safety Analysis-Agenda

- Safety Setpoints
- Control Settings
- Methods
- Non-LOCA
- LOCA
- LTC
- Conclusion



Safety Analysis-Safety Setpoints (Analytical)

Setpoint	EPU	Current
High Flux Trip	$\leq 115\%$	$\leq 118\%$
Steam Line Isolation Hi-Hi	$\leq 5.97 \times 10^6$ lbm/hr	$\leq 3.70 \times 10^6$ lbm/hr
Steam Line Isolation Hi	$\leq 1.50 \times 10^6$ lbm/hr @ $\geq 530^\circ\text{F}$	$\leq 0.66 \times 10^6$ lbm/hr @ $\geq 543^\circ\text{F}$
Pressurizer Safety Lift Setting	≤ 2542 psig	≤ 2544 psig
Safety Injection	≥ 1700 psig	≥ 1715 psig
Containment Spray	≤ 33.5 psig	≤ 32.5 psig
P-8 Permissive (Single loop low flow)	$\leq 35\%$	$\leq 50\%$



Safety Analysis-Control Settings

Setting	EPU	Current
Pressurizer Level - Full Power - Zero Power	56% 20%	50% 35%
T _{Avg} - Full Power - Zero Power	574°F 547°F	561°F 547°F
Rod Control - Low Power Mismatch Gain - High	0.3 °F/% - 0.6 °F/% 1.5 °F/% - 3 °F/%	1.5 °F/% - 3 °F/% 5 °F/% - 10 °F/%
Steam Dump Modulation - Turbine Operating - Turbine Tripped	4°F - 11°F 0°F - 11°F	5°F - 20°F 0°F - 15°F
T _{Hot} Filter	4.5 sec	0 sec



Safety Analysis-Methods

Method	EPU	Current
Non-LOCA	RETRAN	LOFTRAN
Large Break LOCA	BE LOCA/ASTRUM	BE LOCA/SECY-83-472
Small Break LOCA	NOTRUMP	NOTRUMP
Control System Transients	LOFTRAN	LOFTRAN
Containment: LOCA MSLB	GOTHIC GOTHIC	GOTHIC COCO
Dose Assessment	AST	AST



Safety Analysis-Non-LOCA Approach

- Very conservative inputs for pre-EPU analyses used in EPU analyses where possible
- Certain limiting EPU analyses were not successful with pre-EPU inputs
- Inputs were adjusted until acceptable results demonstrated
- No attempt made to demonstrate additional margin
- Understand the conservative nature of methods, inputs and approved limits



Safety Analysis-Non-LOCA

	Event	Criteria	Result
Overheating (Reduced Primary Cooling)	Loss of Flow (Cond III)	DNBR ≥ 1.38	1.385
	Locked Rotor (Cond IV)	Pres ≤ 2997 psia	2782 psia
Overheating (Reduced Secondary Cooling)	Loss of Load (Cond II) (Bounds Loss of Feed) Feed Line Break (Cond IV)	Pres ≤ 2748.5 psia No T _{SAT} in HL	2747 psia (No pZR fill) 2°F subcool
	ATWS	Pres ≤ 3200 psig	3193 psig
Overcooling	MSLB @ Power (Cond IV) (Bounds Increased FW/ARV)	DNBR ≥ 1.38 LHR ≤ 22.7 kw/ft	1.39 22.67 kw/ft
Reactivity Addition	Rod W/D @ Power (Cond II)	DNBR ≥ 1.38 Pres ≤ 2748.5 psia	1.381 2748.1 psia
	Rod Ejection (Cond IV)	≤ 200 cal/gm	178 cal/gm



Safety Analysis-Non-LOCA Loss of Flow DNB

CHF	1.0
Bounding Test Data- (95% probability/95% confidence)	1.17
Design Limit- accounts for parameter uncertainties (95/95)	1.24
Safety Analysis Limit- accounts for generic penalties with margin	1.38
Safety Analysis Result	1.385
Credit for Less Trip Delay	1.42
Credit for Overpressure	1.50



Safety Analysis-Non-LOCA Loss of Load Pressure

Potential Deformation- (ASME Service Level C Limit - Hot)	>3200 psig
Hydrostatic Test Pressure (Cold)	3107 psig
Design Limit- 110% of Design Pressure	2748.5 psia
Safety Analysis Result	2747 psia
Credit for Steam Dump and Pzr Spray	2605 psia
Credit for Steam Dump, Pzr Spray and PORVs	2565 psia
Credit for Reactor Trip on Turbine Trip	2348 psia



Safety Analysis-Non-LOCA

- All Non-LOCA results meet acceptance criteria
- Margin exists in the methods and the inputs
- Margin exists between the acceptance criteria and the failure point



Safety Analysis-LOCA

Results

- Large Break
- Small Break

PCT 1870°F

PCT 1167°F



Safety Analysis-Long Term Cooling

- The Ginna Design
 - High head safety injection (SI) pumps aligned to the RCS cold legs
 - Low head safety injection using the residual heat removal (RHR) pumps aligned to the upper plenum to provide upper plenum injection (UPI)
 - Simultaneous injection - both SI and RHR - will flush the core for all break locations, prevent boric acid concentration and assure Long Term Cooling ☐



Safety Analysis-LTC-Large Break Analysis

- Mixing volume and void fraction calculated with Large Break LOCA code WCOBRA/TRAC ☐
- No credit for mixing with UPI flow, no credit for beneficial effect of sump additives, no credit for containment pressure above atmospheric ☐
- Credit for mixing with one-half lower plenum volume ☐
- Time to reach boric acid solubility limit for atmospheric pressure is 6 hr 13 minutes ☐
- Operators will restart SI beginning at 4.5 hours ☐



Safety Analysis-LTC-Small Break Analysis

- Mixing volume and void fraction calculated with Small Break LOCA code NOTRUMP ☐
- 4" break conservatively used to bound all small breaks
- Boric acid concentration is calculated as a function of time
- No credit for beneficial effect of sump additives
- Credit for mixing with one-half lower plenum volume
- Time to reach boric acid solubility limit for atmospheric pressure is 6 hr 48 minutes ☐
- Operators will depressurize to initiate UPI, or refill to initiate natural circulation, in less than 5.5 hours ☐ ☐





Safety Analysis-Conclusion

- All safety analyses meet acceptance criteria
- NSSS and Emergency Safety Features are robust
- Results are consistent with Kewaunee





Ginna Extended Power Uprate

Jim Dunne
Project Lead Engineer
Mechanical Impacts



Mechanical Impacts-Agenda

- Steam Generator Vibration
- BOP Heat Exchanger Vibration
- Vibration Monitoring Program
- Flow Accelerated Corrosion



Mechanical Impacts-Steam Generator Vibration

- Steam Generator - Vibration
 - Vibration Potential in U-Bend & Tube Bundle Entrance
 - Fluidelastic Instability
 - Vortex Shedding (Tube Bundle Entrance)
 - Random Turbulence Excitation
 - Tube Wear (U-Bend Region)





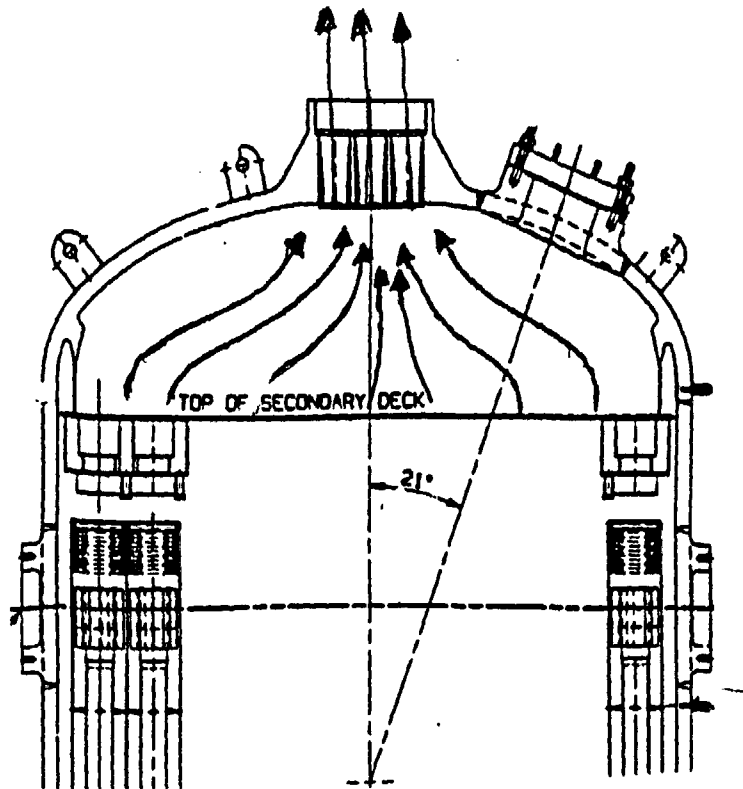
Mechanical Impacts-Steam Generator Separators

- Steam Generator Steam Separators
 - 85 Primary/Secondary Separator Modules
 - Primary & Secondary Centrifugal Type Separators
 - Minimal Cross-Flow Velocities
 - Rigid Separator Bundle
 - Full Scale Testing of Separator Modules
 - Up-rate Flow Bounded by Tested Flow Conditions

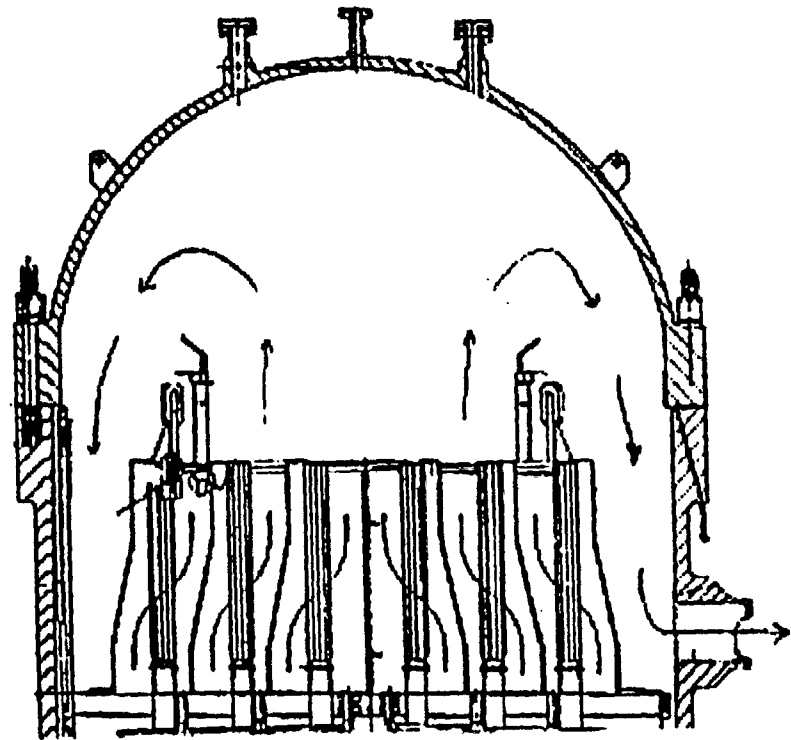




Ginna Separator / BWR Dryer Comparison



Ginna Steam Separators



BWR Steam Dryers



Mechanical Impacts-Vibration

- BOP Heat Exchangers - Vibration
 - Feedwater Heaters
 - Moisture Separator Reheaters
 - Condenser Tubing
- Vibration Monitoring Program
 - Pre-EPU Walkdown @ Full Power
 - Post EPU Walkdown (Pre- and Post-Full Power Levels)



Mechanical Impacts-Flow Accelerated Corrosion

- Flow Accelerated Corrosion (FAC)
 - Power Uprate effects evaluated using CHECWORKS
 - No component replacements required
 - Post Uprate Outage inspection sampling increased based on EPU conditions
 - Piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates





Ginna Extended Power Uprate

Rob Cavedo
Risk Consultant
PRA



PRA-Agenda

- Scope
- Method
- Results
- Conclusion



PRA-Scope

- Address Impact On:
 - Initiating Event frequency
 - Success criteria
 - Equipment failure rates
 - Operator response times and Human Reliability Analysis (HRA)
- Identify Risk Beneficial Plant Changes
- Calculate the CDF and LERF Changes On:
 - Internal events
 - External events
 - Shutdown



PRA-Method

- Initiating Event Frequency
 - No new PSA initiators
 - Frequencies adjusted based on Engineering Evaluations
- Success Criteria
 - PCTRAN analyses to adjust success criteria as needed
 - Bleed-and-Feed Timing Adjusted



PRA-Method

- Equipment Failure Rates
 - Comprehensive reviews of equipment performed
 - Systems operate within allowable limits
 - No significant impact is expected to the likelihood of post-trip Equipment Failure Rates
- Operator Response Times / HRA
 - PCTTRAN analyses to determine available action times
 - Higher decay heat reduced operator action times



PRA-Method

- Plant Beneficial Changes Identified and Incorporated
 - Use of high pressure SI pumps
 - Adjustment of RHR AOV
 - Addition of Back-up Air Supply for Charging Control



PRA-Results

Case	Pre or Post Uprate	CDF	LERF	Optimize SI Pump in Fire	Limit RHR AOVs	Back-Up Air to Charging
Base	Pre	6.36E-05	4.88E-06	No	No	No
Base	Post	7.12E-05	5.35E-06	No	No	No
SI	Post	6.40E-05	4.73E-06	Yes	No	No
SDAOV	Post	6.59E-05	5.32E-06	No	Yes	No
BK-IA-CHG	Post	7.10E-05	5.20E-06	No	No	Yes
SI-AOV-IC	Post	5.85E-05	4.56E-06	Yes	Yes	Yes

From EPU Submittal: Table 2.13-21



PRA-Conclusion

The Plant Risk Level Pre-EPU without the modifications is higher than the Risk Level Post-EPU with modifications



Ginna Extended Power Uprate

Dave Holm
Ginna Plant Manager
Conclusion



Conclusion

- Detailed and comprehensive reviews have been completed
- No safety issues were uncovered
- Comprehensive testing will be performed
- Ginna safety and reliability will be maintained through plant modifications, procedure changes and training

532nd Meeting of the Advisory Committee on Reactor Safeguards

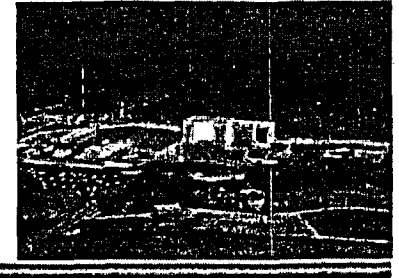
NRC Staff Review of Extended Power Uprate Application
For
R.E. Ginna Nuclear Power Plant



May 4, 2006



Introduction



Patrick D. Milano
Senior Project Manager
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation



Agenda -Topics

- **Licensee Introduction**
- **Plant Modifications to Support Upstate**
- **Safety Analyses**
- **Mechanical Impact**
- **Probabilistic Risk Assessment**
- **Other Evaluation Items**
- **Summary**



Reactor Systems Analyses

- **Fuel and Nuclear System System Design**
- **ECCS and Other Associated Systems**
- **Non-LOCA Transients**
- **LOCAs**
- **ATWS**



Reactor Systems Review

Matrix 8 of NRC Review Standard RS-001

•NRC Review Confirms:

- ▶ Use of NRC-Approved Codes and Methods for Plant-Specific Application
- ▶ Compliance with Limitations or Conditions on Code Use
- ▶ SG Plugging and Asymmetry Accounted in Analyses
- ▶ Licensee's Evaluation of any Vendor Service Advisories
- ▶ Appropriate Analytical Assumptions
- ▶ Results Meet Applicable Requirements
- ▶ Processes to Ensure Analyses Bound As-Operated Conditions
- ▶ Boron Precipitation
- ▶ Long-Term Cooling



Fuel and Nuclear Design

- **Continuity:** WCAP- 9272-P-A, “Westinghouse Reload Safety Evaluation Methodology”
- **Changing Fuel Design from OFA to 14X14 422V+**
- **Notable Differences between OFA and 422V+**
 - 14X14 422V+ Assembly Loss Coefficient is 20% less
 - VIPRE-01 replaces THINC IV Codes
 - Transition Core DNBR Penalty
- **Notable Similarities**
 - RTDP and WRB-1 DNB Correlation
 - STDP and W-3 DNB Correlation
 - DNBR Limits



Non-LOCA Transients

- **Followed the Guidelines of RS-001**
- **Most Events Analyzed with RETRAN and VIPRE**
 - Both NRC-approved
 - Not LOFTRAN and THINC
- **Important to Analyses and Evaluations:**
 - 1817 MWt (19% uprate) assumed in analyses
 - Steam generators replaced in 1996
 - License renewal in 2004 (term extended to 2029)
 - Fuel transition concurrent with EPU
 - Full-power Tavg operating window (564.6 °F to 576.0 °F)
 - Assumed up to 10% tube plugging in steam generators
- **Results Satisfied the Applicable Requirements and Design Limits of TS 2.1 (Safety Limits) for Peak CL Temperature, DNBR, and RCS Pressure**



Large-Break LOCA

- **Analysis results for a double-ended guillotine break at the pump discharge**
- **Implemented Westinghouse Best-Estimate Large-Break LOCA Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)**
- **Conducted for a mixed core consisting of OFA and 422V+ fuel**
- **Met the acceptance criteria for ECCS performance, as specified in 10 CFR 50.46:**
 - calculated peak cladding temperatures (PCTs)
 - maximum cladding oxidation (local)
 - maximum core-wide cladding oxidation



Small-Break LOCA

- **Short-Term Behavior**
- **Within Limits of 10 CFR 50.46**
- **Confirmed Non-Limiting with Staff's RELAP5/MOD3 Analysis**
- **Post-LOCA Long-Term Cooling**



Mechanical Impacts

• Flow-Accelerated Corrosion

- ▶ Corrosion rates for FAC-susceptible components are determined by parameters such as temperature, flow velocity, moisture content, and component material
- ▶ Components have been added to the program based on the potential for increased FAC rate at EPU conditions (higher temperature and velocity)
- ▶ CHECWORKS computer models are being updated prior to implementing the EPU.
- ▶ At EPU conditions the FAC program remains consistent with industry guidelines.



Mechanical Impacts

• Flow-Induced Vibration

- ▶ Main Steam and Feedwater piping instrumented at critical locations to monitor vibration levels at current rated power and during EPU power ascension, up to the full authorized power level.
- ▶ Vibration monitoring and collected data will be evaluated according to ASME OM3 Code
- ▶ FIV effect on steam separator expected to increase at EPU. However, judged to be acceptable based on the design basis steam flow rate of the replacement steam generator that is bounding for EPU
- ▶ Slight increase in FIV on the U-bend tubing, but remains within allowable limits (i.e., maximum stability ratio less than the limit of 1.0)



Mechanical Impacts

Steam Generator Dryer/Separator

- Flow rate and pressure used in testing bound EPU conditions
- Past inspections performed in operating plants not found FIV fatigue
- Integrity of rugged steam separators improved in new SG design
- Low flow velocity makes potential for loose parts to enter main steam line unlikely
- Low velocity and high stiffness reduces potential for FIV
- Capability to identify degradation of SGs through plant monitoring and outage inspections
- Filtering screen ensures collection of small parts in steam flow in unlikely event of degradation of SG internal components



Ginna EPU Risk Evaluation

- **Ginna PSA Level I covers:**

- ▶ Internal Events, including Internal Floods
- ▶ External Events
- ▶ Shutdown Operations

- **Ginna PSA uses a simplified containment event tree to evaluate LERF**

- ▶ Follows NUREG/CR-6595 for PWRs with a large dry containment



PRA Insights

- **Licensee used the Ginna EPU risk evaluation to gain insights and proposed plant modifications and operational improvements that could reduce risk**
- **5 risk and cost beneficial changes identified that would likely completely offset EPU risk increase**
 - ▶ Optimize use of safety injection pumps during fires
 - ▶ Mechanically limit RHR HCVs from failing completely open
 - ▶ Provide backup air supply to charging pumps
 - ▶ Relocate charging pump control power disconnect
 - ▶ Install local controls for the turbine-driven auxiliary feedwater pump discharge motor-operated valve



PRA Conclusion

- **Licensee adequately modeled and addressed potential risk impacts of the proposed EPU**
- **Risks are acceptable (i.e., within RG 1.174 risk acceptance guidelines)**
- **Proposed EPU does not create “special circumstances”**
- **Licensee used its risk evaluation to identify potential changes that would offset any risk increase due to the proposed EPU**



Other Key Items

- **Balance-of Plant**
- **Operator Actions and Procedures**
- **Testing**
- **Inspection**



BOP Scope of Review

- **Review per RS-001, Matrix 5**

- ▶ Internal Hazards
- ▶ Fission Product Control
- ▶ Component Cooling and Decay Heat Removal
- ▶ Balance-of-Plant Systems
- ▶ Waste Management Systems
- ▶ Emergency Diesel Fuel Oil Storage & Light Loads



BOP Review Areas of Emphasis

- **Areas Affected by Increased Decay Heat Load**

- Spent Fuel Pool Cooling
- Service Water System
- Auxiliary Feedwater

- **Operational Considerations**

- Feedwater and Condensate Systems



BOP REVIEW RESULTS

- **Decay Heat Load Will Not Exceed Cooling Capability of Systems that are Relied Upon**
- **BOP Systems will not Pose Increased Challenges to Reactor Safety Systems**
- **Power Ascension and Transient Test Program Provides Adequate Assurance of BOP Performance Capability**



Operator Actions and Procedural Improvements

- **Revisions to Emergency and Abnormal Operating Procedures**
 - ▶ automatic action verification steps in E-0 procedure to expedite diagnosis and plant stabilization
 - ▶ R-H.1, "Response to Loss of Secondary Heat Sink," to provide earlier initiation of SAFW System to mitigate high energy line break
 - ▶ Appendix R mitigation procedures enhanced for effectiveness of operator actions and to incorporate the physical plant changes
 - ▶ ES-1.2, "Post-LOCA Cooldown and Depressurization" to direct operators to initiate cooldown of RCS using condenser dump valves (or ADVs if condensers are unavailable) within 1 hr of SBLOCA
 - ▶ ES-1.3, "Transfer to Cold Leg Recirculation," to instruct operators to reestablish cold leg SI no later than 5.5 hours after the termination of SI in the cold leg to prevent boric acid precipitation



Operator Actions and Procedural Improvements

• For LB LOCA and SBLOCA

- ▶ Operators to realign HHSI for cold leg injection within 10 minutes
- ▶ Times were unaffected for overall operator actions, but procedure and plant modifications being made to maintain operator capability to perform actions in the established time
- ▶ Operator training related to EOP changes to be conducted prior to EPU implementation
- ▶ All times for operator actions affected by EPU modifications and procedure revisions to be validated using simulator and plant walk throughs prior to EPU implementation



Power Ascension and Test Program

- **SP 14.2.1, "Generic Guidelines for Extended Power Uprate Testing Programs,"** provides guidance based on Regulatory Guide 1.68 and plant specific initial test program.
- **EPU test program**
 - includes testing sufficient to demonstrate structures, systems, and components will perform satisfactorily at the proposed power level
 - considers in part, original power ascension test program, and EPU related plant modifications
- **Manual turbine trip test at 30% EPU power to verify the plant's dynamic transient response and control system settings.**
 - pressurizer level and pressure control,
 - steam generator water level control,
 - steam dump control, and
 - rod control



Power Ascension and Test Program

Conclusion

- **The staff concludes that the proposed test program provides adequate assurance that the plant will operate in accordance with its design criteria and that SSCs affected by the proposed EPU will perform satisfactorily in service.**



NRC Inspection

- **Conducted by Resident Staff and Regional Specialists**
- **Inspection Procedure 71004, "Power Upgrades"**
 - Describes inspections necessary for power upgrade related activities
 - Provides guidance in conducting these inspections
- **Recommended Areas for Inspection**
 - Consider recommendations listed in final safety evaluation when selecting a sample for implementing IP 71004
 - These recommendations do not constitute inspection requirements
 - Provided to give the inspectors insight into important bases the NRC staff used for approving the EPU
 - Examples

532nd Meeting of the Advisory Committee on Reactor Safeguards

NRC Staff Review of Extended Power Uprate Application
For
Beaver Valley Power Station, Unit Nos. 1 and 2



May 4, 2006

Introduction

Timothy G. Colburn
Senior Project Manager
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Agenda - Topics

- Licensee Introduction
- Plant Modifications to Support the EPU
- Safety Analyses
- Mechanical Impacts - FIV, FAC
- Probabilistic Risk Assessment
- Implementation
- Summary

Introduction

- Pre-application Submittals Included
 - ▶ Containment conversions to atmospheric
 - Approval of MAAP-DBA for M/E release
 - BVPS-1 relies on COP, BVPS-2 does not
 - Staff performed independent M/E release calculations
 - ▶ SG Replacement (BVPS-1 only)
- October 4, 2004 application with numerous supplements -Included full AST implementation
- Staff Review Followed RS-001, Revision 0

Reactor Systems Analyses

- Fuel and Nuclear System Design (No Changes)
- Non-LOCA Analyses and Transients
- LOCA Analyses
- ATWS
- ECCS
- Boron Precipitation
- Long Term Cooling

Reactor Systems Review

- Staff Review Using Matrix 8 of RS-001
 - ▶ No changes from NRC-approved Codes and methodologies
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Reactor Systems Review (cont.)

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 - Approach to control boron precipitation
- Large-break LOCA
 - Post-LOCA long term cooling (boron precipitation)
- Small-break LOCA
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- Staff conducted independent analyses and audits of Westinghouse calculations

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 - 2917.4 MWt assumed in the analyses
 - BVPS-1 steam generators replaced spring 2006
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- BELOCA methodology w/COBRA-TRAC
- Cold leg break limiting for boron precipitation
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- Staff independent calculations agree with licensee results - short term SBLOCA analyses and SBLOCA and LBLOCA long term cooling analyses meet 10 CFR 50.46 criteria
 - ▶ Identified need for EOP changes
 - ▶ Confirmed timing for boron precipitation

Mechanical Impacts

Flow - Induced Vibration

- MS and FW piping instrumented at critical locations and collected data are evaluated to ASME OM3
- FIV on steam separator typically increases at EPU conditions. FIV on steam separators is minimized due to its high stiffness and low flow velocity
- FIV on the U-bend tubing is within allowable limits (i.e. fluid-elastic instability ratio less than 1.0 and peak stresses less than the material endurance limit)
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- EPU conditions change the temperature, flow velocity, and moisture content for some components.
- Updated CHECWORKS computer models will determine future inspection and repair/replacement plans.
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Scope of Risk Evaluation

- Full-power PRA model
 - ▶ Internal events, including internal flooding
 - ▶ Seismic
 - ▶ Internal fires
 - ▶ CDF and LERF
- Qualitative approach for other risk
 - ▶ High winds, external floods, other external events-screening per NUREG-1407
 - ▶ Shutdown risk-questions in SRP Chapter 19

NRC Staff Review of EPU Risk

- NRC onsite audit (10/05) to check quality of PRA and EPU risk assessment
- Minor impact on success criteria
 - Time to recover offsite power
 - AFW flow for ATWS (cavitating venturis)
 - Containment accident pressure credit for NPSH
- Less time available for some operator actions
 - Post-EPU CDF and LERF-MAAP timing
 - Validated important, short time available actions
 - HRA sensitivity analysis
- Important operator actions with short time available
 - Depressurize RCS
 - Implement feed and bleed cooling

PRA Conclusion

- Licensee assessed potential risk impacts of the EPU
 - CDF/change in CDF-very small
 - LERF/change in LERF-very small
- The EPU does not create special circumstances that rebut the presumption of adequate protection afforded by the licensee meeting current regulations
- Risks of BVPS EPU implementation were adequately addressed by the licensee and are acceptable

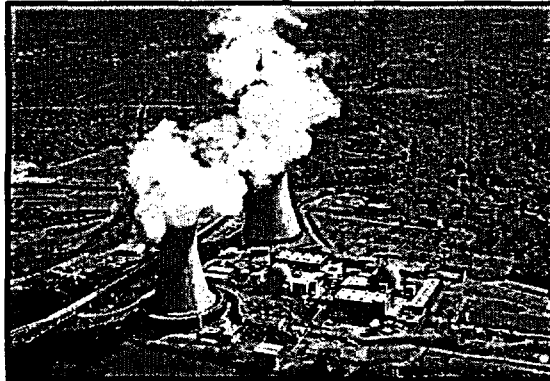
EPU Implementation

- Licensee will perform 2-phase implementation of EPU for both units
 - ▶ BVPS-1 will increase power 3 percent for the remainder of this operating cycle and will implement the remainder of the EPU increase next cycle (all BOP mods are currently complete)
 - ▶ BVPS-2 will increase power by 3 percent during the next operating cycle (following the fall 2006 RFO) and will implement the remainder of the EPU increase following all-reaction HP turbine mod (spring 2008 RFO)

Summary

- The staff reviewed the licensee's proposed EPU against the criteria in NRC Review Standard RS-001
- The licensee supplemented the application numerous times in response to staff requests for additional information-including providing revised analyses, additional commitments, and changes to the application
- Staff audits helped expedite reviews
- The licensee met all applicable review criteria of RS-001 for the uprated conditions

BEAVER VALLEY POWER STATION ***Extended Power Uprate***



ACRS
Full Committee
Meeting
May 4, 2006

FENOC
Federal Energy Nuclear Operating Company

Introduction & **Overview**

Pete Sena
Director, Site Engineering

FENOC
Federal Energy Nuclear Operating Company

Agenda

- Introduction
- Plant Changes
- Safety Analysis
- Mechanical Impacts
- PRA
- Conclusion
- Pete Sena
- Mark Manoleras
- Ken Frederick
- Mike Testa
- Colin Keller
- Pete Sena

Introduction - Agenda

- Beaver Valley History
- Beaver Valley Peer Units
- Preparations for Uprate

Beaver Valley History

- Beaver Valley Power Station Units 1 and 2
- Westinghouse NSSS 3 loop Pressurized Water Reactor (PWR)
- BV-1 Commercial Operation - 1976
- BV-2 Commercial Operation - 1987
- 2652 MWt original licensed Rated Thermal Power (RTP)
- 2689 MWt Appendix K Margin Recovery - 2001
- 2900 MWt Extended Power Uprate (EPU) - pending

Beaver Valley Peer Units - Power Uprates

Plant	Uprated NSSS Power Level (MWt)
Beaver Valley Units 1 & 2	2910
North Anna Units 1 & 2	2905
V. C. Summer	2912
Shearon Harris	2912
Vandell	2954
ASCO Units 1 & 2	2952

Preparations for Uprate

To Position BVPS Units for EPU:

Supporting Submittals Completed:

- New Fuel Storage Rack Enrichment Limit Increase
- Positive Moderator Temperature Coefficient
- Accumulator and RWST Increased Boron Concentration
- Selective Implementation of AST
- Minimum Decay Time Before Fuel Movement
- Relaxed Axial Offset Control (RAOC)

Replacement Steam Generators (RSG) BVPS-1

Containment Conversion

Large Break Best Estimate Loss-of-Coolant Accident (BELOCA) Methodology

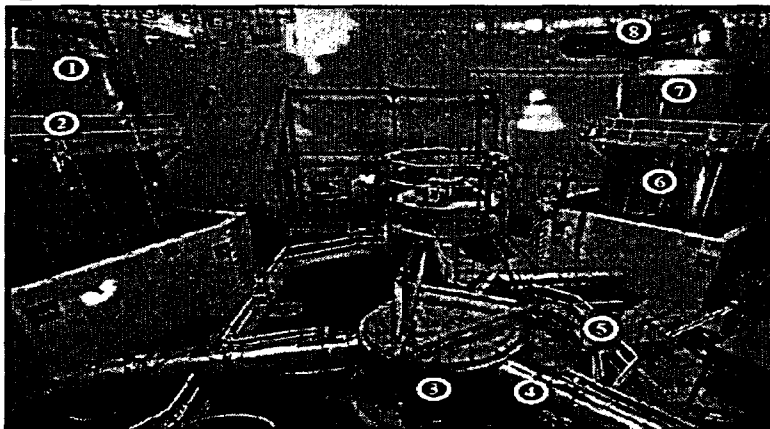
Extended Power Uprate (EPU) - Pending

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WHAT'S NEW inside BV Unit 1 Containment

Take a look below at the improvements made inside Unit 1 Containment during Beaver Valley's 1217 outage.



- 1) Three brand new 365-ton steam generators were installed. Shown here is the top portion of Steam Generator "B."
- 2) New catwalks on the steam generators will eliminate the need to build scaffolding, saving time and dose.
- 3) A new, simplified Reactor Vessel Head will save 12 permit crane lifts per outage in the future.
- 4) A new configuration for the Control Rod Drive Mechanism ventilation was installed.
- 5) The Cable Bridge will allow easier access to the head and will simplify the process of disconnecting the Control Rod Drive Mechanism and Rod Position Indicators in future refueling outages.
- 6) New mirror insulation was installed on all three Steam Generators and the Reactor Vessel Head. The insulation will help keep heat inside the steam generators and debris out of the containment sump.
- 7) Steam Generator "A." Steam Generator "C" is not shown.
- 8) Close to 1.4 miles of welds on the Reactor Coolant System, Main Steam System, Feedwater Lines and instrument tubing were completed.

Project Team and Oversight

- FENOC / BVPS
 - Overall project management
 - Review and approval of inputs
 - Proper interfacing of Information
 - Procedure / Training / Simulator updates
- Westinghouse, Stone & Webster, Siemens
- Oversight of the engineering and licensing process

Plant Changes

Mark Manoleras
(Manager, Design Engineering)

Major Modifications

- Replacement of charging/safety injection pump rotating assemblies
- Conversion from a sub-atmospheric to an atmospheric containment design
 - Installation of fast acting feedwater isolation valves (Unit 1)
 - Installation of auxiliary feedwater cavitating venturies (Unit 1)
 - Addition of reactor cavity drainage port
- Replacement of Steam Generators (Unit 1)

Major Modifications

- Replace high pressure turbine with all-reaction design
- Install stakes in main condenser (Unit 2)
- Raise set-pressure of moisture separator reheater relief valves
- Increase Cv of main feedwater control valves
- Replace Turbine Generator (T/G) rotor and rewind stator (Unit 1)
- Instrument replacements for higher flow range

Safety Analysis

Ken Frederick
(Nuclear Safety Analyst)

Safety Analysis Objectives

- Demonstrate compliance with regulatory limits and acceptance criteria
- To show that BVPS will operate with adequate safety margins at EPU conditions

Safety Analysis - Agenda

- EPU Operating Parameters
- Methods
- Non-LOCA Events
- LBLOCA
- SBLOCA
- Post LOCA Long Term Cooling
- Containment

Nominal Operating Parameters (BVPS-1)

	EPU	Pre-EPU	Change
	Condition	Condition	
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	577.9	576.2	+1.7F
Tcold (F)	544.6	545.1	-0.5F
Delta T (F)	66.6	62.2	+4.4F
Thot (F)	611.2	607.3	+3.9F
Coolant Mass Flow (total lb/hr)	1.11E+08	1.11E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	440	434.3	+5.7F
Stm Out (psia)	805	825	-20 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

Nominal Operating Parameters (BVPS-2)

	EPU Condition	Pre-EPU Condition	Change
Core Power (MWt)	2900	2689	+7.9%
Taverage (F)	574.2	576.2	-2F
Tcold (F)	538.9	543.4	-4.5F
Delta T (F)	70.6	65.6	+5F
Thot (F)	609.5	609	+0.5F
Coolant Mass Flow (total lb/hr)	1.05E+08	1.05E+08	0%
Pressurizer Pressure (psia)	2250	2250	0 psi
SG Power (total MWt)	2910	2697	+7.9%
FW In (F)	437	434	+3F
Stm Out (psia)	774	821	-47 psi
Stm Mass Flow (total lb/hr)	1.27E+07	1.17E+07	+8.5%

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Safety Analysis Methods

Method	EPU	Current
Large Break LOCA	BELOCA/WCOBRA-TRAC	BASH (App K)
Small Break LOCA	NOTRUMP	NOTRUMP
Non-LOCA	LOFTRAN VIPRE	LOFTRAN THINC
Control System Transients	LOFTRAN	LOFTRAN
Containment	MAAP-DBA	MAAP-DBA (LOCTIC pre-CC)
Dose Assessment	AST/ARCON 96	TID/RAMSDALL

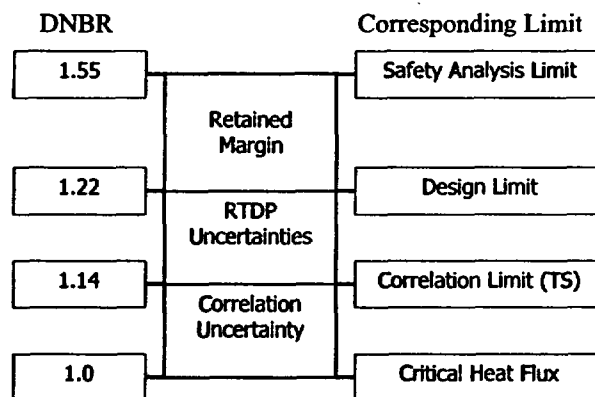
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Non-LOCA Acceptance Criteria

- Most Non-LOCA events are categorized as ANS Condition II for which the acceptance criteria are:
 - The critical heat flux is not exceeded (the calculated minimum DNBR does not go below the limit value at any time during the transient)
 - Peak heat generation rate remains within acceptable limits to prevent fuel centerline melt
 - Pressure in the RCS and main steam systems should be maintained below 110% of the design pressures
 - The event should not generate a more serious plant condition without other faults occurring independently

Non-LOCA DNBR Margin



WRB-2M DNBR LIMITS

Non-LOCA DNBR Results

DNBR Limited Events				
Event	DNBR Correlation	DNBR Limit	BVPS-1 DNBR	BVPS-2 DNBR
RCCA Bank Withdrawal from Subcritical	W-3, WRB-1	1.65, 1.45	1.83, 2.12	1.83, 2.12
RCCA Bank Withdrawal at Power	WRB-2M	1.55	1.57	1.58
RCCA Misalignment	WRB-2M	1.55	(1)	(1)
Loss of Load	WRB-2M	1.55	2.23	1.83
Feedwater System Malfunctions	WRB-2M	1.55	1.75	1.96
a. Feedwater Flow Increase	WRB-2M	1.55	1.67	1.66
b. Feedwater Enthalpy Decrease				
RCS Depressurization	WRB-2M	1.55	1.62	1.64
Main Steam Pipe Rupture (HFP)(2)	WRB-2M	1.55	2.56	2.56
Main Steam Pipe Rupture (H2P)(2)	W-3	1.61	2.41	1.83
Partial Loss of Flow	WRB-2M	1.55	2.25	2.25
Complete Loss of Flow	WRB-2M	1.55	1.64	1.64

- (1) No DNBR Results-Analysis uses peaking factor limits for evaluation
 (2) Condition IV event evaluated with Condition II limits

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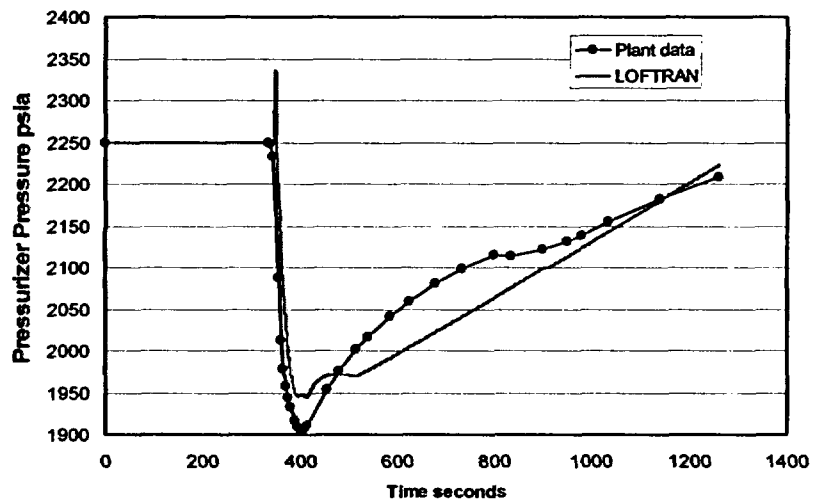
Non-LOCA Pressure Results

Limiting Overpressure Events						
Event	Primary Pressure Limit (Psia)	BVPS-1 Peak Primary Pressure (Psia)	BVPS-2 Peak Primary Pressure (Psia)	Secondary Pressure Limit (Psia)	BVPS-1 Peak Secondary Pressure (Psia)	BVPS-2 Peak Secondary Pressure (Psia)
Loss of Load	2748.5	2747	2746	1208.5	1192	1191
Feedwater System Malfunctions	2748.5	2357	2353	1208.5	1124	1141
Partial Loss of RCS Flow	2748.5	2374	2361	1208.5	989	995
Complete Loss of RCS Flow	2748.5	2504	2503	1208.5	993	1003
Locked Rotor	2997	2797	2825	-	-	-
ATWS	3215	3060	2900	-	-	-

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BVPS-2 Rx Trip on MUG Trip 4/2/2006



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Non-LOCA Other Results

Pressurizer Filling Events			
Event	Pressurizer Water Volume Limit (ft ³)	BVPS-1 Peak Pressurizer Water Volume (ft ³)	BVPS-2 Peak Pressurizer Water Volume (ft ³)
Loss of Normal Feedwater	1458	1384	1193
Loss of AC	1458	1224	1194
Spurious Safety Injection	1458	Pressurizer Fills	Pressurizer Fills
Margin to Hot Leg Saturation Event			
Event	Margin to Hot Leg Boiling Limit (°F)	BVPS-1 Margin to Hot Leg Boiling (°F)	BVPS-2 Margin to Hot Leg Boiling (°F)
Feedline Break	0 (No boiling)	14.4	36
Maximum Fuel Stored Energy Event			
Event	Max Fuel Stored Energy Limit (Btu/Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/Lbm)	BVPS-1 Max Fuel Stored Energy (Btu/Lbm)
RCCA Ejection	360	326.8	326.8

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Non-LOCA Conclusions

- DNBR limits contain margin between safety analysis limits design limits to allow for core design flexibility
- Conservatism in peak pressure limits and analysis inputs allow for maintaining margins in operating limits
- All acceptance criteria for Condition II,III,IV Non-LOCA events are met at EPU conditions

LOCA - Results

- PCT Results meet 10CFR50.46 acceptance criteria

Parameter	Current	EPU	Limit
Unit 1 Large Break PCT	1996 °F	2021 °F	<2200 °F
Unit 2 Large Break PCT	1908 °F	1976 °F	<2200 °F
Unit 1 Small Break PCT	1902 °F	1895 °F	<2200 °F
Unit 2 Small Break PCT	1902 °F	1917 °F	<2200 °F

- Oxidation results meet 10CFR50.46 acceptance criteria including consideration of pre-transient oxidation

Long Term Cooling - Analysis

- Core voiding considered by reducing the mixing volume accordingly
- Time-based Mixing Volume / System Effects considered
- Effect of sump additives on Boric Acid solubility limit quantified but not credited
- Appendix K decay heat was used in all calculations

Long Term Cooling Summary

- Post LOCA long term core cooling has been adequately addressed
- Results show the following for switchover time to hot leg injection:
 - BVPS-1 - 6.5 hours (8 hours pre-EPU)
 - BVPS-2 - 6 hours (7 hours pre-EPU)
- For small breaks, cooldown and depressurization can be accomplished within required switchover time

Containment Analysis

- Containment will operate at slightly sub-atmospheric conditions
 - Prior to containment conversion 9 psia to 10.5 psia (air partial pressure)
 - Following containment conversion 12.8 psia to 14.2 psia
- Analysis credits plant modifications
 - Replacement Steam Generators (BVPS-1)
 - New feedwater isolation valves (BVPS-1)
 - AFW cavitating venturis (BVPS-1)
 - Reactor cavity drainage port
 - Lowered RWST level setpoint for transfer to SI recirculation
- Peak Containment pressures and temperatures within design for all accidents
- Containment Overpressure continues to be credited for BVPS-1

Safety Analysis Conclusions

- All applicable acceptance criteria are met at EPU conditions
- Beneficial plant modifications have been made to maintain safety margins at EPU conditions

Mechanical Impacts

Mike Testa
(EPU Project Manager)

Mechanical Impacts – Agenda

- Steam Generator Vibration
- Piping and Component Vibration
- Flow Accelerated Corrosion

Tube Bundle Region

- Unit 1 – Model 54F
 - Steam Generator installed in 1R17 (April 2006)
 - Designed for uprated conditions
- Unit 2 – Series 51M
 - Review for Flow Induced Vibration (FIV) affects showed acceptable results
 - Unsupported U-bends reviewed for increased fatigue
 - Increase in tube wear at Anti-Vibration Bar (AVB) interface evaluated

Steam Dryer FIV Comparison

- | | |
|---|---|
| <ul style="list-style-type: none">• Series 51/51M<ul style="list-style-type: none">– Low Flow Rates Near Dryer vs BWR<ul style="list-style-type: none">• Pre-Uprate – 3.5 ft/sec• Post Uprate – 4.1 ft/sec• BWR ~ 100 ft/sec– Low Turbulence Potential Vs. BWR– No Operational Issues Reported<ul style="list-style-type: none">• 22 Domestic Plants• 74 Domestic SG• Operational from early 70's | <ul style="list-style-type: none">• Series 54F<ul style="list-style-type: none">– Low Flow Rates Near Dryer vs BWR<ul style="list-style-type: none">• Pre-Uprate – 3.0 ft/sec• Post Uprate – 3.5 ft/sec• BWR ~ 100 ft/sec– Low Turbulence Potential Vs. BWR– No Operational Issues Reported<ul style="list-style-type: none">• 6 Domestic Plants• 18 Domestic SG• Operational from mid 90's |
|---|---|

BOP Heat Exchanger Vibration

- Feedwater Heaters
- Moisture Separator Reheaters
- Condenser Tubing
 - BVPS-1 condenser tubes previously staked
 - BVPS-2 will be staked prior to power uprate

Vibration Monitoring

- Monitor Secondary systems pre EPU
 - Baseline walk downs conducted on each plant
 - Areas of interest targeted for inspection under EPU
- Utilize guidance from ASME OM-S/G-2003, Part 3
- Collect and review data at each power escalation plateau
- Inspections will be augmented as required with vibration monitoring equipment
- Large equipment (e.g. Reactor Coolant Pump, Turbine) consistently monitored with existing plant instrumentation

Flow Accelerated Corrosion

- EPU effects evaluated using CHECWORKS
- Turbine extraction steam tee proactively replaced
- Post Upstate Outage inspection sampling increased based on EPU conditions
- Piping systems impacted will continue to be monitored to detect any deviation from predicted wear rates

PRA

Colin Keller
Supervisor, PRA

Probabilistic Risk Assessment

- Scope of Assessment
 - PRA Model Elements
 - Initiating Event Frequency
 - Success Criteria
 - Equipment Failure Rates
 - Operator Response Times
 - Changes in CDF & LERF for each model

PRA – Model Elements

- Initiating Events
 - No new initiators
 - No significant increase in Initiating Event frequencies due to the Power Uprate
- Success Criteria
 - MAAP analyses establishes EPU success criteria
 - No new accident sequences identified

PRA – Model Elements

- **Component and System Reliability**
 - Comprehensive reviews of equipment performed
 - Systems operate within allowable limits
 - No impact on PRA failure rates or results
- **Operator Response Times / HRA**
 - MAAP analyses to determine operator action time available
 - Higher decay heat reduced times for some operator actions

Summary of Changes (Unit 1)

BVPS-1 Risk Measures	Pre-EPU Model	Post-EPU Model	Change In Risk
Total CDF (/year)	2.25 E-05	2.29E-05	3.36E-07
Internal CDF (/year)	6.25 E-06	6.55 E-06	2.97 E-07
External CDF (/year)	1.63 E-05	1.63 E-05	3.95 E-08
Fire CDF (/year)	4.62 E-06	4.66 E-06	3.89 E-08
Total LERF (/year)	4.37 E-07	4.95 E-07	5.83 E-08

Summary of Changes (Unit-2)

BVPS-2 Risk Measures	Pre-EPU Model	Post-EPU Model	Change in Risk
Total CDF (/year)	3.30 E-05	3.33 E-05	3.55 E-07
Internal CDF (/year)	1.86 E-05	1.89 E-05	2.92 E-07
External CDF (/year)	1.44 E-05	1.45 E-05	6.32 E-08
Fire CDF (/year)	4.89 E-06	4.95 E-06	6.38 E-08
Total LERF (/year)	1.03 E-06	1.07 E-06	4.61 E-08

PRA Conclusion

- All PRA model elements reviewed for impact
- The increase in risk, due to the EPU for BVPS-1 and BVPS-2 is small compared to the current overall risk

Concluding Remarks

Pete Sena
Director, Site Engineering

Conclusion

- Detailed and comprehensive reviews have been performed
- No safety issues identified
- Beaver Valley Power Station safety and reliability will be maintained through plant modifications, procedure changes and training, and adherence to TS / Operating License

End of Presentation

532nd Meeting of the Advisory Committee on Reactor Safeguards

**NRC Staff Review of Extended Power Uprate Application
For
Beaver Valley Power Station, Unit Nos. 1 and 2**



May 4, 2006

1

Introduction

**Timothy G. Colburn
Senior Project Manager
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation**

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Agenda - Topics

- Licensee Introduction
- Plant Modifications to Support the EPU
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 - HRA sensitivity analysis
- Important operator actions with short time available
 - Depressurize RCS
 - Implement feed and bleed cooling

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PRA Conclusion

- Licensee assessed potential risk impacts of the EPU
 - CDF/change in CDF-very small
 - LERF/change in LERF-very small
- The EPU does not create special circumstances that rebut the presumption of adequate protection afforded by the licensee meeting current regulations
- Risks of BVPS EPU implementation were adequately addressed by the licensee and are acceptable

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EPU Implementation

- Licensee will perform 2-phase implementation of EPU for both units
 - BVPS-1 will increase power 3 percent for the remainder of this operating cycle and will implement the remainder of the EPU increase next cycle (all BOP mods are currently complete)
 - BVPS-2 will increase power by 3 percent during the next operating cycle (following the fall 2006 RFO) and will implement the remainder of the EPU increase following all-reaction HP turbine mod (spring 2008 RFO)

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Summary

- The staff reviewed the licensee's proposed EPU against the criteria in NRC Review Standard RS-001
- The licensee supplemented the application numerous times in response to staff requests for additional information- including providing revised analyses, additional commitments, and changes to the application
- Staff audits helped expedite reviews
- The licensee met all applicable review criteria of RS-001 for the uprated conditions

PART 52 RULEMAKING

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Proposed Part 52 Rule

- Proposed rule published in *Federal Register* on March 13, 2006 (71 FR 12781)
- Supersedes proposed rule published on July 3, 2003 (68 FR 40026)
- Revised proposal result of comments on 2003 rule and lessons learned

General Overview

- Rewritten Part 52 contains five subparts:
 - Early site permits (ESPs)
 - Standard design certifications
 - Combined licenses (COLs)
 - Standard design approvals
 - Manufacturing licenses
- Appendices A-D are design certification rules
- Standardized organization and content of each subpart
- Made conforming changes throughout 10 CFR
- Generally kept technical requirements in Parts 50, 100, etc., and put procedural requirements in Part 52

Rule Objectives

- Revised rule will enhance the NRC's effectiveness and efficiency in implementing the Part 52 licensing processes
- Revised rule will provide clarity regarding the applicability of technical and procedural requirements to each of the Part 52 regulatory processes

Key Rule Proposals Affecting Safety Requirements

Emergency Planning

- Mitigation measures for significant impediments
- ITAAC required with complete plans or major features at ESP stage
- Updated emergency preparedness information at the COL stage

Quality assurance requirements for ESP applicants

Applicability of 10 CFR Part 21 to ESPs and design certifications

PRA requirements for COLs