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1 UNITED STATES OF AMERICA

2 NUCLEAR REGULATORY COMMISSION

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4 ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

5 SUBCOMMITTEE ON PLANT LICENSE RENEWAL

6 BEAVER VALLEY POWER STATION

7 + + + + +

8 WEDNESDAY, FEBRUARY 4, 2009

9 + + + + +

10 ROCKVILLE, MD

11 The Subcommittee convened in Room T2B3 in
12 the Headquarters of the Nuclear Regulatory Commission,
13 Two White Flint North, 11545 Rockville Pike,
14 Rockville, Maryland, at 1:30 p.m., Dennis Bley, Chair,
15 presiding.

16 SUBCOMMITTEE MEMBERS PRESENT:

17 DENNIS BLEY, Chair

18 JOHN STETKAR

19 J. SAM ARMIJO

20 WILLIAM J. SHACK

21 SAID ABDEL-KHALIK

22 OTTO L. MAYNARD

23 CHARLES H. BROWN, JR.

24 HAROLD B. RAY

25 JOHN SIEBER

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CONSULTANT TO THE SUBCOMMITTEE PRESENT:

JOHN J. BARTON

ALSO PRESENT:

CHRISTOPHER BROWN,

Designated Federal Official

BRIAN HOLIAN

KENT HOWARD

JOHN RICHMOND

GEORGE WILSON

STAN GARDOCKI

LARRY FREELAND

MARK MANOLERAS

CLIFF CUSTER

JOHN THOMAS

STEVE BUFFINGTON

DENNIS WEAKLAND

TOM WESTBROOK

DAVE GRABSKI

BRIAN PAUL

BRIAN MURTAGH

DUC NGUYEN

ROY MATTHEW

MATTHEW MITCHELL

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JIM MEDOFF

ALSO PRESENT: (CONT.)

ON YEE

SAM LEE

MARK HARTZMAN

FARHAD FARZAM

DAN HOANG

BILL LINTELL

RICH BOLOGNA

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I-N-D-E-X

1

2 Opening Remarks.....5

3 Staff Introduction.....6

4 First Energy Nuclear Operating

5 Company.....7

6 NRC Staff Presentation

7 Kent Howard.....68

8 John Richmond.....75

9 Discussion.....101

10 Adjourn

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

1:30 p.m.

1
2
3 CHAIR BLEY: The meeting will come to
4 order, please. This is a meeting of the plant license
5 renewal subcommittee. I'm Dennis Bley, Chairman of
6 the Beaver Valley Plant License Renewal Committee.

7 ACRS members in attendance are Otto
8 Maynard, John Stetkar, Jack Sieber, Bill Shack, Mario
9 Bonaca, Michael Ryan, Said Abdel-Khalik, and our
10 consultant, John Barton. Christopher Brown of the
11 ACRS staff is the Designated Federal Official for this
12 meeting and he's here, and Harold. I'm sorry. I'm
13 just reading off the list.

14 The purpose of this meeting is to review
15 the license renewal application for the Beaver Valley
16 nuclear power plant, the draft study evaluation report
17 with open items, and associated documents. We will
18 hear presentations from the representatives of the
19 Office of Nuclear Reactor Regulation, NRR, and the
20 applicant, First Energy Nuclear Operating Company.

21 The subcommittee will gather information,
22 analyze relevant issues and facts, and formulate
23 proposed positions and actions as appropriate for
24 deliberation by the full committee.

25 The rules for participation in today's

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1 meeting were announced as part of the notice of this
2 meeting previously published in the Federal Register
3 on January 23rd, 2009. We have received no written
4 comments or requests for time to make oral statements
5 for members of the public regarding today's meeting.

6 A transcript of the meeting is being kept
7 and will be made available as stated in the Federal
8 Register notice. Therefore, we request that
9 participants in this meeting use the microphones
10 located throughout the meeting room when addressing
11 the subcommittee. Participants should first identify
12 themselves and speak with sufficient clarity and
13 volume so that they can be readily heard.

14 We will now proceed with the meeting and I
15 call upon Brian Holian of the Office of Nuclear
16 Reactor Regulation to introduce the presenters.
17 Brian?

18 MR. HOLIAN: Thank you and good afternoon.

19 My name is Brian Holian. I'm the director
20 and I'd just like to highlight a few folks that are
21 here today to support the meeting for Beaver Valley's
22 license renewal application subcommittee.

23 First off, to my far right, is David
24 Wrona, the Branch Chief and License Renewal
25 responsible for the Beaver Valley license renewal

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1 plant application. Next to me is Mr. Kent Howard.
2 Kent has been the project manager the entire time on
3 the Beaver Valley project and you'll be hearing from
4 him later in a staff summary of safety evaluation
5 report.

6 Just several other people to identify.
7 One, of course, is Deputy Dr. Sam Lee who is here. We
8 have numerous other NRC staff and branch chiefs just
9 to support us in the question and answer period. But
10 I wanted to highlight three people from the Region One
11 that are also here.

12 Mr. Rich Conti, the Branch Chief in
13 Division of Reactor Safety that has license renewal
14 inspections. Underneath Rich, we have Ron Bellamy,
15 the Projects Branch Chief who's heading up to a TMI
16 public exit tomorrow for TMI's inspection exit. And
17 you'll be hearing, also, later from John Richmond, the
18 Senior Reactor Inspector from the Division of Reactor
19 Safety.

20 With that, I'll turn it over to Beaver
21 Valley and their Project Manager, Mr. Cliff Custer.

22 MR. CUSTER: Good afternoon. Thank you,
23 Brian.

24 As Brian said, my name is Cliff Custer. I
25 am the Project Manager for the Beaver Valley license

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1 renewal project.

2 With me today are Mark Manoleras,
3 Engineering Director, from Beaver Valley; Larry
4 Freeland, who will be the Implementation Manager for
5 license renewal at Beaver Valley; and John Thomas, one
6 of my technical leads. Along with that there are
7 several members, sites from the Beaver Valley staff,
8 site subject matter experts and members of the core
9 team.

10 The agenda for today we intend to go
11 through is a discussion of the background and
12 operating history by Mark Manoleras. I will then
13 discuss some of the areas in scoping and our
14 application of GALL. Larry Freeland will talk about
15 the commitment process and how we will implement those
16 commitments. And then turn it back to me, we'll
17 discuss some areas of interest and Mark Manoleras will
18 provide closing remarks for the Beaver Valley
19 presentation.

20 So, with that, I'd like to turn the
21 discussion over to Mark.

22 MR. MANOLERAS: Thank you, Cliff. Again,
23 my name is Mark Manoleras. I'm the Engineering
24 Director of Beaver Valley.

25 We have two units at Beaver Valley that

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1 are about 25 miles northwest of Pittsburgh.
2 Westinghouse was our in-trip west. There are 3-loop
3 PWRs. Stone and Webster was our architect engineer.
4 There are 2900 megawatt thermal units and they check
5 in at about 970 megawatts electric. We draw from the
6 Ohio River with natural draft cooling towers.

7 You can see our plant licensees are
8 FirstEnergy Nuclear, Ohio Edison, and Toledo Edison.
9 The operator and the applicant is FirstEnergy Nuclear.

10 Commercial operation at Unit 1 began in
11 1976, at Unit 2 1987. In 1999 the units were
12 transferred from Duquesne Light Company to FirstEnergy
13 Nuclear. We then proceeded in 2001 to have a 1.4
14 percent power uprate at each unit, and we replaced our
15 steam generators and our reactor head at Unit 1 in
16 2006.

17 We completed what we call our extended
18 power uprate, a 9.4 percent uprate. We got the SCR
19 from the NRC in 2006. We submitted our license
20 renewal application August of '07 and you can that our
21 current licenses expire in 2016 at Unit 1 and 2027 for
22 Unit 2.

23 A brief overview of our operating history,
24 we've just completed cycle 18 at Unit 1. We completed
25 our 1R18 refueling outage in October of '07. Our 18-

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1 month average capability factor as you can see is 93.9
2 percent. At Unit 2 we just completed our cycle 13 and
3 our unit 2R13 refueling outage in May of '08. Our 18-
4 month capability factor at Unit 2 is 91 percent.

5 I won't touch on every bullet on these
6 next slides, but I do want to pull out a couple pretty
7 important details. You can see in 1999, that's when
8 FirstEnergy Nuclear took over responsibility for the
9 power station there on the far left.

10 The other bullet I'd like to talk about
11 here is on the bottom right where it says our first
12 license renewal submittal. The submittal that you see
13 before you is our second submittal. In 2005 we
14 withdrew our license renewal application based on some
15 staff comments and feedback.

16 That application, we found we were not
17 current with the industry. We had not kept up with
18 industry working groups. Also, we had too much over
19 reliance on the vendor and we've had very little site
20 interaction with that submittal. We basically have
21 corrected both of those problems and Cliff will talk
22 more about that as we come up.

23 On the next slide, I'll just pull out a
24 couple major bullets. You can see where the NRC
25 improved our extended power uprate. Also, where our

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1 license renewal application was submitted.

2 I'd like at this time to turn it back over
3 to Cliff.

4 MR. CUSTER: Yes. With respect to
5 scoping, members of the Beaver Valley core team
6 included topical leads in all the areas, mechanical,
7 civil, electrical, TLAA, and programs. The core team
8 prepared the background documents.

9 Site owners participated in the
10 development. They were involved and engaged with
11 renew, and then, of course, final approval of the AMP
12 document. AREVA provided support for the initial AMR
13 preparation.

14 The license renewal team remained engaged
15 with the industry. We attended numerous working
16 groups. We attended several peer reviews for previous
17 applicants, and we also attended numerous audit and
18 performed observations during inspections.

19 With respect to oversight of our project,
20 an independent assessment was performed by License
21 Renewal Assessment Board. This Board met in five
22 sessions of approximately one week in length. The
23 Board consisted of peer members, industry peer members
24 from previous applicants, industry experts, members of
25 our own site and corporate staff, and legal

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1 representation.

2 In addition, an independent assessment by
3 our own site quality assurance was performed as we
4 developed the project. Industry peer review of the
5 application and the aspects of the environmental
6 report, the SAMA report, as far as the safety report
7 for primary sections was conducted. In addition, our
8 FENOC Corporate Nuclear Review Board provided final
9 review of the draft application.

10 Continuing with scoping, in particular our
11 methodology is consistent with that of 95-10. Our
12 (a)(2) spatial interaction scoping included non-safety
13 related water-, steam-, oil-retaining components
14 located in safety-related structures. No (a)(2)
15 exclusions were based on the distance from safety-
16 related systems, structures, or components.

17 MEMBER SHACK: That means you had to have
18 a wall in between them?

19 MR. THOMAS: Can I take that?

20 MR. CUSTER: Go ahead, John.

21 MR. THOMAS: We didn't even try and break
22 it down by that with a single exception. If it was a
23 safety-related structure, non-safety-related fluid
24 retaining components inside were scoped in for (a)(2).
25 The exception is the intake structure, for which all

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1 the safety-related components in the intake structure
2 within flood and missile barrier cubicles, so we
3 scoped (a)(2) just within the cubicles for the intake
4 structures. Everything else, the structure was
5 safety-related, (a)(2) components within it were
6 scoped in.

7 MR. CUSTER: Yes, sir.

8 MEMBER STETKAR: A couple of question on
9 the turbine building. I was a little confused in one
10 area. There was an RAI about turbine building
11 failures that could affect the river water, I think
12 it's the river water, return piping on Unit 1.

13 MR. THOMAS: Yes, sir.

14 MEMBER STETKAR: And, apparently, I'm not
15 sure about the specific location, so maybe you can
16 help me out a little bit on this. Essentially, I
17 think as I understood it, those failures or that
18 location was determined to be out of scope I think
19 based on the rationale that even if the river water
20 return piping did fail in that location, the cooling
21 function of the river water system would be maintained
22 because it's the return piping?

23 MR. THOMAS: That's correct.

24 MEMBER STETKAR: However, if it does fail,
25 won't you fill up the turbine building with water?

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1 MR. THOMAS: Yes.

2 MEMBER STETKAR: And you determined that
3 that water level would not affect any safety-related -
4 - in particular I noted that your feed reg valves and
5 feed reg bypass valves are scoped in as (a)(1)
6 equipment here, so the flooding will not affect any of
7 the controls or --

8 MR. THOMAS: Correct.

9 MEMBER STETKAR: Okay. Thanks.

10 The second question that I had, it's also
11 kind of related to the turbine building, was that the
12 turbine building cranes are out of scope. Does that
13 mean failures of the turbine building -- I'm assuming
14 you have a gantry crane over the main turbine flow?

15 MR. THOMAS: Yes, we do.

16 MEMBER STETKAR: Failures of that crane
17 will not damage any safety-related equipment, in
18 particular, again, the feed reg valves and feed reg
19 bypass valves?

20 MR. THOMAS: At Beaver Valley, feed regs
21 and bypass valves are not in the turbine building.
22 They're in the service building.

23 MEMBER STETKAR: Thank you.

24 MR. CUSTER: Does that answer your
25 question?

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1 MEMBER STETKAR: That does. Thank you
2 very much.

3 MR. CUSTER: Continuing on. The boundary
4 drawings that we submitted with the application
5 highlight the components for all scoping criteria and
6 show the (a)(2) components in different colors.

7 Our SBO switchyard scoping is consistent
8 with the proposed ISG 2008-01 and includes breakers in
9 the switchyard. In other words, within, we have
10 cables within scope to go to the first breaker that
11 sees transmission voltage.

12 With respect to TLAA, our TLAA
13 identification and disposition is consistent with
14 NUREG-1800 and NEI 95-10. Included in the review of
15 documentation is extended power uprate, our Unit 1
16 reactor head replacement, our Unit 1 steam generator
17 replacement, and recently-completed nickel-alloy
18 structural weld overlays. Our TLAAs are dispositioned
19 in accordance with 10 CFR 54.2(c)(1).

20 With respect to AMRs in the application of
21 GALL, our aging management reviews are consistent with
22 the guidance in NEI 95-10. Our review is performed
23 and our AMRs were updated prior to submittal to
24 maximize internal consistency.

25 It has been our project intent to maximize

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1 GALL consistency and utilize the same terminology for
2 materials and environment as stated in the GALL to the
3 extent practical. Greater than 90 percent of AMR line
4 items used notes A-3, in other words, consistent with
5 GALL.

6 With respect to age management program,
7 we've prepared 40 aging management programs. This
8 does include a new program we submitted for Boral, the
9 breakdown of which is 27 existing programs. Seventeen
10 programs did not require changes, ten required
11 enhancements, 13 new programs. And the GALL to plant-
12 specific breakdown includes 33 GALL programs, seven
13 plant-specific programs, and eight programs with GALL
14 exceptions.

15 The exceptions include the ASME code year.

16 Four programs are applicable to that. Fire
17 protection testing frequency, fuel oil monitoring and
18 control difference, an exception for no periodic flush
19 of some of the stagnant open-cycle cooling water lines
20 that supplies to the fuel pool and to the aux feed,
21 and AL-6XN piping which is varied but not wrapped.

22 MEMBER STETKAR: Excuse me. Could you
23 explain why you can't flush the service water lines to
24 the aux feed system? I can see why you can't to the
25 fuel pool. But there seem to be valves in the aux

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1 feed supplies, which are normally closed, and still
2 have flushing-through vents and drains, and so forth.

3 MR. CUSTER: John?

4 MR. THOMAS: Right. There is nowhere to
5 flush this line that supplies river water service
6 water to the aux feed system. If we flush it forward,
7 we would be putting raw water into --

8 MEMBER STETKAR: The valves are closed
9 though.

10 MR. THOMAS: We cycle the valves
11 periodically. But to get flow through the line, it
12 would have to go into the aux feed system. There's
13 nowhere else to --

14 MEMBER STETKAR: There are vents and
15 drains on the line, aren't they?

16 MR. THOMAS: There's a very small vent,
17 but it's not effective for a flush. But those lines
18 were also evaluated to be, because of their
19 configuration, they come off the top of the supply
20 header, they were determined not to be susceptible to
21 silting.

22 MEMBER STETKAR: Silting is okay, but
23 corrosion is -- thank you.

24 MR. CUSTER: What I'd like to do now is --

25 MEMBER SHACK: Was the AL-6X pipe

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1 original or were you replacing something?

2 MR. CUSTER: I can take that. AL-6XN pipe
3 is a placement pipe that we used, and, as you know,
4 it's a super austenitic pipe, which by recommendation
5 of the vendor, doesn't require wrapping. Okay?

6 MEMBER SHACK: What did the first set of
7 piping die from?

8 CHAIR BLEY: The first set of piping was
9 due to me.

10 With respect to the commitment process,
11 I'd now like to turn the discussion over to Larry
12 Freeland to discuss our commitment process.

13 MR. FREELAND: Thank you, Cliff. Again,
14 my name is Larry Freeland. I'm responsible for the
15 implementation phase of the project.

16 First off, I'd like to point out that our
17 commitments are tracked via commitment tracking
18 database system. Database tracking method is governed
19 by an administrative procedure which was developed
20 from the NEI 99-04 document regarding a commitment
21 tracking process and, also, endorsed by the NRC
22 Regulatory Information Summary on the same topic.

23 Now, as part of the implementation, we
24 have chosen, based on experience, some other plants to
25 handle the implementation as a project, which means

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1 each of the commitment needs will be scheduled, as
2 well as integrated into the site programs. And I'll
3 also point out that in the development of the
4 application, the individual program owners were
5 involved with that and will ultimately have
6 responsibility for their particular program to
7 continue to manage the commitment.

8 Responsibility for management of the
9 implementation project has been assigned. That is me.

10 But, in addition, we will have ongoing an owner going
11 forward embedded into the engineering organization to
12 continuously be in charge of monitoring and making
13 sure that we meet the commitments going forward.

14 On the next slide, to give you an overview
15 of the commitments, the first bullet represents the
16 multiple commitments related to program implementation
17 or enhancement items. The remaining bullets are in
18 relation to some specific commitments that were made
19 with regard to Beaver Valley.

20 You can see the second bullet was periodic
21 replacement of most elastomer mechanical components.
22 We have periodic testing or replacement of most of the
23 polymer mechanical components. We have maintenance of
24 Unit 1 reactor vessel neutron flux reduction plan in
25 adjusting that program going forward for the life of

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1 the plant.

2 MR. BARTON: That plan been issued for
3 Unit 1 flux reduction? Is it RE out the bio plan?

4 MR. FREELAND: No. There's currently a
5 program that was for the original operation. It will
6 need to be updated. We're evaluating the options
7 associated with that for the flux reduction. We have
8 some time available to do that.

9 As part of the commitment, we have to
10 notify and get NRC approval one year prior to
11 implementing the revised plan. So we will do that.

12 MEMBER STETKAR: Both units have had low-
13 leakage cores since the first refueling. It's more
14 significant with Unit 1 than Unit 2 because of vessel
15 brittle fracture toughness. So it's paid attention to
16 since the plants went online.

17 MR. FREELAND: Okay. The next specific
18 commitment is maintain the standby vessel surveillance
19 capsules. Then we have a commitment to evaluate
20 extended power uprate operating experience. And we
21 have a commitment to confirm effectiveness of new
22 programs by a self-assessment conducted in
23 approximately five years falling entry into the period
24 of extended operation.

25 And then the final one is implement the

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1 needed actions of EPRI and material reliability
2 program, MRP-146, which is management of thermal
3 fatigue in non-icable reactor coolant branch lines.

4 MEMBER MAYNARD: I am sorry.

5 MR. FREELAND: Sure.

6 MEMBER MAYNARD: Implement needed actions,
7 I'm just not sure exactly what you're saying. What do
8 you mean by needed actions? How are you going to
9 evaluate what part of that is needed and not needed?

10 MR. CUSTER: To respond to that question,
11 I'd like to offer Steve Buffington to provide
12 response.

13 MR. BUFFINGTON: My name is Steve
14 Buffington. I'm with the Design Engineering
15 Department.

16 The needed actions for bulletin 146
17 include identifying the applicable lines, screening
18 them in accordance with an EPRI-related software
19 program, and current needed action is for us to do
20 inspections and we have those inspections planned
21 during our upcoming outages.

22 MEMBER MAYNARD: So you're basically going
23 to be implementing the actions of MRP-146?

24 MR. BUFFINGTON: That's correct.

25 MR. CUSTER: Does that answer your

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1 question?

2 MEMBER MAYNARD: Yes. I just want to make
3 sure it wasn't some nuance with needed actions there.

4 MR. CUSTER: No.

5 MEMBER MAYNARD: Okay.

6 MR. FREELAND: As a final comment
7 regarding the commitment process, I'd like to point
8 out we are members of the License Renewal
9 Implementation Working Group and participate in the
10 periodic meetings associated with that. And the
11 purpose of that is to remain aware of the best
12 practices going forward, certainly take advantage of
13 evolving technology that will aid us in inspections
14 for both efficiency and accuracy, and, also, learn
15 from the plants that will be entering the period of
16 extended operation in advance of Beaver Valley so we
17 can learn from that experience to adjust and apply to
18 our own, going-forward implementation programs.

19 MEMBER ABDEL-KHALIK: With regard the
20 vessel neutron flux reduction plan, what is the
21 projected RTNDT at the end of the period of extended
22 operation?

23 MR. FREELAND: Denny Weakland?

24 MR. WEAKLAND: My name is Dennis Weakland.
25 I'm with Fleet Materials and FirstEnergy.

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1 The RTNDT PTS for the extended period
2 would be approximately 270 following the input of flux
3 reduction actions. We have several actions we could
4 take to manage that below the PTS screening criteria.

5 MEMBER ABDEL-KHALIK: Now, what is the
6 setpoint for your FRP-1 emergency operating procedure?
7 Isn't that 270?

8 MR. WEAKLAND: 270 is the screening of it,
9 yes.

10 MEMBER ABDEL-KHALIK: So there is no
11 margin below where you expect your --

12 MR. WEAKLAND: No. You stay below 270
13 according to regulation.

14 MEMBER ABDEL-KHALIK: Okay.

15 MEMBER STETKAR: When do you currently
16 expect to reach that? I thought -- one is like 2033,
17 but that's under an assumed average capacity factor of
18 like 90 percent. You've been exceeding that capacity
19 factor by quite a bit regularly. Do you have any
20 projections of how the improved plant performance is
21 going to affect that 2033 date?

22 MR. FREELAND: As part of the program, the
23 management of that, certainly, we need to continue
24 monitoring exactly the plant performance to stay
25 closer.

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1 MEMBER STETKAR: It's just part of the
2 whole program?

3 MR. FREELAND: Right, exactly.

4 MEMBER STETKAR: Okay.

5 MR. FREELAND: Okay. At this time I'd
6 like to turn it back over to Cliff.

7 MR. CUSTER: What we would like to do now
8 is enter a discussion on a few areas of interest that
9 we've identified that we feel as though are worthy of
10 discussion with the ACRS.

11 A new program we've recommended and
12 provided to the staff is Boral, management of Boral.
13 That's specific to the Unit 1 fuel pool metal fatigue.

14 Discuss containment liner corrosion at Unit 1, and
15 medium voltage cables in that order.

16 With respect to Boral, now, Boral is a
17 material used in the Unit 1 fuel pool. It is a
18 neutron absorber in the pool and prior to the LRA
19 submittal, Beaver Valley had not identified Boral
20 aging as effects that could affect spent fuel pool
21 reactivity.

22 In the fourth quarter of 2007 after we
23 submitted our application, we submitted in August of
24 2007, our surveillance program identified numerous
25 blisters occurring on the Boral material. We proposed

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1 that this aging will be managed by the existing Boral
2 surveillance program now credited for license renewal
3 and our program has been admitted for staff review.

4 MR. BARTON: What's the real concern here
5 with Boral failure, criticality in a pool? What's the
6 gotcha here?

7 MR. THOMAS: I can answer that. In Region
8 1 fuel storage, which is the primary concern for the
9 Boral blistering, the criticality analysis in Region 1
10 fuel storage credits water flux trap region between
11 the cells. The cells aren't immediately adjacent.
12 There is water in between them. The volume of that
13 water is credited in the criticality analysis.

14 There is tolerance in there. There's
15 margin between what is the actual dimension and what
16 is assumed in the criticality analysis. But if these
17 blisters become very extensive, very large, the
18 possibility exists they could challenge the
19 dimensional assumptions made in the criticality
20 analysis.

21 So what the actual effect is I don't think
22 anybody has done any kind of a study to figure out
23 what the actual effect on reactivity is, but it could
24 potentially challenge assumptions that we've made in
25 that analysis.

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1 MR. BARTON: You're the only one with this
2 problem?

3 MR. THOMAS: No, sir, we're not. I don't
4 know how wide spread it is, but other applicants have
5 identified it also. EPRI has a report out on it that
6 was issued in 2005, and when it's translated over into
7 the aging evaluation references, they recommend that,
8 in general, the industry as a whole doesn't have this
9 identified as an aging effect, but plant-specific OE
10 should be reviewed to confirm the absence at that site
11 because a few people have seen it.

12 CHAIR BLEY: Is it only the water gap or
13 is there some worry that these could flake off and the
14 Boron can actually fall out of its position?

15 MR. THOMAS: That hasn't been observed
16 anywhere. It hasn't been postulated. The blisters
17 are in the cladding of the boral and it hasn't been --

18 CHAIR BLEY: I heard some plants have
19 actually done some kind of neutron attenuation
20 measurements to see what the effect is.

21 MR. THOMAS: Our program that we currently
22 have in place, that we're now crediting for license
23 renewal, it monitors coupons that we take out. We'll
24 test coupons for neutron absorption and dimensional
25 checks. It also provides options if it looks like

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1 you're seeing more degradation than expected, provides
2 options to do additional tests, which include in-
3 service flatness testing of the panels in situ.

4 MEMBER MAYNARD: Is what you're finding
5 fairly consistent with what other plants have found?
6 One of the curiosities I have is did this occur
7 rapidly or did your inspections -- I'm not sure what
8 your inspection frequency was and stuff, this would
9 kind of imply to me -- either this could occur rapidly
10 or you -- hadn't been monitored for a while, the
11 blisters.

12 MR. THOMAS: We've sampled coupons on four
13 occasions since the pool was reracked in 1994 when it
14 was completed. In 2002, which was not the most
15 recent, but the one before that, there's very minor
16 blistering of insignificant, eight blisters on two
17 coupons. In 2007, after our submittal for license
18 renewal, pulled coupons. Then on two coupons there
19 was considerably more blistering noted such that we
20 didn't think we could say it was insignificant then.

21 CHAIR BLEY: You said on two out of
22 roughly how many that were pulled?

23 MR. THOMAS: We pulled two coupons at a
24 time, four times now, so eight, eight coupons.

25 CHAIR BLEY: Okay.

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1 MR. THOMAS: Does that answer your
2 question?

3 MR. CUSTER: As I said, with that we
4 developed a new aging management program and submitted
5 for the staff review.

6 Moving to the next area of interest, which
7 is environmentally assisted metal fatigue. Our 60-
8 year cumulative usage factor --

9 MEMBER SHACK: I just asked some questions
10 because I got confused when I read the document. It
11 seems contradictory in some places. One part in Unit
12 1, you've got the
13 B-31-1 and it says in the license renewal document
14 that the pressurized of surge line has been reanalyzed
15 as ASME Code 3 or Section 3, and no other Unit 1
16 piping systems are designed or analyzed to ASME
17 Section 3. But you really did analyze all the 62.60
18 sections to Section 3, is that correct?

19 MR. CUSTER: Yes, that's correct.

20 MEMBER SHACK: Okay. And those are the
21 only portions of the B-31-1 line that have been
22 reanalyzed to -- except for the pressurized of surge
23 line that had been reanalyzed to Section 3?

24 MR. CUSTER: Yes.

25 MEMBER SHACK: One of the things you get

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1 out of B-31-1, of course, the pipes in Unit 1 are
2 thicker than they are in Unit 2. With no other
3 changes, you would think that would make the piping
4 stiffer for thermal expansion purposes. I don't know
5 what other design changes are in there and so I might
6 get higher thermal cycling.

7 Are you sure that at the locations you're
8 not looking at, that are not the 62.60 things, that
9 you're not going to have relatively high fatigue usage
10 factors if you, in fact, computed fatigue usage
11 factors?

12 MR. CUSTER: What I'm going to elect to do
13 is ask Steve Buffington.

14 MR. BUFFINGTON: Steve Buffington, Design
15 Engineering. System by system, our piping is
16 basically the same thickness dimensionally.

17 MEMBER SHACK: No, not between Unit 1 and
18 Unit 2.

19 MR. BUFFINGTON: I believe it is.

20 MEMBER SHACK: That's not what the
21 document says. I'll dig out the tables here in a
22 minute.

23 MR. BUFFINGTON: I'm unaware of a system-
24 by-system difference then.

25 MEMBER SHACK: Hot leg and cold leg? I'll

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1 have to find it.

2 CHAIR BLEY: Maybe we can come back to it.

3 MEMBER SHACK: I'll come back to that.

4 MR. CUSTER: Could we come back to that
5 question?

6 MEMBER SHACK: Okay. But those are the
7 only ones that have been analyzed is the 62.60
8 locations?

9 MR. CUSTER: Yes, the 62.60 locations.

10 MEMBER SHACK: On your review graph, you
11 have one location in Unit 1 exceeding the 1.0. But
12 there's a charging nozzle also, isn't there, or did
13 that get reanalyzed?

14 MR. CUSTER: We reanalyzed that charging
15 nozzle. That number is now below one.

16 MEMBER ABDEL-KHALIK: Do you actually have
17 detailed data records from the early years to support
18 these calculations?

19 MR. CUSTER: Yes, sir. As a matter of
20 fact, we went through a very extensive review of those
21 records. I can let Steve provide the details of your
22 further questions.

23 MR. BUFFINGTON: Yes. As part of our
24 reanalysis efforts, we have gone back through our
25 plant history. We were able to obtain operator logs

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1 from the control room. We were able to obtain plant
2 history data as far as our RCS pressures and RCS
3 temperatures, and put together what we believe to be a
4 best effort of reconstruction of a plant heat-up and
5 cool-down events.

6 MR. CUSTER: Okay? Okay. So our 60-year
7 cumulative usage factor, as I said, exceeds a value of
8 one when we consider environmentally assisted fatigue
9 in two locations: Unit 1 pressurizer surge line to hot
10 leg nozzle and the Unit 2 pressurizer surge line to
11 hot leg nozzle.

12 We have chosen to manage this program in
13 accordance with the guidance and it'll managed by the
14 metal fatigue of reactor coolant pressure boundary
15 program. In management of this program we really have
16 three options and the order of priority:

17 Refinement of the analysis to obtain a
18 value less than one; some of those actions are ongoing
19 now;

20 Management of fatigue by an inspection
21 program, which, of course, proved by the staff;

22 And/or, of course, repair or replacement
23 is the last option.

24 MEMBER STETKAR: Now, can I interrupt? I
25 was just reading something here trying to get a

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1 question in my mind. Back to the use of historical
2 operating experience to project the number of thermal
3 cycles, there was an RAI on it I think and there's a
4 table in the SER that lists the number of cycles, and
5 for Unit 1 several of the projected cycles just at the
6 end of the period of extended operations just meet the
7 limit, 200 heat-ups and cool-downs.

8 Now, I was curious. When I did the math,
9 I figured out how you scaled historical operating
10 experience for all other cycles based on your time of
11 initial criticality except plant heat-ups and cool-
12 downs. The scaling factors for those and Unit 1 trip
13 from full power operations seemed to be numerically
14 smaller than were used to scale all other transients
15 in that table, and I was curious what was the basis
16 for the smaller scaling factors for those particular
17 transients and how were they derived.

18 There wasn't any note about, you know,
19 well, for these types of transients we used a
20 different calculation algorithm or something.

21 MR. BUFFINGTON: Steve Buffington again.
22 Unit 1 had a history in the early period of a lot of
23 start-up and shut-downs, and what we did for the heat-
24 up and cool-down, as well as reactor trip transient,
25 was take our most recent operating history for our

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1 projection. And then at the end of that, we scaled
2 that upwards again because there may be some
3 additional events that would occur as the plant ages.

4 MEMBER STETKAR: When you said most recent
5 operating history, over the period of how many years?

6 MR. BUFFINGTON: It was the last ten years
7 of operation.

8 MEMBER STETKAR: Okay. Thanks. I'll have
9 to think about what that means, but at least I know
10 what you did.

11 MEMBER SHACK: As a point of information,
12 if you look at the UFSAR Unit 1, Table 4.17 and you
13 look at the Unit 2 UFSAR, Table 5.47, you'll find the
14 piping diameters are different by about three-tenths
15 or four-tenths of an inch, the piping thicknesses, the
16 wall thickness.

17 MR. CUSTER: Okay. We will need to take
18 your question and prepare a response to it.

19 If we can move forward, then.

20 The next area of interest is Unit 1
21 containment liner corrosion. During the steam
22 generator replacement outage in the Spring of 2006,
23 corrosion was found on three areas of the liner plate
24 when we exposed the liner plate for removal in
25 processing, preparing for the steam generator

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1 replacement.

2 Two of these locations were repaired. One
3 was considered to be within design margin and we had
4 determined that we will monitor that location for the
5 next three 40-month periods.

6 Hydro-lazing in preparation for removal of
7 the concrete by hydro-lazing removed the corrosion
8 products. So no definitive corrosion source could be
9 established.

10 Our material analysis indicated general
11 pitting corrosion. There was no evidence of stress
12 corrosion for MIC. Corrosion likely occurred during
13 construction or curing concrete curing.

14 MR. BARTON: Let me ask you a question on
15 that.

16 MR. CUSTER: Sure.

17 MR. BARTON: Are there any photos of the
18 liner during construction. There's thousands of
19 construction photos taken at every site. Do you have
20 any of the containment liner during construction that
21 would have helped your argument here that it could
22 have been caused during from weather from the liner
23 sitting outside?

24 MR. MANOLERAS: Yes. This is Mark
25 Mandoleras. We were unable to find any photos that

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1 would allow us to correlate those areas with that
2 construction.

3 MR. BARTON: Okay. Thanks.

4 MEMBER SHACK: So pitting is all too
5 localized and minor to require any reanalysis of the
6 containment shell?

7 MR. CUSTER: Yes, yes. It was localized
8 in the area where we chose to cut out the liner for
9 the steam generator to go through.

10 MEMBER SHACK: This is localized means
11 what, three inches?

12 MR. CUSTER: I'll ask Dennis to categorize
13 the size.

14 MR. WEAKLAND: Dennis Weakland. The areas
15 of corrosion, we cut out about a 20-by-20-foot square
16 opening into the side of containment to allow the
17 passage of the steam generators. On this 20-by-20-
18 foot square area, we had three areas of approximately
19 a foot-and-a-half to two-foot square each where we
20 found general pitting corrosion.

21 The other areas of the liner were
22 unaffected. The areas appear to be random across the
23 20-foot square area. So the pitting in general was
24 not deep. There were a couple of pits that went below
25 what would be considered the nominal wall for the

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1 material, but then, again, our containment liner is a
2 membrane activities.

3 MEMBER SHACK: Oh.

4 MR. WEAKLAND: It's not structural.

5 MEMBER SHACK: It's not structural.

6 MR. WEAKLAND: Does that answer your
7 question?

8 MR. BARTON: Also, in the LRA there was
9 discussion -- maybe it was in the audit report --
10 about missing test channel vent plugs. Is it possible
11 that there is an exchange there to the liner from the
12 missing test plugs to add to this corrosion issue?

13 MR. CUSTER: Dennis will address that.

14 MR. WEAKLAND: Dennis Weakland, again.
15 The containment test channels are on the IV surface
16 of the liner. It's on the opposite side of the
17 corrosion that we saw from the opening that we cut.
18 So they would be unrelated activities.

19 MEMBER SIEBER: One of the characteristics
20 of these units is that the containments are sub-
21 atmospheric. So when you get ready to start up the
22 unit, you draw a vacuum in containment and, of course,
23 they've changed the degree to which their
24 sub-atmospheric in recent times. But that tends to
25 pull the liner away from the containment.

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1 MR. WEAKLAND: Right.

2 MEMBER SIEBER: And the question is, does
3 this induce any deterioration to the containment?
4 Once you do a containment leak rate test, you push it
5 all back up against the concrete and so you have a
6 certain amount of flexing that occurs. Have you
7 thought about inspecting for that? And, if you did,
8 did you find anything or have you analyzed it in any
9 way?

10 MR. CUSTER: I'll ask maybe Tom Westbrook
11 to address that issue.

12 MR. WESTBROOK: Tom Westbrook, Design
13 Engineering. The design of the liner is a membrane.
14 It is backed up by reinforced concrete. There are
15 headed concrete studs attached to the liner that
16 secure it to the concrete, so during sub-atmosphere
17 operation there is no movement of the liner.

18 MEMBER SIEBER: There is none?

19 MR. WESTBROOK: No.

20 MEMBER SIEBER: My memory differs a little
21 bit. I think that there were some bulges some place
22 in there, but that's something you can check.

23 CHAIR BLEY: I'm just curious. How far
24 apart are these places where it's secured?

25 MR. WESTBROOK: The exact number I don't

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1 know. It's within a couple feet out
2 of --

3 MEMBER SIEBER: Thank you.

4 MR. CUSTER: Further discussion on the
5 liner corrosion issue: to manage this issue, we
6 recognized the fact that the corrosion process and the
7 corrosion byproducts caused an expansion and
8 blistering on the coating, specifically, de-lamination
9 of the primer coat would be one example.

10 So an issue similar to this, taken to
11 extreme, would be evident on the interior surface, the
12 stained, bulged, or flaking areas on the painted
13 surface. We enhanced our IWE inspection procedures as
14 a corrective action, such that any surface flaws
15 identified during visual examination will require full
16 NDE characterization and we will utilize qualified NDE
17 examination prior to repair of the indications that
18 characterize the flaw.

19 MEMBER STETKAR: Can I ask about your
20 inspection program?

21 If I recall some place, I've lost my
22 notes, you had a 15-year risk-informed inspection
23 interval at some period of time and you've now come
24 back to the nominal 10-year inspection. Not being an
25 expert on materials, I'll defer to people at that end

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1 of the table.

2 Is there any impetus to increase the
3 testing interval to less than once per 10 years
4 because you have indications of a potential known
5 corrosion problem? I mean you've gone back to the
6 standard 10-year program, which presumes there will
7 not be any corrosion, but it's a periodic check.

8 You reduced the risk-informed frequency of
9 once every 15 years back to the standard because you
10 had observed corrosion, which is in the right
11 direction. I guess my question is, is there any
12 justification to reduce the interval to below once per
13 10 years?

14 MR. CUSTER: I'd like to have Dave
15 Gravsky. Dave's involved with our ISI program.

16 MR. GRAVSKY: Yes, I'm Dave Gravsky. I'm
17 the ISI program owner at Beaver Valley.

18 The Appendix J testing, the Type A is, in
19 fact, 10 years as you stated. However, we do have an
20 IWE program that does visual inspections of the liner
21 once every 40 months. So every other outage at Beaver
22 Valley we will do a visual inspection of the entire
23 liner. If we see any indications, any
24 discontinuities, we'll take further actions at that
25 point.

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1 MEMBER STETKAR: But according to this,
2 the visual would only -- if the corrosion was
3 extensive enough to actually cause blistering and
4 discoloration on the --

5 MR. GRAVSKY: Right, on the ID, yes.

6 MEMBER STETKAR: That would pick it up.
7 That's pretty extensive corrosion by that time, isn't
8 it?

9 MR. GRAVSKY: If it would be coming
10 through wall, it would be.

11 MEMBER STETKAR: I meant where it's
12 starting.

13 MR. GRAVSKY: Right.

14 MEMBER ARMIJO: That's where I'm a little
15 confused. I want to make sure I understand it.

16 Now, the corrosion that you found was on
17 the side adjacent to the concrete, right?

18 MR. CUSTER: That is correct. It was on
19 the inside of the lining.

20 MEMBER ARMIJO: Okay. And you're making
21 the claim that if you had extensive corrosion on that
22 side, you would be able to see some sort of indication
23 on the inside. Is that what you're saying?

24 MR. CUSTER: Based on the fact that --

25 MEMBER ARMIJO: But I mean did it have to

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1 be all the way through the liner?

2 CHAIR BLEY: Yes.

3 MEMBER ARMIJO: And you're saying that's
4 okay?

5 MR. CUSTER: Dennis, would you like to
6 address that issue?

7 MR. WEAKLAND: Yes. This is Dennis
8 Weakland, again.

9 If you have corrosion in the tight-fitting
10 membrane, this corrosion liner should be fitting tight
11 up against the concrete.

12 MEMBER ARMIJO: Yes.

13 MR. WEAKLAND: When corrosion occurs, the
14 volume of the corrosion product versus the volume of
15 the material that's being corroded is somewhere
16 between seven and ten. It's going to displace an
17 awful lot of area and we believe that it would show a
18 bulge on the ID surface and we should be able to pick
19 that up with our examination process because it's one
20 of the things we specifically look for, any change in
21 the ID surface configuration to go through scratches,
22 paints, flaking, or bulges.

23 MEMBER ARMIJO: What's the thickness of
24 your liner again?

25 MR. WEAKLAND: About three-eighths.

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1 MEMBER ARMIJO: Three-eighths of an inch,
2 that's be an awful lot of deformation. Yes, I think
3 you'd be in bad shape by the time you've seen that
4 much deformation. But that's your only indicator that
5 you would then trigger NDE by volumetric inspection or
6 something like that for wall thickness?

7 MR. CUSTER: Yes.

8 MEMBER MAYNARD: Just to make sure I
9 understand and remember what I read, now, you didn't
10 identify this until you took the chunk out?

11 MR. CUSTER: That is correct, sir.

12 MEMBER MAYNARD: You were getting ready to
13 replace. So apparently you didn't see any bulging
14 before you did this?

15 MR. CUSTER: Not in this location, no.

16 MEMBER MAYNARD: And I take it, it's your
17 position that the amount of corrosion that you saw was
18 insignificant, that you could withstand a lot more
19 before -- obviously, you're going to see more before
20 you see the bulging, so you're saying that you have
21 some margin?

22 MR. WEAKLAND: Yes, yes. Again, this
23 serves as a membrane. It's only a --

24 MEMBER MAYNARD: I understand that. I'm
25 just trying to understand why I should buy the

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1 argument that you're going to see the bulging before
2 it's too bad. Yet, you didn't see the bulging in
3 this, but you went ahead and found some and fixed it.

4 So I'm kind of struggling just a little bit here.

5 I'm trying to understand that maybe that
6 was very insignificant. But how do I jump from there
7 to that you're going to be able to identify it before
8 it becomes too significant?

9 MR. WEAKLAND: It wasn't much volume that
10 was displaced in this first go round. Like we said,
11 the pinning was relatively minor. The two areas that
12 did exceed the nominal wall --

13 MEMBER MAYNARD: What I'm struggling for
14 is basically is why I should accept the argument that
15 if you see -- you can wait until you see the bulging
16 before you have to take action I guess is kind of what
17 I --

18 MR. WEAKLAND: It's simply --

19 MEMBER MAYNARD: When you see the bulging,
20 are you still going to have --

21 MEMBER ARMIJO: It's pretty far gone by
22 the time you see the bulging. That's the conclusion I
23 get. Is that what you're saying, you have at least --
24 I don't know. Pick a number. Half the wall thickness
25 of the liner would have had to disappear and turn into

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1 oxide to create the bulge. And that's okay?

2 MR. WEAKLAND: Yes, should be. It's non-
3 structural.

4 MEMBER ARMIJO: I understand. I
5 understand, you know, membrane can be a molecule
6 thick. At some point it's no good.

7 MEMBER SHACK: Well, I think they were
8 also implicitly arguing they don't really expect this
9 to be an active corrosion.

10 (Simultaneous speakers.)

11 MEMBER SHACK: So this is their backup to
12 that argument.

13 MR. BARTON: Just in case.

14 MR. MANOLERAS: This is Mark Manoleras.
15 We did not see that corrosion of that line or as an
16 active process. We believe that that happened in
17 construction and basically retardant and stopped.

18 MEMBER SHACK: Yes. You might take a
19 different attitude if you really thought you had an
20 active process here.

21 MEMBER SHACK: Correct. We did take an
22 opportunity to repair the two locations. We basically
23 replaced the two locations and we committed to do UT
24 on that third location I believe on a 40-month
25 frequency correct data.

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1 MEMBER ABDEL-KHALIK: Was there anything
2 special about that 20-foot by 20-foot area just by
3 chance?

4 MR. MANOLERAS: Yes, there was nothing
5 special about that. That was our entry path for our
6 new steam generators. that's what we had selected.
7 That's correct.

8 MEMBER ABDEL-KHALIK: I mean could there
9 be other locations where much more extensive corrosion
10 is taking place?

11 MR. MANOLERAS: We believe that what we
12 saw was a representative area in our containment. We
13 did not postulate a area that could have been worse
14 than that. We have performed the Type A testing, done
15 our leak rate testing, and we continue to do our
16 40-month visual inspections of our containment as
17 others as per our current license.

18 CHAIR BLEY: Just briefly for me, what are
19 the details of the test that's done at 10-year
20 intervals?

21 MR. CUSTER: Yes. I'd ask Dave Gravsky to
22 run through that.

23 MR. GRAVSKY: Every 10 years the Appendix
24 J program will do a pressure test on it.

25 CHAIR BLEY: Okay. So it's a pressure

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1 test?

2 MR. GRAVSKY: It is a pressure test on 10
3 years. Every 40 months it's a visual and possible ND
4 follow-up on a 40-month frequency.

5 CHAIR BLEY: Thank you.

6 MR. CUSTER: Okay. Moving forward, then.
7 Next slide, please.

8 The next area of interest is our final
9 area of interest for discussion. It is medium voltage
10 cables.

11 A 4kV power supplies to the river water
12 and service water pumps. That's where Unit 1 and Unit
13 2 are submerged. They are normally submerged. These
14 cables are designed for submergence based on the
15 original cable design specification and based on
16 vendor testing and the certification of compliance to
17 specifications provided with those cables.

18 The service application is supported, that
19 there are no failures of HTK cables due to moisture
20 intrusion and aging. We've looked not only at our own
21 site-specific information, but we've also looked in
22 the commercial realm through our vendor, Carite, and
23 confirm that there are no aging effects related to
24 water in HTK cables.

25 We've developed a plant-specific program

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1 to confirm the absence of aging effects through
2 periodic testing and inspection.

3 This is our open item. To resolve this
4 open item, we're proposing that FENOC will submit the
5 details of our own site engineering evaluation that
6 supports this position and vendor documentation from
7 Carite. It also quotes their experience and their
8 design criteria.

9 MR. BARTON: The question I've got for
10 you. I take it that these raceways where this
11 "submerged cable" meets spec and it's okay, are there
12 any other cables that run adjacent to these which are
13 not qualified for submergence that could fail and
14 cause damage to these cables?

15 MR. CUSTER: To respond to that, sir, I'll
16 ask Mr. Brian Paul to provide response.

17 MR. PAUL: Good afternoon. Brian Paul,
18 Beaver Valley Design Engineering.

19 All the cables that were purchased for
20 original construction were purchased as nuclear
21 safety-related cables. All of these engineering
22 specifications contained the requirement that they be
23 designed for this service. We have vendors'
24 certificates of compliance that state they commit to
25 the specifications.

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1 MR. BARTON: All right. Then how about
2 the raceways themselves and the fittings on the
3 raceways and that whole thing could collapse?

4 MR. PAUL: Tom, you want to help me out
5 with some structures?

6 MR. CUSTER: With respect to the question
7 on the structural capability, Tom Westbrook from
8 Design Engineering Structure will provide that
9 response.

10 MR. WESTBROOK: Tom Westbrook, Design
11 Engineering.

12 When the cables are looked at, when the
13 manholes are looked at, we do look at the supports and
14 the raceway, and any deterioration is evaluated and is
15 repaired or replaced as required.

16 CHAIR BLEY: Have you found damage there
17 that you've had to replace?

18 MR. WESTBROOK: There is one case where we
19 did replace a tray and a support. That was a case
20 where we had excess runoff entering the manhole, which
21 caused a severe corrosion problem. That has been
22 remedied. We've diverted the runoff away from the
23 manhole, and now that manhole does not receive that
24 runoff, and we replaced the corroded supports that we
25 found.

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1 CHAIR BLEY: Thank you.

2 MEMBER STETKAR: I would go back and ask
3 John's question a little bit differently because I
4 wasn't quite sure that I understood the answer.

5 I think I heard you say that the cables in
6 question for the river water pumps and the service
7 water pumps are Carite HTK cables. I'll need some
8 help in a minute on that.

9 But are all of the other cables in these
10 raceways also Carite HTK cables or are they different
11 manufacturers with different jackets and insulations
12 types? Because I hear that they were purchased for
13 services, which is what you do with all cables. Are
14 the other cables in the raceways the same cable?

15 MR. PAUL: These manholes service the
16 primary intake structure. You have 4kV power cables,
17 which are the Carite cables for the service water
18 pumps. You also have 480 volt power feeders, control
19 cable, and instrumentation cable of various
20 manufacturer. There's some oakonite cable in there.
21 There's some rockbestos cable in there. But all of
22 these cables were specified by the original AE to be
23 designed for this application.

24 MEMBER STETKAR: Submerged conditions,
25 submarine cables?

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1 MR. PAUL: Well, our current licensing
2 basis does say that these intake structure raceways
3 and manholes are allowed to flood, and the
4 specifications did state that these cables needed to
5 be designed for these wetted locations.

6 MR. BARTON: That's a lot different than
7 being submerged.

8 CHAIR BLEY: Yes. I think I've heard a
9 couple things here. We say this application. This
10 application was nuclear safety cables I take it, not
11 submerged-use.

12 MR. BARTON: Well, the certain cables are
13 supposedly designed for submerged use. Were they
14 actually qualified application?

15 MR. MANOLERAS: If Brian can help you out
16 there.

17 MR. PAUL: Sure, Mark.

18 MR. MANOLERAS: Yes. These cables were
19 constructed to meet industry standards for submerged
20 applications. Okay? When we use the word
21 qualification, for example, these cables are also
22 qualified for use in hard, post-LOCA environments.

23 But really to say that they're qualified
24 for submerged applications, I don't believe that there
25 is an NRC-approved qualification method for

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1 submergence of this type. They were constructed and
2 designed for submergence. Our manholes were not
3 intended to be water tight.

4 What's important about a manhole is you
5 don't want it to be, in this application, where the
6 bottom of the manhole is below the water table, the
7 river. If that manhole becomes buoyant, obviously, it
8 can become structurally unsound and you could start to
9 damage some of the cables or raceway within that
10 manhole.

11 So the original design was that water
12 could definitely come into those manholes. We wanted
13 to make sure and the architect engineer wanted to make
14 sure that the cables used were designed and
15 constructed to meet a submerged application.

16 And if you talk to Carite, they would
17 actually supply this cable for use in submerged
18 applications in outside industry. But to ask are they
19 qualified, there is not a known qualification that we
20 can discuss. They were qualified for post LOCA in
21 harsh environments.

22 CHAIR BLEY: All of the cables?

23 (Simultaneous speakers.)

24 CHAIR BLEY: The oakonite and the other
25 stuff?

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1 MR. MANOLERAS: And what's important, and
2 Brian could talk about this some more, our cables are
3 routed, like our 4kV cables would be routed separate
4 from our 480 volt cables and from our control cables.

5 So they are routed. And, Brian, you could talk about
6 that a little more, the way our tray systems work.

7 CHAIR BLEY: Yes, if you would, and tell
8 us what you mean by routed separately, kind of
9 precisely.

10 MR. MANOLERAS: Sure.

11 MR. PAUL: The duct banks themselves are
12 in array. You have, whatever the number is 4-by-4, 5-
13 by-5. Instrumentation cable is usually on the bottom.

14 It's always on the bottom. And as your higher power
15 cables are routed through the duct banks, they're in
16 different elevations.

17 So your 4kV cables are going to be at the
18 top, then your 480s, then maybe 125 volt DC, and
19 control cables, and then you have your instrumentation
20 cables. As the cables exit a duct, there's a cable
21 tray inside the manhole that takes it to the next
22 preceding duct bank that it goes into so that the
23 trays are all separate for each power level and that's
24 how they route it.

25 MEMBER RAY: What about splices? Visual

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1 failure in a cable is a splice, not the cable.

2 MR. PAUL: There are no splices in the
3 runs to the cables to the service water pumps.

4 CHAIR BLEY: One long pull?

5 MEMBER RAY: Okay. That's a simple, clean
6 answer, but it's pretty definitive.

7 MR. PAUL: We've reviewed all the design
8 documentation and see no evidence of splices in these
9 cables. The runs are all less than 1400 feet.

10 MEMBER ABDEL-KHALIK: How much does the
11 water level in these manholes change?

12 MR. CUSTER: The normal river level is
13 elevation 666. The top set of cables I believe, and,
14 Brian, correct me if I'm wrong, is at elevation 664.

15 MR. PAUL: The top elevation of cables is
16 still below the normal river water elevation.

17 MEMBER ABDEL-KHALIK: The reason I'm
18 asking, if the water level inside these manholes
19 change and your four kilovolt cables are at the top,
20 that means they are the cables that would most likely
21 be subjected to wet-dry-wet-dry conditions, is that
22 correct?

23 MR. CUSTER: No, sir. I think we've
24 gotten in the wrong --

25 MEMBER ABDEL-KHALIK: Continuously

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1 submerged?

2 MR. CUSTER: They are continuously
3 submerged. The elevation of the river, these are
4 right against the river, so the elevation of the river
5 does change at times. It floods and comes over the
6 top of the manhole and then provides water and leakage
7 from the top, as well as from the bottom as the river
8 water level would change, but these cables are
9 continually submerged.

10 MEMBER MAYNARD: And they essentially have
11 been submerged since they were installed?

12 MR. CUSTER: They essentially have been
13 submerged since installation by design.

14 MEMBER BROWN: Thirty years?

15 MEMBER ARMIJO: You've had construction of
16 30 years and no problems?

17 MR. CUSTER: No problems, and we've
18 performed insulation resistance testing. Brian, if
19 you would, would you please talk about that?

20 MR. PAUL: Yes. The cables are
21 periodically testing every two years, electrically and
22 visually, throughout the cable length, and the
23 electrical testing shows no degradation of the cable
24 insulation.

25 MEMBER BROWN: How do you see them if

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1 they're under water?

2 MR. PAUL: Say it again?

3 MEMBER BROWN: How do you see them if
4 they're under water?

5 MR. PAUL: When we visually examine the
6 manholes of the intake structure, we pump them out.
7 We take the covers off, we pump them down, we go in
8 there and we look at them.

9 MR. CUSTER: There's a continuous pumping
10 process. It's not one that's intermittent. I mean
11 there's a large sump pump placed in there such that
12 individuals can enter, and, virtually, when you turn
13 the sump pump off, they flood right back up.

14 MEMBER ABDEL-KHALIK: The testing, what
15 are you measuring, the electrical with?

16 MR. PAUL: We just do a simply 2500 volt
17 DC meggar test and we take them over a period of time,
18 ten minutes, nine minutes, eight minutes, and then we
19 come up with a polarization index form.

20 MEMBER ABDEL-KHALIK: Now, do you expect
21 the degradation mechanism to be catastrophic or is it
22 a gradual degradation?

23 MR. PAUL: The testing that we perform
24 will only really show you a step change. These 4kV
25 cables are unshielded cable. Right now there is no

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1 test method to detect this fine water treeing failure
2 mechanism. There's no good test at this point, no
3 proven test for detecting water treeing on unshielded
4 cable.

5 MEMBER SIEBER: Now, the services in
6 question, one could say fire protection is one of
7 them, the diesel power pumps. The service water, you
8 have two intake structures where most plants have one.

9 So you have separate cable routings depending on
10 which intake structure you're using and they're both
11 available to both units.

12 So you have built-in redundancy in case
13 you get a failure in one cable line, the other intake
14 structure, and with full capacity pump, pumps are
15 still there. Is that correct?

16 MR. PAUL: Yes, yes, it is.

17 MEMBER SIEBER: It is to redundancy that
18 you don't find in other plants.

19 MEMBER ABDEL-KHALIK: I guess the question
20 still remains. I'm still trying to understand the
21 failure mechanism and whether the testing that you are
22 doing will really given you an early indication of
23 potential failure. Is this a catastrophic failure or
24 a gradual degradation of performance?

25 MR. CUSTER: Go ahead, Brian.

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1 MR. MURTAGH: Brian Murtagh from Design
2 Engineering.

3 The failure that we expect, we don't
4 expect the failure I guess is really the question. Do
5 we expect a catastrophic failure? The answer is no
6 and that's based upon the service life of the cables
7 that we have, the OE from within the industry, and the
8 discussion of the HTK cables and specific failures
9 that we talked about with the Carite folks. There
10 have been no identified failures, either within the
11 nuclear industry or outside, due to submergence.

12 MEMBER STETKAR: Of HTK cables?

13 MR. MURTAGH: Of HTK cables.

14 MEMBER STETKAR: And there aren't many HTK
15 cables out there in water conditions if you look at at
16 least the industry's response to the general letter?

17 MR. MURTAGH: For the industry response.

18 MEMBER STETKAR: For the industries, there
19 are some.

20 MR. MURTAGH: There are some.

21 MEMBER STETKAR: But not that much. So
22 that happens to be the cable type, but there isn't an
23 awful lot of experience with it because most of the
24 plants --

25 MR. MURTAGH: But there also are cable

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1 applications outside of nuclear in the commercial
2 world, too.

3 MEMBER STETKAR: Okay. Those don't --
4 those I don't know about. The question about your
5 intake structures, are --

6 CHAIR BLEY: Before you do that, one last
7 simpleminded question to these guys if I might? This
8 is really a naive question.

9 You pull the cables. It's all one cable.
10 You don't have any splices. But I take it you needed
11 to put the manholes in along the path to enable the
12 cable pulls. Is that the reason or just to have
13 access for later?

14 MR. PAUL: Correct. The manholes were put
15 in there to facilitate the cable installations.

16 CHAIR BLEY: So you can only pull in 100-
17 foot sections or something. I'm sorry, John.

18 MEMBER STETKAR: That's okay.

19 MEMBER BROWN: Let me provide one other
20 piece of information for Said. I had an experience
21 with two 4160 volt system cable-type failure. They
22 were not in the cable itself. They were in the
23 connection. When they did fail, they exploded, blew a
24 switchboard apart, almost killed a couple of people.
25 It was a real fireball.

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1 That's an error, and 450 will do it, but
2 it does it not quite as brilliantly. What it does in
3 water, I was just trying to think what would happen if
4 you had some internal 4160 volt phase-to-phase
5 degradation due to whatever failures had due to the
6 water, what that would do, I don't know. I can't
7 visualize it right now.

8 MEMBER STETKAR: That depends on the
9 quality.

10 MEMBER BROWN: When it goes, it's
11 spectacular. That's an error. I mean it's really
12 spectacular.

13 MEMBER ARMIJO: The way I understood
14 Said's question was, is the test you're using capable
15 of detecting progressive degradation or is it only
16 good when you just run out of insulation cable?

17 MR. PAUL: You might know, a meggar test
18 is pretty much a go-no-go-no-go.

19 MEMBER ARMIJO: You're almost at failure
20 when you detect something?

21 MEMBER BROWN: No, no, no, no, that's not
22 the case. You're measuring leakage current through
23 the insulation to ground. They're doing it with DC.
24 I think you said a DC. So you just apply the voltage.
25 It's not a dielectric strength test. It's literally

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1 just an insulation, and you can see the insulation
2 resistance in error. Let me caveat what I just said.

3 You can see it gradually to grade and we do that.
4 We've done that -- that's a maintenance issue.

5 MEMBER ARMIJO: The test does measure
6 degradation of the insulation?

7 MEMBER BROWN: Yes, you can. Again, in
8 water, the rate of -- yes, I can't tell you what it
9 is. An error, you know, somewhat depending on the
10 environmental factors, you can detect it, yes.

11 MEMBER STETKAR: A simpler question, where
12 are your circ water pumps located? Are they in the
13 same intake structures?

14 MR. CUSTER: No, they are not.

15 MEMBER SIEBER: The cooling towers,
16 there's a separate house.

17 MEMBER STETKAR: Okay. Never mind.
18 Thanks.

19 CHAIR BLEY: Did you need more --

20 MEMBER BROWN: No. I just wanted to
21 provide that little bit.

22 MR. CUSTER: Okay.

23 MR. MANOLERAS: Okay. Again, I appreciate
24 the opportunity. Beaver Valley appreciates the
25 opportunity to come and present this application to

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1 the ACRS. We've talked about the license renewal
2 application and its consistency with the GALL, and
3 we've also discussed the existing new and plant-
4 specific programs.

5 Again, I'd like to thank the Board for the
6 opportunity to present this.

7 CHAIR BLEY: Thank you. I guess we
8 finished a little early.

9 MR. BARTON: I've got a question for them.

10 Switchyard, these switchyard components
11 are owned by two different companies, right, FENOC and
12 Duquesne Light?

13 MR. MANOLERAS: That's correct.

14 MR. BARTON: Now, when those two companies
15 do work in the switchyard, how does the plant control
16 that work, or how is that that work is going on? How
17 do you manage those companies working in your
18 switchyard?

19 MR. MANOLERAS: Yes. Very simply,
20 Duquesne Light will do work in our switchyard, as will
21 FirstEnergy. Any work is routed through our control
22 room staff and we are very cognizant of any work that
23 goes on up in the switchyard. We have access control
24 procedures at the site.

25 MR. BARTON: You control access to the

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1 switchyard?

2 MR. MANOLERAS: That's correct.

3 MEMBER SIEBER: It seems to me there was
4 two keys and two locks had to be opened to get in and
5 the control room had one of them?

6 MR. MELTZER: Any work that's done in our
7 switchyard, our control room staff is definitely
8 cognizant of it and obviously must approve that work.

9 MEMBER STETKAR: I had a question. This
10 is a danger of finishing too early.

11 (Laughter.)

12 MEMBER STETKAR: In terms of scoping, you
13 concluded that the fire protection systems for the
14 station service transformers were out of scope
15 apparently because the failures of the station service
16 transformers would not affect the ability to achieve
17 safe shutdown. And yet the station service
18 transformers are your off-site power supplies.

19 So I was curious why the fire protection
20 systems for those transformers were not in scope?

21 MR. THOMAS: Fire protection for the
22 transformers is not addressed in the safe shutdown
23 report. If they burn, it's assumed that they're the
24 cause of the fire, not a fire there causes loss of the
25 transformer. There's no other combustibles in the

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1 area.

2 MEMBER ABDEL-KHALIK: Back to the cable
3 testing question. You indicated that the testing
4 method you are using will give you an indication of
5 gradual degradation of the cable insulation.

6 Do you have criteria as to when you
7 declare these cables to be unacceptable?

8 MR. MANOLERAS: Brian, would you respond
9 to the gentleman's question?

10 MR. PAUL: When we perform a meggar test,
11 our acceptance criteria for a meggar test is greater
12 than 100 megohm resistance. Typically, our numbers
13 are 10 times that.

14 We'd expect that if we were seeing a cable
15 degrade, that we would see a step change, a real step
16 change. You're not going to see this very gradual
17 change. You'll see a big step change in a meggar
18 test.

19 MEMBER ABDEL-KHALIK: So there is a huge
20 difference between the current --

21 MR. PAUL: Well, as I said
22 earlier --

23 MEMBER ABDEL-KHALIK: -- and where you
24 would declare it to be unacceptable?

25 MR. PAUL: As I said earlier, a meggar

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1 test is more of a go-no-go. Your cables are either
2 good or you've really got some questions.

3 MEMBER ABDEL-KHALIK: Thanks.

4 MEMBER BROWN: Let me ask a question, and,
5 again, there's a problem with having too much time.

6 You expect a step change. I mean the
7 experience I had in the naval vessels we did, we used
8 a meggar check periodically as a preventative
9 maintenance feature and we did not see step changes.
10 We normally looked for it and tracked gradual changes.

11 Now, that's in air, I admit, not in a
12 submerged cable, but I was a little bit curious as to
13 what's the basis for expecting a step change in the
14 circumstance, technical basis.

15 MR. PAUL: Well, let me correct myself.
16 Okay. First of all --

17 MEMBER BROWN: Unless it just totally
18 fails, then I understand the step change.

19 MR. PAUL: Right. And we've always
20 considered meggar testing go/no-go. You're either
21 getting a number that's acceptable or not. And,
22 again, our numbers haven't even shown signs of any
23 sort of degradation here.

24 MEMBER BROWN: So you really don't know.
25 You haven't seen a step change --

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1 MR. PAUL: We haven't seen any step
2 change.

3 MEMBER BROWN: So you don't know if it
4 would be a step change or a gradual -- the numbers
5 you've seen have been relatively stable?

6 MR. PAUL: Correct.

7 MEMBER BROWN: Relatively. I mean they
8 haven't varied by factors of 10?

9 MR. PAUL: They haven't really shown any
10 signs of degradation.

11 MR. BARTON: Got a question. Emergency
12 diesel fuel oil storage tanks, I understand they're
13 underground?

14 MR. CUSTER: Yes.

15 MR. BARTON: Do you have any evidence of
16 any corrosion or wall thinning, or have you ever done
17 any UTs or anything on those tanks in 30 years?

18 MR. THOMAS: We have periodical drain,
19 clean and inspect the tanks.

20 MR. BARTON: Inspect them, is visual or do
21 you do any UT on tank bottoms?

22 MR. THOMAS: The ones that are buried is a
23 visual from inside and there hasn't been any
24 significant corrosion.

25 MR. BARTON: Okay.

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1 MEMBER SIEBER: They aren't directly
2 buried, are they? They're in a cubicle?

3 MR. THOMAS: No. The Unit 1 tanks are
4 buried and the Unit 2 tanks are actually in concrete.

5 MEMBER SIEBER: Yes. Right.

6 CHAIR BLEY: Any other questions?

7 (No response.)

8 CHAIR BLEY: I guess then at this point we
9 may as well take a break and come back to you guys
10 after the break. So we'll come back at quarter after
11 by this clock.

12 (Whereupon, the above-entitled matter went
13 off the record at 2:48 p.m. and resumed at 3:14 p.m.)

14 CHAIR BLEY: Okay. I think we're back in
15 session. I think at this time we'll turn it over to
16 the NRC, Brian Holian, again.

17 MR. HOLIAN: Good. Thank you.

18 Moving on as you start to look forward to
19 our aspect and, fortunately, discussion. I just
20 wanted to mention the individual up there at the table
21 helping with the slides is Kim Green, Project Manager
22 for Indian Point. She is up there just helping Kent.
23 You will see Kim next month on the Indian Point
24 presentation and, hopefully, you'll see some e-mails
25 from Kim addressing some of those open items as she

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1 works towards next month here on Indian Point.

2 Just a couple of statements on what you
3 heard from the licensee's presentation and you'll hear
4 more not only from the two individuals, but, also,
5 some of the NRC staff.

6 We are prepared to discuss the Boral issue
7 in a little more depth, also. We have staff here. It
8 is a current operating issue. There's a Region 3
9 plant, Palisades, had the confirmatory action letter
10 just a few months ago on Boral, and so it is an item,
11 also, that crosses both license renewal and the
12 operating plants as we make sure that they manage and
13 have a test program in place. So I just wanted to
14 mention that.

15 The electrical cable issue, we're aware of
16 it. Our electrical staff is also here to give further
17 guidance in that area, and, also, kind of what we've
18 looked at generically. I was glad to see that the
19 ACRS had some of that generic letter data that came
20 back to reference, but we, also, can summarize that.

21 And then, finally, the last item that I
22 just wanted to mention up front was on the liner and
23 corrosion on the liner that occurred during the steam
24 generator replacement really was found in the steam
25 generator replacement project. I just wanted to

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1 mention that did not come up necessarily during the
2 license renewal reviews.

3 It did come up right away and the region
4 even included it in an inspection report back there in
5 the 2006 time frame. There were discussions with the
6 Division of Engineering at headquarters as even in
7 realtime there. The region and headquarters looked at
8 that corrosion, the extent of it, and why it was okay
9 both to button up and continue operation. So I just
10 wanted to mention that.

11 With that, I'll turn it over to -- Yes?

12 MEMBER RAY: Brian, on that point, a
13 comment was made several times that the liner is just
14 a membrane. I don't think that's correct that it's
15 just a membrane, but correct me if you disagree.

16 MR. HOLIAN: Maybe the staff can help when
17 we get to that. I understand that you want more than
18 molecule there and you want it there for a further
19 issue, but let's pick that up when we get there.
20 Thank you.

21 Kent, go ahead.

22 MR. HOWARD: Good afternoon. My name is
23 Kent Howard. I am the Project Manager for the Beaver
24 Valley Power Station, Units 1 and 2 license renewal
25 Application.

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1 For today's discussion, we will be
2 discussing the staff's review of the Beaver Valley
3 LRA. Seated to my right is Mr. John Richmond. John
4 was the senior inspector for the license renewal
5 inspections that took place in June and July of 2008,
6 and John will be presenting the results of those
7 inspections during today's presentation.

8 Also with us seated in the audience are
9 members of the NRC staff that participated in the
10 reviews that are contained within the Beaver Valley
11 safety evaluation report and they're here to answer
12 any question that you may have.

13 Next slide.

14 For today's presentation I'll start with a
15 brief overview of the application, followed by section
16 2, the scoping and screening review results. John
17 will present the license renewal inspections. I'll
18 pick back up at section 3, the aging management review
19 results. We'll finish up with section 4, the time-
20 limited aging analyses.

21 Next slide.

22 For this slide, this is a rehash of what
23 the applicant has already stated, but I'll walk
24 through it any way. The license renewal application
25 was submitted by a letter dated August 27th, 2007.

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1 Both units are Westinghouse 3-loop pressurized water
2 reactors. They're rated at 2900 megawatts thermals.

3 The operating license for Unit 1 expires
4 January the 29th, 2016. The operating license for Unit
5 2 expires May 27th, 2027. The location of the plant is
6 approximately 17 miles west of McCandless,
7 Pennsylvania, or about 25 miles northwest of
8 Pittsburgh on the south bank of the Ohio River.

9 Next slide.

10 The safety evaluation report with open
11 item was issued on January the 9th, 2009. There is one
12 open item. There were 249 RAIs issued.

13 MR. BARTON: Is that a lot, about normal,
14 or is that too little, too many, what, RAIs?

15 MR. HOWARD: Considering that we did not
16 use a Q&A database, I think it's about right.

17 There are 31 commitments for Unit 1, 32
18 for Unit 2. Unit 2 has an additional commitment to
19 implement the electrical pole structures inspection
20 program five years prior to the period of extended
21 operation. So that's the difference in the number of
22 commitments.

23 Next slide.

24 Scoping and screening methodology audit
25 took place the week of December the 3rd through 7th,

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1 2007. The aging management programs audit took place
2 the week of March 3rd through 7, 2008. The regional
3 license renewal inspections took place the weeks of
4 June 23rd through 27, 2008, and July 14th through 18th,
5 2008.

6 Next slide, please.

7 Section 2, structures and components
8 subject to aging management review, section 2.1,
9 scoping and screening methodology.

10 The staff's audio and review concluded
11 that the applicant's methodology is consistent with
12 the requirements of 10 CFR 54.4. and 10 CFR
13 54.21(a)(1).

14 Next slide, please.

15 Section 2.2, plant-level scoping results,
16 components brought into scope.

17 Based on the staff's review, the north
18 pipe trench was added to the scop of the license
19 renewal because the scoping endpoint of a non-safety
20 related pipe directly attached to safety-related
21 piping in the Beaver Valley Power Station Unit 2 valve
22 pit was determined to be located within the north pipe
23 trench.

24 There was a pipe hanger that was located
25 within the pipe trench.

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1 Next slide.

2 Section 2.3, scoping and screening
3 results, mechanical systems.

4 There are 48 mechanical systems. They
5 were 100 percent reviewed, the BOP system, balance of
6 plant systems. There are 34 balance of plant systems.
7 The staff performs a two-tier review.

8 There's a Tier 1 review. For Beaver
9 Valley there were six systems. The Tier 1 review is
10 based upon a review of the LRA and the UFSAR. The
11 Tier 2 review consisted of 28 systems and is based
12 upon a detailed review of the boundary drawings, the
13 LRA and the updated file safety analysis report.

14 Next slide.

15 Section 2.4, scoping and screening
16 results, structures.

17 With the inclusion of the north pipe
18 trench, the staff found no additional omissions of
19 structural components within the scope of license
20 renewal.

21 Next slide.

22 Section 2.5, electrical and
23 instrumentation and control systems.

24 The staff found no omission of electrical
25 and instrumentation and control system components

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1 within the scope of license renewal.

2 Summarizing Section 2, the staff found the
3 applicant's scoping and screening review results meets
4 the requirements of 10 CFR 54.4 and 10 CFR
5 54.21(a)(1).

6 And at this point, we have John presenting
7 his portion of the presentation.

8 MR. RICHMOND: Afternoon.

9 MR. BARTON: Before you go on, I've got a
10 question. On the scoping and stuff, and everything
11 was hunky-dory, I've got a question. Maybe it's just
12 I don't understand design of plant.

13 There's an aging management program called
14 metal-enclosed bus and the formula is only applicable
15 to Unit 2. Does that mean there's no metal-enclosed
16 bus in Unit 1? I don't understand that.

17 MR. HOWARD: I would defer that question
18 to Mr. Duc Nguyen.

19 MR. NGUYEN: My name is Duc Nguyen. I'm
20 the Review Electrical.

21 When we went to the side, we asked the
22 applicant that question and we also reviewed the
23 drawing. For the Unit 1, they don't have a metal-
24 enclosed bus, only Unit 2. The Unit 1, they use what
25 they call a cable bus and the cable bus is designed

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1 different from the metal-enclosed bus.

2 The cable bus has insulation, and, also,
3 it has an enclosure. So the aging effect, we have not
4 identified any aging effect, but the metal-enclosed
5 bus because of the bus barred, so the moisture can get
6 into. So we found a problem with the metal-enclosed
7 bus only. So Unit 1, they don't have any metal-
8 enclosed bus.

9 MR. BARTON: Okay. Thank you.

10 MR. RICHMOND: Okay.

11 MEMBER BONACA: How different are Unit 1
12 and Unit 2? Clear, Unit 2 was staffed after PMI. So
13 we're probably backed very much by PMI, I'm trying to
14 understand the difference between the commitments that
15 you have for Unit 1 and Unit 2.

16 MR. HOWARD: Like I said, for Unit 2,
17 there is an additional commitment for the wood pole
18 structures. Unit 1 did not have any wood poles or
19 structures that were within the scope of license
20 renewals.

21 MEMBER BONACA: Right.

22 MR. HOWARD: That's the additional
23 commitment right there.

24 MEMBER BONACA: And the rest of the plants
25 are very much safe?

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1 MR. HOWARD: Yes.

2 MEMBER BONACA: Thank you.

3 MR. RICHMOND: Okay. John Richmond. I
4 led the team. We had five team members, plus myself.
5 Manny Seyac from license renewal was with us for the
6 first week on site. And we had a Korean observer from
7 the Korean NRC, which made it an interesting two
8 weeks.

9 Next slide.

10 We look at some things that are pretty
11 much the same from inspection to inspection. We
12 looked at scoping and screening, and we looked for the
13 non-safety effects safety aspects. We get out in the
14 field and we eyeball drawings in hand.

15 We reviewed 19 of 42 AMPs, aging
16 management programs, and when we look at an aging
17 management program, we look at program documents and
18 procedures, walkdowns, and we interviewed plant
19 personnel. And what we're really trying to do is
20 figure out is the proposed program that they have,
21 does it look like it's going to work and does it look
22 like it will satisfy the requirements in GALL, the
23 recommendations.

24 CHAIR BLEY: That's about half of the
25 programs.

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1 MR. RICHMOND: Yes.

2 CHAIR BLEY: How did you decide which ones
3 to look at and which ones not to?

4 MR. RICHMOND: Good question. Some things
5 we know we always want to look at, and then we'll ask
6 the individual inspectors to take their pick, see what
7 they like. We get input from headquarters. We got
8 input from both Manny and from Kent, and we take input
9 from the residents, and DRP, and from other regional
10 inspectors.

11 And we ask question like where do you
12 think there are weaknesses in the programs, what's
13 worth looking at. Sometimes you get good ideas and
14 sometimes you get a shoulder shrug that says, you
15 know, it's all the same.

16 In this case, we got some good input. One
17 of the things we got coming out of headquarters was
18 would you please look in the manholes and see whether
19 they're wet or dry. And we look at operating
20 experience.

21 And we did something a little bit
22 different with Beaver Valley. We did a review of
23 their method for doing their operating experience
24 review. We looked at how they did their operating
25 experience review, and then we did the standard

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1 regional thing where we look at the individual
2 operating experience that they've got, plant-specific
3 stuff, condition reports.

4 For the different system, the components
5 that we review in the aging management programs. And
6 in the area of operating experience review, we look to
7 see if their method was in conformance with NEI
8 95-10, which is the guidance that we endorse for the
9 reg guide.

10 Next slide.

11 Inspection results. I've always said that
12 our inspection is focused on some of the audit issues
13 and regional inspection issues that we've seen in the
14 past. The application changes that came about as a
15 result of our inspection, I think there were three
16 that I think are more significant or more interesting
17 than the others.

18 First was inaccessible medium voltage
19 cables. We looked in the manholes and we saw water.
20 We looked at the PM history. They had a quarter of a
21 PM to go in and inspect some of the manholes. We
22 looked at the PM history, and PMs typically show that
23 the manholes had water in them.

24 Based on that, looking at several years'
25 worth of PMs, it became apparent, at least on a

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1 quarterly basis, open and inspect the manhole, you
2 ought to be successful to keep the cables dry.

3 The other things we noted, however, was
4 that FENOC's operating experience review for this
5 aging management program for cables didn't identify
6 any problems in the area of manholes and water and we
7 thought that was a deficiency in their review
8 initially.

9 MR. BARTON: Did you guys consider the
10 corrective action program was effective in handling
11 this issue?

12 MR. RICHMOND: In the past? If you're
13 asking in the past if their corrective action program
14 --

15 MR. BARTON: You go out there and you
16 looked at this problem and you looked at the
17 corrective action program, did you feel the corrective
18 action program was effective in handling this issue?

19 MR. RICHMOND: I think the corrective
20 action program in the past has taken a very low-level
21 view of the issue. I think the corrective action
22 program in the past has taken a broke-fix perspective.

23 MR. BARTON: Well, based on that, did you
24 perform an assessment of the corrective action program
25 to see if it was effective?

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1 MR. RICHMOND: What we did was insure that
2 they put the issue into their corrective action
3 program and there will be either regional follow-up or
4 resident follow-up on their corrective action program
5 results based on the risk-significance of the issues.

6 MR. HOLIAN: This is Brian Holian. John,
7 maybe either you can give the perspective or Ron
8 Bellamy can give it on the site's corrective action
9 program and what the region does routinely.

10 MR. RICHMOND: Routinely, there's a
11 corrective action program inspection that goes on
12 every two years and the residents do corrective action
13 reviews throughout the year. In addition to that,
14 there's about a half a dozen focused problem
15 identification resolution sample inspections that go
16 on during any given year. So the DRP, the residents,
17 and the regional inspectors have an opportunity to
18 pick and choose which issues within the corrective
19 action program they'll do a focused review on during
20 the year, and then on a biannual basis a complete
21 review is done of their corrective action program.

22 MR. BARTON: So what I hear, the bottom
23 line is that the program is effective in the NRC's
24 mind?

25 MR. HOLIAN: I think you'll hear an answer

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1 from the -- well, not the regional interest. But that
2 regional answer is, in general, a good corrective
3 action program, and, if not, one that would be you
4 have a cross-cutting item or further actions in the
5 ROP action matrix would be the answer that.

6 This is probably the time to bring up this
7 cable issue. You know, we're attacking it from the
8 NRC from two different ways. One you heard during the
9 licensee's presentation and we can give further
10 information on it is whether the licensee just hangs
11 their hat on their submerged and their qualified to be
12 submerged.

13 Well, the NRC has not bought off on that.

14 They need to send us more additional information, and
15 whether that happens or not, we'll see. We were
16 talking at the break and some of the members might
17 remember Wolf Creek, also, just a few months ago had
18 tried that tact and there were enough questions left
19 that they didn't go that way.

20 The other way to go is just make sure you
21 have a good aging management program that we'll go
22 ahead and follow up on, you know, de-watering
23 inspecting and inspecting the cables. So that's the
24 second tact and probably one of the reasons why
25 headquarters pushed the region or asked also look at

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1 the good operating experience whether they have it or
2 not and put a little bit of pressure on or just
3 question how they're dealing in this area of operating
4 experience should they end up crediting that aspect.

5 So that piece, also, they put it in their
6 corrective action program, which you hear from John
7 Richmond that the region questioned. If you're going
8 to credit aspect or that program, you know, expect to
9 hear from us again on is quarterly pump downs
10 effective, et cetera.

11 Does that help?

12 MR. BARTON: Yes.

13 CHAIR BLEY: Let me sneak a follow-up on
14 that.

15 We heard, if I heard correctly, I assume
16 correctly, Beaver Valley saying they always expected
17 these manholes would flood because of their location
18 and they pump them down to in and inspect and let them
19 fill up and put cable in they thought was just fine
20 for that kind of application.

21 Has NRC always understood that, or is that
22 something that's kind of new from these recent
23 inspections?

24 MR. RICHMOND: May I ask Duc?

25 MR. NGUYEN: This is Duc Nguyen.

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1 The water manhole is not new to us. We
2 know that the manhole collect the water because where
3 the manhole connects to the conduit or cable train is
4 always slow. So to prevent the water to collect in
5 the conduit, the water only collects in the manhole.

6 The problem is that the water is high
7 enough for the cable to be submerged because usually
8 cable is on several levels and the applicant's plan
9 expanded when you have the 4.6 kilowatt over the
10 higher altitude.

11 But, you know, cable and water do not go
12 together except the submarine cable. So the staff
13 reviewed the qualification and we are asking the
14 applicant to provide additional information from the
15 vendor, so we will still review that.

16 MR. HOLIAN: So that part is still
17 reviewing. This is Brian Holian.

18 The question on the table is, probably
19 other stated, is did the staff look at that for
20 original licensing of the plant. In other words, was
21 that a known position and did we buy off on knowing
22 that water would be in there for the extent of the
23 life. I don't know if we have that answer here.

24 CHAIR BLEY: And have you observed it over
25 the 30 years it's been known?

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1 MR. HOLIAN: Yes, for inspections and
2 that. I think this is clearly an area that the Agency
3 is delving into a little bit more on the generic
4 aspects of it and we can talk to that from the
5 electrical branch.

6 George, do you want to talk to that?

7 MR. WILSON: I'm George Wilson. I'm the
8 Electrical Engineering Branch Chief at NRR.

9 We knew that there was some problems with
10 cables getting submerged. That's why we wrote Generic
11 Letter 2007-01. With information and summary that we
12 got, Letter 2007-01, we looked at the tables and we
13 found compared to what we originally thought we were
14 getting from the industry, we thought there were a lot
15 more failures than what -- we didn't think they were
16 random because of the amount of number that we have.

17 You guys have the summary report. You've
18 looked at it. With 2007-01 there's some additional
19 action items that we're going to be doing. I have
20 regulatory guide that is being written. I've got a
21 user's need to research that says these are going to
22 be the effective characteristics of an effective cable
23 monitoring program.

24 So we're actually going to define what we
25 would like to see in a cable monitoring program, not

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1 just one test, but several tests and how you evaluate
2 the cables. So that's coming out and that should be
3 out by the end of December.

4 The other follow-up that is taking place
5 is we don't expect to see cables being submerged
6 unless they're submarine cables that are actually
7 built to be submerged and that's a special type of
8 cable and I think that you guys have mentioned what
9 that is.

10 So, in addition to that, there's been some
11 recommendations that we've made to change inspection
12 procedures that the NRC does. There's a couple
13 inspection procedures that we do when we look at
14 adverse weather and flooding. I personally wrote
15 changes to that to go out. Now, we're going to start
16 periodically having the licensees open the manholes
17 and look into them ourselves on our own frequency.

18 So the answer to the question is, no, we
19 do not expect to open up a manhole and see that the
20 cables in there are submerged unless they are
21 specifically procured for that and the only cable that
22 we know for that is a submarine cable that has a
23 special lead sheath.

24 MEMBER ARMIJO: And that's not HTK?

25 MR. WILSON: That is correct. That is not

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1 HTK Carite cable.

2 MR. BARTON: Thank you.

3 MEMBER BROWN: Doesn't that create a
4 conundrum as of now?

5 (Laughter.)

6 MEMBER MAYNARD: Not for us right now, but
7 it is between the applicant and the staff that stuff
8 has to be resolved.

9 MEMBER ARMIJO: John, did you get your
10 question answered?

11 MR. BARTON: Got that.

12 MEMBER ARMIJO: John, I was reading
13 something here, so forgive me if I missed something.

14 I recognize that for your inspection
15 you're pretty much only concerned with the cables that
16 are defined as being
17 in-scope for the license renewal. Did you look at any
18 other manholes? I mean you looked at the four where
19 you knew the in-scope cables went through these
20 manholes and you opened them up and you found water in
21 there. Did you open up any other manholes around to
22 see whether the water problem is pervasive?

23 MR. RICHMOND: We looked in four manholes.
24 Three manholes had in-scope cables and one manhole
25 did not and it had the least amount of water in it. I

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1 don't know if that answers your question.

2 MEMBER ARMIJO: Yes, that does. I'm just
3 curious.

4 MR. RICHMOND: Normally, we focus on just
5 looking at those things we need for our inspection.
6 So it's usually a fairly well-focused inspection.

7 MEMBER ARMIJO: This time you at least
8 looked in one additional manhole?

9 MR. RICHMOND: We did in a different
10 physical location from the others.

11 MEMBER ARMIJO: Yes. Thank you.

12 MR. RICHMOND: Okay. All right. We've
13 talked about cables.

14 The next issue that we thought was of more
15 significance for application changes was selective
16 leaching. The original program that was proposed was
17 an aging management program. It's a one-time
18 inspection. It goes out to verify that there's no
19 aging effect to manage.

20 And in looking at the CRs for the plant,
21 the condition reports for the plant, we identified
22 that they'd had selective leaching damage in pipe
23 replacement as a result for the buried fire header,
24 and, when we brought that back to their attention and
25 they looked at the issues in a little more depth, what

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1 they figured out was, in fact, that section piping had
2 had leaching damage in the past and they revised their
3 program to have a one-time inspection for selective
4 leaching except for buried fire pipe and that's going
5 to have a routine condition monitoring program as a
6 result.

7 MEMBER ARMIJO: Didn't they also have a
8 leaching problem on river water and service water
9 piping, or was it only the fire water piping?

10 MR. RICHMOND: It was the fire water
11 piping.

12 MEMBER ARMIJO: Just the firewater, okay.

13 MEMBER BONACA: You said one-time
14 inspection for which piping?

15 MR. RICHMOND: Well, the one-time
16 inspection looks at a number of different types of
17 piping throughout the plant. The problem was the fire
18 water is cast iron and they had buried fire water cast
19 iron piping that had leaching damage.

20 MEMBER BONACA: Could be a long-time
21 inspection to verify the degradation is not occurring?

22 MR. RICHMOND: Correct. That's the intent
23 of the one-time program is to verify that there isn't
24 an aging effect out there. In this case the plant
25 history clearly showed that they already had that

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1 aging effect for the buried cast iron pipe.

2 MEMBER BONACA: Right.

3 MR. RICHMOND: So they revised their
4 proposed program.

5 (Simultaneous speakers).

6 MR. RICHMOND: In order to have a
7 conditioned monitoring for the buried cast iron and a
8 one-time program, which was appropriate.

9 MEMBER BONACA: Yes, appropriate. Okay.

10 MR. RICHMOND: All right.

11 The next area was operating experience
12 reviews. As we've noted with the medium voltage
13 inaccessible cables and selective leaching, there was
14 specific plant operating experience that should have
15 resulted in different programs than they initially
16 proposed, and we asked them to take a look at how they
17 came to the conclusions they did based on the
18 operating experience we saw that they apparently
19 missed. And there's a slide in the package in another
20 slide or two where we'll talk about that in a little
21 more detail.

22 Next slide.

23 There were other application changes based
24 on aging management programs that they need to revise
25 based on the inspection and this is a list of six of

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1 them and I can go down the list for you.

2 One-time inspection, they had revised
3 their sample selection criteria.

4 Bolted cable connections, their proposed
5 program was originally based on an early draft version
6 of an interim staff guidance. Currently, that interim
7 staff guidance is out for public review and it's
8 changed quite a bit from the initial version and they
9 had to revise the program.

10 Fuel oil chemistry, they made some
11 revisions for buried fuel oil tank inspections.

12 Open cycle cooling, they made changes for
13 buried pipe inspections.

14 Structural monitoring and masonry wall,
15 they added administrative controls.

16 And external surfaces monitoring, they
17 added clarification to the scoping to ensure that
18 normally inaccessible areas would get included within
19 the scope of their routine inspections.

20 Next slide.

21 Operating experience issue, first, we
22 reviewed their method for how they conducted their
23 operating experience reviews and what we figured out
24 is that the FENOC procedures for conducting the
25 operating experience reviews were consistent with the

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1 NRC accepted guidance in NEI 95-10.

2 Now, we also note that NEI 95-10, section
3 4.4 says that "plant-specific operating experience
4 with existing programs should be considered." And
5 FENOC interpreted that to mean that no operating
6 experience reviews were required for new programs.

7 And we had asked them when we found the
8 two programs, like the leaching and the cables, how
9 that happened. They went back and they did an
10 extended condition review and they did an apparent
11 cause evaluation and they came back with the reason
12 that they hadn't reviewed operating experience for new
13 programs based on their interpretation and their
14 initial extended condition review didn't find any
15 additional misses as a result of what we saw and
16 additional questions by the audit team.

17 It turns out the audit team had the same
18 questions on operating experience reviews
19 independently, so two different groups pointing to the
20 same problem.

21 Yes?

22 MEMBER STETKAR: This is not, I mean you
23 raised the issue with FENOC, this disconnect between -
24 -

25 MR. RICHMOND: Yes.

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1 MEMBER STETKAR: -- the operating
2 experience review?

3 MR. RICHMOND: Right.

4 MEMBER STETKAR: Is the staff following up
5 on that with NEI to make sure that no other applicants
6 have the same misinterpretation so you don't run into
7 this disconnect in the future?

8 MR. RICHMOND: That sounds like a Brian
9 question.

10 MEMBER STETKAR: I hate to say in the
11 past, but the implication is obviously there, also.

12 MR. HOLIAN: The quick answer is that,
13 yes, we do have quarterly meetings with NEI and cover
14 a variety of topics, and Op experience is one that
15 we've been covering really since the IG report of a
16 couple years ago which criticized the staff for
17 probably not doing enough in the Op experience area.
18 So that's one area you're seeing that type of
19 interaction between us and the region on and, also,
20 the lessons learned.

21 The applicants do a pretty good job from
22 what we've seen of learning from each other. Several
23 members here at ACRS for upcoming applications, they
24 learn and review our request for additional
25 information. Somebody asked a question back earlier

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1 on that I was going to touch on on the number of REIs.

2 We are tracking those to try to
3 internally, at the NRC, to see if that's some
4 indication that the quality of submittals is going
5 down.

6 MR. BARTON: I look for it. If there's a
7 lot them, I say is it a poor application?

8 MR. HOLIAN: That's right. And we're
9 looking at that. And the short answer you had, I was
10 going to come back around, but I'll just address it
11 now.

12 We did have an audit process a couple
13 years ago and I touched on this in our presentation to
14 the ACRS a couple months ago just on license renewal
15 process and it was that -- so you will see a little
16 bit of a step change on some of these applications
17 with the number of REIs. We were trying to use some
18 of our audit time where we verified their consistency
19 with GALL to also do some of the SAR review while we
20 were on site, kind of an efficiency thing, and that
21 did seem to cut down on the number of REIs, and
22 probably, honestly, was a little more efficient.

23 But, on the other side of that, we were
24 getting how formal are we with officially asking the
25 questions and correspondence? We didn't have them

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1 docket those Qs and As that we asked on site.

2 So, in the short term there, we've told
3 you that we kind of minimize that. We've been
4 concentrating their Op experience reviews during those
5 audits and the GALL items, which was the prime item
6 that we have to get done. So that's why we did expect
7 to see an increase in the number of REIs. I wanted to
8 comment on that.

9 But, back to the other issue on Op
10 experience, I think the industry is learning from
11 that. We are pushing it with NEI and pushing it
12 internally with our own staff, too, to make sure we do
13 the extent that we believe we should do.

14 MR. RICHMOND: All right.

15 In follow-up to the operating experience
16 issue, FENOC's committed to perform an operating
17 experience review for the new aging management
18 programs prior to the period of extended operation.

19 Next slide.

20 Summary, pending the NRR review of their
21 cable qualifications, the inspection results support a
22 conclusion that there's reasonable assurance that the
23 effects of aging will be adequately managed. Our
24 review of scoping of non-safety systems was
25 acceptable, and their documentation supporting the

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1 application was auditable and retrievable.

2 Next slide.

3 Question?

4 MEMBER STETKAR: I think I've asked this
5 before, but I'll ask it again.

6 The scoping of non-safety system, I notice
7 that the main condenser and the feedwater system were
8 considered in scope. I'm sorry. You did a more, in-
9 depth review of the main feedwater and the main
10 condenser, but not the condensate system, and I'm
11 always curious about why that is.

12 MR. RICHMOND: Excellent question. Let me
13 explain.

14 What we do is we do a focused review of a
15 small system or a piece of a system. In this case, I
16 think we picked the security diesel and the dedicated
17 aux feedwater pump on Unit 1. And the reason we do
18 that is then we have a single inspector that does a
19 dedicated review to verify that all of the different
20 aging management programs that should be used to
21 manage effects of aging for the system is an entity
22 got done. That's a vertical slice.

23 MEMBER STETKAR: Yes.

24 MR. RICHMOND: So in one regard of the
25 standard inspection that we do is a horizontal view,

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1 programmatic review, and then we do a vertical slice
2 that cuts boundaries of all the different aging
3 management programs.

4 Did that answer you?

5 MEMBER STETKAR: I'm not sure. What I was
6 talking about was -- you kind of categorized -- this
7 might be in the region. It might be in general for
8 the staff. You tend to categorize systems into what
9 you call a Tier 1 and a Tier 2 review.

10 Tier 2 systems receive a more thorough
11 examination I guess as far as scoping, boundaries and
12 scoping and things like. Tier 1 systems are generally
13 considered to be relatively insignificant. They
14 receive a rather cursory review.

15 And within that context the main condenser
16 and the feedwater system are considered to be Tier 2
17 system that receive more in-depth examination from the
18 staff's point, and the condensate system is considered
19 to be a Tier 1 system. I'm just not sure why that is
20 since the condensate system connects in between two
21 Tier 2 things. I mean the feedwater system can't work
22 without the condensate system, and the condensate
23 system can't work without the condenser. So I was
24 just curious.

25 MR. RICHMOND: Stan Gardocki.

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1 MR. GARDOCKI: You work for the balance
2 plant.

3 We have a lot of systems that we review.
4 So we came up with this methodology called Tier 1/Tier
5 2, try to focus on what's most important to review.
6 So the detail review, we have criteria. There's three
7 basic criteria that's explained in the SCR.

8 If it's of high safety significance, we
9 put it in Tier 2. If it's a system that can cause a
10 common-cause failure, we put it in Tier 2. Or if it's
11 a system that has an industry experience that we see
12 with former reviews that they missed something, we put
13 that in Tier 2. So the ones that don't fall in that
14 criteria, we can drop in Tier 1.

15 MEMBER ARMIJO: I understand those, and,
16 yet, I'll come back to the fact that the main
17 condenser goes into Tier 2 and the main feedwater goes
18 into Tier 2, and, yet, the thing that connects those
19 two is in Tier 1, and, therefore, main feedwater and
20 the main condenser must satisfy at least one of those
21 three criteria, high safety significance or observe
22 problems or potential for common-cause type failures.

23 The main condenser and the main feedwater
24 system must satisfy at least one of those three
25 criteria because it's categorized as Tier 2.

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1 MR. GARDOCKI: Right.

2 MEMBER ARMIJO: What I'm curious about is
3 why does the main condensate system not satisfy any of
4 those criteria since it delivers water from the main
5 condenser to the main feedwater system?

6 MR. GARDOCKI: Well, there's definitions
7 that sometimes put them in there. Like the main
8 condensor is sometimes used for plate-out concerns.
9 In previous reviews we've seen applicants miss because
10 there's so many connections to the condenser. We'll
11 put the condenser in review for that particular
12 purpose to make sure all those connections, inner
13 ties, and isolations boundaries are there to make sure
14 you've got a boundary for that plate-out concern that
15 they put in there for a functional (a)(2).

16 The feedwater is always in there for
17 concerns that they have proper isolation for the
18 (a)(1) functions and some issues with the regulating
19 valves, the block valves for redundant isolations.

20 MEMBER ARMIJO: If it's in there for that
21 purpose, the isolation function, not the heat removal
22 function, that I understand.

23 MR. GARDOCKI: All right.

24 MEMBER ARMIJO: Okay. Thanks.

25 MR. GARDOCKI: That's feedwater we always

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1 put in scope for (a)(1) for the heat removal
2 functions.

3 MEMBER ARMIJO: Okay. Thanks. That helps
4 me a lot. Thanks.

5 MR. RICHMOND: Okay. The next three
6 slides are just review of current plant performance
7 using the reactor oversight process. Performance
8 indicators are all green.

9 Next slide, please, Unit 1.

10 Next slide, Unit 2.

11 Both units are currently in the licensing
12 response band. That's the least intrusive from the
13 reactor oversight process perspective. The plants are
14 relatively good performers and there aren't any
15 significant issues at the plants from at least the
16 reactor oversight process at this point, no cross-
17 cutting issues.

18 That really concludes the regional
19 inspection portion of this. Any questions on the
20 inspection itself, what we did and why?

21 MR. BARTON: I had a question on your
22 inspection report.

23 MR. RICHMOND: Yes.

24 MR. BARTON: I was really disappointed.
25 Every inspection report, you do so many walkdowns, you

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1 look at systems, you walk that with system engineers.

2 You always make the comment about what you think the
3 material condition in a plant is and I didn't find
4 that in this inspection report.

5 So what is your assessment of the material
6 condition in the plant?

7 MR. RICHMOND: Well, I would have to say
8 that based on having been there and seen the plant and
9 compared that to other plants, I'd say the material
10 condition of the plant is generally good, a little
11 above average.

12 MR. BARTON: Thank you.

13 CHAIR BLEY: Go ahead.

14 MR. HOWARD: Section 3, aging management
15 review results.

16 For this section, unlike in section 2
17 where we stepped through each section, I'd like to
18 highlight certain portions of the staff review for
19 section 3.

20 Next slide.

21 Section 3.0.3, aging management programs,
22 as the applicant covered in their presentation, our
23 numbers line up with theirs with one exception. They
24 included in their count the boral surveillance
25 program. We didn't include it in our because it

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1 arrived after the NCR open item was issued on January
2 the 9th. The program is still being evaluated by the
3 staff. So it was included in their count, whereas it
4 wasn't included in ours.

5 Next slide.

6 Section 3.0.3.1.11, inaccessible medium-
7 voltage cables not subject to 10 CFR 50.49
8 environmental qualification requirements program.

9 This section is where our open item is
10 located. The staff is concerned that inaccessible
11 medium-voltage cables that have been submerged for a
12 period of time may be degraded and may not perform
13 their intended function during the period of extended
14 operation.

15 The applicant has not used operating
16 experience to adjust manhole inspection frequency
17 and/or automatic means if frequent inspection fails to
18 keep the cables dry. The applicant has provided
19 additional supplement information regarding cable
20 qualification, which is under review by the staff.

21 Next slide.

22 For this slide, this is the groundwater
23 analysis results. The applicant took samples in 2003
24 and 2007. The 2003 samples, the pH was 6.87. The
25 chlorides were 44.6, and the sulfate were 1.2. That's

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1 all per the acceptance criteria.

2 For 2007 there were two samples taken.
3 For the first sample, the pH was 7.12. The chlorides
4 were 18.9 ppm. The sulfates were 177. For the second
5 sample, this sample was taken during the winter time
6 next to a roadway where they salt the road.

7 (Laughter.)

8 MR. HOWARD: The pH was 6.83. The
9 chlorides were 208 and the sulfates were 187. Beaver
10 Valley Power Station groundwater is non-aggressive and
11 groundwater testing will begin five years prior to the
12 period of extended operation for each unit, then
13 continue on a five year interval thereafter.

14 MEMBER RAY: Before you go on, would you
15 back up to the preceding slide. I just want to ask a
16 simple question. I was trying to figure out why I
17 couldn't get my question out fast enough.

18 What are the implications of this
19 conclusion here, relative to the Generic Letter on the
20 subject of submerged cables? In other words, is all
21 the information requested by the Generic Letter
22 provided, but that's insufficient for the purpose at
23 hand?

24 MR. HOWARD: I'll defer that question.

25 MR. WILSON: The Generic Letter just asks

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1 for the amount of failures that they had. We just
2 want to clarify and gather data to see if we need to
3 take any further regulatory actions with that. So
4 when a licensee gave us their data across the
5 industry, we just captured the data, quantified the
6 data, and put in tables for us to see where the
7 failure was and how it was.

8 So to answer the Generic Letter question,
9 all they had to do was to give us the amount of
10 failures and then describe their cable program. So
11 this --

12 MEMBER RAY: It's really the cable program
13 I'm asking about because the Generic Letter does way
14 the purpose was to ask licensees to provide
15 information on the monitoring of inaccessible or
16 underground electrical cables.

17 I just want to know did they do that and
18 was that satisfactory?

19 MR. WILSON: Right. We've closed out
20 Generic Letter 2007-01, but I told you we have some
21 follow-up actions out of it. There's a couple of
22 follow-up actions.

23 One is I have a users' needs to research
24 to write a regulatory guide. The regulatory guide is
25 going to describe the effective characteristics of a

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1 cable-monitoring program. All right. So that was a
2 follow-up because we looked. There is not a
3 consistent way across the industry that they're
4 testing cables.

5 MEMBER RAY: Okay. So basically you're
6 saying they told you what they did, but now you've
7 taken that information --

8 MR. WILSON: Now take that information and
9 follow up with the regulatory, come with a reg guide
10 and some other information for the industry if that
11 answers your question?

12 MEMBER RAY: Yes.

13 MR. WILSON: Okay.

14 MEMBER RAY: And by December of 2009 if I
15 read this?

16 MR. WILSON: That is correct. I'm
17 supposed to have the draft by June, but that's the
18 draft for me to look at and my staff. It should be
19 out to the industry by December.

20 Yes?

21 MEMBER SIEBER: Just for curiosity, one of
22 the items to be reported was cable failures that have
23 occurred. How many have occurred?

24 MR. WILSON: Roy, do you have the exact
25 number? 269? And we separated those out from

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1 installation and we looked at the testing failures and
2 so we've separated them out on that. I just didn't
3 know the exact number because I had correlated the
4 number differently, so 269.

5 MEMBER SIEBER: That number, do you know
6 how many are caused by submergence?

7 MR. WILSON: I don't know. I'd have to
8 look at the summary charts that you guys have and I
9 don't have that. I'll have to get back with you. But
10 it's all in the charts and we've got pictures in the
11 summary report that we provided.

12 MR. MATTHEW: This is Roy Matthew.

13 There were 269 failures. It looks like
14 almost 60 percent of the cable failures reported are
15 related to moisture or water intrusion, but it doesn't
16 say it's completely submerged, but one of the
17 mechanisms.

18 MEMBER SIEBER: Thank you.

19 MR. RICHMOND: As part of the regional
20 inspection effort, we looked at the response to the
21 Generic Letter specifically and we noted that they did
22 not identify any cable failures in their response.

23 MEMBER RAY: They being?

24 MR. RICHMOND: For Beaver Valley.

25 CHAIR BLEY: I assume there has been

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1 interaction with the industry on this. Is the
2 industry in agreement or is there dispute about the
3 fraction of these failures that are associated with
4 moisture or water intrusion?

5 MR. WILSON: This is George Wilson, again.

6 I'll answer that.

7 Actually, based on our discussions and
8 some of the interactions we had with Wolf Creek, NEI
9 has come to us and talked to us. Gordon Clefton and
10 Jim Riley have come and specifically talked to me and
11 Tom Coshe and they have invited us to an industry
12 working group, I think it's March 19th and 20th,
13 sometime in March to discuss the cables.

14 It was also explained to me that they have
15 a working group, and one of the working group's
16 recommendations, and this is what I was told, was to
17 ensure that you keep the cables dry. So we are
18 interacting with NEI and using NEI's industry working
19 group, but there are open conversations on with that,
20 that's correct.

21 MEMBER STETKAR: Correct me if I'm wrong,
22 though, for the other members' benefits who may not
23 have looked into this, 60 percent of the reported
24 failures perhaps being attributed to some type of
25 moisture intrusion is taken at face value. You have

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1 to be careful because the Generic Letter asks the
2 applicants specifically to report the failure
3 experience with cables that may be susceptible to
4 moisture intrusion.

5 So that doesn't mean that 60 percent of
6 all cable failures across the whole nuclear industry
7 in any type of location were moisture related, it's
8 the fraction of a very, very select population. Isn't
9 that correct?

10 MR. WILSON: We threw away installation
11 failures and we looked at if it was a testing failure,
12 so we tried to differentiate the data.

13 MEMBER STETKAR: But you asked
14 specifically for failures of cables --

15 MR. WILSON: Of cables, that is correct.

16 MEMBER STETKAR: -- underground locations
17 that were susceptible to moisture intrusion.

18 MR. WILSON: And, also, to add to your
19 point, we also didn't add in failures if the licensee
20 decided to do wholesale change-outs of cable, such as
21 Oyster Creek. So that data, I'm just going to --

22 MEMBER STETKAR: Yes. But I mean just
23 recognize that a relatively high percentage of the
24 failures of the cables that you asked to have somebody
25 report is not necessarily surprising.

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1 MEMBER RAY: That wasn't surprising.

2 MEMBER STETKAR: It's information.

3 MR. WILSON: It's information.

4 MR. HOWARD: Summarizing section 3,
5 pending resolution of the open item, the applicant has
6 demonstrated that the aging effect is adequately
7 managed for the period of extended operation as
8 required by 10 CFR 54.21(a)(3).

9 Next slide.

10 Section 4, time-limited aging analyses.

11 For this section, I'd like to do the same
12 thing we did in Section 3, is highlight portions of
13 the staff review instead of just walking through each
14 section.

15 Next slide.

16 Section 4.2, reactor vessel neutron
17 embrittlement, reviews were performed to evaluate
18 reactor vessel neutral fluence and the corresponding
19 vessel embrittlement in terms of adjusted reference
20 temperature so and upper-shelf energy, pressurized
21 thermal shock, and pressure-temperature limits.

22 For this slide, the limiting beltline
23 material is the lower shell plate, location B6903-1.

24 For Unit 1 I'd like to point you to the irradiated
25 Charpy V notch upper shelf energy value at 54

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1 effective full power years is 51.5 foot pounds. The
2 acceptance criteria per 10 CFR 50, Appendix G is
3 greater than 50 foot pounds, and this is acceptable.

4 Next slide.

5 The limiting beltline material, lower shell
6 plate, location B9005-1 for Unit 2, again, the
7 irradiated Charpy V notch upper shelf energy value at
8 54, its effective full power years is 60.7 foot
9 pounds, and, again, this meets the acceptance
10 criteria per 10 CFR 50, Appendix G.

11 Next slide.

12 Reference temperature for pressurized
13 thermal shock values.

14 This slide, the limiting beltline material
15 lower shell plate is location B 6903-one for Unit 1,
16 the reference temperature at 54 effective full power
17 years will be 275.7. The acceptance criteria per 10
18 CFR 50.61 is less than or equal to 270 degrees
19 Fahrenheit. In order to deal with this, the
20 applicant has commitment a 24. Prior to exceeding
21 the PTS screening criteria for be BPTS Unit 1, FENOC
22 will select a flux production measure to manage PTS
23 in accordance with the requirements of 10 A C F R
24 50.61. A flux reduction plan will be submitted for
25 NRC review and approval.

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1 MEMBER ABDEL-KHALIK: What is the RTNDT at
2 the end of the current licensing period?

3 MR. HOWARD: I'll defer that question to
4 Matt Mitchell.

5 MR. MITCHELL: This is Matthew Mitchell,
6 Chief, Vessels and Internals Integrity Branch, NRR.

7 If my recollection is correct, and I'll ask
8 the applicant to correct me if I'm wrong, I believe
9 there are approximately 267.8 at the end of their
10 current 40-year license unless that number is dated,
11 about 267.8.

12 MEMBER ABDEL-KHALIK: So if they elect not
13 to do anything between now and the end of the current
14 license period would be very close to this screening
15 criteria?

16 MR. MITCHELL: They comply with the
17 regulation. They will be below 270 degrees.

18 MEMBER ABDEL-KHALIK: Okay.

19 MR. HOWARD: Next slide.

20 The limiting beltline material intermediate
21 shell plate, location B9004-1 for Unit 2, the
22 reference temperature is at 54 effect full power
23 years is 152.4, and, again, this acceptance criteria
24 per 10 CFR 50.61 is less than or equal to 270 degrees
25 Fahrenheit and this is acceptable.

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1 MEMBER BONACA: Does that mean that the PTS
2 for Unit 1, the plan does not have flux induction
3 plan right now?

4 MR. HOWARD: No.

5 MR. WEAKLAND: This is Dennis Weakland from
6 FirstEnergy.

7 Can I ask you to repeat the question? I
8 didn't quite hear it.

9 MEMBER BONACA: Yes. I asked if the plant
10 has a flux reduction measure right now?

11 MR. WEAKLAND: We have no active flux
12 reduction at this point in time.

13 MEMBER BONACA: Okay.

14 MR. WEAKLAND: We had previously had some
15 flux reduction in the early '90s.

16 MEMBER BONACA: And, yet, I mean you're
17 getting close to the limit?

18 MR. WEAKLAND: We believe we can manage it
19 through license extension. We have many options.

20 MEMBER BONACA: Okay. Thank you.

21 MR. HOWARD: Slide 32.

22 Pressure-temperature limits.

23 The BVPS Units 1 and 2 implement a
24 pressure-temperature limits report as part of their
25 CLB. The BVPS PTLR is based on a staff approved

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1 methodology which permits the applicant to generate
2 P-T limit curve is for future periods of operation.
3 The Beaver Valley Reactor Vessel Integrity Aging
4 Management Program will provide the information
5 necessary to implement the PTLR methodology through
6 the period of extended operation. Hence the staff
7 concludes that the Beaver Valley P-T limits will be
8 adequately managed through the period of extended
9 operation in accordance with 10 CFR 54.21(c)(1)(iii).

10 MEMBER ABDEL-KHALIK: How can you reach
11 that conclusion if you don't know exactly what
12 they're going to do?

13 MR. HOWARD: I'll defer that to Matt
14 Mitchell.

15 MR. MITCHELL: Again, this is Matthew
16 Mitchell, Chief, Vessels Internals Integrity Branch.

17 They have established methodology by which
18 they generate a pressure-temperature limits report.
19 They generate pressure-temperature limits in
20 accordance with the methodology staff as reviewed and
21 approved. It's controlled through plant technical
22 specifications. Therefore, they can continue to use
23 that methodology given that they're going to continue
24 to acquire information necessary to monitor the state
25 of their vessel and regenerate pressure-temperature

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1 limit curves going forward for future periods of
2 operation.

3 So there is an established method in place
4 that can be used through the end of the extended
5 period. Therefore, they meet, in our evaluation, the
6 (iii) criteria.

7 MEMBER ABDEL-KHALIK: I must be missing
8 something.

9 MEMBER MAYNARD: The license renewal does
10 not give them the right to violate limits. It's
11 saying that there's programs in place to monitor,
12 evaluate, calculate such that either action will be
13 taken or the plant will shut down. It can't operate
14 if it gets to those limits.

15 I think they're counting on, there are some
16 options that they have available to them coming up
17 here.

18 MR. HOLIAN: This is Brian Holian.

19 On that question, it's a similar question
20 that I have. It's almost do I need that commitment
21 or do I need that conclusion in license renewal space
22 because the staff does have this program and
23 expectation in place that they will maintain below
24 this, and the staff has previously reviewed their
25 methodology throughout life.

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1 So if that's where the question goes, the
2 way I view it in license renewal as director, is
3 we're taking this opportunity because it is such a
4 critical program and a critical aspect of the plant
5 to just make sure our review includes the status of
6 that at the time of license renewal. That's how I
7 answer that question.

8 MEMBER ABDEL-KHALIK: Yes. But I'm just
9 interpreting these words precisely.

10 MR. MEDOFF: Can I address this because I
11 was the one that did the updates for the --

12 CHAIR BLEY: Please. Please, use the
13 microphone.

14 MR. HOWARD: And identify yourself.

15 MR. MEDOFF: This is Jim Medoff of the
16 staff. But prior to my position in license renewal,
17 I worked for Matt Mitchell in Division of Component
18 Integrity and I was the person who was responsible
19 for updating the SRP guidance for the neutron
20 embrittlement TLAA's, including the P-T limits.

21 It became aware to us in the prior version
22 of the SRP that we didn't cover plants whose P-T
23 limits were covered by pressure P-T limit reports.
24 And what this allows them to do is change the reports
25 based on improved methodology and that was permitted

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1 to occur through a process for tech spec changes.

2 What we did is we realized that since the
3 P-T limits would no longer be coming in for review
4 and approval, if we approved the PTLR process for
5 them, that we had to cover it on -- since it was a
6 TLAA, we had it covered under the 54.21(c)(1)(ii) or
7 (iii) options, and what we did is we updated the SRP
8 to clear up what they would do if they had a PTLR
9 granted to the licensee.

10 So what happened is under the old way, if
11 you were doing your P-T changes in accordance with
12 the limiting conditions of operations, they had to
13 come in for review and approval. Once you had the
14 PTLR process approved, you could make the changes
15 through your approved methodology and all you would
16 have to do is submit the P-T limits for information
17 to us because it was understood that you would be
18 using the improved methodology for approval, and
19 since they no longer had to come in -- once they got
20 the PTLR approved, since they no longer had to come
21 through the 10 CFR 50.90 licensing process, we
22 considered the updates of the
23 P-T limits through the PTLR to meet the
24 54.21(c)(1)(iii) option and that's where we worked
25 into the standard of the plant.

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1 It's all in the SRP right now. If you look
2 at the SRP, it will explain to you.

3 MEMBER ABDEL-KHALIK: Thank you. That was
4 very enlightening.

5 (Laughter.)

6 MEMBER MAYNARD: I think it's
7 straightforward. My question is the options
8 available to them are either to reduce their flux,
9 it's to put a new vessel in, it's to thermally
10 anneal, it's to get the rule changed, or shut down.

11 CHAIR BLEY: And they're monitoring where
12 they are.

13 MEMBER MAYNARD: And they're monitoring
14 where they are.

15 MEMBER ABDEL-KHALIK: There is a specific
16 statement here that this will be adequately
17 management through the period of extended operation.

18 At least to me that means --

19 CHAIR BLEY: It will also be shut down.
20 That's right.

21 (Simultaneous speakers.)

22 MR. BARTON: Put up a statement, they will
23 be or the plant won't operate. What's so hard about
24 that?

25 MR. HOWARD: Section 4.3, metal fatigue

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1 analyses.

2 Metal fatigue analysis, review were
3 performed on ANSI B31.1 and ASME Code Class 1, 2, and
4 3 components. Environmentally assisted fatigue, the
5 60-year fatigue
6 re-analysis were performed for certain NUREG 6260
7 components, only two components having a 60-year CUF
8 greater than 1.0.

9 Beaver Valley will manage aging in
10 accordance with 10 CFR 54.21(c)(1)(iii) for NUREG
11 6260 locations. They'll be tracked through
12 Commitments 25 for Unit 1 and 26 for Unit 2.

13 MEMBER ABDEL-KHALIK: Have you reviewed the
14 method by which they retrieved old data from years of
15 essentially paper records?

16 MR. HOWARD: I'll defer to On Yee.

17 MEMBER ABDEL-KHALIK: Have you reviewed the
18 method by they "retrieved" old data from old records?

19 MR. YEE: This is On Yee. I'm not aware
20 that we've reviewed how they retrieve data. It was
21 part of our area of responses how they went back to
22 use operating experience though not specifically how
23 they retrieved the data.

24 MEMBER ABDEL-KHALIK: I mean these results
25 depend on the history, right? And, therefore, to

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1 believe these numbers, you have to essentially
2 confirm whatever data that went into doing these
3 analyses. And some of that involves going back to
4 the vault digging out old strip charts and records
5 and finding out what happened. And the question is,
6 are these data believable especially since you had
7 some items here that exceeded a CUF of one.

8 MR. LEE: This is Sam Lee from Division of
9 License Renewal.

10 We did not go back and look at strip charts
11 data. We looked at the numbers they gave us based on
12 judgment to see if that is reasonable or not and see
13 how they project. Is it conservative? So you hear,
14 what they say, to go back 10 years later and the
15 project based on the 10 years, the recent 10 years.

16 MEMBER ABDEL-KHALIK: There is no ambiguity
17 about that, about projecting from data that you have,
18 more recent data. The issue is what happened early
19 on in the first few years after they started the
20 plant.

21 MR. YEE: They have data, but the thing for
22 us is that we did not go back and look at the strip
23 chart data. We rely on the applicant to identify the
24 data for us. If it seems reasonable, like in this
25 couple of years, the cycle is normal to hot. So we

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1 don't expect anything to be too high, then it drops
2 down, and then project out.

3 But if we see low number cycles at the
4 beginning of life, then we would challenge that. So
5 in this case I don't think it's anything I guess in
6 particular about how to project the cycles. And,
7 also, they are like two locations that exceed one.
8 This is pretty typical. So there is no surprises
9 right here. And then they go into the (iii) manage
10 aging, that's also pretty typical.

11 MEMBER ABDEL-KHALIK: I mean there must
12 have been quite a bit of judgment involved in
13 recreating all of this old data. And the underlying
14 reason for the question, have you just sort of done -
15 -

16 MR. MEDOFF: The cycle counting
17 is --

18 CHAIR BLEY: Come to the microphone.

19 MR. MEDOFF: One thing you need to realize
20 is not only do they do the cycle counting under their
21 fatigue monitoring program, but if you go into their
22 administrative controls tech spec, cycle counting is
23 a tech spec item and they have to have procedures and
24 controls to do that. So it should provide a pretty
25 accurate account of their cycles that are occurring

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1 at the plant.

2 MEMBER MAYNARD: Also, any of the tech spec
3 required activities do get inspected periodically.

4 MEMBER STETKAR: Searching back through my
5 notes here, I found a statement that said that for
6 heat-ups and cool-downs and the reactor trips were
7 estimated from histograms of each transient based on
8 recent operating history, the last ten years. That
9 that to me says that the applicant went back and did
10 some type of time analysis counting the number of
11 transients in each year, and for some reason made the
12 determination that the last ten years were
13 representative and the preceding for Unit 1 I guess
14 18 years were not representative. There was a
15 distinct cutoff point there.

16 I guess the question is, did the staff
17 receive those histograms, the time trends of
18 transients, to make an independent determination of
19 whether that 10-year cutoff is reasonable or should
20 it have been 15 years or 26 years if only the first
21 couple of years of plant operation is an anomaly? I
22 guess the question is, why cut it off at 10.000
23 unless there was some real compelling evidence to
24 show that, indeed, a very large number of transients
25 occurred within the first one or two years?

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1 MR. YEE: This is On Yee of the staff.

2 I think in part one of our responses, they
3 provided the histograms to show the trending, and I
4 believe that they used the last 10 years to be
5 representative of how the current plant is operating.

6 MR. HOWARD: Does that answer your
7 question?

8 MEMBER STETKAR: It answers.

9 MEMBER MAYNARD: I mean we do the
10 projection, but not the -

11 MEMBER STETKAR: We didn't have that RAI or
12 the response to it.

13 MR. YEE: But they did provide the
14 histograms as part of the RAI response and was
15 reviewed by the staff.

16 MR. HOLIAN: And just to add on, this is an
17 area I remarked on. This is Brian Holian.

18 I've heard it on a couple of the last
19 subcommittees, so I think it is a good area. It's a
20 good opportunity during the license renewal process
21 to dig a little deeper possibly into their previous
22 operating history and at least explain it a little
23 fuller in our SERs. So I'll take that as an area for
24 improvement for us.

25 MEMBER STETKAR: In this particular case,

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1 it flags something to me because in the areas -- they
2 could afford to keep scaling from the full 28-years
3 worth of operating experience and many, many types of
4 transients because that didn't get them into trouble.

5 And in these other cases, they made a
6 distinct determination of what fraction of their
7 operating experience they would count and then
8 project into the future. And I recognize that they
9 added some things in on the back end kind of
10 qualitatively to compensate, but it would be
11 interesting, as you mentioned, in these cases to
12 better understand why they selected that subset of
13 conditions and why they didn't expect any of the
14 preceding 18 years to be relevant.

15 MR. HOLIAN: I understand.

16 MEMBER STETKAR: Thanks.

17 MR. HOWARD: Conclusion, pending resolution
18 of open item 3.0.3.1.11-1, the staff has determined,
19 on the basis of its review, that the requirements of
20 10 CFR 54.29(a) have been met.

21 Are there any additional questions?

22 MEMBER RAY: Well, I spoke to Brian at the
23 beginning about containment liner and I --

24 MR. HOLIAN: Yes, thank you.

25 MEMBER RAY: I think we're going to talk

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1 about that.

2 MR. HOLIAN: Yes, there are a couple items
3 I want to cover. As Mark Hartzman heads up to the
4 mike, he'll cover containment liner in general. And,
5 Dr. Bonaca, I think you had asked earlier a question
6 about number of commitments for Unit 1, bias Unit 2.

7 I just wanted you to know I've taken that
8 question. It's a good sanity check for us, pre-TMI
9 vice post-TMI and would you expect maybe a difference
10 in the number of commitments because of that.

11 I think the aging management programs, Sam
12 Lee and I were talking, are general enough that they
13 kind of cover both plants, but we'll take that as we
14 look at these plants and how our reviews do for a
15 good check. I thought it was a good question.

16 MEMBER BONACA: I mean I was surprised when
17 I read through seems as though these are identical
18 appliances and, yet, there are people old enough to
19 have gone through that period. You know that plants
20 that wanted to file in '76, one in 1987, are
21 fundamentally different because you cannot make
22 enough changes to the first plant to match what you
23 had done to the second one.

24 MR. HOLIAN: And the answer may very well
25 be that the programs themselves are wide enough to

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1 include everything and general enough, but we'll take
2 that as ourselves for a good check and a question for
3 us.

4 The second item on the containment liner,
5 is it just a membrane; is it structure integrity?
6 Dr. Hartzman will answer at least in general on that
7 topic. From a regional perspective, we understand
8 the applicant's statement that, well, it's not needed
9 for structural integrity, but I know being in the
10 region when even this issue was first discovered
11 during the outage, from a regional perspective, you
12 do expect that, hey, you want to be able to prove
13 that you have some margin so that if you saw Appendix
14 J testing, for example, trending down, you would
15 expect to ask tougher questions. Can you predict that
16 the liner will still be intact prior to the next
17 Appendix J test. That would be an aspect of our
18 questioning in that case and was back in 2006.

19 MEMBER RAY: Before he responds, let me
20 just say that the containment liner, there's a lot of
21 stuff attached to the containment liner and I'd feel
22 better if I could hear from the guy who designed the
23 containment what its function was before somebody
24 tells me don't worry about it; if it doesn't show any
25 evidence of corrosion on the inside, it's fine.

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1 That's the nature of the concern is, is that really?

2 How can it be true?

3 MR. HARTZMAN: The role of the liner is
4 simply to contain the radiological products under
5 pressure in case of an accident. That is all it's
6 entire structural function.

7 I am well aware that it has anything else
8 attached to it. It is attached to the concrete and
9 there it experiences certain bending stresses, but,
10 primarily, the stress state in the liner is tensile.

11 All it does is it is expected to carry only the
12 internal pressure resulting from the accident and
13 those classified according to ASME as membrane
14 stresses primarily. This is the primary function of
15 the liner.

16 MEMBER RAY: I don't dispute that it's the
17 primary function. I just said it wasn't the sole
18 function.

19 MR. HARTZMAN: It is its sole function.

20 MEMBER RAY: Maybe I've got a unique
21 containment, but there sure were a lot of things
22 welded to it, cable trays, and so on and so forth.

23 MEMBER SIEBER: I don't recall that being a
24 support.

25 MEMBER RAY: It sure as heck was.

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1 MR. HARTZMAN: On the lining itself?

2 MEMBER RAY: Yes.

3 MR. HARTZMAN: It is not my area of
4 expertise, but as far as I know it's primary function
5 is strictly to carry internal pressure.

6 MEMBER RAY: I'm not going to argue that
7 point.

8 MR. HARTZMAN: By the way, my name is Mark
9 Hartzman. I'm with the Mechanical Engineering
10 Branch.

11 MR. FARZAM: My name is Farhad Farzam,
12 Civil/Mechanical Engineering Branch.

13 MEMBER RAY: Here is the guy who can answer
14 the question.

15 MR. FARZAM: As far as cable tray
16 attachment, that's a local effect and the anchors
17 need to be designed to take the load to the concrete.

18 Really, liner plate is designed to take a ride with
19 the concrete as far as behavior, the global behavior
20 of the containment, when it's under pressure, it
21 basically wants to blow up and the strain in a liner
22 plate goes with what the concrete section is.

23 Now, when the containment is under DBE,
24 design basis earthquake, or design basis events like
25 thermal loads, the liner will see a compression

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1 because the inside is hot, outside is cold. So in
2 that particular load case, the anchors need to be
3 carefully designed to take the load to concrete.

4 Those are just generality. I don't know
5 about the licensing basis of Beaver Valley at this
6 point.

7 MEMBER RAY: You've got penetrations go
8 through the liner, welded to the liner. My gosh,
9 there's a zillion things that are hanging off the
10 liner. And the question that was being talked about
11 here was, well, can you adequately assure that
12 corrosion hasn't reduced the required integrity of
13 the liner by just looking at the inside surface.
14 That was the question.

15 And the answer was similar to the first one
16 I got here was, sure, because it's just going along
17 for the ride. It's just a membrane. So as long as
18 it isn't rusted on the inside, it's fine.

19 MR. HARTZMAN: To disturb require to
20 maintain pressure integrity whatever it is designed
21 to.

22 MEMBER RAY: I don't know. I'm taking
23 everybody's time here I guess. It does more than
24 that is my position and it's an odd thing.

25 MR. HOANG: My name is Dan Hoang and I'm

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1 Structural Engineering.

2 For the containment liner, everywhere we
3 have a cable tray support, I create C support
4 whatsoever behind the liner. We do have imbeds in
5 place, and also imbeds have a stud behind it and we
6 looked into the imbeds, not the liner by itself.

7 MEMBER RAY: Okay. So you're relying on
8 the imbeds that are --

9 MR. HOANG: Yes.

10 CHAIR BLEY: Anything else?

11 (No response.)

12 CHAIR BLEY: I guess that finished this
13 part. Thank you very much. I was going to summarize
14 things we heard, but maybe we'll go around.

15 Go ahead, John.

16 MEMBER STETKAR: I had a question. You run
17 a wonderful meeting. We're way ahead of time. Bad
18 dog.

19 Fully acknowledging the fact that this is
20 not a risk-informed application, has nothing to do
21 with PRA, however, there is a requirement to do a PRA
22 analysis and there is one presented in the
23 environmental report in Appendix C, and it's used in
24 the sense of trying to prioritize sever accident
25 mitigation alternatives and things like that.

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1 With all of those caveats in place, and, by
2 the way, I was really impressed from FENOCs, the
3 applicants, that with the amount of information and
4 kind of the quality of the information that's in that
5 appendix, it's really useful, however, I had a
6 question, and that question is -- I guess the first
7 question is, do you folks have anybody here who
8 speaks PRA? Okay, thanks.

9 When I looked at the contributions to core
10 damage frequency -- and I'll cite Unit 1 numbers.
11 Unit 2 are similar, but slightly different -- I
12 noticed that about 20 percent of the core damage
13 frequency was allocated to internal events, about 19
14 percent were from fires, and about 61 percent were
15 from seismic events. That's fine. Okay. Those are
16 numbers.

17 However, when I looked at the large early
18 release frequency, essentially, all of it was
19 attributed to internal events and that made me quite
20 curious because fires for seismic events for many
21 plants tend to be larger relative contributors to
22 containment isolation failures or perhaps failures of
23 containment -- structural failures of containment
24 penetrations in the sense of seismic.

25 So I was curious whether somebody could

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1 quickly explain to me why those disparities between
2 fires and seismic total accounting for about 80
3 percent of the core damage frequency and yet being
4 completely insignificant with respect to large early
5 release frequency, which, again, has some
6 implications on several accident management- and
7 emergency planning-type issues.

8 MR. LINTELL: This is Bill Lintell, Lead,
9 Beaver Valley PRA Engineer.

10 Our large early release frequencies are
11 dominated by interfacing system LOCAs and steam
12 generator tube ruptures with stuck opening safety
13 valves. So those are most commonly due to internal
14 events.

15 MEMBER STETKAR: Okay. Thank you.

16 MEMBER SHACK: Containment is robust unless
17 it's bypassed.

18 MEMBER STETKAR: Again, in my experience, a
19 lot of the fires and seismic events tend to fail,
20 things like control power signals, things like that,
21 that prevent containment isolation for example,
22 especially some fires and things like that.

23 MR. LINTELL: The containment isolation,
24 our cutoff for a large early release frequency is
25 about a 2-inch nominal diameter. Most of our

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1 connections with containment atmosphere are I guess
2 less than that 2-inch nominal. So we have failures
3 of those connections with direct containment
4 atmosphere. They're going to go to a small early
5 release and not a large early release.

6 MEMBER STETKAR: You don't have a large
7 vent line, the normal containment vent line?

8 MR. LINTELL: We do, but it's isolated, so
9 it gets some. We originally were designed for
10 subatmospheric containment. Right now we maintain
11 slightly subatmospheric, so we don't have any
12 pre-existing large.

13 MEMBER STETKAR: Yes, I understand that
14 part. Thanks. That at least explains the reason for
15 the numerical differences. Thanks a lot.

16 CHAIR BLEY: Okay. Just for the record, to
17 mention in my introductory remarks, I failed to
18 identify Harold Ray on the committee. But, also,
19 after we got started, Sam Armijo came in. So it's
20 almost a full committee. We're only missing I think
21 two people, but we'll come back to the full committee
22 later and there are some issues I guess I think we
23 ought to address.

24 I'm going to mention a couple and then
25 we'll go around the table with ourselves and our

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1 consultant.

2 There's some concern that it looks like
3 there's management process to take care of it on the
4 closeness we get to RTNDT. The fatigue cycle
5 estimates were something we weren't able to
6 completely track. And, Brian, if you're going to do
7 that later, we'd like to, maybe in the full
8 committee, if you can clarify how you saw that.

9 We had the wall thickness differences
10 between Unit 1 and 2 and if that makes any
11 difference. We also had the issue of the
12 subatmospheric containment with the liner maybe
13 separating and then going back. Beaver Valley said
14 it can't move because of the way it's mounted, but
15 there was a little difference of opinion and could
16 there be cycles from that.

17 And the last thing I had noticed was that
18 there's a real difference on the submerged cable
19 issue between staff and the applicant and I guess
20 that'll get resolved by the time you come back.

21 But, can we go around the table? Mario,
22 anything you want to add in detail?

23 MEMBER BONACA: No. I share the same
24 observations you made. I think, however, that in
25 general they have met the requirements of the

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1 regulation. And so I think I was reasonably
2 impressed by the application and by the review by the
3 staff.

4 CHAIR BLEY: John?

5 MEMBER STETKAR: I don't have anything
6 else.

7 MEMBER ARMIJO: I would just like to add
8 when the full committee presentation comes up, I
9 think it's important to provide a little more
10 quantitative information on the conclusion that this
11 corrosion of the liner is not a continuing process,
12 maybe just some drawings to show, well, that's
13 impossible, why it's impossible for water to get in
14 between the liner and the concrete, to really justify
15 that and more quantitative rather than just
16 qualitative manner.

17 Other than that, I think things are pretty
18 straightforward. The counting of the cycles for
19 fatigue, I think it would be helpful to us to know
20 that the historical counting is still valid.
21 Nobody's gone back and rewritten history as far as
22 the number of cycles and what's the basis for saying
23 the future cycles will be pretty much based on the
24 recent ten years, but that's just a projection. The
25 cycles will be what the cycles will be. So I think

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1 it's just accounting and assuring us that you haven't
2 rewritten history when you go back.

3 MEMBER STETKAR: Just as a --

4 CHAIR BLEY: Sorry. We skipped you.

5 MEMBER STETKAR: No, I said I had nothing,
6 but Sam reminded me.

7 Something to either the staff or the
8 licensee, in preparation for the full committee
9 meeting, since this topic did come up, it might be
10 useful to see that histogram because, apparently,
11 there was information generated to show the number of
12 events as a function of time. So that picture might
13 help us to understand better what was understood.

14 MEMBER ARMIJO: That reminded me of
15 something else. We had a prior review of another
16 application that had a lot of problems with
17 containment corrosion, and pictures are worth a
18 thousand words. Any photographs of the extent of
19 pitting really puts things in proper perspective
20 because you can imagine all sorts of damage that
21 isn't really there. So if the applicant has pictures
22 or drawings, or something, that says, hey, this is
23 the condition of the liner when we replaced the steam
24 generator, it would be very helpful.

25 MEMBER BONACA: Since we are going back --

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1 (Laughter.)

2 MEMBER BONACA: For the two committees, it
3 would be worthwhile if there are any differences
4 between Unit 1 and 2 to highlight those just because
5 I agree that the programs are not effective, but
6 simply it's of interest to understand what difference
7 are in the systems.

8 CHAIR BLEY: Especially with the TMI.

9 MEMBER BONACA: Yes.

10 CHAIR BLEY: John?

11 MR. BARTON: I don't have anything. I
12 think you covered all the hot spots that need to be
13 backed up for resolution. I think the applicant
14 provided a good application. It was easy to follow.
15 I think FENOC made a good presentation this morning,
16 had answers for just about all the questions we had.

17 MEMBER SHACK: I just make a note that
18 there are difference in the pipe walls in the two
19 plants, but I'm fairly confident that 62.60 locations
20 and the reanalysis they did on the pressurizer surge
21 line will be sufficient to characterize the fatigue
22 lifetimes in those piping systems.

23 MEMBER ABDEL-KHALIK: I have no additional
24 comments beyond your summary and the comments that
25 were made.

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1 MR. CUSTER: Otto is ready with something.

2 MEMBER MAYNARD: Two pages here.

3 (Laughter.)

4 MEMBER MAYNARD: I do want to comment on
5 two things. One is on the containment liner and I
6 think it's just fine. I really don't think there's a
7 problem with it. The only problem is in the
8 justification.

9 You do stress calculations on the
10 containment liner. They're in the FSAR and stuff.
11 What was missing here was some type of acceptance
12 criteria, or at one point wouldn't you start getting
13 worried. You said that when you start seeing
14 bubbling, well, okay, but at that point how thick do
15 you expect it to be? What says that that's still all
16 right?

17 So, again, I don't think there's really a
18 safety concern here, but I don't think there's been a
19 good explanation either by the staff or by the
20 applicant that there's lot of margin here.

21 I guess I'd like to see a little more
22 quantitative or something a little bit more than we
23 should see it bubbling before it gets bad.

24 CHAIR BLEY: A real acceptance criteria?

25 MEMBER MAYNARD: Yes. And so just enough

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1 on that. We've beat that one to death here I think.

2 The other is on submerged cable and that's
3 going to either get resolved or not get resolves
4 before we see it again, or whatever. I guess my
5 caution on that is probably a little bit as much for
6 the staff. On the resolution of this, if we were
7 starting with a brand new cable, it's easy to say
8 that dry may be better than wet her.

9 With Beaver Valley you have a situation
10 where it's been submerged for 30 years. You have two
11 different intakes. Either one can supply either
12 plant. If you say, okay, you've got to change this
13 cable, by pulling a new cable, you could create a
14 problem that you didn't have.

15 If you said, okay, you've got to pump these
16 vaults dry, well, something that's been wet for 30
17 years and then drying it out may be a bad solution.
18 So I just caution on the solution of this take into
19 account what you've got and make sure that the
20 solution, whatever resolved, isn't worse than where
21 it's at right now.

22 That's all I have.

23 MEMBER SHACK: Can I go back one?

24 (Laughter.)

25 MEMBER SHACK: The containment, if you have

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1 to remember, Oyster Creek got into problems where
2 there wasn't any concrete and contact with the steel.

3 I mean steel and concrete together are a fairly
4 benign environment. I'm reasonably convinced that
5 this is a localized corrosion that happened sometime,
6 but it's not an ongoing problem.

7 I don't think that looking for a bump on
8 the inside of the thing would be an acceptable
9 process. If you really believed there was a
10 corrosion process going on, it may be the defense in
11 depth if you're really wrong about something that you
12 think is 99 percent the likely story, which is that
13 there's no active corrosion process. But, just in
14 case you're wrong, that's something.

15 Quantifying the amount of strain that it
16 takes to get a visible bump from the corrosion
17 product wouldn't do anything for me.

18 CHAIR BLEY: John?

19 MEMBER STETKAR: Otto, you said something
20 that I was going to ask early just for my own
21 edification. This is to the licensee.

22 You said that the two intakes are redundant
23 essentially, and is that true? Are the river water
24 system for Unit 1 and the service water system, can
25 you actually connect service water from Unit 2 intake

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1 to Unit 1, also? Are they redundant?

2 MR. BOLOGNA: Rich Bologna, the manager,
3 Plant Engineering, and what we have is an alternate
4 intake structure and we have redundant pumps for each
5 unit down at the alternate intake structure, feed
6 Unit 1 in Unit 2.

7 CHAIR BLEY: A third intake structure?

8 MR. BOLOGNA: No, second intake structure.

9 If you don't want to use two pumps in the main
10 intake structure, then you don't want to use two
11 pumps in the alternate intake structure.

12 MEMBER STETKAR: It's not a Unit 1 intake
13 and a Unit 2 intake?

14 MR. BOLOGNA: No, that's correct.

15 MEMBER STETKAR: Okay. Thanks. Thank you.

16 CHAIR BLEY: Charlie?

17 MEMBER BROWN: Are we ready?

18 CHAIR BLEY: I'm ready.

19 MEMBER BROWN: No. I just Otto phrased my
20 -- when I said something about a conundrum with the
21 cables, Otto phrased it far more eloquently than I
22 did. So I have nothing else.

23 MEMBER RAY: My colleagues did a better job
24 of expressing the concern about the containment liner
25 than I did, but I share. I think there is perhaps, I

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1 agree with Otto, also, on what Charlie just
2 mentioned, but I think there's a generic thing that
3 we have an interest in here on the subject of cables
4 meaning that it transcends this applicant.

5 People have mentioned the good job done by
6 the applicant. I think we should say, I think the
7 staff, Brian's people have done a good job as well
8 and adequately, and responded to all the question
9 that we asked.

10 CHAIR BLEY: Jack?

11 MEMBER SIEBER: Well, I'll be very brief
12 because I'm last and everybody's covered everything I
13 wanted to say.

14 On the other hand, I think it's important
15 that I get clarified in my mind exactly what went on
16 with the fatigue cycle count because it sounded like
17 you took a period and said, well, this looks like the
18 other one, and my memory of the history of Unit 1 was
19 there were lots of cycles early on and so I would
20 feel more comfortable with a better count than what I
21 think we have right now, or somebody to explain why
22 the present method is so good that I should feel
23 comfortable with it.

24 The cables I think is probably generic to
25 all plants. I think it ought to be resolved for all

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1 plants. The question is, does that hold up the
2 license renewal or is that a current issue that needs
3 to be solved in a current time and I'm sort of
4 undecided as to how that should be, but I would
5 certainly like to see it discussed again with a
6 further resolution one way or the other regarding the
7 qualification of the current cables for submersion,
8 which FENOC claims they are, and versus leaded
9 cables.

10 My understand of lead-sheathed cables was
11 it like the Atlantic cable that went in saltwater
12 brine and all kind of chemical constituents.
13 Whereas, the groundwater here is relatively benign,
14 keeps oxygen away from the insulation, which reduces
15 corrosion and cools the cable.

16 On the other hand, wetting it and drying
17 it, and wetting it and drying it is probably the
18 worse thing you want to do with a cable. So right
19 now I agree on what position as an Agency we ought to
20 be taking on that, but I think it needs more
21 exploration than what's been done so far.

22 The containment liner issue, as far as
23 Beaver Valley containment, when it was operated as a
24 subatmospheric containment, I think the containment
25 had a tendency to pull in. It's attached to the

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1 concrete by studs. The studs are welded to the back
2 side of the liner and the liner was more or less
3 shaped around the concrete.

4 The containment was built layer by layer
5 and then the come was placed on top. The liner was
6 one of the early things. The concretes were forms
7 around it. When you pressurized the containment up
8 to it's line pressure, the liner expands and the
9 concrete cracks actually and I think all containments
10 do that.

11 And the structural strength of the
12 containment, in my opinion, is the rebar that's
13 inside as opposed to the concrete maintaining its
14 integrity.

15 In a subatmospheric containment, you get a
16 contraction of the liner compared to the concrete
17 shell outside. The only time that that gets pushed -
18 - and, by the way, that leaves lumps on the inside of
19 the containment when you do that because all these
20 little studs that are used to hold the liner up
21 against the concrete, so where there isn't a stud,
22 the liner has a tendency to pull away.

23 When you would do your 10-year containment
24 integrity test where you pressurize it, you would
25 expand the liner back out to the concrete. Beaver

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1 Valley now operates with a very slight containment
2 vacuum and probably insufficient to pull the liner
3 away again. But it's because of all these different
4 effects, it's not clear to me the corrosion, unless
5 it's a whole lot of corrosion, would cause a dimple
6 that you could distinguish from other dimples that
7 are in there for other reasons. So I'm not sure that
8 measuring dimples is the ultimate predictor of the
9 integrity of the liner, particularly if you think it
10 does more than the few molecules that separate it
11 from the outside world.

12 But, in my opinion, it's not a structural
13 member. Supports and things were put in into the
14 concrete and welded into the liner so it was actually
15 the concrete and the support that was holding
16 components that are fastened to the outside wall.

17 But, to me, I would like to understand more
18 and see more about the liner because right now I
19 can't come to a positive decision on that without
20 additional information.

21 The last thing, as I understand it, the PTS
22 situation with Unit 1, currently, we predict that we
23 will exceed the PTS temperature screening value. The
24 staff accepts that because the licensee is supposed
25 to keep track of that and provide information to the

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1 Agency on a periodic basis so that they do not exceed
2 the criteria.

3 On the other hand, there's got to be a flux
4 reduction plan for some kind of differing analysis or
5 innovative thinking that avoids this problem or
6 you're going to get up to the original licensed 40-
7 year lifetime with two degrees left and then you're -
8 -

9 CHAIR BLEY: Operations get difficult then.

10 MEMBER SIEBER: I guess I don't need
11 additional information to sign off on that. On the
12 other hand, to me, it's a warning that something has
13 to be done. It ought to be started as early as you
14 can do it. Low leak explorers are used in Unit 1,
15 which has got the high cooper vessel from the
16 beginning.

17 If you're aren't using them now, you better
18 go back even though the fuel cost goes up a little
19 bit from that. Or take more aggressive actions or
20 you're going to be faced with the vessel that can't
21 make the 60-year lifetime.

22 So those would be my comments. I need more
23 information to make a final decision for my own vote
24 on this, on three of these four issues. On the other
25 hand, I don't see anything pending the successful

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1 resolution of these issues that would prevent license
2 renewal.

3 CHAIR BLEY: Okay. Thank you.

4 One thing I forgot to do as we went around
5 is ask if there's any reason we should have an
6 interim letter. So, let me ask: is there anybody who
7 thinks there's any reason we need an interim letter?

8 MEMBER SIEBER: Usually the reason why you
9 have an interim letter is when we believe something
10 and nobody else does, or one of the two parties
11 doesn't. My conception of what is going on here is
12 everybody understand what the issues are and we may
13 not exactly know how to solve them all, but it's very
14 clear to me that FENOC has been forthright in their
15 presentation and plant condition and their ability to
16 operate for 60 years, and the staff has been very
17 thorough in its analysis of that, and I don't see a
18 conflict that would bar us to go in and stir the pot
19 some more so to speak. I would say we don't need an
20 interim letter.

21 CHAIR BLEY: Okay. Everybody else? I
22 guess this is the point I'd like to thank, First
23 Nuclear for really excellent presentations and for
24 being really well prepared to answer any of our
25 questions and having people who can do that.

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1 And the same, I thank the staff for good
2 presentations, good response to our questions, and
3 we'll look forward to getting together.

4 I'll write up the key points that I've
5 heard out of this and any other members who want to
6 send me something, I'd appreciate and we'll circulate
7 that later.

8 No other questions, we'll call this meeting
9 adjourned.

10 (Whereupon, the above-entitled matter was
11 concluded at 4:54 p.m.)

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BEAVER VALLEY POWER STATION

License Renewal Application



FENOC
Presentation to
ACRS

February 4, 2009

Introduction

- **Mark Manoleras, Site Engineering Director**
- **Larry Freeland, Implementation Manager**
- **Cliff Custer, License Renewal Project Manager**
- **John Thomas, Project Technical Lead**
- **Site Subject Matter Experts and members of the LRA core team in attendance**

Agenda

- **Background – Mark Manoleras**
- **Operating History – Mark Manoleras**
- **Scoping Discussion – Cliff Custer**
- **Application of GALL – Cliff Custer**
- **Commitment Process – Larry Freeland**
- **Areas of Interest – Cliff Custer**
- **Closing Remarks – Mark Manoleras**

Background - Physical

- **25 miles northwest of Pittsburgh, PA**
- **Westinghouse NSSS**
- **Stone & Webster Architect/Engineer**
- **Two 3-Loop PWR units**
- **2900 MWt, approx 970 MWe each**
- **Ultimate heat sink: Ohio River**
- **Natural draft cooling towers**

Background - Ownership

- **Plant Licensees**
 - FirstEnergy Nuclear Generation Group
 - Ohio Edison Company
 - Toledo Edison Company
- **Plant Operator and Applicant**
 - FirstEnergy Nuclear Operating Company (FENOC)

Operating History

	<u>Unit 1</u>	<u>Unit 2</u>
Commercial Ops	1976	1987
Transfer DLCo to FENOC	1999	
MUR Power Uprate (~1%)	2001	
New S/Gs and Rx Head	2006	-----
EPU SER (~9.4% total)	2006	
LRA Submitted	Aug 2007	
Current License Expires	2016	2027

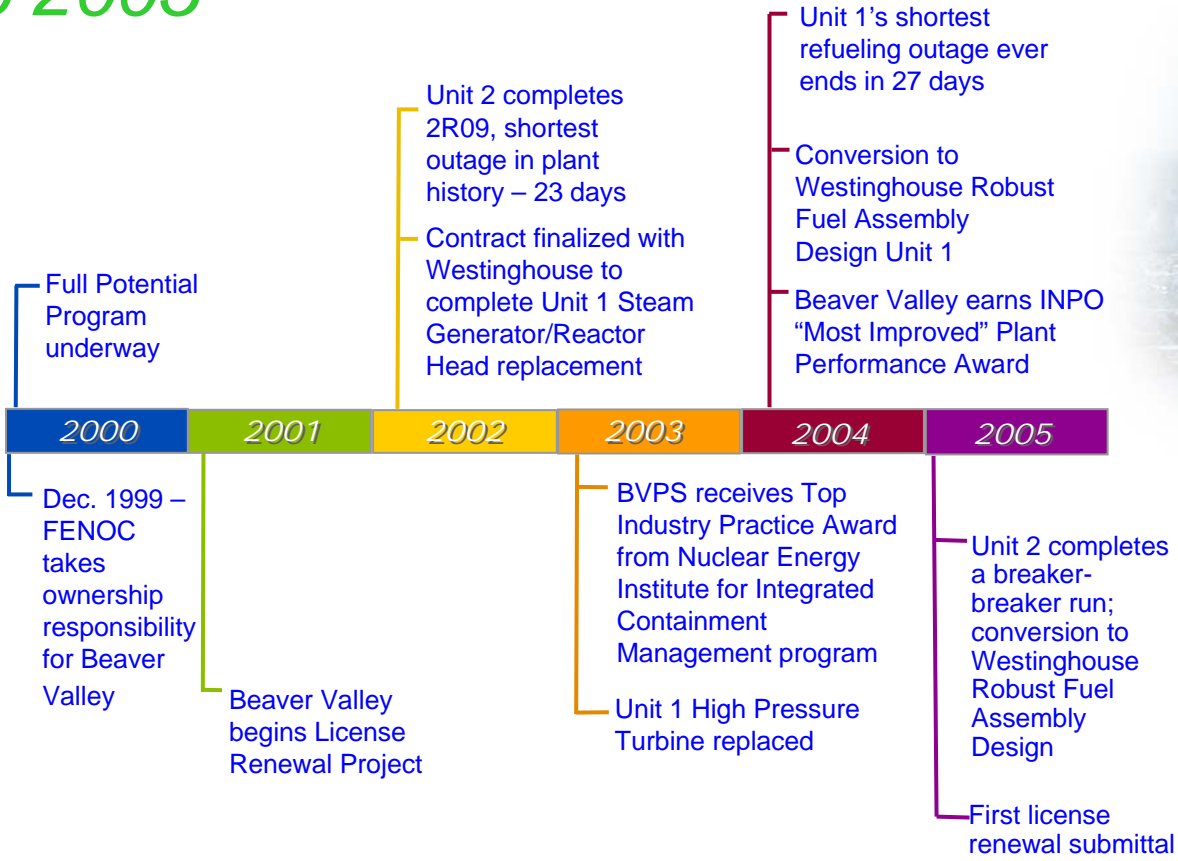
Operating History

- **Unit 1**
 - 1R18 completed Oct 2007
 - 18 month avg. Capability Factor 93.9% (thru 11/08)
- **Unit 2**
 - 2R13 completed May 2008
 - 18 month avg. Capability Factor 91.0% (thru 11/08)

Operating History

Beaver Valley Power Station

2000 to 2005

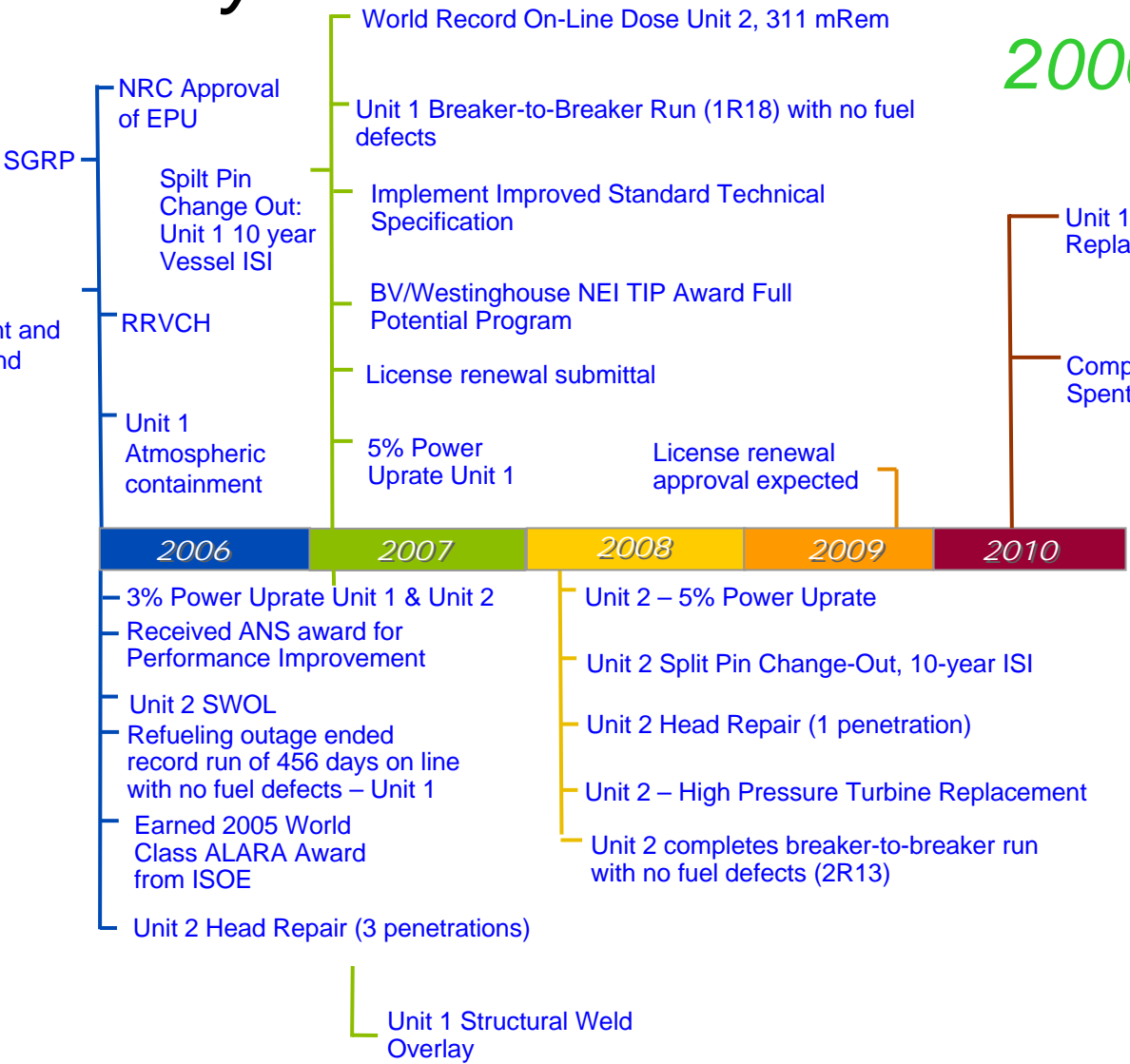


Operating History

Beaver Valley Power Station



MUG Rotor Replacement and Stator Rewind



2006 to 2010



Scoping – Project Team

- **BVPS core team included topical leads for Mechanical, Civil, Electrical, TLAA, and Programs**
- **BVPS core team prepared background documents**
 - Site program owners engagement, approval
 - AREVA support for initial AMR preparation
- **LR team remained engaged with industry**
 - Working groups
 - Peer reviews
 - Audit / Inspection observations

Scoping – Project Team

- **Independent assessment by License Renewal Assessment Board (LRAB)**
- **Independent assessment by site Quality Assurance**
- **Industry peer review of the application**
- **FENOC Corporate Nuclear Review Board (CNRB) review of the application**

Scoping

- **Methodology consistent with NEI 95-10**
 - (a)(2) spatial interaction scoping included NSR water-, steam-, or oil-retaining components in safety-related structures
 - No (a)(2) exclusions based on distance from SR SSCs
- **Boundary drawings highlight components for all scoping criteria, and show (a)(2) components in different colors**
- **SBO switchyard scoping consistent with proposed ISG 2008-01, and includes breakers in the switchyard**

Scoping - TLAA Identification/Disposition

- **TLAA Identification/Disposition Consistent with NUREG-1800 and NEI 95-10**
- **Included Review of Documentation Associated with:**
 - Extended Power Uprate (EPU)
 - Unit 1 Reactor Head Replacement
 - Unit 1 Steam Generator Replacement
 - Nickel-Alloy Structural Weld Overlays
- **TLAAs Dispositioned in Accordance with 10 CFR 54.21(c)(1)**

Application of GALL - AMRs

- **Aging Management Reviews consistent with guidance in NEI 95-10**
- **Review performed and AMRs updated prior to submittal to maximize internal consistency**
- **Project intent to maximize GALL consistency**
 - Used the same terminology for materials and environments as GALL, to the extent practical
- **91.8% of AMR line items used notes A-E (consistent with GALL)**

Application of GALL - AMPs

- **40 Aging Management Programs**
 - 27 existing programs
 - 17 with no changes needed
 - 10 with enhancements
 - 13 new programs
- **GALL / Plant-specific breakdown**
 - 33 GALL programs
 - 7 Plant-specific programs
- **8 programs with GALL exceptions**

Application of GALL - AMPs

- **GALL program exceptions**
 - ASME code year (4 programs)
 - Fire protection testing frequency
 - Fuel oil monitoring and control differences
 - No periodic flush of some stagnant OCCW lines (supplies to Fuel Pool & Aux Feed)
 - Buried AL-6XN piping not wrapped

Commitment Process

- **Commitments are tracked via a commitment tracking (database) system**
- **Implementation of BVPS License Renewal commitments will be managed as a project**
- **Responsibility for management of the implementation project has been assigned**

Commitment Process

- **Program implementation / enhancement**
- **Periodic replacement of most elastomer mechanical components**
- **Periodic testing or replacement of most polymer mechanical components**
- **Unit 1 Rx vessel neutron flux reduction plan**
- **Maintain standby vessel surveillance capsules**
- **Evaluate EPU operating experience**
- **Confirm effectiveness of new programs by self-assessment**
- **Implement needed actions of MRP-146**

Areas of Interest

- **Boral (Unit 1)**
- **Metal Fatigue (EAF)**
- **Containment Liner Corrosion (Unit 1)**
- **Medium Voltage Cables**

Areas of Interest – Boral (Unit 1)

- **Prior to LRA submittal, BVPS had not identified Boral aging effects that could affect spent fuel pool reactivity**
- **Boral surveillance program identified numerous blisters in 4th quarter 2007**
- **Aging will be managed by the existing Boral Surveillance Program (now credited for License Renewal)**
- **Program has been submitted for Staff Review**

Areas of Interest – Metal Fatigue (EAF)

- **60-year cumulative usage factor including environmental effects (U_{env}) exceeds 1.0:**
 - Unit 1 PZR surge line to hot leg nozzle
 - Unit 2 PZR surge line to hot leg nozzle
- **U_{env} will be managed by the Metal Fatigue of Reactor Coolant Pressure Boundary Program by:**
 - Refinement of analysis to obtain $U_{env} < 1.0$,
 - Management of fatigue by an inspection program, or
 - Repair or replacement

Areas of Interest – BV-1 Containment Liner Corrosion

- **Corrosion found on 3 areas of liner plate when exposed for SGRP (Spring 2006).**
- **Hydro-lazing eliminated corrosion products**
 - no definitive corrosion source established
- **Material analysis indicated general pitting corrosion**
 - no evidence of stress corrosion or MIC
- **Corrosion likely occurred during construction and/or concrete curing**
 - liner was exposed to weather
 - subsided in oxygen starved environment following curing

Areas of Interest – BV-1 Containment Liner Corrosion

- **Corrosion process and by-products cause expansion and blistering of coating**
- **Would be evident on interior surface as stained, bulged or flaking areas on the painted surface**
- **IWE inspection procedures enhanced:**
 - Surface flaws identified during visual examination require full NDE characterization
 - Qualified NDE examination prior to repair of indications

Areas of Interest – Medium Voltage Cables

- **4kV power supplies to the River/Service Water Pumps are submerged**
- **Cables are designed for submergence based on:**
 - Cable Design Specification
 - Vendor Testing
- **Service application is supported by operating experience**
- **Plant-specific AMP will confirm the absence of aging effects through periodic testing and inspection**

Areas of Interest – Medium Voltage Cables

- **To resolve the Open Item, FENOC will submit:**
 - Site Engineering Evaluation
 - Vendor Documentation

Closing Remarks

- **BVPS LRA is highly consistent with GALL**
- **40 Aging Management Programs**
 - Existing 27
 - New 13
 - Plant Specific 7

Questions ?





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UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Subcommittee

**Beaver Valley Power Station, Units 1 and 2
Safety Evaluation Report with Open Item**

February 4, 2009

Kent Howard, Project Manager
Office of Nuclear Reactor Regulation

Introduction

- Overview
- Section 2: Scoping and Screening Review Results
- License Renewal Inspections
- Section 3: Aging Management Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

Overview

- License renewal application submitted by letter dated August 27, 2007
- Westinghouse 3-Loop - PWR
- 2900 megawatt-thermal, each unit
- Operating license DPR-66 (Unit 1) expires January 29, 2016
- Operating license NPF-73 (Unit 2) expires May 27, 2027
- Location is approximately 17 miles West of McCandless, PA

Overview

- Safety Evaluation Report with Open Item was issued January 09, 2009
- 1 Open item
- 249 RAI's Issued
- 31 Commitments (Unit 1)
- 32 Commitments (Unit 2)

Overview

- Scoping and Screening Methodology Audit
 - December 3 - 7, 2007
- Aging Management Programs (AMP) Audit
 - March 3 - 7, 2008
- Regional License Renewal Inspections
 - June 23 - 27, 2008
 - July 14 - 18, 2008



Section 2: Structures and Components Subject to Aging Management Review

Section 2.1 – Scoping and Screening Methodology

- Staff's audit and review concluded that the applicant's methodology is consistent with the requirements of 10 CFR 54.4 and 54.21(a)(1)



Section 2: Structures and Components Subject to Aging Management Review

Section 2.2 – Plant-Level Scoping Results

- Components Brought Into Scope
 - Based on the staff's review, the North Pipe Trench was added to the scope of license renewal because the scoping endpoint of a non-safety related pipe directly attached to safety-related piping in the BVPS Unit 2 Valve Pit was determined to be located within the North Pipe Trench.



Section 2: Structures and Components Subject to Aging Management Review

Section 2.3 – Scoping and Screening Results: Mechanical Systems

- 100% Reviewed
- 48 Mechanical Systems
 - 34 Balance of Plant Systems
- Two Tier Review:
 - Tier 1 Review: 6 Systems
 - Review of LRA and UFSAR
 - Tier 2 Review: 28 Systems
 - Detailed review of Boundary Drawings, LRA and UFSAR

Section 2: Structures and Components Subject to Aging Management Review

Section 2.4 – Scoping and Screening

Results: Structures

- With the inclusion of the North Pipe Trench, the staff found no additional omissions of structural components within the scope of license renewal.

Section 2: Structures and Components Subject to Aging Management Review

Section 2.5 – Electrical and Instrumentation and Control Systems

- The staff found no omission of electrical and instrumentation and control system components within the scope of license renewal.

Section 2: Structures and Components Subject to Aging Management Review

Summary

- The staff found the applicant's scoping and screening review results meets the requirements of 10 CFR 54.4 and 54.21(a)(1)



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License Renewal Inspections

John Richmond

Region I Inspection Team Leader

- **54.4(a)(2) Scoping & Screening Non-Safety SSCs**
 - Non-Safety Effects Safety was Acceptable
- **Reviewed 19 of 42 AMPs**
 - Program Documents & Procedures
 - Walkdowns
 - Interviewed Plant Personnel
- **Operating Experience Review**
 - Conformance to NEI 95-10
 - Corrective Action Reports for Prior SSC Problems, associated with the 19 AMPs reviewed

Inspection Results

Portions of inspection focused on audit issues

- Application Changes – Most Significant
 - Inaccessible Medium Voltage Cables
 - Water in Manholes
 - SER Open Item OI 3.0.3.1.11-1
 - Selective Leaching
 - Buried Fire Water Pipe Leaching Damage
 - Operating Experience Reviews
 - Applicant committed to confirm new AMP effectiveness based on OpE

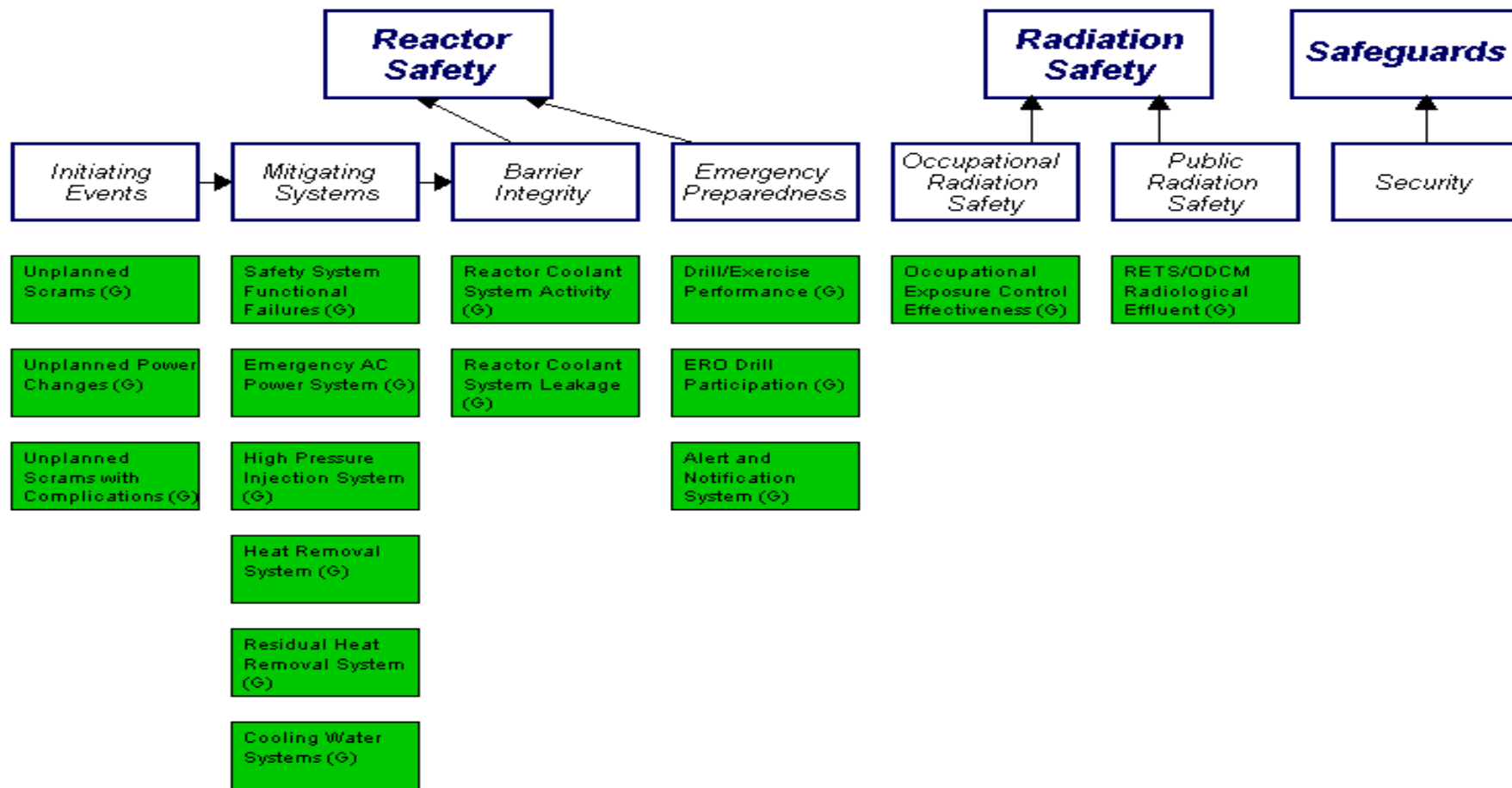
- **Aging Management Program (AMP) Changes**
 - One Time Inspection (sample selection criteria)
 - Bolted Cable Connections (revised to agree w/ draft ISG)
 - Fuel Oil Chemistry (for buried fuel oil tank inspections)
 - Open Cycle Cooling (for buried pipe inspections)
 - Structural Monitoring & Masonry Wall (admin controls)
 - External Surfaces Monitoring (scope clarification)

- Operating Experience Issue
 - FENOC procedures for OpE review consistent with NRC accepted guidance in NEI 95-10 (endorsed by RG 1.188)
 - NEI 95-10 Sect 4.4 “Plant-specific operating experience with existing programs should be considered”
 - FENOC interpreted to mean no OpE reviews needed for “new” programs
 - Extent of Condition & Apparent Cause Eval
 - Committed to OpE review for new AMPs prior to PEO

Inspection Summary

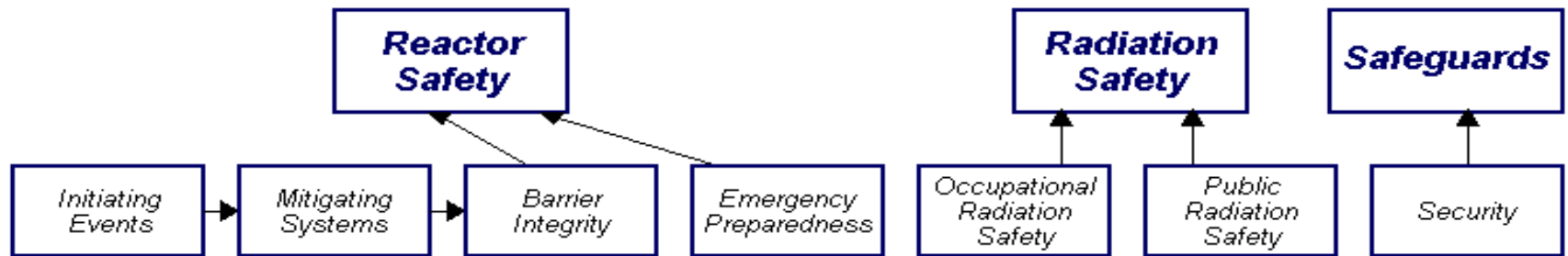
- Pending NRR review of cable qualifications for submergence, inspection results support a conclusion there is reasonable assurance that the effects of aging will be adequately managed
- Scoping of non-safety systems was acceptable
- Documentation supporting the application was auditable & retrievable

Beaver Valley 1 & 2 Performance Indicators



Last Modified: November 26, 2008

Beaver Valley Unit 1 Inspection Findings

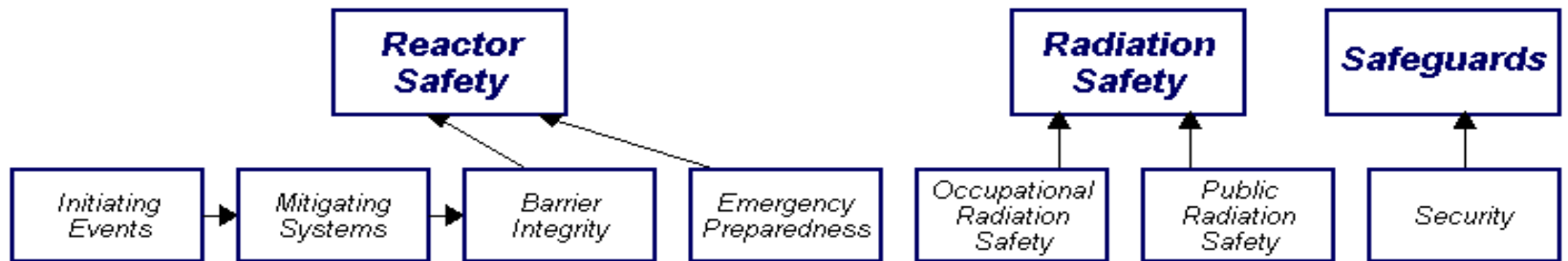


Most Significant Inspection Findings

	Initiating Events	Mitigating Systems	Barrier Integrity	Emergency Preparedness	Occupational Radiation Safety	Public Radiation Safety	Security
3Q/2008	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
2Q/2008	G	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
1Q/2008	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
4Q/2007	G	G	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter

No Cross-Cutting Issues

Beaver Valley Unit 2 Inspection Findings



Most Significant Inspection Findings

	Initiating Events	Mitigating Systems	Barrier Integrity	Emergency Preparedness	Occupational Radiation Safety	Public Radiation Safety	Security
3Q/2008	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
2Q/2008	G	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
1Q/2008	No findings this quarter	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter
4Q/2007	No findings this quarter	G	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter	No findings this quarter

Last Modified: November 26, 2008

No Cross-Cutting Issues

Section 3: Aging Management Review Results

- 3.0 – Aging Management Programs
- 3.1 – Reactor Vessel & Internals
- 3.2 – Engineered Safety Features
- 3.3 – Auxiliary Systems
- 3.4 – Steam and Power Conversion System
- 3.5 – Containment, Structure and Component Supports
- 3.6 – Electrical and Instrumentation and Controls System

Section 3: Aging Management Review Results

Section 3.0.3 – Aging Management Programs (AMPs)

	Plant specific	Consistent with GALL	With Exception	With Enhancement	With Exception & Enhancement
Existing	2	10	4	7	3
New	4	8	1	0	0

- Boral Surveillance Program (AMP) for Unit 1 was added after SER was issued January 9, 2009.

Section 3: Aging Management Review Results

Section 3.0.3.1.11 – Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program

- **Open Item 3.0.3.1.11-1**
 - **Staff is concerned that inaccessible medium-voltage cables that have been submerged for a period of time may be degraded and may not perform their intended function during the period of extended operation.**
 - **The applicant has provided additional supplemental information regarding qualification of cable which is under review by the staff.**

Section 3: Aging Management Review Results

	Acceptance Criteria	2003	2007 (Two Samples taken)
pH	>5.5	6.87	7.12/6.83
Chlorides	<500 ppm	44.6	18.9/208
Sulfates	<1500 ppm	1.2	177/187

- BVPS groundwater is non-aggressive
- Groundwater testing will begin five years prior to period of extended operation for each unit, then continue on a five year interval thereafter

Section 3: Aging Management Review Results

Summary

- Pending resolution of Open Item 3.0.3.1.11-1, the applicant has demonstrated that the aging effects will be adequately managed for the period of extended operation as required by 10 CFR 54.21(a)(3).



Section 4: Time-Limited Aging Analyses

- 4.1 TLAA Process
- 4.2 Reactor Vessel Neutron Embrittlement
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Concrete Containment Tendon Prestress (N/A)
- 4.6 Containment Liner Plate, Metal Containments, and Penetration Fatigue
- 4.7 Other Plant Specific TLAA

Section 4.2: Reactor Vessel Neutron Embrittlement

Reviews were performed to evaluate reactor vessel neutron fluence and the corresponding vessel embrittlement in terms of adjusted reference temperature (ART) and:

- Upper-shelf energy
- Pressurized thermal shock
- Pressure-temperature limits

Section 4.2: Reactor Vessel Neutron Embrittlement – Upper Shelf Energy

Limiting Beltline Material—Lower Shell Plate (B6903-1)

Unit 1

% CU	54 EFPY Fluence (E>1 MeV) at 1/4T 10¹⁹ (n/cm²)	Initial Charpy V notch USE Value (ft-lb)	Irradiated Charpy V notch USE Value at 54 EFPY (ft-lb)	Acceptance Criterion per 10 CFR 50, App. G (ft-lb)
0.21	3.80	83	51.5	≥50

Section 4.2: Reactor Vessel Neutron Embrittlement – Upper Shelf Energy

Limiting Beltline Material—Lower Shell Plate (B9005-1)

Unit 2

% CU	54 EFPY Fluence (E>1 MeV) at 1/4T 10¹⁹ (n/cm²)	Initial Charpy V notch USE Value (ft-lb)	Irradiated Charpy V notch USE Value at 54 EFPY (ft-lb)	Acceptance Criterion per 10 CFR 50, App. G (ft-lb)
0.08	3.92	82	60.7	≥50

Section 4.2: Reference Temperature for Pressurized Thermal Shock (PTS) Values

Limiting Beltline Material—Lower Shell Plate (B6903-1) Unit 1

% CU %Ni	54 EFPY Fluence (E>1 MeV) 10 ¹⁹ (n/cm ²)	Initial Charpy RT _{NDT} °F	RT _{PTS} °F	Acceptance Criterion per 10 CFR 50.61 °F
0.21 0.54	6.09	27	275.7	≤270°F

Commitment 24: Prior to exceeding the PTS screening criteria for BVPS Unit 1, FENOC will select a flux reduction measure to manage PTS in accordance with the requirements of 10 CFR 50.61. A flux reduction plan will be submitted for NRC review and approval.

Section 4.2: Reference Temperature for Pressurized Thermal Shock (PTS) Values

Limiting Beltline Material—Intermediate Shell Plate (B9004-1) Unit 2

% CU % Ni	54 EFPY Fluence (E>1 MeV) 10^{19} (n/cm ²)	Initial Charpy RT_{NDT} °F	RT_{PTS} °F	Acceptance Criterion per 10 CFR 50.61 °F
0.065 0.55	6.22	60	152.4	$\leq 270^{\circ}\text{F}$

Section 4.2: Pressure-Temperature Limits

- BVPS, Units 1 and 2 implement a Pressure-Temperature Limits Report (PTLR) as part of their CLB.
- The BVPS PTLR is based on a staff-approved methodology which permits the applicant to generate P-T limit curves for future periods of operation.
- The BVPS Reactor Vessel Integrity Aging Management Program will provide the information necessary to implement the PTLR methodology through the period of extended operation.
- Hence, the staff concludes that the BVPS P-T limits will be adequately managed through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

Section 4.3: Metal Fatigue Analyses

4.3 Metal Fatigue

Reviews were performed on:

- ANSI B31.1 and ASME Code Class 1, 2 and 3 Components
- Environmentally Assisted Fatigue
 - 60-year fatigue reanalysis were performed for certain NUREG/CR-6260 components, only two (2) components having 60-year CUF>1.0.
 - BVPS will manage aging in accordance with 10 CFR 54.21(c)(1)(iii) for all NUREG/CR-6260 locations (Commitments 25 (Unit 1) and 26 (Unit 2)).

Conclusion

- Pending the resolution of OI 3.0.3.1.11-1, staff determined, on the basis of its review, that the requirements of 10 CFR 54.29(a) have been met.



End of Presentation

Thank you for your time and attention