Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Wednesday, February 4, 2009

Work Order No.: NRC-2648 Pages 1-146

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

SUBCOMMITTEE ON PLANT LICENSE RENEWAL

BEAVER VALLEY POWER STATION

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WEDNESDAY, FEBRUARY 4, 2009

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ROCKVILLE, MD

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

SUBCOMMITTEE MEMBERS PRESENT:

DENNIS BLEY, Chair
JOHN STETKAR
J. SAM ARMIJO
WILLIAM J. SHACK
SAID ABDEL-KHALIK
OTTO L. MAYNARD
CHARLES H. BROWN, JR.
HAROLD B. RAY
JOHN SIEBER

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

JIM MEDOFF

ALSO PRESENT: (CONT.)

ON YEE

SAM LEE

MARK HARTZMAN

FARHAD FARZAM

DAN HOANG

BILL LINTELL

RICH BOLOGNA

I-N-D-E-X

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

1:30 p.m.

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

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

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

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

The rules for participation in today's

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

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

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

MR. HOLIAN: Thank you and good afternoon.

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

First off, to my far right, is David Wrona, the Branch Chief and License Renewal responsible for the Beaver Valley license renewal plant application. Next to me is Mr. Kent Howard. Kent has been the project manager the entire time on the Beaver Valley project and you'll be hearing from him later in a staff summary of safety evaluation report.

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

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

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

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

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

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

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

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

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

We have two units at Beaver Valley that

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

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

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

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

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

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

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

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

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

On the next slide, I'll just pull out a couple major bullets. You can see where the NRC improved our extended power uprate. Also, where our license renewal application was submitted.

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

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

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

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

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

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

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

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

MR. THOMAS: Can I take that?

MR. CUSTER: Go ahead, John.

MR. THOMAS: We didn't even try and break it down by that with a single exception. If it was a safety-related structure, non-safety-related fluid retaining components inside were scoped in for (a)(2). The exception is the intake structure, for which all the safety-related components in the intake structure within flood and missile barrier cubicles, so we scoped (a)(2) just within the cubicles for the intake structures. Everything else, the structure was safety-related, (a)(2) components within it were scoped in.

MR. CUSTER: Yes, sir.

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

MR. THOMAS: Yes, sir.

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

MR. THOMAS: That's correct.

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

MR. THOMAS: Yes.

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

MR. THOMAS: Correct.

MEMBER STETKAR: Okay. Thanks.

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

MR. THOMAS: Yes, we do.

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

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

MEMBER STETKAR: Thank you.

MR. CUSTER: Does that answer your question?

MEMBER STETKAR: That does. Thank you very much.

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

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

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

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

It has been our project intent to maximize

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

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

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

MEMBER STETKAR: Excuse me. Could you explain why you can't flush the service water lines to the aux feed system? I can see why you can't to the fuel pool. But there seem to be valves in the aux feed supplies, which are normally closed, and still have flushing-through vents and drains, and so forth.

MR. CUSTER: John?

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

MEMBER STETKAR: The valves are closed though.

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

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

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

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

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

MEMBER SHACK: Was the AL-6X pipe

original or were you replacing something?

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

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

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

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

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

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

Now, as part of the implementation, we have chosen, based on experience, some other plants to handle the implementation as a project, which means each of the commitment needs will be scheduled, as well as integrated into the site programs. And I'll also point out that in the development of the application, the individual program owners were involved with that and will ultimately have responsibility for their particular program to continue to manage the commitment.

Responsibility for management of the implementation project has been assigned. That is me. But, in addition, we will have ongoing an owner going forward embedded into the engineering organization to continuously be in charge of monitoring and making sure that we meet the commitments going forward.

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

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

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

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

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

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

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

And then the final one is implement the

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

MEMBER MAYNARD: I am sorry.

MR. FREELAND: Sure.

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

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

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

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

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

MR. BUFFINGTON: That's correct.

MR. CUSTER: Does that answer your

question?

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

MR. CUSTER: No.

MEMBER MAYNARD: Okay.

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

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

MR. FREELAND: Denny Weakland?

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

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

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

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

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

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

MEMBER ABDEL-KHALIK: Okay.

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

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

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

MR. FREELAND: Right, exactly.

MEMBER STETKAR: Okay.

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

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

A new program we've recommended and provided to the staff is Boral, management of Boral. That's specific to the Unit 1 fuel pool metal fatigue. Discuss containment liner corrosion at Unit 1, and medium voltage cables in that order.

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

In the fourth quarter of 2007 after we submitted our application, we submitted in August of 2007, our surveillance program identified numerous blisters occurring on the Boral material. We proposed that this aging will be managed by the existing Boral surveillance program now credited for license renewal and our program has been admitted for staff review.

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

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

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

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

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

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

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

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

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

MR. THOMAS: Our program that we currently have in place, that we're now crediting for license renewal, it monitors coupons that we take out. We'll test coupons for neutron absorption and dimensional checks. It also provides options if it looks like you're seeing more degradation than expected, provides options to do additional tests, which include in-service flatness testing of the panels in situ.

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

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

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

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

CHAIR BLEY: Okay.

MR. THOMAS: Does that answer your question?

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

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

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

MR. CUSTER: Yes, that's correct.

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

MR. CUSTER: Yes.

MEMBER SHACK: One of the things you get

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

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

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

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

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

MR. BUFFINGTON: I believe it is.

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

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

MEMBER SHACK: Hot leg and cold leg? I'll have to find it.

CHAIR BLEY: Maybe we can come back to it.

MEMBER SHACK: I'll come back to that.

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

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

MR. CUSTER: Yes, the 62.60 locations.

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

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

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

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

MR. BUFFINGTON: Yes. As part of our reanalysis efforts, we have gone back through our plant history. We were able to obtain operator logs from the control room. We were able to obtain plant history data as far as our RCS pressures and RCS temperatures, and put together what we believe to be a best effort of reconstruction of a plant heat-up and cool-down events.

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

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

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

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

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

MEMBER STETKAR: Now, can I interrupt? I was just reading something here trying to get a question in my mind. Back to the use of historical operating experience to project the number of thermal cycles, there was an RAI on it I think and there's a table in the SER that lists the number of cycles, and for Unit 1 several of the projected cycles just at the end of the period of extended operations just meet the limit, 200 heat-ups and cool-downs.

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

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

MR. BUFFINGTON: Steve Buffington again. Unit 1 had a history in the early period of a lot of start-up and shut-downs, and what we did for the heat-up and cool-down, as well as reactor trip transient, was take our most recent operating history for our projection. And then at the end of that, we scaled that upwards again because there may be some additional events that would occur as the plant ages.

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

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

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

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

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

If we can move forward, then.

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

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

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

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

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

MR. CUSTER: Sure.

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

MR. MANOLERAS: Yes. This is Mark Mandoleras. We were unable to find any photos that would allow us to correlate those areas with that construction.

MR. BARTON: Okay. Thanks.

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

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

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

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

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

The other areas of the liner were unaffected. The areas appear to be random across the 20-foot square area. So the pitting in general was not deep. There were a couple of pits that went below what would be considered the nominal wall for the material, but then, again, our containment liner is a membrane activities.

MEMBER SHACK: Oh.

MR. WEAKLAND: It's not structural.

MEMBER SHACK: It's not structural.

MR. WEAKLAND: Does that answer your question?

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

MR. CUSTER: Dennis will address that.

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

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

MR. WEAKLAND: Right.

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

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

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

MEMBER SIEBER: There is none?

MR. WESTBROOK: No.

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

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

MR. WESTBROOK: The exact number I don't

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

MEMBER SIEBER: Thank you.

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

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

MEMBER STETKAR: Can I ask about your inspection program?

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

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

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

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

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

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

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

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

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

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

MEMBER STETKAR: I meant where it's starting.

MR. GRAVSKY: Right.

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

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

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

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

MR. CUSTER: Based on the fact that --

MEMBER ARMIJO: But I mean did it have to be all the way through the liner?

CHAIR BLEY: Yes.

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

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

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

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

MEMBER ARMIJO: Yes.

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

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

MR. WEAKLAND: About three-eighths.

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

MR. CUSTER: Yes.

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

MR. CUSTER: That is correct, sir.

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

MR. CUSTER: Not in this location, no.

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

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

MEMBER MAYNARD: I understand that. I'm just trying to understand why I should buy the argument that you're going to see the bulging before it's too bad. Yet, you didn't see the bulging in this, but you went ahead and found some and fixed it. So I'm kind of struggling just a little bit here.

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

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

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

MR. WEAKLAND: It's simply --

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

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

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

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

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

(Simultaneous speakers.)

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

MR. BARTON: Just in case.

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

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

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

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

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

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

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

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

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

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

CHAIR BLEY: Okay. So it's a pressure

test?

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

CHAIR BLEY: Thank you.

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

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

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

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

We've developed a plant-specific program to confirm the absence of aging effects through periodic testing and inspection.

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

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

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

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

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

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

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

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

MR. WESTBROOK: Tom Westbrook, Design Engineering.

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

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

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

CHAIR BLEY: Thank you.

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

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

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

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

MEMBER STETKAR: Submerged conditions, submarine cables?

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

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

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

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

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

MR. PAUL: Sure, Mark.

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

But really to say that they're qualified for submerged applications, I don't believe that there is an NRC-approved qualification method for submergence of this type. They were constructed and designed for submergence. Our manholes were not intended to be water tight.

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

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

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

CHAIR BLEY: All of the cables?

(Simultaneous speakers.)

CHAIR BLEY: The oakonite and the other stuff?

MR. MANOLERAS: And what's important, and Brian could talk about this some more, our cables are routed, like our 4kV cables would be routed separate from our 480 volt cables and from our control cables. So they are routed. And, Brian, you could talk about that a little more, the way our tray systems work.

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

MR. MANOLERAS: Sure.

MR. PAUL: The duct banks themselves are in array. You have, whatever the number is 4-by-4, 5-by-5. Instrumentation cable is usually on the bottom. It's always on the bottom. And as your higher power cables are routed through the duct banks, they're in different elevations.

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

MEMBER RAY: What about splices? Visual

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

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

CHAIR BLEY: One long pull?

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

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

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

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

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

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

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

MEMBER ABDEL-KHALIK: Continuously

submersed?

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

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

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

MEMBER BROWN: Thirty years?

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

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

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

MEMBER BROWN: How do you see them if

they're under water?

MR. PAUL: Say it again?

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

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

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

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

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

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

MR. PAUL: The testing that we perform will only really show you a step change. These 4kV cables are unshielded cable. Right now there is no test method to detect this fine water treeing failure mechanism. There's no good test at this point, no proven test for detecting water treeing on unshielded cable.

MEMBER SIEBER: Now, the services in question, one could say fire protection is one of them, the diesel power pumps. The service water, you have two intake structures where most plants have one. So you have separate cable routings depending on which intake structure you're using and they're both available to both units.

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

MR. PAUL: Yes, yes, it is.

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

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

MR. CUSTER: Go ahead, Brian.

MR. MURTAGH: Brian Murtagh from Design Engineering.

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

MEMBER STETKAR: Of HTK cables?

MR. MURTAGH: Of HTK cables.

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

MR. MURTAGH: For the industry response.

MEMBER STETKAR: For the industries, there are some.

MR. MURTAGH: There are some.

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

MR. MURTAGH: But there also are cable

applications outside of nuclear in the commercial world, too.

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

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

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

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

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

MEMBER STETKAR: That's okay.

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

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

MEMBER STETKAR: That depends on the quality.

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

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

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

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

MEMBER BROWN: No, no, no, no, that's not the case. You're measuring leakage current through the insulation to ground. They're doing it with DC. I think you said a DC. So you just apply the voltage. It's not a dielectric strength test. It's literally just an insulation, and you can see the insulation resistance in error. Let me caveat what I just said. You can see it gradually to grade and we do that. We've done that -- that's a maintenance issue.

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

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

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

MR. CUSTER: No, they are not.

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

MEMBER STETKAR: Okay. Never mind. Thanks.

CHAIR BLEY: Did you need more --

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

MR. CUSTER: Okay.

MR. MANOLERAS: Okay. Again, I appreciate the opportunity. Beaver Valley appreciates the opportunity to come and present this application to the ACRS. We've talked about the license renewal application and its consistency with the GALL, and we've also discussed the existing new and plant-specific programs.

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

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

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

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

MR. MANOLERAS: That's correct.

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

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

MR. BARTON: You control access to the

switchyard?

MR. MANOLERAS: That's correct.

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

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

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

(Laughter.)

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

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

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

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

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

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

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

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

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

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

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

MR. PAUL: As I said earlier, a meggar

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

MEMBER ABDEL-KHALIK: Thanks.

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

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

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

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

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

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

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

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

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

MR. PAUL: Correct.

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

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

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

MR. CUSTER: Yes.

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

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

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

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

MR. BARTON: Okay.

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

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

MEMBER SIEBER: Yes. Right.

CHAIR BLEY: Any other questions?

(No response.)

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

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

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

MR. HOLIAN: Good. Thank you.

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

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

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

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

And then, finally, the last item that I just wanted to mention up front was on the liner and corrosion on the liner that occurred during the steam generator replacement really was found in the steam generator replacement project. I just wanted to mention that did not come up necessarily during the license renewal reviews.

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

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

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

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

Kent, go ahead.

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

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

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

Next slide.

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

Next slide.

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

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

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

Next slide.

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

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

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

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

Next slide.

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

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

Next slide, please.

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

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

Next slide, please.

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 scop of the license renewal because the scoping endpoint of a non-safety related pipe directly attached to safety-related piping in the Beaver Valley Power Station Unit 2 valve pit was determined to be located within the north pipe trench.

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

Next slide.

Section 2.3, scoping and screening results, mechanical systems.

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

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

Next slide.

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.

Next slide.

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.

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

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

MR. RICHMOND: Afternoon.

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

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

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

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

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

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

MR. BARTON: Okay. Thank you.

MR. RICHMOND: Okay.

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

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

MEMBER BONACA: Right.

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

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

MR. HOWARD: Yes.

MEMBER BONACA: Thank you.

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

Next slide.

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

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

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

MR. RICHMOND: Yes.

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

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

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

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

And we did something a little bit different with Beaver Valley. We did a review of their method for doing their operating experience review. We looked at how they did their operating experience review, and then we did the standard regional thing where we look at the individual operating experience that they've got, plant-specific stuff, condition reports.

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

Next slide.

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

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

Based on that, looking at several years' worth of PMs, it became apparent, at least on a quarterly basis, open and inspect the manhole, you ought to be successful to keep the cables dry.

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

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

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

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

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

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

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

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

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

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

MR. HOLIAN: I think you'll hear an answer from the -- well, not the regional interest. But that regional answer is, in general, a good corrective action program, and, if not, one that would be you have a cross-cutting item or further actions in the ROP action matrix would be the answer that.

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

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

The other way to go is just make sure you have a good aging management program that we'll go ahead and follow up on, you know, de-watering inspecting and inspecting the cables. So that's the second tact and probably one of the reasons why headquarters pushed the region or asked also look at the good operating experience whether they have it or not and put a little bit of pressure on or just question how they're dealing in this area of operating experience should they end up crediting that aspect.

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

Does that help?

MR. BARTON: Yes.

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

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

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

MR. RICHMOND: May I ask Duc?

MR. NGUYEN: This is Duc Nguyen.

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

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

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

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

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

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

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

George, do you want to talk to that?

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

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

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

So we're actually going to define what we would like to see in a cable monitoring program, not just one test, but several tests and how you evaluate the cables. So that's coming out and that should be out by the end of December.

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

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

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

MEMBER ARMIJO: And that's not HTK?

MR. WILSON: That is correct. That is not

HTK Carite cable.

MR. BARTON: Thank you.

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

(Laughter.)

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

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

MR. BARTON: Got that.

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

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

MR. RICHMOND: We looked in four manholes. Three manholes had in-scope cables and one manhole did not and it had the least amount of water in it. I don't know if that answers your question.

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

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

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

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

MEMBER ARMIJO: Yes. Thank you.

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

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

And in looking at the CRs for the plant, the condition reports for the plant, we identified that they'd had selective leaching damage in pipe replacement as a result for the buried fire header, and, when we brought that back to their attention and they looked at the issues in a little more depth, what they figured out was, in fact, that section piping had had leaching damage in the past and they revised their program to have a one-time inspection for selective leaching except for buried fire pipe and that's going to have a routine condition monitoring program as a result.

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

MR. RICHMOND: It was the fire water piping.

MEMBER ARMIJO: Just the firewater, okay.

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

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

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

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

MEMBER BONACA: Right.

MR. RICHMOND: So they revised their proposed program.

(Simultaneous speakers).

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

MEMBER BONACA: Yes, appropriate. Okay.

MR. RICHMOND: All right.

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

Next slide.

There were other application changes based on aging management programs that they need to revise based on the inspection and this is a list of six of them and I can go down the list for you.

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

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

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

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

Structural monitoring and masonry wall, they added administrative controls.

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

Next slide.

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

NRC accepted guidance in NEI 95-10.

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

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

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

Yes?

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

MR. RICHMOND: Yes.

MEMBER STETKAR: -- the operating experience review?

MR. RICHMOND: Right.

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

MR. RICHMOND: That sounds like a Brian question.

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

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

The applicants do a pretty good job from what we've seen of learning from each other. Several members here at ACRS for upcoming applications, they learn and review our request for additional information. Somebody asked a question back earlier on that I was going to touch on on the number of REIs.

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

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

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

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

But, on the other side of that, we were getting how formal are we with officially asking the questions and correspondence? We didn't have them docket those Qs and As that we asked on site.

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

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

MR. RICHMOND: All right.

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

Next slide.

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

Next slide.

Question?

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

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

MR. RICHMOND: Excellent question. Let me explain.

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

MEMBER STETKAR: Yes.

MR. RICHMOND: So in one regard of the standard inspection that we do is a horizontal view, programmatic review, and then we do a vertical slice that cuts boundaries of all the different aging management programs.

Did that answer you?

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

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

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

MR. RICHMOND: Stan Gardocki.

MR. GARDOCKI: You work for the balance plant.

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

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

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

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

MR. GARDOCKI: Right.

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

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

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

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

MR. GARDOCKI: All right.

MEMBER ARMIJO: Okay. Thanks.

MR. GARDOCKI: That's feedwater we always put in scope for (a)(1) for the heat removal functions.

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

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

Next slide, please, Unit 1.

Next slide, Unit 2.

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

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

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

MR. RICHMOND: Yes.

MR. BARTON: I was really disappointed. Every inspection report, you do so many walkdowns, you look at systems, you walk that with system engineers. You always make the comment about what you think the material condition in a plant is and I didn't find that in this inspection report.

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

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

MR. BARTON: Thank you.

CHAIR BLEY: Go ahead.

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

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

Next slide.

Section 3.0.3, aging management programs, as the applicant covered in their presentation, our numbers line up with theirs with one exception. They included in their count the boral surveillance program. We didn't include it in our because it arrived after the NCR open item was issued on January the 9th. The program is still being evaluated by the staff. So it was included in their count, whereas it wasn't included in ours.

Next slide.

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

This section is where our open item is located. The 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 not used operating experience to adjust manhole inspection frequency and/or automatic means if frequent inspection fails to keep the cables dry. The applicant has provided additional supplement information regarding cable qualification, which is under review by the staff.

Next slide.

For this slide, this is the groundwater analysis results. The applicant took samples in 2003 and 2007. The 2003 samples, the pH was 6.87. The chlorides were 44.6, and the sulfate were 1.2. That's all per the acceptance criteria.

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

(Laughter.)

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

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

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

MR. HOWARD: I'll defer that question.

MR. WILSON: The Generic Letter just asks for the amount of failures that they had. We just want to clarify and gather data to see if we need to take any further regulatory actions with that. So when a licensee gave us their data across the industry, we just captured the data, quantified the data, and put in tables for us to see where the failure was and how it was.

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

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

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

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

One is I have a users' needs to research to write a regulatory guide. The regulatory guide is going to describe the effective characteristics of a cable-monitoring program. All right. So that was a follow-up because we looked. There is not a consistent way across the industry that they're testing cables.

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

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

MEMBER RAY: Yes.

MR. WILSON: Okay.

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

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

Yes?

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

MR. WILSON: Roy, do you have the exact number? 269? And we separated those out from installation and we looked at the testing failures and so we've separated them out on that. I just didn't know the exact number because I had correlated the number differently, so 269.

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

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

MR. MATTHEW: This is Roy Matthew.

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

MEMBER SIEBER: Thank you.

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

MEMBER RAY: They being?

MR. RICHMOND: For Beaver Valley.

CHAIR BLEY: I assume there has been

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

MR. WILSON: This is George Wilson, again. I'll answer that.

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

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

MEMBER STETKAR: Correct me if I'm wrong, though, for the other members' benefits who may not have looked into this, 60 percent of the reported failures perhaps being attributed to some type of moisture intrusion is taken at face value. You have to be careful because the Generic Letter asks the applicants specifically to report the failure experience with cables that may be susceptible to moisture intrusion.

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

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

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

MR. WILSON: Of cables, that is correct.

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

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

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

MEMBER RAY: That wasn't surprising.

MEMBER STETKAR: It's information.

MR. WILSON: It's information.

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

Next slide.

Section 4, time-limited aging analyses.

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

Next slide.

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

For this slide, the limiting beltline material is the lower shell plate, location B6903-1. For Unit 1 I'd like to point you to the irradiated Charpy V notch upper shelf energy value at 54 effective full power years is 51.5 foot pounds. The acceptance criteria per 10 CFR 50, Appendix G is greater than 50 foot pounds, and this is acceptable.

Next slide.

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

Next slide.

Reference temperature for pressurized thermal shock values.

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

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

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

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

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

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

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

MEMBER ABDEL-KHALIK: Okay.

MR. HOWARD: Next slide.

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

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

MR. HOWARD: No.

MR. WEAKLAND: This is Dennis Weakland from FirstEnergy.

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

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

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

MEMBER BONACA: Okay.

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

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

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

MEMBER BONACA: Okay. Thank you.

MR. HOWARD: Slide 32.

Pressure-temperature limits.

The BVPS Units 1 and 2 implement a pressure-temperature limits report as part of their CLB. The BVPS PTLR is based on a staff approved methodology which permits the applicant to generate P-T limit curve is for future periods of operation. The Beaver Valley 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 Beaver Valley P-T limits will be adequately managed through the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

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

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

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

They have established methodology by which they generate a pressure-temperature limits report. They generate pressure-temperature limits in accordance with the methodology staff as reviewed and approved. It's controlled through plant technical specifications. Therefore, they can continue to use that methodology given that they're going to continue to acquire information necessary to monitor the state of their vessel and regenerate pressure-temperature limit curves going forward for future periods of operation.

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

MEMBER ABDEL-KHALIK: I must be missing something.

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

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

MR. HOLIAN: This is Brian Holian.

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

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

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

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

CHAIR BLEY: Please. Please, use the microphone.

MR. HOWARD: And identify yourself.

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

It became aware to us in the prior version of the SRP that we didn't cover plants whose P-T limits were covered by pressure P-T limit reports. And what this allows them to do is change the reports based on improved methodology and that was permitted to occur through a process for tech spec changes.

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

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

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

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

(Laughter.)

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

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

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

MEMBER ABDEL-KHALIK: There is a specific statement here that this will be adequately management through the period of extended operation. At least to me that means --

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

(Simultaneous speakers.)

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

MR. HOWARD: Section 4.3, metal fatigue

analyses.

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

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

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

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

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

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

MEMBER ABDEL-KHALIK: I mean these results depend on the history, right? And, therefore, to believe these numbers, you have to essentially confirm whatever data that went into doing these analyses. And some of that involves going back to the vault digging out old strip charts and records and finding out what happened. And the question is, are these data believable especially since you had some items here that exceeded a CUF of one.

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

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

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

MR. YEE: They have data, but the thing for us is that we did not go back and look at the strip chart data. We rely on the applicant to identify the data for us. If it seems reasonable, like in this couple of years, the cycle is normal to hot. So we don't except anything to be too high, then it drops down, and then project out.

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

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

MR. MEDOFF: The cycle counting is --

CHAIR BLEY: Come to the microphone.

MR. MEDOFF: One thing you need to realize is no only do they do the cycle counting under their fatigue monitoring program, but if you go into their administrative controls tech spec, cycle counting is a tech spec item and they have to have procedures and controls to do that. So it should provide a pretty accurate account of their cycles that are occurring at the plant.

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

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

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

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

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

MR. HOWARD: Does that answer your question?

MEMBER STETKAR: It answers.

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

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

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

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

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

MEMBER STETKAR: In this particular case, it flags something to me because in the areas -- they could afford to keep scaling from the full 28-years worth of operating experience and many, many types of transients because that didn't get them into trouble.

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

MR. HOLIAN: I understand.

MEMBER STETKAR: Thanks.

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

Are there any additional questions?

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

MR. HOLIAN: Yes, thank you.

MEMBER RAY: I think we're going to talk

about that.

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

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

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

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

MR. HOLIAN: And the answer may very well be that the programs themselves are wide enough to include everything and general enough, but we'll take that as ourselves for a good check and a question for us.

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

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

That's the nature of the concern is, is that really? How can it be true?

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

I am well aware that it has anything else attached to it. It is attached to the concrete and there it experiences certain bending stresses, but, primarily, the stress state in the liner is tensile. All it does is it is expected to carry only the internal pressure resulting from the accident and those classified according to ASME as membrane stresses primarily. This is the primary function of the liner.

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

MR. HARTZMAN: It is its sole function.

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

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

MEMBER RAY: It sure as heck was.

MR. HARTZMAN: On the lining itself?

MEMBER RAY: Yes.

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

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

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

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

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

MR. FARZAM: As far as cable tray attachment, that's a local effect and the anchors need to be designed to take the load to the concrete. Really, liner plate is designed to take a ride with the concrete as far as behavior, the global behavior of the containment, when it's under pressure, it basically wants to blow up and the strain in a liner plate goes with what the concrete section is.

Now, when the containment is under DBE, design basis earthquake, or design basis events like thermal loads, the liner will see a compression because the inside is hot, outside is cold. So in that particular load case, the anchors need to be carefully designed to take the load to concrete.

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

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

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

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

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

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

Structural Engineering.

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

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

MR. HOANG: Yes.

CHAIR BLEY: Anything else?

(No response.)

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

Go ahead, John.

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

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

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

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

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

So I was curious whether somebody could

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

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

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

MEMBER STETKAR: Okay. Thank you.

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

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

MR. LINTELL: The containment isolation, our cutoff for a large early release frequency is about a 2-inch nominal diameter. Most of our connections with containment atmosphere are I guess less than that 2-inch nominal. So we have failures of those connections with direct containment atmosphere. They're going to go to a small early release and not a large early release.

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

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

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

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

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

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

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

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

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

MEMBER BONACA: No. I share the same observations you made. I think, however, that in general they have met the requirements of the regulation. And so I think I was reasonably impressed by the application and by the review by the staff.

CHAIR BLEY: John?

MEMBER STETKAR: I don't have anything else.

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

Other than that, I think things are pretty straightforward. The counting of the cycles for fatigue, I think it would be helpful to us to know that the historical counting is still valid. Nobody's gone back and rewritten history as far as the number of cycles and what's the basis for saying the future cycles will be pretty much based on the recent ten years, but that's just a projection. The cycles will be what the cycles will be. So I think it's just accounting and assuring us that you haven't rewritten history when you go back.

MEMBER STETKAR: Just as a --

CHAIR BLEY: Sorry. We skipped you.

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

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

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

MEMBER BONACA: Since we are going back --

(Laughter.)

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

CHAIR BLEY: Especially with the TMI.

MEMBER BONACA: Yes.

CHAIR BLEY: John?

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

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

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

MR. CUSTER: Otto is ready with something.

MEMBER MAYNARD: Two pages here.

(Laughter.)

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

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

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

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

CHAIR BLEY: A real acceptance criteria?

MEMBER MAYNARD: Yes. And so just enough

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

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

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

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

That's all I have.

MEMBER SHACK: Can I go back one?

(Laughter.)

MEMBER SHACK: The containment, if you have to remember, Oyster Creek got into problems where there wasn't any concrete and contact with the steel. I mean steel and concrete together are a fairly benign environment. I'm reasonably convinced that this is a localized corrosion that happened sometime, but it's not an ongoing problem.

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

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

CHAIR BLEY: John?

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

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

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

CHAIR BLEY: A third intake structure?

MR. BOLOGNA: No, second intake structure. If you don't want to use two pumps in the main intake structure, then you don't want to use two pumps in the alternate intake structure.

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

MR. BOLOGNA: No, that's correct.

MEMBER STETKAR: Okay. Thanks. Thank you.

CHAIR BLEY: Charlie?

MEMBER BROWN: Are we ready?

CHAIR BLEY: I'm ready.

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

MEMBER RAY: My colleagues did a better job of expressing the concern about the containment liner than I did, but I share. I think there is perhaps, I agree with Otto, also, on what Charlie just mentioned, but I think there's a generic thing that we have an interest in here on the subject of cables meaning that it transcends this applicant.

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

CHAIR BLEY: Jack?

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

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

The cables I think is probably generic to all plants. I think it ought to be resolved for all plants. The question is, does that hold up the license renewal or is that a current issue that needs to be solved in a current time and I'm sort of undecided as to how that should be, but I would certainly like to see it discussed again with a further resolution one way or the other regarding the qualification of the current cables for submersion, which FENOC claims they are, and versus leaded cables.

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

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

The containment liner issue, as far as Beaver Valley containment, when it was operated as a subatmospheric containment, I think the containment had a tendency to pull in. It's attached to the concrete by studs. The studs are welded to the back side of the liner and the liner was more or less shaped around the concrete.

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

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

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

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

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

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

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

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

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

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

CHAIR BLEY: Operations get difficult then.

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

If you're aren't using them now, you better go back even though the fuel cost goes up a little bit from that. Or take more aggressive actions or you're going to be faced with the vessel that can't make the 60-year lifetime.

So those would be my comments. I need more information to make a final decision for my own vote on this, on three of these four issues. On the other hand, I don't see anything pending the successful resolution of these issues that would prevent license renewal.

CHAIR BLEY: Okay. Thank you.

One thing I forgot to do as we went around is ask if there's any reason we should have an interim letter. So, let me ask: is there anybody who thinks there's any reason we need an interim letter?

MEMBER SIEBER: Usually the reason why you have an interim letter is when we believe something and nobody else does, or one of the two parties doesn't. My conception of what is going on here is everybody understand what the issues are and we may not exactly know how to solve them all, but it's very clear to me that FENOC has been forthright in their presentation and plant condition and their ability to operate for 60 years, and the staff has been very thorough in its analysis of that, and I don't see a conflict that would bar us to go in and stir the pot some more so to speak. I would say we don't need an interim letter.

CHAIR BLEY: Okay. Everybody else? I guess this is the point I'd like to thank, First Nuclear for really excellent presentations and for being really well prepared to answer any of our questions and having people who can do that.

And the same, I thank the staff for good presentations, good response to our questions, and we'll look forward to getting together.

I'll write up the key points that I've heard out of this and any other members who want to send me something, I'd appreciate and we'll circulate that later.

No other questions, we'll call this meeting adjourned.

(Whereupon, the above-entitled matter was concluded at 4:54 p.m.)

BEAVER VALLEY POWER STATION
License Renewal Application

FENOC Presentation to ACRS

February 4, 2009

FENOC

FirstEnergy Nuclear Operating Company

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**

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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)

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Operating History

	Unit 1	Unit 2
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

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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

2000
- Full Potential Program underway
- Dec. 1999 – FENOC takes ownership responsibility for Beaver Valley

2001
- Beaver Valley begins License Renewal Project

2002
- Unit 2 completes 2R09, shortest outage in plant history – 23 days
- Contract finalized with Westinghouse to complete Unit 1 Steam Generator/Reactor Head replacement

2003
- BVPS receives Top Industry Practice Award from Nuclear Energy Institute for Integrated Containment Management program
- Unit 1 High Pressure Turbine replaced

2004
- Unit 1's shortest refueling outage ever ends in 27 days
- Conversion to Westinghouse Robust Fuel Assembly Design Unit 1
- Beaver Valley earns INPO "Most Improved" Plant Performance Award

2005
- Unit 2 completes a breaker-breaker run; conversion to Westinghouse Robust Fuel Assembly Design
- First license renewal submittal

Operating History

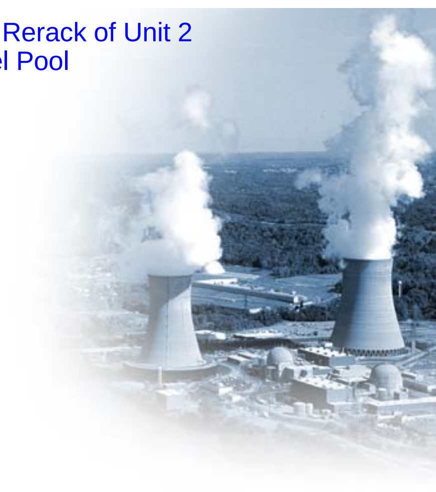
Beaver Valley Power Station

2006 to 2010

- SGRP
- NRC Approval of EPU
- MUG Rotor Replacement and Stator Rewind
- RRVCH
- Unit 1 Atmospheric containment
- Spilt Pin Change Out: Unit 1 10 year Vessel ISI
- World Record On-Line Dose Unit 2, 311 mRem
- Unit 1 Breaker-to-Breaker Run (1R18) with no fuel defects
- Implement Improved Standard Technical Specification
- BV/Westinghouse NEI TIP Award Full Potential Program
- License renewal submittal
- 5% Power Uprate Unit 1
- License renewal approval expected
- Unit 1 Low Pressure Turbine Replacements (U2 2011)
- Complete Rerack of Unit 2 Spent Fuel Pool

2006	2007	2008	2009	2010

- 3% Power Uprate Unit 1 & Unit 2
- Received ANS award for Performance Improvement
- Unit 2 SWOL
- Refueling outage ended record run of 456 days on line with no fuel defects – Unit 1
- Earned 2005 World Class ALARA Award from ISOE
- Unit 2 Head Repair (3 penetrations)
- Unit 1 Structural Weld Overlay
- Unit 2 – 5% Power Uprate
- Unit 2 Split Pin Change-Out, 10-year ISI
- Unit 2 Head Repair (1 penetration)
- Unit 2 – High Pressure Turbine Replacement
- Unit 2 completes breaker-to-breaker run with no fuel defects (2R13)



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**

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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)**

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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)**

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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

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Areas of Interest

- **Boral (Unit 1)**
- **Metal Fatigue (EAF)**
- **Containment Liner Corrosion (Unit 1)**
- **Medium Voltage Cables**

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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**

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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

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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

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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

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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**

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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

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Questions ?

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U.S.NRC
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)

UNITED STATES NUCLEAR REGULATORY COMMISSION

Protecting People and the Environment

License Renewal Inspections

John Richmond

Region I Inspection Team Leader

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Inspection Scope

- **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

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Inspection Results

- **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)

Inspection Results

- 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

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Beaver Valley 1 & 2 Performance Indicators

Reactor Safety				Radiation Safety		Safeguards
Initiating Events	Mitigating Systems	Barrier Integrity	Emergency Preparedness	Occupational Radiation Safety	Public Radiation Safety	Security
Unplanned Scrams (G)	Safety System Functional Failures (G)	Reactor Coolant System Activity (G)	Drill/Exercise Performance (G)	Occupational Exposure Control Effectiveness (G)	RETS/ODCM Radiological Effluent (G)	
Unplanned Power Changes (G)	Emergency AC Power System (G)	Reactor Coolant System Leakage (G)	ERO Drill Participation (G)			
Unplanned Scrams with Complications (G)	High Pressure Injection System (G)		Alert and Notification System (G)			
	Heat Removal System (G)					
	Residual Heat Removal System (G)					
	Cooling Water Systems (G)					

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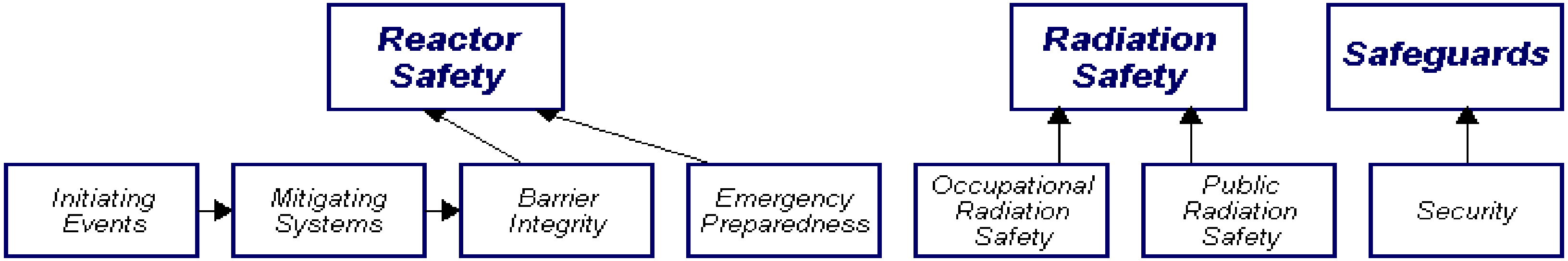
Beaver Valley Unit 1 Inspection Findings

	Reactor Safety				Radiation Safety		Safeguards
	Initiating Events	Mitigating Systems	Barrier Integrity	Emergency Preparedness	Occupational Radiation Safety	Public Radiation Safety	Security
	Most Significant Inspection Findings						
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	
2Q/2008	G	G	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	
4Q/2007	G	G	G	No findings this quarter	No findings this quarter	No findings this quarter	

Last Modified: November 26, 2008

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
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
2Q/2008	G	G	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
4Q/2007	No findings this quarter	G	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

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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

<u>Section 3.0.3.1.11</u> – 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.**

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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

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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 10^{19} (n/cm^2)	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	$\geq$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 10^{19} (n/cm^2)	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	$\geq$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} ^{0}F	RT_{PTS} ^{0}F	Acceptance Criterion per 10 CFR 50.61 ^{0}F
0.21 0.54	6.09	27	275.7	$\leq$270^{o}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} ^{0}F	RT_{PTS} ^{0}F	Acceptance Criterion per 10 CFR 50.61 ^{0}F
0.065 0.55	6.22	60	152.4	≤270^{o}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