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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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HOPE CREEK LICENSE RENEWAL SUBCOMMITTEE

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WEDNESDAY

NOVEMBER 3, 2010

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ROCKVILLE, MARYLAND

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The Subcommittee met, at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, Rockville, Maryland, at 1:30 p.m., William J. Shack, Chairman, presiding.

SUBCOMMITTEE MEMBERS:

WILLIAM J. SHACK, Chairman

J. SAM ARMIJO, Member

JOY REMPE, Member

JOHN D. SIEBER, Member

JOHN W. STETKAR, Member

CONSULTANT:

JOHN J. BARTON

DESIGNATED FEDERAL OFFICIAL:

MICHAEL BENSON

C-O-N-T-E-N-T-S

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

1:29 p.m

CHAIRMAN SHACK: (Presiding) The meeting will now come to order.

This is a meeting of the Plant License Renewal Subcommittee. I am William Shack, Chairman of the Subcommittee meeting.

ACRS members in attendance are Jack Sieber, John Stetkar, Sam Armijo, and Joy Rempe. I got it right.

(Laughter.)

And our consultant, John Barton.

Michael Benson of the ACRS staff is the Designated Federal Official for this meeting.

The purpose of the Subcommittee meeting is to review the license renewal application and associated SER with open items for Hope Creek. We will hear presentations from the NRC staff and PSEG Nuclear, LLC.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting. The entire meeting will be open to public attendance.

The Subcommittee will gather information, analyze relevant issues and facts, and formulate the

positions and actions as appropriate for deliberation by the full Committee.

The rules for participation in today's meeting have been announced as part of this meeting previously published in The Federal Register.

A transcript of the meeting is being kept and will be 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. The participants should first identify themselves and speak with sufficient clarity and volume so they may be readily heard.

We will now proceed with the meeting. I call upon Brian Holian of the NRR's Division of License Renewal to begin.

Brian?

MR. HOLIAN: Good afternoon, Chairman and Committee.

We are pleased to be here today for the Hope Creek Subcommittee on License Renewal Application.

I am the Division Director of License Renewal. The agenda for today is I will just do brief opening comments and then turn it over to the

applicant for their presentation, and following a break, the NRC staff will give their perspective on the open and confirmatory items and the staff review.

To my left is Ms. Bennett Brady. She is the Senior Project Manager on Hope Creek, and she will be doing the bulk of the presentation later.

To her left is Bo Pfam. He is in charge of the Branch that has both Salem and Hope Creek in-house, among other applications.

Behind them, and he will be speaking later, is Mike Modes. He has been to the Committee several times. He is a Senior Reactor Inspector from Region I, who will be giving inspection perspectives later on, and his Branch Chief is also in the audience, Mr. Rich Conte, from the Division of Reactor Safety, the Branch Chief.

Salem/Hope Creek application came in as a common application. We did do a common environmental review. We don't talk about that too much at the ACRS, but that environmental DSEIS is out. We have a public meeting in the area this month out at Salem/Hope Creek for those issues.

We are here this month to talk about Hope Creek, and the Subcommittee will be getting the Salem SER from the staff maybe this week. Yes, this Friday

I believe we will be sending that out. That has got a few other open items and some interesting issues there also.

On Hope Creek, we will be talking, and the applicant will be talking, first about buried piping. That has been a common issue that we have been bringing all plants up to an improved aging management program, as we have identified that in GALL Rev 2. So that is a similar item that the Committee has seen before.

Also, medium-voltage cables, a similar issue that we will bring in the in-house applicants up to the kind of new standards for aging management. And they have got a confirmatory item on metal fatigue. So, you will hear that.

You will also see some slides from the applicant that they appropriately have brought in with some recent operating experience out of the refueling outage that is ongoing now. We had a protracted review with some refueling water leakage that the Committee is seeing on several plants. And where is that water going? What is it doing inside the plant? They've got some new news, even from the recent refueling outage, on that issue.

So, we look forward to a good presentation

today. And with that, I will turn it over to Mr. Paul Davison, Vice President of Ops Support at the site.

MR. DAVISON: Thank you very much, Mr. Holian.

And Good afternoon. My name is Paul Davison. I'm the Vice President of Operations Support for PSEG Nuclear. I'm also the executive sponsor for license renewal at the site.

Before we begin today's presentation, I would like to introduce the three other presenters I have with me at the table. To my right is Jim Stavely. He's the PSEG Nuclear License Renewal Manager for Hope Creek. Jim has 25 years of experience in the industry and 15 specifically with PSEG.

To Jim's right is Mr. Greg Sosson, PSEG Nuclear Engineering Services Director. Greg has 23 years of experience, six with PSEG.

And to Greg's right, we have Jim Melchionna, our Corporate Buried Pipe Program Manager. Jim has 28 years of nuclear experience, the last 18 with PSEG.

In addition, behind you, I would like to have three other introductions. I would like to introduce Mr. Tom Joyce, the President and Chief

Nuclear Officer for PSEG Nuclear; Bob Braun, the Senior Vice President of Nuclear Operations, and John Perry, the Site Vice President for Hope Creek.

Thank you.

Slide 2 shows today's presentation agenda. We will begin with a description, as Mr. Holian mentioned, of the site and an overview of the Hope Creek operating history, followed by an overview of the license renewal application.

We will then continue with discussions on our two SER confirmatory items, one open item, and one topic of interest regarding aging management of Hope Creek's containment structure.

We have developed a comprehensive, high-quality license renewal application and a robust aging management program that will ensure the continued safe operation of Hope Creek Generating Station, and we certainly appreciate the opportunity to make this presentation and look forward to answering any questions you may have.

I will now turn it over to Greg Sosson to begin the presentation.

Greg?

MR. SOSSON: Thank you, Paul.

Good afternoon. My name is Greg Sosson,

and I am the Engineering Services Director for PSEG Nuclear.

Mr. Chairman and Subcommittee members, as shown on this slide, Hope Creek and the two Salem units share a common site on the New Jersey side of the Delaware River in southern New Jersey. They share a common protected area.

Hope Creek is a General Electric BWR owned and operated by PSEG Nuclear. Its reactor building is in the middle of this slide. A second Hope Creek unit was planned, but was not completed. You can see the planned location for the reactor building to the right of the Hope Creek build.

The Hope Creek service water intake structure is on the top of the slide. The Hope Creek cooling tower is to the right, and the Hope Creek switchyard is in the middle of the slide.

Next slide, please.

This slide shows some of the significant highlights in the Hope Creek operating history. Hope Creek was initially licensed to 3293 megawatts thermal. Following a successful startup test program, commercial operation began on December 20th, 1986.

In 1993, hydrogen water chemistry was implemented to enhance our protection of the reactor

coolant system materials.

Measurement uncertainty recapture was completed in 2001, adding 1.4 percent thermal power, to 3339 megawatts thermal. This change involved the installation of ultrasonic flow measurement technology for the feedwater flow system.

In 2004, the generator step-up transformers and the low-pressure turbine rotors were replaced as part of the preparations for an extended power uprate.

As part of long-term asset management, the bravo recirculation pump rotating assembly was replaced in 2006. Also in 2006, we completed our initial noble metals treatment as part of our continuing efforts to protect the reactor vessel and its internals.

The high-pressure turbine rotor was replaced in 2007. It is the last major modification necessary to support the extended power uprate.

Also in 2007, we replaced the alpha recirculation pump rotating assembly as part of long-term asset management.

An extended power uprate of 15 percent, to 3840 megawatts thermal, was completed in 2008.

Hope Creek is on 18-month operating

cycles. Our current unit capacity factor is 92.3 percent.

Our license renewal application was submitted on August 18th, 2009, and our current license expires April 11th, 2026.

I will now turn it over to Jim Stavely, who will present to you the highlights of our license renewal application.

MEMBER SIEBER: Before you do that, Hope Creek is a relatively late model, a late-licensed plant, 1986. So you have Mark I containment?

MR. SOSSON: That's correct.

MEMBER SIEBER: And it's also relatively high-powered compared to other plants with Mark I containments. Does that pose any particular aging management problems for that plant that differ from older and smaller output plants?

MR. SOSSON: Related to the size of the vessel with respect to the Mark I containment, not particularly. There are other reactors that are in similar vintage like that, but with respect to aging management, it doesn't present any challenges. And I will be talking about the Mark I containment later in this presentation.

MEMBER SIEBER: Are you also going to

address aging management of the steam separator inside the reactor vessel?

MR. SOSSON: As part of extended power uprate, we did do extensive inspections of the dryer and separator. Since the extended power uprate, we have done follow-up inspections and have seen no degradation related to the EPU or aging of the steam dryer.

MEMBER SIEBER: Right. As we go through the presentation, I would like to hear a few of the details about what you have found so far, what degradation you have had, what repairs you have had to make, and what your plans are for the future.

MR. SOSSON: With respect to the reactor internals, I will ask Randy Schmidt to provide --

MEMBER SIEBER: Yes, when it comes up in the agenda.

MR. SOSSON: Yes, it doesn't really come up. So, we can address it right now.

MEMBER SIEBER: Okay.

MR. SOSSON: Now is probably the best time to talk about it.

MEMBER ARMIJO: While you are doing that, I notice you probably have the largest fraction of your operating time has been with hydrogen water

chemistry, which addresses the protection of piping and internals. So, if you could incorporate whether that has really afforded you some benefit or not --

MEMBER SIEBER: Yes, noble metals was introduced pretty late.

MEMBER ARMIJO: But hydrogen was like six or seven years after the start of the plant.

MR. SOSSON: Yes, specifically, with hydrogen water chemistry, we did introduce that fairly early on, in accordance with the VIP recommendations.

MEMBER ARMIJO: Okay.

MR. SOSSON: So, we have been taking advantage of that for some time now. Noble metals first went in in 2006.

MR. BARTON: But your application on hydrogen water chemistry only talks about protection of recirc piping. Are you injecting at the rate where you were also protecting some lower reactor internals early on, before you put on noble metals?

MR. SOSSON: Yes.

MR. BARTON: Because your application doesn't address that. It just says you are protecting the piping.

MR. SOSSON: Okay, I'm going to ask Randy Schmidt to address this question.

MR. SCHMIDT: Good afternoon. Randy Schmidt, PSEG Nuclear.

When we injected hydrogen initially, the purpose was to protect the recirc piping only. We do get some benefit to the internals, but we were not fully mitigated in the internals. Therefore, we injected noble metals at a later time to get the full protection of the reactor internals.

MEMBER ARMIJO: From the standpoint of license renewal, the question I have is, how effective has that been? Have you experienced IGSCC in your recirc piping? Have you experienced IASCC on your core internals? That sort of stuff, you know, is it really effective?

MR. SCHMIDT: We have not experienced any IGSCC of reactor coolant system piping. We have seen IGSCC and similar metal welds attached to the reactor vessel. We have experienced some, very little, minor IGSCC in our internals.

CHAIRMAN SHACK: And you have a core shroud that is in very good shape, I mean as these things go, when you measure your cracks in inches.

MR. SCHMIDT: Right. Our core shroud has six indications. Five are less than 2 inches; one is 4.3 inches.

MEMBER ARMIJO: And you haven't had to install any clamps or any of those --

MR. SCHMIDT: No, no repairs were necessary.

MEMBER ARMIJO: Okay.

CHAIRMAN SHACK: I was curious, I mean you do have the corrosion-resistant cladding. You have solution heat-treated. You have done MSIP. You have hydrogen. And yet, it says, "The Hope Creek ISI Program identifies 386 augmented components that are inspected in accordance with GL-8801." So, even after all that, you still have 386 components left? What are those? Mostly the attachment welds?

MR. SCHMIDT: We will have to get back to you on that.

CHAIRMAN SHACK: Yes, okay.

MR. SCHMIDT: Did you want to talk about the steam dryer as well right now?

MEMBER SIEBER: Yes, that would be good.

MR. SCHMIDT: Okay, on the steam dryer, we have not had to make any repairs. Right now, we have 11 indications. Nine are due to IGSCC. One is a freighter crack on a bracket weld from initial welding, and one was caused by a mishandling event early in our operation. So, that is our full extent,

11.

So, we do not have any indications due to fatigue issues.

MEMBER SIEBER: Maybe as a test of my memory, when you did the power uprate, you did agree to some kind of vibration monitoring. How did that work out?

MR. DAVISON: Well, I can address that. In our EPU application, our start-up test program addressed several issues. Randy just talked about the continued results or clean results of not finding indication on our dryer and the subsequent refuel outages since we operated the unit.

As part of the test program, we did flow-induced vibration monitoring as well as the acoustic sensing, if you recall our discussion --

MEMBER SIEBER: Right.

MR. DAVISON: -- around the steam line flows.

MEMBER SIEBER: Yes, that was just a few years ago.

MR. DAVISON: Correct, roughly three years ago.

We did not see any anomalies and had no specific hold points or violations of our criteria as

we went through our start-up program. We did make some minor adjustments, but based on our start-up test program, we did not see anything that was anomalous that would indicate any kind of pulsations back to the dryer or the vessel itself.

CHAIRMAN SHACK: But you have been finding occasional stress corrosion cracks, and you just had one in 2009 in the steam dryer.

MR. SCHMIDT: Randy Schmidt, PSEG Nuclear.

Yes, that is correct. We did find an IGSCC flaw in 2009.

CHAIRMAN SHACK: But, I mean, you have had a history of a crack showing up every once in a while, IGSCC. I mean the good news is there is no fatigue cracks.

MR. SCHMIDT: Right. My own opinion is that, as the inspectors do a better job inspecting, they find these cracks and they have probably been there all along.

MR. DAVISON: Now we will turn it over to Jim Stavely, who will discuss the highlights of our license renewal application.

MR. STAVELY: Thank you.

Good afternoon. My name is Jim Stavely. I'm Hope Creek License Renewal Manager.

My portion of the presentation covers the highlights of our application, including aging management programs, commitments, confirmatory items, and open items.

Next slide, please.

Preparing the application, we used industry and NRC guidance with the goal of making the application as consistent as possible with GALL, and we believe that we were successful.

There are 47 aging management programs, 33 existing programs and 14 new programs, that were developed for the application. Sixteen of the existing programs required no changes to align with GALL. Seventeen of the existing programs required enhancements to align with GALL. Seven of these 33 programs had exceptions. Only one of the 14 new programs had an exception.

The PSEG Nuclear program managers are fully cognizant of the content and the importance of these programs with relation to license renewal.

Next slide, please.

There are 53 license renewal commitments. These commitments are managed under an existing process consistent with NEI 99-04, Revision 0.

Commitments are tracked in the SAP

database system. SAP is the data foundation for many of our site processes, including the corrective action program.

Implementing documents, including procedures and work orders, are being annotated with references to ensure that commitments are maintained. PSEG Nuclear is in the process of implementing many of the enhancements as well as the new programs.

Station and corporate positions are being created to support commitment implementation. In addition to this primary function, these positions will ensure that PSEG Nuclear maintains current with the industry OE with respect to aging management.

Next slide, please.

There are two confirmatory items. The first confirmatory item involves inaccessible power cables. Recent industry operating experience influenced some changes to this program. Low-voltage cables were added to the program.

We changed the maximum cable testing frequency from ten years to six years. The maximum frequency for inspection of cable vaults and manholes for water was changed from two years to one year.

We have submitted this information, which we believe will satisfy the staff's concerns. Our

submittal is currently under staff review.

MEMBER SIEBER: Do your manholes have level detectors and automatic pumpout?

MR. STAVELY: No, there are no level detectors in the manholes, and there is no automatic de-watering system.

MEMBER SIEBER: So, somebody has to look in there to --

MR. STAVELY: Yes. Right now, on the service water vaults, we are performing manual de-watering.

MEMBER SIEBER: Okay.

MR. BARTON: What is your frequency of looking at those vaults?

MR. STAVELY: What I would like to do is introduce our system manager for the vaults, and he can give you some additional information. So, Mr. Andy Huk.

MEMBER SIEBER: But your commitment, I think you said, was only you are only required to inspect once a year?

MR. STAVELY: True, but we adjust. That is the maximum frequency. Our intent is to maintain these cables dry. Right now, we are working through a systematic action plan to get to that state. Andy can

give you some more information, but the maximum frequency is once a year.

MEMBER SIEBER: Okay, and none of your cables are qualified for underwater services, right?

MR. STAVELY: They are not qualified to that extent. They are high-quality cables, which Andy can explain, but not qualified --

MEMBER SIEBER: Yes, I've heard that expression before.

MR. STAVELY: Yes. So, we will not use that.

MR. HUK: Andy Huk, PSEG Nuclear.

Just to provide additional detail, we are doing weekly monitoring of our cable vaults. We are finding water on a weekly basis. That has been the study phase of our project, where we will now move forward, do additional sealing as required, and possibly putting in an automatic draining system, depending on the results of our sealing. So, the end result will be dry cable, but we are still working through that process.

MEMBER SIEBER: Well, you are doing it temporarily on a weekly basis, but I am sure you would prefer to have more time. Do you have any thoughts about extending the interval between inspections based

on, for example, groundwater levels, rainfall, or anything like that?

MR. HUK: We would extend, only extend that inspection frequency if we continually found no water or dry cables each time.

MEMBER SIEBER: That is coming from someplace.

MR. HUK: So, to answer your question, part of this weekly pumping we can correlate water levels within the vaults with rainwater and groundwater. So, that has all been part of the study. So, we will use that information --

MEMBER SIEBER: So you are looking at that?

MR. HUK: Yes.

MEMBER SIEBER: Okay.

MR. HUK: Absolutely.

MEMBER SIEBER: Okay. Thank you.

MEMBER STETKAR: Andy or Jim, I hate to bring this up, but I almost feel compelled on this one because, quite honestly, it sounds like you have had much more problems with water in cable ducts than most of the applications that certainly we have looked at in the last two or three years anyway.

And I am curious why you are not more

aggressive at doing something to solve the problem, rather than just simply monitoring it and pumping the water out when it is in there. Why aren't you aggressively trying to keep the water out or automatically pumping it dry?

And let me give you a little bit of my unease. Part of the staff's reports, I noticed that in June of 2009 you found submerged cables in two manholes for the C service water train, and you initiated a corrective action report to go examine the other vaults because, you know, they are in a similar location, you kind of expected to find water there.

And indeed, when you finally got around to looking in the A vaults in September, three or four months later, you found submerged cables there. And then, when you finally got around to looking at the B and D vaults in November, two more months later, you sort of found water there, too.

I would have understood this sort of -- I don't know what sort of approach -- if this had been 1980, but this was 2009. This has been an issue now since the Generic Letter of 2007-01. The industry is aware of it. The staff is aware of it.

And I see, "Well, we are going to put it in our corrective action program; we are going to

think about adjusting our frequency of inspections based on how frequently we find water in there and have to pump them down again."

Why don't you fix the problem? Why don't you keep the water from coming in there or pump it out? Keep the cables dry?

MR. STAVELY: I think Andy Huk can provide a little bit more information in terms of the timing since we found the first vault with water in the vault, as to what happened with the other ones and what our plan is.

So, Andy, can you provide some more --

MR. HUK: Yes, just some additional information. The service water vaults are not easily accessible. So, they have 60-ton concrete blocks as lids.

So, our first step was to do a modification of the manholes to support frequent inspections. When we did that, we did not expect that weekly pumping would not be sufficient. We anticipated a lot less water ingress into the manholes.

Based on our results as far as having the weekly inspections not be adequate, we went back to the design process to say, hey, look, we need to do,

like you said; let's prevent the water from coming in. So, that is what we are doing.

The next step will be boroscope inspections and additional sealing, because, ideally, stopping the water from coming in to begin with is the ideal solution, which just takes an additional level of effort.

Just to add in terms of timeline, we only can enter the vaults during service water pump outages.

MR. DAVISON: Andy, if I could ask --

MR. HUK: Sure.

MR. DAVISON: -- Mr. Bill Kopchick -- he is an SRO at the station -- to talk about the complications of getting access to those vaults?

MR. KOPCHICK: Good afternoon. Bill Kopchick, Senior Reactor Operator from 1998 to 2000 at the Hope Regenerating Station, PSEG Nuclear.

Yes, sir, understand very clearly the need to get into the vaults, and we are focused on that. As Andy said, it is an evolution to get in. The vault lids had not been lifted, and it did require some design changes to make sure they could be lifted safely.

The weight of the vault lids is extensive,

and it also requires entry into a 30-day LCO, which we go through our work management process to make happen and coordinate.

So, really, from the Station's perspective, the ease to get in there, to really understand what the intrusion of water is, we ultimately did a design change, as Andy mentioned, to get a hole or an access port on top of these heavy vault lids.

Once we in Engineering are able to say exactly what the source of the water is, using a least-invasive process to stop the ingress of water, we may proceed on to actually putting in a de-watering system, which in and of itself also may have some concerns from an environmental perspective, which we have to take into consideration.

MEMBER STETKAR: Can I ask you a couple, while you're up there? From what you said, it sounds like you're not entirely sure what the source of the water is. Do you know, is it infiltration from storms or is it groundwater? Do you know?

MR. KOPCHICK: I would say it's infiltration from storms. The sampling wouldn't indicate that what we have is like a salt intrusion from the river or any brackish. So, it is --

MEMBER STETKAR: So you are not finding that or are you?

MR. KOPCHICK: We are not finding saltwater intrusion from the Delaware River.

So, Andy has actually correlated the sump levels that we have found or the vault levels that we have found compared to rainfall over the previous weeks, which makes us confident that we understand the design to be either a repair to conduit, i.e., plug those that aren't used, or (b) there are transition pieces that go into the vault which we could repair, and those would be the least impactful or intrusive efforts, which are simply stop it. And the last effort that we would go forth is to create a pumping system and ensure that water is disposed of appropriately.

MEMBER STETKAR: And probably, you know, from what I read -- I just want to make sure I understand a bit of the problem also -- it sounded like at least the cable ducts and the vaults and the manholes on the service water side of the plant were originally designed to drain to the manholes. They were the low points, at least what I understood from what I have read. And the original design may have called for sump pumps, but they were never installed.

Is that the design on that side; does everything slope to low points that are accessible for either inspection, if you are just going to follow through on inspection, or for the installation of sump pumps, if you are going to do an automatic de-watering?

MR. HUK: That is correct.

MEMBER STETKAR: Okay.

MR. HUK: Yes.

MEMBER STETKAR: On the other side of the plant, there are a number of cable ducts that contain in-scope cables for station blackout mitigation. I am assuming they are from the switchyard, or wherever.

And from what I was reading there, it almost sounded like the accessible points for either, again, inspection or de-watering, may not necessarily be the low points in those runs. Is that the case or did I read something wrong? It sounded like there seemed to be some uncertainty about saying there could be water trapped between inspection points.

MR. HUK: That is correct. So, there are sections of cable that go in duct banks below the elevation of the manholes for certain sections.

MEMBER STETKAR: Okay. Now I will ask the question that I have finally led you into, of course.

How does your inspection program assure that those cables in those low points that you can't inspect are dry?

MR. HUK: Well, we assure the future operation of those cables through electrical testing. That is why we have the complementary inspect for water and minimize it to the extent practical.

Then, the second part of our program is to monitor it through electrical testing to ensure that the cables are suitable for operation.

MEMBER STETKAR: And what is your commitments on testing frequencies for the cables?

MR. HUK: We are testing with a maximum frequency of every six years. Currently, we are testing every time we take the transformer out of service, every 36 months, and we will adjust the frequency as required to ensure that the cables are acceptable for use. But the six years is the backdrop, the most infrequent we would do.

MEMBER STETKAR: And what kind of test are you doing?

MR. HUK: We are completing tan delta testing at this time.

MEMBER STETKAR: Okay.

MR. STAVELY: Thank you.

MEMBER STETKAR: This is an ongoing -- I mean, well, I will ask the staff, when you come up, about how this dovetails between current licensing basis and ongoing stuff for license renewal.

MR. STAVELY: Thank you.

The second confirmatory item is associated with the selection of locations for environmentally-assisted fatigue calculations. The staff had some questions concerning the selection and its consistency with NUREG-6260, application of NUREG-5999, and our fatigue curves for selection of the power plant components.

We are confirming that the limiting locations selected for NUREG-6260 are bounding when compared to other plant-specific locations. We believe our submittal will satisfy the staff's concerns. The submittal will be submitted no later than November 15th.

CHAIRMAN SHACK: How do you approach that? I mean one of the pieces, when you did the fatigue analysis first, the guys just used enough conservatism to get themselves down below one. If I actually rank those cumulative usage factors, I mean I don't have any real notion that I have ranked them actually in order of severity, just the degree of conservatism the

guy happened to use when he did the analysis.

MR. STAVELY: I would like to ask Tom Quintenz to respond to that question.

MR. QUINTENZ: Tom Quintenz. I'm with the license renewal team.

The process that we used is we went back to every stress report to determine what the maximum values were relative to the calculated CUFs and determined the points that would be bounding relative to --

CHAIRMAN SHACK: Yes, but that may only show you one guy did more conservatism in his calculation than the other guy did. I mean all he was trying to do was to get down below one. You know, he wasn't really trying to do a realistic calculation.

MR. QUINTENZ: Well, once we use the maximum values, then we go and we would, in one case in particular, perform an NB-3200 analysis to look at that particular location in order to assess the environmental effects.

CHAIRMAN SHACK: Yes, but you have picked that location as the worst.

MR. QUINTENZ: Right.

CHAIRMAN SHACK: And you know that on the old stress report, but what is your real degree of

confidence that that is, in fact, the worst location or just the least conservative calculation?

MR. QUINTENZ: Well, you're right, it is all based on the design basis calcs. That is what we used to determine what the limiting locations were.

CHAIRMAN SHACK: Okay. If that's what you used, that's what you used.

MR. STAVELY: Thank you, Tom.

The open item involves buried piping. Since the writing of the draft SER, we have developed an approach that should close this open item. We have submitted our resolution. We believe it will satisfy the staff's concerns. Our submittal is currently under staff review.

I will now turn the presentation over to Jim Melchionna, who will discuss our buried piping program and the associated open item.

MR. MELCHIONNA: Thanks, Jim.

My name is Jim Melchionna. I am a Corporate Buried Piping Program Engineer at PSEG Nuclear.

Next slide, please.

The existing Buried Pipe Program encompasses all the buried piping systems at Hope Creek, three of which are in-scope for license

renewal. This includes the condensate storage and transfer system, the fire protection system, and the service water systems.

The Buried Pipe Program has a risk ranking methodology that has risk-ranked all buried pipe segments according to their relative susceptibility and their consequence of failure. This is based on the National Association of Corrosion Engineers, also known as NACE, and EPRI guidance.

Susceptibility factors of the piping include cathodic protection, coating, physical considerations, materials, and corrosion parameters. The consequence-of-failure factors account for parameters such as whether the piping contains radiological or EPA-sensitive fluids, power production, or plant safety.

Currently, there are approximately 6,000 individually risk-ranked segments in the Buried Pipe Program database.

Based upon the risk ranking, inspections are scheduled to investigate the condition of the buried piping. Any deficiencies identified during excavations and inspections are entered into the corrective action program. For the deficiencies assessed to be adverse to quality, the cause of the

condition is determined and corrective actions are developed.

Extent-of-condition evaluations are performed and the need for additional inspections is evaluated, taking into account such things as similar configurations, environments, and operating experience.

We also review industry operating experience and enter that into our corrective action program. It is reviewed for applicability by the Hope Creek Buried Pipe Program Engineer.

In response to industry OE, the Nuclear Energy Institute, also known as NEI, established an industry initiative on buried piping. PSEG is participating in the industry initiative, and we are currently ahead of schedule in implementing important elements and attributes of that initiative.

We also participate in industry peer groups such as the Electric Power Institute's Buried Pipe Integrity Group and the National Association for Corrosion Engineers. I am on the Advisory Committee of the EPRI Buried Pipe Integrity Group, as well as I am a member of NACE.

Next slide, please.

CHAIRMAN SHACK: Just a question on that.

One of the curious things is the Buried Pipe Program focuses on the external pipe, and it inspects the external pipe. If I look at the open cycle cooling water, they always inspect the inside of the pipe.

MR. MELCHIONNA: That is correct.

CHAIRMAN SHACK: Why don't I do some internal inspections on these systems, too?

MR. MELCHIONNA: And "these systems" meaning?

CHAIRMAN SHACK: The buried pipe systems that --

MR. MELCHIONNA: The buried pipe systems in general is what you are speaking to?

CHAIRMAN SHACK: Yes.

MR. MELCHIONNA: Well, the majority of that piping is fairly non-corrosive for the most part of the systems.

CHAIRMAN SHACK: The fire protection water is treated?

MR. MELCHIONNA: Freshwater is treated, yes.

CHAIRMAN SHACK: Freshwater? It's not just from the Delaware River?

MR. MELCHIONNA: That's correct. So, if you look at the internals of those piping systems, you

never see any, we don't see any issues.

CHAIRMAN SHACK: Do you put corrosion inhibitors in, nitrates, something?

MR. MELCHIONNA: On our freshwater protection system, I don't believe we put any inhibitors.

CHAIRMAN SHACK: Okay. It is just clean water or some sort of clean water?

MR. MELCHIONNA: As I understand it, correct.

CHAIRMAN SHACK: That's good enough.

MEMBER SIEBER: I thought the Delaware River in the location of the artificial island was somewhat brackish?

MR. MELCHIONNA: Yes, the river water itself, the cooling source we use for open cycle cooling itself is very brackish.

MEMBER ARMIJO: So, you use treated water? You don't use river water directly?

MEMBER SIEBER: Well, power water usually comes from your major source.

MR. MELCHIONNA: I think I'm going to ask Ed Keating to probably interject into this and add some clarity to this question.

MR. KEATING: Good afternoon. I'm Ed

Keating. I'm with the license renewal team.

All of our fire water/freshwater is all groundwater taken from the PRM aquifer at Hope Creek at depths of about 900 feet below grade. The Delaware River water is only used for service water and cooling tower makeup.

MEMBER SIEBER: So, you're using wells as your fire water supply?

MR. KEATING: That's correct, sir. And there's no treatment of that water. It's not necessary based on the analytical results.

MR. MELCHIONNA: So, to further clarify your question, yes, the only brackish water that is used from the river is in the open cycle cooling system, which like we discussed prior to the meeting is 95 percent AL-6XN piping.

MR. KEATING: When he is saying "open cycle", he is talking about the cooling tower, which some people refer to as closed cycle.

MR. MELCHIONNA: And service water.

MR. KEATING: And service water, yes.

MEMBER ARMIJO: In these various categories of materials, how many inspections have you done since the plant has been operating and what have your findings been?

MR. MELCHIONNA: So your question is with regard to license renewal systems?

MEMBER ARMIJO: Yes, or any other system that you happen to dig up opportunistically, you know, the carbon steel or the gray cast ductile iron.

MR. MELCHIONNA: Okay.

MEMBER ARMIJO: You know, just to get an idea of what you know already about this condition of the piping.

MR. MELCHIONNA: I understand. So for condensate storage tank system piping, that is stainless steel piping, and we have done guided wave examinations on those. We haven't seen any issues with the in-scope piping. Fire protection, we have done a number of -- we have done a guided wave inspection of that, also have not seen any issues.

We have a number of what we call opportunistic inspections when we have dug holes in the ground. So, any piping that was exposed, we haven't seen any age-related or corrosion-related issues with that piping.

MEMBER ARMIJO: And as far as your cathodic protection system, what has been the availability or percentage time in operation or not in operation?

MR. MELCHIONNA: Okay. So, on the in-scope piping, the cathodic protection availability has been -- we did a survey -- over 90 percent over the last five years.

MEMBER ARMIJO: Okay.

MEMBER SIEBER: Do you ever get any condenser tube leaks?

MR. MELCHIONNA: Yes, we have got condenser tube leaks.

MEMBER SIEBER: Does that put a lot of saltwater in your internal systems, including your stainless steel condensate storage tank?

MR. DAVISON: I will have Mr. Kopchick comment on that.

MR. KOPCHICK: Good afternoon. Bob Kopchick, PSEG Nuclear.

We do have condenser tube leakage. There are, obviously, operator abnormal operating procedures to address them. The condenser tube leaks, the in-leakage is from the brackish water we get from the Delaware River.

MEMBER SIEBER: Right.

MR. KOPCHICK: Historical guidance has changed over time. Typically, if I were to go back in the last five or six years, when we reached 1

microsiemen per centimeter, operators would isolate the water box. We would initiate actions to go find the leak. We have since revised that to 2 microsiemens per centimeter as a must-do and a 1 microsiemen per centimeter we assess performance of the condensate demineralizers and how much really time they have left on them or what the impact would be use on condensate demineralizer capabilities, as to whether or not we would isolate the box and then go and do a leak search.

MR. BARTON: What is your condenser tube material?

MR. KOPCHICK: Titanium.

MEMBER SIEBER: A pretty good pathway to a lot of stainless steel then.

MR. MELCHIONNA: Slide 11.

CHAIRMAN SHACK: Again, on your service water there, I notice you had one set of failures here where you were doing joints that you had to put the Weco seals on. I assume that was in that line in that pre-stress concrete piping?

MR. MELCHIONNA: That is correct. We had installed Weco seals.

CHAIRMAN SHACK: Now how did you find those leaking joints?

MR. MELCHIONNA: There was no leaking joints. There was --

CHAIRMAN SHACK: Corrosion joints, okay.

MR. MELCHIONNA: Yes. Each bell and spigot joint, it is pre-stressed concrete by about 900 foot in the header. Each joint is a bell and spigot. Each joint has an epoxy coating protecting that carbon steel bell ring in the pipe. And 8913, or open cycle loop inspections, revealed blistering of that coating inside the pipe.

So, our plan was to in an outage inspect all that piping, remove the coating that was blistered, examine the material. And where we couldn't repair a joint, we covered it with this EPDM rubber Weco seal which is hydraulically expanded to the pipe with AL-6XN bands, and seal that joint for good.

CHAIRMAN SHACK: Thank you.

MR. MELCHIONNA: Continuing on, this table lists all five of the buried piping materials in-scope for license renewal. These include carbon steel, gray cast iron, ductile cast iron, pre-stressed concrete pipe, and stainless steel.

Column 2 shows the license renewal systems in which each material is present. As shown in column

3, Hope Creek has committed to perform at least one excavation and direct visual inspection on each material grouping during each 10-year interval, beginning 10 years prior to the entering into the period of extended operation. In the case of carbon steel, at least two excavations and inspections will be performed each 10-year period.

This will ensure a comprehensive assessment of all in-scope buried piping material types at Hope Creek.

Next slide, please.

Hope Creek has one open item relating to buried piping, as Jim mentioned. The open item relates to the staff's need for additional information to evaluate how we consider recent operating experience into our Buried Piping Program.

We have considerable site-specific and recent industry operating experience in the development of our program and provided the staff with more information. We provided information about our operating experience and the excavations we have performed which showed the coating to be in good condition. We provided details on our planned inspection locations.

We provided information on the testing of

our cathodic protection system. The cathodic protection system is tested annually, consistent with NACE guidelines.

We also provided details on the quality of our backfill.

MEMBER SIEBER: What percentage of the time or what capacity factor does your cathodic protection system have? What percentage of the time is it in service?

MR. MELCHIONNA: It is designed to be in service all the time.

MEMBER SIEBER: It's supposed to be 100 percent.

MR. MELCHIONNA: A hundred percent.

CHAIRMAN SHACK: What is it?

MR. MELCHIONNA: Correct. For the server we indicated for in-scope piping, it is greater than 90 percent over the past five years that we reviewed.

MEMBER SIEBER: Okay, but you have actually reviewed that? And how often do you check to see that it is operating?

MR. MELCHIONNA: Every two weeks we check volts and amps, compare that to acceptance criteria. Every two months, we do a walkdown of the rectifiers, looking for cable damage, degradation, and making sure

it is in working condition. And then, annually, we do the on/off and instant off potential service.

MEMBER SIEBER: Okay, thank you.

CHAIRMAN SHACK: This water is probably highly conductive.

(Laughter.)

MR. BARTON: You've probably got a good conductor.

MR. MELCHIONNA: We believe the information --

MR. BARTON: You have a separate power station to supply the --

MR. MELCHIONNA: We believe the information we have provided is sufficient to fully address the staff's request. Our submittal is currently under staff review.

Next slide, please.

In conclusion, the Buried Pipe Program will effectively manage the material condition and aging of buried piping at Hope Creek and will do so in a manner that will ensure continued safe operation. We feel we have a very comprehensive and robust program that will continue to develop and improve based on site and industry operating experience, the NEI industry initiative, participation in our industry

working groups, and through the development of any new technology and inspection techniques as they become available.

I will now turn the presentation over to --

MEMBER STETKAR: One quick one. This will be relevant to something later probably, also. I know you said you get your fire water and potable water from deep wells. What's the average groundwater level at the site, feet below plant grade? Zero?

(Laughter.)

MR. MELCHIONNA: I will ask George Seibold or Ed Keating to answer that question. They have the details.

MR. SEIBOLD: George Seibold, PSEG Nuclear.

The site grade is approximately 12 feet above sea level.

MEMBER STETKAR: Okay.

MR. SEIBOLD: And groundwater levels are 5 to 10 feet below site grade.

MR. MELCHIONNA: I will give you a "for instance".

MEMBER STETKAR: Yes.

MR. MELCHIONNA: Just last week, we

uncovered two, we dug two excavations, 36-inch carbon steel pipe, not cathodically-protected, in wet soil. We had quite a few pumping operations to keep that hole dry. That piping, when we inspected it, it was in like-new condition. Once we looked at the coating, the coating was so tight to the pipe and the bolting after 30 years being in the ground, it was in excellent condition.

MEMBER STETKAR: And I am assuming the groundwater chemistry looks an awful lot like river water.

MR. MELCHIONNA: I don't know the exact numbers, but we did sample the soil and the water for analysis out of those excavations.

MR. SOSSON: No, it does not. George Seibold can provide additional detail on the groundwater.

MR. SEIBOLD: George Seibold, PSEG Nuclear.

We have got wells that we have taken groundwater samples from, and those wells generally range from as low as 80 parts per million to 5,000, and our service water system, being tidal, ranges up to maybe 11,000 parts per million.

MEMBER STETKAR: So you get some

filtration. This is chlorides you're talking?

MR. SEIBOLD: Yes.

MEMBER STETKAR: Yes. Thank you.

CHAIRMAN SHACK: Just out of curiosity again, how well is the AL-6X working?

MR. MELCHIONNA: I have seen nothing wrong with the AL-6X except, if you are familiar with sigma phase --

CHAIRMAN SHACK: Yes.

MR. MELCHIONNA: -- there are some material castings with like very thin plates of orifices; you might see some galvanic or crevice corrosion due to the sigma phase. But, overall, we had such tight manufacturing testing with that 6 moly, that there is literally no corrosion on it at all anywhere I have looked.

MEMBER ARMIJO: How long was that?

MR. MELCHIONNA: For Salem, it has been -- both have it, but at Hope Creek since the early nineties. It looks brand-new every time you look at the piping.

MEMBER ARMIJO: Great.

CHAIRMAN SHACK: Almost worth the cost.

(Laughter.)

MR. SOSSON: Thank you, Jim.

Slide 14, please.

That concludes our discussion of the confirmatory and open items. I will discuss the topic of interest for Hope Creek, the Mark I containment.

Next slide, please.

Industry operating experience documents instances of corrosion on inaccessible exterior surfaces of the drywell shell of G.E. BWR Mark I containments. In response to this operating experience, we proactively performed confirmatory ultrasonic thickness measurements, also called UTs, for the drywell shell in 2007 and 2009.

The results of these inspections showed no loss of material due to corrosion. IWE inspections of the inside-to-drywell surface have also shown that the drywell is in good condition.

A small reactor cavity leak was identified in 2009 during the refueling outage. Follow-up inspections of the drywell shell in 2010 identified an area of interest that is being managed through our corrective action program and in accordance with our license renewal commitments. This leak and drywell shell inspection results will be discussed in greater detail later in this presentation.

Next slide, please.

This slide shows the containment house within the reactor building The containment is still pressure vessels and consists of a drywell in the shape of an inverted lightbulb and a toroidal-shaped suppression chamber called the torus.

CHAIRMAN SHACK: Is there some sort of material that is in that air gap or is that really steel-to-concrete?

MR. SOSSON: No, it is a 2-foot air gap that has been --

CHAIRMAN SHACK: Two inches, rather.

MR. SOSSON: Oh, I'm sorry, a 2-inch air gap. Thank you.

(Laughter.)

That was verified during construction. It is truly an air gap.

MEMBER ARMIJO: There is no felt or any other material?

MR. SOSSON: No, there is no insulation or fill material. It is an air gap that would allow air and any potential reactor water to transition through.

MEMBER SIEBER: Could you point out where the reactor cavity leak was on that drum?

MR. SOSSON: Yes. My next slide will show exactly that.

MEMBER SIEBER: Okay.

MR. SOSSON: Above the foundation transitions of the drywell shell there is an air gap, nominally 2-inches wide, as we discussed, that separates the drywell vessel and the concrete drywell shield wall. There is no sand bed region or sand in the foundation transition zone in the air gap at the drywell shell.

At the bottom of the air gap, four equally-spaced drainlines around the perimeter of the drywell shell prevent any water from accumulating in the air gap.

MEMBER ARMIJO: Was that sand removed after construction or was it never put in in the sand bed region?

MR. SOSSON: We do not have a sand bed region. There was sand used during the forming operations, but that was all drained.

MEMBER ARMIJO: All removed?

MR. SOSSON: Yes.

MEMBER ARMIJO: So, you never operated with what was called a sand bed?

MR. SOSSON: That's correct.

MEMBER ARMIJO: Okay.

CHAIRMAN SHACK: And there is a seal

around the bottom of that air gap? Or it just comes down and then it's concrete?

MR. SOSSON: The bottom of the air gap is at the floor level inside the drywell, and there are four air gap drainlines at 90 degrees that I will discuss more.

CHAIRMAN SHACK: But is there a seal between the concrete and the steel shell as it goes down under?

MR. SOSSON: No, there is not.

George, can you?

MR. SEIBOLD: George Seibold, PSEG Nuclear.

No, there wasn't any seal provided. The top of the air gap was one of the four points when we poured the concrete around it.

MR. SOSSON: Thank you.

The exterior surface of the drywell shell is coated with an inorganic zinc to prevent corrosion. The reactor cavity includes a bellows seal to allow flood-up for refueling.

Next slide.

This is a sketch that shows the probable path of a small reactor cavity leak into the drywell air gap that was identified during the 2009 refueling

outage. Note that this leak is not a leak in the containment, but a leak outside the primary containment that has the potential to occasionally wet the exterior surfaces of the drywell shell.

This small leak was identified at the reactor building concrete wall, penetration sleeve No. J13, and it formed a small puddle on the torus room floor.

It was confirmed that the leak only occurs when the reactor cavity is flooded up. The probable leakage path is through a weld defect in the reactor cavity seal plate through the air gap and exiting the gap at the J13 penetration sleeve. This is shown in more detail in the following two slides.

This is a sketch that shows, in blue, the probable leakage path at the reactor cavity seal area. You can see the drawing from the bottom of the seal plate down along the side of the drywell shell.

The reactor cavity seal assembly provides a seal from the exterior of the drywell shell to the reactor cavity liner to permit flooding of the reactor cavity.

This detail shows the normal drains and the seal rupture drainlines. Lack of leakage into the seal rupture drainlines indicated the seal is not

located below the bellows assembly. The probable leakage path is through a small weld defect in the reactor cavity seal plate assembly or piping above the air gap region.

MEMBER ARMIJO: Do you have any idea how big that leak is?

MR. SOSSON: We don't have it quantified, but all the indications, as I will discuss, indicate that it is a very small leak, and the only leakage that we have seen coming out has basically formed puddles that self-evaporate in the 100-drop-a-minute range.

MR. BARTON: And this has been recently found, right?

MR. SOSSON: It was recently discovered in 2009.

MEMBER STETKAR: Greg, I will ask the stupid question I have to ask. You're confident that your reactor cavity seal rupture drainlines are open?

MR. SOSSON: Yes. The cavity drainlines we do test. They run to an instrument that would fill up a float and cause a high-level alarm if we were getting water through there.

MEMBER STETKAR: No, but I mean --

MR. BARTON: They're not closed. There's

no valve that is shut someplace?

MEMBER STETKAR: Well, not a valve, that they're not necessarily just full of, to use a technical term, "gunk".

MR. SOSSON: George, would you like to provide some clarity on that?

MR. SEIBOLD: Yes. George Seibold, PSEG Nuclear.

That system is a completely welded system designed to handle radwaste. Currently, we are providing a design change to provide a port to assure us that that drainage is open. The instrumentation for that drainline is checked every 18 months electrically. So, once we provide a port in there, we can assure ourselves no blockage of that line.

MEMBER STETKAR: But, right at the moment, you don't know whether -- you have not tried to blow air or push water or do something through those lines to see, in fact, that they are open?

MR. STAVELY: I'm sorry. At this point, we haven't, that's correct.

MEMBER STETKAR: Okay.

MR. STAVELY: Because we don't have access to it. So, what we are installing is a test connection, so that we can, through that test

connection, actually add water to the pipe, verify the float mechanically lifts.

MEMBER STETKAR: Yes.

MR. STAVELY: And then, also, through that test connection, put enough water in the pipe to verify it's not blocked downstream, and then use an air source to verify that it is not plugged upstream.

MEMBER STETKAR: That would be a good idea. My only question is, you know, you have isolated the potential root cause for this leak based on the fact that you are not seeing the water out of a drainline that you don't necessarily know is open.

MR. STAVELY: This leak investigation has been systematic in the sense that we have not, even though we do not know at this point whether that drain, the cavity seal rupture drain is open, we continued with a path to implement a design change to be able to check it, as well as implemented a number of actions for this refueling outage to investigate the possible source on the seal plate.

MR. SEIBOLD: George Seibold, PSEG Nuclear.

This is one of our license renewal commitments for the IWE program.

MR. SOSSON: Okay. Yes, slide 19, please.

This slide is a sketch that shows, in blue, the potential leakage path at the lower drywell at the J13 penetration area.

A group of six drywell shell instrumentation penetrations, including penetration J13, are used for instrumentation lines entering the drywell. And they are shown in that matrix on the upper left.

The penetration sleeves provide a path for the instrument lines through the reactor building shield wall. The J37 penetration sleeve is approximately 24 inches directly below the J13 penetration sleeve.

During the 2009 outage, the water leakage was found coming out of the shield wall at the J13 penetration sleeve only.

MEMBER SIEBER: But the normal design drain is the 4-inch drain below it?

MR. SOSSON: That's correct.

MEMBER SIEBER: That's probably 2 or 3 feet below it?

MR. SOSSON: That is approximately 8 feet below, yes.

MEMBER SIEBER: Okay. So, they found a shorter path?

MR. SOSSON: That's correct.

MEMBER ARMIJO: Did they give you an idea of where the leak was in your seal area?

MR. SOSSON: Yes. Our data, it would be likely that the leakage would be occurring somewhere directly above J13 penetration area.

MR. STAVELY: We actually took a look; we boroscoped on each side. If you see that group of six penetrations, we boroscoped a number of times this outage in those penetrations. One of the purposes was to look to the right of J19 and the left of J13 and look back at the concrete, so that we have an idea as to what is the span of the leak.

And we looked at that, the span. You could see where the concrete was dry, where the concrete was wet and then where the concrete was dry. So, we're looking in the 210-to-240 azimuth in terms of the leak span, and that matches up with one of the welds up at the seal plate on top.

MEMBER STETKAR: Greg, before you go on, I will ask the same stupid question about the air gap drains. Are there positive ways of determining that, indeed, those air gap drainlines are not blocked?

MR. SOSSON: Well, I'm going to actually discuss that later in the presentation.

MEMBER STETKAR: Okay. Thanks. No, fine, go on.

MR. SOSSON: Back in the 2009 outage, there was no water coming out of the J37 penetration, the one located right below the J13. Observations indicated that leakage was about a quarter-inch-wide trickle, and the leakage stopped when the reactor cavity was drained.

Slide 20, please.

The reactor cavity leak is small. Our goal is to identify the leakage source and repair it. Without our IWE program commitment, we have indicated a number of actions to monitor the leak and its effects until the leak is repaired. The actions include additional UTs, leakage monitoring, and drainline inspection and testing, as Jim and George pointed out.

Slide 21.

We are currently in a refueling outage at Hope Creek, and we have had the opportunity to implement our corrective action plan for this leak. I will provide you with an update on these actions that we have taken over the last two weeks.

After the cavity was flooded up during the Hope Creek refueling outage, we observed the small

amount of leakage in the torus room below the instrumentation line penetration, as described earlier. Up to approximately 100 drops per minute total were coming from two adjacent penetrations, J13 and J14, during the period while the reactor cavity was flooded.

Using a boroscope, the air gap between the drywell shell and the reactor building shield wall were inspected in the area of the J13 penetration. There were no obstructions in the air gap. A small amount of water was observed to be on the inside surface of the concrete shield wall, which bypassed the penetrations and continued down the concrete wall. The leakage was not on the drywell shell at this point.

The inspection also showed that the water is not trapped against the drywell shell in the area of the J13 penetration. The drywell shell and penetrations visible from the boroscope inspections were all in good condition.

We have also performed daily monitoring of the air gap drains, but did not observe any water leaving the air gap drains. Since we didn't identify any water coming out of the air gap drains, we followed up further to do boroscope inspections of the

air gap drains, and we did find that those drains are covered in all four locations. This is likely a situation that --

MEMBER STETKAR: By covered, you mean plugged?

MR. SOSSON: Yes, blocked.

MEMBER STETKAR: Okay.

MR. SOSSON: And it's likely that this occurred from construction. We have entered it into our corrective action process. This data is about within the last 72 hours. So, this is new information.

MEMBER SIEBER: Does that mean that it will be cleaned out before you start up?

MR. SOSSON: It is in our corrective action process.

If you can go back up to this slide, the air gap drains, the plugs would be located right where the cursor is now. It is about a 40-foot run of pipe. So, in order to actually clear out these drains would require significant scaffold builds to remove the pipe.

So, it is in our action process. Our intent is to remove these, but I can't speak to the timeframe that we will do that. It is obviously a

nonconforming condition that we have to evaluate. And again, this is very new information.

MR. DAVISON: Greg will actually cover some of the things we looked at to make sure that, even if there were some water trapped in there, that wasn't impacting the integrity of the shell. So, he will cover that.

But, more importantly, whatever water does accumulate in that lower area, because now that we have confirmed that the air gap drains are blocked, the source is terminated after approximately 20 days. We're in day 18, and we're already drained back down. Then, with the heatup during normal operations and no source, that water will be quickly dissipated.

MEMBER SIEBER: Yes, the only word you forgot was "hopefully".

(Laughter.)

MR. DAVISON: But we do have concrete evidence that Greg will cover around what the condition of the shell is right now. We do know that.

MR. BARTON: Are you putting a moisture barrier at that juncture of the floor and drywell?

MR. SOSSON: Well, on the inside, there will be a moisture barrier installed on the inside at the drywell floor.

MR. BARTON: There is none now? There never was one?

MR. SOSSON: There is none now. It is in very good condition.

George Seibold can amplify.

MEMBER STETKAR: Why don't we finish this one first? I've got a couple more questions --

MR. SOSSON: Okay.

MEMBER STETKAR: -- about the inside of the drywell.

MR. SOSSON: Okay.

MEMBER STETKAR: In some sense, you are going to talk about the condition of the drywell shell?

MR. SOSSON: Yes.

MEMBER STETKAR: Is there some chance that -- you know, you have discovered this leakage source because in some sense you are fortunate that the water found a pathway out through the J13 place where it could come out. How confident are you that there aren't other leakage positions that didn't have that fortunate pathway somewhere else in the other 358 degrees, or whatever.

MR. SOSSON: That certainly can't be ruled out. But what I can say is, from the drywell floor to

the drywell vent lines that go circumferentially around, the bottom of that drywell air vent is 1 foot 5 inches, and there is an air gap between the drywell vent line and the concrete. So, if water was accumulating in the annulus region between the drywell shell and the concrete of the containment --

MEMBER STETKAR: It would come out through the gap in the drywell --

MR. SOSSON: Yes, and we have seen no indication anywhere else.

MEMBER STETKAR: Okay.

MR. SOSSON: And we have calculated it --

MEMBER STETKAR: But that interference isn't apparent on this.

MR. SOSSON: Yes, it's not clear on the drawing, and we calculated it would take 320 gallons of water in order to fill up before it would start spilling out, and we have not seen anything. So, if there is a leakage, it is so small that it either evaporates before it can fill up that high or there's no leak.

MEMBER STETKAR: Okay.

MEMBER ARMIJO: But that shell is coated with zinc all the way down to the point where it meets the concrete, where it is supported. And it is an

inspectable area, right? You can actually take a look at that area in the sand bed region? At least in some designs you certainly can access it.

MEMBER SIEBER: You can get it from the inside.

MEMBER ARMIJO: I am talking about the outside of the shell. Can you look at --

MEMBER SIEBER: Well, the outside is --

MR. DAVISON: George can walk you through what that looks like.

MEMBER ARMIJO: Okay.

MR. SEIBOLD: George Seibold, PSEG Nuclear.

The air gap region is fairly inaccessible.

(Laughter.)

That is why we are boroscoping it through these penetrations.

MEMBER ARMIJO: Okay.

MR. SEIBOLD: We did review construction reports, and we know the outside of the drywell shell was coated with an inorganic zinc after construction for the purpose of protecting the outside of the shell. But we really can't get in there to inspect it.

MEMBER ARMIJO: You can't take photographs

through your boroscope or anything like that?

MR. SEIBOLD: Well, we have taken boroscopes up through the J13 and J37 area. And as Jim said, the shell and the coating look to be in reasonable shape.

MR. STAVELY: It is an articulating boroscope, and when we turn the head around, we can see maybe 3 feet with the light we have from that. What we are considering, though, is getting a specialized camera that we can lower through the penetration opening, so that we can look at the area down.

So, even though it is an area that right now we can't see, we are exploring ways to look at that.

MEMBER SIEBER: Now that drawing sort of shows that, if you wanted to, right at the drywell floor on the inside, you could perhaps do a UT, but --

MR. STAVELY: We did test that and --

MEMBER SIEBER: -- my experience is that these kinds of drawings aren't all that accurate, and the air gap on the outside may go below where the floor is. So, you are sort of guessing about that.

MR. STAVELY: What we intend to do, we do intend, I said, to drop the camera -- or lower the

camera.

(Laughter.)

MEMBER STETKAR: You might drop one or two.

MR. STAVELY: No, it's an expression. Lower the camera and then retrieve the camera.

One thing we haven't mentioned is the water chemistry. We have three samples of the water chemistry that is coming out of those penetrations. So, it is coming down the shield and the pH is on the order of 8.3 to 8.5. And that would be the type of water that would be at the bottom there.

MR. SOSSON: Which is consistent with it draining down across the concrete.

MR. DAVISON: George, do you want to --

MR. SEIBOLD: George Seibold, PSEG Nuclear.

The design of the drywell at the floor level is such that the drywell floor and the air gap are coincidentally the same.

MEMBER SIEBER: That is what it appears to be here, but in construction it is not always that way.

MR. SEIBOLD: Well, further evidence is that is where the outer skirt of the drywell also is

designed to hold up the drywell shell.

MEMBER SIEBER: Okay.

MR. SEIBOLD: So, it is kind of like that is where the air gap is allowing the drywell shell to move. Therefore, we are pretty confident that --

MEMBER SIEBER: But on the inside of the drywell, the concrete truck came in, they dumped some, smoothed it off, and that's where the joint ended up, however much was in the concrete. You don't know exactly where that level is.

MR. SEIBOLD: Well, you know, they maintain drawing tolerances and there is a potential --

MEMBER SIEBER: Yes.

MEMBER ARMIJO: Jack is skeptical.

(Laughter.)

MEMBER SIEBER: Yes, I have been on construction projects.

(Laughter.)

I know how it's done.

MR. SEIBOLD: Greg will also mention that we dig UT measurements 360 degrees at that junction.

MEMBER SIEBER: Okay.

MR. SOSSON: So, with regard to the ultrasonic testing done to investigate the possible

effects of the identified leakage, we did perform the UT exams of the shell in four areas from inside the drywell.

We examined the shell around the instrumentation penetration assembly where the water entered the torus room and was observed on the concrete wall in the air gap.

We performed the UT exams approximately 25 feet above the instrumentation penetration area on an area where the drywell shell would be more likely to have been wetted by the leak due to the geometry of the drywell.

If you could just back up to slide 17? Seventeen, please.

So, elevation 122 corresponds to that top platform. So that we would surmise that that is where the drywell is being wetted. So, we took UT exams there.

Go back to the previous slide, please.

Additional UT inspections were performed directly below the instrumentation penetration area vertically down to the drywell floor area, which is equivalent to the elevation of the bottom of the air gap.

Finally, a set of UTs were performed on

the shell near the floor around the entire circumference of the drywell.

With the exception of the lower portion of the plate directly below the instrumentation penetration assembly, all readings showed greater than nominal plate thickness, and I will discuss later on the next slide more detail of these UT results.

With respect to the leakage investigation activities, prior to the flood-up of the reactor cavity, we did perform a visual inspection of the seal plate area, the bellows area, and the reactor cavity liner. We saw no indication of the possible source of the leak.

Following refueling activities, the partial drain-down of the cavity, and prior to draining the outer bellows, a boroscope examination of the seal plate and bellows area for any indication of the leak is going to be performed. That will be done over the next couple of days. Following drain-down of the cavity, we will confirm that the leakage has stopped.

We are collecting as much information as possible this outage to facilitate continuing investigation to identify the cause of the leak and implement repairs.

Next slide, please.

This is a complicated slide. This is a summary of our UT results for exams performed during 2010 to investigate whether the leakage discussed has caused any impact on the drywell. The readings also provide a baseline for future UT measurements to determine any corrosion.

So, to orient you to this slide, we basically took, as I described earlier, areas of interest vertically above and below the J13 penetration area. At 121 feet, which corresponded to that top platform I pointed out, UTs were taken at a 1-foot-by-20-foot area to broadly bound above the J13 penetration area. We took a total of 44 UTs. The average reading was 1.576 mils for the 1-foot 576 inches for the 1.5-inch plate. As you see, all the readings were nominal.

MR. BARTON: 1.5 inches?

MR. SOSSON: Yes, 1.5 inches.

MR. BARTON: Thank you.

MR. SOSSON: Yes, thank you.

At elevation 97 feet, corresponding to that lower platform on the drywell drawing, we looked at an area 1 inch by 3.5 feet. We took a total of 20 UT readings. And again, the average reading was 1.564

inches with the low reading still being above nominal.

MEMBER SIEBER: What is your mid-wall, about 8/10ths of an inch?

MR. SOSSON: The analyzed thickness is 1.4375 inches, which is shown in the bottom 1.5-inch plate. Yes, the analyzed -- yes.

MEMBER SIEBER: Okay.

MR. SOSSON: Well, we will come back to that.

For the J13 penetration area, that is actually a 3-inch plate. We took readings across, we took 84 UT readings across that plate area. That is approximately 4-feet wide or 6-feet wide by about 4-feet high. And again, for the 3-inch-thick plate, the average readings were 3.110 inches. The lowest was 3.066, all above nominal.

The lower readings were the 1.5-inch plate that go from just below the J13 penetration area to the floor. That plate, as was discussed earlier, actually goes down below the floor.

We highlighted the gray boxes to indicate our area of interest. As I referred, the lowest spillover point would be 1 foot 5 inches above the floor, according to this slide.

So, the slide results from the UT

performed in the three main areas; looking at the lower slide, you can see the results of the UT measurements. We took a total of 79 measurements. There were between seven and nine measurements taken on 10 different horizontal rows for that lower plate, with approximately 1 foot between each of the readings. The average values for the readings on each row are provided on the slide.

As you can see, although the average values are within the tolerance range, the readings near the bottom plate tend to be the lowest. Therefore, we have established this as an area of interest, and we will be examining this in future outages.

It is important to note that the individual and average thickness readings on the plate are above design plate thicknesses, which is the 1.427.

MEMBER REMPE: What's the accuracy of this ultrasonic technique? What does the vendor claim? How accurate is it?

MR. ROBERTS: Good afternoon. Tom Roberts, PSEG Nuclear.

The accuracy of the ultrasonic testing, which is a standard straight-beam examination for

thickness, is plus or minus .01. So, any reading you have, you can go plus 1/minus 1.

MEMBER REMPE: Okay.

MEMBER ARMIJO: Did you have any interference down at the lower 2 inches? Because that's where your support skirt is on the other side there. Did you pick that up? Or did that interfere with your measurements at all?

MR. SEIBOLD: George Seibold, PSEG Nuclear.

Our UTs did not pick that up. We did plate sections down there, and they alternate between an 1.5-inch-thick plate to a 3-inch plate at the vent lines. And we also have stiffeners in that area. So, we had a UT around them to avoid them.

MEMBER ARMIJO: Okay.

MEMBER STETKAR: Just before, to make sure I understand this one, all of these UTs, though, were done in the area below the penetration assembly?

MR. SOSSON: Yes.

MEMBER STETKAR: Did you do any other UTs?

MR. SOSSON: Yes, we did 360 degrees --

MEMBER STETKAR: You did?

MR. SOSSON: -- at 1-foot intervals, 360, and in all other cases they were above nominal.

MEMBER STETKAR: At nominally floor level or?

MR. SOSSON: At floor level.

MEMBER STETKAR: At floor level?

MR. SOSSON: Yes.

MEMBER STETKAR: Okay. Thanks.

CHAIRMAN SHACK: Now did you see any variability that would indicate that this was a little bit lower than the others?

MR. SOSSON: Well, actually, the data indicated that this one plate appears to be a little lower. All the others were above an inch and a half, but this plate is uniformly a little thinner than the others. So, we have established this as an area of interest. Now this will be a good baseline for us to go in in future outages and to monitor.

MEMBER SIEBER: Now these readings are at the floor level? But the leakage drain was from an instrument line? Above that, did you do readings around that instrument line penetration?

MR. SOSSON: We did not take any readings in the upper cylinder of the containment, but we did --

MEMBER SIEBER: Well, that's in the lower half, where that line --

MR. SOSSON: Yes, if you can go to slide 17, please? I'm sorry, 17.

The highest readings that we took, we did take previous baseline readings in that upper cylinder, which I will show next. But, specifically, following this leak path, right where the cursor is now is the highest point where we were looking at specifically in 2010 as a followup.

If you go to slide 32, these are basic readings that we took through the containment, which this is a backup slide. It's not in your presentation.

But these are the results of some readings taken in 2007 and 2009, prior to knowing about the leak, so that we could assess drywall thickness proactively.

Back to slide 22?

Okay, moving forward on slide 23, in summary, the drywell shell is in good condition. The design includes adequate corrosion allowances to ensure the design margins are maintained through the period of extended operation.

A small reactor cavity leak is being managed in our corrective action program and in accordance with the license renewal commitments.

We have effective aging management programs to ensure continued safe operation of the Hope Creek containment.

I will now return the presentation to Paul Davison for closing.

MR. BARTON: A question: if you never had a moisture shield, according to what I read, there was no moisture barrier at the floor to the drywell connection. Why are you now going to install one?

MR. SOSSON: We are basically installing the moisture barriers as a good practice.

And I will ask George Seibold to --

MR. BARTON: Are you sure that maybe no water got between the concrete and the drywell over the years?

MR. STAVELY: In the previous refueling outage in 2009, we cleaned and performed a VT1 inspection of that junction.

MR. BARTON: Of that joint?

MR. STAVELY: Of that joint specifically.

MR. BARTON: Okay.

MR. STAVELY: And there was no indications of any significant corrosion or problems. Because we wanted to make sure before we put in a moisture barrier that we understood the surface. So, we

performed that in 2009.

MEMBER STETKAR: I mean you can only go a certain depth below where that joint is. What confidence for the lower part of the drywell, which is completely inaccessible, that the water hasn't seeped down in there over the years and has caused corrosion problems?

MR. BARTON: You haven't gone through, drilled a hole, put a UT probe against the drywell surface from the inside?

MR. STAVELY: There was no design gap in there. So, the concrete was poured directly against the shell.

George Seibold can provide a little bit more information.

MR. SEIBOLD: George Seibold, PSEG Nuclear.

During the 2009 outage that we did the VT1 inspection, we probed that joint with a feeler gauge, and trying to see if there was a gap there. And in a few small spots, we got a 5-mil feeler gauge in there, but nothing thicker than 5 mils. And there was no indication of water or corrosion or concrete deterioration that would indicate corrosion in that joint.

CHAIRMAN SHACK: How regularly do you inspect that?

MR. SEIBOLD: As part of IWE, they inspect it, but they do a VT3. As part of our assessment on the drywell, we wanted them to do a VT1 on that area. So, that was done in 2009.

And as one of our commitments, we said that, as part of the IWE, after we install the moisture barrier, then they have to inspect the moisture barrier, which they weren't inspecting before because it didn't exist.

MR. BARTON: You are going to get an opportunity to look at some of that joint when you take the concrete out to put a moisture barrier in, right?

MR. STAVELY: No, we are not actually taking the concrete out, no. We prepare the surface both on the concrete and the shell side, recoat it, and then apply the caulking material, the moisture barrier material on top of that. So, we prepare the concrete and the shell.

We implemented approximately 1/8th of that in the last week. So, the remaining 7/8ths of the moisture barrier will be installed in the next refueling outage.

The reason we chose not to install it all this time was because it is a significant ALARA budget to be able to put in a moisture barrier on a plant that is already operating. So, we choose an area that would be in a lower-dose area where we could verify all our maintenance practices and any sort of tooling and shielding issues. So, when we do it in the next outage, we do it effectively and we manage our dose.

MR. SOSSON: Thank you. I will now return the presentation to Paul Davison for closing comments.

MR. DAVISON: Thanks, Greg.

Mr. Chairman, Subcommittee members, thank you for your interaction during our presentation today. As previously mentioned, we are very confident that our license renewal application reflects an aging management program that will continue the safe operation through the period of extended operation.

And pending any other additional questions, this will complete our presentation.

MEMBER STETKAR: A couple of questions.

CHAIRMAN SHACK: Please. Sure.

MEMBER STETKAR: You're ahead of schedule?

CHAIRMAN SHACK: Yes.

MEMBER STETKAR: Your structures monitoring program, there were enhancements made to

that program to add a relatively large number of structures. One of the ones that I noticed was the fire water tank foundation was added for the monitoring. I didn't go back and look at the scope of the program myself.

Is the condensate storage tank foundation monitored under that program?

MR. SOSSON: Yes.

MEMBER STETKAR: Thank you.

Also, in your structures, I think it was the structures monitoring program, there was an enhancement that says, "Enhanced parameters to be monitored for wooden components to include change in material."

Where do you have wooden structural members for license renewal in-scope components? This is a curiosity because, since you enhanced the program to add wood, you must have some wood somewhere. So, where is it?

MR. STAVELY: Hopefully not in containment.

(Laughter.)

MEMBER STETKAR: Not that you know of.

(Laughter.)

MR. SEIBOLD: George Seibold, PSEG

Nuclear.

Out at the intake structure, we have wooden ice barriers to prevent ice to come in --

MEMBER SIEBER: They're on the outside of the --

MR. SEIBOLD: They are on the river side.

MEMBER SIEBER: Right.

MR. SEIBOLD: And they prevent ice from --

MEMBER SIEBER: That's common.

MEMBER STETKAR: I don't know how common it is, but fine.

(Laughter.)

CHAIRMAN SHACK: In California and Arkansas, they don't do much of it, but up north.

MEMBER STETKAR: Well, not necessarily wood, though. I mean it could be steel or it could be other kind of barriers, riprap.

MR. BARTON: You've gotten some corrosion in the inspections at your service water by on the river, underwater corrosion. Are there plans to go and fix that stuff?

MR. DAVISON: George Seibold, again, is the man with that answer.

MR. SEIBOLD: George Seibold, PSEG Nuclear.

We have done the inspections, and we have noted some deterioration down there. We have provided operability determination, and we will be doing follow-up inspections to make sure those supports are maintained.

We have in the past repaired some of those supports. So, we now have instituted a PM for when they de-water those bays, that we specifically -- they de-water the bays for mechanical components, and now we are making sure a structural engineer also goes down into the service water intake bays to do his inspections.

MR. BARTON: Thank you.

MR. SEIBOLD: And it is also one of the enhancements in the structural monitoring program that, besides those components, he just does general inspections of the de-watered bay.

MR. BARTON: Thank you.

In your small bore Class 1 piping inspection, you committed to do 100 percent inspection of all accessible Class 1 socket welds in the research system. How large a sample is that? Because you're talking about accessible. How many welds do you think you're talking about here?

MR. SOSSON: We have the exact number.

Paul Cervenka?

MR. CERVENKA: My name is Paul Cervenka. I am a member of the license renewal project team.

That weld population is 60 welds.

MR. BARTON: Okay. I wanted to make sure, since you said it was accessible, it wasn't one to five.

(Laughter.)

Thank you, Paul.

MEMBER ARMIJO: Have you ever failed any of those welds?

MR. SOSSON: There has been, earlier in plant life, small bore socket failures which have been subsequently addressed by design improvements to change the structural residence --

MEMBER ARMIJO: Were they fatigue-related?

MR. SOSSON: Yes, they were high-cycle fatigue-related.

MEMBER ARMIJO: Okay.

MEMBER SIEBER: So you put supports in?

MR. SOSSON: Yes, we changed --

MEMBER SIEBER: You changed the length of the pendulum?

MR. SOSSON: Yes.

MEMBER SIEBER: Okay.

CHAIRMAN SHACK: As I read that, I couldn't -- is that a periodic inspection or is that a one-time inspection?

MR. CERVENKA: Paul Cervenka, member of the license renewal project team.

The 60 welds will be inspected during a 10-year period prior to the period of extended operations. So, if there are any problems, we will identify them upfront.

MEMBER STETKAR: Oh, is it only one? It's not --

MR. CERVENKA: It's all the time with 100 percent recirc --

MEMBER STETKAR: Okay.

MR. STAVELY: And if we find any indications on those examinations, it goes in our corrective action program, and we are back at it.

MEMBER STETKAR: I have one last really off-the-wall question. In a fuel oil chemistry program there is an enhancement that says you're going to, for filtering for particulates, you are going to use a filter with a pore size of 3 microns, which, indeed, is consistent with the GALL recommendations, instead of 0.8 microns.

Now a lot of applicants are going to the

smaller filter size recommended by a different ASTM standard to try to capture more particulates. You seem to be going in the opposite direction, at least the way I read it. And I was curious, why? Was that an active decision or is --

MEMBER ARMIJO: It still meets the requirement.

MEMBER STETKAR: I know it still meets the requirements, but I was curious why.

MR. STAVELY: Do you have the reference as to which --

MEMBER STETKAR: Well, I didn't have the LRA in front of me. It is AMPB-2.1.20, and I'm excerpting the stuff that I read out of the SER. So, I might be mischaracterizing it.

MR. STAVELY: I'm not sure. I think that's one we would have to get back, if we could get back to you at break?

MEMBER STETKAR: The way I read it, it sounded like -- I wasn't sure what you're using now, but the enhancement says the modification consists of using a filter with a pore size of 3 microns instead of 0.8 microns.

Then, because this is from the SER, it says the staff compared these enhancements to GALL and

concluded that 3 microns is consistent with GALL.

MR. STAVELY: If you would like, we can get an answer back for you on that.

MEMBER STETKAR: Page 101.

MR. STAVELY: Okay, I don't have that one with me.

MEMBER STETKAR: It is a real minor one. It just struck me because we have seen several where people have said, well, we are going to follow this other standard, and people have noted it as an exception, but the staff says, well, yes, it is an exception, but it is more conservative, so it is okay.

MR. STAVELY: We have an engineer right now looking for that.

Do you have an answer, Pete, or do you want a little more time?

MR. TAMBURRO: I could provide that at the break.

This is Pete Tamburro with the license renewal project team.

I will provide it after break.

MEMBER STETKAR: Okay. Thanks.

MEMBER SIEBER: What's the fuel oil tank material? Is that stainless?

Fuel oil, typically, all the water goes to

the bottom of the tank, and the line that you usually use to sample is about 6 inches off the bottom. So you don't know whether you've got a layer of water down there or not.

A lot of people have stainless steel tanks, but that doesn't help because you have got concentrations over the years of chlorides down there.

MR. BARTON: The Boral Monitoring Program, how does that work? There's seven sites across the country. You're not one of them, but, yet, that supposedly is a program that is acceptable?

MR. STAVELY: The basis for our program is that BWR Boral coupons constitute a single population with common characteristics. So, if it is a single population, we can monitor the testing results at other BWRs with Boral, and ascertain the performance of our Boral through those.

The seven plants you are speaking about is, what we will do at least every two years for our commitment is we survey the plants, the BWR plants, that use Boral and ask if they have had a testing sequence since the last time we contacted them. And they request copies of the reports.

So, the plants that we can use from report to report may change. So we try to get the most

recent inspection data.

MR. BARTON: Okay.

MEMBER ARMIJO: But you don't do any evaluation yourself?

MR. STAVELY: So far, the way the program is set up, we monitor the inspection results at other plants. We also monitor any operational problems in our spent fuel cool racks; for example, difficulty inserting or removing a fuel assembly that could be traced to Boral problems.

We also monitor our water chemistry, including aluminum, boron, and lithium, to see if there's any signs of a chemical degradation of our Boral.

We have a set of triggers in our program that, if we hit a trigger, then we will sample, we will test our own coupons. So far, we have not hit any of those triggers, so we have not tested our coupons.

However, we still have the trees that are in the spent fuel cool racks, and we are radiating the trees, so that if we need to perform our own coupon inspections, the trees are representative and we can do our own coupons.

MR. BARTON: Okay. Thank you.

CHAIRMAN SHACK: Any additional questions?

(No response.)

Well, then, thank you very much for a very good presentation.

And it's time for a break. We will even take a full 15 minutes, even though we are running late.

(Whereupon, the foregoing matter went off the record at 3:05 p.m. and went back on the record at 3:20 p.m.)

CHAIRMAN SHACK: Let's come back into session.

If we can just hold up for a second, the licensee says -- or the applicant (laughter) would like to answer the questions. And I thought we would just do that before we started the staff's presentation.

MR. DAVISON: Yes, thank you. Paul Davison from PSEG Nuclear.

We are prepared to answer the three questions.

The first question will be answered by Mr. Randy Schmidt.

MR. SCHMIDT: Randy Schmidt, PSEG Nuclear.

There are 386 components in the IGSCC

program. The IGSCC program is an augmented program to the ASME Section XI ISI program. These 386 components were categorized in accordance with Generic Letter 8801 --

MR. DAVISON: Excuse me, Randy.

Paul Davison from PSEG Nuclear.

Could you please restate the question for the record and for everyone, to make sure we are clear? Thank you.

MR. SCHMIDT: I believe the question was, what are these 368 welds and why so many?

CHAIRMAN SHACK: Yes, when you have essentially mitigated, I would have thought, with two things, which would get them off the augmented inspection list, because that was the real gist of my question.

MR. SCHMIDT: The majority of the 386 components are IGSCC-resistant and classified as Category A.

CHAIRMAN SHACK: Oh, okay. Okay.

MR. SCHMIDT: Okay? So, they are still in the augmented program.

CHAIRMAN SHACK: They're still in the program, but --

MR. SCHMIDT: They're Category A. There's

364 components to Category A. So, there's only 22 non-Category A.

CHAIRMAN SHACK: Okay. Okay, that's an understandable number.

MR. SCHMIDT: Okay.

CHAIRMAN SHACK: Thank you.

MR. TAMBURRO: My name is Pete Tamburro, and I work for the Hope Creek licensing renewal project.

The second question I am going to answer is, what are the materials of the tanks that store fuel, diesel fuel oil? They are all carbon steel tanks.

The third question related to, why did we go from a 3.0-micron specification to a 0.8 specification? That's the other way around. I apologize.

It's really an improvement. With the 0.8-micron particulate, you are looking from zero to 0.8. The new enhancement would look from a zero size to 3.0 microns. So, we will be looking at larger particles with a wider range.

MEMBER STETKAR: Could you explain that to me, how that works? Why do you capture, why don't you capture -- let me say this: with a 3-micron filter

size, how can you capture 2.9-micron-sized particles? Don't they go through?

MR. TAMBURRO: That's right, and that's what you end up sampling. Your sample is on the other side of the pores, the pore side of the filter. It gets through, and that's what you send.

MEMBER STETKAR: I didn't know that was the way it was done. Because every other one that I have seen has said it is conservative to use the smaller filter size because you trap more of the particulates. So, therefore, you have evidence of a broader range of particulates.

MR. TAMBURRO: With the new method, you would have particulates from zero to 3.0 microns in diameter, the sample.

CHAIRMAN SHACK: Okay, it is a sampling program? It's not an actual filter of the fuel. It's the sampling program.

MEMBER STETKAR: Well, but the other ones give you -- I have not read the procedures. The other ones give you the impression that you collect stuff on the filter, and that's your sample.

CHAIRMAN SHACK: Yes.

MEMBER STETKAR: So, therefore, a 0.8-micron filter will collect more material, and that's

conservative. They always characterize a .8-micron filter size as a conservative compared to the GALL. A number of applicants have taken an exception to GALL. By using the .8-micron filters, they have to justify the exception. The exception is, well, it's conservative because we will trap more stuff, and therefore, our sample will be more conservative. And I can understand, if you are sampling downstream from the filter, the reverse is true. So, okay.

CHAIRMAN SHACK: You are sure you are sampling downstream from the filter? You are not scraping the stuff off the filter and looking at it?

MR. TAMBURRO: We are sure we are sampling downstream of it.

CHAIRMAN SHACK: Okay. Thanks.

I think we can begin the staff's presentation.

Brian, are you going to have opening words?

MR. HOLIAN: Yes, I have just a few opening remarks.

Again, my name is Brian Holian. I am Director, Division of License Renewal.

At that table for the staff, once again, we have a couple of names I have mentioned, but I want

to mention a few more that we have sent up.

Bill Holston is a Senior Reviewer for buried piping. You have heard him at a couple of the previous Subcommittees on the previous plans, and has had the lead technical review on buried piping.

Dr. Allen Hiser is our Senior-Level Advisor in License Renewal. He is up there for support on a variety of issues, including the small bore and metal fatigue and other issues.

Bennett Brady, our Senior Project Manager for Hope Creek; Mike Modes, Senior Reactor Inspector out of Region I, and Arthur Cunanan, New Project Manager, helping us with slides today.

Also, we just want to highlight several Branch Chiefs. I don't often highlight them, but the three technical Branch Chiefs are all here today. In License Renewal, Raj Auluck, Jerry Dozier, and David Pelton, all in the audience here. They help us with a lot of the good RAIs that you see. We also have Meena Khanna from the Division of Engineering here.

We get support from several of the technical offices. So I wanted to highlight them, and members of their staff are here to assist in this staff's presentation.

A couple of comments, just from the

earlier presentation.

One item that had come up on one of the questions was a little frustration brought up by the Committee on the manhole testing timeframe. I just wanted to comment kind of from my position on that.

We also did think, from the staff, that it was a little bit slow, the industry response to that. So, how do we respond to that?

Well, one, we sick our technical Branch Chiefs on them and say, "Get those RAIs out quickly and ask them why they're not doing more in a quicker manner."

We coordinate with the region, where that is necessary, and Mike Modes will be able to give you a little information from their perspective on that.

We also kind of coordinate with NEI. We have quarterly meetings with NEI. We brought it up with them, and all the license renewal kind of community; the plants that are in or are going to come in attend those.

We still thought, even though they are here at these ACRS meetings often, that it was slow getting out, the message to get out and look in advance at these things.

From the industry's perspective, you know,

the arguments I have heard were, "Well, we're not seeing it so much in our cable failure rates. So the safety significance is low."

I think they also, early on there, were trying to convince the staff that, well, we think we can kind of qualify that cable, even though it is not officially qualified.

So, those were a few of the things that they had. And also, maybe in this plant, a lot of them just didn't believe they would have water down there, I think. They were hoping they didn't.

I know in this plant I had seen some pictures that they actually had to carve up some roadways to get at it, if the pictures are right. They had to remove some asphalt to get at the covers, which then were large.

So, a lot of things might have added in, but I was glad that the Committee kind of picked up on that. From what I have seen from my perspective, I think the industry has the message on our audits. They have gotten out ahead and have now gotten to all of the manholes before we get to the site on our audits. That wasn't the case here a year, year and a half ago.

NEI did respond to some the staff's

concern on this with what they call the -- I had to write it down -- "regulatory issue resolution protocol". It is a new thing NEI was doing to try to get ahead and move faster on these issues. And these submerged cables was the first one of those.

And I will reserve any other judgment on whether that helped or not, but I wanted to comment on that from my perspective. We might get into that more.

Second, the applicant's presentation on drywell, I just wanted to give some kudos to my staff. It was just a couple of days ago that I was briefed on this emerging inspection that they did in this outage. I wanted to give credit to Raj Auluck and his structural people, who have been pushing through the RAIs to get at and look at a lot of those issues, and get at UTs. So, hopefully, you see that in the SER, and the licensee seems to be still taking the good path.

That is not an open item, as we went into this. We might still have some RAIs. So, I'm giving the applicant the heads-up on that. As we have seen this latest operational experience, we will have some follow-up questions that even the Committee has asked and some more questions like that.

You know, small bore piping came up a little bit here again with the number, that Hope Creek volunteered to look at their small bore. That's good. I just wanted to remind the Committee, a month ago when we were in here -- no, I'm sorry, a few weeks ago on GALL -- we had supplied this Subcommittee some more information on the GALL revision on small bore piping. We tried to get a little bit better from a couple of weeks ago, where we were on kind of the program for that. So, the Committee will be seeing that. I just wanted to mention that.

And then, finally, on buried piping, I will give the Committee a heads-up. As good as the op experience has been on the Hope Creek side, which you are hearing this month, it hasn't been too bad, and you heard some comments on pristine piping and that.

Salem is coming next month, and it's not as pristine. So, I just want to give you a heads-up on that, and the applicant on that. Salem had some tough operating experience, and they had no cathodic protection. So, the staff is still wrestling with them on kind of the proper position for next month, and that is Salem.

That's it. A little lengthy, but, with that, I will turn it over to Bennett Brady.

MS. BRADY: Thank you, Brian.

As Brian mentioned, I am Bennett Brady. I have been the Project Manager for the Hope Creek license renewal review.

I would also like to mention my boss and Branch Chief, Bo Pham, who is there at the table with Brian, and Arthur Cunanan, who has been my assistant in the license renewal review for Hope Creek and, also, for Salem.

Also, there are many members of our technical staff in the audience who participated in reviewing the application and going on the audits inspections that we have talked about.

Next slide.

The applicant has already covered practically all the topics I am going to talk about. So, I will try to be brief and not repeat any of the information they have given you. My discussion will focus more on our staff reviews and our findings.

This shows an outline of our presentation. It, more or less, followed our Safety Evaluation Report in its structure. I will talk very briefly about the overview of Hope Creek license renewal review, then move to Section 2, where we talk about the scoping and screening methods and the results.

And Mike Modes, the Chief Inspector for Region I for Hope Creek, will give his presentation and findings.

Then, we will go to Section 3, which is really the heart and meat of our SER, quite a long section in which we talk about the aging management programs and the aging management review results. And finally, Section 4, the time-limited aging analyses.

Next slide, please.

I believe the applicant has covered everything on this slide. I would just mention that we received the application on August 18, 2009, and we have proceeded pretty much on schedule in accepting the application and, then, our review, and coming here today to speak to you.

Next slide, please.

This slide shows the major audits and inspections that were conducted during this review and the time periods for our review. You will probably note that the time periods for each of these is a little bit longer than the usual. That is because we covered both Salem and Hope Creek, and that is being reviewed in two different SERs.

You will also note that our major audit, what we call the AMP audit, was in February, the 8th

to the 19th. People in this room will probably recognize this as "the Second Great Snow", also called the federal government holiday.

(Laughter.)

For our staff and for the applicant's staff, it was not a holiday. They kept working through that period. We were very pleased with that.

Next slide.

CHAIRMAN SHACK: They didn't have anything else they could do.

(Laughter.)

MS. BRADY: But they did a good job.

This is our overview of our SER. It was presented to the applicant on September 30, 2010. We have one open item, the piping, and two confirmatory items, which you have already heard some about these, the inaccessible low-voltage power cables. Both of these are relatively new issues, and both of them have arisen from the operating experience. And they have been presented; I think the first one is probably with the Cooper license renewal.

And then, our last confirmatory item concerned metal fatigue, in which we are asking the applicant to provide us a verification that the locations they selected for their environmentally-

assisted fatigue analyses were actually bounding for Hope Creek.

Next slide, please.

I would also mention that I should have mentioned just then that, in addition, we will talk some about our review of the reactor cavity leakage that the applicant discussed essentially and our review of their Section XI IWE program, also, which, as Brian mentioned, it is not an open item, but it is an item of interest and an item of continued discussion.

This Section 2 covers our review of the scoping and screening. The Section 2.1 covers their scoping and screening methodology. And then, Section 2.2 is the results of their systems and structures that were screened into the license renewal review. And then, Sections 2.3, 2.4, and 2.5 present the results of the mechanical systems, the structures, and the electrical systems.

We didn't have any open items in this review that were additional components added to the reactor building and to the power protection system and other parts, as a result of our review.

At this point, I would like Michael Modes, the Region I Lead Inspector, to present you the

results of their inspection.

MR. MODES: Thank you very much.

We performed three weeks of inspection covering both applications. We did that because there are always a large number of common aging management programs when you come to the site with multiple designs. Similarly, most done with two different designs had a substantial number of common aging management programs.

So, we tried to choose as many of those as time would give us, and we, then, tried to sample a set representatively unique to Hope Creek. And of course, as always, the 5054(a)(2) nonsafety affects safety. That takes one inspector an entire week to go through that, walk down various examples in order to ascertain whether the three-dimensional interactions have been accommodated by the applicant.

I selected the Boral Program to determine how the applicant was rolling in an Interim Staff Guidance and how they were dealing with that. In order to give it a broad look, we took a brief look at the feed and condensate system in order to find out how the aging management programs would address the aging that we either knew about or the applicant had discovered in a particular system.

Next slide.

These are just some of the examples of the walkdowns that we did for Hope Creek. We did many more for Salem as well, which you will hear about next month.

MR. BARTON: Let me ask you a question. When you walk down to the Hope Creek Station, what's your overall impression of the anterior condition of the station?

MR. MODES: Very good.

MR. BARTON: Thank you.

MR. MODES: Next slide.

So, one of the issues that came up was the applicant was following the GALL guidance in order to determine whether or not they might have selective leaching. And it was obvious to us, both in the applicant and based on our own experience with the facility over time, that they, in fact, had already experienced leaching.

This is, I think, an example of an applicant who is so good at what they're doing, these applications, they sometimes find themselves going up a blind alley. And once we point it out, "Although your following the GALL is absolutely appropriate and you did it perfectly, you do have it already, don't

you?" And they absolutely agreed, it was for them I think a "eureka" moment. And they reevaluated it very quickly and revised their application. But, overall, a very good application, and we didn't find any situations where they did not identify aging, and the 54A2 program was very sound.

Thank you.

MEMBER SIEBER: Actually, it seemed to me like their analysis was pretty clean as far as based on what I have read. You did not find a lot of issues?

MR. MODES: No, we did not.

MR. HOLIAN: Yes, Bennett, this is Brian Holian, license renewal, just to add in, I meant to add that into my opening comments here also. You know, PSEG, other than I took issue with the cabling issue and the amount of time there, but, overall, they have utilized the Exelon team that we are very familiar with as kind of partners in the license renewal application. Mike Modes had seen many of the Exelon plants also come through license renewal. So, that team approach to this was very beneficial, we thought, to the application process.

MS. BRADY: Thank you, Michael.

Moving on to Section 3, in which we talk

about the aging management review and discuss the aging management programs and the results from our review, the staff in Section 3.0 reviews each of the applicant's aging management programs, compares these go GALL, and determines whether they are acceptable.

Then, in Sections 3.1 through 3.6, we reviewed all the line items, over 5000 I believe. We looked at the intended function of each component, anterior, environment, the aging management program the applicant selected, and the safe review, and determined whether these were acceptable. When they completely followed the GALL, it was pretty easy. There were some cases where we had to do more in-depth review, and these are discussed in our SER.

Next slide, please.

The applicants also presented this slide which shows the breakdown of the existing and new, and how they compared with GALL in terms of exceptions and enhancements. So, I won't go through that. If anybody wants to be checking my figures, they come out right, if you consider the fact that the plant-specific two programs there, the existing programs also have enhancements.

Moving on to our first open item, the buried piping and tanks inspection, this is one of the

issues I mentioned before that has come from our review of recent operating experience. In response to this, we have sent out a generic RAI to all the current applicants asking them to give us their instances or failures they have had with leaks in their buried piping programs, and how are they adjusting their AMPs to take account of this experience.

And the second generic question was, have you considered the industry operating experience with buried piping and leaks and modified your AMP for this? We sent out the generic RAI. They provided their response on September 1. Since then, we have issued a follow-up RAI.

We found that we needed more information on the material of these pipes, whether they had cathodic protection. Did they have hazardous material in the pipes? And they sent their response in by Friday, October 29th, and the staff will be reviewing that.

The next item, please.

This is our confirmatory item that has already received an extensive amount of discussion. As I mentioned before, this was a late-arriving issue, and also it was based on the operating experience.

The GALL medium-voltage program came out in 2005 with GALL Revision 1. Since that time, the NRC has issued Generic Letter 2007-01 on inaccessible underground power cable failures.

In that Generic Letter, they asked licensees to report on any failures they had of cables over a much wider range. As a result of this, the staff found that there were failures in those lower-voltage ranges. And when we looked at the data and the distribution, we found that there were increasing failures and they seem to occur for plants for cables that have been in service from six to ten years.

In view of that, we asked that the applicants add these lower-voltage cables to their medium-voltage cable program, and we asked that they increase the frequency of their cable testing and manholes inspections to a minimum of every six years of testing the cables and a minimum of every year for inspecting the manholes. I think we have had a considerable discussion on that.

The applicant has submitted their change in the program. It includes these lower-voltage cables. It eliminates an exclusion that was in the GALL program for cables not exposed to significant voltage, and it increased the testing frequency of the

cables to every six years, inspections of the manholes at least every year.

MEMBER STETKAR: Bennett, before you go to the next one, I would like to hear from the staff. This is an issue that we are discussing in the context of license renewal. The period of extended operation, if the license renewal is granted, does not start for another 15 years and five months from now.

What is the staff doing in the interim to address this issue? I don't know whether Michael is the best person or Brian, or someone. I understand what the applicant is proposing to do starting 15-and-a-half years from now. How are you following this issue today?

MR. DOUTT: Cliff Doutt, DLR.

That is the Part 50 question.

MEMBER STETKAR: Right.

MR. DOUTT: As far as operating here -- and Mike can probably fill in, too -- but there was an inspection report. There was a violation, uncited, for the service water. There's corrective action that was implemented for that.

So, in the Part 50, there are corrective actions being done, which is either pumping the annulus out, defining the frequency, testing the

cables, determining what test frequency is required, and going forward. All of that, essentially, should set up a baseline for license renewals to what this frequency would be.

When they revise the LRA to include low voltage, they get rid of the 25 percent exclusion and increase the test frequencies. Those are maximum. So, at some point, they are going to have to establish a frequency that fits whatever the operating experience is of the plant.

MEMBER STETKAR: Yes, I guess I understand that. And I understand that, right at the moment, I guess even as we speak, they are inspecting those service water ducts, I think they said weekly.

Is there anything -- and I don't know what capabilities you have in the reactor oversight process -- to address the issues of more proactive keeping the cables dry and the watering systems --

MR. HOLIAN: Yes, we also have Roy Mathew here also.

Go ahead, Cliff.

MEMBER STETKAR: It is a bit outside the scope of this meeting, but --

MR. HOLIAN: No, it is a good issue. We brought it up at previous meetings.

This is Brian Holian, License Renewal.

Roy Mathew is here from the Division of Engineering.

This is an item that crosses Part 54 and Part 50 space. We have several of those, buried piping, and we feel we are leading in license renewal space now.

The NEI initiative is in-house. It's being reviewed. We have similar reviewers that work with license renewal staff, and we have a tech staff still looking at the industry initiative and what they will commit to, because we are very cognizant of we're capturing the plant's in-house, say on sand-buried piping. How am I getting the plants that went previously? So, the staff has those on our plate.

Here I know we mentioned it, but it has probably been at least four months ago, several meetings ago, that we did expand the ROP to have inspectors look at, now on a sampling basis, these manholes. So, that was an issue that crossed over several months back.

Roy, you might also talk with the issues we are doing with the Reg Guide on cable testing and that under Part 50.

MEMBER STETKAR: And quite honestly, I

wouldn't have brought it up necessarily in this forum if the period of extended operation were starting a year from now.

MR. HOLIAN: Yes, yes.

MEMBER STETKAR: But we are --

MR. HOLIAN: Extending time, yes.

MEMBER STETKAR: -- really, really far away right now.

MR. MATHEW: Yes, this is Roy Mathew from the Division of Engineering.

Actually, we are taking a number of actions from a Part 50 perspective. On the reactor oversight process, we have an inspection procedure to go back and look at manholes on a routine basis. We have identified some issues. We have issued, actually, a Region has issued several findings. That's another thing.

The staff portion from a Part 50 point of view is the licensees have to maintain the cables in the environment for which they are designed. So, as far as staff knows, all the cables are designed only for the right environment. So, if the licensees are violating that, we will enforce them. That is another thing we are doing, enforcement aspect through inspection.

Then, staff is issuing a Reg Guide to give, let's say, the staff version, which is consisting of mandating a condition monitoring program. The Reg Guide is going to give the criteria or the limits for a good condition monitoring. So, that involves testing and all kinds of attributes that consist of good cable condition, much broader.

That Reg Guide is already issued. We got comments from the industry. We are in the process of finalizing it. Most likely, that will be issued by January of next year.

MEMBER STETKAR: Michael, if you could, just make a note that we probably would like to see that.

MR. BENSON: Okay.

MR. MATHEW: Anybody else have any other questions?

MEMBER STETKAR: No, thanks.

MR. MATHEW: Okay.

MEMBER STETKAR: Thank you very much.

MS. BRADY: Thank you. If there are no other questions, we received the licensee's commitment on this, and it contains the four elements that we have been seeking.

Next slide, please.

On this topic, already we talked a lot about it, and I thought I would talk a little bit about our staff review of this, the ASME Section XI, IWE program and the reactor cavity leakage.

This issue probably had more RAIs, follow-up RAIs, and discussion than any of the other issues during our review. We were concerned about the leak from the penetration and why it was caused, what was causing it.

During our review, we asked the applicant to do a number of modifications to this program. I think the original IWE Section XI program had six enhancements to it. When we got through, there were 10 enhancements.

In response to our questions, they agreed to monitor the penetration sleeve and repair it, if possible, and if not possible, to continue to look into the cause of it. They also committed to do UT inspections of the drywell.

They have informed us. We have had two briefings since this recent outage in which they have told us about the leaks. We are very pleased to see that there are some fruits coming from our persistence on their monitoring and UT. We think this will be helpful to them in planning their future inspections

at the next outage. We will continue having discussions with them and listening to what their plans are addressing this issue.

Are there more questions of the staff?

(No response.)

Next slide, please.

The last major section of our SER concerns the time-limited aging analysis. We have one confirmatory item from this section.

Next slide.

That concerns the metal fatigue analyses. The applicant, in selecting the locations of their metal fatigue analysis and the environmentally-assisted fatigue analyses, had used the suggested locations in NUREG/CR-6260. This is all of the generic locations for the environmentally-assisted fatigue analyses.

When we were reviewing the SER, we noted that there were some other components that had higher cumulative usage factors than those that were actually selected for the environmentally-assisted fatigue analyses. We have asked the applicant to verify that the locations selected were bounding compared to other locations that they might have selected. And I think the applicant said that we will be receiving their

response around the middle of this month.

CHAIRMAN SHACK: Okay. Well, I had what I questioned before. Do you think using the CUF from the design basis calculations is a good way to pick bounding locations?

MS. BRADY: That is a good question.

(Laughter.)

DR. HISER: We find it hard to ignore if they have a location that has a very high CUF, .8, for example, and using a location that has a CUF of .00-something. I mean it needs to be rationalized as to why the one location bounds the other.

CHAIRMAN SHACK: But you were expecting them to do all the 6260 locations plus --

MS. BRADY: Plus --

CHAIRMAN SHACK: -- additional locations?

DR. HISER: Right. The concern that we have is that there they may be plant-specific locations at Salem or at other plants that may be more bounding than 6260.

CHAIRMAN SHACK: But this way, you will at least have a reasonable sample of locations, including --

DR. HISER: That's correct.

CHAIRMAN SHACK: -- the 6260.

DR. HISER: This is Allen Hiser, the Division of License Renewal.

CHAIRMAN SHACK: I must confess I don't have a better way of coming up with bounding locations, either, but I can always throw rocks at it.

(Laughter.)

DR. HISER: We don't want to throw rocks. We just want a good technical basis for why the way they have analyzed does bound the locations in the plant that could be important.

MS. BRADY: I would also like to mention that we have asked the same question for Salem on their analyses, and we will most likely be asking this to all future applicants.

DR. HISER: What we have found is plants have done 6260, the GALL report says "as a minimum", and that was where they terminated the discussion. Our concern is that there may be plant-specific locations again. So, we want licensees or applicants to address that.

MS. BRADY: The final slide.

On the basis of our review and pending satisfactory resolution of the open and confirmatory items, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal

of Hope Creek Generating Station.

That concludes my presentation. We will be coming back to the ACRS in March, I believe it is, with our final report.

DR. HISER: Can I just make one -- yes, one item that was discussed earlier today was the Boral program. I think the applicant indicated it was a program where they would not do plant-specific testing but would monitor information from other plants.

In a response dated May 11, they did indicate that they would modify their program to include testing of one coupon prior to PEO, and then one coupon every 10 years. So, they will be doing monitoring. That is the staff's expectation at all plants, that they either will have monitoring through coupons or they will do some in situ measurements.

MEMBER ARMIJO: And what kind of tests will they do?

DR. HISER: What they indicated here was conventional and neutron attenuation measurements. There again, it was just confirm that the assumptions in their criticality calculations are maintained.

CHAIRMAN SHACK: Are there any other questions for the staff?

(No response.)

Well, if not, thank you very much for a concise and elegant presentation.

Adjourned.

(Whereupon, at 3:59 p.m., the proceedings in the above-entitled matter were adjourned.)

Hope Creek License Renewal

ACRS Subcommittee
November 3, 2010

PSEG Nuclear LLC

Agenda

Introductions – Paul Davison, Vice President, Operations Support

Site Description – Greg Sosson, Director, Engineering Services

Operating History – Greg Sosson

License Renewal – Jim Stavely, Manager, License Renewal

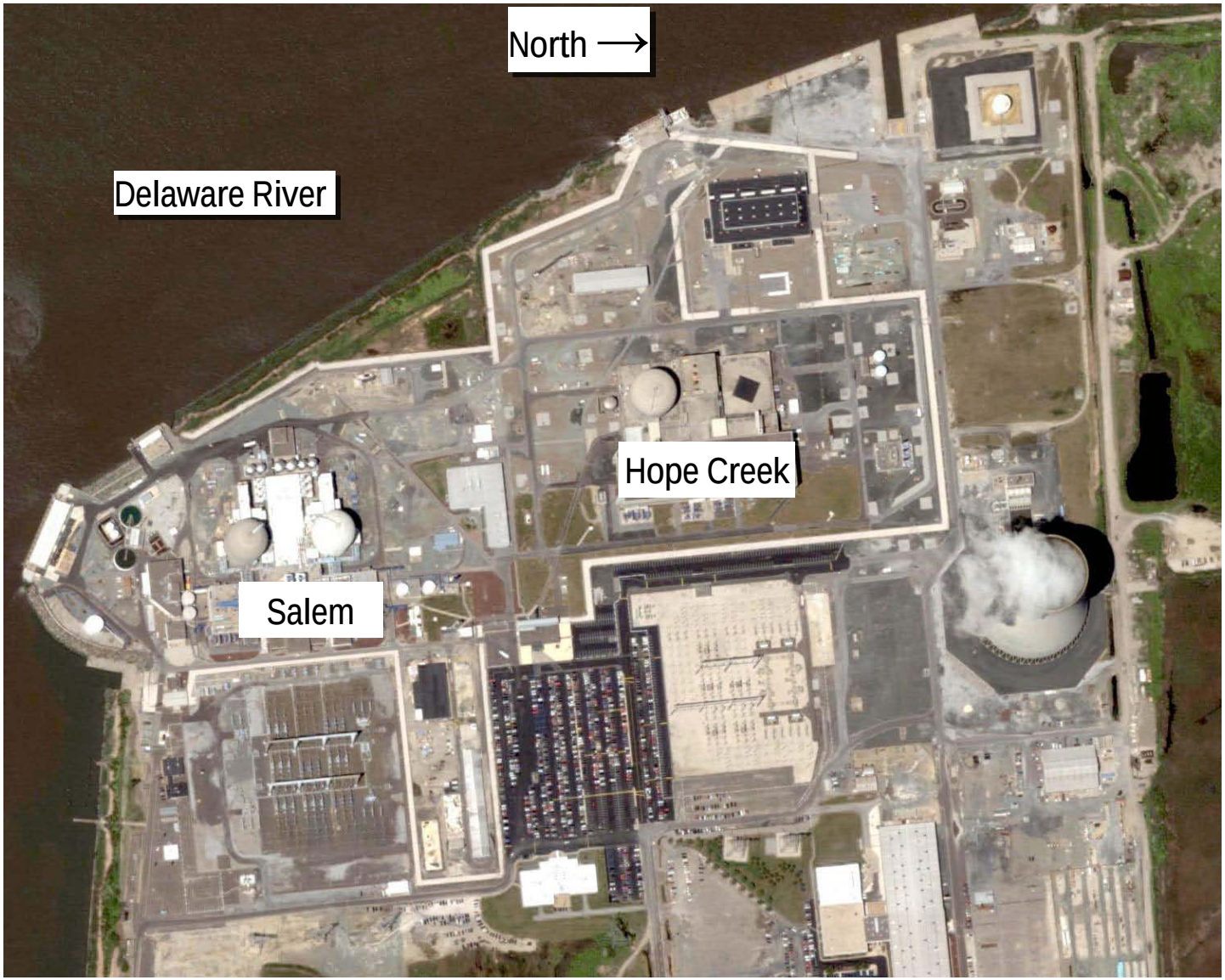
- Inaccessible Power Cables — Jim Stavely
- Environmentally Assisted Fatigue — Jim Stavely
- Buried Piping Program — Jim Melchionna

Topic of Interest:

- Mark I Containment — Greg Sosson

Closing Comments – Paul Davison

Site Description



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Hope Creek Operating History

Initial Operating License at 3293 MWt	1986
Hydrogen Water Chemistry	1993
Measurement Uncertainty Recapture to 3339 MWt	2001
Generator Step Up Transformer Replacement	2004
LP Turbine Rotor Replacements	2004
'B' Recirculation Pump Rotating Assembly Replacement	2006
Initial Noble Metals Treatment	2006
HP Turbine Rotor Replacement	2007
'A' Recirculation Pump Rotating Assembly Replacement	2007
Extended Power Uprate to 3840 MWt	2008
Unit Capacity Factor (18 month)	92.3%
LRA Submitted	08/18/2009
Current License Expires	04/11/2026

License Renewal

Jim Stavely
Manager, License Renewal
PSEG Nuclear

PSEG Nuclear LLC

Aging Management Programs

- 33 Existing Aging Management Programs
  - 16 programs had no changes required
  - 17 programs required enhancements to align with GALL
  - 7 of these 33 programs had exceptions
- 14 New Aging Management Programs
  - 1 of these 14 programs had an exception

Commitments

- 53 License Renewal Commitments
- Commitment Management
  - Process consistent with NEI 99-04, Revision 0, “Guidelines for Managing NRC Commitment Changes”
  - Commitments tracked using SAP Database System
  - Implementing documents (e.g. procedures, work orders) annotated with commitment references
  - Implementation has begun well in advance of PEO
  - Station & Corporate positions created to coordinate commitment implementation

Confirmatory and Open Items

- Confirmatory Items
  - CI 3.0.3.1.20-1

    Inaccessible Power Cables

    The Staff and the Applicant have reached an agreement regarding the Applicant's proposed frequency for manhole inspections and cable testing
  - CI 4.3.5.2-1

    Environmentally Assisted Fatigue

    The Staff requested confirmation that the limiting location per NUREG-6260 was bounding as compared to other plant specific locations
- Open Items
  - OI 3.0.3.1.2-1

    Buried Piping Program

    The Staff required additional information to evaluate the Applicant's consideration of recent industry operating experience on buried and underground pipe leakage

Hope Creek Buried Pipe Program (BPP)

James A. Melchionna
Corporate BPP Program Manager
PSEG Nuclear

PSEG Nuclear LLC

Buried Pipe Program

- Scope
  - Includes all buried piping systems at Hope Creek, 3 are in-scope for License Renewal
- Risk Ranking
  - The program has risk ranked all buried piping segments according to their relative susceptibility and consequences using NACE and EPRI guidance
- Inspections
  - Focused inspections based on risk rankings
  - Opportunistic inspections when excavations created for reasons other than pipe inspections
- Corrective Action Program
  - Off normal findings are entered into the site CAP
  - For deficiencies, cause is determined and corrective actions developed
  - Extent of condition based on inspections, similar configurations, and environments
  - Industry OE is reviewed and input into the CAP
- NEI Initiative
  - In response to industry operating experience, NEI has established an industry initiative on buried piping integrity (NEI 09-14)
  - PSEG is implementing the industry initiative

Buried Pipe Program – License Renewal Inspections

Materials	Systems	Inspections Prior to PEO and Every 10 Years Thereafter
Carbon Steel	Fire Protection Service Water	Two
Gray Cast Iron	Fire Protection	One
Ductile Cast Iron	Fire Protection	One
Pre-stressed Concrete	Service Water	One
Stainless Steel	Condensate Storage & Transfer Fire Protection	One

Buried Pipe Program – Open Item

- OI 3.0.3.1.2-1: Staff requires additional information to evaluate applicant's consideration of recent industry operating experience on buried and underground pipe leakage

  - Hope Creek provided information on October 29, 2010 in response to RAI B.2.1.24-02:
    - Provided details on planned inspections
    - Confirmed annual testing of the Cathodic Protection System
    - Provided details on the quality of backfill around buried piping

Conclusions - Buried Pipe Program

- The BPP is comprehensive and robust
- The BPP will continue to develop and improve based on site and industry operating experience, the NEI initiative, and new technology
- The Program will manage the material condition of buried pipe
- The BPP is an effective aging management program to ensure continued safe operation

Hope Creek License Renewal

Topic of Interest:

Mark I Containment

Greg Sosson
Director, Engineering Services
PSEG Nuclear

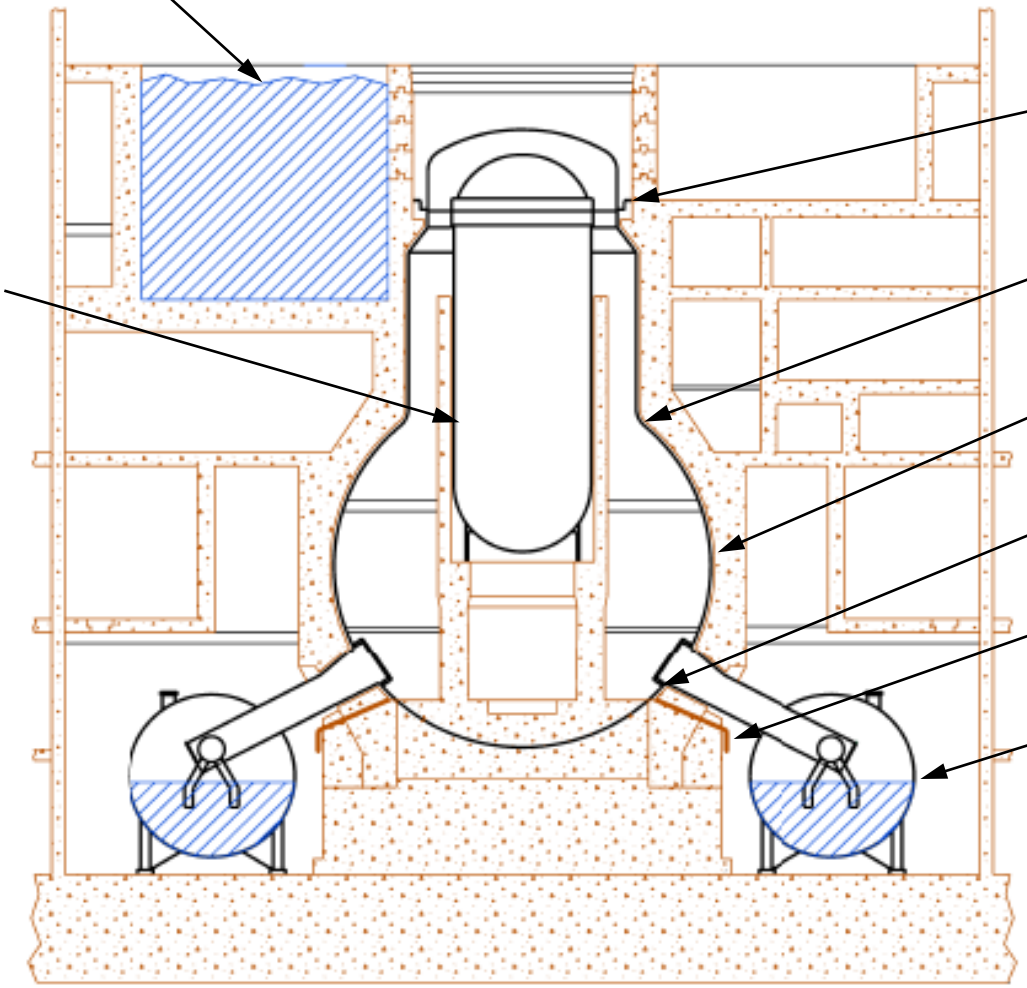
PSEG Nuclear LLC

Mark I Containment

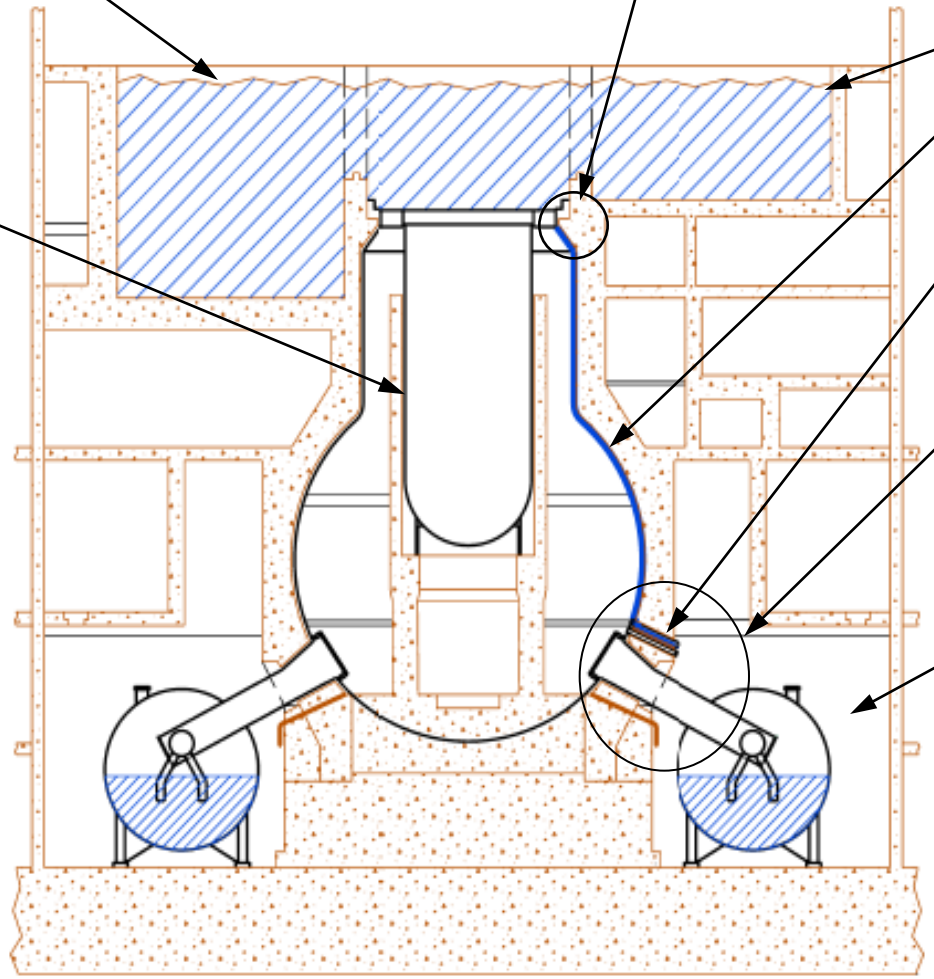
- Conducted an assessment of the Mark I Primary Containment based on operating experience

- The Hope Creek Drywell is in good condition
  - Confirmatory UT readings were performed
  - One small reactor cavity leak
  - One drywell shell area of interest identified

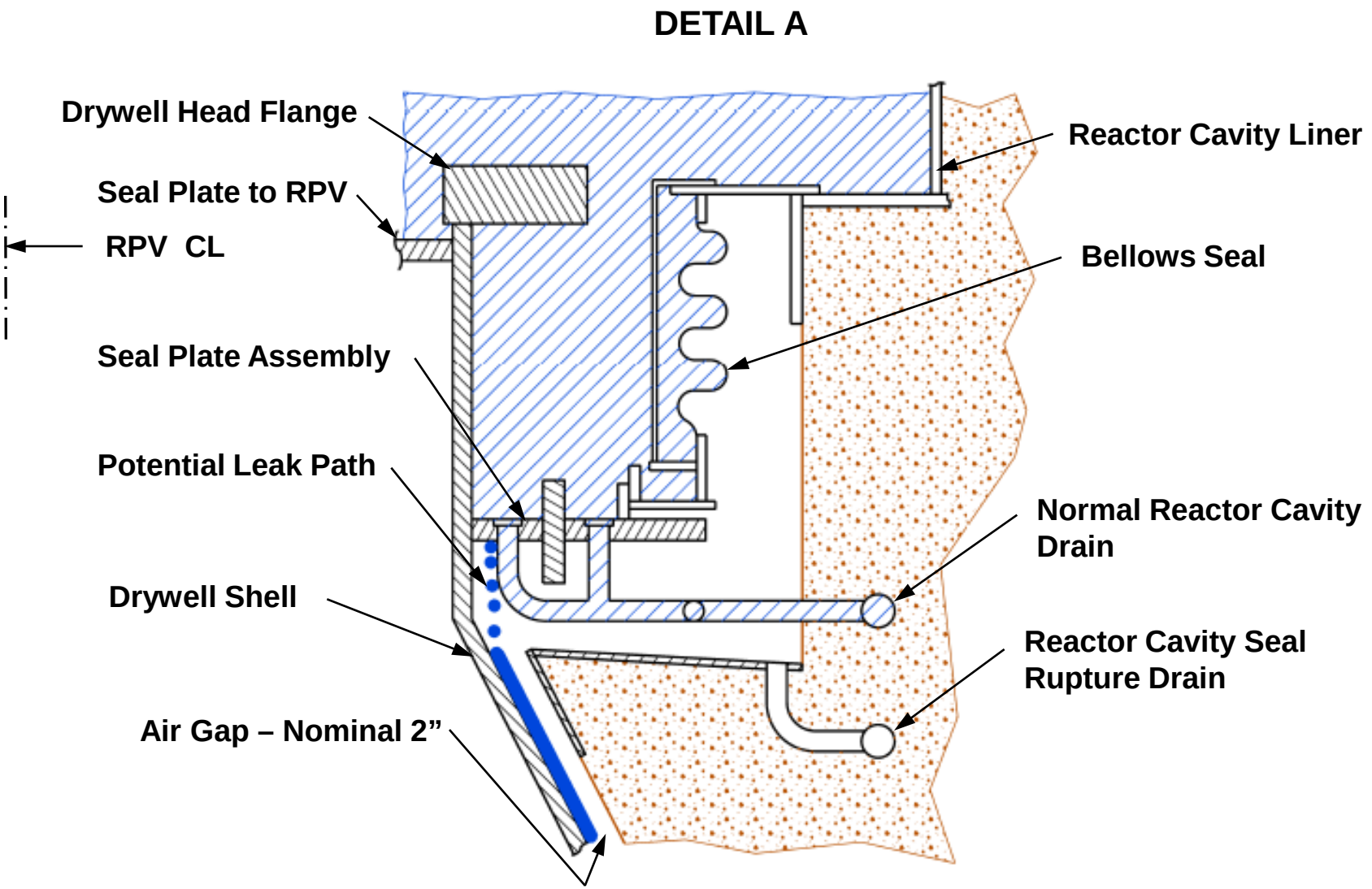
Mark I Containment



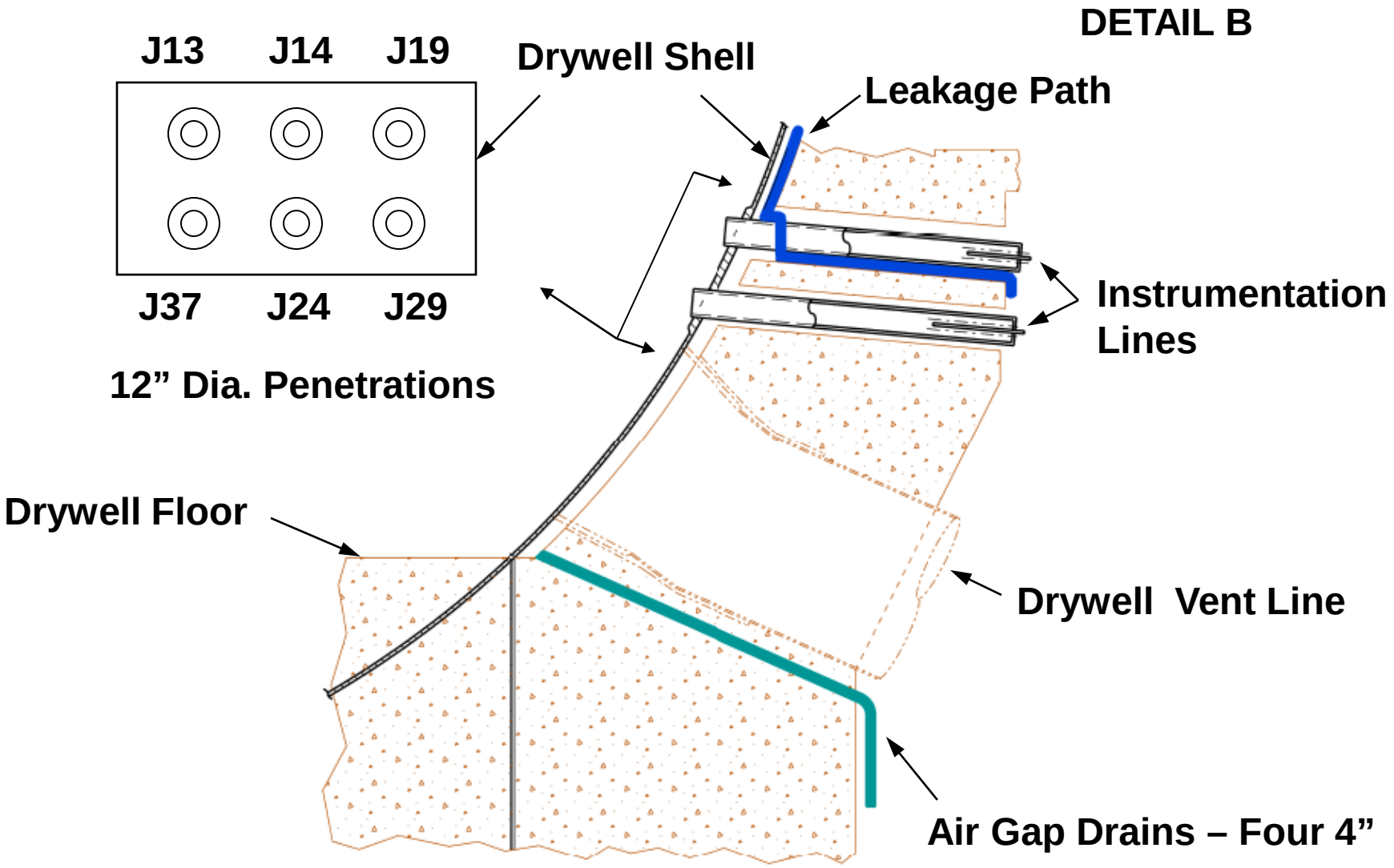
Mark I Containment



Drywell / Reactor Cavity Seal Area



Lower Drywell Area



Reactor Cavity Leak

- Leakage is very small
- Goal is to identify the leakage source and repair the leak
- Actions initiated to monitor the leakage and its effects until the leak is repaired (IWE Commitment 28)
  - Perform ultrasonic thickness measurements of the drywell shell below penetration sleeve
  - Monitor water leakage when the reactor cavity is flooded up
  - Confirm the drywell air gap and reactor cavity seal rupture drain lines are clear and the monitoring instrumentation is functioning properly

Reactor Cavity Leak – 2010 Refueling Outage Update

- Leakage identified at J-13 & J-14 penetrations when reactor cavity filled with water
- Performed boroscope exams in the J-13/14 penetration area
  - Confirmed no obstruction in the air gap
  - Small amount of leakage runs below J-13/14 penetration area but not on the drywell shell in the visible area
- Performed UT exams of shell above, around and below J-13/14 penetration area, and complete circumference of drywell shell at floor junction
  - UT measurements indicate greater than nominal plate thicknesses in all areas except lower portion of plate below J-13/14 penetration
- Actions underway to identify leakage source to allow repair

Drywell Shell UT Summary of Potentially Wetted Area – 2010 Outage

El. 121’ – 7” → **1’ X 20’ Area**

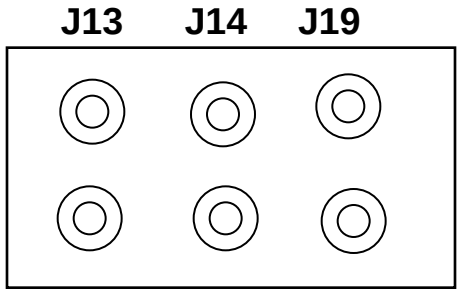
44 UT’s	
High	1.616”
Ave	1.576”
Low	1.542”

El. 97’- 0” → **1” X 3.5’ Area**

20 UT’s	
High	1.594”
Ave	1.564”
Low	1.514”

El. 96’- 4”
Top of 3” Plate

El. 92’-2”
Bottom of 3” Plate



84 UT’s	
High	3.269”
Ave	3.110”
Low	3.066”

Inches above floor	# of UT’s	Average (inches)
96”	8	1.495”
84”	8	1.513”
72”	8	1.502”
60”	8	1.508”
48”	8	1.504”
36”	8	1.501”
24”	8	1.492”
14”	7	1.495”
8”	7	1.494”
2”	9	1.490”

El. 86’-11”
Floor

3.0” Plate Tolerance: 2.99” - 3.19”

Analyzed Thickness: 2.9375”

1.5” Plate Tolerance: 1.49” - 1.69”

Analyzed Thickness: 1.4375”

PSEG Nuclear LLC

Conclusion - Drywell Condition

- Drywell is in good condition
- A small reactor cavity leak is being managed in the Corrective Action Program and in accordance with our license renewal commitments
- We have effective aging management programs to ensure continued safe operation

Hope Creek License Renewal

ACRS Subcommittee
November 3, 2010

PSEG Nuclear LLC

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Subcommittee

Hope Creek Generating Station (HCGS)

Safety Evaluation Report (SER) with Open Items

November 3, 2010

Bennett M. Brady, Project Manager

Office of Nuclear Reactor Regulation

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Presentation Outline

- Overview of HCGS license renewal review
- SER Section 2, Scoping and Screening review
- The Region I License Renewal Inspection
- SER Section 3, Aging Management Programs and Aging Management Review Results
- SER Section 4, Time-Limited Aging Analyses (TLAAs)

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Overview (LRA)

- License Renewal Application (LRA) submitted August 18, 2009
  - Applicant: PSEG Nuclear LLC (PSEG)
  - Facility Operating License No. NPF-57 expires April 11, 2026
- Approximately 40 miles from Philadelphia, PA and 8 miles from Salem, New Jersey,
- BWR with a Mark I containment.

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Audits and Inspections

- Scoping and Screening Methodology Audit
  - January 11-20, 2010
- Aging Management Program (AMP) Audits
  - February 8 -19, 2009
- Region I Inspection (Scoping and Screening & AMPs)
  - June 7 -10, June 21 – 24, and August 9 -12, 2010

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Overview (SER)

- Safety Evaluation Report (SER) with Open Items issued September, 2010

- SER contains 1 Open Item (OI):
  - Given recent industry events involving leakage from buried and underground piping, the staff needs additional information (OI 3.0.3.1.2-1)
- SER contains 2 Confirmatory Items (CIs):
  - Incorporation of inaccessible low voltage power cables in aging management program (CI 3.0.3.1.20-1)
  - Confirmation that locations selected for the environmentally assisted fatigue analyses were bounding for Hope Creek (CI 4.3.5.2-1)

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SER Section 2 Summary

Structures and Components Subject to Aging Management Review

- Section 2.1, Scoping and Screening Methodology
  - Methodology is consistent with requirements of 10 CFR 54.4 and 54.21
- Section 2.2, Plant-Level Scoping Results
  - Systems and structures within the scope of license renewal are appropriately identified in accordance with 10 CFR 54.4
- Sections 2.3, 2.4, 2.5 Scoping and Screening Results
  - SSCs within the scope of license renewal are appropriately identified in accordance with 10 CFR 54.4(a), and those subject to an AMR in accordance with 10 CFR 54.21(a)(1)

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Regional Inspection

- Three Weeks of Inspection
  - Most of the Common Aging Management Programs for Hope Creek and Salem.
  - Representative Unique Programs
  - 54.4(a)(2) Nonsafety Affects Safety
  - Selected Boral Program to determine response to Interim Staff Guidance
  - Selected System – Feed and Condensate

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Regional Inspection

Example Walkdowns

- Auxiliary Building Service/Radwaste Area
- Auxiliary Building Control/Diesel Area, including B EDG
- Reactor Building
- Hope Creek Turbine Building
- Traveling screen spray piping
- 30"-HZC-019 SACS Heat Exchanger Cross Tie
- Fire Barriers
- Fire Pumps
- Switch Yard

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Regional Inspection

- The application provided operating experience indicating selective leaching had occurred
- Aluminum bronze and gray cast iron have experienced selective leaching
- The applicant re-evaluated the aging management for selective leaching and supplemented the license renewal applications

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Section 3: Aging Management Review

- Section 3.0 – Aging Management Programs
- Section 3.1 – Reactor Vessel & Internals
- Section 3.2 – Engineered Safety Features
- Section 3.3 – Auxiliary Systems
- Section 3.4 – Steam and Power Conversion System
- Section 3.5 – Containments, Structures and Component Supports
- Section 3.6 – Electrical and Instrumentation and Controls System

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SER Section 3

3.0.3 – Aging Management Programs

47 Aging Management Programs (AMPs) presented by applicant and evaluated in the SER

	Consistent with GALL	Consistent with exception	Consistent with enhancement	With exception & enhancement	Plant Specific
Existing (33)	13	3	11	4	2
New (14)	9	1			4

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SER Section 3 Open Items

Buried Piping and Tanks Inspection

OI 3.0.3.1.2-1

- Staff has noted a number of recent industry events involving leakage from buried and underground piping/tanks
- Staff is concerned about continued susceptibility to failure of buried/underground piping within the scope of license renewal
- Staff issued as RAI on August 6, 2010; applicant responded on September 1, 2010; staff issued a follow-up RAI on October 12, requesting additional information on material composition of piping, portions of piping that are cathodically protected, possible hazardous material in in-scope buried pipes, and quality of backfill
- Staff will review the RAI response received October 29

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SER Section 3 Confirmatory Item

Inaccessible Low Voltage Power Cables

CI 3.0.3.1.20-1

- Staff has noted a number of recent industry events water or moisture has contributed to failures of inaccessible power cables at lower voltages (480 V to 2kV)
- Low voltage power cables response received October 7
  - Expanded scope of Inaccessible Medium Voltage Cables AMP to include low voltage power cables
  - Eliminated exclusion of cables not exposed to significant voltage
  - Increased testing of cables and inspection of manholes to at least every six years and every year, respectively.

– Staff has received the applicant's response and commitment

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SER Section 3 Item of Interest

Review of ASME Section XI, IWE Program and Reactor Cavity Leakage

- The staff reviewed this program (SER Section 3.0.3.2.13) and the small leak from a penetration in the reactor drywell that occurs only when the reactor cavity is flooded
- In response to staff requests, the applicant agreed to enhance the ASME Section XI, IWE Program to
  - monitor the penetration sleeve and lower air gap drains for leakage daily during reactor cavity flood up and perform UT inspections of the drywell
  - identify the cause of the leakage and repair it before the period of extended operation or, if not possible, implement IWE augmented inspections and develop a corrosion rate from UT inspections
- The staff will reevaluate commitments based on the new operating experience and consider whether additional actions are required

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SER Section 4: Time-Limited Aging Analysis

- 4.1 Introduction
- 4.2 Reactor Vessel Neutron Embrittlement
- 4.3 Metal Fatigue Analysis
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Concrete Containment Tendon Prestress Analysis (not applicable to Hope Creek)
- 4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis
- 4.7 Other Plant-Specific TLAAs

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SER Section 4 Confirmatory Item

Environmentally Assisted Fatigue Analyses CI 4.3.5.2-1

- Analyses of the effects of reactor coolant system environment on fatigue life of components were performed for six generic locations identified in NUREG/CR-6260
- The staff noted that there were other components that had higher CUFs
- The staff asked the applicant to verify that the locations selected were bounding as compared to other plant-specific locations.
- The staff is awaiting the applicant's response.

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Conclusion

On the basis of its review and **pending satisfactory resolution of the open item and confirmatory items**, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Hope Creek Generating Station.