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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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583RD MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY

MAY 12, 2011

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ROCKVILLE, MARYLAND

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The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 1:30 p.m., Said I. Abdel-Khalik, Chairman, presiding.

COMMITTEE MEMBERS:

SAID I. ABDEL-KHALIK, Chairman

J. SAM ARMIJO, Vice Chairman

SANJOY BANERJEE, Member

CHARLES H. BROWN, JR., Member

DENNIS C. BLEY, Member

MICHAEL CORRADINI, Member

DANA A. POWERS, Member

HAROLD B. RAY, Member

JOY REMPE, Member

MICHAEL T. RYAN, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

ACRS STAFF PRESENT:

PETER WEN

KENT HOWARD

P R O C E E D I N G S

1:29 p.m.

CHAIRMAN ABDEL-KHALIK: The meeting will now come to order. This is the first day of the 583rd meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following:

One, final safety evaluation report associated with the license renewal application for the Hope Creek Generating Station. Two, final safety evaluation report associated with the license renewal application for Salem Nuclear Generating Station, Units 1 and 2, and three, preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Peter Wen is the Designated Federal Official for the initial portion of the meeting. We have received no written comments or requests for time to make oral statements from members of the public regarding today's sessions.

There will be a phone bridge line. Members of the public will be listening to the Salem license renewal discussion. To preclude interruption of the meeting, the phone will be placed in a listen-only mode during the presentations and committee

discussion. A transcript of portions of the meeting is being kept, and it is requested that the speakers use one of the microphones, identify themselves and speak with sufficient clarity and volume, so that they can be readily heard.

At this time, we will move to the first item on the agenda, final safety evaluation report associated with the license renewal application for the Hope Creek Generating Station, and Dr. Shack will lead us through that discussion.

Hope Creek Generating Station

MEMBER SHACK: Okay. Our Plant License Renewal Subcommittee reviewed this application back in November.

I think the number of issues that came up, the ones that the Committee might want to pay particular attention to, again are the inaccessible power cables, the plant operating experience here for Hope Creek, has had a considerable problem with water intrusion for these cables, and you might note that even if they're managed to drain and to keep the manholes dry, there are portions of the cables that still could be exposed to water. So we want to keep that in mind.

They also have a problem with a leakage

into the drywell. So that there's a possibility of wetting the drywell shell, and they've taken measures to address that. As I understand it, the final safety evaluation report is currently being revised, and the staff is considering a license condition that will address this problem of the drywell wetting.

So that we probably will not be writing a letter on this license renewal at this meeting, but we'll have to address that issue separately. I'll turn it over to Brian Holian to finish up.

MR. HOLIAN: Thank you, and good afternoon Committee, and members of the public. My name is Brian Holian. I'm the Director of the Division of License Renewal. We're pleased to be here today for the Hope Creek, and then followed by the Salem final safety analysis and safety evaluation report reviews.

Just brief introductions and I'll have just a couple of opening comments and I'll turn it over to the licensee. The agenda is the licensee will give their presentation on 11 items, and their summary followed by the staff. To my left is Bo Pham. He's the branch chief in charge of both Salem and Hope Creek. He's had it for the duration of the reviews.

One other member I'd like to highlight now is the branch chief from the region in charge of

regional inspections that's with me today, Mr. Rich Conte, sitting behind me, from Region I Division of Reactor Safety. I'll introduce other NRC staff, when they take their turn at the table.

Just two opening remarks. One on the Excelon and PSEG renewal. One was, just to highlight overall, several technical issues came up during the review. But it was generally well-done. I give credit to my staff for the types of questions they asked, and the responsiveness of the license.

We, for a long time, worked with the Excelon team that worked with PSE&G on this. So those relationships were there, and turn around on our requests for additional information, I thought, were very prompt. I would remind the Committee this was some efficiencies here. We did have a common environmental report done for this site, separate safety evaluation reports, as you've seen, and we've treated them as separate units because of the different designs, with boiling and the pressurized water reactor.

We did see some efficiencies, even in requests for additional information, the way some of the programs are set up, and the licensee was able to respond in kind on both plants. So there was some

efficiencies seen on still on our safety review.

As mentioned, we'll get into the drywell leakage issue. You know, not a new issue, obviously, at some boiling water reactors. But as Mr. Shack mentioned, there are some issues on, even recently, with the status of their drywell leakage monitoring. So it's an item that the staff wants to ensure is appropriately categorized, and that will be just a slight modification of the safety evaluation report.

The second item I just wanted to briefly mention was this is the first ACRS meeting following the events at Fukushima. So I just wanted to highlight that. We often get asked, and are responding on letters to members of the public about, you know, license renewal. Does that go on, and is that appropriate, even, in the case of the events there.

There was a Commission meeting briefly this morning. I'm sure the Committee's aware of that, and I just wanted to state on the record that, you know, the License Renewal Division and our technical staff are looking at the lessons learned, and are there any unique issues there from aging management.

That will be a piece for both the short and the long term aspects. But you know, those have

not been identified to this point. The main item, and I stated just for a reminder here, is that Part 50, you know, still applies to these plants, regardless of the license renewal review.

So we fully expect any lessons learned, coming out of Fukushima reviews, will be applied across the fleet, whether plants have license renewal or don't have license renewal, and I just wanted to state that at the outset. With that, I'll turn it over to the licensee, Mr. Paul Davison and the Vice President of Operations Support.

MR. DAVISON: Thank you, Mr. Holian. Good afternoon. My name is Paul Davison. I'm the Vice President of Operations Support at PSEG Nuclear. I'm also the executive sponsor for the license renewal program. Before we begin today's presentation, I would like to introduce the presenters.

To my right is Jim Stavely. He's with the License Renewal Project. Jim has 25 years of nuclear experience, including 15 with PSEG Nuclear. The gentleman to the right is John Hilditch, the Electrical lead for the License Renewal Project, and John has 28 years of nuclear power plant experience, including 15 with PSEG Nuclear.

Then to John's right is Jim Melchionna,

the corporate Buried Pipe Program Manager. Jim has 29 years of plant experience and 19 with PSEG Nuclear. He's also heavily involved with the industry initiative concerning buried pipe. In addition to today's presenters, we also have with us today Tom Joyce, the president and Chief Nuclear Officer of PSEG Nuclear; Bob Braun, the PSEG Nuclear Senior Vice President for Nuclear Operations; and John Perry, the site Vice President for Hope Creek.

Slide 2 shows our agenda for the presentation. We will begin with our brief description of the site, and a summary of the License Renewal Aging Management Programs and commitments.

We will then continue by discussing the closure of the two confirmatory items, one open item, and several other issues that were mentioned in the ACRS Subcommittee meeting on November 3rd of 2010, and for which we received requests for additional information.

We will continue our presentation with an update regarding the aging management of the Hope Creek containment. We look forward to answering any questions you have, either during or after the presentation, and I'd now like to turn it over to Jim Stavely to begin with the presentation. Jim.

MR. STAVELY: Thank you, Paul. Slide 3 please. Good afternoon. My name is Jim Stavely. This slide is an aerial view of the site, with north on the right side. Hope Creek and the two Salem units are a common site on the New Jersey side of the Delaware River and southern New Jersey.

Hope Creek is a General Electric BWR-4, owned and operated by PSEG Nuclear. The key structures for Hope Creek that you can see on this slide are the reactor building, the service water intake structure, the cooling tower, and the switchyard. A second Hope Creek unit was planned, but was not completed. You can see the planned location for its reactor building to the right of the Hope Creek reactor building.

Slide 4 please. This slide summarizes the aging management programs and commitments for Hope Creek. There are 47 aging management programs, including 33 existing programs and 14 new programs that were developed for the application. Of the existing 33 programs, 16 required no changes to align with GALL, while 17 required enhancements to align with GALL.

There are 54 license renewal commitments for Hope Creek. These commitments are managed under

an existing process consistent with NEI 9904, Revision 0. The commitments are tracked in our SAP database system, which is the data foundation for most of our site processes, including the corrective action program.

Implementing documents, including procedures and work orders, are being annotated with commitment references, to ensure that the commitments are maintained. PSEG Nuclear is in the process of implementing many of the program enhancements, as well as the new programs. Slide 5 please.

MEMBER POWERS: What additional manpower is required to carry out these new programs, and the augmentation of the existing programs.

MR. STAVELY: The project team has had a significant impact on implementing these commitments, whether it's procedures and work orders, to try to offload some of the work from the actual site personnel. Which means that the implementation of them will generally be level of effort within the existing organization.

MEMBER POWERS: So we're going to do more with the same people?

MR. STAVELY: That is true. We will be targeting a lot of our efforts on the aging management

programs, to ensure that we have an effective program for maintaining the aging on the plant. We can --

MR. DAVISON: We have added staffing, and we have a corporate program person for the oversight of license renewal activities at both Salem and Hope Creek. Each site, in this case Hope Creek, has an individual added to the Programs Group in Engineering, to also specifically manage the overall programs.

All implementation of the programs themselves are built into our corrective action process and programs moving forward, and we use the base level of effort in maintenance operations in other organizations, in addition to the contractors that we would utilize during a refuel outage, in which we would bring extra work force members in to implement a lot of these programs, inspections, et cetera.

MR. STAVELY: The next part of the presentation will discuss the closure of the two confirmatory items, the one open item, and several other issues for which PSEG Nuclear input was requested following the ACRS Subcommittee meeting. At this point, I will turn the presentation over to John Hilditch, who will discuss the closure of the confirmatory item involving inaccessible power cables.

MR. HILDITCH: Thank you, Jim. Slide 6 please. Good afternoon. My name is John Hilditch. I'm the lead electrical engineer for the License Renewal Project. The first confirmatory item was related to inaccessible power cables.

As agreed, PSEG is modifying our E3 program commitments, to reduce the maximum manhole inspection frequency from two years to one year, reduce the maximum cable testing frequency from ten years to six years, eliminate any exclusion of cables due to service time, and add low voltage power cables to the scope of the E3 program.

Based on the additional information and our commitments, the staff closed this confirmatory item. Subsequent to the Subcommittee meeting, we tested some of our in scope station blackout recovery cables. The results were satisfactory.

We are implementing aspects of our aging management program, to ensure that in scope underground cables are not exposed to significant moisture. We have repaired the switchyard cable manhole during the system pump. In June of 2011, next month, we'll begin the installation of a permanent drainage system in the service water manholes, and complete that installation by the end of 2011.

We will assess the effectiveness of these activities, and determine if further corrective actions are required. That concludes my update on inaccessible power cables. I will now turn the presentation over to Jim Melchionna.

MEMBER SHACK: You also have a commitment to essentially establish a frequency of inspections. You've identified the maximum here.

MR. HILDITCH: Yes.

MEMBER SHACK: What was your current estimate of the frequency of inspections, or what is your current interval in frequency of inspections?

MR. HILDITCH: The current interval for the service water cable vaults is weekly. That's when we pump out and we trend how much water's coming in. For the switchyard, it's annual.

MEMBER SHACK: Okay, and are you finding water when you're doing those weekly inspections?

MR. HILDITCH: We are finding water in some manholes some of the time, as correlated to rainfall. I will now turn the presentation over to Jim Melchionna, who will discuss the one open item involving buried piping. Jim.

MR. MELCHIONNA: Thanks, John. Slide 7, please. Good afternoon. My name is Jim Melchionna.

I'm the corporate Buried Pipe Program Manager at PSEG Nuclear. I'm also the Vice Chairman of the EPRI Buried Piping Integrity Group Advisory Committee, as well as a member of the National Association of Corrosion Engineers.

Hope Creek had one open item relating to buried piping. The open item addressed the staff's need for additional information, to evaluate how we considered recent industry operating experience into our buried pipe program.

We have considered both site-specific and recent industry operating experience, in the development and maintenance of our program, and have provided the staff with information confirming that such operating experience information has been evaluated and addressed by our aging management program.

As part of the resolution of this open item, we modified our buried pipe program commitments to add a second direct inspection of carbon steel piping, and to perform our existing inspections on those systems of higher safety significance. All committed inspections will occur every ten years, beginning prior -- beginning ten years prior to entering the period of extended operation, and at a

different location each time.

Finally, we've provided information on the testing of our cathodic protection system. The cathodic protection system is tested annually, consistent with NACE guidelines, and we expect to maintain a 90 percent availability in the future.

MEMBER BROWN: Question. Is this the piping where you all identified you're going to inspect eight, roughly eight feet of the pipe each of those ten-year intervals or something like that? I remember reading something.

MR. MELCHIONNA: That is correct. Part of this particular inspection, which is not cathodically protected piping, that eight or so feet is on the service order system, that's correct.

MEMBER BROWN: And how many feet are total in the service water system on the site?

MR. MELCHIONNA: Approximately 1,000 linear feet per header. There's two headers that run from the intake structure to the reactor building.

MEMBER BROWN: So eight feet is considered okay for 2,000 feet of pipe?

MR. MELCHIONNA: That is the carbon steel portion of the system.

MEMBER BROWN: So the piping actually

exits and enters building. There's carbon steel transition pieces in those areas, and then it transitions to that pre-stress concrete piping, such as 995 feet of piping, which is cement line and cement coated. So it's just those end pieces that are coated carbon steel that's not cathodically protected.

MEMBER BROWN: Okay. So it's not a large --

MR. MELCHIONNA: That is correct.

MEMBER BROWN: Okay.

MEMBER BLEY: How does one come to the conclusion that 90 percent availability is good, is good enough for cathodic protection?

MR. MELCHIONNA: Over the past, since 2005, we've recorded our availability. We have greater than 95 percent availability right now. We set that threshold as an entrance to our corrective action program.

MEMBER POWERS: We still don't understand, be it 90 or 95 percent, why is that good enough?

MR. MELCHIONNA: Okay. I'd like to ask Dylan Cimock on the License Renewal team to further clarify the answer to that question for me.

MR. CIMOCK: Dylan Cimock, License Renewal Project team. The basis of the 90 percent comes from

the recommendations in the new GALL Rev. 2 program. The 90 percent, as far as I understand it, is to allow variances when rectifiers could be out of service, in between the times at which they're expected. So it allows a little bit of mediation when privy to the finding detected, and so that's not a 100 percent requirement for operations.

MEMBER POWERS: I mean I understood that. I'm still struggling. Why is that good enough?

MR. CIMOCK: Our basis was simply from the recommendation of the GALL Rev. 2 program. I'm not familiar with the sufficiency of why 90 percent.

MR. MELCHIONNA: We also have procedures in place every two weeks to check voltage and amps on the rectifiers. Every month, we go out and check all the equipment, to make sure there's no degradation or malfunction of the equipment, and the annual test itself. So those are the ancillary things we're doing, to make sure that those requirements are met.

VICE CHAIRMAN ARMIJO: But you know, it really -- what we're trying to address is the physical condition of the protected piping. In the event you've maintained 90 percent, you know, what's the correlation between that 90 percent and the actual condition of the pipe. You know, that's been

developed by some research. Do you --

MEMBER POWERS: Well, one would hope so, and that's --

VICE CHAIRMAN ARMIJO: Well you know, I happen to know something about it, and you know. But so I'm looking for the answer from the Applicant, that you've inspected piping that's been protected this way for a long time, and you find it looks good or --

MR. MELCHIONNA: Well yes. I can further. Every pipe that we have excavated on site so far, that had been or not been cathodically protected, has shown no signs of corrosion or aging management, or excuse me, aging degradation.

If you go to Slide 20 please, I'll show a photograph of carbon, service water carbon steel piping buried in the ground for 30 years, non-cathodically protected, and that is a floor that shows carbon steel piping, after the coating was removed from the piping, which was very difficult for us to do.

VICE CHAIRMAN ARMIJO: Okay. What was your coating?

MR. MELCHIONNA: That was a coal tar epoxy-type coating. It was very difficult to remove. So we're very comfortable with the fact that either

cathodically protected or not cathodically protected, the piping's in very good condition.

MEMBER RYAN: Was the piping buried in wet environment or buried in dry environment?

MR. MELCHIONNA: That was piping in a very wet environment.

MEMBER RYAN: It's helpful to know that as well.

MR. MELCHIONNA: And soil samples prove that that piping can be very non-corrosive. All of our piping outside is buried in engineered fill, with very strict requirements for that type of backfill. Okay, thank you.

MEMBER RYAN: That's helpful, thanks.

VICE CHAIRMAN ARMIJO: You recoat it with the same material that you've used in the past?

MR. MELCHIONNA: Actually, we upgraded the material and went to a more technologically sufficient --

VICE CHAIRMAN ARMIJO: I'm not sure that was wise.

(Simultaneous speaking.)

MEMBER RYAN: You're qualifying it more.

VICE CHAIRMAN ARMIJO: Yes. Probably the Environmental Protection Agency won't let you use it.

MEMBER SIEBER: Do you have chemistry data for the soil?

MR. MELCHIONNA: Yes, we do have quite a bit of that. So on average, to date, resistivity readings were averaging around 30,000 ohm centimeters. Some samples as high as 200 to 300 hundred thousand ohm centimeters. So very non-corrosive soil.

MEMBER SIEBER: Okay. It's basic, as opposed to acidic?

MR. MELCHIONNA: Yes.

MEMBER SIEBER: Contain phosphates, fluorides?

MR. MELCHIONNA: Fluorides, sulfates, moisture, pH.

MEMBER SIEBER: What are the ranges?

MR. MELCHIONNA: Fluorides are usually around non-detectable. The limit of detection is 21 pp. Sulfates also. So all the halogens are in a non-detectable or slightly above --

MEMBER SIEBER: Depends on the lab. For some labs, non-detectable can be significantly higher.

MR. MELCHIONNA: And pH in the range of seven and above. So --

MEMBER RYAN: Jim, it might be helpful if you talked a little bit about the site-wide

geohydrologic modeling, your understanding of the ground water system?

MR. MELCHIONNA: Yes. The piping on site typically ranges from about below the fault line obviously, three feet, to anywhere down to 20 to 25 feet. That pipe being -- is in compacted soil, with a high density compaction, and it typically sees rainwater. So there's no infiltration of --

MEMBER RYAN: The river?

MR. MELCHIONNA: We're so close to the river. There's no infiltration from the river in that aspect.

MEMBER RYAN: But you do get rainwater going out to the river?

MR. MELCHIONNA: We actually do, but a very slow diffusion, depending on the compaction of the soil around the pipes. Yes, we do.

MEMBER RYAN: The rest of the site carries most of the water, not just the compacted part around the pipe down. So --

MEMBER SIEBER: And the site topography is pretty flat. How far up from the river is it typically, elevation-wise?

MR. DAVISON: Nominal river level is 89 feet. The ground itself is 100 feet. So it's roughly

11 feet above. It's tidal, but it's roughly 10 to 11 feet below the surface of the ground where the plant's built.

MEMBER SIEBER: To the east of the site, is that flat or hilly or --

MR. DAVISON: It's actually marshland.

MEMBER SIEBER: Hmm, okay. Thanks.

MR. MELCHIONNA: During our 2010 fall refueling outage, we excavated two non-cathodically protected high risk end scope carbon steel spools that I just showed you a picture of, and as I said, that pipe has been buried in the ground for 30 years.

We found the coating to be well-adhered, as I said, and it to be in excellent condition when we took the coating off, although not within the scope of license renewal, we also inspected a three-inch type 304 stainless rad waste line, which was also in like-new condition. That concludes my discussion of the open items. I will now return the presentation to Jim Stavely.

MR. STAVELY: Thank you, Jim. Slide 8 please. The second confirmatory item is associated with the selection of locations for environmentally assisted fatigue calculations. The staff had some questions concerning its selections, and it's consist

with NUREG 6260, Application NUREG 5999, interim fatigue curves to select the nuclear power plant components.

In response, we committed to confirm, prior to entering the period of extended operation, if the locations selected for NUREG 6260 are bounding, compared to other plant-specific locations. If there are any more limiting locations identified, the most limiting location will be evaluated.

If the most limiting location involves nickel alloy, NUREG 6909 methodology will be used in the evaluation. Based on the additional information and our commitment, the staff closed this confirmatory item.

Slide 9, please. Following the ACRS Subcommittee meeting, the staff requested specific information on sampling for the one-time inspection program, the selective leaching program, and the small bore Class 1 piping inspection program.

In general, these requests were related to additional program detail provided in GALL Revision 2. Our responses were consistent with GALL Revision 2, and the staff closed these issues.

Slide 10, please. As part of our presentation at the ACRS Subcommittee meeting, we

provided detailed information on the Hope Creek Mark 1 containment, as a topic of interest. Today's presentation is an overview of that presentation, coupled with some updated information.

Slide 11, please. This sketch shows the configuration of the containment during a refueling outage, with the reactor cavity flooded. The containment is a steel pressure vessel, and consists of a drywell in the shape of an inverted light bulb, and a donut-shaped suppression chamber called the torus. The drywell and torus are connected by vent lines.

There's an air gap, nominally two inches wide, that separates the drywell shell from the surrounding concrete drywell shield wall. There's a seal between the reactor cavity and the drywell, to prevent water from entering the drywell air gap during refueling outages, when the reactor cavity is flooded. The seal is in a circled area labeled "Reactor Cavity Seal Area."

During the 2009 refueling outage, with the reactor cavity flooded, we observed water trickling out of the penetration sleeve in the torus room. The issue was entered into the corrective action program. The leak stopped when the reactor cavity was drained.

The leakage in the 2010 refueling outage was consistent with the leakage in the 2009 refueling outage.

VICE CHAIRMAN ARMIJO: Excuse me. When you saw that leakage through the penetration sleeves, did you also pick it up in the drywell air gap drains?

MR. STAVELY: It was first -- no, it was. There was no water coming out of the drywell air gap drains.

VICE CHAIRMAN ARMIJO: So it was either all leaking out through those penetration sleeves, or trapped somewhere?

MR. STAVELY: If I can -- I'll explain how we actually found it. It was on the shield wall, coming down the penetration sleeves, by that penetration sleeve. So we reviewed all the penetrations and looked for any additional leakage, and none was identified. We walked down the air gap drains that you just mentioned, and there was no water coming from those.

So the water was either coming out the sleeves, or it was of sufficiently small volume that it was not accumulating in the bottom of the air gap.

VICE CHAIRMAN ARMIJO: And that was only in one segment of the torus, some location that's not

around the holes?

MR. STAVELY: The only location that we identified the leak was on that, in that area of that penetration.

VICE CHAIRMAN ARMIJO: Okay.

MEMBER SIEBER: And the water was on the floor of the torus room, right?

MR. STAVELY: Yes. The drains, the water exited the penetration sleeve and then you take a look at the blue line here. That's probably the best way to explain it. This dark blue line shows the most probable path of the leakage. So starting up in the reactor cavity seal area, comes down, most likely on the concrete shield wall, transitions over to the shell, and then as it goes around, it transitions back over to the concrete shield wall, intersects with the penetration sleeve and then comes out the penetration sleeve and continues down the side of the shield wall.

MEMBER SIEBER: Okay, but there is a gap between the concrete and the drywell metal?

MR. STAVELY: Yes. There's a nominal two inch air gap.

MEMBER SIEBER: Okay, and that's air? There's nothing in there, right?

MR. STAVELY: There's nothing in the

drywell air gap, both by design, and we verified that via boroscope examination.

MEMBER SIEBER: Now during the original construction, was the outside of the drywell, the metallic part of it, coated, painted or otherwise prepared to limit corrosion?

MR. STAVELY: Yes. It has an inorganic zinc coating, to minimize corrosion.

MEMBER SIEBER: Okay. Is that coating intact or don't you know?

MR. STAVELY: The coating is intact, based on the boroscope examinations, and looks in good condition.

MEMBER SIEBER: How far up could you go with the boroscope? I take it you went through the drain?

MR. STAVELY: We actually, in terms of looking at the condition of the shell, the examinations were boroscopes through the penetration sleeves.

MEMBER SIEBER: Okay. You did not do any from the reactor cavity?

MR. STAVELY: No. There was no boroscope examination from the reactor cavity.

MEMBER SIEBER: Now when you take the

refueling seal out, there is a gap there, right?

MR. STAVELY: There is a gap. It's an area of that is very difficult to access at the top of the reactor.

MEMBER SIEBER: Yes, I know. Okay.

MR. STAVELY: The observed leakage --

VICE CHAIRMAN ARMIJO: Just one last thing. Did you verify that the drain lines were clear? They weren't blocked or anything like that?

MR. STAVELY: No. The drain lines, based on boroscope examinations in the 2010 refueling outage, the four air gap drain lines are blocked and are not capable of draining water from the bottom of the air gap.

VICE CHAIRMAN ARMIJO: Okay. Well, will they remain blocked or --

(Laughter.)

VICE CHAIRMAN ARMIJO: Why are they blocked? I'm sorry I didn't attend the Subcommittee meeting --

MR. STAVELY: As part of -- during the 2010 refueling outage, we examined all four of these drains, to verify that they were open and that any water that did make it to the bottom of the air gap, would be coming out the drains, because we did not see

anything from the drains. So when we found that they were blocked, they did enter the corrective action program.

Since the outage, we have been taking actions to establish drainage from the bottom of the air gap. At this point though, we have not established drainage from the bottom of the air gap.

MEMBER BLEY: Did you find out how they were plugged or why?

MR. STAVELY: In the boroscope examinations in the 2010 refueling outage, there are covers on the end of those four drain lines. So we recently boroscoped again, in attempt to remove the cover, and we found that the cover is a portion of the way through the shield wall.

MR. DAVISON: If I could make a recommendation, Jim's actually going to walk through all those steps in his presentation, and there are a couple of pictures coming up, if you'd like to see that laid out for you.

VICE CHAIRMAN ARMIJO: Yes, okay. Well you know, where I'm leading to is in prior reviews, we've had a lot of concerns related to the region, what used to be called the sand bed regions and corrosion there. If water accumulated in that region

and drains were blocked, it would obviously not be a good thing.

So I'm just -- I would like to get some more information about the condition of the vessel, containment vessel in that region.

MR. DAVISON: Jim will specifically cover that.

VICE CHAIRMAN ARMIJO: Thank you.

MR. STAVELY: Would you like me to do that now, or move on?

VICE CHAIRMAN ARMIJO: Oh no, when you get to it.

MR. STAVELY: Okay, thank you. I just want to make sure. The observed leakage varied with a maximum rate of Approximately 100 drops per minute. The dark blue lines started from the reactor cavity and continuing down the air gap, is the most probable path for the leakage.

The most probable source of the leakage is a small weld defect on the sealed plate in the reactor cavity seal area. Actions are being taken to determine the source of the leak, and repair it if possible.

Note that this leak is not a leak in containment, but a leak outside of containment, that

has the potential to wet portions of the exterior surface of the drywell shell, two leaks out of over 18 months during refueling outages.

As we've shown on the next slide, there's been no indication that this leak has impacted the drywell shell. The containment design includes drain lines at the bottom of the drywell air gap, that discharges onto the torus room floor. These are the drains that we've been talking about with respect to the drains at the bottom of the air gap.

The non-conformance was entered into the corrective action program because of the block. Potential water accumulation in the drywell air gap is limited, because it would drain out of the sleeves around the vent lines. These sleeves are just above the bottom of the drywell air gap. No water --

VICE CHAIRMAN ARMIJO: It's a foot and a half, right?

MR. STAVELY: Approximately a foot and a half, that's correct.

VICE CHAIRMAN ARMIJO: What's the foot and a half, I'm sorry? The orange line at the bottom? If you're going to get to a figure later, just point it out.

MR. STAVELY: This one I can show in a

figure. Maybe we can go to that one too. You can see the drywell floor and approximately a foot and a half is where the sleeve is around that vent line. So the water in that two inch nominal gap would have a maximum depth of that 1-1/2 foot --

VICE CHAIRMAN ARMIJO: Then it would pour down the vent line into the torus room?

MR. STAVELY: We would see it in the torus room, and it will be detected by our monitoring of the shield wall.

VICE CHAIRMAN ARMIJO: Okay, thanks.

MR. STAVELY: Actions are being taken to establish drainage at the bottom of the air gap. I'll provide additional information on this issue in a later slide.

VICE CHAIRMAN ARMIJO: Do you have any idea when the -- how long those drain lines were blocked?

MR. STAVELY: It is likely that they were blocked since construction.

VICE CHAIRMAN ARMIJO: That's not good.

MEMBER SIEBER: You can actually have a water level standing in the area, from the penetration down to the bottom of the concrete and blocked vent line that's there permanently?

MR. STAVELY: There are eight vent lines, and the water would come up to a maximum of a foot and a half that we discussed, before we'd see it out of one of those vent lines.

MEMBER SIEBER: Okay.

MR. STAVELY: Also we have performed boroscopes at the bottom of the drywell air gap, and we have -- there's been no accumulated water, and there's been no signs of corrosion, and the coating is in good condition.

MEMBER SIEBER: Thank you.

MEMBER SHACK: And you've done UT?

MR. STAVELY: And we have also done UT for a full 360 degrees, at the junction of the concrete floor and the shell.

VICE CHAIRMAN ARMIJO: Done that from the inside?

MR. STAVELY: Yes.

VICE CHAIRMAN ARMIJO: Okay.

MR. STAVELY: So we are basically -- I'm sorry.

MEMBER SIEBER: You had some UT measurements below nominal. Are they fabrication errors within the fabrication tolerance?

MR. STAVELY: Yes, they are. There is one

one and a half inch plate, that has readings on it that are -- some readings on that are below nominal, but they are within the construction tolerances for the plate.

MEMBER SIEBER: Thank you.

MEMBER BROWN: I got lost again. How does the water get into -- you keep talking about the vent line draining water out.

MEMBER SIEBER: It's the gap between them.

MEMBER BROWN: No, but I thought he said the water -- go back on that part.

(Simultaneous speaking.)

MR. STAVELY: Go back to Slide 12 please. Okay. If you look at the bottom, okay, the green is the drywell air gap drain line. So that's the one we're saying is blocked. So right where the pointer is was the air gap itself.

If the water was to fill up and go along that air gap, right there is where the sleeve is. There's a sleeve around the vent line, and then --

MEMBER BROWN: Oh, okay. It's from the sleeve. I'm sorry. I got it now. Thank you.

MR. CUNANAN: But your, the first place you discovered the leakage was the dark blue line?

MR. STAVELY: Yes, and that's -- the dark

blue line is the most probable path, and that shows it coming, intersecting with the penetration sleeve, so the sleeve around the penetration, going through the sleeve and then coming out along the shield wall.

MEMBER BROWN: So it's not coming out the sleeve itself; it's around the sleeve where you're seeing the drainage?

MR. STAVELY: Yes. It's coming -- there is a carbon steel sleeve that goes around the penetration, and that's where it's coming out through that, along the sleeve.

MEMBER BROWN: Okay.

MEMBER SIEBER: I take it, though, the instrument lines are filled with electrical cables, as opposed to hydraulic sensing lines?

MR. STAVELY: The penetration that was noted with -- the penetrations which had water leakage coming out of them, our instrumentation ones, the penetrations have no signs of corrosion. They're in good shape.

MEMBER SIEBER: Yes, but they're -- what's in them is electrical cables, instrument cables?

MR. STAVELY: I'd like to ask George Seibold to provide some information on what's in the penetrations.

MEMBER SIEBER: That looks like a conduit to me.

MR. SEIBOLD: Yes. My name is George Seibold, PSEG Nuclear. Correct. If you look on the sketch, those are 12-inch penetrations going through the drywell, and they contain one inch instrumentation lines, as necessary for wires.

MEMBER SIEBER: Oh for wires, okay.

MR. SEIBOLD: Yes. So that's --

MEMBER SIEBER: That's what I thought.

MR. SEIBOLD: So that's an electrical penetration, and so there are one-inch piping that contains wiring.

MEMBER SIEBER: Conduits.

MR. SEIBOLD: Yes, and so that's why we have that labeled up there as instrumentation lines.

MEMBER SIEBER: So the electrical cables are insulated from the flow of water, because they are also enclosed in the tubing?

MR. SEIBOLD: Well, the flow of water, the flow of water flowing down the penetration that goes through the drywell, and then the electrical lines are in another tube inside of that.

MEMBER SIEBER: Right. That's what I'm saying.

MR. SEIBOLD: And then there's a sleeve in the concrete, that the water exits.

MR. STAVELY: John, could you please put up Slide 28? This might help. This is a picture of penetration.

MEMBER BROWN: These are backup slides?

MR. STAVELY: This is the backup slide.

VICE CHAIRMAN ARMIJO: You know we like your backup slides better.

(Simultaneous speaking.)

MR. STAVELY: Okay. This is the J13 penetration. So this shows you the penetration coming out of that sleeve, and you can see the sleeve around it.

MR. CUNANAN: And the rusty-looking stuff is where it leaks?

MR. STAVELY: That is where it's carbon steel on the inside of that --

MR. CUNANAN: I'm just talking about the --

MR. STAVELY: Yes. That was the trickle, that was the trickle.

MR. CUNANAN: Yes, okay.

MEMBER POWERS: What was the character of this water, constitution-wise?

MR. STAVELY: In terms of chemistry?

MEMBER POWERS: Yes.

MR. STAVELY: The pH was between 8.3 and 8.5, and it was consistent with reactor cavity water.

MEMBER POWERS: Right.

MR. STAVELY: Back to Slide 12 please. We are focused on maintaining the integrity of the drywell shell. Our design features include an inorganic zinc coating on the exterior of the shell that prevents corrosion. This is one that is in good shape, good condition, and good adherence. Design has never included a sand bed region.

Boroscope examinations of the exterior of the drywell shell, including at the bottom of the drywell air gap, show no indications of corrosion. The coating is in good condition. No obstructions were observed in the drywell air gap that could hold water against the shell. There is no water accumulation at the bottom of the drywell air gap.

VICE CHAIRMAN ARMIJO: Did you take any pictures of, when you did the boroscope examination, of the bottom of the drywell air gap?

MR. STAVELY: Yes. We have full video of it. I do not have any backup slides on that though.

VICE CHAIRMAN ARMIJO: Okay.

MR. STAVELY: We performed approximately 350 ultrasonic thickness measurements during the 2010 refueling outage. All but one area showed measured thickness above nominal. The one area, that we mentioned a little earlier, was below nominal thickness but within construction tolerances.

MEMBER SHACK: But that was just below the J13 penetration?

MR. STAVELY: Yes. This was the one and a half inch plate directly below. All measured thicknesses were above the thickness used in the drywell analysis. Boroscope examinations of the exterior of this area show that the drywell shell coating was in good condition, and there was no corrosion.

This issue was entered in the corrective action program. The ultrasonic thickness measurements will be repeated in the next three refueling outages.

MEMBER BROWN: How far below nominal was -- you said it was within construction tolerances, so that's a wide range. Was it --

MR. STAVELY: The lowest, in terms of nominal, is 1.50. The lowest individual reading was 1.475. The analysis limit is 1.4375.

MEMBER BROWN: You're about halfway

through, though.

MR. STAVELY: Yes, but the --

(Simultaneous speaking.)

MEMBER BROWN: Not through --

MR. STAVELY: Well not through, confirmed to the margin. I shouldn't have said that. Yes, I misspoke there. One of critical aspects of this is that the fact that when we look, using the boroscope, on the outside of the same plate, that we see good coating and we see no signs of corrosion. That is one of the reasons -- pardon?

MEMBER BROWN: Going inwards.

MR. STAVELY: Pardon me?

MEMBER BROWN: Going inwards.

MR. STAVELY: Yes, or no. Yes. From the drywell air gap looking in towards the drywell, looking at the shell itself. So the shell shows no signs of corrosions.

VICE CHAIRMAN ARMIJO: So that's why you think that's just was initial thin plate, and not thinned as a result of corrosion?

MR. STAVELY: That's one of the reasons. Another reason, for example, is on each side of the 1.5 inch plate are three-inch plates. Those three-inch plates show nominal readings.

So if it was a physical mechanism, such as corrosion, you would expect to appear on the adjacent plates, because the only way it wouldn't would be if there was some dam that was right in between the two three-inch, between the plates and holding the water.

MEMBER SHACK: Now you can see the surfaces of those plates, though, right, when you do the boroscope exam?

MR. STAVELY: That is correct.

MEMBER SHACK: And they look --

MR. STAVELY: They looked fine.

MEMBER SHACK: The coatings looked --

MR. STAVELY: The coatings looked fine. They looked intact.

MEMBER SIEBER: Did you repair your refueling seal?

MR. STAVELY: Pardon me?

MEMBER SIEBER: Did you repair your refueling seal?

MR. STAVELY: No.

MEMBER SIEBER: Obviously, that's where the leak is coming from. So I presume that your correction action program would have addressed that.

MR. STAVELY: When we were looking or attempting to determine the location of the leaks, one

of the things we did was went to -- let me bring up a slide. How about Slide 24 please?

Let's try, I've got the wrong one there, Slide 23. Thank you. The seal I'm talking about is labeled the bellows seal. So what you're looking at right now is that reactor cavity seal area. That was the one that was circled on a previous slide. So the water -- this is your shielding configuration.

So you see the water filling up the reactor cavity. Off to the left is the drywall shell, and if you look again, we're trying to be consistent, the blue line is the most likely location of the leak. If the water was actually -- if the bellows seal, and that's the curved part of the sketch right there. If that was leaking, it would be -- the water would be collected by the reactor cavity seal rupture drain.

It's part of our investigation of the source of this. We installed a design change into the plant, so that we could test whether that drain was open, and whether the supporting instrumentation was functional.

We verified that, since the 2010 refueling outage, that the instrumentation is functional and would alarm if water entered that drain, and also that the drain line is open both to the reactor cavity seal

area and then farther down into the normal drain system.

VICE CHAIRMAN ARMIJO: So another way of saying that is, you know, you didn't find where the leak was.

MR. STAVELY: We did not find -- well, that is true. We have not found a leak yet, but we've eliminated the area around the bellows seal.

VICE CHAIRMAN ARMIJO: Found where it is not?

MR. STAVELY: Yes, exactly, correct.

MR. DAVISON: Well specifically, those actions that Jim has been describing are all part of our investigation into this. So through process of eliminating, verifying, we're all part of our plan to narrow down, find that and fix the leak.

MEMBER SIEBER: So you intend to do that?

MR. DAVISON: Yes, absolutely. It's in our corrective action process, and we're pursuing it.

MEMBER SIEBER: I think that's an important thing to say here, that you intend to fix the leak.

MR. DAVISON: That is correct.

MR. STAVELY: Yes, definitely, most definitely.

MEMBER SHACK: I think they would also argue they can manage it, even if they can't find the leak.

MR. STAVELY: I'm sorry?

MEMBER SHACK: You can manage it, even if you can't find the leak.

MR. STAVELY: Our intent is to find and fix the leak. In the interim, we're making sure, by monitoring both the inside of the shell via UT, ultrasonic fitness measurements, and boroscopes on the outside, that there is no impact to the dry wall shell integrity.

MEMBER SIEBER: Thank you.

MR. STAVELY: I'd like to go to Slide 12 Alpha, please. This sketch shows the lower drywell area. The shaded regions are the drywell shield wall and the drywell foundation, and the concrete floor in the interior of the drywell.

I would like to just emphasize with this one, because this is the issue we've been talking about, is that the UTs of the shell show good condition, and as I talked about, until we fix this, we need to make sure that we maintain that good condition.

So I described the approximately 350 UTs

we performed in the previous refueling outage. We will be performing those UTs for each refueling outage.

VICE CHAIRMAN ARMIJO: How difficult do you think it's going to be to clear those drain lines?

MR. STAVELY: Right now, we're in the investigatory phase of that. We're not sure how difficult it's going to be. What we have done so far is we have assembled a mock up of the drain lines.

We have a contract in place and we have tested various techniques and tools, to try to remove the covers and see what's on the other side, and then perhaps -- we will determine what is necessary to reestablish drain line drainage from the bottom of the air gap.

VICE CHAIRMAN ARMIJO: And you kind of expected the same kind of blockage in all eight of those drain lines?

MR. STAVELY: There's a total of four drain lines.

VICE CHAIRMAN ARMIJO: Oh four. I'm sorry.

MR. STAVELY: At this point, we don't, we're not sure what is in the other three, but there isn't any reason to suspect we won't see the same

thing. Our intention is to interrogate the distance to the cover and the other three, and determine if we have the same configuration.

MR. DAVISON: And the same corrective action plans will be applied to all four of the drain lines.

MEMBER POWERS: On your drywell vent line, there's the bellows that went in?

MR. STAVELY: There's a seal between the drywell and the cavity, and then there's -- I'm sorry. I'd like to ask George Seibold to answer that.

MR. SEIBOLD: George Seibold, PSE&G Nuclear. Yes. The vent lines contain a double bellowed system that separates the drywell from the torus.

MEMBER POWERS: Stainless steel?

MR. SEIBOLD: The bellows are stainless steel.

MEMBER POWERS: Were they corroded?

MR. SEIBOLD: Well, they're shielded and they're double bellows, so they are tested. So --

MEMBER POWERS: They can be clogged, but they're still functional?

MR. SEIBOLD: Well, they're not directly accessible, and the testing has shown them to be

intact.

MEMBER POWERS: And the testing is that, is done how?

(Off the record comments.)

MR. SEIBOLD: George Seibold, PSE&G Nuclear. Those are, like I said, double bellows, and I think they're pressure-tested to show that they do not leak. I think that's part of the Appendix J testing.

MEMBER POWERS: When was the last Appendix J test done?

MR. SEIBOLD: I'm looking for our inspection guy. Tony?

(Off the record comments.)

MR. STAVELY: If you'd like, we can try to find an answer for you before the end of the meeting.

MEMBER POWERS: I appreciate it, and if you have a diagram of the bellows, that would be useful too.

MR. STAVELY: Although we're aggressively pursuing resolution of this non-conformance, drainage has not yet been established. We understand that staff intends to impose a license condition that ensures adequate monitoring of the drywell shell and its region, until drainage is established.

This license condition will require boroscope measurements and ultrasonic thickness measurements. PSEG Nuclear concurs with this approach. The combination of boroscope examinations of the exterior of the drywell shell, and ultrasonic thickness measurements of the drywell shell from the interior of the drywell are appropriate compensatory measures for the lack of drainage at the bottom of the air gap.

Slide 13, please. In summary, the containment is in good condition. A small reactor cavity leak and the non-conformance in the drywell air gap drain lines are being managed effectively in a corrective action program, and in accordance with our license renewal commitments. There is no indication of any effect on the containment-intended functions.

Our aging management programs ensure continued safe operation of the Hope Creek containment. Slide 14, please.

MEMBER BLEY: Well before you leave that, what could be the consequences of those drains being plugged up under odd conditions? I assume there are some of kind of unit coolers in the torus room? There's cooling water that comes in there, that if you had a leak there, you could flood that room. What

would be the effect of that?

MR. STAVELY: These drain lines are not the drain lines for the room. These are the drain lines that go from the air gap into the torus room.

MEMBER BLEY: Just directly there?

MR. STAVELY: Correct.

MEMBER BLEY: So there are other -- okay.

MR. STAVELY: Yes. This is not part of the drainage --

MEMBER BLEY: So it's really just for the gap area?

MR. STAVELY: That is correct.

MEMBER BLEY: Okay, thank you.

MEMBER SIEBER: The room actually has drains out of the room?

MR. STAVELY: That is correct.

MEMBER SIEBER: So you don't end up flooding the room in that --

MR. STAVELY: Oh, and those --

MEMBER SIEBER: --is only there during refueling.

MR. DAVISON: We're talking approximately ten ounces per hour over a two week period, when we're flooded up in the refuel outage. Any other time --

MEMBER SIEBER: Not this much.

MR. DAVISON: Correct.

MR. STAVELY: Slide 14, please. Before returning the presentation to Paul Davison, I'd like to correct the record regarding the answer to a question related to the fuel oil chemistry program that was posed by Mr. Stetkar during the ACRS Subcommittee meeting.

Mr. Stetkar's question is captured starting on line 18 of page 86 of the transcripts for that meeting. The response we are now correcting starts on line 14 of page 93.

"In essence, there three parts to this question. First, do we sample the material collected on the filler."

As Mr. Stetkar expected, the answer is yes. Our initial response involving the sampling material passing through the filter was incorrect.

Second, why are we using a three micron filter, when some other applicants are using a 0.8 micron filter? We use a three micron filter, consistent with our technical specification bases. GALL Revisions 1 and 2 refer to the plant's technical specification for directions on maintaining proper fuel oil quality.

Third, why are we calling the use of a

three micron filter an enhancement? We are calling it an enhancement because we are enhancing our fuel oil chemistry program to apply this filtering activity to the diesel fire pump fuel oil, as well as the emergency diesel generator fuel oil.

I will now turn the meeting over to Paul Davison for closing comments.

MEMBER SIEBER: I have a question about that. Three microns is a smaller size than what is typical for diesel fuel, right? Is that correct or not correct?

MR. STAVELY: The three microns is what has been approved and within our tech spec bases for the emergency diesel generators.

MEMBER SIEBER: That's your tech spec?

MR. STAVELY: That is correct.

MEMBER SIEBER: Okay.

MR. CUNANAN: A side question.

MEMBER SIEBER: That's pretty small, and --

MR. STAVELY: Yes, it is.

MEMBER SIEBER: -- and commercial diesel fuel has particles bigger than that.

MR. CUNANAN: Side question about the leakage. When you're back at power, what is the

nominal temperature of the drywell wall?

MR. STAVELY: It's approximately -- opposite the bottom of the air gap is approximately 95 degrees Fahrenheit at full power.

MR. CUNANAN: It will dry up.

MR. DAVISON: Okay, Mr. Chairman and Committee members, thank you for your interaction during today's presentation. We are confident that our aging management programs will be effective, to ensure the continued safe operation of Hope Creek through the period of extended operation. Pending any additional questions, this concludes our presentation.

MEMBER SHACK: Go ahead, Bill. You can go ahead with the staff presentation.

(Off the record comments.)

MR. HOLIAN: This is Brian Holian, Director of License Renewal. We're ready to continue to staff presentation. I'd just like to do introductions again from the staff, the NRC staff, that's present at the table. I'll go left to right.

The left is, my left up there, is Bill Holston, senior mechanical engineer in the Division of License Renewal. Bill's one of our senior reviewers in the Buried Piping program. So he'll pick up again on the question we had about the cathodic protection

and those issues, and the staff will deal with buried piping.

To his left is Abdul Sheikh. Abdul is a senior structural engineer, and he'll be able to highlight the staff's review of our structural issues, and in particular the leakage evident along the drywell.

One other note I wanted to make, mention on that drywell, and it was brought up by one of the Committee members, was the issue of previous operating experience on clogged drywell drains. That was a little bit of a surprise to the staff that, you know, that op experience hadn't been picked up, at least in this case here.

We are including that in another information notice being drafted by the staff, to again remind the industry of the importance of those drywell drains and other issues. To his left is Dr. Allen Hiser, a senior level advisor with the Division of License Renewal. Dr. Hiser is a peer reviewer for many issues on our license renewal SERs, but in particular metal fatigue issues.

To his left is Arthur Cunanan, the project manager, and he'll be highlighting the slides and leading off with the presentation, and to his left is

Ms. Bennett Brady, the senior PM for Hope Creek. With that, I'll turn it over to Art.

MR. CUNANAN: Good afternoon, Mr. Chairman and members of the ACRS. As Brian mentioned, my name is Arthur Cunanan, and I'm the License Renewal project manager for Hope Creek Generating Station. I'll be discussing the staff's safety review of the Hope Creek license renewal application, as documented in the safety evaluation report.

Joining me today is Bennett Brady, who presented during the Hope Creek Subcommittee meeting, and I would like to thank her for her mentorship and preparation for this full Committee meeting. I would like to also add Abdul Sheikh, the structural technical reviewer, who will be discussing the reactor cavity leakage in drywell shell. He was part of the second wave of staff support that deployed to Japan as a subject matter expert for structures.

Brian mentioned who was in the table. There is also staff seated in the audience, who was part of the review for the license renewal application and was in the audit. Also on the phone was member support for Region I, who's available to answer any questions, and we have Rich Conte, a branch chief from Region I.

My agenda for this presentation includes an overview of the Hope Creek safety evaluation report, a discussion of the staff efforts involved in closing the open item and confirmatory items, a discussion of additional RAIs following issuance of the SER with open items, and the staff's conclusion of its review.

Next slide. The SER with open items was issued to the Applicant on September 30th, 2010. The ACRS Subcommittee meeting was held on November 3rd, 2010, and since then, the final SER, which was issued on March 9th, 2011, has closed one open item related to buried piping, and two confirmatory items related to the inaccessible power cables and environmental assisted fatigue.

An additional item I will be providing, in addition to the open and confirmatory items, is new information concerning the reactor cavity leakage, and the containment drywell shell inspection program that the Applicant had mentioned.

I will also do a brief discussion of RAI's need for clarification related to sampling plans. The one open item for Hope Creek involves the Applicant's aging management program for buried piping and buried non-steel piping inspections. The staff issued RAIs,

asking the Applicant to address information on the Applicant's material composition of piping, cathodic protection, possible hazardous material flowing through inscope buried piping, and the quality of backfill.

I would like to introduce Bill Holston to summarize the staff acceptance of the Applicant's buried piping aging management program.

MR. HOLSTON: We evaluated the Applicant's response, and we evaluate that against Revision 2 of the GALL, the AMP 41 for buried and underground piping, found that the Applicant had acceptable backfill quality, that their coatings were acceptable, that their cathodic protection system, as was discussed, was available greater than 90 percent of the time.

In a couple of places where they don't have cathodic protection, they increased the magnitude of their inspections, and the Applicant discussed the fact that in their service water system, they have four small two to three foot service water piping schools.

They inspected two of those last fall; they're inspecting at least a minimum of one each of the ten year periods, which covers, if you just look

at the percentage inspection, and then knowing the results of those inspections, it's well-covered.

So given that it was consistent with GALL and 41, we accepted the AMP. Would you like me to discuss the 90 percent criteria or are we at --

VICE CHAIRMAN ARMIJO: Not me.

MEMBER POWERS: Yes.

MR. HOLSTON: Okay, all right.

(Simultaneous speaking.)

MR. HOLSTON: We established a 90 percent. We talked with some folks from NACE. Recognize that a cathodic protection system cannot be in service reasonably 100 percent of the time. So what's an acceptable balance?

Ninety percent of the time provided us with a clear point where we knew that if it came out of service, the Applicant would prioritize it in their maintenance system, to get it promptly back in place. You know, basic math, it's a 37 day outage per year.

We did a balance between the fact that cathodic protection is not the only thing protecting that pipe. We have requirements for backfill quality, so they can't damage the coatings. You have good coatings. You have the cathodic protection.

And then the remedy, if you don't meet the

90 percent, was to increase your inspections. The GALL AMP says if you're available greater than 90 percent of the time, you do one inspection per material type. If you're not available, then you do four inspections.

And we balance availability cathodic against the risk of increased inspections and digging up. I mean, you know, we want the pipe looked at visually, but we don't want the -- we recognize the risk of doing lots of digging up, lots of excavations where damage could occur. So that's where we came to the balance between 90 percent or an 80 percent number or a 95 percent number.

On average, the applicants that we evaluate, and we're around about a dozen now, are in the mid-90's, versus just being right there at 90.0 percent. That was the basis.

MEMBER POWERS: I think I understand what you're building, but I'm a little surprised you didn't tell me look, the maximum corrosion rate that's possible here is five mils a year. So that if it's out of service for a week in a year, I'm going to corrode two microns or something like that.

If I do that over 40 years, I stay within some limit. Is that sort of calculation done? I mean

you have a different approach. Yours is a balance between digging it up and the risk associated with that. I understand that. But there is a fundamental material property here that's somewhere.

Should that arise, and somebody's thinking --

MR. HOLSTON: Well, yes. We didn't calculations, because of the variety of soil conditions all the way across the U.S. But if you use, and this is the discussions I got in with one of the leading guys at NACE, when you know, I sat down with them and looked at average corrosion rates. An average corrosion rate doesn't --

MEMBER POWERS: It doesn't answer the question.

MR. HOLSTON: It doesn't mean a lot, or it doesn't give you a quantifiable --

MEMBER POWERS: It's an interesting number, but it's not the number I want.

MR. HOLSTON: Right. So we did not do a specific calculation, but given average corrosion rates, there's no threat if they're protected ten percent or not protected for ten percent of the time. That's because as soon as you put the current back on, the corrosion stops.

It's not -- it doesn't continue for a while and mitigate, or if you left it unprotected and that portion you left unprotected continues to corrode.

MEMBER POWERS: I think I understand that aspect of it. What I don't understand is how corrosion is affected when you go -- when you have an episodic loss of cathodic protection? Now I just simply cannot recall somebody doing that kind of an experiment. You know, usually they put the piping in. It's a corrosive environment and they let it corrode and they pull it out every once in a while, weigh it and measure the residual metal thickness.

But this going on and off of a cathodic protection, I would presume has some effect on any past wear. I mean I just don't know what it is.

MR. HOLSTON: Well actually, as soon as you turn the current on, the corrosion starts. As soon as you turn the current back on, the corrosion stops.

MEMBER POWERS: That's where the electrons are going, right. What else gets affected? You know, from my talking to the experts, that's all -- you know, if you're talking about bare steel, that's all that occurs. But it's not bare steel shortly after

you stick it in the ground.

MR. HOLSTON: Say again, I'm sorry?

MEMBER POWERS: It's not bare steel shortly after you stick it in the ground?

MR. HOLSTON: Oh no. I'm just saying well first of all, if there's no loss of coating, there's no issue at all. You can leave the cathodic protection system off forever. So but I'm saying if you have a holiday, and right where you have that holiday and you turn the cathodic protection off, it will start corroding then and it will stop immediately, and there's no lingering effect.

MEMBER POWERS: Now you've got a corrosion product layer there, and it sits there, and the current comes back on or you're there. Some change of electrical potential there. Whatever it is, it doesn't corrode anymore.

Now I turn the current back off, it's sort of a different chemistry than you stated before. What happens? I mean maybe the corrosion rate's exactly the same as if I left the current off all the time. Maybe it's not. I just don't know of anybody that's ever done that experiment.

MR. HOLSTON: Right. I didn't get into details when I talked to the -- that sort of detail.

Have you done any experiments? I didn't think to ask if you've done experiments in that regard. But again, you know, talking to the folks that are far more knowledgeable than I am, you know, that it's an on/off function, and that terminates it.

VICE CHAIRMAN ARMIJO: Particularly carbon steel.

MR. HOLSTON: Yes, with carbon.

VICE CHAIRMAN ARMIJO: They really don't --

MEMBER POWERS: They're past the --

VICE CHAIRMAN ARMIJO: Yes. They really don't have much, much, anything that comes close to--

MEMBER POWERS: Well, I mean Bill, you joke. But in fact, aren't you the one that bleeds all over me over crevice corrosion and things like that, that the environment now is different in there? So when the current goes off -- right. The current flow is all from below, and it was found instantaneously they were changing potential.

But now, back off, don't I have a different chemical environment there for the corrosion than I would if I had not stopped it? I don't know.

MR. HOLSTON: Yes, but I'm not sure --

VICE CHAIRMAN ARMIJO: I don't think it

matters.

MEMBER SHACK: These things, you know, you're generally looking for something that's greatly different, and then the thing is that you just don't get a protective layer here.

MEMBER POWERS: I know. I mean it's -- well it's protected in a mass transport sense or a medium sense, something like that.

VICE CHAIRMAN ARMIJO: Right.

MEMBER SHACK: Yes. There is that kind of -- but that's not very much protection.

VICE CHAIRMAN ARMIJO: Right. Not like a stainless steel --

MEMBER POWERS: I'm just curious. I mean, everybody seems to be very confident on this, and so far I can find absolutely nobody, nothing that substantiates this confidence, except for the industrial experience.

MEMBER SHACK: The industrial experience, perhaps is where it comes from. But nobody's seen enough to provoke them to do an experiment.

MEMBER POWERS: Yes, I mean you know. Nobody says you need to run this thing 99.9 percent of the time or you're toast.

MEMBER BLEY: Well even just here, we had

the Applicant telling us that they've run it 95 percent. So it's off some of the time, and still when they dig it up--

MEMBER POWERS: Well, and the nice thing is he's got a piece of unprotected steel that he's going to be looking at. So he's got a nice, inspectible backup.

MEMBER SHACK: Yes. Well, the problem with protected steel is that, I think what they refer to as holidays, you get a focused corrosion there.

MEMBER POWERS: You get a focused corrosion.

MR. CUNANAN: Okay. Is there -- thanks Bill. Any follow-up --

MEMBER POWERS: I mean I understand your basis. It's a little different than my basis, but I'm working from my basis. I understand what you're thinking. I mean that's the kind of thing you guys have to worry about, because you want it looked at, but the looking at it itself poses a risk to the pipe.

But this is one place where worldwide industrial experience is applicable to a nuclear plant. There's a carbon steel pipe in the ground --

VICE CHAIRMAN ARMIJO: It's still carbon steel.

MEMBER POWERS: Looks like a carbon steel pipe.

VICE CHAIRMAN ARMIJO: Why don't you keep going?

MR. CUNANAN: Okay. Moving on the next slide, the first confirmatory item for Hope Creek involves the inaccessible power cables. The staff notes industry operating experience, where water and moisture cause failures of inaccessible power cables at low voltages. Industry operating experience also showed a trend in cable failures, which could have been detected earlier if they had increased the frequency of inspection and testing of the cables.

In response to the staff's concerns, the Applicant committed to a limited exclusion of cables not exposed to significant voltage, and to add low voltage power cables into the scope of the program. They also --

MEMBER SHACK: Did they actually eliminate the exclusion, or did you just say that whether they had the exclusion or not, it didn't make any difference? Because I read the SER. I got the impression it was --

MR. CUNANAN: I have Cliff Doutt. He's the electrical technical lead, and can answer that

question.

MR. DOUTT: Cliff Doutt. What originally in GALL, sort of one hand, was if the cable was energized less than 25 percent of the time it was excluded. We just hold that.

MEMBER SHACK: I was trying to get at what the licensee actually said. I thought their statement still said they had the exclusion, but it didn't affect anything.

MR. DOUTT: Part of the -- I mean some of the SER still says that, and we talked about the revision. Then when they meet that, they'll say it's no longer there at the --

MEMBER SHACK: It's no longer there, okay.

MR. CUNANAN: Yes. It was a description, and then we asked additional RAIs. The Applicant also committed to a change in testing frequency from ten years to six years, and changed manhole inspection frequency from two years to one year. The Applicant also committed to add event-driven inspections for manholes for events such as storms.

The staff has determined that the following commitment is a conservative approach to ensuring the operability of inaccessible power cables. Do you have any further questions?

Next slide, please. The second confirmatory item involves environmental assisted fatigue analysis. As a side note, you will also see this as an open item in the Salem review. In the license renewal application, the Applicant used the six generic locations in NUREG 6260, to perform the environmental-assisted fatigue analysis.

The staff noted that the license renewal application did not take into account locations with higher cumulative usage factors, when analyzing for environmental-assisted fatigue.

The Applicant's plant-specific configuration may contain locations that should be analyzed for the effects of the reactor coolant environment, other than those generic locations identified in NUREG 6260. In an RAI, the staff requested that the Applicant justify why additional locations do not need to be analyzed for environmental-assisted fatigue.

I would like to introduce Allen Hiser to summarize the staff's acceptance of the Applicant's response to the RAI.

DR. HISER: The Committee may remember from other recent full Committee meetings on license renewal applications, that the same confirmatory item

has been identified several times. Actually, Hope Creek was the one that indicated to us that we need to ask that question, because they had in their application --

MEMBER POWERS: So no good deed goes unpunished, right? Provided lots of good information. But what we saw was that they didn't use the highest CUF value for environmental effects, and that seemed not to be logical to us. So we asked for this item. They have committed to go back and look at all of their design basis, ASME Code Class I component fatigue evaluations.

If they find other locations that are more limiting than the ones that they considered for environmental effects, then they will change their location. They may go back and reevaluate the fatigue calculation.

But they will ultimately get a point that they have used the highest CUF in their fatigue calculation, as indicated on the slide there. So based on that, the staff found that to be an acceptable commitment by the Applicant.

MR. CUNANAN: Okay. Thanks, Allen. I would like to go to the next slide. As I indicated earlier, and this was covered in the Applicant's

presentation, that this is an additional issue that the staff received information on after issuing the safety evaluation report.

During our initial review of the ASME IWE program, this item was resolved. However, during the refueling outage in October 2010, when the Applicant reported continued leakage at two penetration sleeves, and indicated that all four air gap drains at the bottom of the drywell were blocked, this prompted the staff to review this item again, and the staff issued an additional RAI.

I would like to introduce Abdul Sheikh to summarize the Applicant's aging management program, the staff's concern with the program based on the new information, and our intended path forward. Abdul.

MR. SHEIKH: So I think most of the information on this slide is covered by the Applicant. But this slide provides chronological information, you know. Initially, the leakage was observed in 2009, and it was observed at Gate 13. But we were concerned, like you are, whether the water is getting trapped at the bottom.

So we asked the Applicant to perform additional inspections. So in 2010, when they did these inspections, they again found leakage at that

penetration, and an additional penetration, which is next to it. They also found that all the four air gap drains are blocked, and the Applicant went ahead and did the UT examination, over the full height, from the floor of the drywell up to the penetration, which is about eight feet.

They found the thickness everywhere was more than nominal. In this area, the average thickness was 1.49 inches. In a couple of spots, it was 1.475 inches. The design, original design as documented in the FSER, the containment has 1/16th inch tolerance of corrosion. So they were still within the more than the design value.

So based on this, we agreed with the Applicant, to perform additional UT examinations for the next three outages, to develop a corrosion rate and identify whether we are, if there's any corrosion taking place or not. They also agreed to -- they also agreed to remove the blockage from the four drain lines.

In addition, we are preparing an information notice to, you know, inform the other licensees about this condition. As the Applicant finds out, this plan doesn't have a sand bed region. So it's a little different than most of the earlier

BWR plants. Next slide.

VICE CHAIRMAN ARMIJO: Did you review the photographs that the Applicant took of the outer part of the containment? They said that when they did their boroscope, they saw that the coating was in good shape and everything, and took a lot of pictures. Did the staff review that either in the inspection or in the course of resolving this?

MR. SHEIKH: I didn't review it, but --

MR. PHAM: This Bo Pham with the staff. We just found out this information and got more details as of Monday this week. So we have not gotten chances to take a look at all those details from the boroscope inspection.

So most of what the Applicant had indicated earlier, and what we know as of right now, the fairly recent information, and that's why we alerted the Applicant, we would follow up with taking a look at the SER and providing additional details of that later.

VICE CHAIRMAN ARMIJO: But you have reviewed the UT data?

MR. SHEIKH: Yes, we have reviewed the UT data. So on Monday, the 9th of May, the Applicant informed us about this recent, you know, condition,

which was when they went in to try to remove the blockage. They found that the blockage was not at the drywell, but further inside. Can we have page 16? Yes. So the way we understand, from our recent conversations, that the drain is blocked halfway inside the conduit.

MR. CUNANAN: How do they know it's halfway?

MR. SHEIKH: Because what they did, as we understand, they cut the pipe at that elbow and they put a rod in.

MR. CUNANAN: So then, so I have to ask then, what's the diameter pipe, four inches, the pipe itself, the drain pipe?

MR. SHEIKH: I think it's three inches.

MEMBER SHACK: It says four inches on the --

MR. CUNANAN: Okay, so four inches, and it was a -- maybe I should have asked this of the Applicant. So what's the character? If they were able to see it, what's the character of the blockage?

VICE CHAIRMAN ARMIJO: If it is rust, something's wrong.

MR. CUNANAN: A plug? A piece of steel?

MR. STAVELY: Jim Stavely, Hope Creek

License Renewal Project. The plug appears to be a cover at the end of the four-inch pipe.

MR. CUNANAN: Oh.

MR. STAVELY: But it's half -- as shown on the figure, it's part-way through the wall. So we're not sure of what is on the other side of that.

VICE CHAIRMAN ARMIJO: I still don't understand. What is it? Is it like a plate?

MR. CUNANAN: That pipe must not be going all the way through?

MR. STAVELY: That is possible, yes.

MR. CUNANAN: So it's a pipe that was stuck in and had a cap on it, but it didn't go all the way through the concrete, into the gap?

MEMBER SHACK: It's too short.

MR. CUNANAN: Too short, yes.

VICE CHAIRMAN ARMIJO: And so the rest of the way could be concrete?

MR. STAVELY: That is possible. But as we said before, we haven't yet established what's on the bottom of the air gap.

MR. CUNANAN: So if this is the steel, that means it's about a foot of concrete that's potentially there instead of the pipe?

MR. SEIBOLD: George Seibold, PSE&G

Nuclear. We poured the shield wall in two steps. So where that covering is is where a field weld, which changes the pipe, it's four inch, Schedule 40 pipe, and it changes to Schedule 80 at that location.

So if I would surmise, I would say that could have been an FME cover that got left in during some of the pours, and when they did the weld for the other piece of pipe to go up there, they didn't know there was a covering there.

So my thinking is we've got to get rid of that cover, and check to see what's on the other side of the cover.

VICE CHAIRMAN ARMIJO: That's something you can't do.

MR. CUNANAN: Ask the question, Sam.

VICE CHAIRMAN ARMIJO: How could you weld it without noticing it was covered?

MR. SEIBOLD: Well, if it had an internal FME cover, they could have just done the field weld without looking inside the pipe. The area was to be grouted in the future. So they may have put an internal FME cover in there, and then when they come and weld it on the other section of pipe, it goes up to the drywell air gap that got overlooked.

MR. CUNANAN: Okay, thank you. Sam can

carry on. Sam?

VICE CHAIRMAN ARMIJO: No, it's all right. I think you just have to get your drills, concrete drill ready is my guess.

(Laughter.)

VICE CHAIRMAN ARMIJO: But go ahead.

MR. SHEIKH: So that's where we are. This is recent information, and we are looking at it, and based on that, we're going to impose a license condition which will ask the Applicant to perform boroscope examination and UT thickness measurements every outage, until the drain is established.

MEMBER BROWN: They'll do it in the same locations, whether you measured the minimum?

MR. SHEIKH: Right.

MEMBER BROWN: It wasn't noted.

MR. SHEIKH: We are looking at how many, whether that is enough, whether we need to have more area for the UT.

MEMBER SHACK: But I mean you could have -- okay, that's given.

MR. SHEIKH: That's given, but how much and what type, we're looking into it right now. And they will submit a report to the Commission every time they complete this work.

After they have removed the blockage, they will still continue to do UT examinations for the next three outages, as was the case previously. That will establish a corrosion rate, which will tell us whether the containment is able to -- the aging can be managed until the end of the period of expanded operation. We will revise the SER accordingly.

MEMBER BROWN: So is the UT done on the -- it's done on the interior of the --

MR. SHEIKH: Yes, yes.

MEMBER BROWN: Okay. I kind of figured that's what it is.

MR. SHEIKH: Yes. Can you put 16 back? Yes. So you can see on this picture that the area under the penetration, it will be examined the full nine feet height. The area of the 360 degree, we are evaluating how much height we need to do. Whether it is up to the downcomers or higher or lower, we haven't established that.

MR. CUNANAN: So may I ask another question? Maybe I don't understand the operating procedures here. So since it's a large enough pipe, why not drill a test hole to see what's on the other side? Is that difficult to do?

MR. SHEIKH: I do not --

MR. STAVELY: Jim Stavely, License Renewal Project. Our plan is to continue with this, and drill through that, to see what is on the other side. But again, we have a lot of preparations, including mock-ups and test runs, to make sure that we do that.

MR. CUNANAN: Okay. Don't drill too far.

(Simultaneous speaking.)

MR. SHEIKH: Also, the dose rate is pretty high, so --.

MR. CUNANAN: Okay. That's a no.

MR. SHEIKH: So that concludes --

MR. CUNANAN: Thank you, Abdul. Just like Abdul mentioned, the path forward will be establishing the license condition. We'll revise the aging management program and the SER, and submit it to the ACRS for review.

Next slide, please. On this slide is a short summary of three programs we received additional clarification on, on the Applicant's sampling plans. The ACRS has seen these generic RAIs before and all the in-house license renewal reviews. Does anyone have questions on this slide?

(No response.)

MR. CUNANAN: So in conclusion, on the basis of this review, with resolution of the IWE

program in the SER and establishing a license condition, the staff determines that the requirements of 10 C.F.R. 54.29 Alpha has been met for the license renewal for Hope Creek Generating Station.

VICE CHAIRMAN ARMIJO: Are there any questions from the Committee? No. Okay. Well, I'd like to thank the staff and the Applicant for the presentations. Right on time, which is really great. So we'll take a recess now. Oh, there was something else. I'm sorry, a clarification.

MEMBER SHACK: A clarification?

VICE CHAIRMAN ARMIJO: Yes.

MR. SEIBOLD: George Seibold, PSE&G Nuclear. We took a look, and the date for the Appendix J test, the Type A test, was April 2009. It's also tested under Type B, but I don't have that date. Does that answer your question?

VICE CHAIRMAN ARMIJO: Yes, thank you. Any other questions, comments? All right. With that, why don't we take -- we'll recess until 3:15.

(Whereupon, a short recess was taken.)

Salem Nuclear Generating Station

VICE CHAIRMAN ARMIJO: All right. Let's reconvene. Mr. Stetkar, who is the Subcommittee chairman on the Hope Creek license renewal, is not

available. Dr. Shack will lead us through the presentation.

MEMBER SHACK: Okay. We had a Subcommittee meeting on the Salem Nuclear Station, Units 1 and 2 license renewal on December 1st last year. At that time, there were four open items and no confirmatory items in the safety evaluation report. The four open items dealt with leakage of borated water from the spent fuel pools, buried piping inspection and cracking due to stress corrosion cracking and primary water stress corrosion cracking on the metal tip.

The Applicant and the staff will brief the Committee about how those items were resolved in today's meeting. In addition to these items, the staff will explain a recent revision to the license renewal guidance, updating the GALL report on aging management of treated borated water, and the changes required to the safety evaluation report to implement that revision. I'll turn to Brian Holian to start.

MR. HOLIAN: Yes, thank you. Brian Holian, Director, Division of License Renewal again. The staff is pleased to be here again, to present our results on the Salem safety evaluation review. If I might, I just might go back to the previous session on

Hope Creek just for a second, and just comment on the drywell leakage and that issue.

There was some late-breaking information in that. We realized a lot of that was just due to the licensee's schedule for getting at those drywell drains. I think, as brought out from our presentation and the licensee's, that however, the staff has been very comfortable with the UT results that have been taken in that case, and that have been committed to in the future. So we see it more as a minor update to the SER that we discussed with them. Dr. Shack.

MEMBER SHACK: On Salem, one other comparison I wanted to make and was planning to make between Salem and Hope Creek was, you know, the difference on buried piping program. You'll see it in the SERs. You'll see no cathodic protection on the Salem side of the house. So you know, it's a difference the staff had to wrestle with. It's no different than we've wrestled with on previous applications that haven't had cathodic protection. I reflect on the discussion we had earlier and the discussion on GALL Rev. 2, that cathodic protection kind of is viewed by the staff as another kind of layer in the defense indepth process for evaluating the buried piping. I think the staff worked well, and

independent of the industry, but well at categorizing different tables for the number of inspections that would be acceptable to staff, with or without cathodic protection. So I wanted to highlight that, and you'll be seeing that in the Salem presentation.

The second item really to highlight is the spent fuel pool issue again and leakage. We've had this leakage in the spent fuel pool on several plants over the past couple of years that have been highlighted.

This is extensive leakage, but on the same side, the licensee has been taking proactive actions, you know, for years, including pumping and treating. So hopefully the Committee will see that in the evaluation and in the discussion today.

There was one other introduction. With me again is Bo Pham, the branch chief for License Renewal with Salem and Hope Creek. Also, in the audience I forgot to mention during the Hope Creek discussion, but one of our contractors, Dan Naus from -- to oversee and review our structural from Oak Ridge has been here and has helped both on the Hope Creek issues and the Salem issues for the staff. With that, I'll turn it over to Paul Davison.

MR. DAVISON: Thank you, Mr. Holian. Good

afternoon, and again, my name is Paul Davison, Vice President of Operations Support at PSEG Nuclear, and the executive sponsor for the license renewal program.

Before we begin today's presentation, I'd like to introduce the new presenters here. To my right is Ali Fakhar, the PSEG License Renewal manager for Salem. Ali has 29 years of power plant experience, 15 at PSEG Nuclear.

To Ali's right is Jim Melchionna, our corporate Buried Pipe program manager. Jim has 29 years of nuclear experience, 19 with PSEG, and he's also heavily involved, as he mentioned, in the industry initiative concerning buried pipe programs.

To Jim's right is Tom Roberts from the License Renewal Project. Tom has 31 years of nuclear power plant experience, including 27 years at PSEG Nuclear. And again in the audience, we have with us Tom Joyce, the president and Chief Nuclear Officer of PSEG Nuclear; Bob Braun, the PSEG Nuclear Senior Vice President for Nuclear Operations; and Carl Fricker, the Site Vice President for Salem.

On Slide 2 shows our agenda for the presentation today. We will begin with a brief description of the site and a summary of our license renewal aging management programs and commitments.

We will then continue by discussing the closure of our four SER open items, and several other issues that were mentioned in the ACRS Subcommittee on December 1st of 2010, and for which we've received requests for additional information.

I look forward to answering any questions you have, either during or after the presentation, and I would now like to turn it over to Ali Fakhar, who will begin with the presentation.

MR. FAKHAR: Thank you, Paul. Good afternoon. My name is Ali Fakhar, and I am the License Renewal manager of PSEG Nuclear. Mr. Chairman and Committee members, as shown on this slide, the two Salem units and Hope Creek share a common side on the New Jersey side of the Delaware River in southern New Jersey. They share a common protected area.

Salem is a two unit, four nuke Westinghouse PWR co-owned by Excelon and PSEG Nuclear, and operated by PSEG Nuclear. The key structure for Salem that you can see on this slide are the two containment buildings, the intake structure for service water and circulating water, and the fuel shaft.

Next slide. This slide summarizes the aging program and commitments for Salem. There are 48

aging management programs, including 32 existing programs and 16 new programs that were developed for the application. Of the 32 existing programs, 15 required no changes to align with GALL, while 17 required enhancement while on the GALL.

There are 54 license renewal commitments for Salem. These commitments are managed under an existing process, consistent with NEI 9904, Revision 0. The commitments are tracked in our SAP database system, which is a data foundation for most site processes, including our corrective action program. PSEG Nuclear is in the process of implementing many of the program enhancements, as well as the new programs as we speak.

The next part of the presentation will discuss the closure of four open items and several other issues, for which PSEG Nuclear input was requested, following the ACRS Subcommittee meeting. I will now turn the presentation over to Jim Melchionna, who will discuss our first open items in buried piping. Jim.

MR. MELCHIONNA: Thanks, Ali. Good afternoon. My name is Jim Melchionna. As I previously mentioned, I'm the corporate Buried Pipe program manager at PSEG Nuclear, and the Vice

President of the EPRI Buried Pipe Integrity Group.

Next slide, please. The first SER open item related to buried piping was closed by modifying our program commitments with the following enhancements. PSE&G will perform a cathodic protection study, prior to entering the period of extended operation, to assess the benefits of installing such a system, versus other mitigative and preventative actions.

We will also perform a soil characterization study prior to PEO, to incorporate corrosivity into the risk ranking and selection process, for identifying buried pipe locations for inspection.

If this initial study determines that the soil is non-corrosive, we will perform a second soil study 15 years after the first study, which will either confirm that the soil is still non-corrosive, and that the initially specified number of inspections is appropriate. If the soil has become corrosive, additional inspections will be performed.

We also committed to replace the buried auxiliary feed water piping located inside the Unit 2 fuel transfer tube area, and reroute it above ground prior to entering the PEO. That activity was

completed this spring.

We resolved the staff's concerns regarding non-cathodic protective carbon steel piping by focusing our inspections on the buried safety-related portions of the auxiliary feed water, compressed air and service water systems, and the inscope portion of the fire protection system.

We also added two additional inspections for a total of three inspections on the service water system prior to entering the PEO.

MEMBER BROWN: So contrary to Hope Creek, this i s -- you don't know that this soil is non-corrosive right now?

MR. MELCHIONNA: We have done soil samples at Salem as well, and prior to the outage, which was in April, those soil samples were on average of 30,000 ohm centimeters, chlorides, fluorides, sulfates, all in the range of non-detectables or just slightly above as well.

MEMBER BROWN: So it's similar to the other results?

MR. MELCHIONNA: Similar results.

MEMBER SIEBER: Quick question for you. You talk about inscope portion of your fire protection system. Is that connected to out of scope sections of

the fire protection system?

MR. MELCHIONNA: I have to ask Dylan Cimock if he can answer.

MEMBER SIEBER: I'll give you the follow-on questions too. If you have a failure in the out of scope portion of the fire protection systems, what happens to the pressure in the inscope portion?

MR. MELCHIONNA: Okay.

MR. MUGGLESTON: This is Kevin Muggleston, License Renewal Project team. There are some portions of the fire protection system that are not in scope, and they're limited. They're for out buildings, the admin building. Pretty much all of it comes off of the same main loop.

But they are, by design, you can isolate them with post-indicator valves, and that's --

MEMBER SIEBER: And manually isolate them?

MR. MUGGLESTON: Correct.

MEMBER SIEBER: So anything connected to the main loop fire protection system probably will not work properly until you do that isolation, right? You have to know where the leak is, and you have operate --

MR. MELCHIONNA: The system's normally pressurized and monitored, you know, at the normal

pressure.

MEMBER SIEBER: Yes. But it fails and diesel pumps come on and that doesn't do the job, and you say "I've got a problem." So now you've got to figure out where the problem is, and if it doesn't reach the surface right away, then the operator's got to figure out which post-indicator valves he's got to close, in order to regain pressure in the in-service portion.

MR. MELCHIONNA: Historically, the water, the leakage, we have seen some leakage in the fire protection system, and it comes to the surface right away. Everywhere on site we've had a fire protection leak, it has surfaced very quickly.

We also have conducted a number of opportunistic inspections on the fire protection piping, and seen no corrosion-related degradation, either internally or externally. The leaks that we have had have been at mechanical joints, just due to looseness of the joint.

MEMBER SIEBER: Fire protection systems, for some reason or other, particularly the cast iron ones, have had some availability problems --.

MR. MELCHIONNA: We've looked at that OE, but we have not experienced that to date at our site.

MEMBER SIEBER: And good luck.

MR. DAVISON: The one additional advantage we do have at PSEG Nuclear is within my organization, we actually have a dedicated fire department, which are responsible for all the mains. So the quick identification, the reaction to that is their function, and not a burden on operations. So at least we have folks that are dedicated associated with the fire department and the mains themselves.

MR. MELCHIONNA: The next slide, please. During our recent refueling outage on Salem Unit 2, we performed a number of inspections as shown on this slide. In all cases, the pipes were found to be coated. Upon removal of the coating, the pipes were found to be in good condition as well.

VICE CHAIRMAN ARMIJO: Were they similar in appearance to the slide you showed us on the Hope Creek? I mean, yes, from the Hope Creek inspection? Did they look that good?

MR. MELCHIONNA: Yes, they did look that good. If you could juts quickly go to Slide 64. That's a picture of a carbon steel service water spool, non-cathodically protected, coating very well adhered, and exactly the same. If you go to 65 very quickly, that's how we left it.

VICE CHAIRMAN ARMIJO: Thank you.

MR. MELCHIONNA: Okay.

MEMBER SHACK: So you didn't do the pulsed eddy- current inspections? You took the coating off.

MR. MELCHIONNA: We did both. We did pulsed eddy-current from the ID of the pipe. We did UT from the outside of the pipe, and we took the coating off and replaced it, to make it good for another however many years, until the time we determine the next inspection's required.

The particular note is the inspection of the auxiliary feed water piping for Unit 2. During a Subcommittee meeting last fall, we presented an operating experience related to Unit 1 to aux feed piping, that was excavated and found uncoated in 2010.

The reason for the lack of coating was determined to be an isolated event, due to inadvertent coating removal during original plant construction. This similar condition of auxiliary feed water piping was excavated for Unit 2 during this past outage, and the coating was found present, further proving the Unit 1 findings to be an isolated case.

In addition to direct inspections, we performed an indirect inspection of the non-safety related carbon steel service water piping, with

satisfactory results. During our recent Unit 2 refueling outage --

MEMBER SHACK: What's the indirect inspection?

MR. MELCHIONNA: I'm sorry?

MEMBER SHACK: What is the indirect inspection?

MR. MELCHIONNA: That actually should say "direct." We inspected it from the inside using pulsed eddy-current; inspected 1,100 feet section of the non-safety supply to our turbine building.

During our recent Unit 2 refueling outage, we also replaced and rerouted above ground two buried auxiliary feed water pipes located inside the fuel transfer tube area, which is required to be done prior to entering the period of extended operation.

MEMBER SHACK: You did that with a PIG that goes down the pipe?

MR. MELCHIONNA: Correct. We had a PIG manufactured. A company out of Australia has a proprietary technology, and we used that.

MEMBER SHACK: So when you say you inspected 1,000 feet, you really did send --

MR. MELCHIONNA: We sent the PIG, a manually pushed PIG 1,100 feet of the pipe. In

conclusion, the buried pipe program will effectively manage the material, condition and aging of buried piping at Salem, and will do 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, and the development of any new technology in inspection techniques as they become available.

MR. DAVISON: Okay. The next part of our presentation is the discussion on our open item regarding the spent fuel leakage on Unit 1. Salem Unit 1 has approximately 100 gallons per day leakage through very small cracks in the spent fuel pool liner welds. We have tried to identify the location of these liner weld cracks, but they're too small to locate.

Currently, there is no leakage outside the plant structures. However, we are not satisfied with the fact that we have this leakage, and we will continue to pursue ways to eliminate the leakage. Additionally, we have been implementing a program since 2003, that manages the leakage in order to minimize degradation of the spent fuel pool concrete

structure.

Tom Roberts will present a brief history of our leakage, our discovery of leakage outside the plant structures, the remedial actions we have taken and how we will manage the leakage, until such time that we can identify and fix the source of the leakage. I will now turn it over to Tom Roberts.

MR. ROBERTS: Thank you, Paul, and good afternoon. My name is Tom Roberts. I'm a member of the Salem License Renewal team. I'm also the lead advisor for EPRI's NDE for Ground Water Protection Technical Advisory Committee, and Spent Fuel Pool Leakage Subcommittee.

Today, I'll be discussing the Salem Unit 1 spent fuel pool, specifically the management of the spent fuel pool liner leakage, and the aging effects of the spent fuel pool liner leakage on the concrete. Following my discussion of the technical details, I will discuss the spent fuel pool open item.

Next slide, please. The Salem Unit 1 spent fuel pool currently leaks approximately 100 gallons per day, which has been stable over the last seven years. This leakage represents approximately 0.3 percent of the pool volume per day.

The leakage is through cracks in liner

welds, and the cause of the cracks has been attributed to being the differential thermal expansion between the liner and the concrete surface. There is approximately 2,100 linear feet of liner seam welds, and 1,400 plug welds to the concrete embedments, which are used to attach the liner to the concrete structure.

The estimate leak size, if it were a single or multiple cracks, would total six inches long and .001 inches wide. As Paul noted earlier, in the past, Salem has made attempts to locate the seam weld leaks, but we were not successful.

MEMBER SIEBER: You never found one?

MR. ROBERTS: No. We did vacuum box testing in the mid-90's and did not find any leakage. But we did have evidence of leakage at the time from the telltale signs.

VICE CHAIRMAN ARMIJO: What kind of techniques did you use to try and find these leaks?

MR. ROBERTS: The techniques that were used in the 90's was vacuum box testing, which is the traditional methodology used for spent fuel pools. In fact, as I noted earlier, EPRI and myself and other industry groups are looking at other NDE technology that would have a greater detection factor, that could

also be used to overcome some of the accessibility issues.

VICE CHAIRMAN ARMIJO: A lot of this water leaks through and collects through various leak chases, and winds up in the sump some place.

MR. ROBERTS: It all winds up in sumps, yes.

VICE CHAIRMAN ARMIJO: Okay. You didn't try pressure? It seems to me that that big, those leaks should be findable. I don't know how you concluded it's one six inch long, equivalent to a six inch long, one mil wide, and still leak that much.

MR. ROBERTS: Well, as I said, we have a lot of evidence that supports that the leakage is occurring at plug welds, and the reason for that is the plug welds are not served by channels directly. If I could go to, this might help explain, Slide 53 please.

VICE CHAIRMAN ARMIJO: Okay. That one helps a lot.

MR. ROBERTS: And you'll see, there are seam welds that are served by channels, right. If leakage were to occur at that specific location, it would simply leak from the channel to an associated pipe telltale. It would also represent, from a

chemistry standpoint, the pool chemistry.

That being said, our chemistry coming out of the telltales is actually reactive, and has a calcium carbonate foundation to it, which suggests that the plug welds are actually leaking, and the plug weld has a leak path that can migrate, say, across the floor and then recollect in the channels, because the channels are not welded on the back sides, other than the seam weld itself.

MEMBER SIEBER: Okay. So you're going to -- you've concentrated on inspection at the plug welds and still can't find anything?

MR. ROBERTS: Yes, and the plug welds are -- the plug welds are also perhaps a more vulnerable location, given the fact that this is a stainless assembly. They are stainless plug welds. We have calculated that the inherent residual stress essentially is beyond the yield point, and therefore the likely locations for the actual welds, sources of leakage.

That being said, there's 1,400 of them, and we have not been successful in finding leakage. We believe it's very, very small leakage, probably spread out amongst many plug welds.

MEMBER SIEBER: You have spent fuel racks

on top of that risk.

MR. ROBERTS: We have spent fuel pool racks from the floor up. There's 23 feet of water above the fuel racks.

MEMBER SIEBER: So inspecting underneath the rack to the surface --

VICE CHAIRMAN ARMIJO: You have to move racks.

MR. ROBERTS: You have to move racks, you have to move fuel, et cetera. So part of the industry challenge at this point is finding not just the technology, because frankly, things like ultrasonics could be done. However, it can't be done because of accessibility.

So there are techniques that are being evaluated, that could be done globally, that would provide higher reliability of detection and accessibility.

MEMBER SIEBER: But as I recall from the Subcommittee meeting, your master plan, at least my perception of what was said there, was that you're going to collect and control the leakage as your main effort, and there may be some effort, maybe some effort to find the leaks?

MR. ROBERTS: That is correct.

MEMBER SIEBER: So really your strategy is collect it and control it, as opposed to aggressively hunting for it.

MR. ROBERTS: I will perhaps recharacterize that. To collect it and control it, until such a time that there is available technology, so that we can detect and remediate.

MEMBER SIEBER: Okay. I guess there is a subtle difference there.

MR. ROBERTS: Well, it is being actively addressed by EPRI initiatives and from international initiatives as well.

MEMBER SIEBER: Thank you.

MR. DAVISON: You're right. We're mitigating it right now. But it's in our corrective action process, and that is a goal, to drive towards identification and fixing it.

MR. ROBERTS: PSEG implemented a program in 2003 to manage this leakage, after discovering it had leaked external to the building, due to a clogged leakage collection system.

PSEG has committed to manage the leakage, after confirming that the impact to the fuel handling building structure is not significant, and after exploring that suitable technology for leak detection

and repairs is presently not available.

MEMBER SIEBER: You see, I have another question. The Salem spent fuel pool is borated, right?

MR. ROBERTS: That is correct.

MEMBER SIEBER: 2,600 ppm roughly?

MR. ROBERTS: Correct.

MEMBER SIEBER: That's an acid, that's pretty corrosive. Is there anything in the leakage pathway that would be impacted by this, what I would consider a pretty corrosive solution, like carbon steel or concrete?

MR. ROBERTS: Obviously, the more concerning question would be rebar. But that is buried substantially below cover concrete, all right.

MEMBER SIEBER: Hopefully, yes.

MR. ROBERTS: Yes, and we actually know that information. The other aspect of this is that you are correct; the borated water concentration is normally between 22 and 24 hundred parts per million. pH is about 4.8. However, what we actually find in our telltales is a very alkaline solution, because the borated water actually reacts with --

MEMBER SIEBER: The concrete.

MR. ROBERTS: Correct.

MEMBER SIEBER: Right, and so you're dissolving concrete in the process?

MR. ROBERTS: Correct.

MEMBER SIEBER: So it's a matter of time until you get to the rebar?

MR. ROBERTS: Well yes, but we have done calculated projections of degradation, from the beginning of plant life conservatively to beyond the period of extended operation, and the degradation effect does not have any structural consequences on the building, which I'll be explaining as we go through.

MEMBER SIEBER: Okay. I am a little nervous about that, but go ahead.

MR. ROBERTS: Okay. Go to the next slide, please. Historically, you put this in perspective, the sketch on the left hand side of this slide shows the situation in 2002, when ground water contamination was discovered just outside the fuel handling building and the adjacent auxiliary building.

The design of the leakage collection system is to capture any leakage from the liner seam welds into the embedded channels behind the liner, and route it to a series of telltale drain lines. The telltales are piped to a drainage trench in the sump

room.

The channels, as I noted earlier, are not welded to the back side of the liner at the seam welds. Therefore, any potential leakage from intermediate plug welds can also reach the channel and then flow out through the telltales. The system did not work as designed, because the telltales became clogged over time with mineral deposits from the concrete.

The blockage caused the leakage from the spent fuel pool to accumulate in the gap between the liner and the building concrete. As the water level increased in the gap between the liner and the concrete, the hydrostatic pressure forced water into construction joints in the building.

The water migrated through the construction joints, then seeped out of the fuel handling building into the seismic gap between that building and the adjacent auxiliary building. This resulted in contamination external to the structure. However, the contamination did not migrate off site, nor did it impact drinking water sources.

MEMBER SIEBER: I presume that the water that you -- or water mixture, you know, soil and everything else that you did find, was from a nuclide

standpoint, more tritium than anything else?

MR. ROBERTS: Yes. Basically, the gamma's basically played out from a filtering standpoint. So what is primarily seen in the outdoors monitoring levels for tritium.

MEMBER SIEBER: At the point where it became uncontrolled, which is where it enters the soil, what's the activity level do you think?

MR. ROBERTS: Well, actually it doesn't enter the soil. It enters into an interstitial space between the buildings. There's a seismic gap. Actually, it doesn't have a soil foundation to it. It's concrete foundations abutted against each other.

MEMBER SIEBER: Yes. On seismic gaps, I'm familiar with it actually connected with the ground.

MR. ROBERTS: This is actually multiple elevations of foundations that actually --

MEMBER SIEBER: Slide.

MR. ROBERTS: How the buildings were constructed was one, I don't recall which sequence of events. But one wall was in place. There was a phone barrier between outer wall, which was used as the forming surface for the next wall.

MEMBER SIEBER: Now that seismic gap is usually a couple of inches thick,

MR. ROBERTS: Yes.

MEMBER SIEBER: Three, four inches.

MR. ROBERTS: Yes, six inches with --

MEMBER SIEBER: Okay.

MEMBER REMPE: When you've been monitoring the leakage rate, has there been an increase. It is regular? Is it, is this 100 gallons per day OAC on a regular basis?

MR. ROBERTS: Let me give you a little bit of perspective. At the initial discovery in 2003, we had a diminished leak rate, and that was in part due to the blocked telltales, all right. There was always evidence of leakage from the telltales.

After cleaning the telltales, we essentially established I'll call it the active steady state leak rate. That is what is represented int his discussion as the 100 gallons per day. While there is some variation in that, it normalized over basically a period of a month. As it's trended basically weekly, it is 100 gallons per day.

MEMBER SIEBER: So that's 36,500 gallons a year. That's a fair amount of water, right?

MR. ROBERTS: There's a very, very small percentage in the pool itself.

MEMBER BANERJEE: It was ten percent,

right, of the pool volume?

MR. ROBERTS: No. It's 0.3 percent of the pool volume.

MEMBER BANERJEE: Per day.

MEMBER SIEBER: Yes. The makeup would not be a big factor. But that's a lot of water.

MR. ROBERTS: Going back to the slides, the ground water remediation that was instituted, has been put in place, and as I said, the initial contamination plume has both diminished in size and in concentration. The right hand side of this slide shows the situation after corrective measures were implemented, and that is also the present condition.

The telltales are maintained open and clear, to properly maintain leakage flow back to the rad waste system. This flow path is currently assured through periodic monitoring and cleaning.

Seismic gap drains to the auxiliary building were also installed to ensure any leakage that could migrate to the seismic gap, is also captured. These corrective actions manage the leakage to minimize the potential impact of the fuel handling building structure, and to ensure there is no leakage to the environment.

Next slide. As I mentioned previously,

PSEG committed to manage the leakage, after confirming that the impact on the fuel handling building structure is not significant, and given repair methodology is presently not fully developed.

I'll now give you a summary of our analysis of the fuel handling building structural impact. PSEG performed laboratory testing to quantify the potential for long-term degradation of the concrete structure, exposed to borated water. The testing confirmed that the borated water attacks the calcium hydroxide component of the cement paste, weakening the cement paste and causing debonding of both the coarse and fine aggregate.

Based upon the testing, the predicted depth of concrete degradation after 70 years of exposure for the spent fuel pool water is 1.30 inches. We also confirmed that the degradation of rebar is not significant, based both on published studies and industry operating experience.

MEMBER BANERJEE: Are there any cracked pots in the --

MR. ROBERTS: Is there any --

MEMBER BANERJEE: Cracked pots --

MEMBER SIEBER: They want to know.

MR. ROBERTS: No. The entire fuel

handling building from the accessible surfaces have been visually examined. We have done ACI structural inspections. There's no evidence on the external surfaces.

MEMBER BANERJEE: But what about the internal surface?

MR. ROBERTS: The internal surface is not accessible. They're behind the liner.

MEMBER SIEBER: Right. That's what the liner does.

MEMBER BANERJEE: So that you presume that there is not, right?

MEMBER SIEBER: We have done testing, our own laboratory testing to see what the degradation results would be. I will get to it shortly, but let jump to it.

MEMBER BANERJEE: Is there any evidence of in similar situation, of cracking in these types of buildings?

MR. ROBERTS: Now, we were very fortunate, however, that we secured, from the decommissioned Connecticut Yankee plant, concrete cores from their spent fuel pool, which had evidence of leakage. What we found is that it corroborated our test results with respect to the degradation mechanism.

And as I noted, what really happened is the reaction with the cementitious materials, and you get kind of a, I'll call it, a paste-type effect. But it doesn't cause any structural backing per se. You simply have the cementitious material -- yes, exactly. A better way to describe it characteristically would be a corrosion mechanism.

MEMBER SIEBER: My understanding of these, the structural forces on the building, for that type of building, are greater in the foundation areas. You know, the higher up the building, the less hydrostatic force you have, and environmental audits are small. But the concrete's pretty thick.

MR. ROBERTS: Right. The concrete's very thick.

MEMBER SIEBER: It's what, two feet thick or something like that?

MR. ROBERTS: Actually it varies. The thinnest wall is six feet thick.

MEMBER SIEBER: Six feet thick.

MR. ROBERTS: Right. So it's going to take a while to --

MEMBER BANERJEE: So the stresses are compressive? There must be tensile, right? I mean --

MEMBER SIEBER: That depends on where you

are.

MEMBER BANERJEE: Why don't they crack?

MR. ROBERTS: Rebar. The rebar is carrying the load, which is the primary element for the structural aspects.

MEMBER SIEBER: Yes. Concrete is a stabilizer, and the rebar is --

MR. ROBERTS: It's a matrix composite, but the primary loads are basically carried by the rebar.

MEMBER SHACK: Now you do have leakage through the east wall, right, a very small amount?

MR. ROBERTS: That's correct, yes.

MEMBER SHACK: So I mean there are cracks through the east wall at least.

MR. ROBERTS: We actually know that there are construction -- well, historically how we resolve all this is in the sump road, which is the west wall, right, and the east wall is the seismic gap, that the floor or foundation of the pool floor or walls there is a construction joint.

While there is a designed water stop in that construction joint, it's certainly not designed for a 40 foot head of water, which is what we assumed, based upon all of our data and research. But we had developed this hydrostatic head between the liner and

the concrete.

That became a preferential path, and we know factually on the west wall, when we did the original inspections and analysis and chemistry monitoring, that we were getting chemistry results that were indicative of the pool, although we saw that there was a change in pH, of a more alkaline nature, as well as calcium carbonate.

So that in part gave us rise to basically say the reason we got water to the seismic gap is because of the preferential path at this construction joint. Since we have removed the clogs and the subsequent hydrostatic CAD, we don't see evidence of water basically migrating on either side.

MEMBER BANERJEE: Is there a crack or not that let the water out?

MEMBER SIEBER: It's an intentional crack.

MR. ROBERTS: It's an intentional -- well, I wouldn't call it a crack. A construction joint.

MEMBER SHACK: You have a potential for a way out without a crack?

MR. ROBERTS: Correct.

MEMBER SHACK: I mean it's hard to prove there's no crack, but there is an explanation for how to get water through the wall without a crack?

MR. ROBERTS: It's more than an explanation, because we actually saw, I don't have the photographs here, but the sump room has a walkway at 84 foot elevation, 89 foot elevation is the location between the slab and the interface of the wall, all right.

During the original investigation, we saw a white streak literally placed at 89 foot elevation, that isotopically and from a chemistry standpoint gave very strong evidence that that was the preferential path. The configuration on the west wall, which is the seismic gap, but otherwise inaccessible, has an identical configuration.

VICE CHAIRMAN ARMIJO: I wanted to get a clarification. In that building, you also have a transfer pool.

MR. ROBERTS: That's correct.

VICE CHAIRMAN ARMIJO: Now is that also suspected of leaking, or have you confirmed that that does not leak?

MR. ROBERTS: We believe -- well, we know that it is leaking, and the reason, it's constantly filled. The transfer pool at Salem, there's a weir gate that can be used to separate the pool. However, that weir gate has been removed, and we actually use

the additional volume for heat load capacity on the pool.

VICE CHAIRMAN ARMIJO: So it's effectively the same pool?

MR. ROBERTS: It's essentially, yes. There's a wall in between, but it's communicated by water on both sides.

MEMBER SIEBER: But that area typically does not have racks in it?

MR. ROBERTS: That is correct.

MEMBER SIEBER: And so if you wanted to try some inspection technique, that's probably where you would try it. But that's usually deeper than the remainder of the pool?

MR. ROBERTS: It is a little bit deeper, that is correct.

MEMBER SIEBER: Especially to load a cask in there. That's what it's for.

MR. ROBERTS: Right. I see that.

VICE CHAIRMAN ARMIJO: But is it lined and has plug welds and --

MR. ROBERTS: It is a bit --

MEMBER SIEBER: Typically it's the same, but they place their configuration is different, and the equipment that's in there is minimized. So if you

wanted to do some trowel inspection, that would be the place.

MEMBER BANERJEE: How much of a load does the stacked fuel put on the line?

MR. ROBERTS: It's a dead weight load. I don't know the exact loading, but you have the hydrostatic head load because of the water, plus the dead weight load of the rack and fuel assemblies.

MEMBER SIEBER: Yes. It's the fuel that weighs.

MR. ROBERTS: Right.

MEMBER SIEBER: The racks --

MEMBER BANERJEE: Have you done sort of a stress analysis of this liner?

MR. ROBERTS: Yes, we have.

MEMBER BANERJEE: What did that show?

MR. ROBERTS: Well actually, it's part of the presentation, but we have done predictive --

MEMBER BANERJEE: Are you going to tell us about it?

MR. ROBERTS: Yes.

MEMBER BANERJEE: Okay. So then that's fine.

MR. ROBERTS: Okay, all right. We noted that we've also confirmed that the degradation of the

rebar is not significant, based upon published studies and industry operating experience. We've performed visual examinations of the fuel handling building on all accessible surfaces.

These examinations confirmed that the fuel handling building concrete is in good condition. Further, we corroborated our testing and structural assessment using *in situ* data from Salem and other plants. PSEG collaborated with EPRI to test concrete cores from the decommissioned Connecticut Yankee spent fuel pool.

These cores included concrete just behind the liner that had been exposed to borated water from their spent fuel pool. The test corroborated the results of PSEG laboratory tests, and the degradation projections that were established for Salem.

PSEG also performed hardness tests on the concrete surfaces that had been previously exposed to leakage, which had migrated through a construction joint. Those tests confirmed that the concrete is in good condition. The structural calculations of the fuel handling building --

MEMBER SHACK: Is that concrete that's sort of behind the west wall somewhere, is how you got access to it?

MR. ROBERTS: Yes. It is on the west wall, near the sump room.

MEMBER SHACK: Oh, but that's six feet on the other side?

MR. ROBERTS: That's correct.

MEMBER SHACK: I wouldn't expect it to be too much problem.

MEMBER SIEBER: They used that same group condition because it wasn't involved.

MR. ROBERTS: But there was water that migrated through the construction joint. The structural calculations of the fuel handling building were reviewed, to identify the calculated margins at various areas in the structure.

The projected depth of concrete degradation is less than the concrete cover over the reinforcing steel, and is very small compared to the thickness of the walls and slabs surrounding the spent fuel pool.

Also, the effects of the rebar steel is not significant. As a result of the projected degradation, there is no significant impact on the structural capacity of the fuel handling building. By way of example, the largest projected reduction in structural capacity was on the east wall of the fuel

handling building, which is the thinnest wall, with a projected reduction in capacity of .7 percent.

There is an available design margin of five percent, in excess of the code design allowables for that wall, essentially 105 percent margin. Therefore, based on the fact that the potential impact in the fuel handling building is not significant, that liner repairs were determined to be not practical at the present moment, and that leakage to the environment has stopped, PSEG will continue to manage the leakage until it can be repaired.

MEMBER RAY: Okay. Now could you just explain how you determined that leakage to the environment is stopped?

MR. ROBERTS: Yes, twofold. We have reestablished the design flow path, which is through the telltales back to the sump here. On the outside wall on the west side, we've installed a drain line actually through the wall of the auxiliary building.

What that -- any leakage that can migrate to the seismic gap is actually collected through that drain line, and then processed back to the rad waste system.

MEMBER RAY: Well, what you're basically saying is that there's no stability of an undetected

or unmonitored path through this leakage tube would follow.

MR. ROBERTS: We actually have more conclusive information than that. Since we've installed the drain line in the auxiliary building, and we've installed remediation and monitoring welds, we have actually seen a decrease in the dimension of the plume and the concentration of the plume that was previously identified in the 2003 time frame.

MEMBER RAY: Okay. Well, I think that's more relevant. How do you monitor the plume?

MR. ROBERTS: All right. I'm going to have Mr. Ed Keating speak to that question.

MR. KEATING: Good afternoon. My name is Ed Keating. I'm with the License Renewal team. Salem has installed a network of 38 monitoring wells, to monitor the tritium plume transport and concentrations. Included within that are six pumping wells to remove the tritium from the ground water, and measure it and monitor it prior to release.

By constantly monitoring and trending those wells, we've identified that the plume is significantly reduced in concentration. As Tom mentioned, it is significantly decreased in spatial. Since the pumping wells are designed to pump greater

than the precipitation infiltration, we draw a negative hydraulic radiant in that zone where we have the pumps operating.

MEMBER RAY: Well, it sounds to me as though the answer would be if there is continued leakage, you are capturing it and preventing it from migrating further than it had.

MR. KEATING: If there were to be further leakage, it would be identified by an increasing trend in the wells in the area that it would leak. So we would see that there was an increase, and the system that's there that would prevent it from leaving.

MEMBER RAY: Yes. Well, I think the last thing is the more important. Whether you have a sensitivity to detect the difference between cleaning up a prior release and there being no further release is --

MR. KEATING: At the time of the release, we have 15 million picocuries per liter.

MEMBER RAY: Yes.

MR. KEATING: And right now, we have nothing over 60,000 on the entire site. We've never found a gamma in any well water so far, site-related gamma obviously --.

MEMBER RAY: These wells will continue in

service?

MR. KEATING: Yes. At this time, it's currently planned to do that, working with the New Jersey Department of Environmental Protection and the NRC with this program.

MEMBER RAY: Yes. Well I mean I think all of the explanations about why there isn't any more leakage probably represents the best that you can do. But to say that therefore there is no more, I think, requires something more than what you described to be done, and because a given leak chase can plug. You can't tell whether it's plugged or not, and there are going to be cracks in concrete. But since there isn't, has never looked at concrete very much.

MR. ROBERTS: If I may speak to the fact of we can tell the telltales are plugged or not. In fact, that's part of the ongoing monitoring process.

MEMBER RAY: Okay. Well, tell me about that, because telltales go, and I have some experience with this, telltales go all over the place. It's very hard to tell, if they're not plugged in some location that you can't get access to, unless you've got a technology I'd be pleased to hear about.

MR. ROBERTS: Yes, it's actually boroscopic fibroscopes, and actually let me kind of

carry on and perhaps hopefully answer your question. There have been several actions that have been taken, to ensure that the leakage collection system is operating properly. One, daily walkdowns are performed, to monitor the telltale drains. Number two, sump pump collection run times are recorded weekly and trended monthly, to ensure that the drains do not become locked, and let me expand for a moment.

We know that the steady state leakage rate is 100 gpd. We monitor that and trend it. In addition, every six months, the telltale drains are boroscoped, and if required, cleaned to verify that the telltales remain open. The seismic gap drains are also sampled weekly, and the sample results are trended.

For the fuel handling building, PSEG will conduct periodic structural inspections, to confirm that no significant structural degradation is developing. These inspections will be performed every 18 months for the Unit 1 sump room wall, and every five years for the remainder of the fuel handling building.

This completes my technical discussion of the Unit 1 spent fuel pool. Our open items involving the spent fuel pool, as part of the structure's

monitoring program, was closed with our commitment to ensure that the leakage collection system is operating properly, in addition to the following enhancements:

One, testing the water drained from the telltales and the seismic gap drains; monitoring the water chemistry parameters to assess any changes that could indicate building degradation from the borated water; and evaluating and taking appropriate corrective action for any readings outside of the expected ranges.

We've also committed to performing a core bore in both the east and west walls of the Unit 1 spent fuel pool, in areas that have historically shown ingress of borated water. The core bores will allow us to test the concrete and inspect the rebar for any signs of degradation.

In summary, the spent fuel pool liner leakage does not have a significant impact on the fuel handling building structure. Available structural margin ensures that any potential degradation due to borated water leakage does not result in a loss of intended function.

Keeping the leakage collection system and the seismic gap drains operating properly assures that, or minimizes the potential for concrete

degradation, and prevents contamination of the environment. The integrity of the fuel handling building will be maintained, to ensure continued safe operation. I will now turn the presentation back to Ali Fakhar --

MEMBER RAY: Now wait a minute.

MEMBER SIEBER: One more question.

MEMBER RAY: Is there a fuel transfer canal leak at all, in the inside containment?

MR. ROBERTS: No.

MEMBER RAY: Doesn't leak at all?

MR. ROBERTS: No, the fuel transfer tube?

MEMBER SIEBER: Yes, there has to be.

MEMBER RAY: The fuel transfer canal.

MR. ROBERTS: Oh, the fuel transfer canal. All right. Let me be precise. The transfer pool has evidence of leakage. The transfer tube between the containment and the transfer pool does not leak.

MEMBER RAY: How about inside containment?

MR. ROBERTS: There has been evidence of leakage in the containment cavity, reactor cavity, when it's flooded up.

MEMBER RAY: Okay. Tell us about that.

MR. ROBERTS: Similar construction, similar design, and we believe that there is probably

a similar phenomena. However, it's a very minor amount of leakage. It's evidenced in one or two of the telltale systems that occurs, and then stops completely once the cavity is drained.

MEMBER RAY: You're sure?

MR. ROBERTS: Yes. We've actually monitored that. That's part of an ongoing monitoring program.

MEMBER SIEBER: I was going to ask a question, but I think I'll just make a statement, and that will make --

MEMBER RAY: Well, wait a minute, Jack. I'm not finished.

MEMBER SIEBER: Oh, you're not done? I thought you were done.

MEMBER RAY: No, no. I guess, you know, there's been concern about -- you talked a lot about the massive monolithic structural design of the spent fuel pool and all that. But there has been concern about even just during refueling outages, leakage resulting in corrosion of containment liners and things like that.

Is that -- that all has been put to bed? I will ask the staff if they're satisfied too. But you don't have any residual borated water sitting in

some location against the containment liner, for example? You're sure about that?

MR. ROBERTS: The configuration in the cavity and transfer canal is similar, in that it's a lined, wallpapered stainless, served by telltales similarly to the spent fuel pool, where we have seen evidence of leakage is drippage through the telltales, not on the containment liner structure.

MEMBER RAY: Does that mean that there is none?

MR. ROBERTS: No. I can't make that statement.

MEMBER SIEBER: Is your liner stainless?

MR. ROBERTS: The liner is not stainless.

MEMBER SIEBER: Okay. I didn't think so. Thank you.

MR. ROBERTS: The liner -- well, let me be precise. The liner for the transfer pool and the cavity, yes.

MEMBER SIEBER: The containment liner is not stainless.

MR. ROBERTS: The containment is not, that's correct.

MEMBER SHACK: You were supposed to have examined that this spring, right?

MR. ROBERTS: That is correct.

MR. FAKHAR: Yes. I will have Alan Johnson to just discuss a little more detail, as far as the containment liner, so we understand --

MEMBER RAY: I mean the containment liner is obviously one vulnerable thing, probably the most vulnerable complement inside containment, to residual borated water that's migrated out of the transfer canal.

MR. JOHNSON: Alan Johnson from the, with PSEG Nuclear. I'm the Salem design manager. There are no areas that borated water could accumulate next to the containment liner.

The liner is either coated and inspected, or covered with concrete. So we don't have a concern that the short-term leakage from the filled reactor cavity areas could be pooling or causing corrosion on the containment liner.

MEMBER RAY: Well, you're real unique in that lack of concern, I guess.

MEMBER SHACK: Well, what did your inspection and examination of that liner show?

MR. JOHNSON: Okay. So our inspection of the liner, that we did in this outage, was in response to the discovery we had corrosion at the bottom of the

liner, at the concrete to liner juncture, in fall of 2009.

This spring, we looked at the liner, reexamined it with ultrasonic examination, and found that the wall thicknesses were above design. We completely cleaned all accessible areas, flushes. We completely cleaned the entire perimeter where we had the corrosion, recoated it, and are preventing further corrosion from liquids.

We also did investigation by drilling two holes through the concrete to the floor of the liner, and confirmed that the liner in that location was not corroded or impacted by either -- water of any sort.

MEMBER RAY: Well, I think it would have been useful for you to spend a little more time on that area, and perhaps sacrifice some time on the spent fuel building, because it's hard, in just what you've said, to feel fully satisfied. I'll have to leave it at that.

MR. FAKHAR: During the Subcommittee, we spent, we went through the whole containment liner, and Alan went through a whole presentation on the liners.

MEMBER RAY: Okay. Well, if you discussed it in the Subcommittee --

MR. FAKHAR: That's what we did in the Subcommittee.

MEMBER RAY: Not something I'm going to try and --

MR. JOHNSON: I could also show you some slides. We did measurements on page 43, or Slide 43.

MEMBER SIEBER: Page 47-48.

MEMBER RAY: That's in the backups.

MEMBER SIEBER: Yes, 47-48.

MR. JOHNSON: These are the Subcommittee slides, that I'll talk about very briefly.

MEMBER RAY: In any event, that's fine. If it was discussed adequately in the Subcommittee, I'll defer to the Subcommittee members to have pursued it sufficiently. But I mean, you know, the fact is that if you've got leakage during the refueling outage, where does it go? Is it fully passivated if it gets in between the liner and the concrete, and so on and so forth.

Those are all questions that people normally ask and answer, and I would have encouraged you to include it in this discussion as well in some form. But in any event, we've heard, I guess, that it was covered.

MR. FAKHAR: The Subcommittee, yes. Okay,

any other questions before -- I will now discuss the closure of the remaining two SER open items, and several other issues for which PSEG Nuclear input was requested, following the ACRS Subcommittee meeting.

Slide 17 please. The third open item was related to the metal fatigue evaluation. Specifically the staff had questions on Salem's methods for evaluating the metal fatigue using the WESTEMS software, and also on the environmentally-assisted fatigue evaluation.

This item has been closed, based on our responses to RAIs and to NRC audit requests, including adding new commitments. Salem committed to document justification for the software user intervention in future analyses, and not to use the NB-3600 module, since there are open RAIs on this software module, stemming from the staff's review of the AP-1000 design.

Additionally, Salem committed to verify, prior to period of extended operation, the NUREG 6260-based location of bonding compared to other plant-specific locations. If other locations are found to be more limiting, they will be evaluated. If any of these locations are comprised of a nickel alloy, NUREG 6909 will be used for the evaluation.

Slide 18, please. Our final open item was related to the steam generator tube to tube sheet welds. This item was closed, based on our program commitments to implement plans for each unit to perform either an analysis or a one-time inspection of the representative number of the welds.

Slide 19, please. I will now address two other issues raised by the staff, following ACRS Subcommittee. The staff requested specific information on sampling for one-time inspection program, and the selective leaching program. In general, their requests were related to the additional program detail provided in GALL Revision 2. Our responses were consisted with the GALL Revision 2, and staff closed these issues.

The final item is response to a question raised by Mr. Stetkar during the ACRS Subcommittee meeting, regarding the Salem flux thimble tube inspection program.

Next slide, please. The question raised by Mr. Stetkar is how will Salem establish wear rates in the PEO. Salem has replaced tubes over the life of the plant, due to non-aging issues. Therefore, there are multiple tubes with different service times in each unit.

The inspection program includes eddy-current testing of tubes having different service times, determine wall measurement over the entire length of the tubes as a function of the operational services. Comparison of the measurement to design drawing specification, to determine wall loss for each of the tubes examined.

Wall losses will be determined based on measurement over the tube's service life. This will be trending of the data on prediction for -- this will permit trending of the data on prediction for future losses and a loss comparison to acceptance criteria for corrective action.

This concludes our discussion of Salem SER open items and other issues. I will now return the presentation over to Paul Davison for closing comments. Paul.

MR. DAVISON: Okay, Mr. Chairman and Committee members. Thank you again for your interaction during today's presentation, and again with Salem, we're confident that our aging management program will be effective in ensuring continued safe operation through the period of extended operations.

Pending any additional questions, this concludes our presentation. Thank you.

MEMBER SHACK: If there are no additional questions, I'm going to turn it over to the staff.

MR. HOLIAN: This is Brian Holian, Division Director of the Division of License Renewal. Staff's ready to begin its presentation of the Salem safety evaluation. Once again brief introductions. At the table, Bill Holston, senior mechanical engineer, expert on buried piping; Abdul Sheikh, senior structural engineer; Dr. Allen Hiser, senior level advisor in the Division of License Renewal.

A different project manager for Salem, Sam Cuadrado, and Ms. Bennett Brady, a senior project manager who has overseen both Salem and Hope Creek. One opening comment, and then I'll turn it over to Sam. He's got the slides up.

I appreciate the Committee's questioning and interest in the Salem spent fuel pool issue. One item I saw in the slides and I want to highlight, and I'll ask Abdul Sheikh when he covers staff's review of the spent fuel pool, is on the licensee's Slide 11, I think it was, where Mr. Ray, I think, you took some issue with the words on there about "no additional contamination is exiting the structures."

I think the staff's view, and their briefings of me have been skeptical of that position,

I'll state it that way. We do see the licensee doing the right issues, and historically over the years on that plant, we do recognize the sampling.

I did ask that Rich Conte, the regional branch chief, be here to talk in general, and I think we have a backup slide highlighting some of the regional inspections reports, that have covered the tritium plume that has been present on the site.

So we don't have any disagreement, I think with, obviously with the results and the trending in the right direction. But we have been skeptical about could there be other concrete cracks exiting the building that are not known. So part of the staff's approach on request for additional information was to verify on other walls, through core bores, the condition of those walls.

I wanted to highlight that right away and Abdul Sheikh, I think, will speak to that when he gets there.

MEMBER RAY: Well thanks for those comments. I guess I would also say it's a completely different question, the one I raised at the end, which is is there any threat to the pressure boundaries inside the containment. It's a different proposition altogether, but I'd appreciate any --

I wasn't at the Subcommittee meeting, so if it was fully addressed there, then --

MR. HOLIAN: Oh, on the line, I did want to highlight that. Yes. At the Subcommittee, it was brought up. I do highlight in the beginning that, you know, the Excelon team that has helped at PSE&G, sometimes when they come in for an application, I'll historically meet with the team and I'll go over the list of 10 to 15 hot topics that are on my mind or the staff's mind that we learned from recent operating experience.

Back at the time this application came in, I believe it was the Three Mile Island application had, through inspections. It was really during the process that we saw extensive liner degradation. The Committee probably remembers that, at the seal inside containment.

So that was one item that we were asking almost right from the beginning. They had done a real good look at that as part of their application here. I know there's a commitment in the supplement there to continue to remove liner plate insulations, and look, in the period of extended operation, at the liner was one item, and Abdul Sheikh might be able to expand on that as needed.

MEMBER RAY: Thank you.

MR. HOLIAN: Sam, are you ready?

MR. CUADRADO de JESUS: Yes.

MR. HOLIAN: Okay. I'll turn it over to am Cuadrado.

MR. CUADRADO de JESUS: Good afternoon. My name is Sam Cuadrado de Jesus, and I'm the License Renewal operating manager for Salem Nuclear Generating Station. I will discuss the staff's review of the Salem License renewal application, as documented in the safety evaluation report.

Sitting in the audience, or on the phone, are members of the NRC staff who participated in the review of the license renewal application, or in audits that were conducted by the applicant's facility.

Next slide, please. My agenda for this presentation includes another review of Salem safety evaluation report, a discussion of the staff's efforts in closing the open items, another discussion of additional areas needed for clarification for the SER with open items.

Next slide, please. SER with open items was issued to the Applicant on November 5, 2010, and the ACRS Subcommittee meeting was held on December 1,

2010.

Since then, the final SER has closed four open items related to spent fuel leakage, buried pipe inspections, borated water, stress corrosion cracking, leakage due to faulty welds, metal fatigue of the coolant pressure boundary, issues with WESTEMS software, and locations for environmental-assisted fatigue.

The buried piping and locations for environmental-assisted fatigue analysis items are similar to open items discussed for Hope Creek earlier. The spent fuel pool, steam generator, and WESTEMS issues are related to Salem. Salem final SER was issued on March 31, 2011.

Next slide, please. The first open item relates to Applicant's statement in its license renewal application, that the spent fuel pool of Unit 1 has experienced leakage of borated water.

As discussed by the Applicant, leakage of 100 gallons per day have been noted into their drains on the west side of Unit 1 spent fuel pool, and that a small amount of leakage is migrating to the inaccessible east wall of the pool.

The staff was concerned that this leakage of borated water may cause degradation of either the

concrete or embedded steel reinforcement of the spent fuel pool. I requested additional information on the leakage, to confirm the Applicant's findings. I will turn it over to Abdul Sheikh, to describe the resolution of this open item.

MR. SHEIKH: Yes. Before I start with the spent fuel pool, I want to address Mr. Ray's concern about the containment liner plate. This -- we explored this issue in detail during our Subcommittee, and also several RAIs on this issue. During the refueling, there is some leakage from the fuel transfer canal, both in Unit 1 and both in Unit 2.

But the leakage is very small. It's about 100 drops per minute, and the Applicant explained that the probable source of this leakage is small cracks in the reactor cavity, or the fuel transfer canal liner. Most of the leakage enters the leakage system. However, some of the water exits and migrates through the concrete down the sides of the containment liner behind the --.

So we asked the Applicant made a commitment to remove the insulation which covers the liner in that area. In addition, the bottom 30 feet of the liner in Salem is covered by insulation.

So we have agreed with the Applicant, and

Applicant made a commitment to remove about 200 panels of these insulation, to inspect the liner and check the condition of the liner. So I believe we have tried to address that issue, to the extent possible.

MEMBER RAY: Okay.

MR. SHEIKH: Now coming back to spent fuel pool issue, Mr. Roberts will give you much more detail on this spent fuel pool, and he has been involved in this issue since 2003. So he's more knowledgeable in this area. But basically, there is a leakage in the Unit 1 pool, and we looked at all the studies, and the experimental work they have done.

But we were still, wanted to have some confirmatory confirmation about those studies and their evaluation. Based on that, we agreed to have commitments with them to inspect to accessible portion of the west wall every 18 months. That's the only portion of the spent fuel pool which you can inspect.

If you -- do you have the backup slides? Okay, yes. Go to page three. Yes. So the only accessible portion is where it says "core drill in west wall by 2013." That's the only portion where we can inspect the pool concrete. On the left side, that tunnel thing.

(Pause.)

MR. SHEIKH: Yes. So that's the only place, and that they committed to inspect it every 18 months. The reason we wanted to inspect that is that's where originally there was leakage, before the telltales were clear.

MR. CUNANAN: So can I ask a question? This is not -- I wasn't at the Subcommittee meeting, but I guess I have to ask this then. So is it the staff's view that this can go on, as long as it's monitored indefinitely?

MR. SHEIKH: Yes.

MR. CUNANAN: Why?

MR. SHEIKH: Because the reason is the structure, the spent fuel structure. The issues are whether the rebars are being corroded, and there are -- we started that part. Number one, the leakage is mostly in the base of the liner plate. The rebars, if you go to -- if you go to page two of -- yes.

So if you see, if you go to this picture, you will see the rebars are about eight inches below the liner plate. So the possibility of water leaking from the liner plate, and leaching up to the concrete, is very remote. That's number one.

Number two, if it reaches there, by the time it reaches there, the pH value of this water will

become alkali, because of interaction with cement. Once it becomes alkali --

MEMBER POWERS: We understand that all better. It follows a leak path, and the first quantity of water that goes through that leak path assuredly attacks and interacts with calcium hydroxide and calcium hydroxy-aluminates. The second quantity of water comes through when there's no such calcium hydroxide to attack, because it's already reacted with the first quantity of water.

Pretty soon, you have a leak path where you're not increasing the pH of the water, don't you?

MR. SHEIKH: But there is, you know, they have done tests, and they have refreshed the solution all the time.

MEMBER POWERS: I'd like to see that test, because that promotes -- speaks to a mass transfer of calcium hydroxide that I would find remarkable.

MR. SHEIKH: Mr. Roberts.

MR. SAUNDERS: John Saunders with the License Renewal Project team. The testing that was done, and our published studies show that the degradation of the concrete is a diffusion-controlled process. The boric acid works through from the surface behind the liner, and penetrates through the

concrete, followed by diffusion, and that limits the rate to one point, three inches over 70 years.

So you would not reach the rebar. You would not get through all the covered to get to rebar.

MR. CUNANAN: This is in a flow? I think what Dan is asking, I guess I was thinking similar to Dan. In a flowing system, or in a stagnant system, because --

MEMBER SHACK: No, he's diffusing through the concrete. Dan is talking about a crack, I think, to provide more direction --

MR. CUNANAN: He was kind of talking about a crack that's flowing, so that everything passes -- after you've essentially created a barrier, it will just flow on and attack further downstream.

MR. SAUNDERS: We did look at degradation of the rebar from migration through a construction joint, which is how we think it has migrated through the wall, and the rebar concern is the outer rebar, because that is the rebar that is loaded in tension, and you have to go through feet of concrete, and it would not be acidic by the time it gets there, and it would not have th at concrete.

There are tests done by other utilities, where they simulated flow of boric acid through

cracks, by dripping it through a narrow gap between concrete specimens. After eight years of exposure, there was nothing other than minor surface scarring of the rebar. Published studies from Germany show the exact same result.

MR. SHEIKH: Can I continue or --

VICE CHAIRMAN ARMIJO: I hear all these analyses and explanations, and I still feel uncomfortable or dissatisfied that leaks can't be found and fixed. Is there a date certain where you say okay, we've fooled around with this thing for 10 years, 15 years. If we can't find it the sophisticated way, can we go in there and we're going to cap every plug weld until we stop the leak?

MEMBER BANERJEE: Or build another plate. I mean the whole pool has leaked out in ten years.

MR. SHEIKH: Yes, but you realize that as represented in their calculations --

MEMBER BANERJEE: You can calculate anything, right? I mean I can probably sharpen my pencil and show you whatever I want to.

MR. SHEIKH: No, but actually what they've presented, the crack width of one mil for six inches is really conservative. If you have 40 feet of water, and you calculate the 100 gallons per day, the actual

area is even smaller than what they have provided you.

MR. CUNANAN: But I guess that's what led me to the original question. If the staff satisfied with allowing this pool to leak for N years, N being greater than ten, N being greater than 20, without any sort of eventual corrective action? That's what I'm hearing. That's what's got my concern.

VICE CHAIRMAN ARMIJO: That's my question. You know, we've fooled around with it. It's tough to do. We're going to have to do some global fix and stop this.

MR. SHEIKH: That's why --

MR. HOLIAN: This is Brian Holian, Director of License Renewal. Just to add in, and the staff's focus is on is the aging management program adequate to detect degradation that would be unacceptable with this ongoing leakage? The question on the table is, you know, do I have a regulation, in the current licensing basis, that would have the staff hold them to for stopping that at a certain point in time?

And you know, the simple answer is no. No regulation for that. If I am dissatisfied with the corrective action program, you know, we can continue with that process, primarily through the regional

inspections, and make a position there on are you dealing with a degradation in a safety-significant area.

VICE CHAIRMAN ARMIJO: The problem I see, Brian, is that if this is meeting all the regulations, what's to, and you know, current management at PSE&G wants to find and fix it. But some new management says why are we bothering with this stuff? It's being managed. It meets all the regulations. The pot's right. Let's not waste resources on that, and somehow that just bothers me.

MEMBER RAY: Well Sam --

VICE CHAIRMAN ARMIJO: Because this is just engineering, just to find and fix something that's maybe difficult.

MEMBER RAY: The design has leak chases in it for a reason. The reason is because it was understood in the beginning that you couldn't assure that the seam welds in this liner plate wouldn't develop cracks. So they put in leak chases.

The problem here seems to be that first of all, the leak chases were inoperable for a time, number one. Number two, there's a question potentially whether or not they're going to capture leakage through the plug welds, as well as the seam

welds, because the leak chasers were just put in for the seam welds.

VICE CHAIRMAN ARMIJO: Right.

MEMBER RAY: But I mean to the extent that the seam welds are leaking, or you could say well that's what the design assumes. That's why they're there.

VICE CHAIRMAN ARMIJO: If it was designed in and it's working the way it's designed, that's fine.

MEMBER RAY: It was, it is. Every pool's the same way that I know of.

VICE CHAIRMAN ARMIJO: Yes.

MEMBER RAY: The real question is are the leak chasers effective in capturing whatever leakage takes place, or is there other leakage that's migrating elsewhere?

Now that can either be because the leak chasers are poorly designed, they don't capture all the leakage. They told us that the leak chasers weren't welded to the liner, so that water can migrate to the chase, instead of going some other way. That's one way to look at it, I guess.

MEMBER SHACK: That's a feature, not a bug.

MEMBER RAY: Huh?

MEMBER SHACK: A feature, not a bug.

MEMBER RAY: Well, all right. But I'm just trying to draw attention to the fact that don't look at it as if any leak is somehow a deficiency, because the doggone liner is designed to capture leakage, on the assumption that it will exist. The problem was in the beginning here probably, that they didn't assure that it was operable, that the --

MEMBER BANERJEE: Harold, let me take this to absurdity, which is that if you allow this water to come into contact with the concrete, that only moves a few inches in seven years, why have the liner at all? We can take it away.

MEMBER RAY: I don't know that that's an absurd question, Sanjoy.

MEMBER BANERJEE: But that's what they're saying, basically exposing the concrete to water.

MEMBER RAY: I don't know what they're saying. But what I'm saying is that the plant was licensed with a design that presumed there could be leakage, and there's a system installed to capture the leakage and make sure that it doesn't go into the ground water or do other damage. I mean that's the design.

Maybe you should have required a different design. I don't know. I had a plant that didn't have leak chasers in it. It was built in the 60's, and it should have had. But we'll leave it at that. Later on, later on we got smarter, and put in leak chasers in the design, and that's the way this thing is designed.

MEMBER BANERJEE: That's fine, but it's not leaking into the leak chasers.

MEMBER RAY: Yes, but the question is why, and to what extent, and I just said obviously if the plugs leak, you're counting on it migrating to the leak chaser, and then going in through some crack to the rebar. I understand that, or to the containment liner inside containment.

MEMBER BANERJEE: There's no way to know where it's going.

MEMBER RAY: Well, no way is maybe a little exaggerated.

MEMBER BANERJEE: Well, there's no way without cutting it open and taking a look.

MR. SHEIKH: No, but let me --

MR. CUNANAN: If I just might, if I might just try it differently, because the staff has looked at this a whole lot more than I have, so I don't want

to presume that I know a better way. But my question really is if you're going to allow this to continue to leak and monitor it, is there some sort of corrective action plan to, for example, try to find a way to fix some of the plug leaks, and see if that mitigates or slows down the leak.

So now you've shown that what was 100 gallons per day is now 90, because you've fixed three of these. In other words, now you're showing some definitive empirical proof that you've done something. I guess that's kind of where I thought Sam was going.

VICE CHAIRMAN ARMIJO: Yes. It just seems to me this is an engineering problem --

MR. SHEIKH: Let me just say that we also have asked for additional inspections. Like we are going to -- they are going to do a core drill in 2013, which they will expose the rebar. They will do petrographic examination of concrete. That will tell us whether what they have assumed in their analysis is valid or not.

Then they're going to do another core drill in 2015, and there also they're going to expose the rebar. So that will tell us whether it's really happening or not.

MEMBER BANERJEE: Well, let me ask you a

question. Do you think you need the liner at all or not? Let's take it step by step. What do you think about that?

MR. SHEIKH: We need the liner.

MEMBER RAY: Of course. The damn concrete would leak like crazy if you didn't have a liner in it.

(Simultaneous speaking.)

MR. CUNANAN: I'm glad he's sitting next to you.

MR. HOLIAN: And Abdul was going to say yes. He was just slowly getting that.

MEMBER BANERJEE: All right. So you need the liner. Now suppose I have a path into the liner of water, which is not being caught somewhere? So what is the difference between that and exposing the liner? Is it the amount of water? If so, is it the fact that this area is not cracked and therefore doesn't leak? What is the reason for that?

MR. SHEIKH: I think that the --

MEMBER BANERJEE: Okay. Let's start all over again.

MR. SHEIKH: Yes. Then let's assume the liner is bleeding.

MEMBER BANERJEE: Let's stop. Let me

follow the print. Now we have a few, right, without a liner.

MR. SHEIKH: Now let's say that you have a liner.

MEMBER BANERJEE: Okay. Now let's say I make holes in the liner, so it leaks stuff into the concrete.

MR. SHEIKH: Right.

MEMBER BANERJEE: What is the difference between that and having a liner, if I allow this to go on for years and years and years, while the whole pool leaks out in a few years? That's the difference.

MR. SHEIKH: Well, as the migration of water is so slow, as it --

MEMBER BANERJEE: Then I don't need to have a liner at all, right?

MEMBER SIEBER: Right, and the shipping port didn't have one.

MEMBER BANERJEE: Right.

MEMBER SIEBER: Ran for 25 years. When we decommissioned it, it was filled with tritium.

MEMBER BANERJEE: Yes. The Canadian plants don't have a liner.

MEMBER SIEBER: Right.

MEMBER BANERJEE: The liner is not needed.

1 That's what I asked you.

2 CHAIRMAN ABDEL-KHALIK: Perhaps we should

3 limit the intra-committee questions, and just take it

4 one at a time. So Harold.

5 MEMBER RAY: Well, the premise to which I

6 wanted to take exception was that water that leaked

7 through a plug would necessarily go into the concrete,

8 rather than leaking to an adjacent leak chase. That

9 may be true, but at least that's not what is being

10 hypothesized.

11 The hypothesis is that the water will

12 migrate to a leak chase, rather than penetrating the

13 concrete.

14 MEMBER BANERJEE: That is past going

15 through the concrete right?

16 MEMBER RAY: No. It's going along the

17 interface between the liner and the concrete, to a

18 leak chase, because that's the path of least

19 resistance. Now that may not be a perfect assumption;

20 that is to say, you can argue with that assumption.

21 I understand that. I argued with it.

22 So I don't object to anybody else arguing

23 with it. But the idea that therefore it's tantamount

24 to not having a liner, as I think where I would draw

25 the line --

MEMBER BANERJEE: It's just speculation.

MEMBER RAY: Well --

MR. SHEIKH: If you let me go, we will see that this is some gravity in the assumptions.

MR. CUNANAN: So let me ask it another way, and then I'll stop. So when does the staff get worried? At 100 gallons a day, at 200 gallons a day, at 300 gallons a day? When does it cross a level that you say stop, go fix it?

MR. SHEIKH: I don't have a right answer for that, but the concern I have is whether it's going to affect the rebar and concrete.

MR. CUNANAN: Let me ask the licensee. When does that, when do you cross that boundary, that you stop monitoring and you start fixing?

MR. SHEIKH: If there is, the way I see it --

MR. CUNANAN: Well, this time I'm asking the licensee. I think that's kind of where Sanjoy was going. I might be wrong.

MEMBER BANERJEE: Exactly. You can go on extrapolating. There is not limit to it.

MEMBER SHACK: Where it can make a difference, they can make the argument that most of this leakage is going through the construction joint.

If you felt that the leakage was all going through cracks in the concrete and infiltrating everywhere, you might have a different --

MEMBER BANERJEE: Yes, assuming there are no cracks.

MR. HOLIAN: This is Brian Holian, Director of License Renewal, and I will wait for the licensee to answer. It's a fair question for both of us to answer. The region's been asking them that question for inspection reports, and their assessment from the region about is this, are your actions, you know, under the corrective action premises, which is based on the significance of the issue, are you taking time in corrective actions? So I meant to have one of the lead inspectors from the region here, but we do have a regional branch chief here, and I'll ask him to comment on that as we continue.

But in my view, also having been a manager in the region, this region, aware of the Salem spent fuel pool leak, it is an issue. It's a question of the extent of the leakage that we believe is there. So the liner does have some significance.

You heard us also question the "no" statement, that they believe, and we're skeptical of that. We don't believe that. I would rather not have

it on a slide. You don't see it on our slides. Our staff has asked additional questions, not believing the "no" question.

We want you to check a core bore through the other wall there, just to make sure, and also to make sure about the rebar. But I'll take the question back, you know, really to the current licensing basis. They are allowed to have leakage.

If you were asking, as a regional manager, you know, where, it would probably -- it would definitely be at the time where I see a plume extending. Now this plume's going in the right direction. Their corrective actions are making gains on the site. So, you know, as a regional manager I'd see that, and as a license renewal manager right now, that would bother me more, would I maybe take some more progressive corrective actions. I believe you'd see that. But let me ask the licensee.

MEMBER RYAN: Just one point here Brian, and I think you'd probably agree this way. Plume is a lighting indicator, not forever.

MR. HOLIAN: I know. And, you know, the monitoring wells are, I understand, approved well. I've got a real good story from the regional inspectors on that, but no, I agree.

MEMBER RYAN: Okay. I think Sanjoy's looking at a leading indicator kind of thought, versus --

MR. HOLIAN: Well, the core bore is, you know, some of the items we've done are, you know, I'll call them confirmatory. Maybe not leading, but leading from the fact that the licensee wasn't going to do them, and now we've asked them to do them. Let me ask the licensee to respond.

MR. DAVISON: Paul Davison, PSEG Nuclear. The important part of our monitoring program is, you know specifically the trending of the leakage rate. As we mentioned, ever since we established the trending program back in 2003, the leakage rate has been steady at 100 gallons.

What our monitoring program would have us to do is if we see an increase, that the trend would indicate that we would have an increasing leakage rate, that would be entered into our corrective action process, and that would require us to disposition that through the corrective action progress, through an evaluation of what does that increased leakage mean, and what would we have to do.

That would also tie in with what is the latest technology that's available to say at what

leakage do we think we should go in and do vacuum box testing or some other technology to -- now that the leak has grown or increased, that we would be more likely to find the actual leak or source of leakage.

No specific at this number. It would be identified in our trending program, and entered into the corrective action program.

VICE CHAIRMAN ARMIJO: Well, let -- the postulate, the weakest part, is that the plugged welds, the leaks in the plugged welds, and that's where you suspect that they are, always migrate to the telltales, and since the telltale is an engineered system, and if they're not blocked, everything's just fine.

But I don't know why that leak has to migrate to the telltales, as opposed to somewhere else.

MEMBER BANERJEE: It could be soaking the concrete.

VICE CHAIRMAN ARMIJO: And it seems like you'd want to fix it, instead of just leaving it forever. It's been around since 2003, and once this is accepted for license renewal, that corrective action item could be on your corrective action list for the next 40 years.

So if there was something that says okay, after we fool around for so long, we're going to start capping those plugged welds or bring in the smartest people we can find, with proposals to fix them, even if you don't necessarily -- you're not even able to find them.

MEMBER RAY: But you're basically saying that the leak chases aren't an adequate provision.

VICE CHAIRMAN ARMIJO: If they're designed to handle plugged weld leakage, yes. But if they're being claimed as a good fortune, that they take -- the leak chases are fine if it was -- the leakage was happening in the seam welds, because that's what they were designed to do. But the other one is not designed; it's just claimed that it's going to take care of them too.

MEMBER BANERJEE: Yes. The problem here is you're getting an output of flow. You don't know how much is leaking, because there could be an accumulation jammed up somewhere, right. The assumption here is that it's all going to these telltales or whatever they're called.

MR. SHEIKH: No, we are not saying that.

MEMBER BANERJEE: Right. So how are we to know that this stuff -- that was my original question,

which I'll come back to again. The reason you have a liner is obviously because the concrete could get saturated through its cracks or whatever. But the stuff may be somewhere else. It worked in Canada; I don't know.

MEMBER SIEBER: Pennsylvania.

MEMBER BANERJEE: Pennsylvania, okay. But leaving that aside for the moment, there's a reason for this liner, and you've got things which draw out the leaks if the leaks were exactly at the seam welds. But now you've got a leak somewhere else, not at the seam welds, because you're picking up content in the water, which is clearly associated with concrete. It has been in contact with concrete.

How do you know that that flow is the only amount of flow leaking? How do you know that the other stuff isn't seeping into the concrete? Did you do some tests? You can't inspect there, right?

MR. SHEIKH: Mr. Roberts wants to --

MR. ROBERTS: If I may. Tom Roberts, PSEG License Renewal team. I understand the questions. They're all very valid questions. However, we're looking at a single schematic representation of the pool channel configuration. As I mentioned earlier, there's 2,100 linear feet of seam welds.

So on the floor alone, it's not one channel. There are multiple channels, because the plates that are welded together, at each of the seam welds, is the standard 4 by 8 plate. There are 2,100 linear feet of channels as well. The question about can water pool up? Yes, it could theoretically pool up, but it surrounded by a square of channels, where preferentially the flow will travel to.

It's not simplistically -- it's simplistically represented here, but in reality, there are channels every eight feet on spans of every four feet, and therefore any water that may accumulate in that space will migrate to one of the adjacent channels. It is the preferential path. It is the path of least resistance.

MEMBER BANERJEE: The cracks, it's not, right. I mean we can do a little hydrodynamic analysis of this. I'm sure that we can figure out pots which can go into the concrete, and not to the channels. We can do a network analysis if you want, but I don't think you can prove that it will only go to the channels.

MR. SHEIKH: I just want to find out that the slab is about eight feet thick.

MR. ROBERTS: That is correct.

MEMBER BANERJEE: Yes, okay. You know, and you don't need a liner.

MEMBER SIEBER: Maybe I can offer this, that this is a current operating issue. It's probably not a license renewal issue. You don't commit a violation until you have an uncontrolled release. That being said, you've got all the monitoring welds, so they can tell whether they have an uncontrolled release or not.

I suspect that a real consideration is will the leak rate suddenly change, or can you do something about it, which requires some kind of a --

MEMBER SHACK: We have had our own discussion, to come to a conclusion. The question is whether we have any additional questions, and we've sort of established from the staff they have no threshold. The licensee has no threshold. Do we have additional information we want from them before we move on?

VICE CHAIRMAN ARMIJO: Yes. If they could provide that layout of where the leak traces were in the welds and for the plugs, so you can get a better feeling that yes, it's reasonable that telltales will pick it up.

MR. SHEIKH: Basically, they are 4 by 8

plates.

VICE CHAIRMAN ARMIJO: Yes. I can't visualize that. I just need a sketch or something.

MEMBER BANERJEE: Or also cris-cross across the containment. It's representative, and we will call them maps.

MR. SHEIKH: No. All right. The last is Slide 5.

MEMBER BANERJEE: We also would like to know is there is a gap between the liner and the concrete? It's in contact.

MR. SHEIKH: No, because the way it's done, is we put the channels first, you level the concrete, and then come on and put, weld the liner on top of it. So there could be liner gaps --

VICE CHAIRMAN ARMIJO: It's not bonded.

MR. SHEIKH: It is not bonded.

VICE CHAIRMAN ARMIJO: Put all that weight on it, it's water included, hydrostatic pressure.

MR. SHEIKH: Okay. So this, I tried to, you know, capture all the information here. As you can see, we are going to have core drill on both sides of it. There is a tritium pool on this right-hand side.

MEMBER SHACK: Can you tell us the average

in range of concentration in that pool?

MR. SHEIKH: Yes. This is given, yes. It has been going down appreciably over the years. Right now, it's about 20,000 pci.

MEMBER SHACK: So it's the drinking water standard.

MR. SHEIKH: I'm not an expert in that area.

MEMBER RYAN: So it's -- I mean I understand the problem with it, but you've got a tritium concentration that somewhere else would be at or maybe above in some spots the drinking water standard.

MR. SHEIKH: But it's being reduced appreciably every year.

MEMBER RYAN: What's appreciably?

(Simultaneous speaking.)

MEMBER RYAN: They're also pumping this --

MR. SHEIKH: There are 32 welds --.

VICE CHAIRMAN ARMIJO: Now is the plume going down because there's no leakage, or is the plume going down because they're just pumping it out?

MR. SHEIKH: That is a very hard question to answer.

MEMBER RYAN: That's an easy answer.

You're pumping it out pretty fast. The pumping's winning. I mean the ground water is not going to move all that fast.

MR. SHEIKH: And we have backup slides --

(Simultaneous speaking.)

VICE CHAIRMAN ARMIJO: So if you stop pumping when the plume is shrinking --

MR. PHAM: This is Bo Pham from the staff. I think it's a dynamic situation. I don't think we have a clear indication, because the pumping is continuing at this point, to the best of my understanding of it.

MEMBER RYAN: You can look at the rate of pumping and the rate of decrease of the tritium concentration, and figure out whether it's gone down, because you're pumping and there's an addition, you know, what the relative contributions for those are.

VICE CHAIRMAN ARMIJO: You know, if the tritium plume is a very low concentration, you can afford to just stop pumping for a year or so, and if it started building up again, that means you haven't stopped the leakage.

MEMBER BROWN: Do you have a backup slide on change in concentrations?

MR. HOLIAN: We have a comment from the

licensee.

MR. SHEIKH: Ed Keating.

MR. KEATING: Good afternoon. This is Ed Keating from the License Renewal team. There's about eight questions out there, but essentially we have the 38 well network I mentioned earlier, from the point of -- okay. Tritium results, if they show up on this slide here, is a good way to look at the plume. You can see the wells. The wells are in the blue marks there.

There's also some maroon wells showing up. The maroon ones are a little deeper. The tritium plume on the left is the original one. You can see the different concentrations by coloration. The one on the right is 2009, which is not substantively different from 2010.

MEMBER BANERJEE: Can we have the most recent one?

MR. KEATING: They have the most recent one. Put it up on the slide.

MEMBER RYAN: Can you help me out here? I can't read it.

MR. KEATING: Sure, okay.

MEMBER RYAN: I can't read that even worse.

MR. KEATING: That one's hard to read on full 44 by 36.

MEMBER RYAN: Back up please. The purple is higher than the light green?

MR. KEATING: Yes.

MEMBER RYAN: So what's the purple mean in concentration?

MR. SHEIKH: One million.

MR. KEATING: One million.

MEMBER RYAN: One million.

MR. KEATING: One million, correct.

MEMBER RYAN: And the light green at the outer edge is --

MR. KEATING: 20,000.

MEMBER RYAN: 20,000.

MR. KEATING: Drinking water limit.

MEMBER RYAN: That's a pretty small gradient of tritium.

MR. KEATING: Yes sir, and you can see where it initiates. You can also see --

MEMBER RYAN: Yes. That tells you it's coming out pretty quick.

MR. KEATING: Yes. Well, no. The reason I say "no" is that we're on a dredge spoil fill and engineered soil. So there's a very slow migration of

fluid through that.

MEMBER RYAN: Really?

MR. KEATING: Yes.

MEMBER RYAN: That dredged soil would have -- what, is it concrete level or what is it?

MR. KEATING: No, it's dredge spoil taken out of the river.

MEMBER RYAN: River mud.

MR. KEATING: River mud, which when it dries, gets very, is very dense.

MEMBER RYAN: All right. So you have an unsaturated zone there that I'm guessing is very, very shallow. It's really, you know, doesn't go down very far.

MR. KEATING: Goes down 40 feet.

MEMBER RYAN: Unsaturated zones?

MR. KEATING: The unsaturated. The first time you hit ground water is at 40 feet, because that's been referred to artificial island, and the reason for that is it used to be part of the Delaware River, the same volume of river. The Corps of Engineers around 1900 closed off that sand bar and utilized that entire area for dredge spoil, for keeping the channel open in Delaware.

MEMBER RYAN: That's interesting.

MR. KEATING: So that's why at 40 feet, what you're hitting is what they call a river bed sanding level.

MEMBER RYAN: So the river level is above your, the top of your ground, the saturated zone --

MR. KEATING: Yes sir.

MEMBER RYAN: By 30 feet, it sounds like.

MR. KEATING: Approximately, approximately yes.

MEMBER RYAN: You have 30 feet of unsaturated zone in the middle of a river.

MR. KEATING: Of unsaturated with river water zone, which is not -- if rainwater comes down --

MEMBER RYAN: No, I understand. I'm saying the same thing you're saying.

MR. KEATING: --and percolates very slowly.

MEMBER RYAN: And runs off.

MR. KEATING: And runs off and runs down.

VICE CHAIRMAN ARMIJO: I'd just like to repeat my question. If you stopped pumping, you're down to very low levels, drinking water standards, stopped pumping for a period of time, pick a year or something, would you expect that that plume would stay --

MR. KEATING: Exactly as it is now? No. What I would expect it to do is slightly narrow and head towards the river. That's the direction of ground water flow.

VICE CHAIRMAN ARMIJO: And if that happened, then you would prove that you're managing the leakage and telltales are doing the job, and you don't have to boring into --

MEMBER RYAN: I like that, Sam, and I think, correct me if I'm wrong, but I think that if you did stop and there was continued leakage, right where that, you know, the center line of the dark purple area is, you'd see it climbing up.

MR. KEATING: Up at the upper left corner of the dark, because that's the end of the seismic gap, against adjacent --

(Simultaneous speaking.)

MEMBER RYAN: You'd start to see it go up right away.

MR. KEATING: We would not want to --

MEMBER BANERJEE: We would definitely go back to that, right, if it's leaking?

VICE CHAIRMAN ARMIJO: Shrinkage of the pool.

MR. KEATING: If it's leaking.

MEMBER BANERJEE: If it's leaking.

MR. KEATING: We would not want to stop pumping, because part of what the pumping does right now is maintain a negative hydraulic gradient, so that the tritium is not leaving the site. It's staying on the site. Like the natural ground water flow would have it leave the site. Some places believe that that's inappropriate. We chose not to go that route.

VICE CHAIRMAN ARMIJO: Yes I understand.

MR. KEATING: It's just two different approaches to managing the --

VICE CHAIRMAN ARMIJO: Okay. I've asked all the questions --

MR. KEATING: But we don't have anything leaking into the environment anymore, we don't believe.

MEMBER RYAN: Off site.

MR. KEATING: Even on site.

MEMBER RYAN: Outside of your boundary.

MR. KEATING: Outside the plant structures.

MEMBER RYAN: Oh, out of the structures. You believe that, okay.

MR. KEATING: Yes. I believe that.

MEMBER RYAN: Okay. Well, I mean the

other argument is that you're dewatering faster than it's entering.

MR. KEATING: We definitely are, but the dewatering is occurring down, away from the reactor belting. The dewatering is occurring off of the coffer dam. Don't think you see those like gray circles around?

MEMBER RYAN: On the left?

MR. KEATING: Using the right -- on the left-hand one, it's hard to see the gray circles, because of the plume.

MEMBER RYAN: Uh-huh.

MR. KEATING: On the right-hand one, you can see the gray circles around. That's a coffer dam, right. So inside that coffer dam, you're only 20 foot below surface. Outside of that, you go down to 40 foot before you -- inside the coffer dam, that 20 foot is lean concrete down to 70 feet below surface. So you're not getting any infiltration there.

Off of there is where we put the pumps, the extraction system. So if there was still a leak, you would see inside the coffer dam in that shallow zone, between the lean concrete and the 20 foot surface, you would see elevated tritium concentrations, and we don't see that.

MEMBER RYAN: Yes. Don't take this as a criticism, but I understand what you're saying. It's hard to visualize it with these figures.

MR. KEATING: It is.

MEMBER RYAN: It's just not, the detail's not there and understandable.

MR. KEATING: But one of the key points is that coffer dam. We've got lean concrete that goes from 20 foot below surface to 70 foot below surface, inside that entire coffer dam.

CHAIRMAN ABDEL-KHALIK: What are the sampling points inside the coffer dam?

MR. KEATING: They're difficult to see on this slide. They're not on this slide at all. But yes, you could see. The problem is that the coloration, the welds that are designated on here for inside the coffer dam are in a light green.

CHAIRMAN ABDEL-KHALIK: You have green on green.

MR. KEATING: So if you can focus in maybe a little bit more on the one on the left, you can see -- the other left. You can see, for example, AC is up there. You see the Unit 1 containment is the round circle.

CHAIRMAN ABDEL-KHALIK: Yes.

MR. KEATING: Just to the bottom left of that, you see a square --

MEMBER RYAN: The white square?

MR. KEATING: The white square. That's a pad, concrete pad, and on either side of that concrete pad, you can see a light green well. At six o'clock on the Unit 1 containment, you can see another light green well.

MEMBER SHACK: Yes, those light greens are the wells?

MR. KEATING: Yes sir. They're the wells that are inside the coffer dam, because they only go down 20 feet. The blue ones that you see outside are the 40 foot wells that go down to the river bed sanding level, and then I don't think there's any.

We also, the next aquifer down, we have wells in, just to make sure that it has never gone that far, and here's an aqua chart all the way down there.

MEMBER BANERJEE: How much water are you pumping out of each of these?

MR. KEATING: So far, we've pumped about 26 million gallons of water.

MEMBER BANERJEE: So how many wells do you have?

MR. KEATING: Six.

MEMBER BANERJEE: Six wells.

MR. KEATING: Six pumping wells, 32 just monitoring six, monitoring and pumping.

MEMBER BANERJEE: So six. And so let's say pumping rate per day is roughly what?

MR. KEATING: About 36 gallons a minute. Depends on the day, because what it is, is with the soil the way it is, although you have a well in there, you don't get a lot of flow. So the pumps only turn on when there's actual water that comes in.

MEMBER RYAN: You aren't forcing the pumping. You're letting the accumulation --

MR. KEATING: You have to let it accumulate. It's got a flood switch on the pumps. It's a flood switch on the pumps. So when the well recovers, but we have one six inch well that we can't get to recover. It's a quarter or a gallon a day. That's six inch well, a ten foot screen. It's just, that's the type of soil the dredge spoil is.

MEMBER RYAN: I think the questions that Sanjoy's raising and I'm raising, we're trying to understand the hydrodynamics of how things flow and how much and when, so we can appreciate your interpretation of it. Without that understanding,

it's hard to --

MEMBER BANERJEE: So the leak originally was coming from the -- the tritium was coming from the fuel pool?

MR. KEATING: From the fuel pool into the seismic gap, and then either overflow to seismic gap, or where the seismic gap ends, there's a rubber liner, and EPR rubber liner. It's possible that was not perfectly sealed against the concrete structure, so it leaked out there, somewhere at that point.

MEMBER SIEBER: The flow gradient's to the river?

MR. KEATING: I'm sorry?

MEMBER SIEBER: The flow gradient --

MR. KEATING: The flow gradient is to the river, yes. Actually, the flow gradient --

MEMBER SIEBER: So the flow is in acre feet per minute?

MR. KEATING: I don't have that.

MEMBER SIEBER: Probably.

MR. KEATING: It's in feet per year.

MEMBER BANERJEE: So if you --

MEMBER SIEBER: --per minute is usually the way you measure river flow.

MR. KEATING: Oh, river flow. River flow

is --

MEMBER SIEBER: Yes. The dilution factor is probably a million to one.

MR. KEATING: It's moire than that, yes. But we're not going for a dilution factor. That's why we're taking it out.

MEMBER SIEBER: Yes. If there were a regular discharge, it would be zero.

MR. KEATING: It would not be detectable. We have calculated. It would not be detectable at the river.

MEMBER SIEBER: Right.

MEMBER BANERJEE: If you stopped pumping now, as Sam was saying, if you were not adding any tritium into the spoon, then it would stay -- it would slowly sort of --

MR. KEATING: It would dissipate and move toward the river, and be discharged into the river.

MEMBER BANERJEE: Yes, yes.

MR. KEATING: At a level that we could not measure.

VICE CHAIRMAN ARMIJO: And you'd never see the purple thing again.

MR. KEATING: As long as the spent fuel pool is not leaking into the environment, we'd never

see a purple thing again. But even today, while we're pumping, we're not impacting what's on top of that pumper dam, other than allowing it to come off. So if there were purple there, you would see it.

MEMBER RYAN: And what are you doing with the tritiated water that you bring up?

MR. KEATING: We measure the concentration and the volume; we composite the discharge and we release it in accordance with our NRC license, as a radioactive discharge, and account for it in the -- that's reported every year.

MEMBER RYAN: Okay, and the concentration that you use as the guideline for your discharges is what?

MR. KEATING: Well, we composite sample every week, and we use that number.

MEMBER RYAN: But you discharge whatever you bring up, but just make a record of the composite sample?

MR. KEATING: Correct.

MEMBER RYAN: Do you have any idea, can you tell us the range of concentration --

MR. KEATING: When it started out, it was about 105,000 picocuries per liter blended.

MEMBER RYAN: Discharge, yes.

MR. KEATING: And now we're down to around 20,000 picocuries per liter blended.

MEMBER RYAN: Got you.

MR. KEATING: Because the pumping wells are obviously in the center of the plume. We're trying to get as much, as far enough away, so that we don't impact anything else.

MEMBER RYAN: Well, I guess that we -- I'm sure you've got a fairly steady trending down of that concentration from when you start to where you are now, and I think that's how, both to the question of Sanjoy, you know, that there's -- that's the aggregate information, was the discharge that they're collecting and discharge into the river, that the rates have been steadily decreased. Is that a fair statement?

MR. KEATING: That is a fair statement.

MEMBER RYAN: So that's how -- yes.

MR. KEATING: And you have to look at a trend. You can't look at every sample, because --

MEMBER RYAN: No, no.

(Simultaneous speaking.)

MR. KEATING: These are quarterly reports that are submitted to the Bureau of Nuclear Engineering, as well as the NRC, that demonstrate that.

MR. SHEIKH: Let me just add one piece of information. Where the leakage on the east wall is, they are going to excavate 15 feet deep, to do the core drill. So in 2015, and if there is a leakage, we will find that out. So that is another way to find out whether the leakage has stopped or not. That's why --

MEMBER SIEBER: Drill a hole through the liner.

VICE CHAIRMAN ARMIJO: Just one clarification. If there was no leakage going on, there was nothing going into the sump room and nobody had to be filling the pool to keep the level up, would you still do that core drill? Would you still require that core drill, or is it, just to verify that prior damage didn't do anything, or is the core drill kind of like required, because you -- there may be still things going on?

MR. SHEIKH: We are not sure whether some leakage is occurring on the east wall or not. That's where we have a little difference of opinion. The reason is they have -- they have a pipe to the seismic drain, and there they're collecting 1/8th gallon per day.

So we are not sure whether if the water,

where that water is coming from. But there is a leakage, 1/8th of a gallon which was reported. So to make sure, we asked for a core drill on the east wall, as well as on the west wall, and to make that core drill on the west wall, they have to excavate 15 feet deep, to get to that core drill.

They are going to do it at the same time they do inspect the buried piping in that area. So that will tell us whether there is a leakage on that side. Okay.

So let's go to page six. In addition to this, the core drills, we have asked them to monitor the chemistry of this leakage, which is coming out of the telltales, as well as the seismic drain. This will be done monthly, and as far as the Applicant has told, the ranges of the pH shown on this table, they have been observing it for several years before, and they are stable in this range.

If there is a change in these values, they will follow their corrective action program, to investigate why that change has occurred. Also, they're going to also monitor the island content, because what we think, if there is a corrosion in the island, you know, particles will come out.

If there is a rapid change of corrosion,

it will show up in the island content, which is coming out of this leakage So that's why we have agreed to monitor the chemistry of the water coming out.

I think that's end of our presentation. If any more questions.

MEMBER SIEBER: Don't ask them.

(Laughter.)

MEMBER SHACK: Run for cover.

CHAIRMAN ABDEL-KHALIK: Thanks, Abdul.

MR. CUADRADO de JESUS: We'll now continue with the discussion for the second open item. The second open item is the Applicant's safety management program for buried and steel piping inspections. This issue is similar to Hope Creek. The section has no cathodic protection on its stainless steel piping.

In response to the staff's RAIs, the Applicant has completed or committed to complete an extensive number of inspections in a ten-year period prior, and every ten-year period during the period of extended operation. The technical reviewer, Bill Holston, will describe the commitment, on the original basis, that was taken into account for the resolution of this open item. Bill.

MR. HOLSTON: Yes. My name is Bill Holston, senior engineer in the Division of License

Renewal. We looked at Salem's program for four aspects. They have effective backfill that's not damaging their coatings. They have good coatings through extensive inspections. Uniquely, because they don't have cathodic protection, we interfaced with the Applicant in regard to their soil conditions.

They talked about the soil samples they've done to date. They've committed in their application to complete soil samples and analyze their soil for corrosivity against American Water Works, Charlie 105 standard that measures some factors, to determine whether the soil's corrosive or not.

If the soil is corrosive, they're going to increase their number of inspections, versus if it's not corrosive, they'll be at a lower value. We accepted Salem's, also from looking at their plant-specific operating experience. They've had no age-related coating degradation.

You know ironically for them, they had a test coupon in the soil since the days of construction, which was their AFW piping, and which wasn't planned as a test pipe, but it was a test pipe. With no coatings, they never violated -- they never got any area of that piping to corrode enough to cause a challenge to the safety function of the AFW system.

Then, in their corrective actions in their extent of conditions, they've performed the equivalent of 45 inspections. Now for steel piping at a plant that had cathodic protection, we would have expected one inspection.

So they have well-characterized the condition of their piping, the conditions of their backfill, the conditions of their coating, and will continue to monitor soil corrosivity and with their lack of OE or, you know, the lack of operating experience, demonstrating that they have a buried piping corrosion problem, we accepted the program as is.

MEMBER SHACK: Now is that program consistent with GALL 2?

MR. HOLSTON: GALL 2, when we issued AMP 41, currently does not address a non-cathodically protected plant. In the Division of License Renewal, we have worked with DCI and developed a standard for a plant without cathodic protection, which we're going to issue in an interim staff guidance, and they are in alignment with that interim staff guidance requirement, the recommendations.

VICE CHAIRMAN ARMIJO: Just one second, quick. The title says "Non-Steel Piping." Is there

some other kind of piping?

MR. HOLSTON: They actually wrote two programs. They have a non-steel piping program to cover their concrete, and they have a -- well, they have a steel piping for the carbon steel. So their stainless steel and their concrete piping is a non-steel.

VICE CHAIRMAN ARMIJO: So steel is not steel.

MR. HOLSTON: Well it is, but it's not the classic steel that was in the AMP 34.

VICE CHAIRMAN ARMIJO: Got it.

MR. HOLSTON: So they split those two off and did a plant-specific AMP and an AMP that could be completely consistent with GALL 34.

VICE CHAIRMAN ARMIJO: Okay, thank you.

MR. HOLIAN: And Bill, this is Brian Holian, Director of License Renewal. Could you go to the backup slide with your coupon there? I just would like to see that picture there. I'm proud, one, that the licensee, you know, gives us this picture. It came from them. We did use it as a Commission meeting.

I'm proud that the program somehow found this before it happened. It was a success. But it

does show you need to look and, you know, the staff has demanded. But that was aux feed water in the safety-related piping. The licensee covered this in their presentation. This was on Unit 1, where they found that. Somehow they removed the coating way back when.

So that was -- I just wanted to remind you during your presentation. But that's what it looked like. So Bill's right. It maintained its functionality, but I don't know if we quantified how long it might have, if we hadn't uncovered this. So the licensee, one of the reasons I think they were behind that 45 inspections was, you know, kind of to verify what they had on site. Anything else, Bill?

MR. HOLSTON: No sir, not unless there's questions.

MR. HOLIAN: Are there questions?

MEMBER RYAN: And you know, I guess you say you've done initial inspection, so you're now confident there is no other piping missing its coating?

MR. HOLSTON: Yes. They did an extensive, when they discovered it on Unit 1, they did an extended condition, and that was part of us. So a couple -- when they went over to the refueling outage

this year on Unit 2, to go and verify, they found no other uncoated piping.

There's a logical explanation for the coating that was inadvertently removed on Unit 1, that they've determined through the corrective action process.

MR. HOLIAN: This is Brian Holian. I just wanted to balance those pristine pictures that you'd seen before.

VICE CHAIRMAN ARMIJO: With the muddy ones.

MR. CUADRADO de JESUS: No further questions? We'll continue with the third open item. The third open item on the pipe concerns with the steam generators, potential for primary water stress corrosion cracking. The staff concern is that primary water stress corrosion cracking could cause a failure of the tube to tube sheet welds, and reactor coolant pressure boundary.

The staff requested the Applicant to create a specific aging management program that will complement the primary water chemistry program, in order to ensure the cracking due to primary water stress corrosion cracking is not occurring. The senior staff advisor, Allen Hiser, will describe the

resolution of this open item.

DR. HISER: Yes. I'm Allen Hiser with License Renewal. The concern that was identified in this open item really goes back to the GALL Revision 2 development. There was an item for once-through steam generators for B&W plants, that had primary water stress corrosion cracking and the tube sheet welds as an issue, but there was no companion item for recirculating steam generators, such as the Salem plant with the Westinghouse steam generators.

For the Salem, Unit 1 has 600 thermally-treated steam generator tubes, the tube sheet, welds, the cladding of the tube sheet is the weld analog of Alloy 600. For Unit 2, the tubes and the weld are 690 thermally treated. I take that back. The tubes are 690; the weld is 600 analog.

In order to assure that you don't, you're not susceptible to PWSCC, you need to have a sufficient chromium content. Their chromium content for Alloy 690 is sufficient to preclude PWSCC. Since the Applicant could not demonstrate, at least during the application phase, that they were not potentially susceptible in both units, they made a commitment that would, and I will flip it around. The bottom bullet, either one, they will perform a one-time inspection,

to demonstrate that there are no cracks in the tube sheet welds.

Or they will do an analysis to demonstrate that they have sufficient chromium content in the tube to tube sheet weld, or if they obtain what is called an alternate repair criteria, such that the pressure boundary, that tube to tube sheet weld is no longer a pressure boundary. But by analysis, the pressure boundaries moved up to a higher location into the tube sheet, then they would not need to do that inspection.

So this commitment provides reasonable assurance that they would have, that they would not suffer from a potential failure of the pressure boundary in that area, through either the inspection or the analysis.

MR. CUADRADO de JESUS: Any questions? Thanks.

MEMBER SHACK: Now how does this apply to the 600 600? I mean I can understand the argument, you get enough chromium. The 600 600 on Unit 1, they would, the ARC, the ultimate repair criteria, would be the only way to get around that?

If we hop to a 690, then do they have a temporary approval of that, or do they have, I think, one cycle? This goes down to the H Star. This is H

Star.

DR. HISER: The analysis that the staff has been reviewing for quite a while. So they do have a --

MEMBER SHACK: Right.

MEMBER BANERJEE: Are these the new steam generators?

One of them --

DR. HISER: I'm not sure if they have been replaced.

MEMBER BANERJEE: One of the units was replaced for sure, right? Which one?

MR. FAKHAR: Yes. This is Ali Fakhar, License Renewal team. Unit 1 is a Modelift (ph); Unit 2 is an AREVA 6119T model that the, that was put in place in 2008.

MEMBER BANERJEE: Right.

MR. CUADRADO de JESUS: Any further questions?

(No response.)

MR. CUADRADO de JESUS: Let's go to the next open item. The fourth open item identified two concerns related to the metal fatigue of the reactor coolant pressure boundary program. The first concern is where the Applicant had verified that the locations

listed in NUREG 6260 were indeed bounding for same.

This is similar to the complementary item this caused for Hope Creek. The staff requested that the Applicant justify the methodology assumptions, component locations that the Applicant included in the environmental-assisted fatigue evaluation for the license renewal application. Again, Allen Hiser will describe the resolution of the first part of this open item.

DR. HISER: Yes. As Sam mentioned, this is the same issue we discussed a couple of hours ago for Hope Creek. I wanted to correct one misstatement I made regarding Hope Creek. It's not -- the limiting component is not that which has the highest CUF cumulative usage factor, but you have to combine the environmental factor with it.

So we want to ensure that they manage to -- that component that has the highest environmentally-assisted fatigue factor. So they have to go back and consider the material and environmental differences, to make that determination. But the commitment here is identical to that for Hope Creek, and various other plants that have come before the Committee recently.

MR. CUADRADO de JESUS: For the second

part of this open item, the concern was the use of WESTEMS for ASME Code Section III for the analysis. Specifically, the staff concern was related to the ability of users to modify intermediate data using the WESTEMS analysis.

The staff issued an RAI to the Applicant, asking whether they just identified that the staff in the reactors are using WESTEMS at Salem, and to describe how the Applicant used WESTEMS. In addition, the staff requested a benchmark evaluation to demonstrate that WESTEMS provides the results consistent with ASME Code Section III usage factors calculations. Again, Allen Hiser will describe the resolution.

DR. HISER: Yes. I think the Applicant actually did a very good job in their presentation of describing actually the two concerns that we had. The first of these concerns were identified by the New Reactor Office, during review of AP-1000.

They had an issue with one of the calculational models in the software WESTEMS for NB-3600 calculations, that you wouldn't necessarily get the correct answer. During the audit, we verified that Salem has not used that module, and we -- they again made a commitment that they would not use that

module in any of their use of WESTEMS. So that satisfied the concern that we had on that item.

The item that's related to user intervention in the calculation is one that ties back to repeatability of calculations. The WESTEMS code did not provide for documentation of user interaction. The way the code operates is that it automatically determines peaks and valley points for the fatigue calculations, because its software sometimes will find duplicate points.

It's technically appropriate for the analyst to go ahead and eliminate some of those duplicate points, because they had no engineering mean. The concern that we had was that there was no documentation of which points were eliminated and the basis for those.

In the audit, the Applicant and its vendor went through several calculations, satisfied our concerns that the analyst was using the right judgment, first of all, so we had confidence that the intervention --

MEMBER SHACK: This is when WESTEMS is actually monitoring cycles in the plant, and then the software is computing --

DR. HISER: No. Actually, this is more

design basis calculation, so if you go in with design transient. The code is used for two sets of calculations. The concern identified by the Office of New Reactors relates to a design basis sort of calculation.

So if we assume a certain number of cycles with a certain time temperature history, time temperature pressure history, then the code would allow the user to go in and modify what are really intermediate results, and clearly affect the bottom line.

We reviewed those calculations. We were confident, based on that review, that the user judgment was appropriate, consistent with ASME code requirements. The Applicant then made a commitment that -- and for the calculations that they reevaluated, as a part of the audit, they have made a commitment to document the basis for the changes made from the intermediate input.

In addition, they committed to document any changes that are in the user intervention, if they go back and redo any of those calculations. The second use of WESTEMS in an online monitoring mode does not have the user intervention capability. So it would include whatever redundant points that are determined.

From calculations that the Applicant showed us in the audit, there is a substantial increase in the CUF that one gets in that case. So based on the results from the audit and the commitments made by the Applicant, we were comfortable that their use of WESTEMS was appropriate and reasonable.

MR. CUADRADO de JESUS: Questions? Thanks, Allen. I will now continue on the next slide. We also have the SER with open items. The staff also received additional clarification of the Applicant's sampling transfer to aging management programs, as well as generic RAIs sent to all applicants. As the ACRS has seen before in other license renewal reviews, such as Kewanee, and most recently in Hope Creek.

In response to the staff RAI, the Applicant will develop a sample, which will establish sampling based on aging effects, environments and component materials of fabrication. The staff found the Applicant's response acceptable, and such concerns were resolved.

Also, as you recall in the Hope Creek presentation, the inaccessible power cables also affected the aging management program. In the case of Salem, the Applicant had enough time to provide that

information before we issued the SER with open items, and we closed it out then. If you have no questions, next slide?

Finally, this is a late-breaking issue that the staff recently discovered, and would like to bring it to the attention of the Committee. The staff recently noted that Gall Revision 1 states that boron is a recognized inhibitor of corrosion. We believe that this may have come from confusion with borates, that it may be an inhibitor of corrosion in certain materials and in controlled concentrations.

Upon further review, the staff has a better understanding of the types of boron, and can no longer recognize it as a corrosion inhibitor. Also, GALL Revision 2 took this standard out and corrected some of the tables. Not all items were corrected. As a result, the NRC staff will be providing an interim staff guide to correct this.

We will also be asking all current and future BWR applicants, as necessary, to address this change. The NRC staff has closed this with the Applicant, and they agreed to submit a license renewal supplement that, as the one-time inspection, to verify the effectiveness of the water chemistry program for over 110 AMR items, update the description of the one-

time inspection program, the water chemistry program, and in the UFSAR supplement.

The staff finds this acceptable, and will update the SER.

MEMBER SHACK: What do you do about all of the previous applicants?

MR. CUADRADO de JESUS: We'll be asking the same question.

MR. HOLIAN: Yes. Brian Holian, Director of License Renewal. Great question, great question. We get it all the time. We should get it all the time. That's a good question. We're putting out a list right now. I've seen it already. It's on the way out, for the 20 top items that GALL Rev. 2, after we improved GALL Rev. 2 on, to go after the previous applicants. So we'll engineer a correspondence to pick up issues like this.

This one was a minor item really that we just picked up. We'll have got it in GALL Rev. 2 if we had it. It will be in GALL Rev. 3, but it will probably be picked up by an ISG before that.

So we will use generic correspondence to go to the previous applicants, and then I do intersect with Part 50, and we'll be able to check with our regional counterparts, when they go out for their 7103

inspection, prior to the extended period.

A licensee that was previously licensed, did you take into account, you know, changes to the aging management programs and see if they're applicable to your plant. So that's how we'll address that.

DR. HISER: Now mainly for this, the water chemistry is the real aging management program. The one time just confirms that there is no degradation. So plants would really have to deal with it, if some of their one-time inspections find that there really is degradation ongoing. That would ratchet up the need.

MEMBER SHACK: But I mean these other plants don't have the one-time inspection requirement, right?

DR. HISER: At present, they do not.

MEMBER SHACK: Right.

DR. HISER: Now water chemistry alone was found to be sufficient in those cases. But as Brian mentioned, if putting this into the corrective action program, that now one-time inspection is found to be necessary, it would be up to each plant, then, to process it through the corrective action program, and make a determination whether they need to add a one-

time inspection as well for their unit.

MR. HOLIAN: You know, in getting to this point, and I know we're running late, but just 30 seconds on this. Individually, I'd have to run each of these by a backfit process, to see if I could safely apply it to a previously-licensed renewal plant. I would like to get to the point, you know, a potential rule change or if you're looking at subsequent renewals, where there would be a generic type of in the rule for Part 54, that a plant would then update their operating experience based on that.

That's something I posited during discussions with licensees, and we'll see how we can take that. But that would be part of a rule change if I went that way.

MR. CUADRADO de JESUS: Thank you, Brian. Any further questions? Next slide. Conclusion. The Applicant has met the requirements of 10 C.F.R. 54.29(a) have been met for the license renewal of Salem Nuclear Generating Station, Units 1 and 2. If there is no further questions, this concludes our presentation.

MEMBER SHACK: Thank you very much. Quite a stimulating discussion.

MR. DAVISON: Paul Davison, PSEG Nuclear.

I do have two items. First, I'd like to introduce Ed Keating, to make a correction to part of the conversation we had regarding the ground water pumping and the tritium discussion. Ed.

MR. KEATING: Good afternoon. I apologize. I misspoke. I said the ground water withdrawal was 36 gallons a minute. It's 3.6 gallons per minute.

MEMBER RYAN: Ah, okay. That's a little bit better.

MR. KEATING: Which is still greater than the 0.7 gallons per minute recharge.

MR. DAVISON: Thank you, Ed, and the second is Dr. Armijo, if you'd like a simplified drawing of the lattice work of drain channels, that shows the interconnectivity --

VICE CHAIRMAN ARMIJO: I'd appreciate it, yes, thank you. We'll make copies for the other members.

MR. DAVISON: This is the spent fuel pool, and how they connect up into the telltale drains.

VICE CHAIRMAN ARMIJO: Okay.

MR. DAVISON: And then a bunch of details showing.

CHAIRMAN ABDEL-KHALIK: You'll have to

submit that on the record.

VICE CHAIRMAN ARMIJO: Yes.

MEMBER SHACK: Does that show the spacing of the plug welds?

(Simultaneous speaking.)

VICE CHAIRMAN ARMIJO: I think it does, but I'm not sure.

MEMBER SHACK: Just think off the top of your head from the licensee. I mean the plug welds every X feet.

VICE CHAIRMAN ARMIJO: It's really hard to see. It's very small, small print here.

MEMBER SHACK: That's why I'm asking for --

VICE CHAIRMAN ARMIJO: A bigger one.

MEMBER SHACK: No, for clarification.

MR. ROBERTS: The plug welds are mixed vent welds. To kind of give you a simple analogy, the liner was not the form work for the concrete. The liner was wallpapered to the concrete, and therefore the seam weld in and of themselves are insufficient to hold the dead weight of the steel.

So I don't have the exact dimensions or dimensions of the plate on there. But the plug welds are literally intermediate between each seam weld.

VICE CHAIRMAN ARMIJO: That's helpful.

MEMBER SHACK: Okay, close enough.

MR. ROBERTS: Okay. Yes, vertically, horizontally, floor to walls. It's essentially a set of seam welds -- plug welds between seam welds.

MEMBER SHACK: So there's one in the center of the plate?

MR. ROBERTS: Yes. Multiple in the center of the plate.

MEMBER RAY: Four by eight plate.

MR. ROBERTS: It's a four by eight plate.

MEMBER SHACK: How many plug welds in a four by eight section? Two, four, eight?

MR. ROBERTS: Probably in the order of about half a dozen to a dozen. I'd have to count them up. But there are 1,400 plug welds, right.

MEMBER SHACK: 1,400.

MEMBER SIEBER: Okay. We're done.

(Simultaneous speaking.)

CHAIRMAN ABDEL-KHALIK: Are there any other questions for either the staff or the Applicant?

(No response.)

CHAIRMAN ABDEL-KHALIK: Okay. At this time, our schedule calls for us to take a break, a 15 minute break. When we return, we will be off the

record, and we will begin the last item on the agenda for today, which is preparation of ACRS report.

(Whereupon, at 5:39 p.m., the meeting was recessed.)

Hope Creek License Renewal

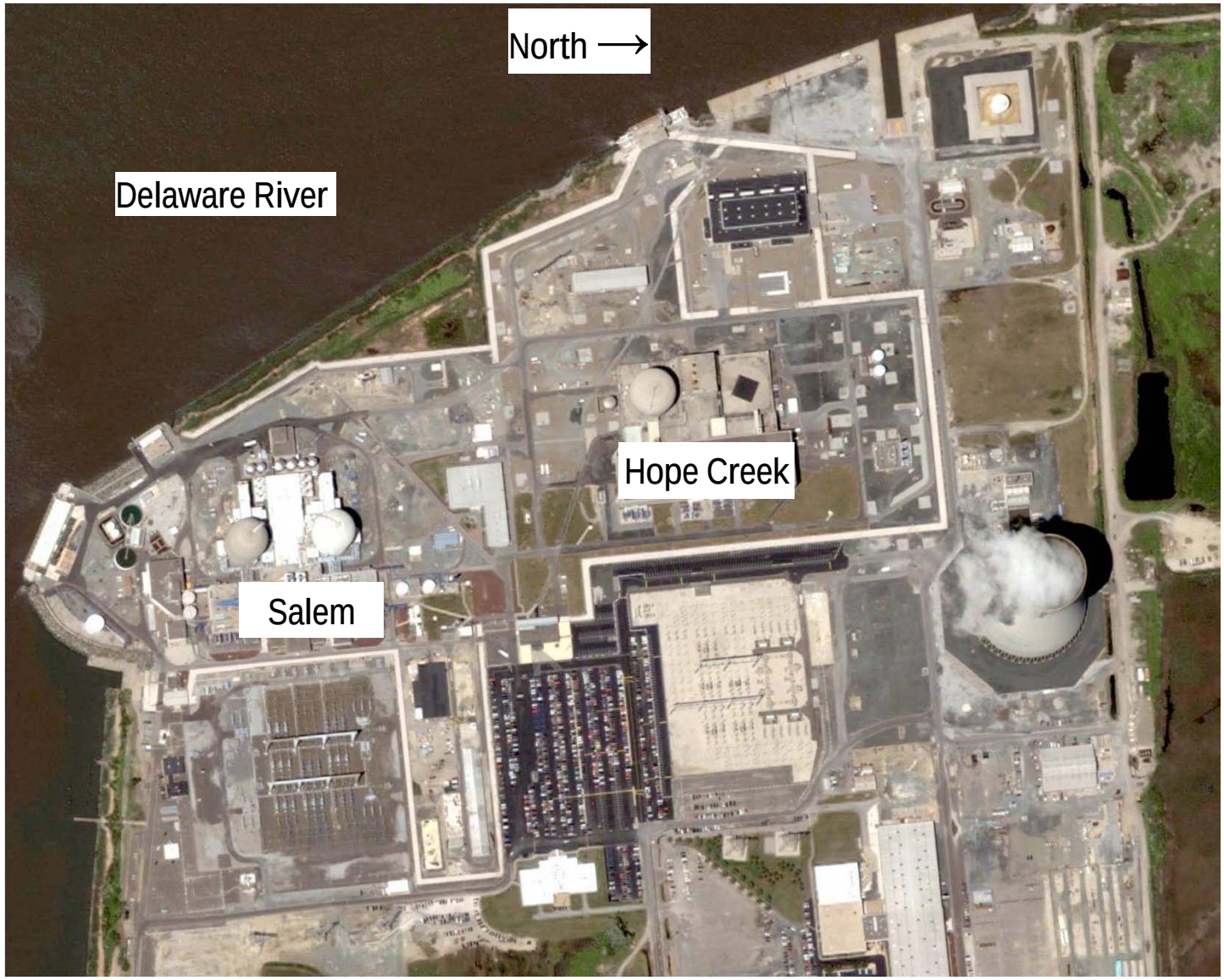
ACRS Full Committee
May 12, 2011

PSEG Nuclear LLC

Agenda

- Introduction – Paul Davison, Vice-President, Operations Support
- License Renewal – Jim Stavely, License Renewal Project
- Closure of Confirmatory, Open Items and Other Issues
  - Inaccessible Power Cables — John Hilditch
  - Buried Piping — Jim Melchionna
  - Environmentally Assisted Fatigue — Jim Stavely
  - Other Issues — Jim Stavely
- Topic of Interest – Jim Stavely
  - Containment
- Closing Comments – Paul Davison

Site Description



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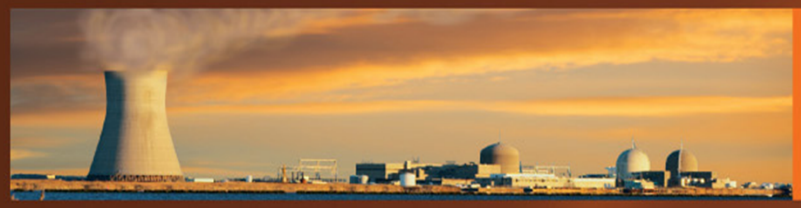
Aging Management Programs & Commitments

- 33 Existing Aging Management Programs
  - 16 programs required no changes to align with GALL
  - 17 programs required enhancements to align with GALL
- 14 New Aging Management Programs
- 54 License Renewal Commitments
  - 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



Closure of Confirmatory , Open Items and Other Issues

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Inaccessible Power Cables

CI 3.0.3.1.20-1 Closure

- Modified Program commitments to:
  - Shorten the maximum frequency of manhole inspections and cable testing (to 1 year & 6 years respectively)
  - Eliminate the exclusion of cables based on their not being subjected to system voltage for more than 25% of the time
  - Add low voltage (480v & above) power cables to the E3 Cable Program

Implementation Update

- In-scope SBO recovery cables (B Channel) tested with satisfactory results
- Program to ensure underground cables are not exposed to significant moisture is being implemented
  - The switchyard cable manhole drainage system pump was repaired
  - Installation of a permanent drainage system in the service water manholes starts in June, 2011 and completes by the end of 2011

Buried Piping

OI 3.0.3.1.2-1 Closure

- Provided the Staff with details on site-specific Operating Experience
- Modified Program commitment to include a 2nd inspection of carbon steel piping and to perform all committed inspections on the more safety-significant systems
- Described the Cathodic Protection System, annual NACE rectifier testing and maintain at least 90% availability

Implementation Update (Fall 2010)

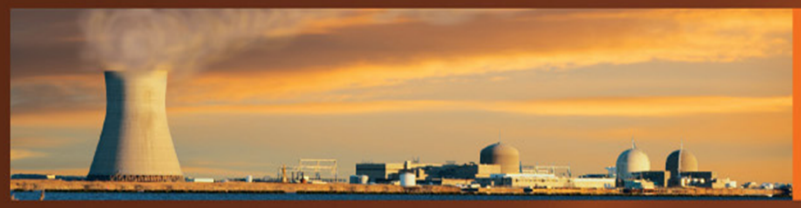
- Inspected two high risk, in scope, non cathodically protected, coated carbon steel Service Water spools
    - Piping was in excellent condition
- Inspected stainless steel Rad Waste piping (not in scope)
    - Piping was in excellent condition

CI 4.3.5.2-1 Closure

- Provided new commitment to:
  - Perform additional EAF reviews to confirm the limiting Hope Creek locations per NUREG-6260 are bounding as compared to other plant-specific locations prior to PEO
  - Perform future EAF evaluations for any Ni-Cr-Fe alloy materials in accordance with NUREG-6909

Other Issues

- One-Time Inspection Program Sampling
- Selective Leaching Sampling
- Small Bore Class 1 Piping Inspections Sampling



Hope Creek License Renewal

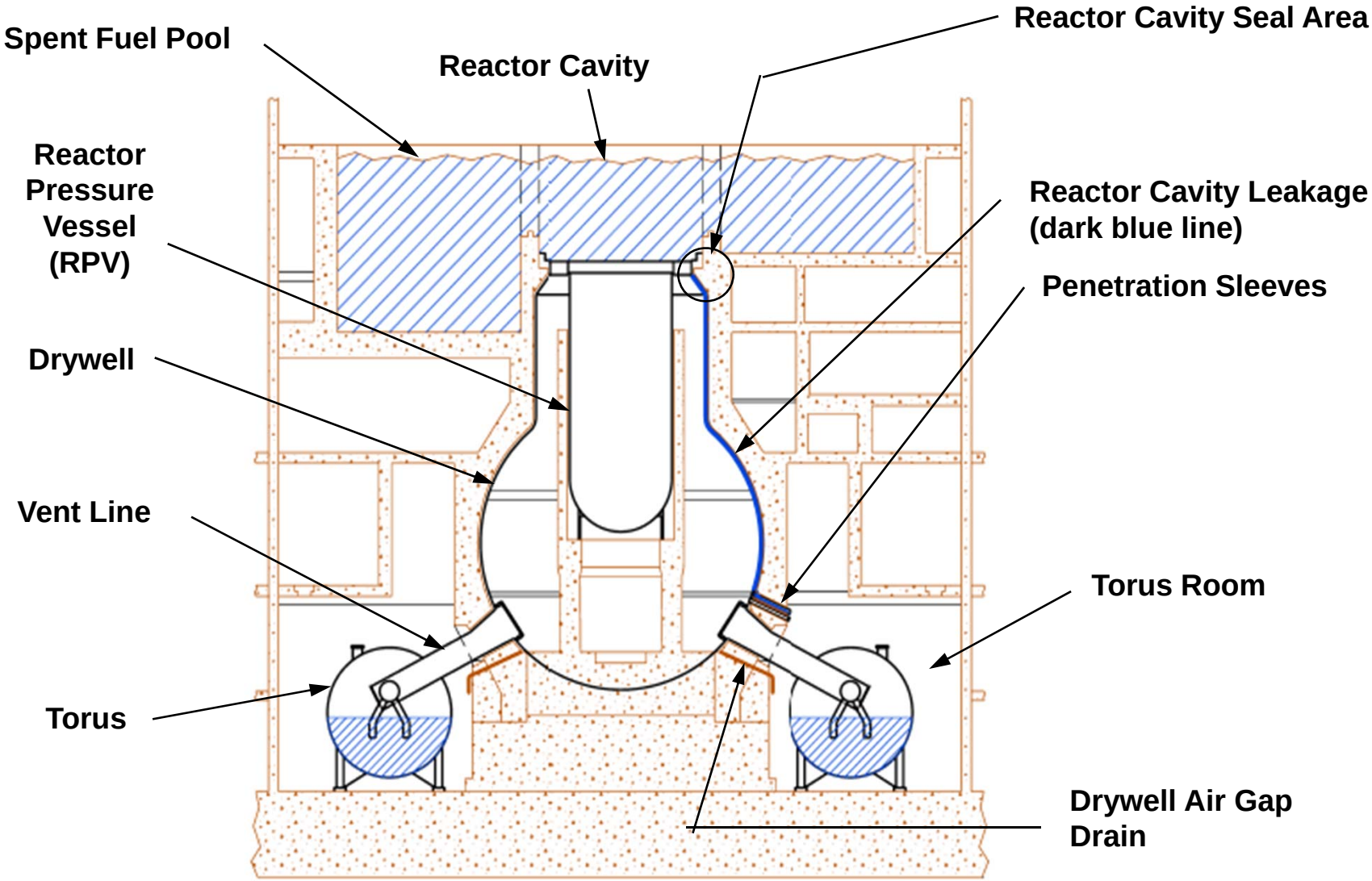
Topic of Interest:

Containment

Jim Stavely
License Renewal Project
PSEG Nuclear

PSEG Nuclear LLC

Containment – Refueling



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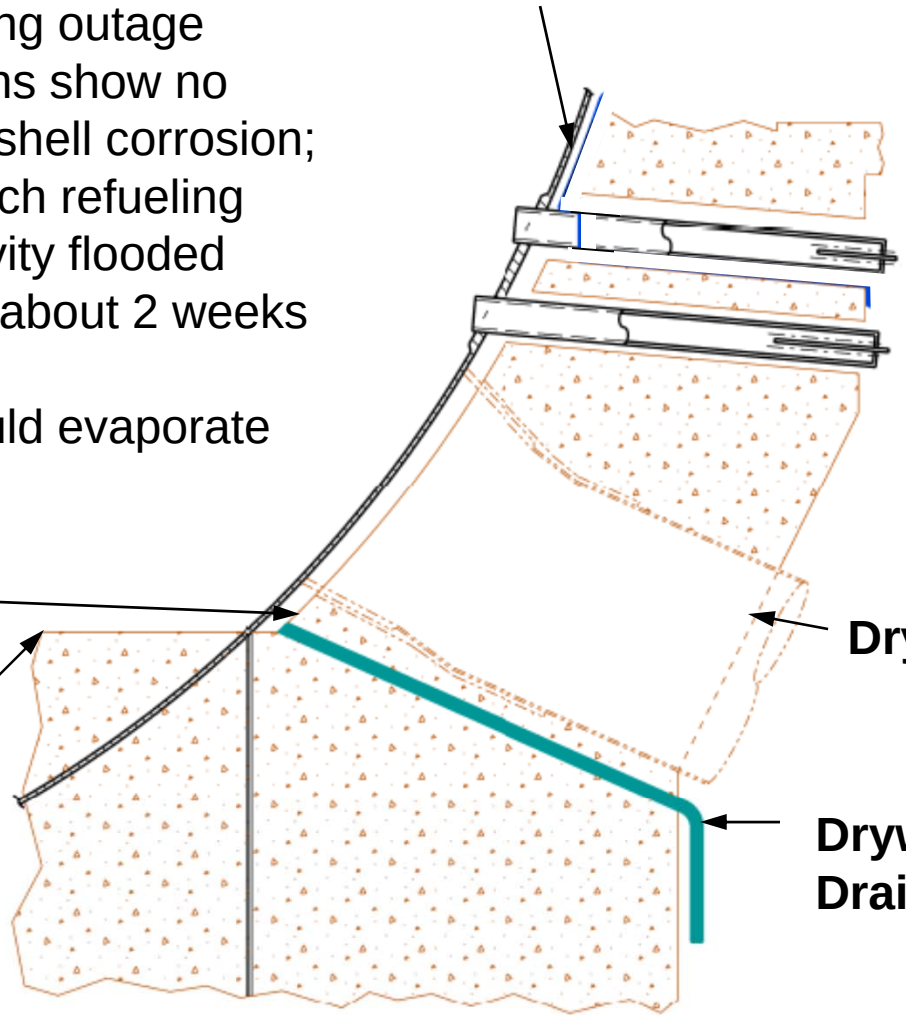
Containment – Drywell Shell

- Design features
  - Inorganic zinc coating to prevent corrosion
  - No sand bed region
- Boroscope examinations
  - No indications of corrosion
  - No obstructions in drywell air gap
  - No water accumulation at bottom of drywell air gap
- UT thickness measurements
  - Approximately 350 thickness measurements
  - All but one area greater than nominal thickness
  - One area below nominal but within construction tolerances

Drywell Air Gap Drain Lines

- UTs of shell show good condition; future UTs each refueling outage
- Boroscope examinations show no water accumulation or shell corrosion; future examinations each refueling outage with reactor cavity flooded
- Reactor cavity flooded about 2 weeks every 18 months
- Moisture in air gap would evaporate with plant heatup



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Containment – Conclusion

- Containment is in good condition
- A small reactor cavity leak and a non-conformance in the drywell air gap drain lines are being managed effectively in the Corrective Action Program and in accordance with our license renewal commitments
- Our aging management programs ensure continued safe operation of the containment

ACRS Subcommittee Meeting Correction

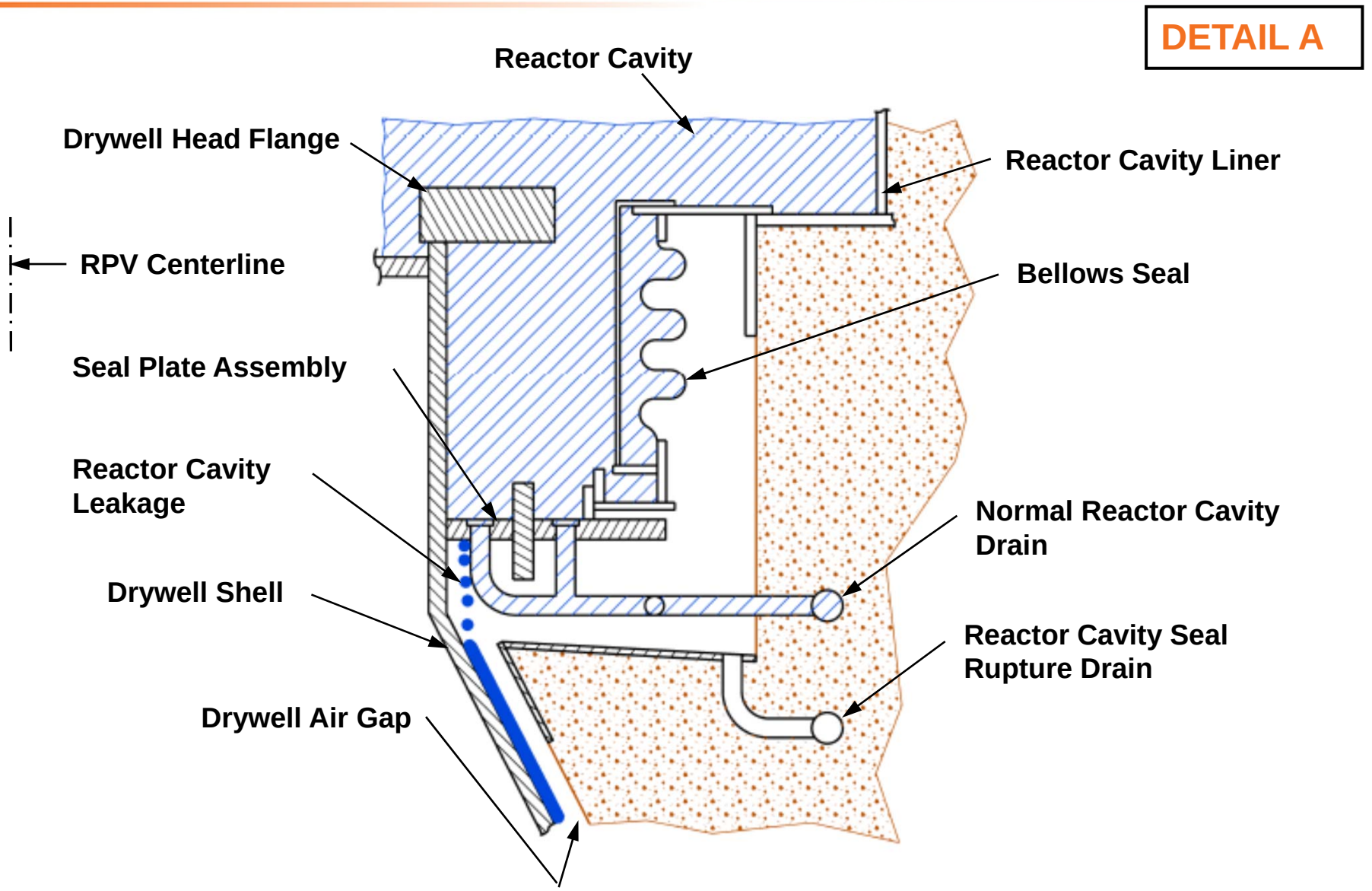
- Fuel Oil Chemistry Program
  - Do you sample material collected on the filter?
    - Yes.
  - Why use a 3 micron filter instead of a smaller one?
    - A 3 micron filter is consistent with Technical Specification Bases.
  - Why is the use of a 3 micron filter called an enhancement?
    - Because it is being used for the diesel fire pump fuel oil as well as the emergency diesel generator fuel oil.

Hope Creek License Renewal

The Hope Creek Aging Management Programs will ensure continued safe operation through the Period of Extended Operation

PSEG Nuclear LLC

Containment – Reactor Cavity Seal Area



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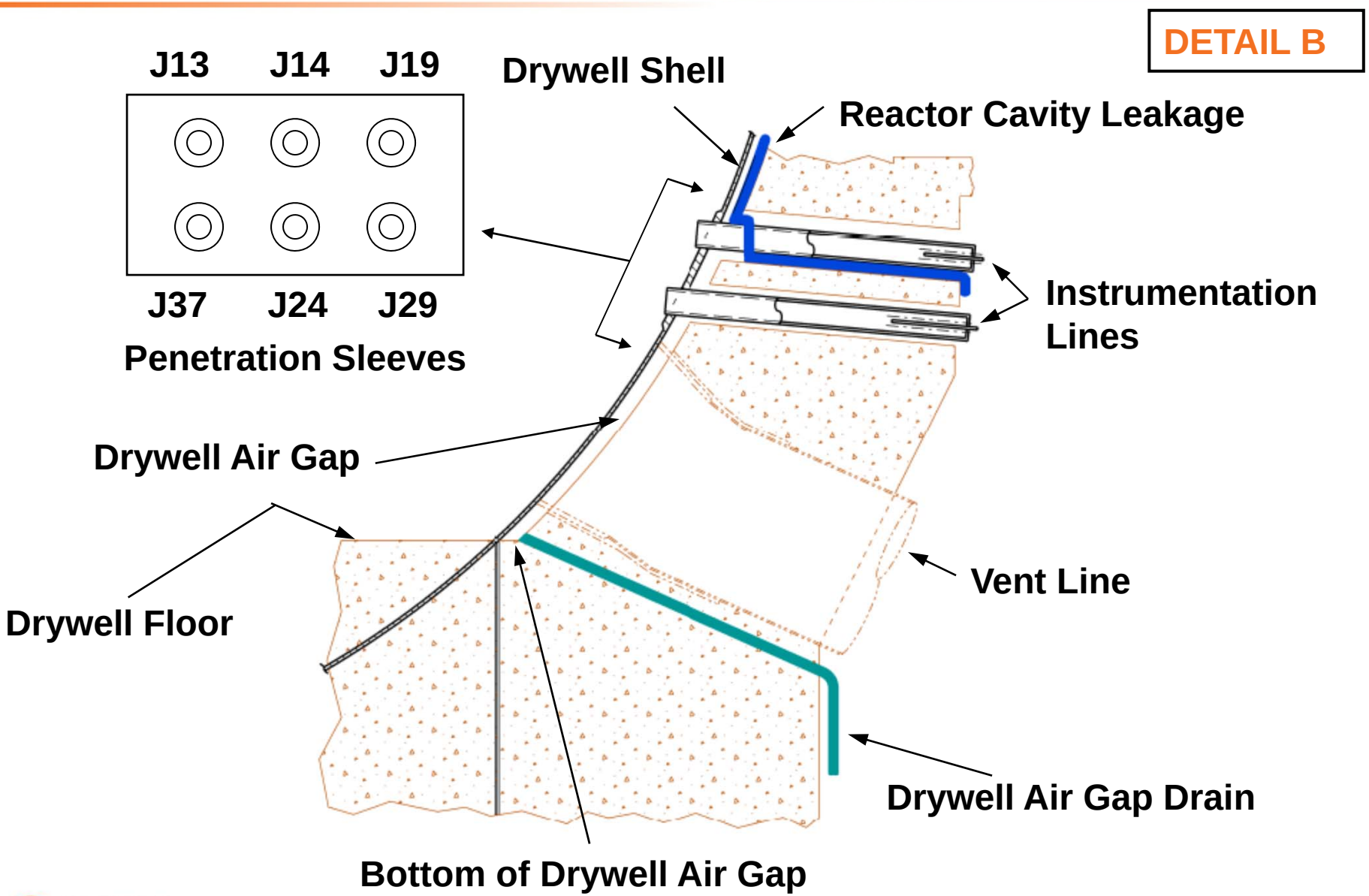
Containment – Lower Drywell Area



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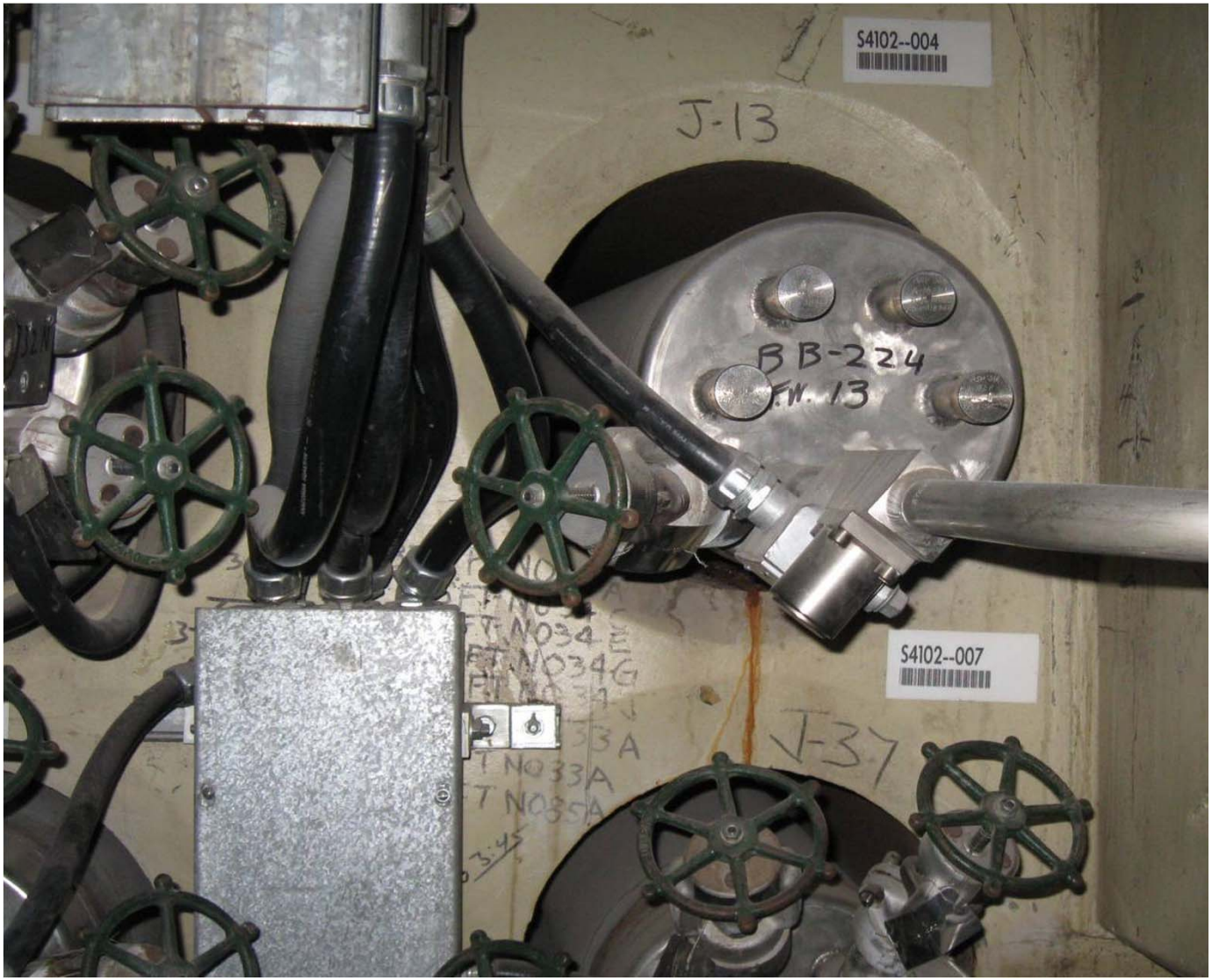
J13 Penetration Sleeve



United States Nuclear Regulatory Commission

Protecting People and the Environment

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Full Committee

Hope Creek Generating Station (HCGS)

Safety Evaluation Report (SER)

May 12, 2011

Arthur Cunanan, Project Manager
Office of Nuclear Reactor Regulation

Presentation Outline

- Overview of the SER
- Closure of Open Item
- Closure of Confirmatory Items
- Conclusion

Overview (SER)

- SER with Open Items issued September 30, 2010
- The Open Item and Confirmatory Items for the SER are closed
- The final SER was issued March 9, 2011

SER Open Item Closed

Buried Piping Inspection (SER 3.0.3.2.12 and 3.0.3.3.4)

- Staff noted a number of industry operating experience involving leakage from buried and underground piping/tanks
- The applicant revised its program and stated:
  - All buried steel piping are cathodically protected except four short transition (concrete to steel) piping spools in the Service Water system, and portions of the Fire Protection system
  - Steel inspections include Fire Protection piping and Service Water transition piping spools
  - Cathodically protected systems are tested annually per NACE standards
  - Backfill specifications as validated by recent inspections are acceptable

SER Confirmatory Items Closed

Inaccessible Power Cables (SER 3.0.3.1.20)

- Staff noted industry operating experience where water or moisture had contributed to failures of inaccessible power cables at lower voltages (Generic Letter 2007-01)
- Applicant revised its program to include enhancements to:
  - Expand the scope of Inaccessible Medium Voltage Cables AMP to include low voltage power cables (480 V to 2kV)
  - Eliminate exclusion of cables not exposed to significant voltage
  - Increase frequency of testing of cables (at least every 6 years) and inspection of manholes (at least once every year)
  - Add event driven inspections for manholes

SER Confirmatory Items Closed

Environmentally-Assisted Fatigue (EAF) Analyses (SER 4.3.5)

- Based on the applicant's plant-specific configuration, additional locations may need to consider EAF beyond those in NUREG/CR-6260.
  - The applicant committed to:
    - Perform a review of design basis ASME Code Class 1 component fatigue evaluations
    - Use most limiting location for the effects of the reactor coolant environment on fatigue usage

SER Section 3 Additional RAI

Reactor Cavity Leakage (SER 3.0.3.2.14)

- Leakage observed from Penetration J13 during 2009 refueling outage
- Staff was concerned about water being trapped below Penetration J13
- Applicant committed to perform additional inspections during 2010
- During October 2010 refueling outage, water leakage was observed from Penetrations J13 and J14
- All four air gap drains below Penetrations J13 and J14 were blocked
- Containment shell thickness below the Penetrations J13 and J14:
  - Nominal Plate Thickness: 1.500 Inch
  - UT measurement in October 2010: 1.490 inch
  - Design Thickness: 1.4375 inch
- Containment shell thickness in other areas were greater than 1.50 inch
- Applicant committed to:
  - UT examinations of the containment shell for the next three outages
- Information Notice in process of being issued to alert other nuclear plant operators

SER Section 3 Additional RAI

Reactor Cavity Leakage (Cont.)

- Recently, the applicant examined one of the air gap drains and found the drain was blocked 6 feet prior to reaching the drywell shell.
- Applicant was not able to detect an exit port to the air gap drains when it sent a boroscope through the instrument lines. The other three air gap drains were not inspected. The current configuration of the air gap drains are unknown.
- Based on new information of the air gap drains, the staff will:
  - Establish a license condition for the applicant to:
    - Perform boroscope and UT thickness measurements every outage until drainage is established
    - Submit a report to the staff summarizing the results from the boroscope examinations and the ultrasonic thickness measurements
    - Perform UT thickness measurements of the drywell shell, after the drainage is established from all four quadrants, during the next three refueling outages to establish a corrosion rate to demonstrate that the drywell structural integrity will be maintained through the period of extended operation
  - Revise the aging management program in the SER related to the reactor cavity leakage

SER Section 3 Additional RAIs

Small-Bore Piping Program (SER 3.0.3.3.6)

- Applicant provided inspection sampling of both socket welds and full penetration welds
  - Inspect 25 full penetration welds (out of a population of 51 welds) and 25 socket welds (out of a population of 250 welds) using a sampling methodology to select the most susceptible and risk-significant welds.

One-Time Inspection (SER 3.0.3.1.11) and Selective Leaching of Materials (SER 3.0.3.1.12) Programs

- Applicant's sample methodology will
  - Establish a sample size of 20 percent of the population (up to a maximum of 25 inspections) for each sample group
  - Sample groups are based on aging effects, environments and component materials of fabrication

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Conclusion

On the basis of its review, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Hope Creek Generating Station.

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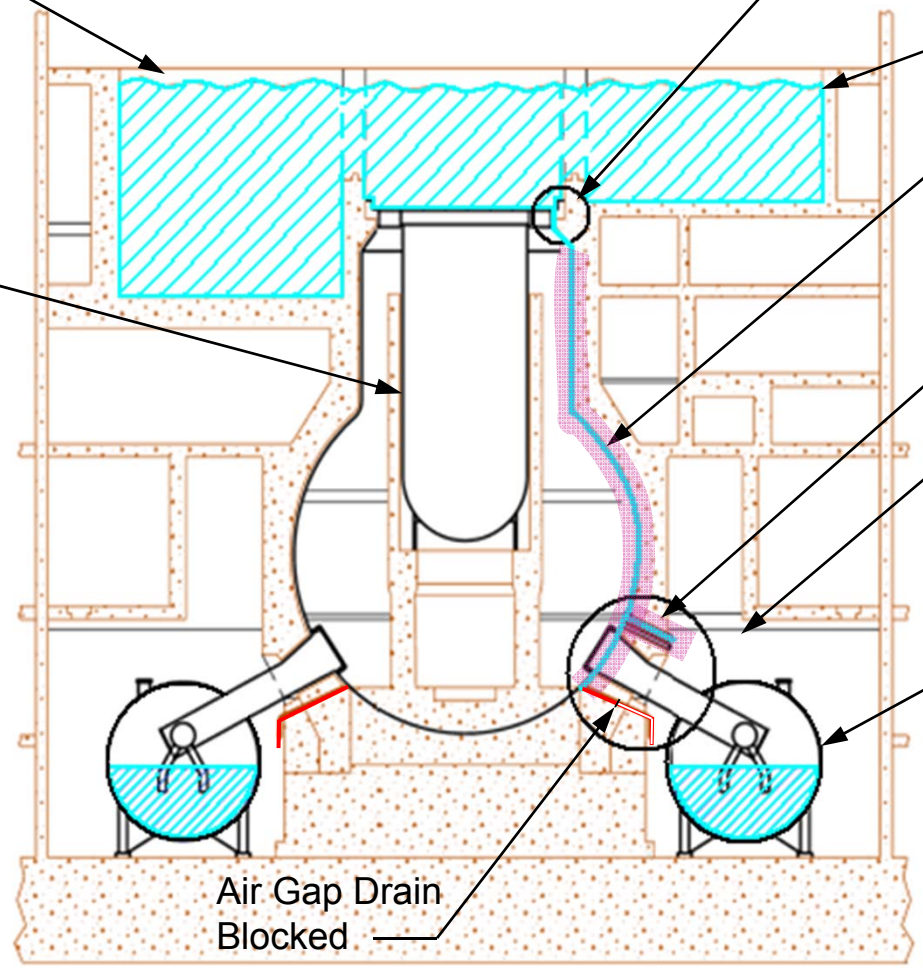
Buried Piping and Tanks Inspection Program

System	Material	Committed Inspections	AMP Recommended Inspections	
			Code/Safety Related	HAZMAT
Fire Protection	Gray cast iron	1	Flow test or inspections	
	Carbon steel	1		
	Ductile iron	1		
	Stainless steel	0[2]		
Service Water System (SRW)	Carbon steel	1	1	
SRW short piping spools, not CP	Carbon steel	4[1]	4	
SRW	Reinforced Concrete	1	1	
Condensate Storage & Transfer	SS	1		1

One-Time Inspection of Small Bore Piping

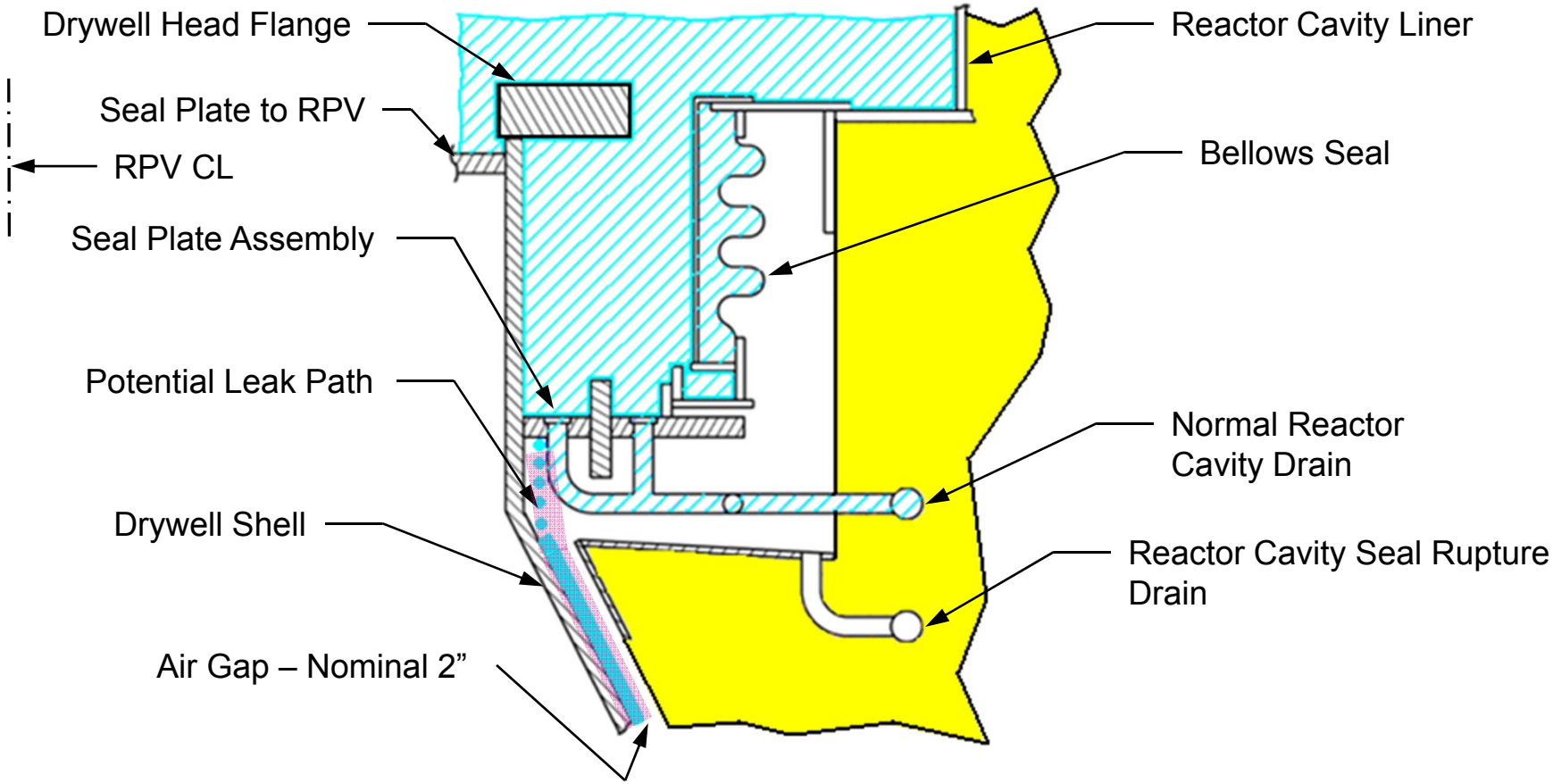
Failures (or with less than 30 years of operation)			No Failures
High cycle fatigue-mitigated	High cycle fatigue – not mitigated	Stress corrosion cracking or thermal fatigue	More than 30 years
10% of welds; max. of 25 welds of each type	Plant-specific periodic program	Plant-specific periodic program	≥ 3% of welds; max. of 10 welds of each type
One Time Inspection within 6 years before period of extended operation			OTI within 6 years before PEO
1 destructive exam = 2 volumetric exams			1 DE = 2 VE

Mark I Containment
During Refueling Operation

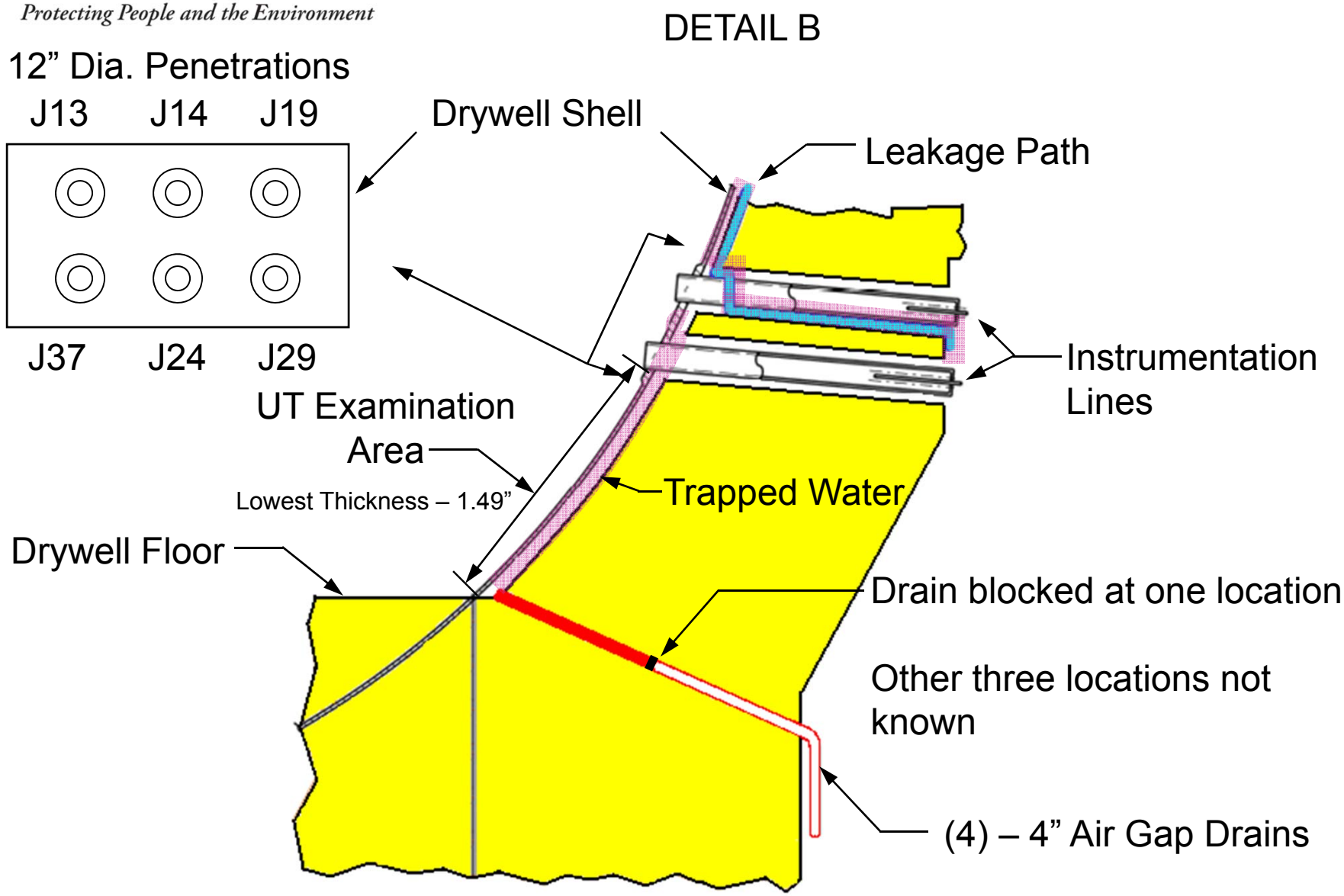


Drywell / Reactor Cavity Seal Area

DETAIL A



Lower Drywell Area



Salem License Renewal

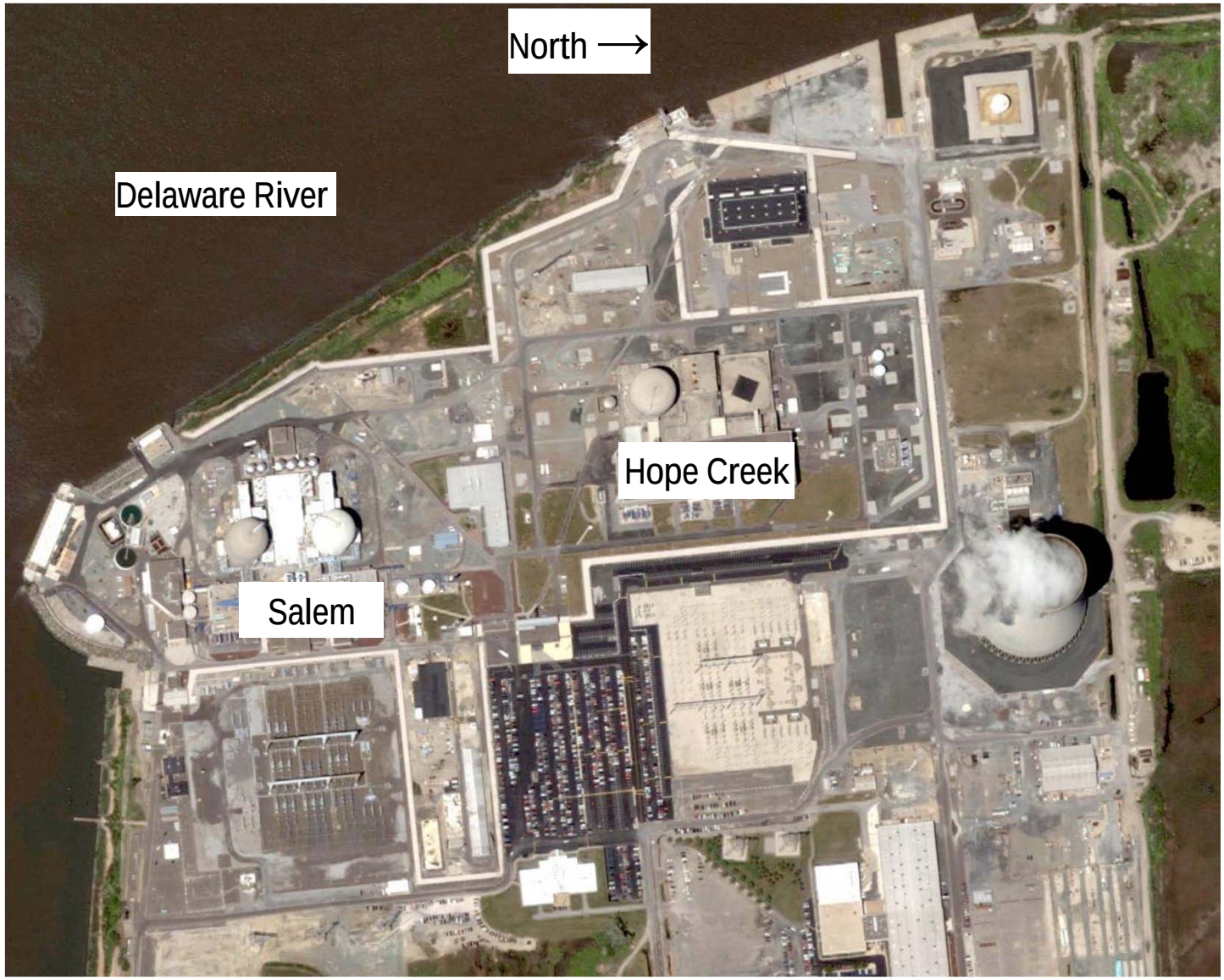
ACRS Full Committee
May 12, 2011

PSEG Nuclear LLC

Agenda

- Introduction – Paul Davison, Vice-President, Operations Support
- License Renewal – Ali Fakhar, Manager, License Renewal
- Closure of Open Items and Other Issues
  - Buried Piping — Jim Melchionna
  - Spent Fuel Pool — Tom Roberts
  - Metal Fatigue — Ali Fakhar
  - Steam Generator Tube-to-Tubesheet Welds — Ali Fakhar
  - Other Issues — Ali Fakhar
- Closing Comments – Paul Davison

Site Description



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Aging Management Programs and Commitments

- 32 Existing Aging Management Programs
  - 15 programs required no changes to align with GALL
  - 17 programs required enhancements to align with GALL
- 16 New Aging Management Programs
- 54 License Renewal Commitments
  - Commitments tracked using SAP Database System
  - Implementing documents (e.g. procedures, work orders) annotated with commitment references
  - Implementation has begun well in advance of Period of Extended Operation (PEO)

Salem Buried Piping

Jim Melchionna
Corporate BPP Program Manager
PSEG Nuclear

PSEG Nuclear LLC

OI 3.0.3.2.10-1 Closure

- Modified Program commitments to:
  - Perform a cathodic protection study prior to entering the PEO
  - Perform a soil characterization study prior to entering the PEO
    - If this initial study determines that the soil is non-corrosive, a second soil study will be performed in 15 years to confirm the soil is still non-corrosive
  - Replace and reroute above ground the buried Auxiliary Feedwater piping located inside the Unit 2 Fuel Transfer Tube Area prior to entering the PEO
  - Resolved Staff's concerns for carbon steel non-cathodically protected piping by:
    - Focusing inspections on the buried, safety-related portions of the Auxiliary Feedwater, Compressed Air Systems and Service Water Systems and the in-scope portions of the Fire Protection System
    - Added two additional (total of 3) inspections on the buried, safety-related portions of the Service Water System prior to entering the PEO

Outage Update (Unit 2)

- Performed 3 Direct Inspections of Auxiliary Feedwater Piping
  - Coating found and piping in good condition
- Performed 2 Direct Inspections of Service Water Piping
  - Coating found and piping in good condition
- Performed 3 Direct Inspections of Compressed Air Piping
  - Coating found and piping in good condition
- Performed 3 Direct Inspections of non safety-related Compressed Air Piping
  - Coating found and piping in good condition
- Performed Indirect Inspection of non safety-related carbon steel Service Water Piping with satisfactory results
- Replaced Aux FW Piping inside Unit 2 Transfer Tube Area

Conclusions - Buried Pipe Program (BPP)

- 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

Salem Unit 1 Spent Fuel Pool

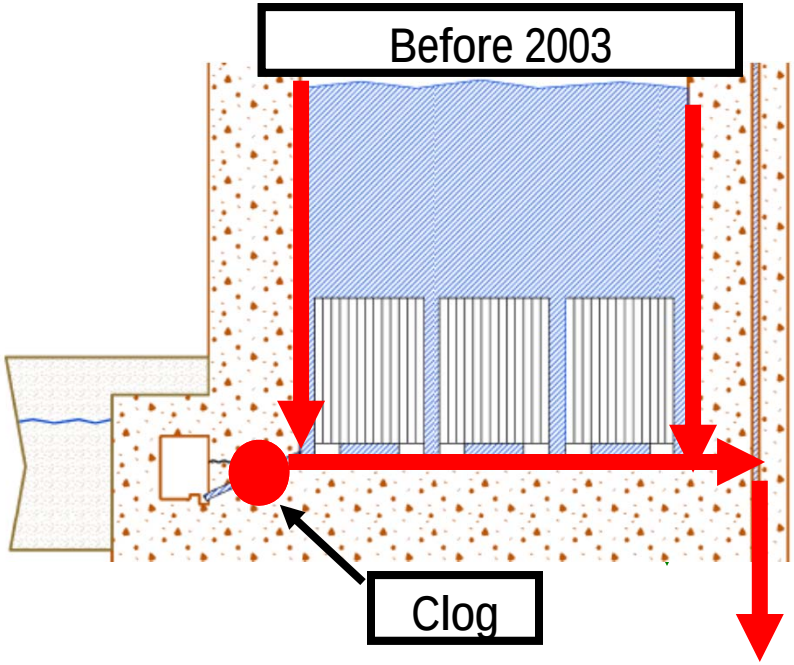
Tom Roberts

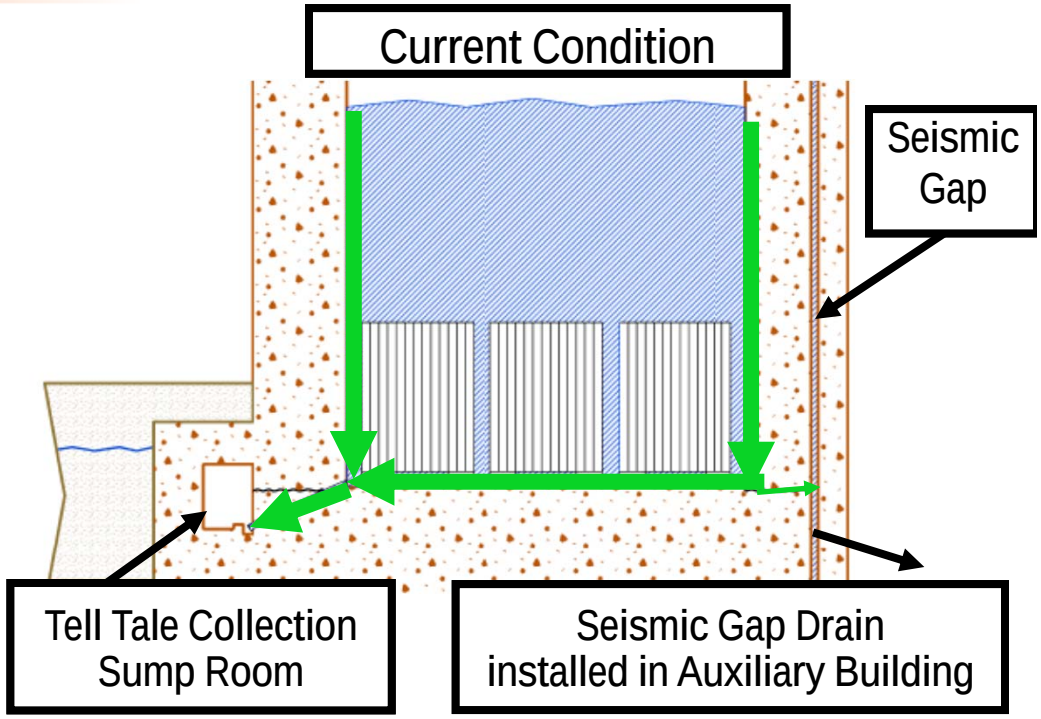
PSEG Nuclear LLC

Salem Unit 1 Spent Fuel Pool

- Leakage occurs through small cracks in liner welds
  - 100 gallons per day
  - Leak size estimate is multiple cracks totaling 6 inches long and 0.001 inch wide
  - Cracks are too small to be readily identified, located & repaired
- Confirmed impact on the Spent Fuel Building Structure is not significant
- Implemented a program since 2003 that manages leakage
- Integrity of the Salem Unit 1 Spent Fuel Pool will be maintained to ensure continued safe operation

Salem Unit 1 Spent Fuel Pool Leakage Path





- Leakage exited the structures through seismic gap
- Contamination did not migrate offsite
- Contamination is being remediated

- Tell Tale Drains are maintained open to ensure leakage is captured
- Seismic Gap Drain installed in the Auxiliary Building to ensure any leakage is captured
- No additional contamination is exiting the structures

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Salem Unit 1 Fuel Handling Building Structural Assessment

- Laboratory tests of concrete in borated water
  - Borated water effects on concrete were conservatively estimated for 70 years
  - Results supported by examination of concrete cores from the Connecticut Yankee Spent Fuel Pool
- Rebar degradation was determined to be not significant
- Visual examinations & concrete surface hardness testing were performed
- Verified potential impact on structural margin was not significant

Salem Unit 1 Spent Fuel Pool Monitoring

- Ensure that the leakage collection system is operating properly
  - Daily walkdowns to monitor tell tale drains and sump
  - Log sump pump run-time weekly
  - Data trended monthly to ensure tell tale drains are cleaned before becoming blocked
  - Inspect and clean out as required tell tale drains every 6 months
  - Seismic gap sampled weekly
- Perform structural inspections
  - Every 18 months for Unit 1 Sump Room wall
  - Every 5 years for the Fuel Handling Building

OI 3.0.3.2.15-1 Closure

- Ensure that the leakage collection system is operating properly including:
  - Testing water drained from the telltales and seismic gap drains
  - Monitoring water chemistry to assess any changes that could indicate building degradation from the borated water
  - Initiating an investigation and evaluation for readings outside the expected range
- Perform structural inspections including:
  - One core bore of the Unit 1 Spent Fuel Pool east and west walls that have shown ingress of borated water to test concrete and inspect rebar

Conclusions – Salem Unit 1 Spent Fuel Pool

- The Spent Fuel Pool liner leakage does not have a significant impact on the Fuel Handling Building Structure
- Available structural margin ensures that any potential degradation due to borated water leakage does not result in a loss of intended function
- Keeping the leakage collection system and seismic gap drains operating properly
  - Minimizes the potential for concrete degradation
  - Prevents contamination of the environment
- Integrity of the Salem Unit 1 Fuel Handling Building Structure will be maintained to ensure continued safe operation

Closure of Open Items and Other Issues

Ali Fakhar
Manager, License Renewal
PSEG Nuclear

PSEG Nuclear LLC

OI 4.3.4.2-1 Metal Fatigue/WESTEMS™ Closure

- Closed Open Item by:
  - Resolving staff questions on the use of WESTEMS™ at Salem
  - Adding Program Commitments related to ongoing use of WESTEMS™ and for verification that current EAF Locations are bounding

OI 3.1.2.2.16-1 Steam Generator Tube to Tubesheet Welds Closure

- Resolved staff questions by modifying program commitments to perform appropriate inspections or analysis

Other Issues

- One-Time Inspection Program Sampling
- Selective Leaching Sampling
- Flux Thimble Tube Wall Thinning

Flux Thimble Question

Question Raised During the Subcommittee Meeting

- How will Salem Reestablish Flux Thimble Tube Wear Rates in the Period of Extended Operation?

Response

- Program will reestablish wear rates by:
  - Performing Eddy Current Testing (ECT) on Flux Thimble Tubes
  - Determining Tube Wall Loss

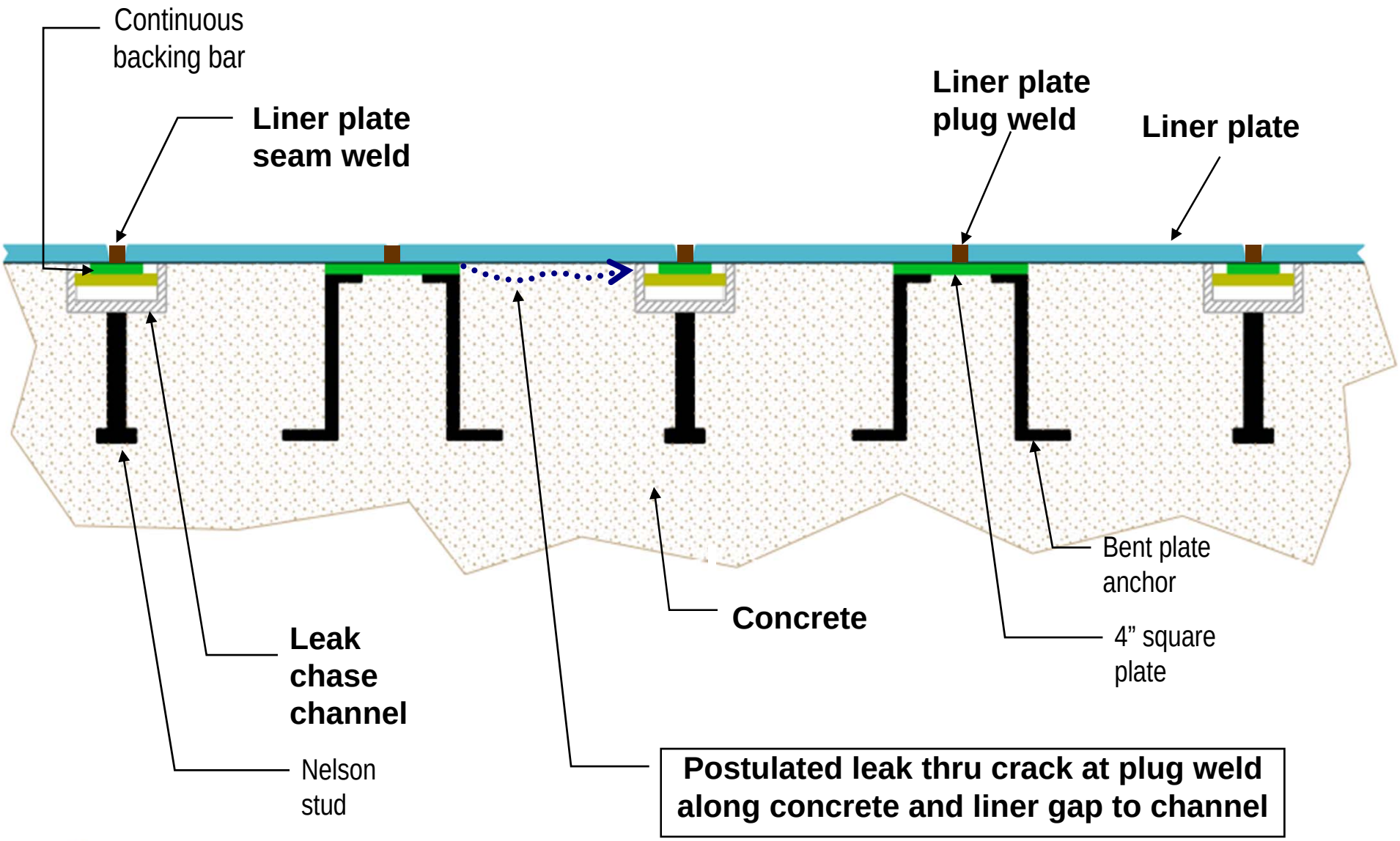
Salem License Renewal

The Salem Aging Management Programs will ensure continued safe operation through the Period of Extended Operation

PSEG Nuclear LLC

BACKUP SLIDES

Salem Unit 1 Spent Fuel Pool Liner – Seam & Plug Welds



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Buried Pipe Program – License Renewal Inspections

PSEG Nuclear LLC

Buried Pipe Program – License Renewal Inspections

PSEG Nuclear LLC

United States Nuclear Regulatory Commission

Protecting People and the Environment

Advisory Committee on Reactor Safeguards (ACRS) License Renewal Full Committee

Salem Nuclear Generating Station

Safety Evaluation Report (SER)

May 12, 2011

Samuel Cuadrado de Jesús, Project Manager
Office of Nuclear Reactor Regulation

Presentation Outline

- Overview of the SER
- Closure of Open Items
- Conclusion

Overview

- Safety Evaluation Report with Open Items issued November 5, 2010
- The Open Items for the SER are closed
- The Final Safety Evaluation Report was issued March 31, 2011

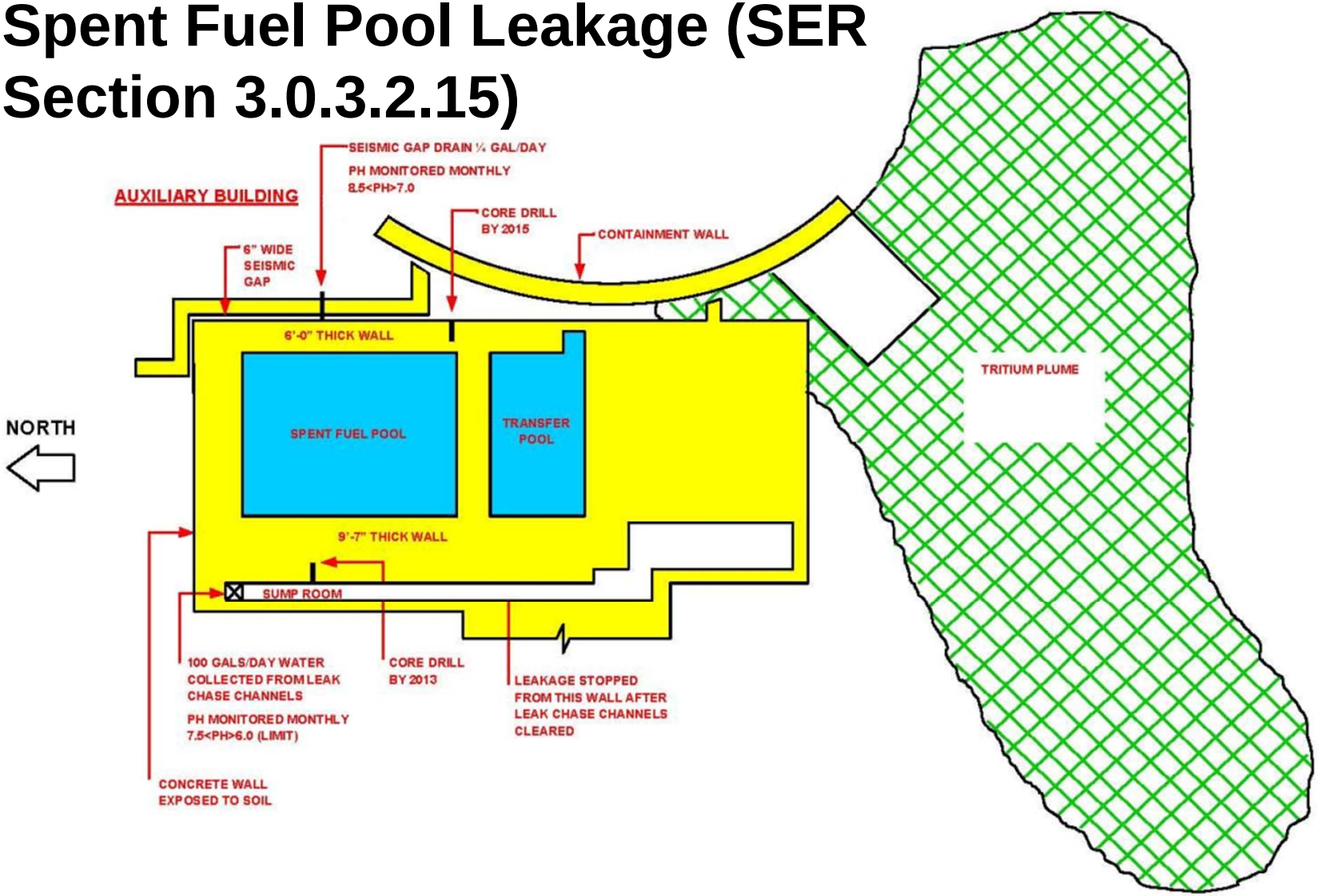
Closure of Open Items

Spent Fuel Pool Leakage (SER Section 3.0.3.2.15)

- Leakage of borated water at Unit 1 may result in degradation of the concrete and embedded steel reinforcement of the SFP
- In response to the staff's concerns, the applicant committed to (Commitment 33):
  - Visually inspect the accessible west wall every 18 months
  - Monitor leakage and water chemistry
  - Take concrete core samples from both the east and west walls
- The staff made the concrete core samples a license condition for the renewed license. Sample results, recommendations and planned actions will be reported to the NRC

Closure of Open Items

Spent Fuel Pool Leakage (SER Section 3.0.3.2.15)



Closure of Open Items

Spent Fuel Pool Leakage (SER Section 3.0.3.2.15)

Structures Monitoring Program acceptance criteria for leakage

Chemical Analysis	Acceptance Criteria		Frequency for monitoring
	SFP Telltales (West Wall)	Seismic Gap Drain (East Wall)	
pH	6.0 < pH < 7.5	7.0 < pH < 8.5	Monthly
Chloride	≤ 500 ppm	≤ 500 ppm	Every 6 months
Sulfate	≤ 1500 ppm	≤ 1500 ppm	Every 6 months
Boron	Information Only	Information Only	Monthly
Iron	Information Only	Information Only	Every 6 months

Closure of Open Items

Buried Piping and Buried Non-Steel Piping Inspections (SER Sections 3.0.3.2.10 and 3.0.3.3.4)

- No cathodic protection for buried steel piping
- During buried piping inspections in Spring 2010, licensee discovered that the coating had been removed from Unit 1 AFW piping due to a construction error
- The applicant:
  - Conducted extensive buried pipe inspections equivalent to 45 inspections prior to PEO
  - Committed to perform a soil characterization study in accordance with AWWA C-105 to determine corrosivity prior to the PEO, and repeat during PEO if soil found not to be corrosive
  - Committed to inspect 6 steel piping locations if soil is non-corrosive, and up to 9 if it is corrosive, in addition to one of stainless steel and one of concrete, every 10 years during the PEO
  - Use risk ranking to plan future inspection locations
- Salem's in-scope buried piping does not contain hazardous materials

Closure of Open Items

SG Tube-to-Tubesheet Welds and Potential PWSCC (SER Section 3.1.2.2.16-1)

- Initiation of PWSCC could cause a failure of the weld and RCP boundary
- The applicant committed to (Commitment 51):
  - Demonstrate that the tubesheet cladding and welds are not susceptible to PWSCC or obtain permanent approval for Alternate Repair Criteria (ARC) from the NRC which re-defines the RCPB to no longer include the autogenous tube-to-tubesheet or,
  - Perform a one-time inspection of tube-to-tubesheet welds in all SGs. If weld cracking is identified:
    - Resolve the condition (engineering evaluation/repair)
    - Establish a periodic monitoring program

Closure of Open Items

Metal Fatigue of Reactor Coolant Pressure Boundary (SER Sections 3.0.3.2.18, 4.3.4.2, and 4.3.7.2)

NUREG/CR-6260 locations for Environmentally-Assisted Fatigue

- The applicant committed to (Commitment 52):
  - Perform a review of design basis ASME Code Class 1 component fatigue evaluations
  - Use the most limiting location for the effects of the reactor coolant environment on fatigue usage

Closure of Open Items

Metal Fatigue of Reactor Coolant Pressure Boundary (SER Sections 3.0.3.2.18, 4.3.4.2, and 4.3.7.2)

WESTEMS™ software impact on cumulative usage factor (CUF) calculations

- Audit on January 18 and 19, and February 8, 2011
- Staff's audit determined:
  - Salem does not use WESTEMS™ NB-3600 module
  - Salem's use of WESTEMS™ NB-3200 module provides results consistent with ASME Code Section III, NB-3200
  - Salem demonstrated it has sufficiently documented user intervention when using WESTEMS™
- As a result of staff's audit, the applicant committed to:
  - Commitment 53: Include written explanation and justification of any user intervention in future evaluations using the WESTEMS "Design CUF" (NB-3200 module)
  - Commitment 54: Not use or implement the NB-3600 option (module) of the WESTEMS™ program

SER Section 3 Additional RAI

One-Time Inspection and Selective Leaching Programs Sampling Criteria (SER Sections 3.0.3.1.11 and 3.0.3.1.12)

- Applicant's sample methodology will:
  - Establish for each program sample group a sample size of 20 percent of the population (up to a maximum of 25 inspections)
  - Sample groups are based on aging effects, environments and component materials of fabrication

Revision to License Renewal Guidance

Treated Borated Water (SER Sections 3.2.2.1.X and 3.3.2.1.Y)

- The staff is developing interim staff guidance to update the GALL Report on aging management of treated borated water.
- Boron is no longer credited as being a corrosion inhibitor, and one-time inspections are recommended to verify the effectiveness of the Water Chemistry Program to manage loss of material and cracking in treated borated water that is not deoxygenated.
- Affected systems at Salem include the spent fuel pool systems, containment spray system, portions of the ECCS, and others
- The applicant submitted a draft LRA supplement that:
  - Adds the One-Time Inspection Program to verify the effectiveness of the Water Chemistry Program to over 110 line items
  - Updated the description of the One-Time Inspection Program and the Water Chemistry Program and one commitment in the UFSAR supplement
- The staff finds this acceptable and will update the SER

Conclusion

On the basis of its review, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Salem Nuclear Generating Station, Units 1 and 2.

U.S.NRC

United States Nuclear Regulatory Commission

Protecting People and the Environment

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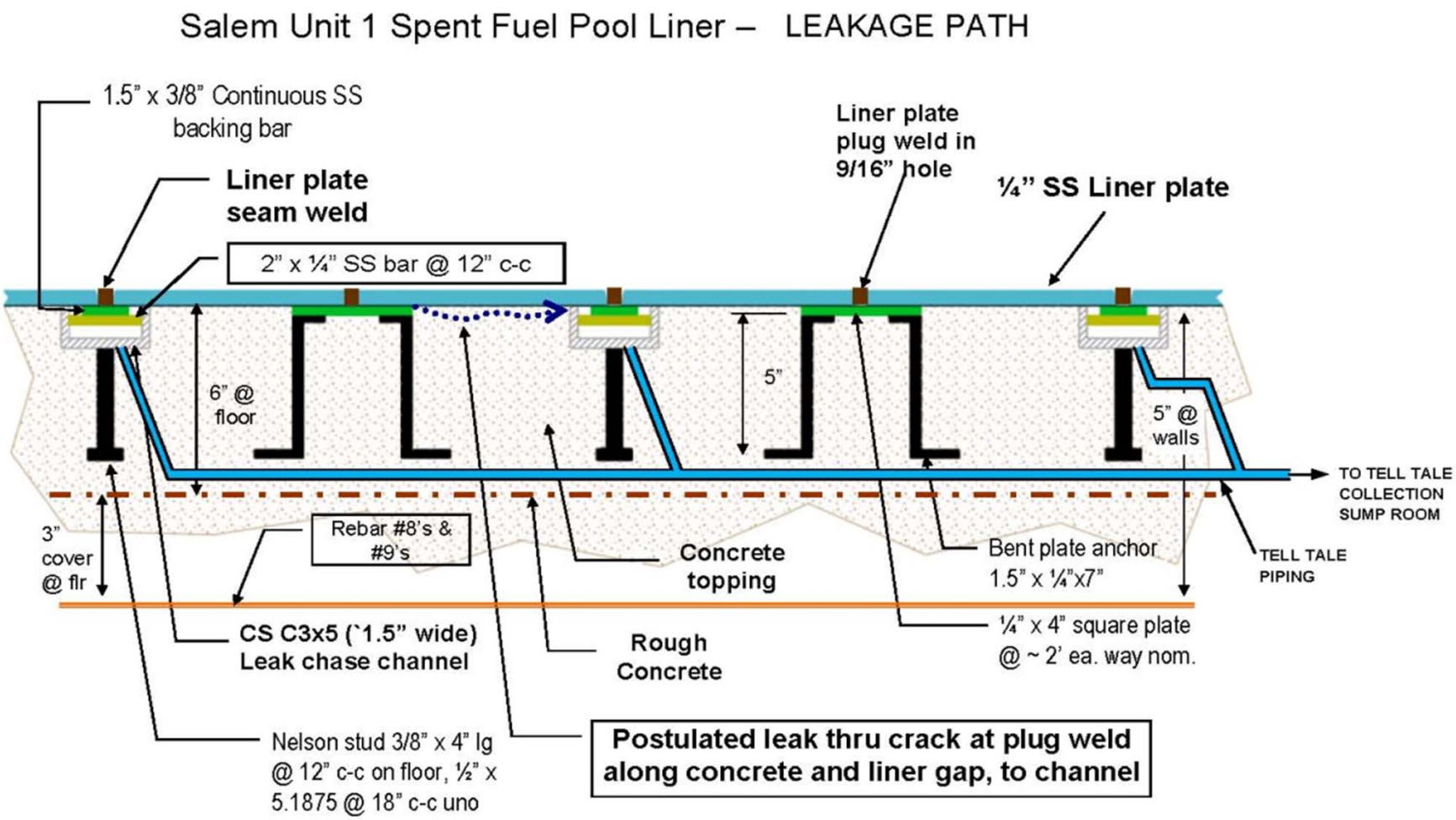
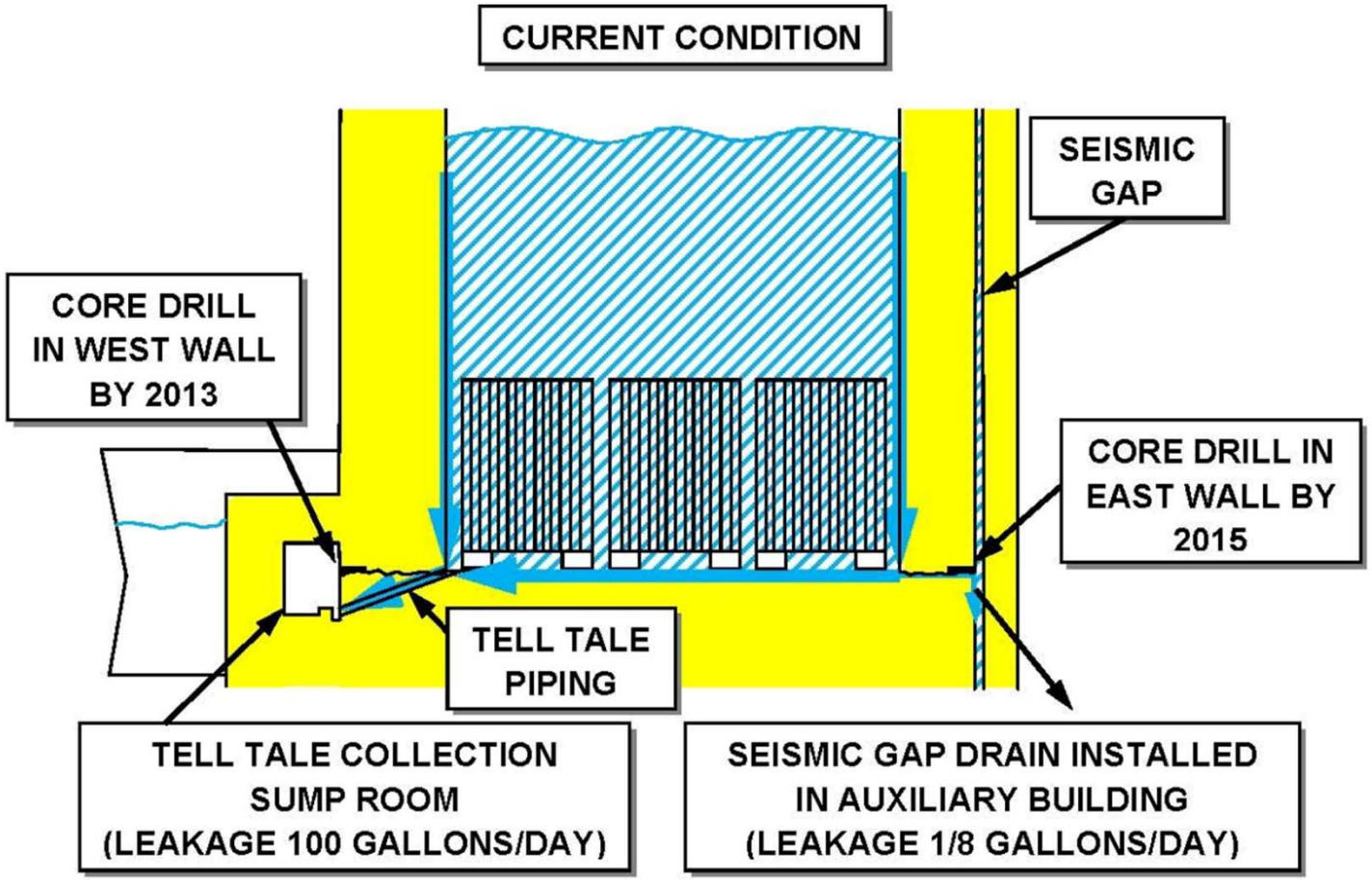
Closure of Open Items

Spent Fuel Pool Leakage (SER Section 3.0.3.2.15)



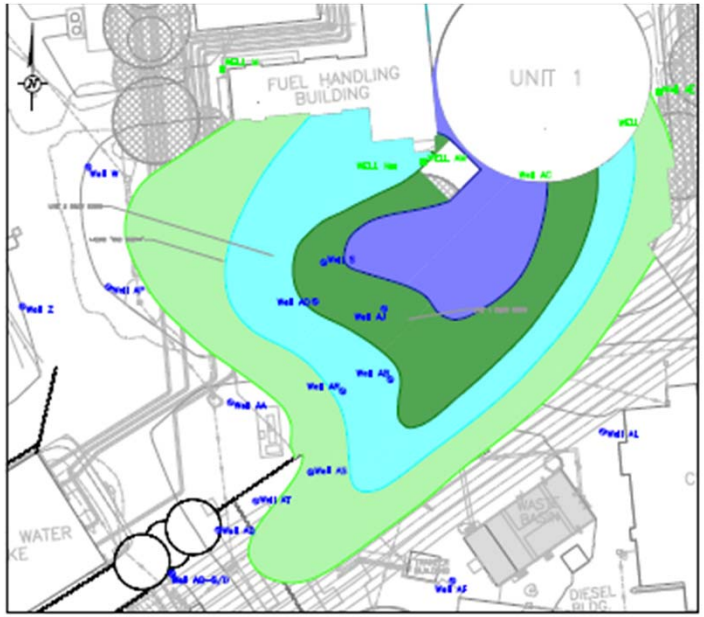
Closure of Open Items

Spent Fuel Pool Leakage (SER Section 3.0.3.2.15)

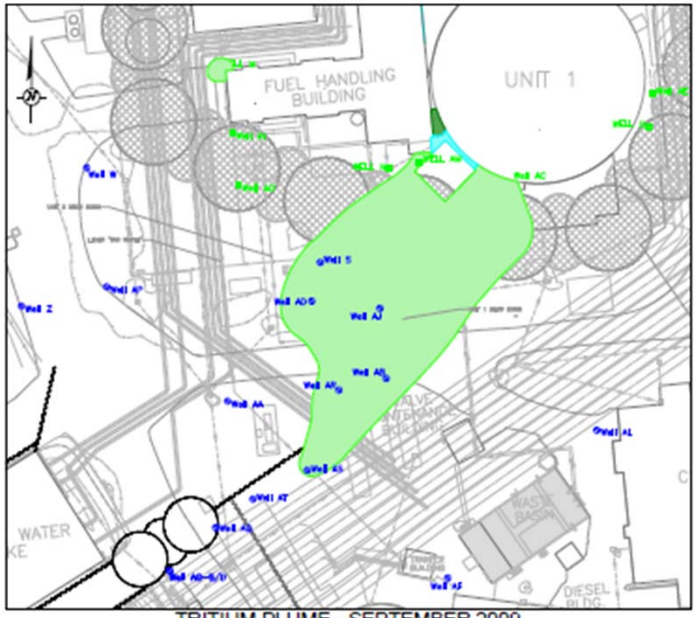


Groundwater

Tritium Results 2004 and 2009



BASELINE TRITIUM PLUME - PRE-GROUNDWATER EXTRACTION - MARCH 2004



TRITIUM PLUME - SEPTEMBER 2009
FULL SCALE SYSTEM IN SERVICE

LEGEND:

WELL R MONITORING WELL SCREENED IN THE SHALLOW, WATER-BEARING UNIT WITHIN THE LIMITS OF THE COFFERDAM.

WELL S MONITORING WELL SCREENED IN THE SHALLOW, WATER-BEARING UNIT OUTSIDE THE LIMITS OF THE COFFERDAM.

LIMIT OF GROUNDWATER WITH TRITIUM ABOVE 1,000,000 pCi/L

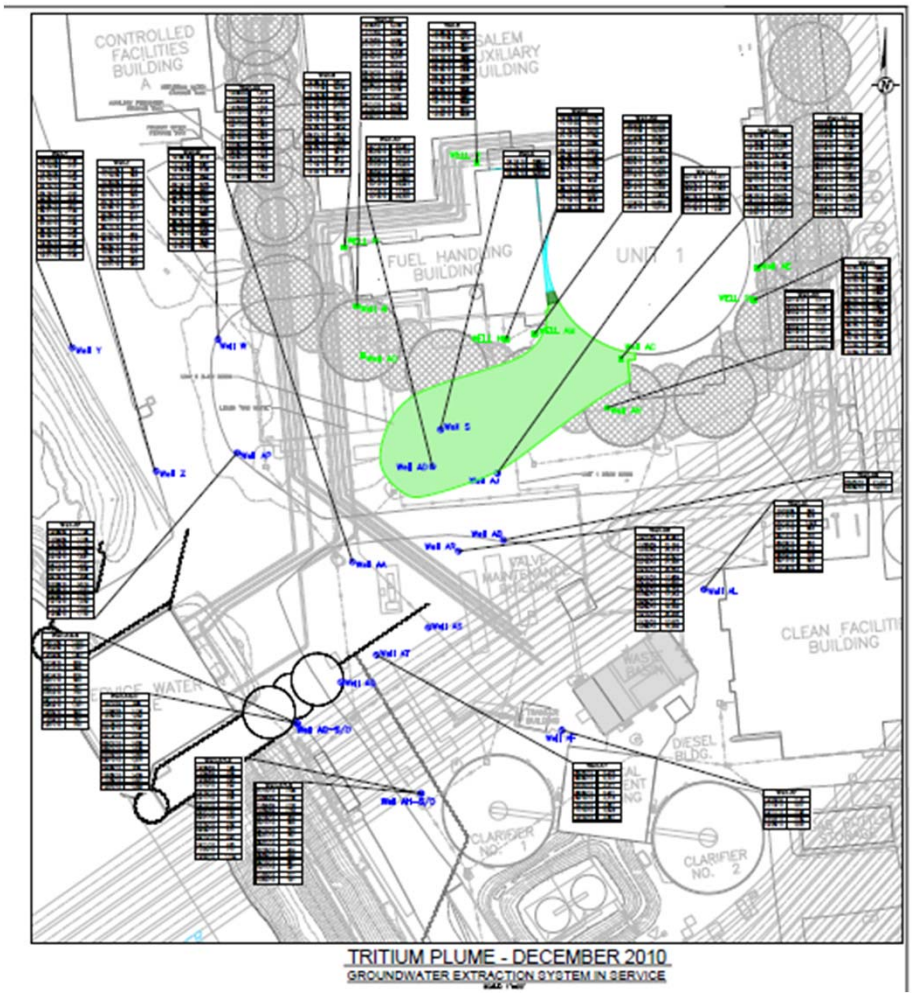
LIMIT OF GROUNDWATER WITH TRITIUM ABOVE 500,000 pCi/L

LIMIT OF GROUNDWATER WITH TRITIUM ABOVE 100,000 pCi/L

LIMIT OF GROUNDWATER WITH TRITIUM ABOVE THE NEW JERSEY GROUNDWATER QUALITY CRITERION (20,000 pCi/L)

Groundwater

Tritium Results December 2010



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LIMIT OF GROUNDWATER WITH TRITIUM ABOVE 100,000 pCi/L

LIMIT OF GROUNDWATER WITH TRITIUM ABOVE THE NEW JERSEY GROUNDWATER QUALITY CRITERION (20,000 pCi/L)

Buried Piping and Tanks Inspection Program

System	Material	Committed Inspections	AMP Recommended Inspections	
			Code/Safety Related	HAZMAT
Fire Protection	Gray cast iron	1	Flow test or inspections	
	Carbon steel	1		
	Ductile iron	1		
Service Water[5]	Steel	Before PEO -3 During PEO -1 or 2[4]	Footnote [2]	
AFW	Steel	Before PEO -22 During PEO -1 or 2[4]	Footnote [2]	
Compressed Air	Steel	Before PEO -23 During PEO -1 or 2[4]	Footnote [2]	
Demineralized Water	Steel	0	0[3]	
Non-Radioactive Drain	Steel	0	0[3]	
Penetration Bellows between Containment Structure and Fuel Handling Building	Stainless Steel	1		1
Circulating Water and Service Water	Reinforced concrete	1	1	

Buried Piping and Tanks Inspection Program

Salem Buried Pipe Program

Number of Carbon Steel Inspections since 2009 on the specified Systems [1]

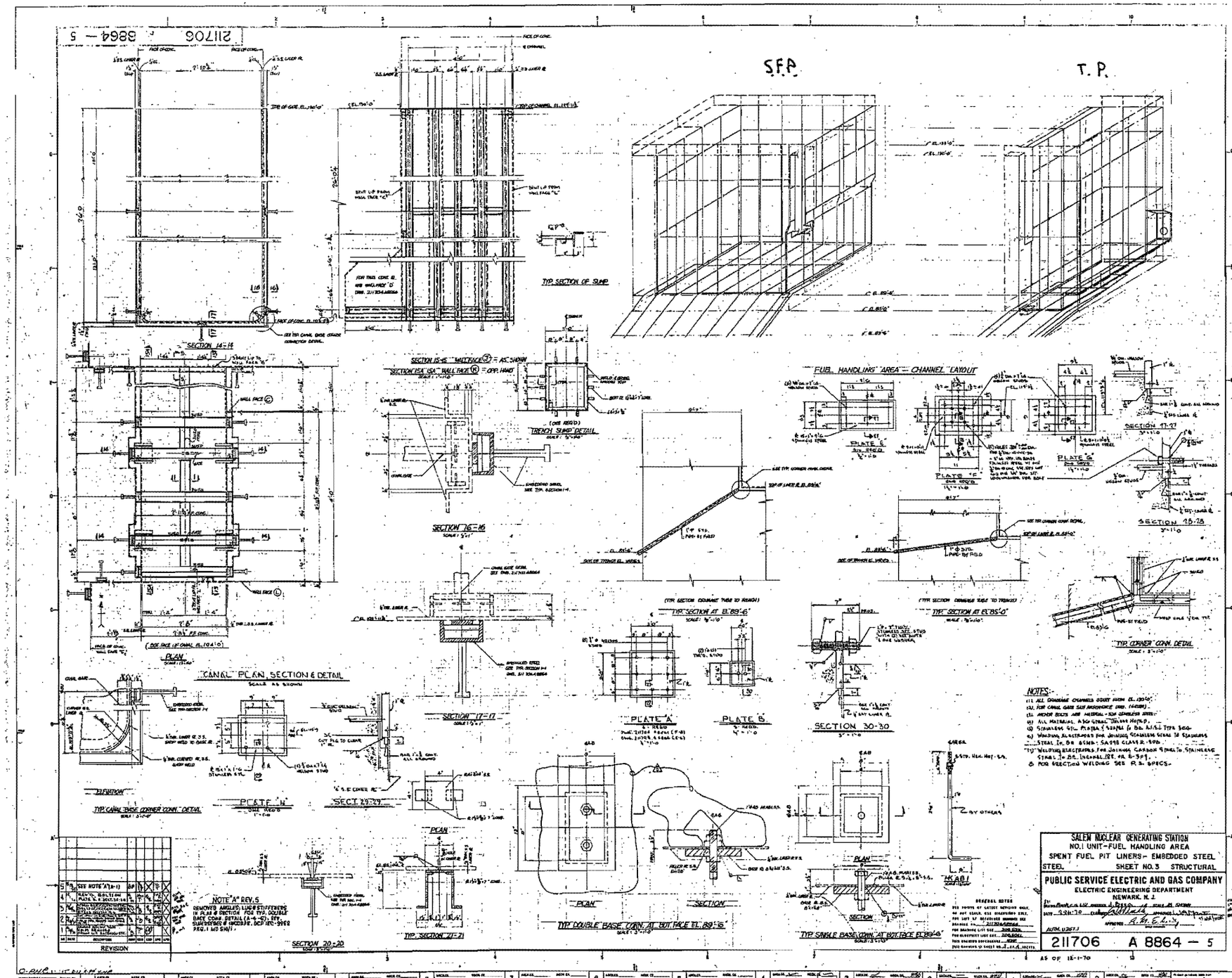
	Unit 1	Unit 2	Common
In-scope Systems	(2) Auxiliary Feed Water (5) Compressed Air (1) Service Water	(2) Auxiliary Feed Water [2] (5) Compressed Air	
Not In-scope Systems	(1) Circ. Water (1) Steam Gen. Blowdown	(1) Steam Gen. Blowdown	(1) Fire Protection (7) Fuel Oil [3] (1) Sewage Lift Station

Notes:

1. The numbers in parenthesis ( ) represent the number of individual pipelines for each system found coated upon excavation.
2. Two AFW lines were inspected inside the Unit 2 Fuel Transfer Tube Area in 2010 as part of the extent of condition for missing coating on Unit 1 AFW pipes. Inspections exposed ~3ft on each of the two AFW lines. The pipes were found coated. *(See Response to RAI B.2.1.22, submitted in PSEG Letter LR-N10-0322 on September 7, 2010)*
3. The number of inspections for Fuel Oil piping includes three separate locations exposed on one pipeline with coating found present at all 3 locations.

Buried Piping and Tanks Inspection Program

Auxiliary Feedwater Buried Pipe Corrosion at Salem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S.F.P.
T.P.
SECTION 14-14
PLAN
CANAL PLAN, SECTION & DETAIL
SCALE AS SHOWN
TYP. SECTION OF SUMP
SECTION 15-15 "WALL FACE" = AS SHOWN
SECTION 15A "WALL FACE" = OPP. HAND
TRENCH SUMP DETAIL
SECTION 16-16
SECTION 17-17
FUEL HANDLING AREA - CHANNEL LAYOUT
PLATE "E"
PLATE "F"
PLATE "G"
SECTION 17-17
SECTION 18-18
TYP. SECTION AT EL 89'-6"
TYP. SECTION AT EL 85'-0"
TYP. CORNER CONN. DETAIL
PLATE "A"
PLATE "B"
SECTION 30-30
TYP. CANAL BASE CORNER CONN. DETAIL
ELEVATION
PLATE "H"
SECT 29-29
PLAN
SECTION
TYP. DOUBLE BASE CONN. AT BOT. FACE EL. 89'-6"
TYP. SINGLE BASE CONN. AT BOT. FACE EL. 89'-6"
SECTION 20-20
TYP. SECTION 21-21
NOTE "A" REV. 5
REMOVED ANGLES & LIGHT STIFFENERS IN PLAN & SECTION FOR TYP. DOUBLE BASE CONN. DETAIL (A-6-01). ETC. SUPERSEDES & INCORPS. DCP NO. 3962 REQ. 1 NO SAFI.
REVISION
NOTES:
(1). ALL CONCRETE CHANNELS DOWN FROM EL. 130'-0".
(2). FOR CANAL GATE SEE MECHANICAL DWG. 14-0189.
(3). ANCHOR BOLTS ARE MATERIAL - NON STAINLESS STEEL.
(4). ALL MATERIAL A36 STRUC. TO ASM MATL. P.
(5). STAINLESS STL. PLATES & SHAPES to DR. A-151 TYPE 304.
(6). WELDING ELECTRODES FOR JOINING STAINLESS STEEL TO STAINLESS STEEL IN DR. A-5.18: SA-298 CLASS R-606.
(7). WELDING ELECTRODES FOR JOINING CARBON STEEL TO STAINLESS STEEL IN DR. INCONEL (RE. PR. E-3.9).
& FOR ERECTION WELDING SEE R.S. SPECS.
SALEM NUCLEAR GENERATING STATION
NO. 1 UNIT - FUEL HANDLING AREA
SPENT FUEL PIT LINERS - EMBEDDED STEEL
STEEL SHEET NO. 3 STRUCTURAL
PUBLIC SERVICE ELECTRIC AND GAS COMPANY
ELECTRIC ENGINEERING DEPARTMENT
NEWARK, N.J.
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AS OF 12-1-70