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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARD

(ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE

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WEDNESDAY

DECEMBER 1, 2010

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 1:30 p.m., John W. Stetkar, Chairman, presiding.

SUBCOMMITTEE MEMBERS:

JOHN W. STETKAR, Chairman

MARIO V. BONACA, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

ACRS CONSULTANT:

JOHN J. BARTON

ACRS STAFF PRESENT:

KATHY D. WEAVER, Designated Federal Official

NRC STAFF PRESENT:

BENNETT BRADY

DE JESUS SAMUEL CUADRADO

MELANIE GALLOWAY

ALLEN HISER

WILLIAM HOLSTON

STEPHEN KLEMENTOWICZ

MICHAEL MODES

BO PHAM

ABDUL SHEIKH

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

1:30 p.m.

CHAIRMAN STETKAR: The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I'm John Stetkar, Chairman of this subcommittee meeting. ACRS members in attendance are Bill Shack and Mario Bonaca and Jack Sieber. Our ACRS consultant, John Barton, is also present. Kathy Weaver of the ACRS staff is the designated federal official for this meeting.

The subcommittee will review the license renewal application for the Salem Nuclear Generating Station Units 1 and 2 and the associated draft safety evaluation report with open items. We will hear presentations from the NRC staff, PSEG Nuclear, LLC representatives and other interested persons regarding this matter. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting. The entire meeting will be open to public attendance. There is a phone bridge line. To preclude interruption of the meeting, the phone will be placed in listen in mode during the presentations and

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

The rules of participation in today's meeting have been announced as part of the notice of this meeting previously published in the federal register. A transcript of the meeting is being kept and will be made available as stated in Federal Register Notice. Therefore we request the participants in this meeting use the microphones located throughout the meeting when addressing the subcommittee. The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

We will now proceed with the meeting and I call on Melanie Galloway for introductions.

MS. GALLOWAY: Thank you Chairman Stetkar. My name is Melanie Galloway. I am the deputy director of the division of license renewal. On behalf of the division and all the staff that I support at this license renewal activity, we are happy to be here and to present

the staff's review so far in response to ACRS interest and questions. There are a few folks that I would like to introduce right off the bat. Bo Pham is our branch chief for te project branch number one with responsibility for Salem. Bennett Brady is our senior project manager responsible for the license renewal activity. In addition we have a representative from Region I, Mike Modes, who is the lead inspector for license renewal activities associated with Salem. In addition, there are a number of technical staff in the audience who are here to support this meeting and response to any questions that the ACRS members may have. Brian Holian, the division director, is not able to be here today because for a period of three weeks, including this week, he is acting as the deputy regional administrator in Region IV. So he sends his regrets.

I would like to mention before we turn it over to the applicant, that over the course of the last few months as we pulled together GALL Revision 2, that has served as a reminder and an opportunity for us to make sure that the current staff positions which are being documented in

GALL Rev 2 have in fact been appropriately reviewed against all of our in-house applications. In doing that we've undertaken a systematic look at each one of the applications that remains in-house to ensure that we have been complete in ensuring that those current staff positions have been looked at and that we have taken the appropriate follow up as necessary with the applicants to make sure that their applications are in sync to support our license renewal. In the course of doing that, we have come up with a number of gaps. Those gaps have been communicated to each of the licensees including Salem in order that we can have them completely filled and Bennett in her presentation will discuss those few additional RAIs and the closure of those items as they have occurred to Salem.

With that I would like to turn it over to Paul Davison of PSE&G.

MR. DAVISON: Thank you Ms. Galloway. Good afternoon. My name is Paul Davison. I am the Vice President of Operations Support PSEG Nuclear and I am the executive sponsor for the license renewal. Before we begin today's

presentation, I would like to introduce the presenters. To my right is Ali Fakhar, the PSEG nuclear license renewal manager for Salem. Although he has 29 years of experience, 15 of which are with PSEG. To Ali's right is Greg Sosson, the PSEG nuclear engineering services director. Greg has 23 years of experience, six with PSEG. To Greg's right is Jim Melchionna, our corporate buried pipe program manager. Jim has 28 years of experience, 18 of which are with PSEG. And finally to Tom's right, excuse me, to Jim's right is Tom Roberts, our corporate engineering specialist. Tom has 31 years of nuclear experience, 27 with PSEG. And Alan Johnson, our senior manager of design engineering at Salem. Alan has 28 years of experience and 18 with PSEG. There are two other individuals in the audience that I would also like to introduce in addition to today's presenters. That is Bob Brown our senior vice president for nuclear operations and Carl Fricker, the Salem site vice president.

Slide two contains the agenda for today's presentation. We will begin with the description of the site and an overview of Salem

units one and two operating history. Followed by an overview of our license renewal application. We will then continue with our discussions on four SER open items and one topic of interest regarding aging management of Salem's containment liner. We have developed a comprehensive high quality renewal license application and a robust aging management program that will ensure the continued safe operation of Salem Generating Station. We appreciate the opportunity to make these presentations and look forward to answering any questions you may have. I would like to now turn it over to Greg Sosson who will begin with the first presentation. Greg?

MR. SOSSON: Thank you Paul. Good afternoon. My name is Greg Sosson and I am the engineering services director at PSEG Nuclear. Mr. Chairman and subcommittee members, as shown on this slide the two Salem units and Hope Creek share a common site 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 WESTEMS PWR co-owned by Exelon and PSEG and operated by PSEG Nuclear. The two containment buildings are towards the left of the

slide. The Salem service water intake structure is the small structure on the river as indicated by the arrow. The Salem circ or pump house is the larger structure on the left side. And the Salem switch yard is directly below the containment.

This slide shows some of the significant highlights in a Salem unit one operating history. I will not be discussing all of the items on the slide but I do want to point out that we have made some significant equipment reliability and long term asset management improvements on Salem Unit one including replacement of the steam generators, the high pressure and low pressure turbines and the reactor head. We also performed mechanical stress improvement process on the reactor vessel hot and cold leg nozzles. Our current Salem Unit one capacity factor is 90.7 percent. The current license for Salem Unit one expires on August 13, 2016.

MEMBER SHACK: Have you finished the MSIP on both units?

MR. SOSSON: We have done MSIP on the hot and cold legs on Unit One. Unit Two we have

done the hot legs but we have done phrase UT on the cold legs also.

Next slide please. On this slide, this shows some of the significant highlights in the Salem Unit 2 operating history. We have similarly made significant equipment reliability and long term asset improvements on Unit 2 including replacing the steam generators, the high pressure turbine rider and the reactor head. As I stated earlier a mechanical stress improvement was performed on the hot legs. Our current Salem Unit 2 capacity factor is 91.7 percent. The current license for Salem Unit 2 expires on April 18, 2020.

Salem is on 18-month operating cycles. Our license renewal application was submitted on August 18, 2009. I will now turn it over to Ali Fakhar, who will present to you the highlights of the license renewal application.

MR. FAKHAR: Thank you Greg. Good afternoon. My name is Ali Fakhar and I am the Salem license renewal manager. My portion of the presentation covers the highlights of our license renewal applications including aging management programs, commitment and open items.

In preparing the application, we used all necessary guidance for the goal of making the application as consistent with the goal as possible. There are 48 aging management programs including 32 existing programs and 16 new programs that have developed for the application. 15 of the existing programs required no changes. 17 of the existing programs require enhancement to go. Six of the 32 programs had exception to goal only two of the 16 new programs had an exception to the goal. Beside PSGM program, fully cognizant of the content and importance of these programs relative to license renewal.

There are 50 license renewal commitments. These commitments are managed under an existing process consistent with NEI 99-04. The commitment attract SAP database. SAP is a data form for most site processes including the corrective action program. Intermittent developments including procedures and work orders are being annotated. They come in differences to ensure that the commitments are maintained. PSEG Nuclear is in the process of implementing many of the program enhancement as we speak. The station on public positions are being created including a

commitment implementation. In addition to this primary function, these positions will ensure that the PSEG Nuclear remain connected and involved in the industry with respect to aging management.

There are four open items for Salem. The first open item is related to the user WESTEMS software for monitoring fatigue at Salem. The staff requested to provide clarification on how the WESTEMS software is used at Salem as a fatigue monitoring tool by performing a benchmark evaluation. Salem is performing the benchmark evaluation for the pressure of the nozzles and the boric injection tank injection nozzle as requested by the staff. The benchmark evaluation will be completed and submitted to the NRC by January 7, 2011. Additionally, the staff requested verification that the NUREG-6260 location evaluated for fatigue bound other high fatigue usage locations in the plant. Salem is in the process of responding to the RAIs this month which use WESTEMS at Salem and describes a resolution plan for the benchmark evaluation to the staff. In addition Salem will commit to an evaluation to ensure the selected NUREG-6260

locations are the most limiting and bonding. This evaluation will be completed prior to PEO. This evaluation will review all class one fatigue analyses to determine if there are more limited locations and perform an involvement fatigue evaluation for the most limited locations in the plant. If the limited location consists of a nickel alloy, Salem will use NUREG-6909 methodology to determine the environmental factor. The location will be added to WESTEMS for online monitoring as required to ensure that the cumulative usage factor remains below the designed limit. Based on our discussion with the staff the we believe this information will add and be responsive to the concern.

The second open item, an associated ROI concern the aging and mechanism of cracking need the primary cooling side of cracking and the primary cooling of the nickel alloy steam generator. Salem Unit 1 and 2 steam generator have nickel alloy 600 on the parameter of the tubesheets. We are responding to staff concern and plant to all this cracking due to primary water stress corrosion cracking at the tubesheet welds. This plan includes inspection of the two

tubesheet welds as part of the plan is specific aging management program unless an evaluation conclude that welds are not required to perform the active coolant pressure. The above plan will be developed for both Salem units. The plan will be implemented prior to the generator reaching 20 years of service life. This will respond to 2018 for Unit 1 and 2028 for Unit 2, both of which are unit PEO. Salem will submit the resolution plan for this staff which we believe will satisfy their concern.

MR. BARTON: Is there a date for that?

MR. FAKHAR: For implementation of the --

MR. BARTON: The submission of it.

MR. FAKHAR: It will be done before PEO we submit. Salem's resolution plan established we believe will satisfy your concern.

MEMBER SHACK: Just a question. On your new steam generator, the one from AREVA with the 690 tubes and the Alloy 600 on the primary side. Was that a Salem decision or is that the way AREVA fabricates the steam generators to still use the Alloy 600 on the tubesheet facing?

MR. FAKHAR: I would ask Sam to

answer that question.

MR. SPEAR: Good afternoon. Sam Spear with the Salem new project team. The tubes were 690 but the cladding at the time was 600 cladding, which was consistent with the design.

MR. HUFNAGEL: Excuse me. Mr. Sieber, I'm not sure -- this is John Hufnagel. I am with the license renewal team, licensing league. I just wanted to clarify to make sure we answered your question. I think you asked when we were going to submit the plan that would address the two chief welds. The answer to that is this week.

MR. FAKHAR: The third open item is associated with Salem 1 and Mr. Tom Roberts will discuss this in more detail. The fourth open item is related to the buried piping program. Following Mr. Roberts' discussion, Mr. Jim Melchinonna will discuss the buried piping program and associated open item.

MR. DAVISON: Thanks Ali. Are there any questions before I transition into the open items?

Okay, moving to our next open item which is to our first open item which regards the

spent fuel pool leakage on Unit 1. Salem Unit 1 has approximately 100 gallons per day of leakage through very small cracks in the wells. We have tried to identify the location of these cracks but they are too small to locate. But having said that, we are not satisfied with the fact that the leakage continues and we have a plan to pursue that elimination by participation in industry forums that will help us determine and detect ways to find and then ultimately resolve the leak. In the meantime we have implemented a program since 2003 that manages the leakage in order to minimize segregation on the concrete structure. Tom Roberts will present a brief history of the leakage. Our 2002 discovery of leakage outside the plant structures of remedial actions that we have taken and how we will manage the leak until a such that we can fix the source of the leakage. I will now turn it over for the detailed presentation to Tom Roberts.

MR. ROBERTS: Thank you Paul and good afternoon everyone. My name is Tom Roberts. I am the corporate engineering specialist for PSEG in the areas of non-destructive examination and welding. I am also the lead utility advisor for

EPRI's, NDE, for ground water protection, technical advisory committee and spent fuel pool leakage subcommittee. I will be discussing the Salem Unit 1 spend fuel pool, specifically the management of the spend fuel pool liner leakage and the aging effects of the spent fuel pool liner leakage on the concrete. Following my discussions of the technical details I will also discuss the spend fuel pool open item.

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 total volume on a per day basis. The leakage as Paul noted earlier, is through cracks and line welds. Because of the cracks have been established as being differential thermal expansion between the liner and the concrete surfaces. There are approximately 2,100 linear feet of seam welds, and 1,400 plug welds which are used to attach the liner to the concrete structure. The estimated leak size in aggregate if it were a single or multiple smaller crack would total in single flaw of six inches long by .001 inches wide. In the

past Salem has attempted to locate the source of leakage but was not successful. In 2003 we implemented a program to manage this leakage after discovery that the leakage had a path to the environment due to clogged tell tales in the leakage collection system. If opted to manage that leakage after confirming that the impact in the fuel handling building structure in and of itself was not significant.

CHAIRMAN STETKAR: Before you get into more of the details in the upcoming slides, what's the status of leakage, if any, from the Unit 2 spent fuel pool?

MR. ROBERTS: Unit 2 does have evidence of leakage. However, the extent of leakage is approximately one gallon per day as opposed to the steady state conditions we have seen over the last seven years for Unit 1.

CHAIRMAN STETKAR: Has that leakage been extent for a reasonable period of time and is it stable?

MR. ROBERTS: Yes.

CHAIRMAN STETKAR: It is stable?

MR. ROBERTS: It is trended the same manner that we trended monitor Unit 1.

CHAIRMAN STETKAR: And you said it is about one gallon?

MR. ROBERTS: It is one gallon per day, yes.

CHAIRMAN STETKAR: Okay, thank you.

MEMBER SHACK: You said its stabilize. What's your history of observing leakage in the Unit 1 fuel?

MR. ROBERTS: We've been monitoring it. We monitor it actually on a weekly basis and trend it for the last seven years.

MEMBER SHACK: okay. And prior to that?

MR. ROBERTS: If I could go a little bit further ahead, it might make a little bit more sense as to how we entered into that monitoring program. In fact if we could turn to the next slide. The sketch on the lefthand side of the slide shows the situation that was identified in 2002 when ground water contamination was discovered just outside the fuel handling building. The design of the leakage collection system is to capture any leakage from the liner seam wells into embedded channels behind the liner and then route it with

a series of tell tale drains which are then processed through the rad waste system. The tell tales are pipped to the drainage system and in the sump room and the sump room is denoted on the lower left hand side of the slide there. The channels are not welded to the back side of the liner at the seam welds. Therefore, any potential leakage from intermediate plug wells can also reach the channels and flow out through the tell tales. The system did not work as designed because the tell tales 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 concrete of the building. As the water level entraced in the gap between the liner and concrete the hydrostatic head pressure forced water into the concrete construction joints. The migrated, the water migrated through the construction joints, then seeped out of the fuel handling building into what is denoted as the seismic gap between the fuel handling building and the adjacent auxiliary building in contamination external to the structures. However, the contamination never

migrated offsite and never entered drinking water sources. Ground water remediation and testing is performed to mitigate the ground water contamination. Since these actions have been put into place, the initial contamination plume has diminished both in size and in concentration. The sketch on the right side of this slide shows the situation after corrective measures were implemented. I would note this is also the current state of affairs. The tell tales remained open and clear to properly maintain leakage 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 that any leakage that might migrate to the seismic gap is also captured. These corrective actions manage the leakage to minimize the potential impact on the fuel handling building structure and to ensure that there is no leakage to the environment.

CHAIRMAN STETKAR: Before we go off this slide here. A few questions. Have you, you said you installed drains from the seismic gap to route water somewhere into the aux building.

MR. ROBERTS: That's correct.

CHAIRMAN STETKAR: Have you observed any flow through those drains?

MR. ROBERTS: We do see flow into the seismic gap drain that is actually, we monitor it for two purposes. One to see if there is active short-lived isotopes that would be emanating from the spend fuel pool but it is also influenced by rain water. We do see water from that perspective.

CHAIRMAN STETKAR: Do you -- well my question then is the water, since you do monitor it, is there evidence of leaking spent fuel pool water coming out of those drains, out of the seismic drains?

MR. ROBERTS: We have calculated that there is a leakage rate into the seismic gap of about 1/8 of a gallon per day.

CHAIRMAN STETKAR: Which means the tell tales still aren't removing all of the flow. Is that right?

MR. ROBERTS: The preferential path simply due to the geometry would be through the tell tales. But given the fact that area, the seismic gap put into perspective for all people

in the room is a 6-inch space between the physical building. So it is virtually in accessible. However, anecdotally once the hydrostatic head pressure had developed a path through the construction joints. We do and did anticipate and have seen that there are some minor amounts of leakage that is to the seismic gap, which is why the seismic gap drain route were installed.

CHAIRMAN STETKAR: Do you have -- I had a question. The version of the license renewal application that we received, didn't have a lot of the drawings in it so I'm kind of at a loss. Do you have a plan view that shows the configuration of the fuel building and the auxiliary building? I'm going to have a later question about down water and I think it is somewhat relevant to also ground water intrusions questions because I couldn't quite --

MR. ROBERTS: This one can be used as a description, I think will answer your question. The auxiliary building is actually at the, start at the intersection of the containment radius and directly that's up against the fuel handling building. That point is uniface of the auxiliary

building and the fuel handling building.

CHAIRMAN STETKAR: So the seismic gap that you are talking about on this drawing, which is pretty difficult to see with my old eyes. The seismic gap is that vertical gap right there where the cursor is.

MR. ROBERTS: That is correct.

MS. BRADY: Excuse me, this is Bennett Brady. The state did prepare their own little sketch of the drawing. Would that help?

CHAIRMAN STETKAR: We'll take a look at it.

MR. ROBERTS: When you come up.

MEMBER SIEBER: The seismic gap is the load of the fuel pool.

MR. ROBERTS: That is correct.

MEMBER SIEBER: So putting a drain in, the remainder, and seven years, that's 2-1/2 million gallons of water. That's a fair amount of water. It would seem to me and correct me if I'm wrong, but it would seem to me that installing drains will not prevent the leakage.

MR. DAVISON: If I could ask Mr. Ed Keating to talk about the actual plume, which will provide evidence of how we are actually

mitigating the release of the water and what the size of the plume is doing. So Ed if you could start out with just summarizing what we are looking at here and talk a little bit about the plume.

MR. KEATING: Sure. Good afternoon. My name is Ed Keating. I am with the license renewal project. This map you are looking at is the plume map, which I believe we are going to get to questions later. The seismic gap drains are intended to keep the seismic gap below the level of grade that would overflow into the environment. We've installed a ground water recovery system of 36 wells, six wells of which are pumping wells. And those wells are removing the shallow ground water at a rate 15 times that at the recharge rate of the area. So you can see in the drawing up here, the large circle in the center of the drawing is the containment. The box to the left of it is the fuel handling building and the seismic gap is that darkened area in between the two. The map on the left shows the concentrations of tritium, relative concentrations of tritium in a plume. The dark purple being the highest concentration and the

light green being something over 20,000 picocuries per liter. We started out with 15 million piccocuries per liter. The map on the right is a current flume map and you'll notice its much smaller and its generally all except for right next to the building less than 100,000 piccocuries. Right now all wells at Salem are less than 50,000 piccocuries. That map is anything over 20.

MR. DAVISON: Does that answer your question on how we are preventing the leakage on how we are preventing this leakage, Al, and we are monitoring it not very, not at the gap itself but actually at the plume external?

MEMBER SIEBER: It doesn't really answer my question but I'll have some more later.

MR. DAVISON: Okay.

MEMBER SIEBER: I think you have a permanent leak and the site of Salem sits right off the double.

MR. KEATING: Yes sir it does. And what we, we have monitoring wells in 40 foot --

MEMBER SIEBER: 34, yes, but the leak continues. And under your plan it will always continue.

CHAIRMAN STETKAR: It will continue for the next 26 years.

MR. KEATING: Okay. The leak you are speaking of is the gallon per day going into the seismic gap which we are collecting in the seismic gap drain. So there is nothing continuing into the environment. The purpose of the seismic cap drain is to create a negative hydraulic head such that radionuclides are not released to the environment. The recovery system is creating negative radiant toward the center of the site to prevent anything from leaving the site.

MEMBER SIEBER: I'd like to think about that for a while. We'll probably come back to it. Thank you.

CHAIRMAN STETKAR: Tom, before you leave this slide.

MR. ROBERTS: Yes.

CHAIRMAN STETKAR: How do we know that all of the drains are open on the Unit 2 spend pool?

MR. ROBERTS: Unit 1 and Unit 2 we institute the same program. What we have is a 6-month period maintenance test which goes in and

inspects the tell tales. If there is any evidence of buildup or blockage we clean them at that point in time.

CHAIRMAN STETKAR: How far back up can you get? Can you actually get back up into the gap?

MR. ROBERTS: We can get into the shingles.

CHAIRMAN STETKAR: You can?

MR. ROBERTS: Yes.

CHAIRMAN STETKAR: Okay.

MR. ROBERTS: Next slide please. Thank you. To recap the corrective actions we've taken minimize both the potential impact on the fuel handling building structure and ensure that no leakage is continuing into the environment. As I noted earlier PSEG has opted to manage the leak after confirming that the impact on the fuel handling building structure is not significant. I will 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 that had been exposed to borated water. The testing confirmed that

borated water attacks the calcium hydroxide component of the cement paste, weakening the cement paste and causing debonding of both course and fine aggregates. Based on the testing the over projected seven year exposure to water at 100 degrees Fahrenheit is 1.30 inches. We've also confirmed that degradation of the reinforcing steel is not significant based on a number of points including published studies and industry operating experience. We've conducted visual examinations of the fuel handling building of all accessible surfaces. These examinations confirmed that the fuel handling building concrete is in good condition.

Further, we collaborated our testing in structural assessment using actual in situ data from Salem and other plants. As part of the investigation PSEG collaborated with EPRI to test concrete cores from the Connective Yankee spend fuel pool. These cores included concrete just behind the liner that had been exposed to borated water from their spend fuel pool. The test collaborated the results of PSEG laboratory tests as well as the degradation projections. PSEG performed hardness tests at the concrete surfaces

that we knew had been exposed to leakage, which had migrated through a construction joint. These tests confirmed that the concrete was in good condition.

The structural calculation 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 walls and slabs surrounding the spend fuel pool. As I noted before, the effects of the rebar steel is also insignificant.

As a result of the projected degradation, there is no significant impact on the structural capacity of the fuel handling building. 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 incapacity of .7 percent. There is an available design margin of 5 percent in the east wall.

CHAIRMAN STETKAR: Let me pull up the plan view that you had there before. The east wall --

MR. ROBERTS: The east wall is where the seismic gap is located.

CHAIRMAN STETKAR: Not that one. The plan view that is not all --

MR. ROBERTS: That's the east wall.

CHAIRMAN STETKAR: Oh, there it is. Sorry. Okay, thank you.

MEMBER SIEBER: 27 percent degradation is over what period of time?

MR. ROBERTS: Seven years.

MEMBER SIEBER: So that gives you 49 years to reach that if it doesn't increase?

MR. ROBERTS: Correct. Based on the fact that the potential impact in the fuel handling building was not significant and that liner repairs were determined not to be practical at this point in time and that the leakage to the environment has been stopped. PSEG has opted to manage the leakage.

Next slide please. This slide shows how PSEG will manage the leakage and confirm the structural condition of the fuel handling building. There are actually several actions that we take to ensure that the leakage collection system is operating properly. First,

there are daily walk downs that are performed to monitor the tell tale drains. There is a pump located in the room and run-times are recorded weekly and trended monthly to ensure that there is not a diminishing in discharge rate and therefore a increase of tell tale drain blockage. Every six months the tell tale drains as I noted earlier are boroscoped and it required their cleaning to keep the tell tales open. The seismic gap drains are sampled weekly to identify if any new contamination leakage is entering into the seismic gap. The following actions are performed to confirm the structural condition of the fuel handling building. Periodic structural inspections to confirm that no significant structural degradation is developing. These inspections will be performed every 18 months on the Unit 1 sub room wall and every five years on the remainder of the fuel handling building surfaces. Prior to the period of extended operation, PSEG plans to perform a core bore in the sub room wall to be handling for degradation from borated water.

Next slide please.

MEMBER SIEBER: Before you leave this

one, no place in that list do you tell us how you are going to monitor to see daily the tritium concentration. Could you tell us what you are doing there because these measures don't exclusively prove that you know where are the leaks are.

MR. ROBERTS: Okay. I would like to have Mr. Ed Keating respond to that particular question.

MR. KEATING: Good afternoon again. Ed Keating, the license renewal project team. We have a monitoring well network. Ti is called a ground water recovery system. 36 wells, six of which are pumping. This gives you an indication. You can see the two Salem units near the center of the slide. The auxiliary building in between them and the fuel handling building. Those colored spots you see, they are difficult to read from here. But those are the monitoring and/or pumping wells. The green ones are located within the cofferdam area which is right adjacent to where the seismic gap would be. The blue ones are in the directional flow toward the Delaware River where the 40 foot aquifer would discharge. The black ones are part of our radiological

protection program under the NIOs and 07 program. And the magenta ones which I believe are difficult to pick out are the 70 foot aquifer. There is between there and the 70 foot aquifer we have not found any plant related radionuclides including tritium. So we are confident it is not leaving the site. We are confident it is not going down to the next aquifer. And by trending the, if you go back to the last slide. By looking at that flume and trending that, you can see that we are not adding to that plume. We are actually reducing the concentration and the dimensions of the plume.

MEMBER SIEBER: Can we have a copy of the slide on 41? I think we asked for it before. Have you done ground water studies so you are certain as to where the ground water travels?

MR. KEATING: We've done a site conceptual model which demonstrates the direction of ground water flow. It has been impacted somewhat by site structures which made it more of a challenge. But in the area of the plume we've actually developed a model that goes down to 70 foot on a 10 foot by 10 foot grid or 10 foot by 10 foot for each node to determine tritium

concentration, porosity, flow rates, that type of information.

MEMBER SIEBER: I take it these walls that you have on this slide, a lot of them were the cause of the issues that you have here?

MR. KEATING: All of those were installed because of the tritium issue.

MEMBER SIEBER: And when you drilled those wells did you take the profiles of the soil structure down to the bottom of each of the wells so you could actually do a ground water reconstruction veracity levels and the layers under the site?

MR. KEATING: Yes sir. That's the information that we were able to base our site conceptual hydraulic model on, by doing that every five and ten feet. They normally do it at five or ten feet intervals in a short well like this. And by reviewing that, they were able to do the 10 x 10 nodes on the model.

MEMBER SIEBER: Has the staff seen that study?

MR. KEATING: The staff has seen -- I don't know sir. I know the NRC Region I has seen that study. I know NRC Region I has seen that.

CHAIRMAN STETKAR: Do you have a backup slide that shows the vertical profile through the subsurface to show the different layers? Did you bring something like that?

MR. KEATING: No, we do not have a backup slide but in general --

CHAIRMAN STETKAR: It would be very interesting to see what those layers look like given the way the water likes to go.

MEMBER SIEBER: We have an expert on our committee.

MR. ROBERTS: I'd like to point out without going into a great deal of elaboration, if you will note the cofferdams that ring the units. Salem 1 and 2 have a very unique site hydrology. Those were cofferdams that were originally installed to de-water the site during construction. That entire area inside those cofferdams is actually filled with lean concrete up to 20 feet below grade. Right? Which come up to the building structures themselves. The site separation between the lean concrete and the structures, but the real migration of any water and I would defer to Mr. Keating if I incorrectly state anything, is within that top 20 feet from

what is the visible surface grade.

CHAIRMAN STETKAR: You're confident you don't have vertical migration that will eventually get down into a deeper aquifer and then horizontal.

MR. KEATING: Yes sir and the way we ensure that is by those wells in the 70 foot aquifer. By monitoring them we've confirmed that there is no tritium going down below that.

MR. ROBERTS: Not in the last seven years there hasn't?

MR. KEATING: There has been some, there was tritium from bomb testing. We did atom level testing for hydrogen helium tritium and determined that the only tritium that we found in the 70 foot aquifer arrived there before the plant was in place, arrived into the aquifer. You can do, if you get a deep enough aquifer where there is no interference of air, natural air into the water, you can actually test that ratio. A 40 foot aquifer you can't do that because of the air appearance. And things like our drinking water comes from greater than 600 feet, between 600 and 1,000 feet below grade so we are not concerned about impacting your

drinking water. An aquifer is about 70 foot and is run at 240 feet. There is one that starts at 600 feet, which is the upper arrogant and then the middle starts around 740. That's a verbal profile if you will.

CHAIRMAN STETKAR: You said the first aquifer is at 70 feet?

MR. KEATING: Correct. The 40 foot is the river bed sand and gravel -- Salem was held by the Corp of Engineers with dredge material. And that is the original river bed.

MR. ROBERTS: Thank you. Could we turn to slide 18 please. Thank you. This completes my technical discussion on the spend fuel pool. As noted on part of the agenda, we do have one open item that involved the structured monitoring program. We are preparing our response to the RAI associated with this open item which we believe will satisfy the staff's concerns. Our submittal will be with the staff for review by December 15. As previously noted in this presentation PSEG ensures that all leakage is contained within building structures by maintaining proper operation of the leakage collection system.

Next slide please. In summary, the spend 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 the loss of intended function. Keeping the leakage collection system operating properly first minimizes the potential for concrete degradation and secondarily presents the escape of contamination to the environment. The integrity of the Salem Unit 1 fuel handling building will be maintained to ensure continued safe operation.

MEMBER SIEBER: Your borated water in the fuel pool is the 2,400?

MR. ROBERTS: Possibly 2,400 yes.

MEMBER SIEBER: Pretty acidic?

MR. ROBERTS: It is actually a very weak acidic in terms of --

MEMBER SIEBER: Boric acid is not the strongest thing out there but 2,400 that's pretty good.

MR. ROBERTS: I will not turn over the presentation to Mr. Jim Melchionna who will be discussing our buried piping program.

MR. MELCHIONNA: Thanks Tom. Good afternoon. My name is Jim Melchinonna. I am a corporate buried pipe program manager at PSEG Nuclear. I am also on the advisory committee of the EPRI buried pipe integrity group. I am on the buried piping integrity test boards with NEI. I am a member of NACE.

Next slide please. Existing buried pipe program encompasses all the buried pipe systems at Salem. Of these systems, seven are in scope for license renewal. These include auxiliary feed water, compressed air, water, cathodic protection, non-radioactive drain, service water and circulating water.

CHAIRMAN STETKAR: Could you Jim, just a little more slowly.

MR. MELCHIONNA: Auxiliary feed water, air, service water, circulating water, water, cathodic protection and non-radioactive drain. The buried pipe program has methodology that has restrained all the buried pipe program segments according to the relative suspectability and consequence of failure. This is based on NACE guidance and EPRI guidance. Currently there are approximately 6,000 individually ranked

segments in the Salem buried pipe program database. Based upon the restraining, inspections are scheduled to investigate the condition of the piping. Any deficiencies identified during excavations inspections are entered into our corrective action program. The deficiencies identified to be adverse to quality, the causes determined and corrective actions are developed. In response to industry OE, the Nuclear Energy Institute established an industry initiative on buried piping. PSEG is currently participating in this initiative and we are head of schedule on implementing key elements and attributes of the initiative.

Next slide please. This table lists all five of the buried pipe materials, in scope license renewal. These include carbon steel grade cast iron, cast iron, stainless steel and pre-stressed concrete.

CHAIRMAN STETKAR: What carbon steel buried piping do you have in the aux feed water system?

MR. MELCHIONNA: Higher buried pipe section of the auxiliary feed water system is carbon steel.

CHAIRMAN STETKAR: But what pipe is that?

MR. MELCHIONNA: That's the piping that runs from the auxiliary feed water pumps to the auxiliary building.

MR. SOSSON: Basically the piping from the discharge of the pumps to the steam generators?

CHAIRMAN STETKAR: It is -- oh.

MR. MELCHIONNA: One of the units is buried -- two of the trains are buried in the outside contaminated area and two of the trains are within the building themselves.

CHAIRMAN STETKAR: Okay, thank you.

MR. MELCHIONNA: It shows the license renewal systems and with each which material is present. In three you can see how much is committed to perform at least one excavation and direct visual inspection on each material grouping during each ten-year interval beginning ten years prior to entering the period of extended operation. In the case of carbon steel at least four excavations and inspections will be performed each ten year period. This one is a comprehensive assessment of all in scope buried

pipes at Salem.

Next slide please. Included in our presentation today on buried piping, is a discussion on an operation experience that occurred in April 2010. During the Spring 2010 Unit 1 refueling outage, two buried auxiliary feed water pipes were planned for excavation and inspection. These lines were proactively identified for inspection based on their high risk ranking in the Salem buried pipe program. Upon excavation the two carbon steel auxiliary feed water lines were found with degradation and were missing coating. As part of the condition of the investigation, the entire links of the piping were excavated. Due to the lack of coating and apparently visual degradation on the piping, new thickness rings were taken to determine the extent of wall loss. Of all the wall thickness measurements demonstrated that the system had remained operable, the decision was made to replace the entire links of piping rather than repair and recoat them. As a result of the apparent cause investigation, it was determined that the coatings were inadvertently removed from the Unit 1 auxiliary feed water lines prior to

burial and during construction.

MR. BARTON: The implication of this is none of the pipe was coated. Is that correct?

MR. MELCHIONNA: That is correct.

MR. BARTON: Okay. Did you replace it with the same material or different material?

MR. MELCHIONNA: We replaced it with the exact same material with an upgraded coating.

MEMBER SHACK: That's not hard -- any coating would be much better.

(Laughter.)

CHAIRMAN STETKAR: Newspaper.

MR. MELCHIONNA: Also as part of the extended condition, the portion of auxiliary feed water piping buried in the region of the fuel transfer tube area was excavated and rerouted above ground with new piping. That's the area between the contaminate and the fuel handling.

As you will see on the next slide, we did find evidence of the coating on the piping in the fuel handling building wall penetration. Also as part of the extended condition investigation we excavated and inspected similar Unit 2 auxiliary feed water piping in the Unit 2 field transfer tube area, which also identified

the presence of coating.

Next slide please.

CHAIRMAN STETKAR: And this is, you are going to look at more of the Unit 2 piping next year? I'm sorry in a few months?

MR. MELCHIONNA: In the Spring 2011. On this slide, you will see on your left a photo of the pipe from the Unit 1 auxiliary feed water system that was removed from a wall penetration. The Piece that has the coding on it is the lower section which was in the wall and the piece above was the piece underneath, under the ground. The right side of construction, the lower one, 1970/1971 vintage and the upper photo, upper right is just an exploded view of the lower picture.

As you can see there is yellow coating still on the pipe, on the left side of the picture. However, like I said, it appears that the coating is torn but as indicated by the arrow, like it has been mechanically or physically removed from the pipe.

Following this event we did a review of Salem construction photos. We identified the photo on the right showing the presence of yellow

protective plastic wrap on the auxiliary feed water piping as well on control air and station air that run parallel next to them. You can see the wrap more clearly in the exploded view on the upper right. The plastic wrap was placed over the existing yellow pipe coating as a means to protect the coating from damage during other construction activities. Prior to burial only the outer protective wrap should have been removed such that only the pipe coating that had been left on the piping and contact with soil.

CHAIRMAN STETKAR: Jim, you almost force me to ask. Have you, what about the control air instrument air pipes in the same area? Have you examined those?

MR. MELCHIONNA: Yes, since we did that excavation we had all six lines totally exposed. The other pipes have the coating on.

CHAIRMAN STETKAR: They did?

MR. MELCHIONNA: They did have.

CHAIRMAN STETKAR: Because somebody actively decided that the aux feed water pipe coating needed to be removed apparently.

MR. MELCHIONNA: That's what we concluded. And that is my next statement.

However, because the pipe coating and the protective yellow, protective wrap are yellow, direction was given to remove the protective wrap. They took the coating off as well. And you can see that in the picture. It looks like, right at the wall, it looks like a yellow plastic wrap was torn off the pipe. Based on the fact that the Unit 2 auxiliary feed water piping and the fuel transfer tube area on the Unit 2 once again, had its yellow coating intact as well as properly installed coating in other excavations on site at Salem, which included this was a one time isolated incident where the coating was inadvertently removed during original construction.

Ultimately though the buried pipe program was successful because this piping was scheduled for excavation and inspection and the condition was found and repaired before the pipe became inoperable and before any leaks had occurred.

MR. BARTON: That doesn't say much for QC in those days.

MR. MELCHIONNA: We will be excavating and inspecting the Unit 2 auxiliary

feed water piping during the upcoming Spring 2011 refueling outage.

Next slide please. Salem has one item related to buried piping. The open item relates to the staff's need for additional information. How do we consider recent operating experience into our buried pipe program? We consider both site specific and recent industry operating for the development of our program and have provided the staff with more information. We provided information about our operating experience and the excavations we have performed. We provided details on our planned inspection locations. And we provided details on a quality of our back fill. Based on the stats of these, we believe the information we have provided will be useful in addressing the staff. However, we would expect to be receiving additional RAI in the near future requesting information associated with buried in scope steel piping. We plan to address this additional RAI in a timely matter in order to close out the open item.

Next slide please. In conclusion the buried pipe program will effectively manage the material condition and aging, the buried piping.

We will do so in a manner that will ensure continued safe operation. We have a very comprehensive and robust program that will continue to develop and approve based on site and industry operating experience, the NEI initiative, participation in our industry working groups and development of a new technology and inspection techniques as they become available.

CHAIRMAN STETKAR: Thank you Jim. Before we leave that, I was reading through the SER anyway. And there is a statement that said that most of the safety related carbon steel pipe at least in the service water system has been replaced with stainless. Has any of the underground?

MR. MELCHIONNA: No. The original piping in the underground is original.

CHAIRMAN STETKAR: That's concrete exterior. What is the configuration?

MR. MELCHIONNA: It is the piping from the intake structure to the sprayer. The only pieces that are carbon steel are stub pieces that penetrate through the wall.

CHAIRMAN STETKAR: Okay.

MR. MELCHIONNA: So there is about a

foot or foot and a half of carbon steel that is coated with the poxy coating on the outside. There has been transitions to a pre-stress concrete one of about a couple hundred or 900 feet and the same geometry is on the other side where it penetrates into the building.

CHAIRMAN STETKAR: That did you have, there has been some historical leakage of joints in the service water piping?

MR. MELCHIONNA: We did have one week on a bell and spigot joint. The second joint coming from the intake structure on a bell and spigot. We had a pre-existing flaw that subsequently that turned into a break in a line. It started out as leakage coming through the top of the pipe, came right to the surface. We knew about it immediately. We managed that leak for about a month and then we went in and did a repair.

CHAIRMAN STETKAR: One other thing that I kind of highlighted as I was going through. There is apparently a question about inspections of piping or it is just called building bolting. But the concept is, it says buried, the applicant also stated that buried

bolting in the service water system is designated as Class 3 and so forth. And the conclusion is that you can use a flow test to confirm that there is no significant leakage through bolted connections. Where are there bolted connections in your buried service water piping?

MR. MELCHIONNA: As I described before, that first joint. That is a bolted connection.

CHAIRMAN STETKAR: That first joint coming out of each building?

MR. MELCHIONNA: Correct. That is a B7 bolting all around, nuts and bolts, epoxy coated on the outside.

CHAIRMAN STETKAR: How can a flow test tell, I mean I understand that if you don't get any flow you don't have any bolts. But how can a flow test tell you anything about the condition of the bolts given it's a service water line and pretty high flow system I'm assuming.

MR. MELCHIONNA: Yes, reading from once again --

CHAIRMAN STETKAR: I'm actually reading from a section in the safety evaluation report and I don't have the full quote here. But

it was in response apparently to a question. If you want the reference, I can give you the SER section reference. It is 3.3.2.3.4. The title of that section is circulating water system. The quote that I extracted says "the applicant also stated that buried bolting in the service water system is designated as Class 3 and is inspected in accordance with ASME code section 11, IWD 2,500 and IWD 5,000, 1998 edition, year 2000 agenda which allows use of a flow test to confirm no significant leakage in lieu of visual inspections." It says you will perform opportunistic inspections of the bolts if not excavated.

MR. MELCHIONNA: It sounds like there are two questions there. One of those questions is do you inspect bolting with your buried pipe and we obviously are revising our procedures and commitments so that whenever we dig up a pipe we inspect the bolting associated with it.

CHAIRMAN STETKAR: Right.

MR. MELCHIONNA: It sounds like there is another question there.

CHAIRMAN STETKAR: The other question, it seems to be relying on a flow test

to confirm the integrity of those bolts. And its, its got to be a pretty special kind of flow test to do that. Of if you discover it during a flow test --

MR. BARTON: You know the bolts are gone.

CHAIRMAN STETKAR: You know the bolts are all gone.

MR. FAKHAR: We would love to have Kevin Muggleston to answer that question. Kevin?

CHAIRMAN STETKAR: My question is are you basically taking credit for the opportunistic inspection of those bolts and the statement regarding the flow test is perhaps irrelevant information.

MR. MUGGLESTON: Kevin Muggleston. I am on the license renewal project team. Yes, I think there are basically a couple of different questions going on. That issue was about specifically the bolts and what are we doing to examine buried bolts. And that answer is, I guess the relevance is that we don't normally have to go dig up Class 3 bolts just to look at them and that was the point of that statement. However they are looked at as Jim said, as part

of the buried pipe program opportunistically.

MR. MELCHIONNA: And we have dug up bolting on the service water system and found them to be in like new condition at the intake structure over those couple of years.

MR. MUGGLESTON: Yes, that reference that you read from --

CHAIRMAN STETKAR: I was going to ask the staff. I mean the staff accepted that response as an adequate inspection program but I wasn't clear whether that was because of the flow test or because of the opportunistic inspection. All the staff's conclusion was that the response was adequate and the program was okay. Thank you. That at least explains where the bolts are and clarifies that information.

MR. SOSSON: That you Jim. That completes our discussion of the buried pipe program and its associated open item. We will now discuss one topic of interest, the Salem containments and I will introduce Alan Johnson.

MR. JOHNSON: Good afternoon. My name is Alan Johnson and I am the design and engineering manager. I will be discussing the Salem containment and our ongoing enhancement for

Salem Section 3, I'm sorry Section 11 IWE program. I am going to focus on areas of the containment liner that are covered by insulation. The self containment is a reinforced concrete structure with a carbon steel liner plate. Our common feature of the Salem containment design is liner insulation cover the bottom 32 feet of the containment cylinder. This insulation limits accessibility to the containment liner for internal inspection.

MR. BARTON: What is that insulation? What is the material?

MR. JOHNSON: It is a mineral, it is with respect to the non-moisture absorbing or retaining, about an inch and a half thick covered with a vapor barrier.

MR. BARTON: Some place I read that containment you had was asbestos.

MR. JOHNSON: That material may have asbestos in it. And there is other areas of containment where we know we have had asbestos such as calcium silicate insulation.

MR. BARTON: In the aging management containments, list the materials of construction that containment include. Asbestos. Where is

asbestos located and why hasn't it been removed I guess is my question?

MR. JOHNSON: As we know asbestos is a good material. Unfortunately it is unhealthy. We follow our processes when we open it to maintain it and move it and take the right precautions to protect our employees.

MEMBER SIEBER: What function does the insulation perform?

MR. JOHNSON: The insulation is only on the bottom 32 feet. It is intended to prevent fast heat up of the steel since the design basis accidents, the steel will of course heat faster than the concrete. We are protecting the system from buckling.

MEMBER SIEBER: Yes, but that's a lot of other PWR containments are not insulated.

MR. JOHNSON: Absolutely.

MEMBER SIEBER: What is unique about yours that requires insulation.

MR. JOHNSON: As best I can tell it's a design choice. It was a design choice over our original designers and said let's give ourselves some margin against the buckling. We are a little different than other plants in that we

have a thicker liner at that point and we are also a thick highly reinforced containment that's highly restrained at the bottom so that the less growth of the concrete as less growth. And after many days when the temperatures, but initially the steel is growing much faster.

MEMBER SIEBER: If you have an accident you have to pressurize the containment.

MR. JOHNSON: Yes.

MEMBER SIEBER: I would think that would keep that up to the concrete.

MR. JOHNSON: It will stay against the concrete but the concrete in the upper areas of the cylinder will expand with pressure. The ones restrained by its anchorage into the base mat don't expand so there is higher rigidity.

MEMBER SIEBER: That is still going to happen. Because the upper part of containment is not insulated right?

MR. JOHNSON: That's correct. But has the advantage of expanding more freely with internal pressure.

MEMBER SIEBER: It is my question why would you need it and I would imagine mineral wool is not good for Generic Safety Issue 191.

MR. JOHNSON: Wool fiber insulation was a consideration and our resolution of Generic Letter 191. Our direct response to that in the Salem containment was going from a 400 square foot strainer to 5,000 square foot strainer. We looked at every source of debris. Our most important sources of debris were from reactor flume system breaks which were much higher pressure, picked up insulation from significantly larger areas.

MEMBER SIEBER: We've got about 9,000 square feet of fiber insulation. So that's a lot.

MR. JOHNSON: True. But we also, we need to look at what could be damaged by the initiating event and much less what will be damaged in the parameter area of our containment that is protected from the major breaks.

MEMBER SIEBER: Do you have an analysis that shows that?

MR. JOHNSON: We've aggressively looked at every debris type and accounted for all debris input. We have a fine analysis of our debris.

MEMBER SIEBER: Not of the debris.

Of the stresses of containment that would result in the preparation of failure or yielding. Do you have an analysis that says I shouldn't get rid of the insulation or is that just part of the design basis that is part of the history of the plant?

MR. JOHNSON: It is our original design basis installing it and it clearly gives us margin. So we've chosen to leave it in place.

Okay, we'll go back to the slides. Reinforced concrete containment. Carbon liner insulation is the green on the bottom 32 feet. On the bottom left you see detail lighting which is our area of interest I will talk about more. On the next slide we will see a three dimensional blowup of that. This represents containment liner. Green again is the insulation system which is insulation, stainless steel lagging. We show test channels, horizontal and vertical. These were a part of the original design prior to Appendix J. They are no longer used for real testing. You have moisture barrier is our primary barrier to prevent water from getting between the concrete floor and the cylinder.

CHAIRMAN STETKAR: Have you had

problems with the moisture barrier at, at least one of your units? Did you have any degradation to the liners as a result of it?

MR. JOHNSON: We haven't. We've corrosion on it and will show that on the next slide. But the direct, we have not had any damage to the liner or any known moisture intrusion because of degradation of the moisture barrier. In areas where we had liner corrosion, specifically probed the moisture barrier but we were always able to demonstrate good adhesion and no moisture passing the moisture barrier.

The last thing I would like to point out on this, is the area between the horizontal channel and the concrete floor is an area that was previously covered by the stainless steel lagging. One of our enhancements is part of our license renewal is trimming and lagging to the bottom of the channel so we can have clear access to the bottom three to four inches of the liner and the moisture barrier so we can inspect it easily.

CHAIRMAN STETKAR: Have you done that?

MR. JOHNSON: Yes. We have fully

trimmed the lining in Unit 1 and 2. If we go to the next slide. These are photos from Unit 1. The upper left photo shows the stainless steel lagging all the way to the concrete floor. The upper right slide shows the lighting removed. The surface corrosion, remnants of coating. Bottom center slide or bottom center photo shows our prep cleaning and replacement of moisture barriers to bring it into performance with our design?

MEMBER SIEBER: What are the pit depths were the corrosion occurred? If you can give me a range and a maximum.

MR. JOHNSON: We -- let's go to slide 32. The correct answer is 1732, in that range. This slide is a flat or a projection of the entire containment cylinder and plots if UT measurements in the bottom three inches. The vertical scale is thickness measured. Horizontal is the seismic. 440 readings around the full parameter. Choosing preferentially the areas that looked worse after cleaning. All areas were well above the analysis thickness of Unit 1. Five locations were below the specified nominal thickness of .75 inches. The condition of the

containment was erosion of surface. All locations were above nominal. Five locations were not. None exceeded ten percent, which was within IWE criteria. We have maintained significant and we have returned it to conditions that give us a good safe containment liner.

MEMBER SIEBER: This is carbon steel liner?

MR. JOHNSON: That's correct.

MEMBER SIEBER: And what's its nominal thickness?

MR. JOHNSON: Three-quarters of an inch. The measurements in an area to be called an upper region which was bent, it is curved in two directions and the manufacturer started with a thicker plate to assure he had met the specified thickness. It is notable that those measurements about nominal.

CHAIRMAN STETKAR: Alan, when you pulled out the old moisture barrier. You removed the old moisture barrier and then resealed the joint. Is that correct?

MR. JOHNSON: We only removed moisture barrier in areas where we had corrosion and needed to prep the liner because still the

elastic and adhesive in good shape.

CHAIRMAN STETKAR: In the areas where you moved it, could you look down in the gap and see where the corrosion extended down below the level of the moisture barrier?

MR. JOHNSON: We always moved moisture barrier to the point of no corrosion and then coat it. We left it in the right condition. We are very comfortable and proud of the condition we left it in and will do the same on Unit 2 when we do that in 2011.

CHAIRMAN STETKAR: You said Unit 2 is scheduled for 2011?

MR. JOHNSON: That's correct.

CHAIRMAN STETKAR: You have removed the lagging on Unit 2? Yes.

MR. JOHNSON: This is the same measures so plenty of locations were below nominal thickness and well above the analyzed thickness.

CHAIRMAN STETKAR: Any particular reason on Unit 2, it is sort of notable that it has about 190 degrees or something like that. You seem to have, that's where your indications are concentrated. Is there any particular reason

why you have more corrosion in that area than elsewhere?

MR. DAVISON: I'd like to have Phil O'Donnell tell you.

MR. JOHNSON: This is my discussion of service work.

CHAIRMAN STETKAR: Good. So early in our plant life we had service water inside the containment building. They were common.

MR. BARTON: Air cooler.

MR. JOHNSON: Yes, air cooler. They were served by cement lined carbon sealed piping. That was replaced by stainless steel which is very resistant to our service order. We also replaced our heat exchangers which were also leaking. We enhanced our methods for maintaining CFCUs so they wouldn't leak. We improved our condensate caption system. We became intolerant for leaks. We had weekly walk downs by operations department that recognized those. In the face of leaks we responded to them quickly. We've developed good procedures for investigative to the extent of chloride contamination, lenient and continuos swiping and checking until we finished. We believe we've done a fine job of

addressing the service order leaks that led us to this.

MEMBER SIEBER: So basically the corrosion was caused by river water?

MR. JOHNSON: Yes.

MEMBER SHACK: On slide 31, did you sort of start marching up the containment wall? It doesn't look like it.

MR. JOHNSON: I mentioned earlier that the bottom of that sheet metal lighting is the bottom of the horizontal channel. The vapor barrier that's with the insulation system comes down to the face of that channel and adhered to it. So there is not, we did investigate several locations as part of IWE expansion criteria, confirmed that panels above it were not corroded and we around multiple locations pulled the lagging out and used flashlights to make sure our assumption that the vapor barriers were in fact there.

MEMBER SIEBER: I think your slide 29 shows that.

MR. JOHNSON: Yes.

MEMBER SIEBER: So this was boxed in?

MR. JOHNSON: Yes. It is not just

lagging. There is a vapor barrier that has been effective in keeping vapor and the correct moisture away from the bulk of the liner.

MEMBER SIEBER: I take it the entire insulation system was boxed in the way this one shows it to be?

MR. JOHNSON: That's correct. Flashing at the top and the entire system is boxed in.

MEMBER SIEBER: And it is sealed at the top of the insulation. So the chance of it become airborne and ripped up during an accident is less than one might imagine.

MR. JOHNSON: It is not going to fall off with light water spray. It is going to take a direct jet impingement for this to become part of the debris.

MEMBER SIEBER: All right.

CHAIRMAN STETKAR: Back to, just so that I understand this drawing that's no longer up there. Keep going backwards, go to 29. There you go. From what Bill asked if I can understand what you did, you removed selectively some of those panels that you say are attached to the channel. Is that my understanding?

MR. JOHNSON: Correct.

CHAIRMAN STETKAR: Did you observe any significant corrosion in the area of the liner behind those panels above the channel?

MR. JOHNSON: No.

CHAIRMAN STETKAR: All of the corrosion was in the area between the channel and the top?

MR. JOHNSON: Yes.

CHAIRMAN STETKAR: Okay.

MR. JOHNSON: This vertical channel and horizontal channel and we saw rust of the horizontal channel that's where we expanded our inspection into the liner. We saw rust blushes coming through the paint. Generally good condition.

CHAIRMAN STETKAR: Nothing that looked like the other photograph.

MR. JOHNSON: No.

CHAIRMAN STETKAR: So that's an indication that whatever moisture was getting in there was in whatever that gap is. What's the -- is this the scale or this --

MR. JOHNSON: Yes, the channels themselves are about one and half by three inches

and the space between the bottom of the channel and the concrete about three inches.

CHAIRMAN STETKAR: About three inches?

MR. JOHNSON: Moisture barrier on Unit 2 is three-quarters of an inch.

MEMBER SIEBER: And all of this, you've inspected it, cleaned it up, repainted it and then refitted it the way it is shown on this drawing now?

CHAIRMAN STETKAR: That's correct. And in the picture, in the photo on the subsequent slide is -- it looks like the bottom center slide.

MEMBER SIEBER: It is no worse off after your repair than it was originally?

MR. JOHNSON: Insignificantly better.

MEMBER SIEBER: I think I prefer my characterization.

MR. JOHNSON: I call it better because it is easily accepted and inspectible.

MEMBER SIEBER: Yes, you can see it.

CHAIRMAN STETKAR: Alan, if you go to the Unit 2 slide that showed the, number 33. That area where you did show the increased,

directly below do you have any indications? Was the water not, did you pull off panels in that area and confirm that the water was not coming down between the panels and the liner, that it was coming on the exterior of the panels and cooling on the floor there?

MR. JOHNSON: As part of license renewal enhancement, we pulled four panels to demonstrate that we were in good shape behind the panels.

CHAIRMAN STETKAR: But those panels were randomly around.

MR. JOHNSON: That's true but we also pulled additional panels that were at our worst locations. The ones that IWE caused us to expand our inspection. And those areas were fine and they were under the CFC.

CHAIRMAN STETKAR: Okay.

MR. JOHNSON: And they were also prejudiciously understanding.

CHAIRMAN STETKAR: One of the questions as reading through the program, as part of your aging management program you have commitments to remove, if I understand it correctly, 12 panels in each ten-year cycle

basically.

MR. JOHNSON: We've summarized here, we've committed to inspect the liner behind 57 panels prior to the period of extended operation in 2012 to 2016. The 57 panels will be randomly selected to provide a 95 percent confidence with the liner, areas behind the liner panel.

CHAIRMAN STETKAR: One of the questions that I had is prior to kind of today's presentation was I understand 95 percent confidence and a random sampling of 57 out of whatever it is, 260 some odd panels. Have you considered at all an informed sampling program to in fact give you a higher confidence than just a random sampling program? In other words looking at areas where you might suspect corrosion in an areas under those --

MR. JOHNSON: I am going to turn the question Jim Giles, or ISI program manager so he can give us his perspective.

MR. GILES: Hello. Tim Ginles. I am the ISI program manager at Salem Nuclear. The expansion that you are talking about in accordance to the IWE program, when we find areas that have evidence of degradation or even

staining on the floor require through that program to investigate and evaluate those inaccessible areas. So to answer your question, yes in accordance with the code we will do that.

CHAIRMAN STETKAR: That wasn't quite my question. My question was, the second colored bullet on this slide and indeed the third colored bullet talks about randomly selecting a number of locations where you will then inspect. As you mentioned if you indeed do find corrosion in those locations, you will have to increase the sample size. My question was have you thought about an informed sampling program. In other words, if you are making commitment to take 57 panels --

MEMBER SHACK: That's risk ranked.

CHAIRMAN STETKAR: Risk rank the panels, thank you. I didn't want to use that term but we do it. And other people had taken that approach to working for locations.

MR. JOHNSON: In our IWE program as a risk informed inspection program and one of the inputs to Tim's programs is chloride contamination. So he is using that in his selection of inspection area.

CHAIRMAN STETKAR: Okay. So you are saying there is some input from that this may not necessarily be a purely random sampling.

MEMBER SHACK: It better be a purely random sample if you are going to make a statistic. But I'm assume this is a purely random sample from a population where you rarely have no reason to expect them to be different. When there is a reason, that's not going to be part of this inspection. That's going to be part of --

CHAIRMAN STETKAR: This is the only inspection they are committing to.

MEMBER SHACK: Yes.

CHAIRMAN STETKAR: This is the only inspection they are doing.

MEMBER SHACK: I'm sure assuming they have identified the places --

MR. JOHNSON: in our current licensing basis we have, we are using the risk informed requirements. We believe we have looked at the right areas to help us understand and its in good shape.

CHAIRMAN STETKAR: Okay.

MR. JOHNSON: Now we've looked not

only at areas at the bottom. We've looked at areas where we saw staining on the cover where we knew we had other moisture areas. So we have done the right actions from a --

CHAIRMAN STETKAR: From a current licensing basis.

MR. JOHNSON: What evidence drives you to it and we believe we are in good condition with our liner connection for the 57 panels.

CHAIRMAN STETKAR: As long as you have no reason to believe that there is corrosion anywhere else.

MR. JOHNSON: The last part of those inspections during our period extended operation we will be doing inspections behind 12 panels during each ten year ISI.

MEMBER SHACK: Did you have any idea of using the Paul to do this?

MR. JOHNSON: No, that's still in the, its still in and looked at as a potential screening method for where to look or what to look. We are still evaluating its value to us and how we all interpret it.

In summary the Salem containments are in very good condition. Our inaccessible areas,

the moisture barrier and adjacent liner have been accepted. The conditional liner panels behind insulation panels will be confirmed before PEO. The integrity of the Salem containments which are contained will continue in safe operation. Now I will turn the presentation back to Paul Davidson for closing comments.

MR. DAVISON: Thanks, Alan. Mr. Chairman and subcommittee members, thank you for your interaction during today's presentation. As we did mention we are confident that our license renewal application reflects an effective aging management program that will ensure continued safe operation of Salem through the period of extended operating, extending operation and pending any additional questions that will conclude our presentation for today.

MR. BARTON: I've got a couple of questions here. In your plant level scoping you talk about a gas turbine that's not in scope. I take it is not safe to ready the system but does it have the capability in a station blackout to provide power?

MR. DAVISON: John Hilditch will respond to that question.

MR. HILDITCH: John Hilditch of PSEG Nuclear. And the gas turbine is non-safety related. It's a peaking unit for the PJM.

MR. BARTON: Okay.

MR. HILDITCH: So that's the purpose. So its not accounted for in our SPO regulation. We are a four-hour ACM dependent plan.

MR. BARTON: Thank you. Service order system. I will read you a description of it. You talk about, there is only exhaust fans in each compartment. My question is how is the structure heated in the winter.

MR. DAVISON: I'll -- Phil O'Donnell will respond to that.

MR. O'DONNELL: Phil O'Donnell, license renewal project team. I was licensed at Salem for more than 20 years. The exhaust fans are heated by the, there's area heaters in the particular pump compartments that provides the heating as well as the waste pump heat.

MR. DAVISON: John you got any more?

CHAIRMAN STETKAR: You're on a roll. I'm going to let you go.

MR. BARTON: Okay, switch yard. The question I have here is maintenance of the switch

yard I assume is not performed by plant personnel. Who does perform it and what is the, if it is not plant personnel, what is the arrangement and how is it controlled by the plant?

MR. SOSSON: PSEG Nuclear does maintenance on the 13 KV and below. The PSE&G are transmission and distribution operator does all the maintenance on the 500 KV system. And we have interface agreements with them to perform those.

MR. BARTON: That work is controlled through the control room or something like that?

MR. SOSSON: Yes, we maintain very tight access controls to PSE&G transmission operator when they come into our yard.

MEMBER SIEBER: And you're transmission operator is PJM?

MR. SOSSON: Well yes. The regional system operator is PJM. We have PSE&G is the company that operates the 500 KV system in our area.

MEMBER SIEBER: Yes, but they take orders from PJM.

MR. SOSSON: Right.

MR. BARTON: I noticed Union charging bumps, cases of carbon steel or stainless cladding and were restored and returned in 2004. My question is have they been inspected for any cladding crimes?

MR. DAVISON: Ill have Phil O'Donnell answer that.

MR. O'DONNELL: The particular charging pumps you are talking about are on Unit 2 only. They are carbon steel with stainless steel cladding. Those are the safety charging pumps and they have always been in service. What we are specifically talking at that point is the restoration of the positive displacement pumps. There is one on each unit. So basically that was put in normal service for normal operation to take the safety charging pumps out of normal service.

MR. BARTON: Thank you. In small bore piping inspection. I couldn't find if they are supplement in the appendix in the application. Have you committed to do any examinations for small bore piping? Later on I did find in the SER, they talk about performing four volumetric examinations, two per unit. To

me that doesn't appear to be very representative of small bore piping examinations. Can you kind of explain what you are doing.

MR. DAVISON: I'd like to have Albert Piha answer that.

MR. PIHA: Okay, right now we did, I'm sorry. Albert Piha, license renewal project team. We did have an RAI in July. We submitted that identifies the four UTs you are speaking about to per unit looking at an IGSC location. So based on the plant at Salem having no OE on class one socket welds, we decided that four UTs out of her suspectible locations of 36 on Unit 1 and 34 on Unit 2 would be appropriate.

CHAIRMAN STETKAR: Did you say the report? I don't have a copy of that.

MR. BARTON: They meet the requirements.

CHAIRMAN STETKAR: I need a copy.

MR. BARTON: We need to get you one of those.

MR. PIHA: Yes Rev 2 of the goals says 30 percent and we are at five to six percent.

MR. BARTON: Also your submerged cable manhole inspections what I got out of

reading the documentation is that you did commit to doing inspections every two years. But I didn't see any commitment regarding the severe weather, hurricanes, floods or whatever that you go look at manholes. What are you really doing there?

MR. DAVISON: Jim Stead from the station can answer that.

MR. STEAD: My name is James Stead. I am PSEG Nuclear. I am the cable program manager. And we revised our commitment to inspect our manholes annually and to test our cables every six years. We also committed to direct assessment of the cable condition as a result of rain or other events or occurrences.

CHAIRMAN STETKAR: Jim, before you -- let me interrupt. And you probably have a couple more. But let me interrupt you because as long as Jim is up there. When I was reading here this again was in response to an RAI. I don't have the RAI number but I will hit you with it anyway. It says the applicant stated for buried conduit, the switch is the only structure that contains sections of inaccessible buried galvanized steel conduit within the scope of license renewal

extending from underground duct banks to manhole wall penetrations. Now it further stated periodic inspections of the penetrations in the conduit ends will detect the presence of any water leakage. Does conduits all positively slope to the manholes? In other words are there low points in those conduits that can collect water and retain water for substantial periods until it starts to eventually leak out the end?

MR. STEAD: All conduits are designed to drain either back into manholes or other structures. There is no mid low point so that water would settle in the conduit itself.

CHAIRMAN STETKAR: Okay, thank you.

MR. BARTON: Do you have any plans to do any more power upgrade?

MR. DAVISON: We have no current plans for upgrades.

MR. BARTON: Okay.

CHAIRMAN STETKAR: John do you have any more?

MR. BARTON: I've got one more. Have you performed inspections election tanks for evidence of corrosion? I have not seen any place that documents that.

MR. DAVISON: I'll have Sam Spear talk to that.

MR. SPEAR: Sam Spear, license and renewal team. The station does perform routine inspections of the tanks. We will perform a one-time inspection of the oil water tank to ascertain the condition the material of the tank.

MR. BARTON: And did you find any corrosion in the inspection?

MR. SPEAR: Not on the exterior, no.

MR. BARTON: Okay. That's it.

CHAIRMAN STETKAR: I've got a couple more. You had problems with your in core flux thimbles too apparently early in life and it is my understanding you upgraded them and then had problems with the upgrades and then replaced the upgrades. Is that correct?

MR. DAVISON: Phil O'Donnell please.

MR. O'DONNELL: Phil O'Donnell, license renewal project team. Initially we replaced all of the in core flux thimbles from the single wall to a double wall design. The replacement subsequent to that from the late 1980s to the early 1990s we did an evaluation. Subsequent to that we replaced some of the double

walls due to the thermal couples going bad within the inner wall and also the actual insertion of the flux symbols themselves. We are having problems inserting them into that. So that's why those were replaced subsequent to that with new ones.

CHAIRMAN STETKAR: Okay. And that was, you replaced a bunch of them in, I don't remember 1993/1994 kind of time frame. Is that--

MR. O'DONNELL: We did an analysis on the ones we have replaced to that point in time.

CHAIRMAN STETKAR: Okay. So that's why you replaced them. One of the questions that I had, is there is quite a bit of discussion in the SER about estimating the rate of wall thinning in those flux tubes. Can you explain sort of briefly the process that you've selected to develop estimates of the wall thinning rates?

MR. DAVISON: Sam Spear?

MR. SPEAR: I'm Sam Spear, license and renewal team. The process we are going to use would be comparing the drawing thicknesses and then using UT measurements to determine what the as found the thicknesses were to determine the wear rates. And we'll do that from outage to

outage to determine prediction of wear rates.

CHAIRMAN STETKAR: I guess the problem is that they are quite a few questions about how do you know how thick the tubes are today and at what rate they've been thinning because you've not been doing any eddy current testing since 1993? So we have 17 years of accumulated experience that with essentially no indications of what the tube thicknesses are. You've made commitments to do eddy current testing going forward. But the question is in terms of estimating wear rates such that I can make projections of expected life of these tubes. It doesn't seem that we have any relevant historical experience, except that there was a discussion that I had difficulty following about how you were going to try to make estimates of those historical wall thinning rates over the last 17 years or however many years it will be.

MR. SPEAR: There is a population within me. The fuel has relatively new tubes and we could take, compare them to the ones that have been in service for a longer period of time.

CHAIRMAN STETKAR: I'm still not quite sure what that means. We have a lot of

time here. We have no lives. This is important to you guys.

MR. SPEAR: We have tubes that have been in there since 1993 and replaced with the double wall design. And also we have tubes that we replaced subsequent to 1993 as of a couple of years ago. So when we do our eddy current testing we'll compare the thicknesses of the older one with older lives to the ones that have recent lives.

CHAIRMAN STETKAR: Okay. That is sort of what I understood. When, do you have some indication -- I know that you replaced a number of those tubes in 1993. That is relative, if I have my dates here correct. My concern is are you taking measurements over only a couple of years of experience with the new tubes in trying to project 17 years worth of wear or do you have a reasonable population over those intervening 17 years of tubes in the fuel pool such that you can get some estimates of wear rates over that 17 year period or at least some confidence of projections.

MR. DAVISON: I'll ask Phill O'Donnell to respond to that.

MR. O'DONNELL: Phil O'Donnell, license renewal project team. Since we've replaced approximately 25 percent of these thermal couples since 1993 and we will look at them in quadrants. We have a specification requirement for operability in various quadrants. We will look across those particular, we'll have a high enough sample to determine a wear rate based on time and service. We will go after the particular ones so that we make sure we have adequate sample.

CHAIRMAN STETKAR: What I was asking was in particular, it says in August of 1993 an evaluation was performed of eleven tubes that had been removed from Salem Unit 1. Those tubes apparently, that was about three years after you installed the tubes. So that's not a very long time. Now eleven out of, I believe, what's the total number of tubes per unit, 56?

MR. O'DONNELL: 58.

CHAIRMAN STETKAR: 58, okay. Eleven out of 58 is pretty doggone close to almost 20 percent. If you've only replaced something on the order of 25 percent it says between 1993 and today, you've not replaced a very large number of

additional tubes, unless I'm missing something.

MR. O'DONNELL: 25 percent of the tubes since that time were replaced.

CHAIRMAN STETKAR: Since that time.

MR. O'DONNELL: Again, due to failures of the thermal couples or inability to insert the probes themself.

CHAIRMAN STETKAR: But not including those eleven tubes?

MR. O'DONNELL: Correct.

CHAIRMAN STETKAR: Okay. Okay.

MEMBER SIEBER: The reason for this was --

MR. O'DONNELL: It's not for leaks.

CHAIRMAN STETKAR: It's not for leaks.

I'm just trying to figure out over the 17 years, kind of make projections just looking at a large population over a short period of time. I can draw those curves but I don't have a lot of confidence in them. I think that's it.

MR. BARTON: While you are looking, I have another one. I thought I read that you --

CHAIRMAN STETKAR: Oh, let me John. This one just quick.

MR. BARTON: Okay.

CHAIRMAN STETKAR: It has to do though in different places I get different impressions of -- you made a commitment to 100 percent eddy current testing. Will that be done before entry into the period of extended operation or subsequent?

MR. O'DONNELL: The intent is to complete it into the period of extended operation.

CHAIRMAN STETKAR: Okay. I got it. Thank you.

MEMBER SIEBER: This is, the eddy current testing they are doing is the standard type not the multiple frequency and all that, right?

MR. O'DONNELL: Not determined yet.

CHAIRMAN STETKAR: I'm good, thank you.

MR. BARTON: I thought I read it was a ground water leak at Unit 1. Is that right?

MR. ROBERTS: That historically occurred, yes.

MR. BARTON: As a result of having that leak, have you considered looking at the

foundations of other buildings to see if there is any degradation of concrete?

MR. ROBERTS: We have assessed the condition of the auxiliary building. The ground water and to be more precise probably to your question in the area where it is adjacent to the fuel handling building. It is non-aggressive environment. The non-structural assessment to the building we have found no evidence of concrete degradation.

MR. BARTON: Okay.

CHAIRMAN STETKAR: Tom, I didn't probably read as much as John did. Is that location in the auxiliary building the only place that you've seen ground water intrusion or have you seen it in other locations in other buildings?

MR. ROBERTS: Let me answer that in two parts if I may. There is a natural, site hydrology towards the building. So we have seen evidence of ground water in filtration. However, in the area that precipitated the original investigation and root cause for this fuel pool, during construction of the auxiliary building, there was actually cold joint that actually had

to be repaired and the entire section of that wall was removed and restored. That was the preferential path into the auxiliary building that led to the event.

CHAIRMAN STETKAR: Okay. Okay. Any questions from any other members?

MEMBER SHACK: Just a curiosity one. You said we have lots of time.

CHAIRMAN STETKAR: You have a life?

MEMBER SHACK: You found a PWSCC crack in one of the nozzles, the RPB14 that you had subsequently mentioned. I was curious did the signal change when you looked at for and after the MSIP.

MR. ROBERTS: Let me respond to that and be precise. We don't have evidence that we had PWCSS. We did not do an above sample. The information suggested it most likely was PWSCC. And to answer the question could that be mechanical stress improvement? Yes, in the post MSIP UT examination the reflection response was dramatically reduced, yes.

CHAIRMAN STETKAR: Any more? Good. Very good presentation. Thank you very much. I think we had useful discussion.

MR. BARTON: Is anybody back at the plant running it?

CHAIRMAN STETKAR: And again, thank you very much. It is an excellent presentation. At the close of the meeting before we close, we will have a short discussion about what information we should probably come prepared at the full committee meeting. At the moment, thank you very much. We will recess until 20 minutes to four. 17 minutes if you are keeping.

(Whereupon the foregoing matter went off the record at 3:22 p.m. and went back on the record at 3:41 p.m.)

CHAIRMAN STETKAR: Okay, we're back in session. I guess it is time to hear from the staff. Melanie, I don't know if you want to say something.

MS. GALLOWAY: Yes, let me introduce the staff. We have had quite a quadri of folks involved in the Salem license renewals, which is typical of any renewal. We have a few folks here representing technical staff to talk about some of the key issues that we believe will be of interest. First, on the far right here is Bill Holston. He is a senior mechanical engineer,

responsible for a lot of the buried piping work. Next to him is Sam Cuadrado. He is one of the project managers that has assisted Bennett in the Salem license renewal effort. Abdul Sheikh is next to him. He is one of our senior structural engineers. Mike Modes has already been introduced. He is the Region I inspector responsible for license renewal activities. Bennett Brady is our senior project manager who has been sheparding the Salem license renewal activities for the staff. And next to her is Allen Hiser, our senior level staff focusing on materials and mechanical issues. Bennett.

MS. BRADY: Thank you. As Melanie told you I'm Bennett Brady. I am the project manager for the Salem license renewal review application. I am very pleased to be here and to tell you about review of the application and our SER which documents our review. I think Melanie mentioned Sam Cuadrado is here. He has assisted me in this project.

Also in the audience are many of the staff that participated in our technical view and audits and inspections and they too will be here to answer your questions.

Next slide. On this slide we have an overview of our presentation today. As you will note it follows pretty much the structure of our SER. I will speak very brief about the Salem license review. Much of this has already been covered by the applicant and I will try not to duplicate what they have said. I will try to focus my presentation more on our review and our findings. But please ask any questions at any point.

Section 2 will cover th review of the scoping and screening process. Then we will have presentation from Mike Modes here from the license renewal inspection. Then we will move back to Section 3, aging management programs and aging management review where we have to discuss three of our four open items and two new addition REIs that were not covered in the SER. Then the final Section 4, the time limited aging analysis where we have one open item.

Next slide. This is an overview of the license renewal application. I think the applicant has covered all of this. We received the application on August 18, 2009. Our acceptance of the application and review is

proceeding on schedule.

Next slide. This slide shows the periods when we conducted our major audits and the region wide inspection of Region I inspection as you covered June through August. The time periods for these inspections and audits is longer than usual because they covered both the Hope Creek and Salem. In addition to these audits and inspections we had many audits in the areas to review of the analyses.

Next slide please. In preparing the safety evaluation report in addition to the audits and inspections that I've talked about, our staff did a detailed review of the application. We asked more than 120 REIs. We had many conference calls. The responses from the applicant were very thorough and complete I think. We did not have many follow up REIs. We did have a follow REI but it is one of the more sensitive areas that we will be discussing. We issued our SER to the applicant on December 4, 2010. It contains four open times, two of which you have already discussed extensively on buried piping and the leakage from the fuel pool.

Next slide. The third open item

relates to the potential for primary water stress corrosion cracking on the primary side of steam generator tube-to-tube sheet welds. And the fourth item is on metal fatigue. We have two questions here. The first concerns the software that they used for analyzing metal fatigue. And the second question relates to the locations for the environmentally assisted fatigue analyses. As Melanie mentioned to you before we began this presentation, the staff and the division of license renewal has recently done a review of all of our current policy positions and whether these are being applied completely to all the applicants. And as a result of that REI, we will be sending out a number of REIs to the current applicants and two of these will be going to Salem, which I will speak about.

Next slide. The section two of the SER concerns the structures and components of the subject to aging management review. Section 2.1 looks at the scoping and screening methodology and then Section 2.2 goes into the plant level scoping resolves that is the system and structures that are scoped into license renewal And then the Section 2.3 and .4 and .5 goes into

the specific systems and components that are in the license renewal scope. We did not have a lot of REIs on this. The main ones that we had were concern drawings, anchor points and the cathodic protection program. I will now turn the presentation over Michael Modes, Region I lead inspector who will discuss the license renewal inspection values.

MR. MODES: Michael Modes, senior reactor engineer in Region I and team lead for the Salem Home Creek license renewal inspection. As it has been pointed out it was a three week inspection, an attempt to cover most of the common aging management programs for Hope Creek and then to select a representative unique sample set, unique to each facility. What we didn't look at were the programs that are normally covered by the ROP, such as ISI and etc. Those are reviewed and no point taking up for separate for an AMP review.

I also personally took a look at the Boral Program to determine the applicant's response, how they responded and why they responded to an interim staff guidance on the subject. In general, how do they handle interim

staff guidance. And we also selected a single system, feed and condensate to try to get some appreciation of how the AMPs would fit instead of looking at an AMP and then a system and flip it the other way around.

Next slide. These are the regional inspection walk downs that were performed during the three weeks. Those first five are mine. This time I tried to identify some very, very specific locations in the plan in order to test the applicant's understanding of their own plant layout and configuration. In order to get to some areas it normally wouldn't be part of a normal walk down. So go show me this one particular place in this particular room and as a consequence you get to see a lot of the plant. The remainder of those walk downs were done by Glenn Meyer. He is becoming a non-safety effect safety expert in the region as well as in the agency because he does almost all of those. And the plant condition was good. That's all I have. Thank you.

MS. BRADY: Thank you Michael. Next slide. Moving on to our aging management review. This slide just shows the structure of our SER.

3.0 is a major section that did a detail review of each of the aging management programs of the application. And then Section 3.1 through 3.6 cover over 5,000 line items that our staff evaluation. Each of these line items say what it reviewed, its intended function, material, environment, the aging effect and the program that the applicant had selected to manage the aging effect. We examined these to determine if they aligned with GALL. If they did not then we did a more in-depth view to determine the acceptability.

Next slide. This slide is a breakdown of the 48 management programs of the applicant. I would like to go through one of the applicant's slides already show this. Just mention the results of our review. There were several of what we call generic license renewal issues that were reviewed and resolved. I won't be discussing them because they were resolved. Like the small bore piping, the low voltage cables and the steam generator tube divider plates.

The next slide concerns our first open item, the buried piping inspections. We've already had considerable discussion of this but I

would like to present the staff's view on this. During that discussion we discussed extensively the three instances of which they had reported leaks. In 2004 there was the fuel oil steel piping leak. This was due to missed wrapping. At the end one our auxiliary thick water line, as they told you the coating had been removed and this resulted in a wall thickness being below nominal thickness. At Unit 2 there was a small leak in the control air line. This was due to individuals stepping on the coating. The industry then comprised these plant specific events have brought the staff concern. We sent a number of REIs, REI responses with applicant. In doing these REI and our responses we've resolved a number of issues, like the coating, the backfill quality but we have not reached resolution. The staff is still concerned that applicant doesn't have any cathodic protection on any of these in system pipes. If given this lack of cathodic protection, the current sample size that the applicant is comprising may not provide a reasonable basis for assurance if the piping will meet or exceed design minimal values to the period of extended operation. We are now in the

process of sending another REI to the applicant because it is not apparent that the applicant has informed their inspections and they've used localized data such as the soil pH, the composition for soil, the water table, chemical runoff probability and the potential for straight currents. So as I mentioned we are sending a follow up to the applicant to ask that the staff is prepared on the REI addressing the sample size basis. Is this the right number? Can they defend the number they've selected? Have they used the localized soil conditions and informed in the inspection? And have they looked at projections of the pipe wall thickness?

MR. BARTON: What's their reason for not wanting to put in for cathodic protection?

MS. BRADY: I think the applicant will have to address that.

MR. MELCHIONNA: Is your specific question why do we not want the put in cathodic protection? Is that the question.

MR. BARTON: Yes, why don't you think you need it?

MR. MELCHIONNA: Well the plant was initially designed with out cathodic protection

on the buried pipe systems. There is some cathodic protection on other structures in the system. The plant was designed with specific materials selected. The coatings were also selected based on that fact. So we do have a study from it for early 2011 to go ahead and look at and evaluate the need for cathodic protection. Everything that we have seen to date in the ground that we have done either focused inspections on or opportunistic inspections has indicated no piping degradation. In certain cases some piping that we dug that had a fuel line for instance you can still see the original etchings on the pipe, the SA_105 stamping in the pipe itself. So, we need to take a hard look at do we really need cathodic protection at this point. And we had done soil sampling. We had done resistivity measurements. Across the board where we have taken that soil data, the resistivity measurements are on the order of the average of 3,300 ohm centimeters, which if you are familiar with that, that is a very non-corrosive condition. All of our backfill is in the vicinity of piping is chrome or low graded sand. Chlorides and sulphate measurements in the

soils are almost non-detectable when you look at the data. So as part of the cathodic protection study, we'll take all that into account and make a decision and evaluate what actions do we need to take. That's the story in a nutshell.

MR. BARTON: I'm surprised your chlorides were almost non-detectable because you are right on the Delaware River which is kind of salty.

CHAIRMAN STETKAR: For the record before you answer that, please identify yourself just so we get you on the record.

MR. MELCHIONNA: I'm sorry. Jim Melchionna of PSEG Nuclear. Could you just repeat your question John?

MR. BARTON: I thought the chloride levels in the soil were elevated but maybe I don't remember the numbers.

CHAIRMAN STETKAR: The groundwater shows high chlorides. What is the average groundwater level relative to the depth of typical buried piping systems at the site.

MR. MELCHIONNA: The groundwater, it does fluctuate. But the specifics, we have a program in place now with the buried pipe program

that the soil samples that we take, we take them specifically every time we dig, the buried pipe program manager goes out and directs exactly where to take the sample which is immediately adjacent to the pipe. So the majority of our pipe is in an engineered fill or sand filled chrome limestone and those samples very clearly indicate less than detectable limits of chlorides, sulphates. The resistivity values are very high in all those areas. It is surprising.

CHAIRMAN STETKAR: It is surprising.

MR. MELCHIONNA: I have to take it with me so I can share that with you.

CHAIRMAN STETKAR: Any idea why the groundwater is selectively avoiding your pipe?

MR. MELCHIONNA: I can't answer that. I have pure factual data that shows those constituents.

CHAIRMAN STETKAR: Bennett, a couple of questions somewhat rhetorical but just to get them on the record. In the Reg 2 of the GALL report there is guidance regarding sample sizes and programs for sites that do not have cathodic protection. Is that correct?

MS. BRADY: Not exactly. It does not, Sam can bring up the slide from the Word Perfect file. It does not specifically address plans that don't have cathodic protection. Can people read that? I'm not sure that they can. You see right up there at the top of the slide, there are three areas.

CHAIRMAN STETKAR: We are getting close to be able to read it.

MS. BRADY: This just to say they don't have any cathodic protection. The coatings we feel acceptable. The backfill is acceptable. Then this is the inspections that you would expect for a plant that has cathodic protection. Am I right on that Bill?

MR. HOLSTON: Yes. What GALL AMP41 is bases the inspection tables on a plant that is committing to and ensured in the period of extended operation that the cathodic protection system is installed and its operating effectively. So when you look at those tables and you would look for instance at the steel line for non-cathodically protected, but good backfill and good coatings, you would see that you would inspect four times or four inspection locations.

But given that the applicant is not proposing to install cathodic protection, they would be taking an exception in the GALL AMP41 venue to the not having cathodic protection. And then would have to individually justify their inspection and it had to be an appropriate inspection size to provide reasonable assurance that you were going to meet your design minimum wall thickness throughout the period extended operation. We don't believe, as a staff, that number 4 will accomplish that without having cathodic protection over the period of extended operation.

CHAIRMAN STETKAR: Okay.

CHAIRMAN STETKAR: Bill, could you give the record your name.

MR. HOLSTON: I'm sorry. It is Bill Holston, NRC staff.

CHAIRMAN STETKAR: Thank you. I did have since I challenged the applicant regarding the underground bolts on the service water system, I did want to follow that up a little bit and get some feedback since we are talking about buried piping. I'm quoting from a section of the SER that I've lost here. So bare with me. It is Section 3.3.2.3.4. 3.3.2.3.4. This is kind of a

follow up about using flow test to identify the condition of bolts in the service water system. And this section of the SER says "the staff notes that ASME code section 11, subsection IWA5244 buried components indicates that for buried components where VT2 visual inspection can't be performed, the examination requirement is satisfied by conducting a pressure lost test or a flow test. The applicant finds that or the staff finds that the applicant response to RAI 3.3.2.3.4-1 and its proposal to manage aging for bolt being exposed soil using the bolting integrity, etc. etc. acceptable." This seems to say you are accepting that service water system flow test to identify the integrity of bolts on flanges that are buried. Could you explain how that's done?

MS. BRADY: Bill Holston, can you answer that?

MR. HOLSTON: Yes. When you look at the bolting integrity program, the bolting integrity program for above ground piping is t do a visual walk down and look for signs of leakage. Obviously that's not an opportunity you can take with buried piping. So we looked at it from a two

pronged approach. There will be times when the applicant digs up the buried piping and they add it to their program that they will ensure that the bolting is inspected when that is done. Now given that they aren't going to dig up every single location that has installed bolting, we looked at the Section 11 requirements and acknowledge that those are an industry consensus standard way of demonstrating that you have integrity in the piping system. And they will have to have accurate flow instrumentation. They will have to compare that to design flows. But that's all possible and plants have been doing that for quite a while for buried pipe.

MR. BARTON: Okay, thank you. If bolts were really bad --

CHAIRMAN STETKAR: Oh you would know it if the bolts were really bad.

MR. BARTON: Okay, thank you.

CHAIRMAN STETKAR: Continue.

MS. BRADY: Moving on to the next open item. The spend fuel leakage. Before we go into this, there was a lot of discussion during the last presentation about the radiological impact. My presentation today mainly regards

controlling the leakage as opposed to the impact of the, radiological impact. The staff, we did not look at this as part of our safety study. But we did look at the impact on human health resulting from radiological release as part of our environmental study and the safe environmental impact study. I can say that what we found is documented to the environment but it was small. But we also have Steve Klementowicz here who will speak for the staff on the impact.

MR. KLEMENTOWICZ: Steve Klementowicz, a senior health physicist. I did the environmental review. Could you elaborate a little more what you are looking for. As Bennett summarized there was, the impact was determined to be small from these leaks into the environment. And there were essentially no impacts in the offsite environment. It was all contained onsite. So maybe I can address your concerns.

MEMBER SIEBER: Well first I would add as far as license renewal is concerned, I think the staff did the right thing, which is to identify whether this condition degrades structure systems and components important to

long term life of the plant. On the other hand and I don't know every detail so this is a presumption on my part as opposed to a declaration. It seems to me that the licensee is in violation of their discharge permits, which is a state permit which says you have to be able to control the discharge. You have to know what the discharge is before you release it. But then you have a continuous release that is not controllable according to the long term with the plant that they have. I don't know if they have a discharge permit for them or not. I don't think you could legitimately fill one out. And 20,000 picocuries is the water limit.

MR. KLEMENTOWICZ: That's correct.

MEMBER SIEBER: As related to the river I didn't see any in the river either to determine that but the possibility exists that there may be an ongoing violation occurring now, not necessarily related to license removal. Maybe you could comment on that.

MR. KLEMENTOWICZ: Yes I can. Again my name is Steve Klementowicz, senior health physicist with the NRC. The NRC has been following this event since September 18, 2002. I

was involved with Region I inspectors who went up to the site to talk to the licensee when they were first identified. So we have been well aware of this situation since 2002 and its been evolving ever since. To address your concern that there may be a violation of their release permits. We have to look at it from two perspectives. As far as the effluent discharge into the environment, the ashes releases liquid, releases into the river. They are in full compliance with NRC's regulations. And the dose impact was well below the ALARA, as low as reasonably achievable criteria. The data for all three units for 2009 showed a level of approximately a fraction of a milirem via the liquid pathway. And I reviewed five years worth of data going back into 2004 and the numbers were similar. A fraction of a milirem for the liquid pathway all well within NRC ALARA design objectives. So there is no issue there. It is also a subject of the reactor oversight process that looks at this release affluence on a periodic basis. So there are no issues there. The other side of it, about an ongoing release into the environment, that, we have looked at

that several times now. There have been lessons task force reports. And the NRC's criteria, the regulations are dose based. So if this material were to get into the environment and impact a member of the public, that's what we would evaluate. The leak that occurred from the spent fuel pool was contained on site. In 2004 the licensee worked with the State of New Jersey to undertake a remediation program. And so since they've been pumping the water out of the site, from the groundwater, processing it through their plant rad waste systems and releasing it into the river in accordance with NRC regulations.

MEMBER SIEBER: A small fraction?

MR. KLEMENTOWICZ: Yes, a small fraction.

MEMBER SIEBER: What they were able to collect?

MR. KLEMENTOWICZ: Right.

MEMBER SIEBER: I see it was in the ground.

MR. KLEMENTOWICZ: Well what's in the ground they are in the process of remediating and they have an approved program from New Jersey. So they are working very closely with New Jersey

on that remediation. They also have a groundwater protection program that is to look for leaks of buried piping and systems and components around the site. That's the Nuclear Energy Institute voluntarily initiative that was started in 2006. So that's another program. And then we have our radiological environmental monitoring program, which looks offsite to see any radiological impacts. But as far as this leak into the groundwater, it has to be evaluated from a radiological health perspective to determine whether or not there is a violation. It is not an NRC violation to release the material into the groundwater.

MEMBER SIEBER: Thank you.

CHAIRMAN STETKAR: Are you -- I recognize that we are treading in the area of current licensing versus license renewal. I think my only question from a license renewal perspective when I think of long-term effects, are you reasonably confident that indeed the current remediation efforts are successful in preventing vertical migration into the deep, this 70 foot aquifer for example which might not be detected for some reasonable period of time. The

question is, the current pumping efforts and the current remediation efforts and the successful in terms of preventing that potential pathway.

MR. KLEMENTOWICZ: This is Steve Klementowicz, senior health physicist with the NRC. The answer to that is yes. The data was, we had hydrologist also look at the groundwater quality and the environmental impact, the site order we performed. And their data, their review of the licensee' date showed it was only in the shallow aquifer. It had not gotten down to any deeper aquifer.

CHAIRMAN STETKAR: Do you have confidence that the local geohydrology is such. Is there confidence that its not going to migrate?

MR. KLEMENTOWICZ: As a health physicist, not a hydrologist, I can't answer that.

CHAIRMAN STETKAR: Okay.

MR. KLEMENTOWICZ: But as far as the radiological health impacts, we see no problem.

CHAIRMAN STETKAR: I understand. Okay, thank you.

MS. BRADY: Going back to the spent

fuel leakage and talk about the structural impact of the LARA and the discussion today talked about the spent fuel leak at Unit 1, borated water that has migrated through small cracks in the concrete to reach the seismic gap that's between the auxiliary building and the fuel handling building. And the applicant told you that they cleared the tell tale drain system and now believe the majority of the leakage is contained within the drain system. They also talk about the studies and testing that indicate that the borated water did not effect the structural integrity of the pool. In doing our review, the applicant committed to include visual inspection of the one accessible spent through wall vault every 18 months and to remove a concrete core sample from the accessible spent fuel through wall at the location that has previously indicated water leakage. However, the staff is still concerned that there may be through wall leakage may be occurring the three inaccessible walls and we have sent an RAI to the applicant to address that concern.

CHAIRMAN STETKAR: Bennett, I meant to ask the applicant. This is really a question

for the applicant. They took a core sample through that wall into the spent fuel pool wall structure. Some place I think I recall, I have a note to myself that it was characterized as a shallow core sample. Could you tell us really the extent of that proposed core sample and you apparently have a drawing that does that.

MS. BRADY: The drawing that we prepared and you can see.

CHAIRMAN STETKAR: Maybe you can see. You are a lot closer and have better eyes than I do.

MS. BRADY: The little black --

CHAIRMAN STETKAR: Black thing there.

MS. BRADY: Right.

MR. SHEIKH: Yes, the wall is more than eight feet take and core two feet.

CHAIRMAN STETKAR: Two feet?

MR. SHEIKH: Yes sir.

CHAIRMAN STETKAR: I'm not a structural engineer, so, you have confidence that's a deep enough core?

MR. SHEIKH: Yes. We looked at this thing and the water has been flowing through this wall.

CHAIRMAN STETKAR: So this is in an area where they've actually through wall leakage?

MR. SHEIKH: Through wall leakage. And in addition to the core they have agreed to expose the rebar and check whether there is any indication of corrosion or not in the area of the core.

CHAIRMAN STETKAR: Okay.

MR. SHEIKH: As you can see there is no more leakage on this west well any more but there is leakage being detected on the east wall through that seismic gap. And they have placed a drain which the drain is about seven feet below the concrete fall and they are collecting about a quarter of a gallon of water every day. It is the same.

CHAIRMAN STETKAR: Yes, that's the flow path that they showed. And you said that's about a quarter of a gallon a day, roughly a liter a day?

MR. SHEIKH: Yes.

CHAIRMAN STETKAR: Okay.

MR. SHEIKH: And the applicant has performed extensive studies and testing to show that the borated water in this concentration had

24 ph. It doesn't affect the concrete and doesn't corrode the rebar. And we have looked at all the studies and different literature and we couldn't find anywhere which indicates a different opinion. I can ask Dr. Naus, who is our expert.

DR. NAUS: Dan Naus, Oak Ridge National Laboratory. We did some preliminary literature searches looking for the interaction of boric acid and some cementitious materials. We found two primary references. Neither one of these references indicated there was much interaction between the boric acid and the cementitious materials. One indicated that if you are below a ph of around 3.6 that's when an acid can have a significant affect on concrete. The borated water, I believe, is in the order of 4.5 to 4.7 ph. Also, one of our cement chemists did a thermadynamic study looking at the interaction of the cementitious material, such as calcium hydroxide and borated water. His basic conclusion was that the reaction would probably form a crust or an insoluble precipitate that would stop or mitigate the reaction somewhat unless you had a continual replenishing of the

calcium hydroxide by leakage. And the best proof is going to be the core sample which is obtained.

CHAIRMAN STETKAR: Okay, thank you. We need a copy of this slide.

MS. BRADY: Yes certainly. We will review that RAI response and we will get back to the committee.

Next slide please. This concerns our third open item and that is the potential cracking due to primary corrosion cracking and steam generated tube to tube sheetwelds. Our concern here is that the Alloy 600 tubesheets, that the tube to tube sheet welds may not have sufficient content to prevent PWSCC. For Unit 1 the UFSAR states that the tubes are fabricated from Alloy 600 and are welded to Inconel cladding. For the Unit 2, it states that the tubes are fabricated with Alloy 690 and is weld clad with Alloy 600. Even when the steam generated tubes are made from Alloy 690 as this configuration for Unit 2 steam generator tubes, this could lead to primary crust corrosion cracking and this could in turn lead to weld failure and compromise reactor compressor boundary. We have sent an RAI to the applicant

and if the wells are in the bracket of pressure boundary and if not to provide an AMP to verify that. And for Unit 2 to either plan specific AMP or to give a rationale why such a program is not needed. The applicant today mentioned to you the proposed response and we will be evaluating when we receive it.

CHAIRMAN STETKAR: This is kind of a programmatic question. If Brian was here I would beat him up a little bit about it. But he's not, so maybe you can get beaten up. As I understand, I went back and I looked at GALL Rev 1 and GALL Rev 1 explicitly said, specified this type of aging management program for once through steam generators. It did not specify it for recirculating type steam generators. I believe the applicant originally justified their position based on GALL Rev 1. GALL Rev 2 now includes a line item for this. Is Salem the first plant for which you are basically applying this requirement or pressure or however I want to characterize it. This is where we have had these long ongoing, the evolution of underground cables, the evolution of socket welds and now we seem to be having the evolution of steam generator tube

sheet welds.

MS. BRADY: No it is not. Kewaunee has also received this RAI. They will be talking about that tomorrow.

CHAIRMAN STETKAR: Okay. But Kewaunee and Salem are the first to --

MS. BRADY: Yes, that is correct.

CHAIRMAN STETKAR: How many of the, do you have an idea of how many of the previously approved license renewals have Alloy 600 tube sheet welds that have not instituted this?

MS. BRADY: No I don't know the exact number. It is a relatively small number.

CHAIRMAN STETKAR: Okay. I think we would be interesting in hearing that at the full committee meeting.

MS. BRADY: Yes, we will get back to you on that.

CHAIRMAN STETKAR: It is just a concern of --

DR. HISER: This is Allen Hiser from the NRC staff.

CHAIRMAN STETKAR: I knew you would get to say something.

DR. HISER: We may have a problem

providing that answer because our first REI is always is what is the weld clad. So that is --

CHAIRMAN STETKAR: You never even ask.

DR. HISER: That's not information that's in the UFSAR and in general as you accurately reported, the GALL 1 position was that this was not an issue for recirculating steam generators. So we did not even ask that question. So we may have a very difficult time even pointing that level of information. It is something that is on our list of items that as the regions do 71 003 inspections that will be one of the things that they will look at.

CHAIRMAN STETKAR: Okay.

DR. HISER: We call them positions. They are not issues.

CHAIRMAN STETKAR: Yes, I'm not politically correct nor am I an attorney. Okay, thank you.

MEMBER SHACK: Just out of curiosity too, I see it -- what is the primary water chemistry going to do to stop my PWSCC and susceptible Alloy 600? How much credit can I give it?

DR. HISER: We believe not too much. And that fundamentally is the reason that this question has come up. We looked at differences between the circulating generators and once throughs and structurally, mechanically, fabrication-wise there really are no differences. The materials are the same. The water chemistry is nominally the same. It has been pointed out many times, the Alloy 600 will crack in primary water. I don't know that there's much that you really can do to the water.

MEMBER SHACK: That is what I was trying to figure out.

DR. HISER: So it will crack. This is an area that we believe it is potential damage. We don't believe it's a part 50 today issue. But the concern is that as you go out to 60 years of operation or close to that with tubes that you may develop cracks and could compromise that.

CHAIRMAN STETKAR: Thank you.

MS. BRADY: Thank you. Next slide please. This slide concerns an RAI that is not discussed in our SER and we will be sending out to the applicant shortly. Melanie had told you that we had been recently assessing the current

staff positions with respect to that completeness against all the in-house applicants. Are we being complete in ensuring that all applicants address these current issues? Our purpose in this review was to make sure that our reviews have considered the most current information and that our decisions are based on the most current information. And too, to make sure that we are in position to explain that position to the public. I think both the ACRS and intravenous have asked us are we complete and consistent in our reviews of all applicants. And then we want to as we do our reviews, to ask ourselves how does this issue apply to the plant under review and how does it apply to all plants.

As a result of this review we've looked at actions we should take and we will be sending about 50 to 60 RAIs to the current applicants. Two of these will be going to Salem. They are probably selective reaching materials program in the one time inspection program. And both of the RAIs asked the same question. We are asking the applicant to explain how they determine the sample size and how they will be determining the components and be selective

sampling. We will report back to the ACRS in our final presentation.

CHAIRMAN STETKAR: When did those RAIs go out?

MS. BRADY: We had sent the draft to this applicant. We have asked the applicant to take a look at them and let us know if they need any clarification and they will go out some time this month.

CHAIRMAN STETKAR: This month, okay.

MS. BRADY: Yes. Section 4 is the last section and it contains the staff review of the time limited aging analysis. The staff review was complete for this section except for one open item and that is the metal fatigue analysis.

Next slide. We have two questions here. The first question concerns the WESTEMS that is used as a fatigue monitoring software for monitoring the cumulative usage factor and cycle counting. Although offices at the NRC and in particular the new actors have noted concerns regarding the results determined by WESTEMS. The users can modify any data such as the peak and valley express times. There is also different approaches for summation of moment stress terms.

And these items can have a significant impact on the calculated cumulative usage factor. It is difficult for us to ascertain the accuracy or conservatism of the WESTEMS given that there are a variety of analyst judgments that may be applied to the software outputs by the user. And so we sent an RAI to the applicant as I think they told you asking them to explain to us how they used WESTEMS and to conduct a benchmark study to compare calculated CUF from WESTEMS with the results from the initial design basis of record. Applicant explained their proposal today of what they were doing. We've been discussing it with them and we expect some time in mid-January to review the results.

MEMBER SHACK: This is different than some of the other fatigue monitors. So you don't have a concern with the way the calculation is done. I sort of read through this thing and I wasn't quite sure whether they were just sort of making explicit with every fatigue analysis. Someone is making a judgment on peaks and valleys and it becomes more obvious here when you have to set the input to the computer program.

DR. HISER: The concern by NRO is that

there, some of the results that the program puts out from the stress analysis and from the trangent analysis needs to be modified by the analyst. And the one concern was that there was insufficient guidance or training or controls on how that, those adjustments are made. And the applicant has told us that portion of the code is not something that they are using. The concerns that we have are that identify certain concerns, we just want to ensure that the portions of the code that are used by the applicant do not have the same weaknesses to them.

MS. BRADY: Next slide. The other question for the fatigue analyses concerns the environment assisted fatigue analysis locations. This was a similar issue that we had with Hope Creek and we discussed last month with them. The applicant has used the six locations that are identified in NUREG/CR-6260 and the SAV has asked the applicant to verify that the locations they were selected on the most bounding is compared to other plants specific locations. The applicant today explained their plans for addressing this and this is another one of those issues that we will be following up with a lot of the applicants

with RAIs.

In conclusion, on the basis of its review and pending satisfactory resolution of the four open items, the staff determines that PSEG has met the requirements of 10 CFR 54.29(a) for the license renewal of Salem Nuclear Generating Station. This completes the staff's presentation. Are there any questions?

CHAIRMAN STETKAR: Pending before open items, the two RAIs.

MS. BRADY: Plus the two RAIs. I should add that in parenthesis.

CHAIRMAN STETKAR: Okay. That's, as far as you are concerned those six potential areas are it? You don't anticipate other things arising over the next month or so?

MS. BRADY: Not over the next month or so. We couldn't speak for a long period though.

CHAIRMAN STETKAR: Okay. Any other questions from any of the members? Or John?

MR. BARTON: No, NRC did a good job.

CHAIRMAN STETKAR: Thank you very much for the presentation again. It was a very good presentation. I think the staff, I'm always

impressed by the way, the amount of effort that the staff puts into these reviews and the depth of the questions that are asked. They are really impressive. You are doing a very, very good job in my opinion.

MS. BRADY: Thank you.

CHAIRMAN STETKAR: I think you should be congratulated for that. It's a tremendous amount of work and delving into a lot of the details. I think it's a really good process.

With that, what I would like to do is we, I think we have folks on the bridge line. So if I could first open up the bridge line and see if anyone, members of the public who are on the line would like to make a statement or have any comments. At times we need to have some sort of positive indication that the line is open because silence is -- While we are waiting to confirm that. Is there any member of the public here in the meeting room who would like to make any comments or statements? Hearing and seeing none, let's wait for confirmation that the line is in deed open. It is open. If that's the case, if you are out there and listening and you choose to, would like to make a statement or comment,

please do so. Hearing none, I'm assuming that either no one is there or it is a negative reply. So we'll take that.

Now before we close two more pieces of business. What I would like to do is go around the table among the members and see if there are any lingering issues that you would like to bring up and also whether anything you heard today would potentially prompt the need for a possible interim letter on any of the issues. We are down to two members and I will start over here. Bill?

MEMBER SHACK: No.

CHAIRMAN STETKAR: Thank you. And Jack?

MEMBER SIEBER: No.

CHAIRMAN STETKAR: All right. Well that was easy. And I think one last thing that I would like to do is give the applicant and the staff a little bit of feedback on specific issues that we feel are relevant for presentation at the full committee meeting given what we heard today. Obviously close out of the four open items. But, is there anything else, given the limited time that we'll have at the full committee meeting which is typically an hour and a half to

two hours time frame, with respect topics that we feel that should be highlighted during those presentations.

MEMBER SIEBER: Well I think one of things that ought to be discussed a little bit is the flux of the tubes and sampling frequency and how that applies to other elements where sampling frequency is important in determining degradation.

CHAIRMAN STETKAR: Okay.

MEMBER SIEBER: I think the staff has addressed that. And you can't take a bunch of samples early on and then say that they will tell us what is going to happen 20 years later. So I would like to, I think that ought to be discussed a little bit. I don't know if the staff has thought about that.

CHAIRMAN STETKAR: Yes, that is one of the reasons I brought it up. There's been a discussion in there I just wasn't quite sure how the math was going to be done basically. Bill do you have anything?

MEMBER SHACK: No, there's sort of a generic issue with the cathodic protection on the buried pipe. But I assume that will come out.

CHAIRMAN STETKAR: I would assume that would come out of buried piping.

MEMBER SHACK: One thing I thought about is because we've as a committee expressed interest, should we, the applicant today highlighted it as an area of interest. And that is the status of the containment liner and corrosion. It is not an open item currently. Should we ask the applicant to include that in there presentation to the full committee or not?

MEMBER SIEBER: It's sort of a choice.

CHAIRMAN STETKAR: Well given the limited amount of time.

MEMBER SIEBER: I think it is sort of like driving your car and saying I don't want to change the oil. And so the chance of failure moves up a little bit. It depends on the condition. There's nothing in the regulations that I know that force you to have cathodic protection.

MEMBER SHACK: Bill, I don't know, on the containment liner, right. I think I would rather stick to, with the limited time that we have, I think, it's an interesting given the fact

that they had a great deal of interest.

CHAIRMAN STETKAR: It is interesting topics. I leave it up to the applicant. Consider, previous discussions, consider the amount of time you have available. Recognize that I suspect --

MEMBER SHACK: Open that can of worms.

CHAIRMAN STETKAR: I was going to say recognize that if there is a presentation there probably will be reasonable discussion. That's just, I'm not trying to make the decision one way or the other. I think it is an interesting topic. I'm not trying to downplay it. If the staff is assured that the condition of the liner and the monitoring program satisfies the requirements.

MEMBER SHACK: It is interesting, they new insulation on the lining and that certainly complicates your visual inspection considerably.

CHAIRMAN STETKAR: But they have a plan. They have a sampling plan.

MEMBER SIEBER: As long as they mention that it is encapsulated.

CHAIRMAN STETKAR: Don't go there.

MEMBER SIEBER: There are containment water problems in a number of plants and this one they are pursuing it in reasonable form that it is worth mentioning and also having to include something about these spent fuel pool

CHAIRMAN STETKAR: Well the spent fuel pool certainly will come up because we need to hear about how that open item is closed out. That is an interesting one certainly. Anything else? Well if nothing else, again I would like to thank both the applicant and all of the assembled multitudes and the staff and the assembled multitudes and the staff for an excellent presentation and indeed we didn't have to stay until midnight. And with that, we are adjourned.

(Whereupon the above-entitled meeting was concluded at 4:41 p.m.)

Salem License Renewal

ACRS Subcommittee
December 1, 2010

PSEG Nuclear LLC

Agenda

Introductions – Paul Davison, Vice-President, Operations Support

Site Description – Greg Sosson, Director, Engineering Services

Operating History – Greg Sosson

License Renewal – Ali Fakhar, Manager, License Renewal

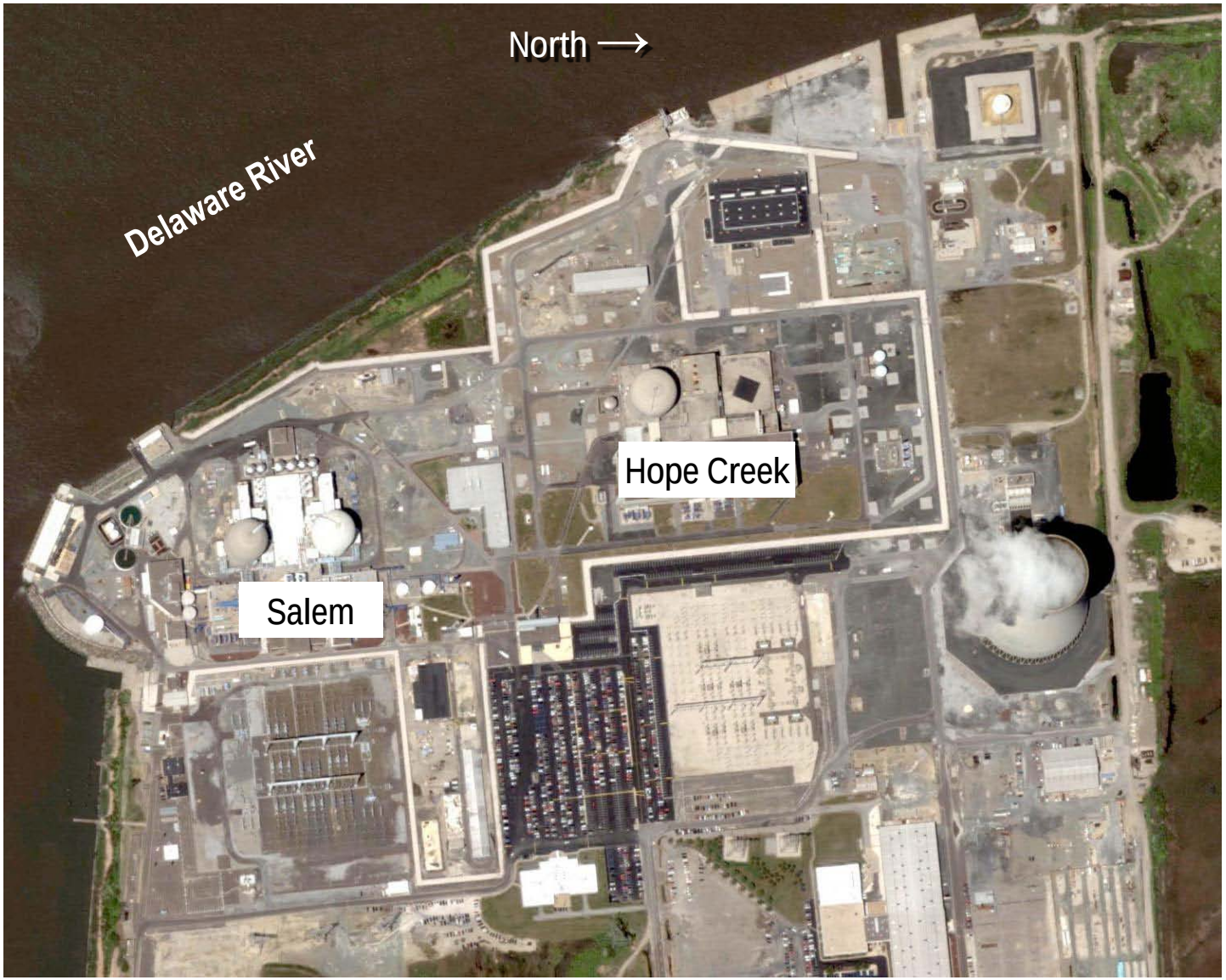
- Metal Fatigue of Components and Piping — Ali Fakhar
- Steam Generator Tube-to-Tubesheet Welds — Ali Fakhar
- Salem Unit 1 Spent Fuel Pool — Tom Roberts
- Buried Piping Program — Jim Melchionna

Topic of Interest:

- Salem Containment — Alan Johnson

Closing Comments – Paul Davison

Site Description



PSEG Nuclear LLC

Operating History – Unit 1

Initial Operating License at 3338 MWt	1976
Increased Licensed Power to 3411 MWt	1986
13kV Switchyard Modification	1994
Steam Generator Replacements (Westinghouse Model F)	1998
Measurement Uncertainty Recapture to 3459 MWt	2001
LP Turbine Rotor Replacements	2004
HP Turbine Rotor Replacement	2004
Reactor Head Replacement	2005
Mechanical Stress Improvement Process (MSIP)	2008
Unit Capacity Factor (18 month)	90.7%
LRA Submitted	08/18/2009
Current License Expires	08/13/2016

Operating History – Unit 2

Initial Operating License at 3411 MWt	1980
13kV Switchyard Modification	1994
Measurement Uncertainty Recapture to 3459 MWt	2001
HP Turbine Rotor Replacement	2003
Reactor Head Replacement	2005
Steam Generator Replacements (Areva Model 61/19T)	2008
Mechanical Stress Improvement Process (MSIP)	2009
Unit Capacity Factor (18 month)	91.7%
LRA Submitted	08/18/2009
Current License Expires	04/18/2020

License Renewal

Ali Fakhar
Manager, License Renewal
PSEG Nuclear

PSEG Nuclear LLC

Aging Management Programs

- 32 Existing Aging Management Programs
  - 15 programs required no changes to align with GALL
  - 17 programs required enhancements to align with GALL
  - 6 of these 32 programs had exceptions
- 16 New Aging Management Programs
  - 2 of these 16 programs had an exception

Commitments

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

Salem Open Items

Ali Fakhar
Manager, License Renewal
PSEG Nuclear

PSEG Nuclear LLC

Open Items

- OI 4.3.4.2-1 Metal Fatigue of Components and Piping
- Issue
  - The Staff recently requested
    a. A benchmark evaluation to confirm the adequacy of using WESTEMS™ as a fatigue monitoring tool
    b. Verification that the NUREG-6260 locations evaluated for EAF bound all other plant-specific locations that may have higher CUF values
- Resolution
    a. Salem will complete the benchmarking evaluation in early January, 2011
    b. Salem plans to add a new commitment to review plant-specific locations to ensure selected EAF locations are bounding. This review will be completed prior to PEO.

Open Items

- OI 3.1.2.2.16-1 Steam Generator Tube-to-Tubesheet Welds
- Issue
  - The Staff requested a plant-specific AMP to verify the effectiveness of the primary water chemistry program and to ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds or to provide a rationale as to why such a program is not needed
- Resolution
  - The tube-to-tubesheet welds will be added to an inspection program unless an evaluation determines that these welds are not required to perform a reactor coolant pressure boundary function

Open Items

- OI 3.0.3.2.15-1 Salem Unit 1 Spent Fuel Pool
  - The Staff required additional information to understand the Applicant's basis for concluding that leakage is completely contained within the leak chase channels

- OI 3.0.3.2.10-1 Buried Piping Program
  - The Staff required additional information to evaluate how the Applicant considered industry and plant-specific operating experience in its buried piping programs

Salem Unit 1 Spent Fuel Pool

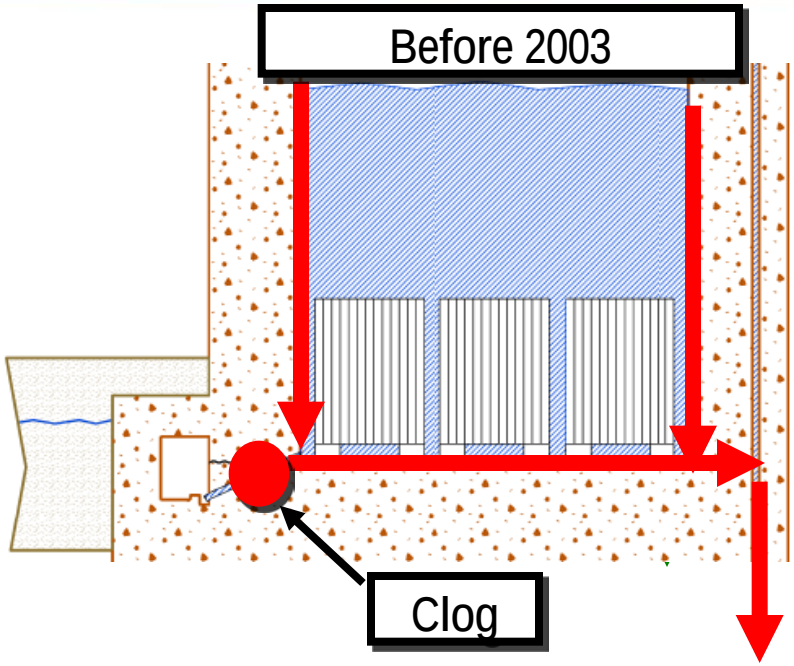
Tom Roberts
Corporate Engineering Specialist
PSEG Nuclear

PSEG Nuclear LLC

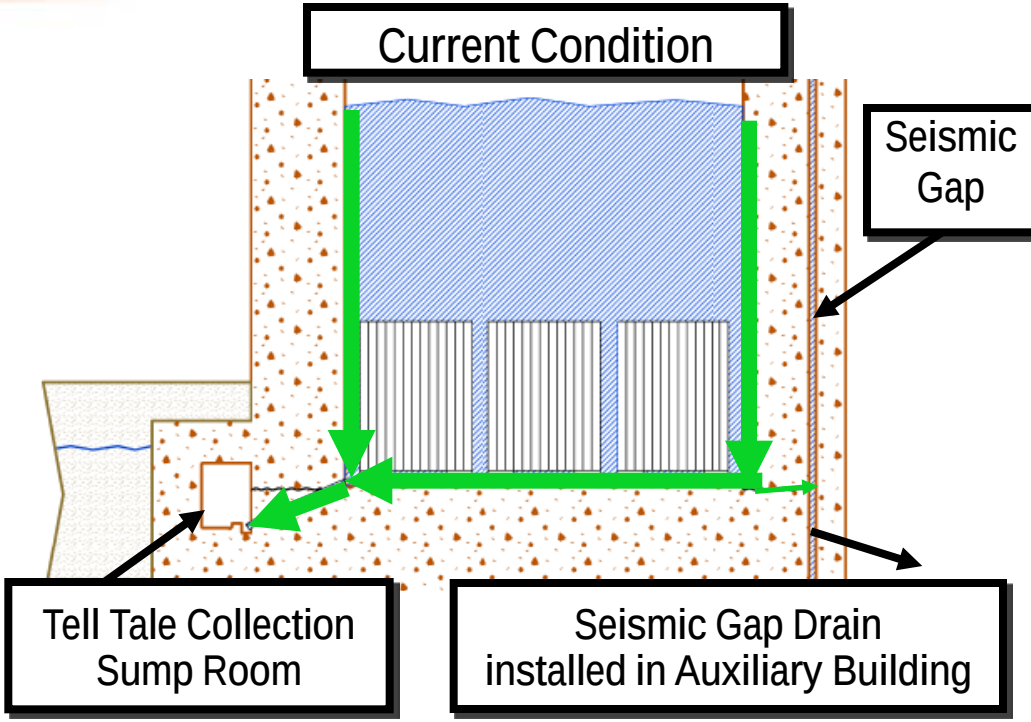
Salem Unit 1 Spent Fuel Pool

- 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
  - Core bore of Sump Room wall prior to PEO to further confirm concrete condition

Salem Unit 1 Spent Fuel Pool – Open Item

- Open Item for Structures Monitoring
  - Provide the basis for concluding that the Spent Fuel Pool leakage is completely contained within the leak chase channels

- Proposed Resolution
  - PSEG ensures that all leakage is contained within the plant structures by maintaining proper operation of the leakage collection system

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 operating properly
  - Minimizes the potential for concrete degradation
  - Prevents the escape of contamination to the environment
- Integrity of the Salem Unit 1 Fuel Handling Building Structure will be maintained to ensure continued safe operation

Salem Buried Pipe Program (BPP)

Jim Melchionna
Corporate BPP Program Manager
PSEG Nuclear

PSEG Nuclear LLC

Buried Pipe Program

- Scope
  - Includes all buried piping systems at Salem, 7 of which are in-scope for License Renewal
- Risk Ranking
  - The program has risk ranked all buried piping segments according to their relative susceptibility and consequences using NACE and EPRI guidance
- Inspections
  - Focused inspections based on risk rankings
- Corrective Action Program
  - Deficiencies are entered into the site CAP
  - For deficiencies, cause is determined and corrective actions developed
- NEI Initiative
  - In response to industry operating experience, NEI has established an industry initiative on buried piping integrity (NEI 09-14)
  - PSEG is implementing the industry initiative

Buried Pipe Program – License Renewal Inspections

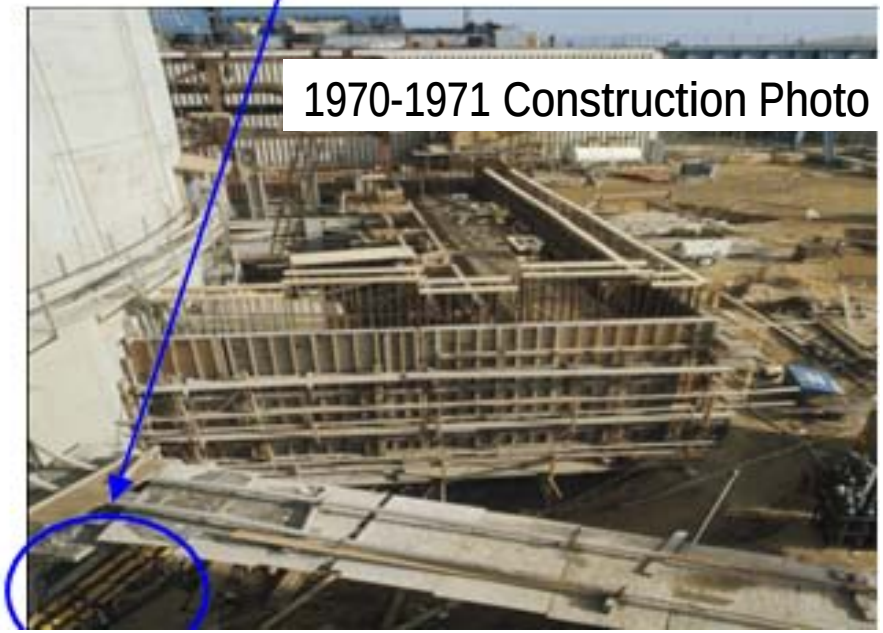
Materials	Systems	Inspections Prior to PEO and Every 10 Years Thereafter
Carbon Steel	Auxiliary Feedwater Compressed Air Demineralized Water Fire Protection Non-radioactive Drains Service Water Circulating Water	Four
Gray Cast Iron	Fire Protection	One
Ductile Cast Iron	Fire Protection	One
Pre-stressed Concrete	Circulating Water Service Water	One
Stainless Steel	Fuel Transfer Tube	One

Buried Pipe Program – Unit 1 Auxiliary Feedwater (AF) Pipe

- 2010 Operating Experience
  - Pre-planned excavation of two Unit 1 AF lines in April 2010
  - Discovered missing coating and corrosion on AF piping
- Apparent Cause
  - Coating on Unit 1 AF Piping was inadvertently removed during construction
- Extent of condition
  - AF buried piping was replaced
  - AF piping below Fuel Transfer Tube Area (FTTA) was rerouted above ground with new pipe
  - Unit 2 AF lines inspected in FTTA
  - Construction photos reviewed
  - Excavation & inspection scheduled for Unit 2 AF lines in Spring 2011

Buried Pipe Program – Unit 1 AF Piping

Coating present on AF line at wall penetration – removed during 2010 replacement



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Buried Pipe Program – Open Item

- OI 3.0.3.2.10-1 Staff required additional information to evaluate how the Applicant considered industry and plant-specific operating experience in its buried piping programs
  - Salem provided information dated November 10, 2010 in response to RAI B.2.1.22-02
    - Provided information on operating experience and excavations showing coating to be in good condition with the exception just discussed
    - Provided details on planned inspection locations
    - Provided details on the quality of backfill around buried piping

Conclusions - Buried Pipe Program (BPP)

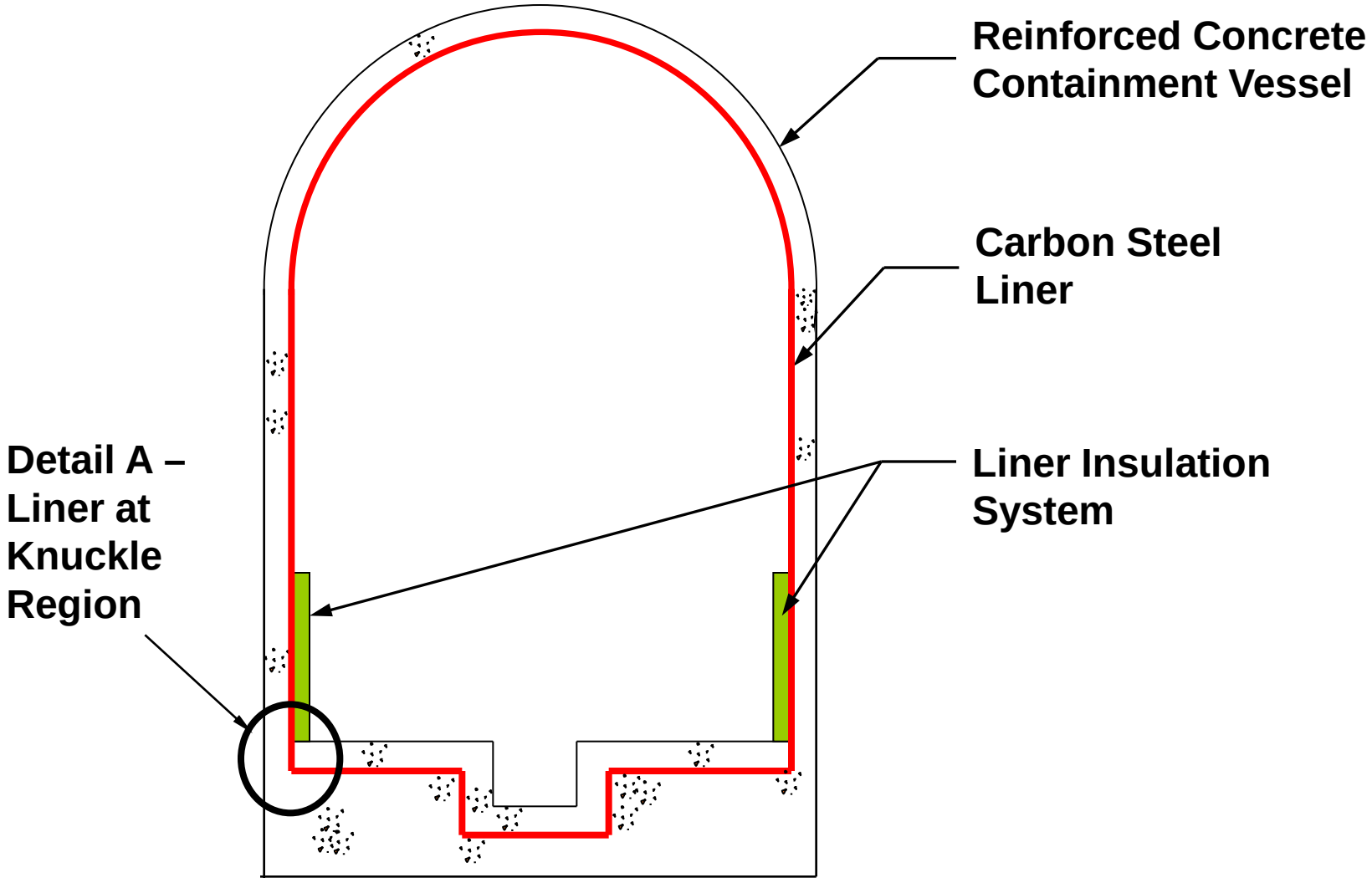
- The BPP Program is comprehensive and robust
- The BPP will continue to develop and improve based on Site and Industry Operating Experience, the NEI Initiative, and new technology
- The Program will manage the material condition of buried pipe
- The BPP is an effective aging management program to ensure continued safe operation

Salem Containment

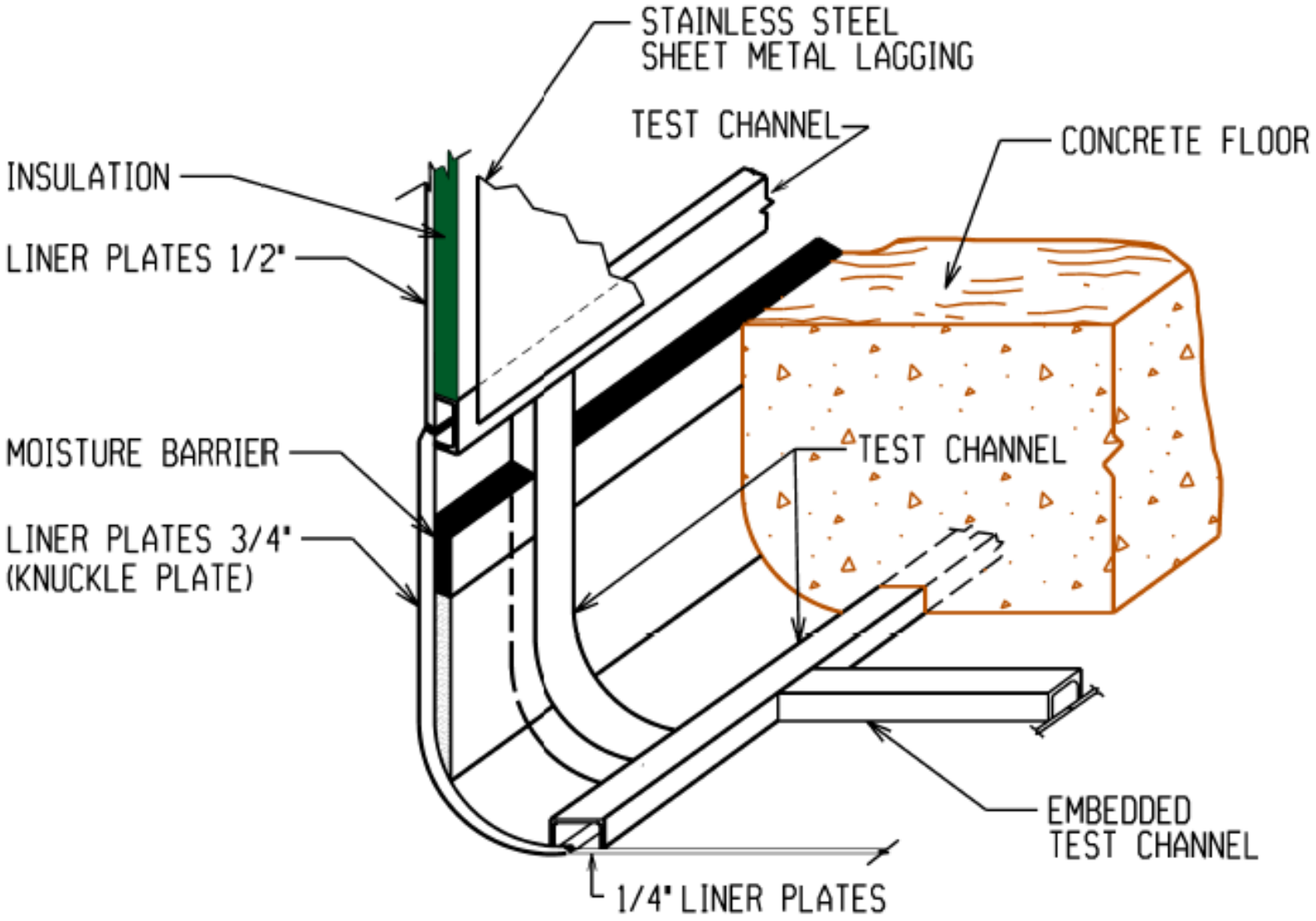
Alan Johnson
Manager, Salem Design Engineering
PSEG Nuclear

PSEG Nuclear LLC

Salem Containment



Salem Containment – Detail A – Liner at Knuckle Region



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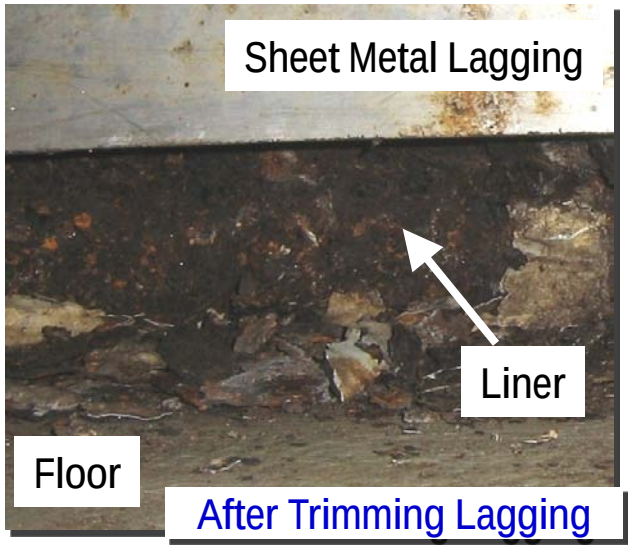
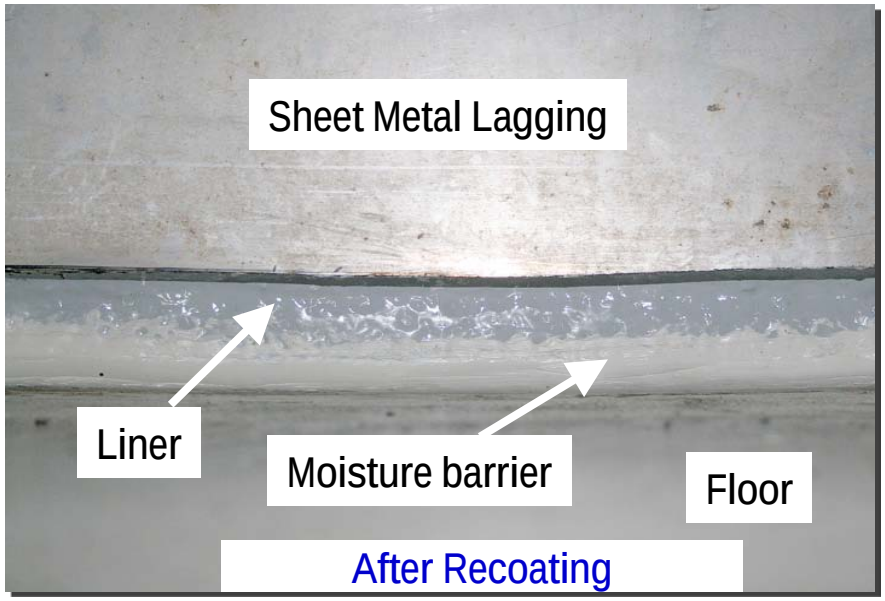
Salem Containment Operating Experience

- Salem Containments are in very good condition
- Early in plant life there were service water leaks in the containment building
  - The leaks were corrected in the 1990s
- Industry Operating Experience has shown potential for liner degradation at the floor
- PSEG proactively addressed the issue with inspection of previously inaccessible areas behind the insulation panels

Salem Unit 1 Liner





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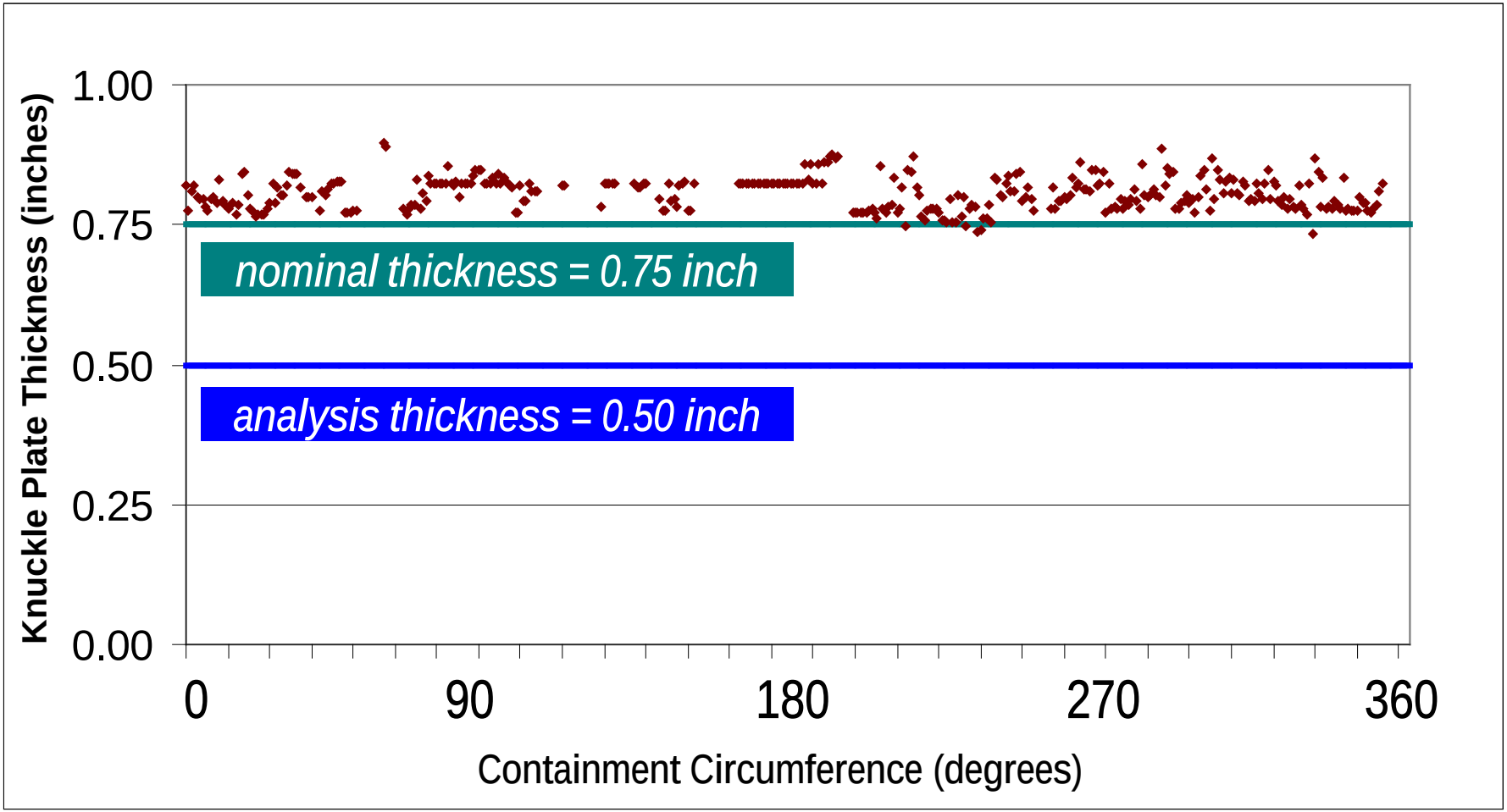
Salem Unit 1 Liner Knuckle Plate Thickness – March 2010



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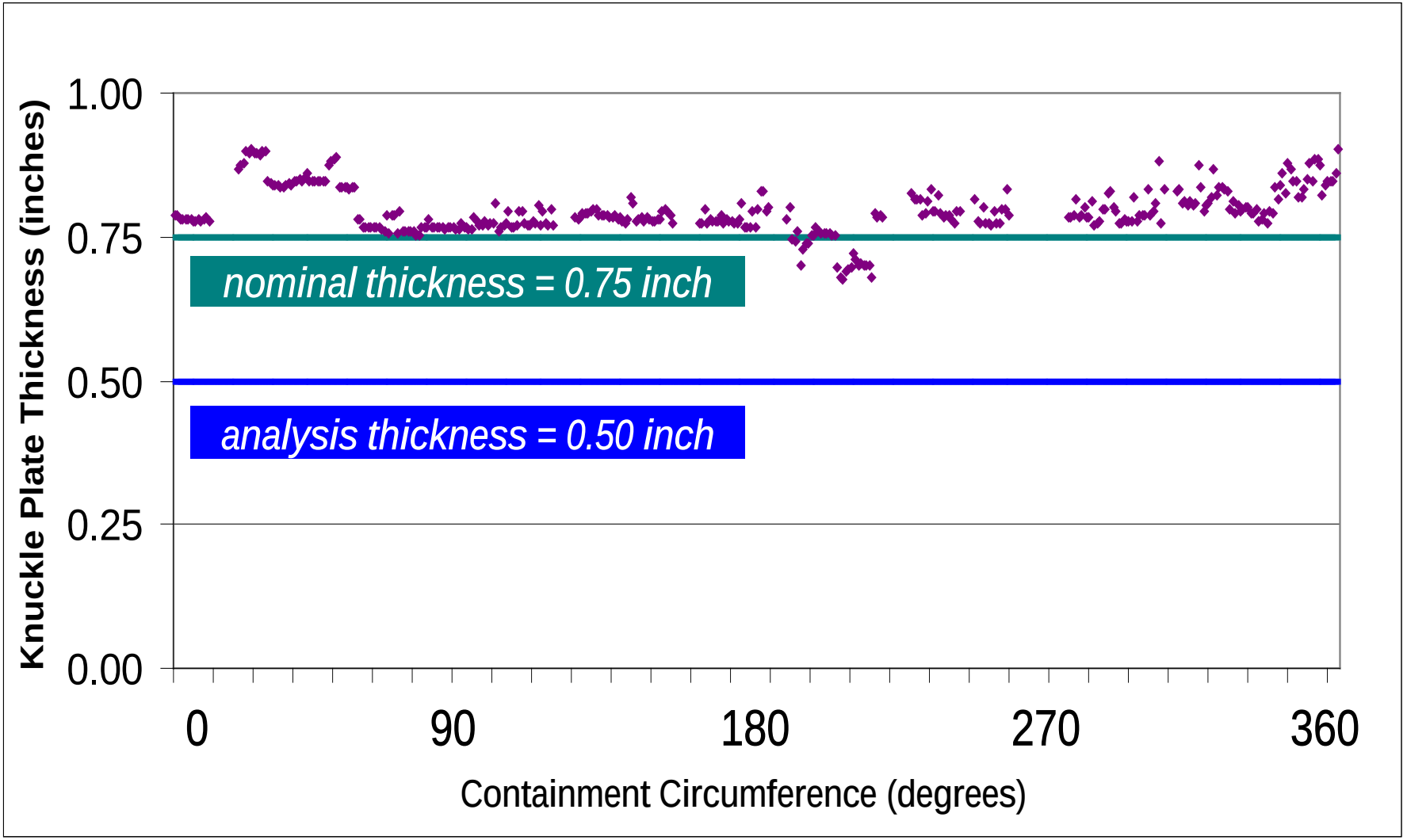
Salem Unit 2 Liner Knuckle Plate Thickness – October 2009



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Salem Containment – Enhancement Summary

- The previously inaccessible areas of the moisture barrier and adjacent liner for each unit have been inspected and are acceptable
- The condition of the liner behind the insulation panels will be confirmed
  - Inspections of the liner behind four insulation panels for each unit were performed and found to be in good condition
  - Inspect liner behind 57 panels prior to PEO on each unit in years 2012 through 2016
    - 57 randomly selected panels provides 95% confidence level
  - In the PEO, inspect liner behind 12 panels during each 10 year ISI interval on each unit

Conclusions – Salem Containment

- Salem Containments are in very good condition
- The previously inaccessible areas of the moisture barrier and adjacent liner have been inspected and are acceptable
- The condition of the liner behind the insulation panels will be confirmed before the PEO
- The integrity of the Salem Containments will be maintained to ensure continued safe operation

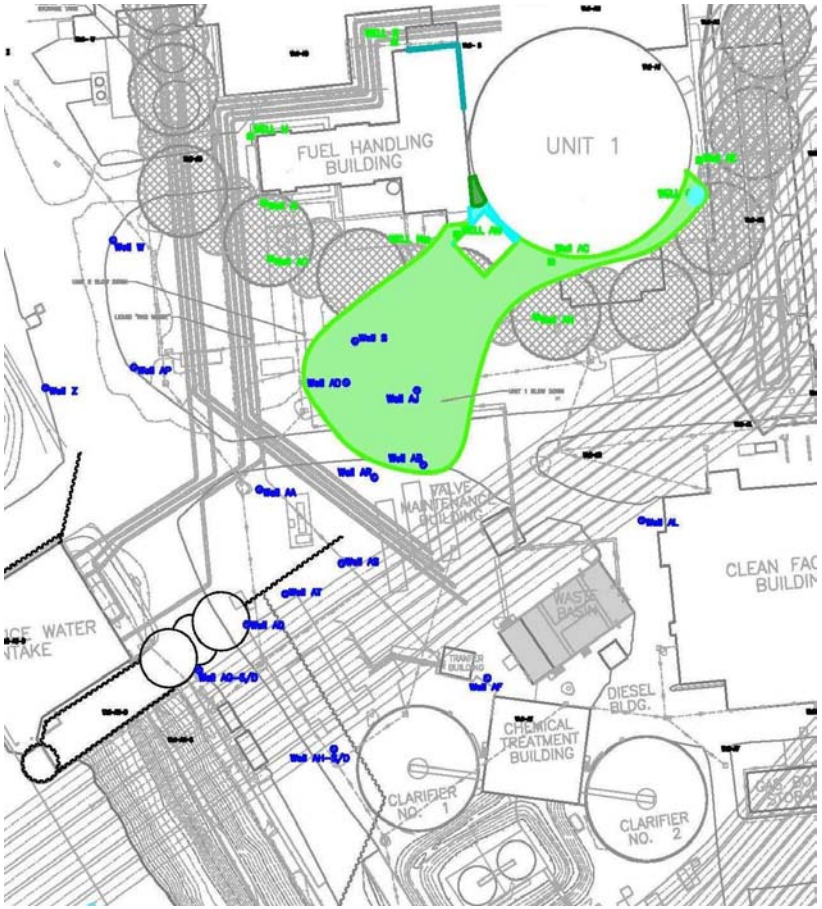
Salem License Renewal

ACRS Subcommittee
December 1, 2010

PSEG Nuclear LLC

Tritium Plume

2004



2010

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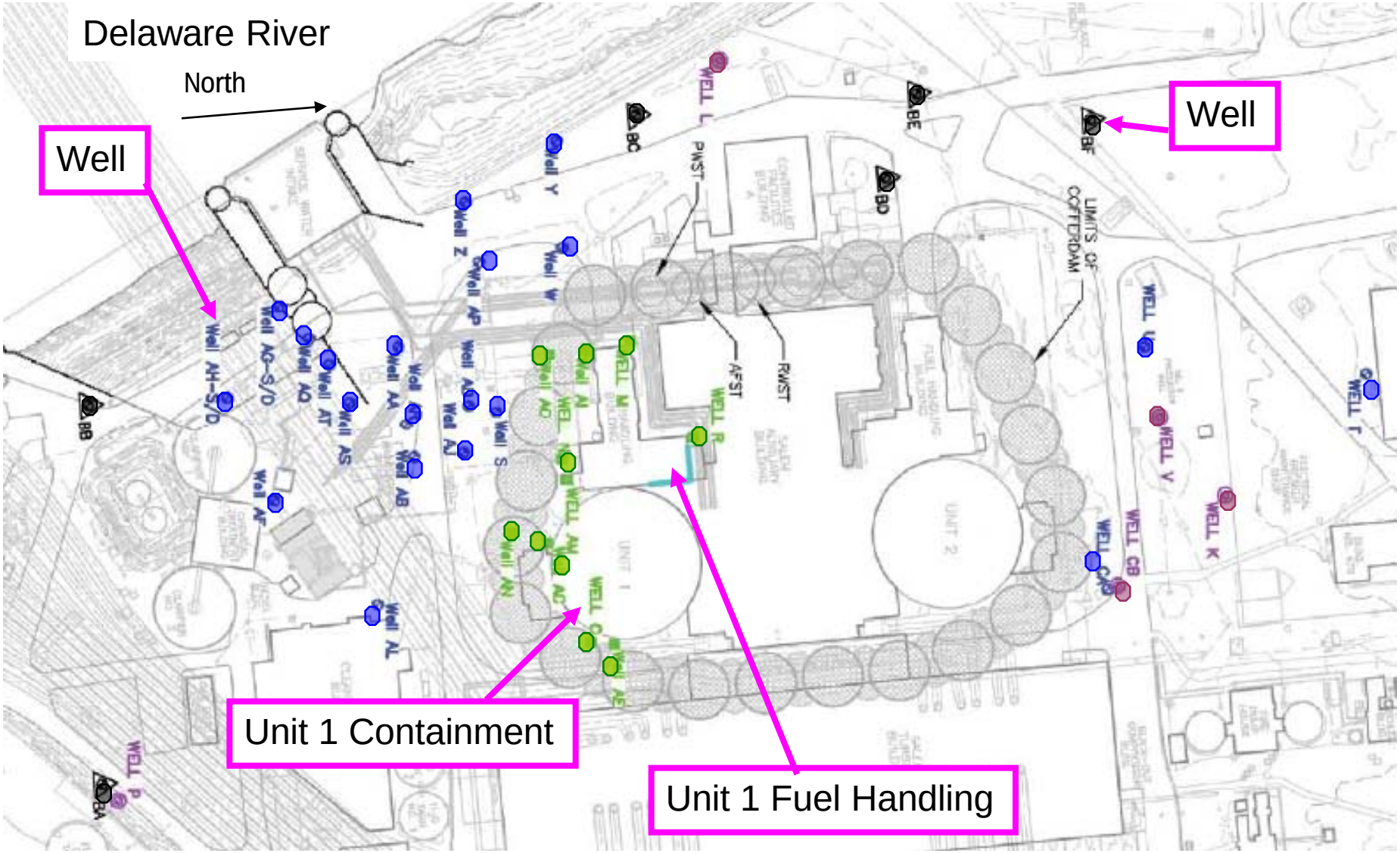
Salem Monitoring Wells



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Advisory Committee on Reactor Safeguards (ACRS)
License Renewal Subcommittee
Salem Nuclear Generating Station, Units 1 and 2 (Salem)

Safety Evaluation Report (SER)
with Open Items

December 1, 2010

Bennett M. Brady, Project Manager

Office of Nuclear Reactor Regulation

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Presentation Outline

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

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Overview of LRA

- License Renewal Application (LRA) Submitted August 18, 2009
  - Applicant: PSEG Nuclear LLC (PSEG)
  - Facility Operating Licenses
    - Unit 1, No. DPR 70 expires April 13, 2016
    - Unit 2, No. DPR-75 expires April 18, 2020
- Approximately 40 miles from Philadelphia, PA and 8 miles from Salem, New Jersey
- Both Units are Westinghouse 4-Loop PWRs

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Audits and Inspections

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

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Overview of SER

- Safety Evaluation Report (SER) with Open Items issued November 4, 2010
- SER contains 4 Open Items (OIs):
  - Given recent plant-specific and industry events involving leakage from buried and underground piping, the staff needs additional information (OI 3.0.3.2.10-1)
  - Leakage of borated water from the spent fuel pool (OI 3.0.3.2.15-1)

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Overview of SER (cont.)

- SER contains 4 Open Items (OIs)
  - Potential primary water stress corrosion cracking in steam generator tube–to–tubesheet welds (OI.3.1.2.2.16-1)
  - Metal fatigue of components and piping(OI 4.3.4.2-1)
    - Use of WESTEMS® software in analyzing metal fatigue
    - Confirmation that the locations selected for environmentally assisted fatigue analyses are the most limiting and bounding for each site.
- Two Supplemental Issues Not Discussed in SER
  - Sampling plan for One-Time Inspection Program
  - Sampling plan for Selective Leaching Program

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SER Section 2 Summary

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

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Regional Inspection

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

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Regional Inspection
Walk Downs

- No. 12 Service Water Pump and Strainer
- No. 11 Nuclear Header 24" and 11/12 cross tie
- No. 12 Safety Injection Pump Lube Oil Cooler
- No. 11 RHR Pump Room Cooler
- No. 11 Component Cooling Heat Exchanger
- 4" Crosstie for Chiller Condenser 11 and 12 header
- Containment Penetrations for 11,12, 13 containment fan coil unit
- Service Water Accumulator Vessel Piping
- Turbine Buildings
- Auxiliary Buildings, including 1B and 2A Emergency Diesel Generators
- Unit 1 Service Building
- Unit 1 Service Water Accumulator Building
- Pipe Tunnel

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Section 3: Aging Management Review

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

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SER Section 3

3.0.3 – Aging Management Programs

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

	Consistent with GALL	Consistent with exception	Consistent with enhancement	Consistent with exception & enhancement	Plant Specific
Existing (32)	12	2	11	4	3
New (16)	10	1	1	1	3

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SER Section 3 Open Item

- Buried Piping Inspection OI 3.0.3.2.10-1
  - Staff has noted a number of recent industry and plant-specific events involving leakage from buried and underground piping/tanks
  - The staff and applicant have addressed several buried piping Issues (e.g. coatings, backfill quality) but has not reached resolution on the lack of cathodic protection
  - As a follow-up to the applicant's recent RAI response, the staff has prepared an RAI addressing sample size basis, localized soil conditions, informing inspection locations, and pipe wall thickness projections
  - Staff will review the RAI response and report to the ACRS in the final SER

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SER Section 3 Open Item

- Spent Fuel Leakage OI 3.0.3.2.15-1
  - LRA reports that Unit 1 spent fuel pool has experienced through-wall borated water leakage
  - Applicant studies and testing indicate that borated water did not affect structural integrity of pool
  - Staff was concerned that leakage may have degraded the concrete or embedded steel
  - Due to staff concerns, the applicant has committed to additional visual inspections and a core sample of the accessible wall.
  - The staff is still concerned about the effects of through-wall leakage on the inaccessible walls
  - Staff has issued an RAI and is awaiting response

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SER Section 3 Open Item

- Potential Cracking due to PWSCC in Steam Generator Tube-To-Tubesheet Welds OI 3.1.1.1.16- 1
  - Staff is concerned that PWSCC could occur on the primary coolant side of PWR steel steam generators (SG) tube to tubesheet welds
  - UFSAR for Unit 1 states tubes are fabricated from Alloy 600TT and are welded to the Inconel cladding. UFSAR for Unit 2 states tubes are fabricated from Alloy 690TT and is weld clad with Alloy 600
  - Staff sent RAI to the applicant
    - That asks whether Unit 1 welds are included in the reactor coolant pressure boundary. If not, provide an AMP to verify the effectiveness of the water chemistry program.
    - For Unit 2 SGs tube-to-tubesheet welds, provide either a plant-specific AMP that will complement the Primary Water Chemistry Program in order to verify the effectiveness of the primary water chemistry program and ensure that cracking due to PWSCC is not occurring in tube-to-tubesheet welds, or a rationale for why such a program is not needed.

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Supplemental Issues, Not in SER

- DLR recently assessed the current staff positions for completeness against in-house applications
  - We have identified the actions needed to be taken for all current in-house applicants
- Two RAIs will be going to Salem
  - For Selective Leaching of Materials and One-Time Inspection Programs
  - Same RAI for each program: how was the sample size and the selection of sampled components determined

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SER Section 4: Time-Limited Aging Analyses

- Section 4.1 – Identification of Time-Limited Aging Analyses
- Section 4.2 – Reactor Vessel Neutron Embrittlement
- Section 4.3 – Metal Fatigue of Piping and Components
- Section 4.4 – Other Plant-Specific TLAAs
- Section 4.5 – Fuel Transfer Tube Bellows Design Cycles
- Section 4.6 – Crane Load Cycle Limits
- Section 4.7 – Environmental Qualification of Electrical Equipment

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SER Section 4 Open Item

- Metal Fatigue of Pipes and Components OI 4.3.4.2-1 – WESTEMS
  - Metal Fatigue Program uses a fatigue monitoring software program for monitoring cumulative usage factor (CUF) and cycle counting
  - The staff has identified concerns with options in the WESTEMS® that may have significant impacts on calculated CUF
  - The staff has asked the applicant for additional information on how the program is used and to conduct a benchmark study to compare calculated CUF from WESTEMS® with the results from the initial design basis of record
  - The staff is awaiting the applicant's response.

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SER Section 4 Open Item

- Metal Fatigue of Pipes and Components OI 4.3.4.2-1 – Environmentally Assisted Fatigue Analysis Locations
  - Analyses of the effects of reactor coolant environment on fatigue life of components were performed for six generic locations identified in NUREG/CR-6260
  - GALL AMP X.M1 recommends that the program should monitor a sample of high fatigue usage locations and that the program should include at a minimum the NUREG/CR-6260 locations
  - The staff asked the applicant to verify that the locations selected were bounding as compared to other plant-specific locations.
  - The staff is awaiting the applicant's response.

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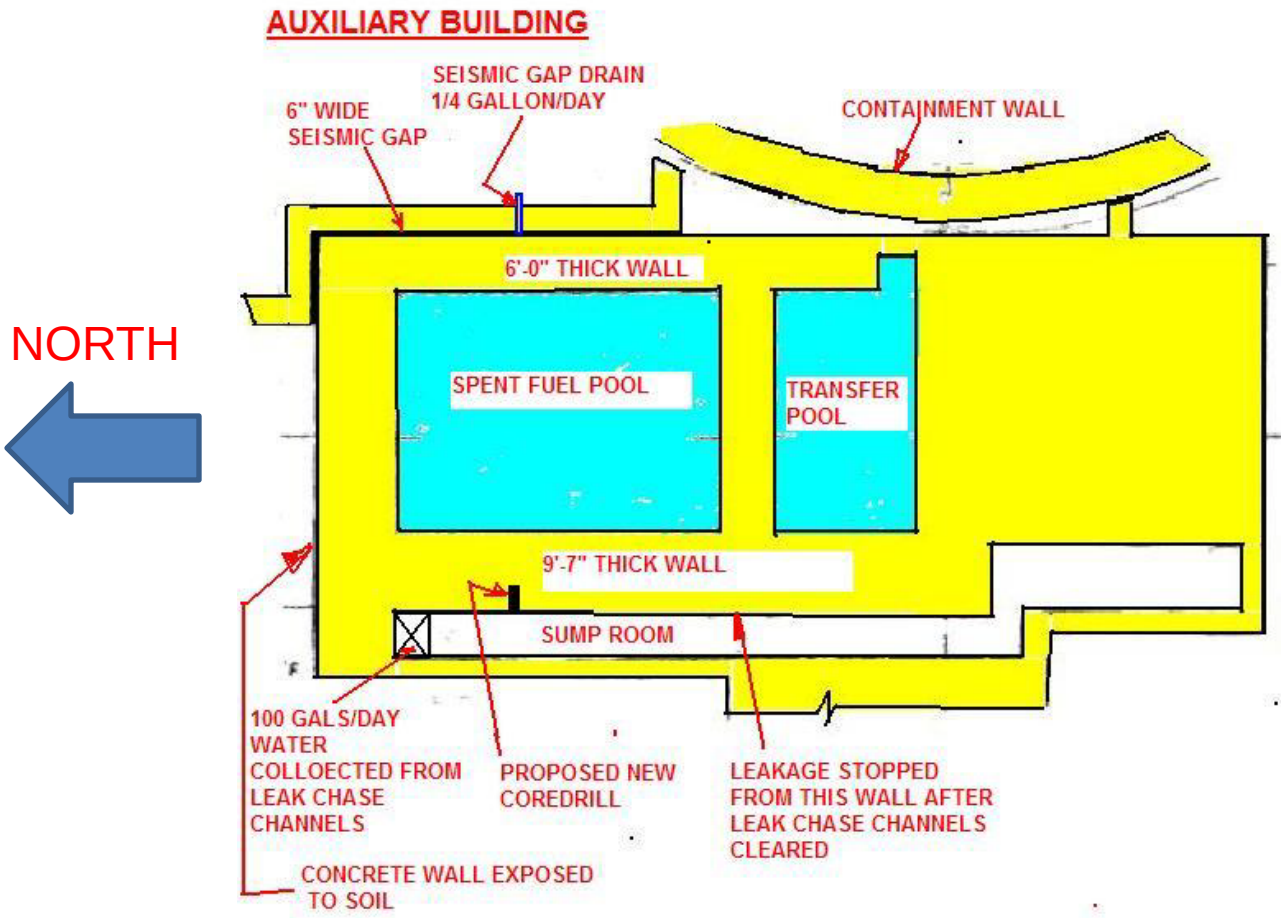
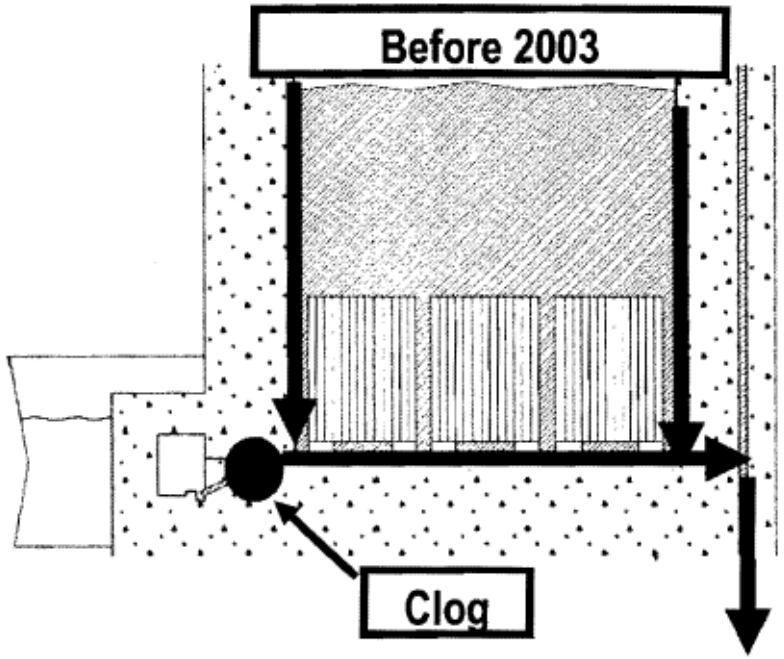
Conclusion

On the basis of its review and **pending satisfactory resolution of the four open items**, the staff determines that PSEG has met the requirements of 10 CFR 54.29(a) for the license renewal of Salem Nuclear Generating Station.

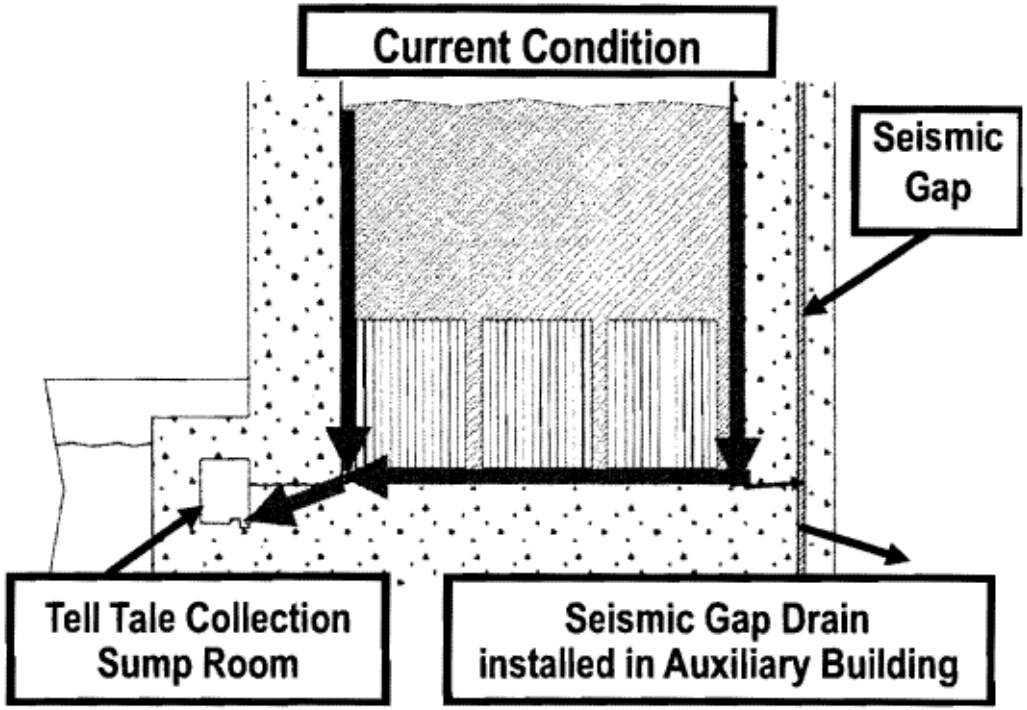
Salem Fuel Handling Building



Salem Unit 1 Spent Fuel Pool Leakage Path



- Leakage exited the structures through seismic gap
- Contamination did not migrate offsite
- Contamination is being remediated

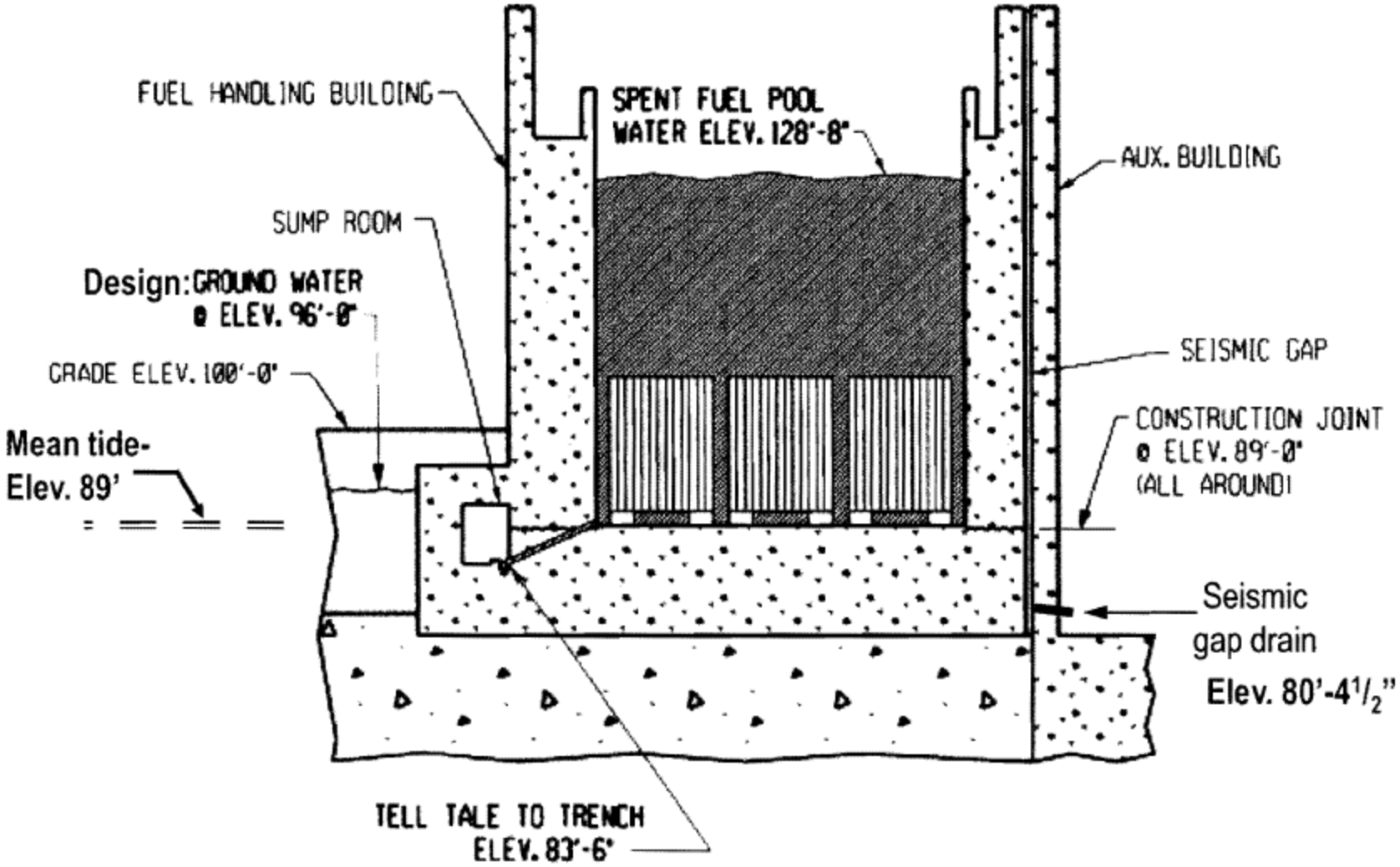


- Tell Tale Drains are maintained open to ensure leakage is captured
- Seismic Gap Drain installed in the Auxiliary Building to ensure any leakage is captured
- No additional contamination is exiting the structures

PSEG Nuclear LLC

Fuel Handling Building (Cross-Section at Spent Fuel Pool)

Cross section looking north



Salem Buried Pipe OE

- 2004 fuel oil steel piping leaked due to missing wrapping
- 2010 missing Unit 1 AFW coating
- 2010 control air pipe steel piping leaked where protective coating had been damaged

Salem Buried Pipe Staff Questions

- Basis of the inspection population size in relation to standard industrial sampling methods (5060 feet of in-scope buried pipe, 2110 of this total is SR) to ensure that the wall thickness of in-scope piping will meet or exceed design minimum values, though the period of extended operation

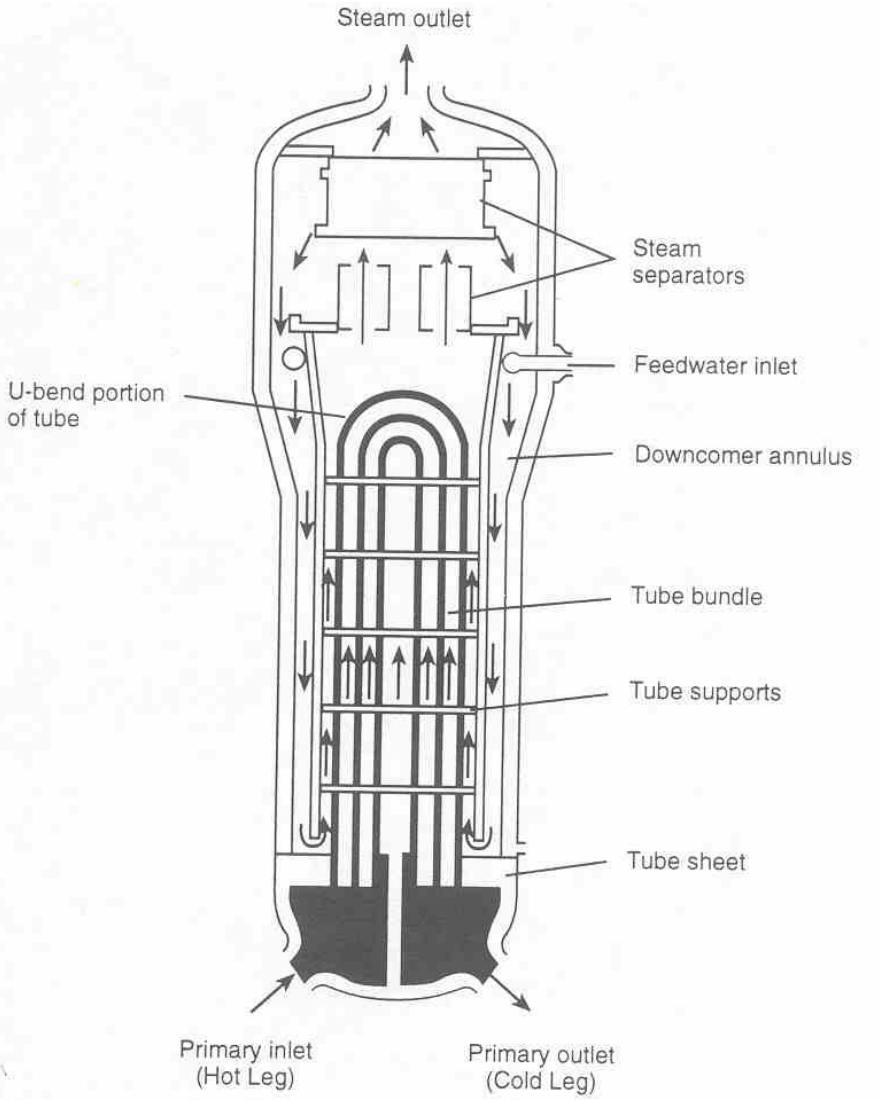
- How will localized soil data (e.g., pH, composition of the soil, water table, chemical runoff probability, soil resistivity, potential for stray currents) be used to inform the inspection locations

Resolution of other license renewal generic issues

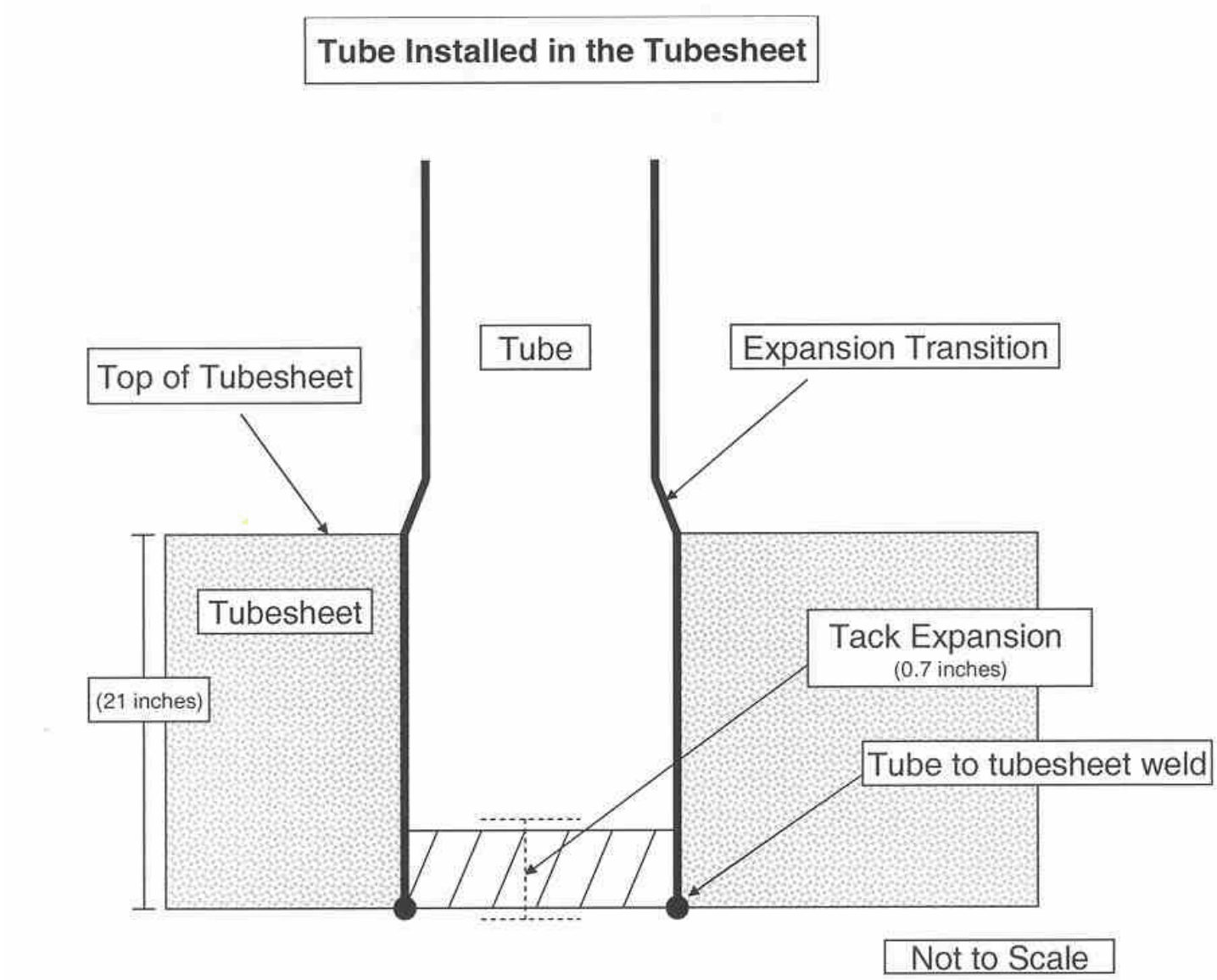
- One time inspection of small bore piping
  - Four volumetric examinations, two per unit, from a population of 34 and 36 socket welds, respectively
- ASME Section XI inspections of containment liner
  - 57 randomly selected liner panels for each unit before PEO
  - 12 in each 10 year period
- Inaccessible medium voltage cables
  - Expanded scope to low voltage cables
  - Test cables at least every six years and inspect manholes at least yearly
- Steam generator divider plate
  - Inspect each Unit 1 SG (4) divider plate assembly to detect PWSCC

AMP XI.M35, One-Time Inspection of ASME Code Class 1 Small Bore Piping - continued

Failures			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
OTI within 6 years before PEO			OTI within 6 years before PEO
1 DE = 2 VE			1 DE = 2 VE



PWR Recirculating Steam Generator


Tube Installed in the Tubesheet
Top of Tubesheet
Tube
Expansion Transition
Tubesheet
(21 inches)
Tack Expansion
(0.7 inches)
Tube to tubesheet weld
Not to Scale