UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

February 17, 2011

MEMORANDUM TO: ACRS MEMBERS

FROM: Michael L. Benson, Staff Engineer ***/RA/***
Reactor Safety Branch A

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING, DECEMBER 1, 2010, ROCKVILLE, MARYLAND

The minutes of the subject meeting, have been certified as the official record of the proceedings for that meeting. A copy of the certified minutes is attached.

Attachment: As stated

cc via e-mail: E. Hackett
C. Santos
Y. Diaz-Sanabria

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

February 8, 2011

MEMORANDUM TO: Michael Benson, Staff Engineer
Reactor Safety Branch A, ACRS

FROM: John W. Stetkar, Chairman
Plant License Renewal Subcommittee

SUBJECT: CERTIFICATION OF THE MINUTES OF THE MEETING OF THE SUBCOMMITTEE ON PLANT LICENSE RENEWAL ON DECEMBER 1, 2010

I hereby certify, to the best of my knowledge and belief, that the Minutes of the subject meeting held on December 1, 2010 are an accurate record of the proceedings for that meeting.

/RA/ ***February 8, 2011***

John W. Stetkar, Chairman Date
Plant License Renewal Subcommittee

Certified by: John Stetkar
Certified on: February 8, 2011

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
Plant License Renewal Subcommittee Meeting Minutes
December 1, 2010
Rockville, MD

INTRODUCTION

The Advisory Committee on Reactor Safeguards (ACRS) Subcommittee on Plant License Renewal met on December 1, 2010 at 11545 Rockville Pike, Rockville, MD, in Room T2-B1. The purpose of the meeting was to review and discuss the license renewal application and associated Safety Evaluation Report (SER) with Open Items for the Salem Nuclear Generating Station (SNGS) Units 1 and 2. The Subcommittee heard presentations from Public Services Enterprise Group (PSEG) Nuclear, LLC and the Nuclear Regulatory Commission (NRC) staff. The Subcommittee gathered information, analyzed relevant information and facts, and formulated proposed positions, as appropriate, for deliberation by the full ACRS. The entire meeting was open to the public. Ms. Kathy Weaver was the Designated Federal Official for this meeting. The Subcommittee received no written comments or requests for time to make oral statements from any members of the public regarding this meeting. The meeting was convened at 1:30 pm and adjourned at 4:41 pm.

ATTENDEES

ACRS

John W. Stetkar, Chairman
Mario V. Bonaca
John D. Sieber
William J. Shack

John J. Barton, Consultant

Kathy D. Weaver, Designated Federal Official

NRC Staff

Bennet Brady
De Jesus Samual Cuadrado
William Holston
Michael Modes
Abdul Sheikh
Melanie Gallowy
Allen Hiser
Stephen Klementowicz
Bo Pham

PSEG Nuclear, LLC

Paul Davison
Ali Fakhar
Jim Melchionna
Greg Sosson
Tom Roberts
Alan Johnson

SUMMARY OF MEETING

Opening Remarks

Chairman Stetkar called the meeting to order and introduced the attending Members. Ms. Galloway introduced the speakers and presentation topics.

[pp. 5-8 in the transcript]

PSEG Nuclear, LLC – Salem Nuclear Generating Station

Site Description/Operating History

Mr. Sosson explained that the Salem and Hope Creek plants share a common site on the Delaware River. Salem is a two-unit, four-loop Westinghouse pressurized water reactor (PWR). PSEG Nuclear has replaced the steam generators, the high- and low- pressure turbines, and the reactor head at SNGS Unit 1. The steam generators, high-pressure turbine rotor, and reactor head for Unit 2 have been replaced. The Mechanical Stress Improvement Process (MSIP) was performed on the Unit 1 hot and cold leg nozzles and the Unit 2 hot legs. SNGS is on an 18-month operating cycle.

[pp. 8-12 in transcript, slides 3-6 in presentation]

License Renewal Overview

Mr. Fakhar stated that there are 48 aging management programs (AMPs), with 32 existing programs and 16 new programs. Seventeen existing programs required enhancements. Six existing programs and two new programs had exceptions to the Generic Aging Lessons Learned (GALL) report. The 50 license renewal commitments are managed under Nuclear Energy Institute (NEI) document 99-04 and are tracked in a database. Implementation documents are being revised to ensure that commitments are accounted for. Station and corporate positions are being created for commitment implementation.

There are four open items associated with the application. The first is related to the use of the WESTEMS software for fatigue monitoring. NRC staff requested a benchmark evaluation, which is being performed for the pressurizer nozzles and the boron injection tank injection nozzle. Staff also asked PSEG Nuclear to verify that the NUREG/CR-6260 locations bounded the plant for fatigue evaluation. PSEG Nuclear will review all Class 1 fatigue analyses to determine if there are more limiting locations. Environmental effects will be included in the analysis, if appropriate.

The second open item entails potential primary water stress corrosion cracking (PWSCC) in the steam generator Alloy 600 tubesheet welds. PSEG Nuclear plans to implement inspections of the tube-to-tubesheet welds, as part of a plant-specific AMP for both units.

The final two open items involve spent fuel pool leakage and buried piping.

[pp. 12-17 in transcript, slides 7-12 in presentation]

Technical Items of Interest

Mr. Davison said that the third open item addresses spent fuel pool leakage in Unit 1. Approximately 100 gallons per day is leaking through undetected cracks in the walls. PSEG Nuclear has implemented a program to manage the leakage.

Mr. Roberts explained that the Unit 1 spent fuel pool has been leaking at a rate of 100 gallons/day over the last seven years. The leakage is occurring through weld cracks, which are believed to be the result of differential thermal expansion between the liner and the concrete. There are 2,100 linear feet of seam welds and 1,400 plug welds that attach the liner to the concrete structure. The estimated aggregate flaw dimensions are six inches long by 0.001 inches wide.

Groundwater contamination was discovered outside the fuel handling building in 2002. The leakage collection system should capture any leakage from liner welds and route it through tell tale drains. Subsequently, the leakage should be processed through the radioactive waste system. Mineral deposits from the concrete eventually clogged the tell tale drains. As a result, the leakage accumulated in the gap between the liner and the building concrete. The build-up of hydrostatic pressure forced the leakage into the concrete construction joints, eventually leading to seepage of the water into the seismic gap between the fuel handling building and the auxiliary building. The contamination has remained on site and has not entered drinking water sources. Corrective actions have included contamination remediation, unclogging the tell tale drains, and installation of seismic gap drains.

Mr. Roberts explained that laboratory testing was performed to determine the degradation of the concrete structure due to exposure to borated water. While borated water does attack the cement bonding phase, visual examination and hardness testing of the exposed surfaces have revealed no significant degradation. Calculations showed that design margins remain adequate after projected degradation.

Managing the leak requires several actions. Daily walk downs are performed to monitor the tell tale drains. Pump run times are recorded and trended to obtain indication on possible tell tale drain blockage. The tell tale drains are examined every six months with a boroscope. The seismic gap drains are monitored to identify possible contamination. The Unit 1 sump room wall and fuel handling building surfaces are periodically inspected for possible structural degradation. A core bore in the sump room will be performed prior to entering the period of extended operation.

Mr. Roberts said that one open item involved the structures monitoring program. All leakage is contained within the building structures by maintaining the leakage collection system. The leakage does not have a significant impact on the fuel handling building. Design margin ensures that the concrete will not degrade substantially. Maintaining the leakage collections system minimizes concrete degradation and contamination of the environment.

[pp. 17-41 in transcript, slides 14-19 in presentation]

Mr. Melchionna said that the buried pipe program encompasses all the buried pipe systems at the Salem site. The buried piping systems in scope for license renewal include the auxiliary feed water, compressed air, demineralized water, fire protection, non-radioactive drain, service water, and circulating water systems. SNGS does not have installed cathodic protection for any in-scope piping systems. NACE International (formerly, the National Association of Corrosion Engineers) and Electric Power Research Institute (EPRI) guidance are used to risk rank the various piping segments. The ranking system drives inspection schedules. PSEG Nuclear is participating in the NEI program on buried piping. Buried pipe materials in scope for license renewal include carbon steel, gray cast iron, ductile cast iron, stainless steel, and pre-stressed concrete. Each material group is subject to a specified number of inspections.

During the Spring 2010 refueling outage for Unit 1, two auxiliary feed water piping segments were excavated for scheduled inspections. Portions of these lines were found with degradation and missing coating. Entire piping runs were replaced. The coatings were inadvertently removed during construction. The piping located near the fuel transfer tube was rerouted above ground. Similar piping for Unit 2 was inspected to verify the presence of coating. The buried pipe program was successful, since the issue was detected before leaks occurred.

Mr. Melchionna explained that there is one open item on buried piping, requesting additional information on the incorporation of recent operating experience into the buried piping program.

[pp. 42-56 in transcript, slides 21-26 in presentation]

Mr. Johnson explained that the containment building is constructed with reinforced concrete and a carbon steel liner. Liner insulation covers the bottom 32 ft of the cylinder, limiting the ability to inspect the liner. Modifications had to be made such that the bottom three inches of the liner and moisture barrier are easily inspected. The Unit 1 moisture barrier has been replaced. The Unit 2 moisture barrier is scheduled for replacement in 2011.

Early in plant life, Salem experienced service water leaks inside containment. Equipment was replaced and procedures were implemented to decrease the likelihood of continued leaking. Twelve panels will be inspected during each 10-year inspection interval.

Mr. Davison concluded the applicant's presentation.

[pp. 56-76 in transcript, slides 28-35 in presentation]

NRC Staff Presentation SER Overview

Ms. Galloway and Ms. Brady introduced the NRC staff's presentation. Ms. Brady said that the Salem license renewal application was received by NRC on August 18, 2009. The audit and inspection activities required more time than normal, because they covered both Salem and Hope Creek nuclear plants. In reviewing the application, the staff issued 120 Requests for Additional Information (RAI).

The SER was issued with four open items on December 4, 2010. Two of the open items involved the buried piping program and leakage from the spent fuel pool. The third open item relates to the potential for primary water stress corrosion cracking in steam generator tube-to-tubesheet welds. The final open item addresses the software used for analyzing metal fatigue and the selection of limiting locations for environmentally-assisted fatigue analysis.

[pp. 92-96 in transcript, slides 1-6 in presentation]

Scoping and Screening Results

Section 2 of the SER evaluates the applicant's scoping and screening process. The few RAI issued on this topic involved drawings, anchor points, and the cathodic protection program.

[pp. 96-97 in transcript, slide 7 in presentation]

Onsite Inspection Results

Mr. Modes said that the onsite inspection involved review of AMPs that were common for Hope Creek and Salem and programs that were unique to each facility. Programs that are reviewed in the reactor oversight process, such as inservice inspection, were not considered by the license renewal inspection team. The Boral Program was scrutinized to determine how the applicant responded to an interim staff guidance issued on the subject. The team selected the feed and condensate system to determine how an AMP was implemented. A number of systems were walked down by the inspection team to test the applicant's understanding of the plant configuration.

[pp. 97-98 in transcript, slide 8-9 in presentation]

NRC Audits

Ms. Brady explained that the various AMPs were evaluated in Section 3 of the SER. Over 5,000 line items describe the system reviewed, its material, its environment, the aging effect, and the program intended to manage the aging effect. The AMPs were reviewed for consistency with the GALL report. Programs that were not consistent with GALL required a more in-depth review to determine acceptability.

During Staff's review of the buried piping program, discussion centered on instances of leaking. In 2004, there was a fuel oil leak that resulted from missing pipe wrapping. A leak in the Unit 2 control air line resulted from damaged coating. Several RAI were issue, and a number of issues were resolved. However, the staff is concerned about the lack of cathodic protection on certain pipes. Without cathodic protection, the sample size proposed by the applicant may not be adequate for assuring integrity of buried piping. An additional RAI will be issued on whether inspection samples are properly informed by available data.

Ms. Brady introduced the next open item, spent fuel pool leakage. Borated water had migrated through small cracks in the concrete to reach the seismic gap between the auxiliary building and the fuel handling building. After cleaning the tell tale drain system, the applicant believes that the majority of the leakage is contained. During staff's review, the applicant committed to visually inspecting one accessible wall vault every 18 months and to remove concrete core samples from leaking locations. The staff is still concerned that leakage may be occurring in three inaccessible walls.

The third open item addresses PWSCC in steam generator tube-to-tubesheet welds. The Unit 1 tubes are fabricated from Alloy 600 with Inconel cladding. The Unit 2 tubes are made from Alloy 690 with Alloy 600 cladding. The staff issued an RAI on whether the Unit 1 welds were considered part of the reactor coolant pressure boundary. If they are not, then the applicant should provide an AMP to verify the effectiveness of the water chemistry program. For Unit 2, the staff asked the applicant to provide a plant-specific AMP or to provide rational on why one is not needed.

Ms. Brady said that the staff has been examining their review process to ensure that the reviews are based upon the most current information and that issues are consistently addressed across all license renewal applicants. As a result, the staff will be sending additional RAI to the current applicants. Salem will receive two RAI on the Selective Leaching of Materials and One-Time Inspection programs regarding sample size and component selection. The RAI will be issued in December 2010.

[pp. 98-125 in transcript, slides 10-16 in presentation]

Time Limited Aging Analyses

Section 4.0 of the SER describes the staff review of Time Limited Aging Analysis. The one open item in this section is on metal fatigue analysis. The first question involves the use of the WESTEMS software for calculating fatigue usage factors. Users have the option of modifying many parameters that affect the results of the calculation. It is, therefore, difficult for the staff to assess the accuracy or conservatism of the calculated fatigue usage factors. The RAI asked PSEG Nuclear to explain how WESTEMS was used to benchmark against the initial design analysis of record.

The other question addresses concerns about selection of limiting locations for environmentally-assisted fatigue analysis. The applicant used the six locations listed in NUREG/CR-6260, and the staff asked the applicant to verify that those locations are indeed bounding.

[pp. 125-128 in transcript, slides 17-18 in presentation]

Ms. Brady said that the staff finds that, pending satisfactory resolution of the open items, PSEG Nuclear has met the requirements of Title 10 Code of Federal Regulations Part 54.29(a) for license renewal of Salem Nuclear Generating Station.

[p. 128 in transcript, slide 19 in presentation]

SUBCOMMITTEE DISCUSSION

PSEG Nuclear, LLC

Site Description/Operating History

Member Shack asked whether MSIP had been performed on both units. Mr. Sosson said that MSIP was performed on the hot legs on Unit 2, with ultrasonic testing completed on the cold legs.

[pp. 11-12 in transcript, slide 4 in presentation]

License Renewal Overview

Mr. Barton asked whether there was an expected date for the submission of the inspection plan for the tube-to-tubesheet welds. Mr. Fakhar replied that the plan will be submitted before entering the period of extended operation (PEO). Member Shack asked about the choice of Alloy 600 for the Unit 2 tubesheet facing. Mr. Spear explained that the tubes were made of Alloy 690, with Alloy 600 cladding. Mr. Hufnagel clarified that the plan to inspect the welds would be submitted this week.
[pp. 16-17 in transcript, slide 11 in presentation]

Technical Items of Interest

Chairman Stetkar asked about leakage from the Unit 2 spent fuel pool. Mr. Roberts replied that Unit 2 shows 1 gallon/day of leakage. Member Shack asked about the history of observing leakage in Unit 1. Mr. Roberts explained that they monitor the leakage weekly, with trending data available for the last seven years.

[pp. 20-21 in transcript, slide 14 in presentation]

Chairman Stetkar inquired about the seismic gap drains. Mr. Roberts explained that water flow has been observed in those drains. The hydrostatic head developed during the initial event created a flow path, which still allows water to flow. Chairman Stetkar asked about the physical layouts of the buildings. Member Sieber pointed out that 2.5 million gallons of water would have leaked. Installing drains may not be sufficient to stop the leakage. Mr. Keating discussed a contamination plume map. The seismic gap drains are designed to keep the leakage below grade level, so that it will not overflow into the environment. PSEG Nuclear has installed 36 wells, six of which pump shallow ground water. The current contaminant concentration in the wells is below 50,000 pCi/L. Member Sieber pointed out that the leak will always continue under PSEG Nuclear's current plan. Mr. Keating replied that none of the leakage will contaminate the environment. Chairman Stetkar asked about the drains in the Unit 2 spent fuel pool. Mr. Roberts said that the tell tale drains for each unit are inspected for blockage every six months.

[pp. 23-30 in transcript, slides 15 and 37 in presentation]

In response to a question from Member Sieber, Mr. Roberts explained that the leak's impact on the fuel handling building was minimal and that the leakage to the environment is stopped. Based upon this status, PSEG Nuclear opted to manage the leak rather than repair the liner.

[p. 33 in transcript, slide 16 in presentation]

Member Sieber asked about the applicant's plan to monitor tritium content. Mr. Keating explained that 36 wells monitor radioactivity in the groundwater and described a slide showing the locations of the wells. Based upon observations of the wells, PSEG Nuclear is confident that radionuclides are not leaving the site nor entering the aquifer. The dimensions and activity of the plume are decreasing. Member Sieber asked whether the applicant had performed ground water studies to determine the direction of water travel. Mr. Keating said that they have developed a conceptual model to calculate ground water flow.

Member Sieber asked whether PSEG Nuclear obtained soil structure profiles while digging the wells. Mr. Keating explained that the profiles were obtained at five or ten feet intervals. This information was incorporated into their models. NRC Region I staff has seen the study. Chairman Stetkar pointed out that the Committee may like to see the soil structure profile data. Mr. Roberts stated that a unique site hydrology exists due to cofferdams installed during construction. Water migration occurs within the top 20 ft of soil. Chairman Stetkar pointed out that the water could migrate vertically into a deep aquifer. Mr. Keating responded that monitoring the aquifer well ensures that water is not migrating vertically. The tritium detected in the aquifer is believed to be a result of weapons testing. Drinking water comes from 600 – 1,000 ft deep aquifers, so PSEG Nuclear is not concerned with impacting drinking water.
[pp. 34-40 in transcript; slides 17, 37, and 38 in presentation]

Chairman Stetkar asked about carbon steel buried piping in the auxiliary feed water system. Mr. Sosson said that the section of piping from the discharge of the pumps to the steam generators is carbon steel. Mr. Melchionna explained that two of the trains are buried in the outside contaminated area and two are within the auxiliary building.

[pp. 43-44 in transcript, slide 22 in presentation]

Mr. Barton asked whether all the auxiliary feed water piping was missing coating. Mr. Melchionna replied that it was.

[p. 46 in transcript, slide 23 in presentation]

Chairman Stetkar asked whether PSEG Nuclear would be inspecting more Unit 2 piping. Mr. Melchionna stated that additional inspections would occur in Spring 2011. The coating appears to have been physically removed from the pipe. An outer protective wrap was placed outside the coating to prevent coating damage during construction. Only the outer wrap should have been removed prior to burial. Chairman Stetkar asked about the instrument air pipes. Mr. Melchionna stated that those pipes had coating. The coating may have been intentionally removed from the auxiliary feed water piping, since both the protective wrap and the coating were the same color.

[pp. 47-49 in transcript, slide 24 in presentation]

Chairman Stetkar pointed out that most of the safety-related carbon steel pipe in the service water system was replaced with stainless steel. He asked whether the underground pipe materials were changed in a similar manner. Mr. Melchionna replied that the underground pipe is the same carbon steel material. This piping runs from the intake structure to the sprayer. The carbon steel portions are coated with epoxy. There are transitions to a pre-stressed concrete pipe. A bell and spigot joint demonstrated some leakage in the past.

Chairman Stetkar asked about bolted connections in the buried service water piping. Mr. Melchionna explained that the first joint is bolted, with epoxy coating on the outside. Chairman Stetkar asked about the flow test used to assess the condition of the bolts. Mr. Muggleston said that they do not excavate Class 3 bolts, but they are examined opportunistically.

[pp. 51-56 in transcript, slide 26 in presentation]

Mr. Barton asked about the material of the containment liner insulation. Mr. Johnson said that it is a mineral that does not retain moisture. It may contain asbestos. When the insulation is moved, PSEG Nuclear takes precautions to protect their employees. Member Sieber asked about the function of the insulation. Mr. Johnson explained that the insulation prevents fast heat up of the steel during design basis accidents. Member Sieber asked whether the insulation was necessary. Mr. Johnson stated that it was a design choice to provide more margin against buckling. Member Sieber pointed out that mineral wool may not be desirable, due to Generic Safety Issue 191. Mr. Johnson said that PSEG Nuclear's response to Generic Letter 191 was to replace the 400 ft^2 strainer with a 5,000 ft^2 strainer. Member Sieber asked about the applicant's analysis on this issue. Mr. Johnson said that PSEG Nuclear has an analysis that accounts for every debris type. The insulation is part of the applicant's original design basis, and it gives them margin against buckling. They have decided to keep the insulation in place.
[pp. 51-56 in transcript, slide 26 in presentation]

Chairman Stetkar asked about the condition of the moisture barrier. Mr. Johnson said that portions of the containment liner immediately above the moisture barrier had slightly corroded. No known damage has occurred to other components, as a result of the corrosion.

[pp. 61 in transcript, slide 29 in presentation]

Member Sieber asked about the pit depths in the liner. Mr. Johnson said that five locations along the circumference were below the specified nominal thickness of 0.75 in. None of the thickness measurements deviated by 10% from nominal (0.75 in), meeting inspection criteria. In response to a question from Chairman Stetkar, Mr. Johnson explained that the moisture barrier was removed only in those areas where corrosion was present. Chairman Stetkar asked whether the applicant could observe the corrosion extending below the moisture barrier. Mr. Johnson said that the moisture barrier was removed to the point of no corrosion, in all cases.

Chairman Stetkar observed that Unit 2, around the 190^{o} azimuth, exhibited lower thickness measurements than was typical for the other measurements.

[pp. 63-66 in transcript, slide 32 in presentation]

Member Shack asked if the applicant obtained thickness measurements at different heights along the containment wall. Mr. Johnson explained that they did investigate different locations. Member Sieber asked whether all the insulation is boxed in. Mr. Johnson stated that the insulation was boxed in and that a direct jet impingement would be required to create insulation debris.

In response to a question from Chairman Stetkar, Mr. Johnson stated that all the corrosion was located above the test channel. Chairman Stetkar asked whether the applicant verified that water was not coming down between the insulation panel and the liner. Mr. Johnson said that panels were pulled as part of license renewal commitments. Additions panels were removed in low-thickness locations. No water intrusion was observed. Chairman Stetkar pointed out that 12 panels are to be removed every ten years, as part of an AMP. In response, Mr. Johnson explained that they will inspect the liner behind 57 panels prior to entering the PEO. The panels will be randomly selected. Chairman Stetkar asked whether the sampling locations could be selected based upon corrosion susceptibility, rather than at random. Mr. Giles stated that areas that have evidence of possible corrosion would be investigated. Mr. Johnson said that chloride contamination is one input to risk inform the inspection program. Member Shack pointed out that the sample locations should be randomly selected for performing statistical analysis on the data. If a location is selected based upon a susceptibility determination, then it would be inspected separate from the aging management program. Mr. Johnson said that they are using risk-informed requirements in their current licensing basis.

[pp. 67-75 in transcript, slide 31 in presentation]

Mr. Barton asked about a gas turbine that is not in scope for license renewal. Mr. Hilditch explained that it is not safety related. The turbine is not credited for station blackout mitigation. Mr. Barton asked about winter heating of exhaust fans that are associated with the service water system. Mr. O'Donnel replied that the fans are heated by area heaters in the pump compartments and by pump waste heat.

Mr. Barton asked about maintenance of the switch yard. Mr. Sosson said that PSEG Nuclear maintains components 13 kV and lower, while the distribution operator maintains the 500 kV system. Tight access controls are implemented when the transmission operator enters the switchyard. Mr. Barton asked about the restoration of charging pumps. Mr. O'Donnell explained that the Unit 2 positive displacement pumps were restored.

Mr. Barton observed that four volumetric examinations of small bore piping are required. He said that this approach is not representative of small bore piping examinations. Mr. Piha said that Salem has no operating experience on stress corrosion cracking of Class 1 socket welds. Performing four exams out of 36 susceptible locations on Unit 1 and 34 locations on Unit 2 seems appropriate.

Mr. Barton asked about inspections of submerged cable manholes after severe weather events. Mr. Stead explained that they committed to inspect manholes every six years and to assess cable condition after rain or other events. Chairman Stetkar asked about inspection of cable conduit ends and whether low points exist in the conduit that can collect water. Mr. Stead responded that there are no low points in the conduits. Mr. Barton asked about future plans for power uprates at the Salem plant. Mr. Davison said that PSEG Nuclear has no plans for power uprates.

Mr. Barton inquired about inspection of tanks. Mr. Spear stated that the tanks are inspected periodically. A one-time inspection of the oil water tank will occur. No exterior corrosion has been identified during inspections.

Chairman Stetkar asked about multiple replacements of the in-core flux thimbles. Mr. O'Donnell explained that the initial replacement involved upgrading to a double-wall design. Some of the double-walled thimbles were replaced due to thermocouple malfunctions and thimble insertion issues. Chairman Stetkar asked about estimates of wall-thinning rates for the flux tubes. Mr. Spear stated that the drawing thickness will be compared to thickness measurements. Wear rates will be calculated during each outage. Chairman Stetkar pointed out that eddy current testing has not occurred since 1993, creating difficulties in determining accurate wear rates. Mr. Spear said that relatively new tubes could be compared with tubes that have been in service for a long time. Chairman Stetkar expressed concern that the applicant was taking measurements over a short time period and trying to make projections for longer time periods. Mr. O'Donnell explained that they have replaced 25% of the thimbles. They will be considered in quadrants. The sample will be adequate to determine wear rates. Chairman Stetkar pointed out that 11 tubes were originally replaced. If only 25% have been replaced, then not many additional tubes have been replaced since the original 11 were changed out. Chairmen Stetkar asked about the timing of the eddy current testing. Mr. O'Donnell responded that it will be completed during the PEO.

Mr. Barton asked whether the applicant has inspected building foundations as a result of a historical groundwater leak. Mr. Roberts explained that the auxiliary building has been inspected in the area adjacent to the fuel handling building. No concrete degradation was observed. Chairman Stetkar asked whether ground water intrusion has been observed in buildings other than the auxiliary building. Mr. Roberts said that there is evidence of ground water infiltration. Some of the wall of the auxiliary building had to be removed as part of a repair activity. The groundwater leaked from a path associated with that activity.

Member Shack asked about the ultrasonic testing results of a nozzle after MSIP had been applied. Mr. Roberts said that they do not have evidence of any stress corrosion cracking in the nozzle. The signal was dramatically reduced after MSIP was applied.

[pp. 76-92 in transcript, slide 35 in presentation]

<u>NRC Staff Presentation SER Overview</u>

<u>NRC Audits</u>

Mr. Barton asked about the applicant's reasoning for not applying cathodic protection. Mr. Melchionna explained that the plant was initially designed without cathodic protection for buried piping. Materials and coatings were selected based upon the supposition that cathodic protection would not be applied. A study is scheduled to consider the need for cathodic protection. No piping degradation has been discovered during inspections. Data from soil sampling indicate that the soil is noncorrosive, including undetectable chlorides. Mr. Barton expressed surprise that chlorides were undetectable because of the plant's vicinity to the salty Delaware River. Chairman Stetkar pointed out that the groundwater has high chloride content. He asked about the groundwater level relative to the typical burial depth of piping systems. Mr. Melchionna stated that soil samples are taken very close to the pipe. The results show no chlorides or sulphates and high soil resistivity. Chairman Stetkar wondered how the groundwater was avoiding the buried pipe.

Chairman Stetkar asked whether Revision 2 of the GALL report specified guidance on sample sizes for sites that do not employ cathodic protection. Ms. Brady responded that the GALL report does not contain that guidance. Mr. Holston explained that GALL AMP 41 ensures that the cathodic protection system is operating effectively. If a plant does not have cathodic protection but has good backfill and coatings, then the GALL suggests inspecting four locations. The applicant in this case would be taking an exception to AMP 41, since they are not installing cathodic protection. They have to, therefore, justify their inspection plan. The staff does not believe that the proposed four inspection locations are adequate to ensure buried pipe integrity.

Member Stetkar asked the staff about the service water system flow test used to verify the integrity of buried bolts. Mr. Holston explained that the bolting integrity program for above-ground bolting specifies a visual walkdown. Since buried bolting cannot be examined that way, the staff asked the applicant to visually inspect the bolting whenever the pipe is excavated. The flow test is an alternative method, given that the accurate flow instrumentation is in place. Plants have been performing flow tests for a long time.

[pp. 101-108 in transcript, slide 12 in presentation]

Mr. Klementowicz, who performed the environmental review, asked the Subcommittee for clarification on their questions about the radiological impact of the spent fuel pool leak. Member Sieber said that PSEG Nuclear may be in violation of their state-issued discharge permits. Mr. Klementowicz said that the NRC has been following the spent fuel pool leakage since 2002. The applicant is in full compliance with NRC's regulations on radiological releases to the river. The dose impact of the release was within As Low As Reasonably Achievable (ALARA) objectives. The reactor oversight process considers effluent release to the environment. The leaking water always remained within the site. According to a remediation program between the applicant and the State of New Jersey, the groundwater is pumped into Salem's radioactive waste system and released according to NRC regulations. NRC's radiological environmental monitoring program considers offsite dose impacts. Chairman Stetkar asked about the possibility of the contamination reaching the 70-ft aquifer. Mr. Klementowicz said that the NRC retained a hydrologist to inspect the site. All data indicated that the deep aquifer was not contaminated. Chairman Stetkar asked whether the staff was confident that the existing contamination would not migrate to the deep aquifer. Mr. Klementowicz could not answer the question.

[pp. 109-114 in transcript, slide 12 in presentation]

Chairman Stetkar asked about the core sample. Mr. Sheikh said that the wall is over 8 ft thick, with the core being 2 ft. The applicant has agreed to expose the rebar to examine for corrosion, as well. While there is no leakage along the west wall, there is leakage on the east wall through the seismic gap. The applicant is collecting 0.25 gal/day in an installed drain. Studies by the applicant have shown that the contamination will not affect the concrete or rebar. Dr. Naus said that the literature does not indicate that boric acid adversely affects cementitious materials. The borated water pH is 4.5-4.7, which is too high to damage the concrete. Experiments showed that the reaction would likely result in a crust or precipitate that would stop the reaction. The core sample will confirm what is actually happening.

[pp. 116-119 in transcript, slide 13 in presentation]

Chairman Stetkar pointed out that GALL Revision 1 specified an AMP for tube-to-tubesheet welds in once-through steam generators, but not recirculating-type steam generators. He asked if Salem is the first plant that is receiving pressure from the NRC to implement an AMP on the tube-to-tubesheet weld integrity. Ms. Brady said that Kewaunee and Salem are the first to receive an RAI on this subject. Chairman Stetkar asked about the number of plants with approved license renewal applications that have Alloy 600 tubesheet welds and no AMP. He said that he would like to hear about that at the Full Committee meeting. Dr. Hiser said that it may be difficult to obtain that information. The GALL Revision 1 position was that PWSCC was not an issue for recirculating steam generators. Onsite inspections may address this issue, however. Member Shack asked about the effects of primary water chemistry. Dr. Hiser said that water chemistry is not likely very effective. There are not many differences between once-through and recirculating steam generators. Alloy 600 can crack in a primary water environment. It may not be an issue for today's operating reactors, but it is of concern at long service lifetimes.

[pp. 120-123 in transcript, slide 14 in presentation]

<u>Time Limited Aging Analyses</u>

In response to a question from Member Shack on WESTEMS, Dr. Hiser explained that the results from the stress and transient analyses have to be modified by the analyst. There may be insufficient guidance or training on how the modification should be done.

[pp. 126-127 in transcript, slide 17 in presentation]

Chairman Stetkar said that resolution of the open items should be discussed at the Full Committee meeting. Member Sieber said that sampling frequency of the in-core flux thimble tubes and how that relates to determining wear rates should be included in the Full Committee presentation. Member Shack said the issue of whether cathodic protection will be employed at the plant should be discussed with the Full Committee. The Members discussed the issue of containment liner corrosion. Member Sieber pointed out that containment water problems are occurring at other plants, so it may be a relevant topic for the Full Committee meeting.

[pp. 130-134 in transcript, slide 19 in presentation]