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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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SUBCOMMITTEE ON PLANT LICENSE RENEWAL

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WEDNESDAY

MAY 7, 2008

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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 10:30 a.m., Dr. John Stetkar, Chairman, presiding.

COMMITTEE MEMBERS:

JOHN STETKAR, Chairman

MARIO V. BONACA, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

OTTO L. MAYNARD, Member

SAID ABDEL-KHALIK, Member

CONSULTANTS TO THE SUBCOMMITTEE:

JOHN J. BARTON

NRC STAFF PRESENT:

PETER WEN, Cognizant Staff Engineer

SAMSON LEE

LOUISE LUND

CAUDLE JULIAN

ROBERT HSU

KEN CHANG

ALSO PRESENT:

CHRIS BURTON

JOHN CAVES

ROGER STEWART

CHRIS MALLNER

BOB REYNOLDS

MIKE HEATH

MIKE FLETCHER

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

(10:29 a.m.)

CHAIR STETKAR: The meeting will not come to order. This is a meeting of the Plant License Renewal Subcommittee. My name is John stetkar. I'm Chairman of the Shearon Harris Plant License Renewal Subcommittee. ACRS Members in attendance are Otto Maynard, Jack Sieber, Bill Shack, Mario Bonaca, Said Abdel-Khalik, and our consultant, John Barton.

Peter Wen of the ACRS staff is the cognizant staff engineer for this meeting.

The purpose of this meeting is to review the license renewal application for the Shearon Harris Nuclear Plant, the Draft Safety Evaluation Report and associated documents. We will hear presentations from representatives of the Office of Nuclear Reactor Regulation and the applicant, Carolina Power & Light. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for deliberation by the full committee.

The rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the Federal Register on April 15th, 2008. We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

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

We'll now proceed with the meeting and I call upon Dr. Sam Lee of the Office of Nuclear Reactor Regulation to introduce the presenters.

MR. LEE: Thank you very much. Good morning. This is Samson Lee. I'm the Acting Division Director for the Division of License Renewal NRR, and on my left is Louise Lund. She's the Project Branch Chief. On my right is Maurice Heath. He's the Project Manager for the Shearon Harris Safety Evaluation Report. And I also have Caudle Julian from Region II. He's the Team Leader. He'll be part of the presentation. I have Dr. Ken Chang. He's the Engineering Branch Chief, and he'll be discussing some of the technical details.

And also I have other technical staff

that are in the audience that can help answer questions. And I would also like to acknowledge Peter Wen, the ACRS staff member who actually coordinated the presentation.

And with that, the Applicant, Carolina Power & Light is going to start the presentation. And Chris Burton, the Director of Site Operations, you can start.

MR. BURTON: Thank you. Good morning. My name is Chris Burton. I'm the Director of Site Operations at the Shearon Harris site. It's a pleasure to be hear this morning. With me this morning are four members of the team that have association with this license renewal application -- Christ Mallner, part of the license renewal team and the mechanical engineering portion, Roger Stewart who's the manager for our fleet of license renewal overall, John Caves who's a member of my staff at the Harris site and technical services in the engineering group -- present to you this morning. We have several additional people that are available to answer questions if possible, if we're not able to.

This morning Mr. Stewart and I primarily will present information on plant background, a short description of the site, some of the improvements that have been made over the course of the first 20 years of operation of the Harris unit, the scoping of license renewal, generic aging, lessons learned, discussion, commitments associated with our application, open item discussion and then any confirmatory items.

In 1971, Carolina Power & Light, now known as Progress Energy, announced plans for construction of the Harris units. In 1978, a construction permit was issued. In 1986, the license was issued and in May 1987, commercial operation began, or October 2026 will be the expiration date for the current license for the Shearon Harris unit.

Just a little bit about the Harris site and the reactor design. The NSSS is a Westinghouse 3-PWR. The architect engineer is EBASCO, 990 megawatts electrical, 2900 megawatts thermal. We operate on an 18-month refueling cycle, have a large site area encompassing a large lake, a cooling lake, and we use a cooling tower and that lake for our ultimate heat sink.

Just a note about the ownership of the output of the unit. Progress Energy or Carolina Power & Light owns 84 percent of the output. We do have a co-owner. North Carolina Eastern Municipal

Power Agency owns 16 percent of our output and participate pretty actively in reviews of our performance and our daily operations.

MR. BARTON: Construction management was who? Was it also a EBASCO?

MR. BURTON: Yes, sir. Is that correct, Roger?

MR. STEWART: No. It was -- excuse me. I apologize -- Daniels.

MR. BARTON: Okay.

MR. STEWART: Actually, at the time Carolina Power & Light did the construction management, we had the construction management team and Daniels was the --

MR. BARTON: Was the contractor?

MR. STEWART: Yes, sir.

MR. BARTON: Got you. Okay. Thank you.

MR. SIEBER: Where is the makeup water for the lake come from?

MR. BURTON: It comes from the Cape Fear river. Really, it comes from -- that's how we fill the lake. We now have runoff that comes into the lake.

MR. SIEBER: Is runoff enough to keep the lake at operating conditions?

MR. BURTON: David?

MR. COLLETT: I'm Dave Collett from the Harris staff. The lake is fed from creeks, approximately four creeks.

MR. SIEBER: Well, the question was is that enough to provide you --

MR. BURTON: Yes, it is.

MR. SIEBER: -- with normal and emergency operation, or do you have some pump house someplace?

MR. BURTON: We also have an auxiliary reservoir that we keep full that's independent and available to use for emergency cooling water. The lake, the rainwater, and the runoff from the creeks is sufficient. As we went through a period of very dry weather last year, we still had sufficient margin in that lake to operate the plant without question. We never tabled at five or six months, capacity-wise, of having to question our ultimate heat sink capability.

MR. SIEBER: Do you have tech spec restrictions on the lake condition, like level comfort or --

MR. BURTON: Yes, sir, we do.

MR. SIEBER: Thank you.

MR. BURTON: Okay. Just a little bit

about some of the improvements we've made in recent years. We did replace our steam generators preemptively in 2001. The condition of those steam generators was not such they required replacement, but based on the materials, the tubing, we chose to do it at that time for the long-term health of the plant. At the same time in that outage, we performed a power uprate, a 4.5% power uprate of the Harris Plant and also did a T-ave or a T-hot recovery. Wee had derated our hot light temperature to preserve steam generator tube integrity over the few years prior to the replacement. So we regained some megawatt output in that activity.

In the last refueling outage completed in the fall of 2007, we mitigated the pressurizer Alloy 600 issue, number of welds on pressurizer spray, code safety lines and the surge line itself, conducted reactor vessel head inspections per MRP 139 expectations, and we also enlarged our containment sump capacity approximately 275 square feet to approximately 3,000 square feet of containment sump capability and have completed that work.

MEMBER SHACK: Now when you recovered that T-hot, is that going to increase the temperature of your vessel head, too?

MR. BURTON: Yes.

MR. SIEBER: Yes, sir, it did.

MR. SIEBER: Yes, T-ave went up. Those were model 51 steam generators originally?

MR. BURTON: They were D-4s.

MR. SIEBER: D's, oh, okay. I understand why you replaced them. And what's in there now?

MR. BURTON: D-75s.

MR. SIEBER: Okay.

MEMBER MAYNARD: On your pressurizer weld overlays, did you do any inspections before the overlay or just do the overlay?

MR. BURTON: We went straight to mitigation, sir.

Several things I want to share with the Subcommittee on our future improvements I think would be of interest, potentially germane. We are in the midst of a transition to NFPA-805. We are one of the two pilot fleets in doing that along with the Duke fleet, and we are well on our way. We expect to submit a license request to NRC in the next 60 days which will outline what we're going to do in risk space in an NFPA-805 for fire protection.

We also have installed a digital control platform for the site, and we have some applications, some nonsafety-related applications already running on that digital control system to improve our familiarity, our maintenance ability with digital controls, and we're certainly watching other people in the industry for the application of additional systems on the digital control platform. So that's a big effort for us as well.

And we do have several smaller power uprates on the books for the next couple of outages. We will do the LEFN or the Appendix K, the uncertainty recapture uprate. We'll install some of the equipment in our next outage and then we will go through the actual licensing effort and take advantage of that in a following outage. So we're two cycles away. We will also be upgrading our low pressure and high pressure turbines, rewinding our generator and will be doing some work on our coolant system.

So all of those things have some fairly small but still important megawatts regains there. And those are the key items that we're working on from a plant standpoint to continue to make the plant better, more reliable and safer.

MR. BARTON: When you add all your uprates, how much total percentage have you added to the plant, originally licensed?

MR. BURTON: Including the ones that we conducted in 2001, the one where we did the steam generator replacement and a T-ave or just the ones in the future, sir?

MR. BARTON: The one in the future.

MR. CAVES: It's about -- we expect about 1.6 for the measurement uncertainty uprate, and we still don't have a final answer in terms of how much we're going to be able to get out of the generator rewind.

MR. BARTON: Okay.

MR. BURTON: It could be anywhere between 8 and 20 associated with those turbines non-deadly the rewind, but the uncertainty recapture should be somewhere between 1 and 2% of our rate right now.

MR. SIEBER: Also, what's T-hot now?

MR. CAVES: I'm not sure about T-hot. Five eighty-eight is the T-cold.

MR. COLLETT: I'd have to figure it out, the -- somewhere on the quarter of 620 --

MR. SIEBER: Six twenty?

MR. COLLETT: -- the full power T-ave is 588.8.

MR. BURTON: We can get confirmation that and answer that after a break if that's acceptable, sir.

MR. CAVES: I would like to -- one of the things we had talked about earlier -- you had some questions about lake level. You know, since we're talking about future improvements, just for the standpoint of completeness, we have submitted the licensed amendment request to allow another approximately 15 feet of lake level. You know, right now I don't remember the exact number --

MR. SIEBER: It's even less feet?

MR. COLLETT: Yes, so we can go 15 feet deeper than we are right now.

MR. SIEBER: What's that tell me about your water supply?

MR. BURTON: Well, as I was talking about before --

MR. SIEBER: If you feel you need that?

MR. BURTON: Well, as we were going through what we considered to be a regional drought we were within five months of reaching the tech spec required low level in that lake which is, I believe, 215 feet, as I recall. And so as a precautionary measure, we looked at all the options including taking the plant offline at the appropriate time to determine how are we going to react if the drought persisted. Now the drought did not persist. The lake is currently full but we pursued taking some of the what we felt was the available calculational basis and examining it and determining, based on our pump suctions from that lake, did we have enough margin to have a lower tech spec limit on that lake. And as it worked out, we did. There's significant margin there.

MR. SIEBER: And the concern is the MPSH on your --

MR. BURTON: Yes, Ohio Emergency Service water pumps. Yes, sir.

MEMBER MAYNARD: Is your lake -- do you have like an ultimate heat sink? What's the safety-related part of the lake versus -- is the whole lake safety-related or?

MR. CAVES: What we have is we've got the main lake and we've got the main lake and we've got what we call the auxiliary reservoir. Both are required by our current tech specs, and -- but the auxiliary reservoir is the especially safety-related piece.

CHAIR STETKAR: What feeds the auxiliary reservoir?

MR. CAVES: They're bot fed from same creeks.

CHAIR STETKAR: Okay. It's just an overflow something from the main, the auxiliary.

MR. STEWART: If you think of it as two impoundments, you've got the main reservoir and the auxiliary reservoir is a separate impoundment. They're both seismic category one water structures, and both required per our licensing basis. But if something would happen to the main reservoir, the aux reservoir is still available.

CHAIR STETKAR: ESW return, though, is to the main reservoir through some, if I was reading it correctly, through a torturous path or something like that to enhance cooling?

MR. COLLETT: If I may add, the emergency service water returns to the auxiliary reservoir.

CHAIR STETKAR: To the auxiliary reservoir.

MR. COLLETT: Yes. And the auxiliary reservoir overflows to the main reservoir, so it's possible to keep the auxiliary reservoir by pumping from the main reservoir to the auxiliary reservoir. And I think it's also important to note that the reservoir is full now.

MEMBER MAYNARD: Roughly, what's the size of the lake, the reservoir we're looking at here, surface area?

MR. BURTON: I will get that information for you by right after lunch if that's acceptable?

MR. SIEBER: Yes, or acres.

MR. BARTON: Three hundred and forty acres or something --

MR. BURTON: I'd rather give you exact --

MR. SIEBER: It was real big. It was less than a square mile. So the reservoir is receiving the discharge, so that is going to be a lot warmer than the main lake?

MR. BURTON: That's only when emergency service water --

MR. SIEBER: That's right.

MR. BURTON: -- is running.

MR. SIEBER: Okay. And that's your ultimate heat sink, too? Okay.

MR. BURTON: Okay. At this point, I would introduce Roger Stewart again, our manager of license renewal, to go through some of the rest of the agenda items form our sampling. Roger?

MR. STEWART: Good morning. First, we'll talk about scoping. When we did our scoping, our sources of information included the equipment database and from the equipment database, we can get a listing of the systems and the components and the component plant locations that also includes quality class information. We also looked at the FSAR. We looked at our Design Basis Documents. We looked at current licensing information. And we also looked at the maintenance rule database.

We did our scoping on a system level, and one of the starting points that we used is we used the component classifications within a system to identify system as something that's potentially in-scope for licensing renewal, so if it had something that looked like it might be an (a)(1) or an (a)(2) or an (a)(3), we through and evaluated that system as potentially being in-scope for license renewal. The way we identified our structures is once we had gone through and identified the systems that were in scope, we looked at the structure to see what they contained and brought those into scope accordingly.

Relative to application of generic aging lessons learned, relative to GALL consistency, if you look at standard notes A through D, we were 89% consistent with GALL. As we did our aging management reviews, we relied on 40 aging management programs.

Twenty-eight of those were existing programs, 19 requiring enhancements. There were 12 new aging management programs credited. We did take exceptions in 14 aging management programs of GALL, and we had one site-specific aging management program. That's oil-filled cable testing program.

MEMBER SHACK: Just a question on that. There's a comment in the SCR on your fact program that you had leakage in carbon steel pipes without catastrophic failures, but when did those occur in the context of your FAC program?

MR. STEWART: I will have to get back to you on that. I don't recall offhand.

MR. CAVES: Yes. We've had some minor leaks. Our -- I don't recall the exact reference that you're referring to.

MEMBER SHACK: It's just there's a comment in the SCR that you've had leakage in carbon steel pipage, through-wall leakage but no catastrophic fail -- and it wasn't even clear to me -- it was in the context of the FAC program, but I don't know whether the through-wall leakage was FAC or something else.

MR. CAVES: I don't recall any FAC failures but I'll double check and get back to you on that. The leaks that we've had in the carbon sealed piping are primarily in the service water system.

MEMBER SHACK: Okay. And --

MR. CAVES: Okay. But I'll --

MEMBER SHACK: -- I was just --

MR. CAVES: -- double check and see if there's something else associated with FAC.

MR. SIEBER: Yes, it would be good if you, while you're checking on when, if you could check on the size of the line, material composition, how you repaired it, what implications they had to the application of CheckWorks otherwise.

MR. CAVES: Okay, sure.

MEMBER SHACK: That was just another curious thing is your application never mentions CheckWorks, but I assume that you actually use CheckWorks?

MR. CAVES: We do.

MR. SIEBER: Right.

MEMBER SHACK: I wasn't sure whether the document had some back door thing that you could use instead. You reference the EPRI document, but you never say CheckWorks anywhere in the 1600 pages, so --

MR. CAVES: That's true. Our utilization

of the CheckWorks program is actually expanding. You know, we have not taken full advantage of it in the past, and we do have plans in place and actually have it implemented now. But at the time the amendment was submitted, it's possible that we didn't have full implementation.

MEMBER SHACK: Okay. Just another aging management program, too. It's the thermal aging of the cast stainless steel. I was trying to figure out what was actually in this, because every time I came to a stainless steel component, you reference the letter from Chris Grimes that gave you an exemption that said it wasn't embrittled. What actually -- what components are actually in this aging management program that, you know, will embrittle?

MR. MALLNER: Okay. My name's Chris Mallner. The only component that was part of the program was the -- well, part of the review was the pressurizer spray head. And for the pressurizer spray head, we pulled the CMCRs for that component, did the evaluation according to the methodology in the Grimes letter and determined that it wasn't susceptible to thermal aging.

MEMBER SHACK: It wasn't?

MR. MALLNER: It was not. That's why we

don't have a program. We did the evaluation beforehand. The program itself, normally, the first thing you do is do a susceptibility evaluation and then determine required inspections. In this case, we did the susceptibility evaluations while we were in the process of doing the AMRs and had already dispositioned it.

MEMBER SHACK: Okay. So all your cast stainless components are rendered unsusceptible by those criteria?

MR. MALLNER: As far as the -- for the pressurizer spray head, we did a specific evaluation. The reactor cooling loop elbows also made of case were also determined not to be susceptible. Now we've evaluated those as part of the leak before break evaluation. We took into consideration the material properties. We came to the conclusion that thermal aging -- it was not susceptible per the Grimes letter, even though they do show some thermal aging over the full 60 years, but not to the level that's required by the Grimes letter to put it into program. But they were also evaluated, like I said, as part of the leak-before-break evaluation.

MEMBER SHACK: But again, just as part of the license renewal, you will look at every cast component and decide whether it has to be in a thermal aging program or not?

MR. MALLNER: That's -- well, we've already done that.

MEMBER SHACK: You've already done that.

MR. MALLNER: And that's why we don't actually have a program. We have an installation where we've done the evaluations already and we've already determined that those components that would have been -- could have potentially been in the program as defined in GALL, the M12 program, that ends up being a null set.

MEMBER SHACK: A null set. Okay. That's why I couldn't find any compounds?

MR. MALLNER: That's correct.

MR. STEWART: Relative to commitments for license renewal, to date Harris has made 37 commitments in support license renewal. And if you looked at the application of the SER, it was 35. When we talk about confirmatory items, we've made two additional commitments since the SER was issued in response to the confirmatory items. So that's how come we have a count of 37.

These commitments are tracked by the Progress Energy commitment tracking process. That's a corporate process that we use at all of our nuclear stations.

As we made a commitment in license renewal, we develop an implementation plan which is some guidance to take whatever the words are in the commitments and try to give some idea to the engineer or whoever may be implementing it as to okay, here's what you really need to do. And in those commitments we are working with the plant now, some of them will be implemented early. Some of them, obviously, will have to go on, like if we go to some of the one-time inspection stuff, you don't do those until the last ten years. The plan is all open commitments will be assigned to sone on the plant staff, private closure of the license renewal project.

Now I want to discuss the open item. First off, I'll give you some background. Here's mitigation of a main steamline break includes redundant isolation of the feedwater lines. And isolation of the feedwater is accomplished by closure of the feedwater isolation valves, and these are accredited containment isolation valves with backup closure feedwater-regulating valves and bypass valves.

On here is the feedwater isolation valves or the containment isolation valves, so they are safety-related, and they're located in the reactor auxiliary building. We identified these as being in scope for license renewal in accordance with 10 CFR 54.4(a)(1).

The feedwater regulating valves and bypass vales are nonsafety-related, and they're located in the turbine building and were identified as being in-scope for license renewal per the criteria of 10 CFR 54.4(a)(2).

And to give you an idea of what we're talking about is the -- if Chris will show you the isolation valves that are in green? And relative to safety class designation on the piping, it runs up to the check valve that's upstream of the isolation valves. And you can see that the check valve and the isolation valves are contained in the reactor auxiliary building.

And next we'll move to the turbine building, and in yellow, you can see the regulating valve and the bypass valves. And the thing that I'd like you to keep in mind on our turbine building for the Harris plant, it's an open turbine building, and it's a non-seismic Category 1 structure. Now there is -- underneath the building, there's a service water tunnel that's a seismic Category 1 structure that takes the service water from the reactor auxiliary building toward the diesel generator building, but the turbine building itself is open and not safety-related.

MR. SIEBER: Typically, feedwater regulating valves and bypass valves are not leak type and are not counted as containment isolation valves? Is that the case here?

MR. STEWART: Yes.

MR. SIEBER: So you only have one set of containment isolation valves on the steam side?

MR. STEWART: That's correct. If I look at what we --

MR. SIEBER: Yes. A lot of plants have shutoff valves inside and outside. This plant does not.

MR. STEWART: That's correct.

MEMBER MAYNARD: You take no credit for the check valves?

MR. STEWART: Let me confirm that and get back to you.

MR. SIEBER: Well --

MR. STEWART: I don't believe we do but I need to confirm that.

MR. SIEBER: In an accident condition, the check valve is not going to do --

MR. STEWART: The check valve would work from pressure coming from the containment but it wouldn't stop the feedwater --

MR. SIEBER: Right.

MR. STEWART: -- and --

CHAIR STETKAR: It would be protection against a break in the turbine building but not a break at the steam generator building?

MR. MALLNER: Ready?

MR. STEWART: Yes, sir. Specifically, the open item, and this is from the SCRs, the staff's position remains that the main feedwater regulating valves and bypass valves, by definition, fulfill a safety-related function. Therefore, they should be included in the scope of license renewal under 10 CFR 50.4(a)(1). In addition, the function to provide main feedwater isolation should be included in the scope under 10 CFR 54.4(a)(1) for Section 2.3.4.6 to include main feedwater isolation valves and the regulating and bypass valves.

To discuss the open item further, the orignal SER for Harris -- this is NUREG-1038, and it's dated November 1983 -- recognizes that the feedwater regulating valves and bypass valves are non-nuclear safety and that they do provide a backup isolation function to mitigate a main seam line break. In addition, if you look at the NRC Guidance in the Standard Review Plan -- that's NUREG-0800, both Revision 2 which is 1981 version and Revision 3 which was updated in 2007 -- they recognize that for a main steamline event, you can credit -- under certain conditions, you can credit nonsafety-related equipment for this backup isolation.

In addition, this design that we have is consistent with the Westinghouse standard information package that was released at the time we did the plan. That's all the discussion I have on the opinion item. We'll go onto the confirmatory items.

The first confirmatory item relates to elastomers an thermoplastic components that were discussed in the main steam and power conversion system. The staff questions the specifics of the inspection method, our use of the External Surfaces Monitoring Program acceptance criteria and the GALL applicability for this application.

Since then we've talked to staff and we submitted a response by amending the license renewal application to provide that the condensate storage tank goes into the internal inspection aging management program. And by the way, we had replaced that diaphragm in 1994, and the last inspection that we did was in 2006. So we do have an APM where we basically do go in and inspect it, so we're moving it that direction.

Relative to the other elastomeric and thermoplastic components, we made a commitment that will replace those prior to the period of extend operation. We'll add those to periodic maintenance program and replace those on as-needed basis.

CHAIR STETKAR: What -- would you give a brief summary of the types of applications of these other elastomeric and thermoplastic --

MR. STEWART: Yes, sir. The main steam power-operated relief valves, there were some hydraulic grinds associated with the actuator, and there's also a breather cap on the hydraulic system. We had some sample lines on the secondary sampling system, and we had an instrument air hose on the -- providing instrument air to the feed reg valve actuator. Those are the elastomeric components other than the condensates storage tank diaphragm.

CHAIR STETKAR: Thank you.

MEMBER MAYNARD: ON your condensate

storage tank, do you one or two?

MR. STEWART: One.

MEMBER MAYNARD: One. Is it safety-related or not safety-related?

MR. STEWART: Safety-related.

MEMBER MAYNARD: Okay.

MR. STEWART: The second confirmatory item relates to the TLAA section, and there's two parts to it. The first part deals with the operational transients. And for Harris, if you remember back with some of the bulletins and stuff, we were looking at insurge and outsurge and thermal stratification on the pressurizer surge lines. And the staff expressed a concern that we had not updated the design speculation to reflect these redefined transients. All the analyses that we did in going forth for the license renewal and the previous analyses that we had done when we did the steam generator replacement power rate were consistent with the transients, but we had not revised the design specifications.

So we have since responded to that by amending the application to include a commitment to update the design specification and that update is in progress now. The commitment says we'll do it prior to the period of extended operation. We'll have it done before the summer.

The part two relates to disposition of some of the Environmentally-Assisted Fatigue Analysis, whether we had used projections, i.e., the method II or we were going to manage it with the Fatigue Monitoring program which is the III, and the staff requested that we make it clear in our FSAR supplement which method we were using. Since then we have responded by amending the application to indicate which components we were using for the method 10 CFR 54.21(c)(1)(ii)(r)(iii), and that should resolve that item.

That's all I have. Do you have any questions?

MEMBER BONACA: You're doing the one-time inspection or small-bore piping?

MR. STEWART: Yes, sir.

MEMBER BONACA: I do not understand clearly your -- how do you collect your sample of piping for the inspection? Will it be based on susceptible locations or will it be based on risk informed --

MR. STEWART: We're using several locations to try to identify the most susceptible locations and we'll do a sample from those.

MEMBER BONACA: Okay. So you're really staying with the -- you're really looking for susceptibility --

MR. STEWART: Yes, sir.

MEMBER BONACA: -- and then see if you have any, you know, conditions like that. Okay.

MEMBER ABDEL-KHALIK: Who's the manufacturer of your emergency diesels?

MR. STEWART: Do you have that?

MEMBER ABDEL-KHALIK: Can you still obtain spare parts for those diesels?

MR. BURTON: Yes, we do. We have not had any problems that I'm aware of, sir.

MR. CAVES: We are implementing some upgrades. You know, for instance, as some of the components become obsolete, we're replacing them with a design change upgraded component.

MEMBER ABDEL-KHALIK: Okay, for example --

MR. CAVES: Yes, for --

MR. CAVES: -- would be a good example of that?

MR. CAVES: And we've got it planned, for instance, to do that during the upcoming outage.

MEMBER MAYNARD: On that picture, could you just kind of identify those bodies of water, what --- their function, not their name.

MR. STEWART: Okay. This is the main intake structure and this is from the auxiliary reservoir, so this is the aux intake structure. This is the discharge structure over here. This is our cooling tower obviously, but you can't see it on this, but there, I'm guessing it's a 30 or 40-foot elevation difference between the water level here and the water level here -- I mean between the main dam and the aux reservoir.

MEMBER MAYNARD: So that's the aux reservoir --

MR. STEWART: This is -- we call it aux intake structure. The aux reservoir is impounded on this side. If you had a larger picture, if I thought I could have --

MEMBER MAYNARD: Okay. So that's a continuos body of water around the bottom there?

MR. BURTON: Yes, sir, wrapped around.

MEMBER MAYNARD: And where would the main --

MR. BURTON: Off the bottom of the picture, sir.

MEMBER MAYNARD: Off the bottom.

MR. BURTON: Yes, sir.

MEMBER MAYNARD: You do not see any part of it or --

MR. BURTON: Well, you see a finger of it that comes up, supplies the normal intake right there. That's an extension of the main reservoir. The reservoir itself would be below the picture that you're currently seeing.

MEMBER MAYNARD: Okay.

CHAIR STETKAR: You have to identify yourself.

MR. FLETCHER: My name is Mike Fletcher. I work with Progress Energy License Renewal Team. The lake was originally sized for four units, and only one was eventually built.

MR. STEWART: To clarify that, the plan was for four units. The lake would have been a little higher elevation to go for four units, but the site was sized for four units. We just didn't fill the reservoir quite as high as we would if we had four.

MR. CAVES: Yes. If we had built the four, the lake level would have been about 30 feet higher than it is right now.

CHAIR STETKAR: I had a couple of questions on your heat exchanger performance monitoring. You've taken exception to flow temperature pressure monitoring for performance for a number of heat exchangers. I came across a curious statement, if I can find it here. It says an engineering evaluation concluded that factors inherent in the testing process make the test results too unreliable to be used for operability determinations whereas a basis for an inspection program -- that's with respect to monitoring flows and temperatures.

There's a list of heat exchanges but the ones I was more curious about were the component cooling water heat exchangers and the fuel pool heat exchangers, because that statement is used for both of those. I was trying to think about what factors inherent in the testing process would make it difficult to evaluate flows and temperatures.

MR. MALLNER: Okay. This is Chris Mallner. I'll take that question. Part of the problem of doing heat exhcanger testing is getting enough heat load on your heat exchangers where the fouling factor doesn't overly influence the results. Obviously, the CCW heat exchanger and the spent fuel pool heat exchangers are designed for accident-level heat loads which are much greater than their normal heat loads, so we currently don't have a way of getting that amount of heat load into the heat exchangers to come up with a test where you get a big enough delta-T to make a good evaluation of whether or not you're having a problem with the heat exchanger in that case.

CHAIR STETKAR: What about CCW heat exchangers, though, when you shut down for refueling? You should have a fairly decent load on them when you line up RHR, don't you?

MR. MALLNER: It's fairly decent but I still don't think it's going to be high enough. Now we relied on -- when we're doing license renewal, evaluations had been done previously by the plant, and we had taken those evaluations to heart when we did the license renewal evaluations. So we thought it would be better to do other things than try to come up with a performance test that we didn't feel confident would actually give us any information that was worthwhile, especially like I said, for the spent fuel pools, Harris has tremendously large spent fuel because it was originally designed for four units, and we've put two sets of haet exchangers in service now because we had a spent fuel pool expansion project about ten years ago. So to try to get a significant amount of heat load on those heat exchangers will be problematic.

The other thing is that when you look at the water -- for example, if there's spent fuel heat exchanges, you have essentially clean water on both sides, and we don't expect to get significant amounts of fouling on those heat exchanger tubes. So we discuss things like we have alarms on the pool temperatures and things like that, so if we notice a rise in pool temperatures, then we would take corrective actions to go back and investigate why the pool temperature would be going up when those heat exchangers are in service.

CHAIR STETKAR: You mentioned those alarms. What is the alarm temperature for high -- what do you normally run at and what's the alarm temperature for high temperature in the fuel pool?

MR. MALLNER: I want to say I think the alarm temperature is 140 degrees, but I'd have to go back and verify that. As far as the normal operating temperature of the pools, John, can you help me with that?

MR. CAVES: Yes, typically, we adjust the spent fuel cooling to maintain between 90 and maybe 104, 103 degrees. You know, it does change. It's a manual operation to put the spent fuel pool cooling in operation and simply monitor the temperatures as they --

MEMBER BONACA: On the buried piping and tanks program, you don't have any tanks, buried tanks on site or do you? They are not in the program?

MR. STEWART: No. The closest thing to a buried tank would be the diesel fuel storage, but it's a concrete -- it's a blowdown structure that's concrete and steel-lined. It doesn't fall under the program.

MR. MALLNER: That's a vault.

MR. STEWART: It's a vault.

MR. MALLNER: And the security diesel has a tank, but it's a plastic tank that's inside another tank for the security diesel. But that doesn't meet the definition of the type of tank that would go in that program, because it's a special application. So it really is not a direct burden tank.

MEMBER BONACA: I don't remember. Do you take any exceptions from GALL as far as this program?

MR. MALLNER: I would have to look at the application. I don't remember off the top of my head.

MEMBER BONACA: You agree to perform at least one inspection in ten years, either an opportunistic inspection or if you don't get any in ten years, you would then look for an inspection if I remember.

MR. MALLNER: Yes, I'm pretty sure that we felt the current industry practice, which is --

MR. STEWART: We did not take any exceptions to the program.

MR. MALLNER: Right, no exceptions. And we would do opportunistic inspections when the lines are uncovered, but no more than ten years --

MEMBER ABDEL-KHALIK: Did I understand you correctly that your component cooling water heat exchangers are somewhat oversized?

MR. CAVES: Oversized for a normal operation.

MEMBER ABDEL-KHALIK: Okay. How well do you control the letdown temperature?

MR. CAVES: Dave, do you want to handle that. Dave Collett, our licensing supervisor, is head of shift supervisors in the control room, so.

MR. COLLETT: It's automatically controlled iwth a temperature control valve.

MEMBER ABDEL-KHALIK: You can maintain it within the control bank?

MR. BURTON: Yes.

MR. COLLETT: Yes.

MR. BURTON: There is no operational challenges.

MEMBER ABDEL-KHALIK: There are no, with regard to control of letdown temperatures or any reactivity implications with regard to ability to control letdown temperature?

MR. COLLETT: That's correct. We have no operational temperature control problems whatsoever.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MR. SIEBER: You have a regenerative heat exchanger which is --

MR. COLLETT: Yes.

MEMBER BONACA: Yes. I had a question regarding your plant-specific PRA. Do you have an estimation of CDF for the plant?

MR. CAVES: It's on the order of 10 to the minus 6.

MEMBER SHACK: It's 9.24 times 10 to the minus 6.

(Off the record comments.)

MEMBER MAYNARD: Your head -- you

mentioned this in your application -- you had inspected in 2007. I take it you didn't find any significant issues with your head?

MR. CAVES: That's correct.

MEMBER MAYNARD: The other part of that is on the scale from a materials and service standpoint, your's is considered to be one of the lower susceptible heads to the degradation?

MR. CAVES: That's correct.

MEMBER SHACK: Even after you've raised T-hot --

MR. CAVES: That's right.

MEMBER ABDEL-KHALIK: Now when T-hot is raised, is it raised to the original design value --

MR. CAVES: That's what we do.

MEMBER ABDEL-KHALIK: -- which was reduced, I guess, when you had degradation --

MR. CAVES: We covered it --

MEMBER ABDEL-KHALIK: -- in steam generator?

MR. CAVES: That's correct.

MEMBER MAYNARD: But with some of your future power uprates -- of course, you're looking pretty small -- are you looking at increasing T-hot or are you -- whatever you get additional out of the turbine is not going to matter, but your instrument assurance and others need to know that you're going to be running your reactor power a little bit higher, right?

MR. BURTON: Yes, actually slightly higher. Yes, sir.

MR. CAVES: Yes. We haven't gone far enough with the design to be able to answer that question.

MEMBER MAYNARD: And it would be a very small amount and it's just -- philosophically looking, are you going to continue rasing T-hot, or would you look at going to a reduced T-ave?

MR. SIEBER: Six twenty is pretty hot.

MR. CAVES: It's premature for us to be able to answer that.

CHAIR STETKAR: Since Mario opened the question, I feel obliged to follow-up on one thing. I noticed in your masonry walls inspection program, one of the criteria for identifying the masonry walls that you mention is risk significance. So I got curious about that and I looked back at the PRA, and I noticed that the seismic part of the risk assessment was done only according to the EPRI seismic margins. So there's been no quantification of seismic risk.

There are some arguments that say well, everybody knows th the fire risk is dominant so we'll assume that the fire risk is 85% of the total risk from other external events which sounds rather specious, at best. I was curious what type of -- if risk insights are used for classifying your masonry walls for inspection, what are they since you don't have a seismic risk ranking on a consistent risk basis for those walls? In other words, you can't go to your PRA and say this particular wall has this risk importance because indeed those walls are not in your PRA. You can't actually measure their contribution to risk.

MR. MALLNER: will turn it over Bob Reynolds. He was the civil lead for the application.

MR. REYNOLDS: Yes. Bob Reynolds, the civil lead. We had a question on that based on the wording in the GALL as to which. I think it was more related to how often do we inspect the walls, you know, which ones do we prioritize first and things, and we came up with -- the answer that we gave was is that we -- mainly, it's by safety-related. In other words, if it's a safety-related structure with masonry walls, safety-related walls, then we would look at those perhaps more frequently than we would some of the others. We set a frequency on some of the buildings that have masonry walls in them that are more -- that are at various year whereas some of the nonsafety-related structures are like at ten years or nine years. So that was the way we addressed that. It was basically more on the fact whether it was safety-related or nonsafety-related --

CHAIR STETKAR: So it's just a pass/fail criterion rather than a risk --

MR. REYNOLDS: Yes, sir.

CHAIR STETKAR: -- because if you read the walls -- if you read the words, you're led to believe that it's kind of a risk ranking type base.

MR. REYNOLDS: It was nothing to do with the risk ranking at all, sir.

CHAIR STETKAR: Thank you.

MR. SIEBER: I take it a wall is a structural member as opposed to a partition which is nonstructural but separates a structure into cubicles?

MR. REYNOLDS: We have some walls at Harris that are fire protection-related walls in the fuel handling building, and those are in-scope of license renewal, and those are being included in the inspections as well as we had a structure even that was a nonsafety-related structure that had equipment that was in the scope of license renewal and say for SBO or for protection or some other reason, that wall also would be in-scope of license renewal, and those were inspected as well.

MR. SIEBER: Okay. Thanks.

MR. BARTON: You have an AMP that covers inaccessible medium voltage cables not subject to 50.45 EQ requirements, and in there it states manholes will be inspected for ore accumulation and drained as needed, and this inspection program will be based on field data and not to exceed two years. Now do you have a program in place now that inspects manholes?

MR. STEWART: Yes, we do.

MR. BARTON: And what is covered under --

MR. STEWART: It's part of -- there's Pms where we do -- it's quarterly or semi-quarterly drain down of the manway. Then separate, we do an inspection of them as part of the structure monitoring program. And I believe that's currently on a nine-year frequency.

MR. SIEBER: Do you ordinarily find water in the vaults below the manholes?

MR. CAVES: It's not infrequent to find water.

MR. SIEBER: It's not infrequent. So you do find it --

MR. CAVES: We do find it occasionally.

MR. SIEBER: -- quite a bit?

CHAIR STETKAR: There was -- if I remember, the NRC Regional Inspection Team apparently audited inspections of two of those manholes, and there was water in them.

MR. HEATH: This is Mike Heath. We do do those inspections on a quarterly basis. We do find water. The water is not up to the level of the cable.

MR. SIEBER: You say the water is not up to the level of the cables?

MR. HEATH: That's correct. The water is -- we have not found -- we do not find water above the cable level.

CHAIR STETKAR: You said quarterly, you actually inspect. Is that only the safety-related manholes or all manholes?

MR. STEWART: The production manager that we do the -- it's not the inspections basically to open the manholes and drain them. It's quarterly on the nonsafety and I think semi-quarterly on the safety -- I'll confirm those frequencies.

CHAIR STETKAR: I didn't find those. I was curious about that frequency.

MEMBER MAYNARD: Can you just give us a feeling? You say you normally find water in there or it's not unusual to find water but it's not up to the cable. Relatively speaking, you know, are we looking at six feet with the water being a foot below it. or are we looking at an inch or two of water with four, five feet of clearance? I'm just trying to get a feel for whether it's something that the water's getting close to it or whether it's --

MR. HEATH: To my understanding, it's not a significant amount of water. In other words, it's not -- we're not nearly up to the cables but we do find water in there. And we do pump that out. From my understanding of it, it's not an issue at the plant.

MR. CAVES: Yes, it can be more than a couple of inches. You know, it can be a foot or so, but we've still quite a bit of margin.

MEMBER MAYNARD: Just quantify a little bit quite a bit. Are we --

MR. CAVES: To get that specific, I'll

get an answer and bring it --

MEMBER MAYNARD: I don't have it by the inch or the foot, but I mean --

MR. BARTON: Relatively speaking --

MEMBER MAYNARD: -- relatively speaking, you know, if we got two feet of water in there, and we got quite a bit of clearance, quite a bit of clearance to you might mean four, five inches, and quite a bit of clearance to me may mean four or five feet.

MR. CAVES: Yes, it's on your four and five feet, but I'll confirm that.

MEMBER MAYNARD: Okay.

CHAIR STETKAR: Are the results from these inspections, whether they're quarter or semi-quarterly, are they recorded and trended, does somebody look at that information?

MR. CAVES: System engineers monitor that.

CHAIR STETKAR: So they have a historical trending or historical monitoring of what the level was --

MR. CAVES: It doesn't go back 20 years. It's a program that we, you know, increased the rigor, you know, in that monitoring program a couple of years back. Okay? But over the last, you know, three or four years, we do have good information --

MR. SIEBER: You're doing a quarterly, it's going to go up and down.

MR. STEWART: Caudle, would you like to speak to that? This was a particular question that Mr. Julian had when he was on site, so he can --

MR. JULIAN: During our inspections, we did look into what they were doing with the manholes, and they do have a quarterly PM to go out and measure the level of water that they find in there. And they were -- looked to us like the water was well below the cable height. We did ask them to pull open one of the manholes, and they're actually vaults, kind of, then look in there and it was a very small amount of water in that one vault that we'd looked at. And the cable distance, my memory fails also, but I'm talking three feet or so it seems like from the highest water level they had reported to the cable we were looking at.

When we asked about trending, at that time, they did not have trending. That's one of the issues that we talked about in our inspection report is that the workers were dutifully writing the data down, but it wasn't going anywhere. So they responded by getting a system engineer who's responsible for that, routed the information. He started a trending program , in fact, I think, in reaction to our discussions with him. So now I have faith that they are indeed trending it, recognizing, of course, the -- trying to recognize the particular manholes might have problems. You know, containing you only had water again and again.

MEMBER ABDEL-KHALIK: What's the main source of the water?

MR. BURTON: Rainwater.

MEMBER ABDEL-KHALIK: Rainwater and it's just sort of gradually draining into these vaults through the manholes?

MR. BURTON: Yes.

CHAIR STETKAR: DO you have a sense -- does it come in through the manholes or --

MR. BURTON: Yes.

CHAIR STETKAR: -- or it's not groundwater seeping through the cable canals and the ducts and stuff?

MR. BURTON: You know, it could come in and drain through the cable ducts and get down into the manhole because it's a low point.

MR. SIEBER: Well, you know you have a flow path all the time from the manhole. You'd have to rupture or break the conduit box or the piping in order to get water in from that standpoint. The interesting thing is that where the manholes are is where the splices usually are. And so if you think if you have qualified cable, it's -- the important thing is whether you have a qualified splice or not.

MR. JULIAN: We did observe that Harris' layout, their cable vaults that they have are large, big concrete cavities, and after they've pulled them periodically to inspect them, they go back and seal them. So they do attempt to keep rainwater out of the things, but I guess that sealant probably ages with time. But the layout then, I think, from the vaults is -- my memory is that it's, you know, sealed conduit that runs underground.

CHAIR STETKAR: That's what I was going to ask. Isn't sealed conduit out? Or are they just concrete -- I've seen a lot of different things. Some people just have concrete ducts with, you know, cable raceways, and other people have actual sealed conduit as you go out.

MR. STEWART: We better check that to give you --

MR. JULIAN: Because some of the concrete ducts, you can get ground water, you know, in the ducts, and it just sort of goes down the sluice if it's cracked.

MR. BURTON: I'm not sure that we know and we will find out through that answer.

CHAIR STETKAR: Where are -- you know, since you have the nice picture of the site up there, are these -- the underground cables that we're talking about, are they throughout the site or are they for only a few particular functions?

MR. JULIAN: Primarily, cabling, in my memory, has to run for the auxiliary building to the diesel building. Is that --

MR. STEWART: The diesel building is right here, and the auxiliary building is here. The other place that we would go is back to the screening structure here which are these, along this place where we'd have safety-related type cable.

CHAIR STETKAR: Where are your ESW pumps physically located?

MR. STEWART: In this (indicating) structure right here.

CHAIR STETKAR: They're in the inatke structure itself?

MR. STEWART: Yes, sir.

MR. CAVES: And are motor-driven fire

pumps are in the same location.

MR. JULIAN: So those are the cable runs, primarily the long run down to the intake structure for safety-related application. And the ones we looked at were the cable vaults on the cabling that's going from the auxiliary building to the diesel building. Those are the ones we selected.

CHAIR STETKAR: Those are the ones that you actually --

MR. JULIAN: We selected to look into and we thought that the condition of them was good. It looked like, from marks in there, they if they had water accumulating in there, it's rather low. And we didn't see evidence, certainly, that there is recurring flooding. We don't think water ever gets up to the cables in those --

CHAIR STETKAR: Thank you.

MEMBER BONACA: You said in your presentation that the aging evaluations were 89% consistently GALL. But also, you stated that there are 14 aging monitoring programs take one or more exceptions to GALL. Would you characterize a little? You know, for example, is it most of it is to do with different ASME --

MR. STEWART: I took a quick look back at it and more than half of them are due to either ASME code addition or revision of EPRI guidelines or in one of them on the steam generator tube integrity is the revision of NEI 97-06. The majority of them are just a different addition or revision of the reference document.

MEMBER BONACA: So you don't feel that there is real departure from GALL? I mean they're just variation or rule changes?

MR. MALLNER: The --

MEMBER BONACA: I'm trying to understand because we have seen a trend in later applications where there'd be more and more exceptions to GALL. And GALL, when it was issued, was really almost a contract between the industry and the NSC. So I just -- I'm curious to know what's driving the exceptions. Some of them are just convenience in a sense that you already have a program in place, you feel is appropriate and adequate the way it is, and you don't want to change that, but you don't have fundamental disagreement with GALL.

MR. MALLNER: This is Chris Mallner again. I would say the answer to that question is no. It's basically in trying to apply the requirements in the GALL aging management program at your particular site. I mean a good example is the Brunell hardness testing of the selective leaching program.

MEMBER BONACA: Yes.

MR. MALLNER: You know, that one has been -- an exception has come up for almost all the applicant's, and we're always trying to figure out what's the best way to accomplish of the selective leaching program to find what we need to do. And we're just looking for an alternative to -- because that Brunell hardness testing could be problematic where you can do -- can you get to the actual component that you suspect. So those are the type of things. And we've tried to communicate this back to the staff in the reviews, that when GALL is updated -- I'm sure they're working on it now -- that we'll try to get a better way to try to convene at a point where we can have less exceptions in the program space.

MEMBER BONACA: Good.

MR. STEWART: And in addition, the one -- I'm just looking -- I have some of the exceptions in front of me, but fuel oil chemistry, we took exception or exceptions. We had additional scope items that weren't covered in GALL. So we -- I mean it was an exception to the program. Chris mentioned the selective leaching. On the one-time inspection of Class 1 small-bore pipe, we took the exception that we would not do a volumetric examination of the small socket welds. And then on the electrical cable connections, we took the exception that the connections that we're looking at are the external connections, not the ones that are contained inside of a panel, and those are the exceptions other than the code addenda are.

MEMBER BONACA: Okay. Thank you.

CHAIR STETKAR: You mentioned socket welds. I think in the discussion, it said there are socket welds in some safety-significant systems, I think, is the way it said. Do you happen to -- what are those systems since you won't be examining those welds? Do you know which systems those -- that they point to?

MR. STEWART: I don't.

CHAIR STETKAR: I've forgotten the exact words and it's too difficult for me to find my notes on it, but the term was small-bore socket welds do exist in, I believe it was, safety-significant systems, which had me curious as what systems they were.

MR. STEWART: I don't know the specifics but I --

CHAIR STETKAR: I don't think it said safety-related. If -- find my notes here.

MR. STEWART: We do have some small-bore socket welds in our RSI program, and my recollection for license renewal is what we committed to. There is not a substantial number of them, but we do a visual exam of all of them each outage. I'll confirm that and we'll get back to you in terms of --

MEMBER SHACK: Yes, each refueling outage.

MR. STEWART: And my recollection is there's not a substantial number of those, but we committed to do a visual of each -- of all of them each outage. And these are the -- I believe these are the Class 1 ones, and so the systems, if it's Class 1, it's got to be reactor coolant --

MR. CAVES: Or an extenision.

MR. STEWART: -- or extension thereof.

CHAIR STETKAR: My notes on this, and they're just sketchy, said there are socket welds in locations that are classified as high safety-significance from your risk-informed ISI program if that points you to some reference document.

MR. STEWART: We'll get back to you.

CHAIR STETKAR: Sure. Where are your containment spray valve chambers located? I noticed when you were talking about containment liner and so forth corrosion problems that there had been some repeated evidence of corrosion in those containment spray -- they're categorized as containment spray valve chambers. And I was curious where they're located and why are they more susceptible to corrosion than some, you know, other locations that you've examined?

MR. STEWART: The chambers themselves are -- it's in the reactor auxiliary building just outside of containment, very lowest elevation. I think it's 190 feet elevation. And I'm not familiar enough with the corrosion to discuss the specifics on that.

MR. REYNOLDS: I don't remember all the details -- Bob Reynolds of Progress Energy -- these chambers are in the scope of IWE, and they are inspected on the frequency of, you know, the IWE frequency. And there has been some flaking and some loss of coating and things on those valve chambers outside and inside. And they have had some -- they are looked at and they are repaired each time. I don't think it's -- I don't -- as I recall, it is not a generic problem with them. It's just some localized problems in each of the -- in those chambers.

CHAIR STETKAR: Okay.

MR. REYNOLDS: Does that answer your question or?

MR. SIEBER: Yes. I was just curious whether there was any -- you've answered as long as you don't believe it's a generic problem whether its not water or condensation because of their location, if they are out in the auxiliary building.

MR. REYNOLDS: They are located in the auxiliary building and the chambers themselves are partially embedded in the reactor building wall, I guess you -- containment wall. And actually, when I was -- when they did some of the inspections, they think they even damaged some of it when they were trying to do the repairs on the other, and it was just -- it was fairly minor. But there have been -- it has occurred several times, and they -- it's not a -- think -- what's the word -- it's not a -- it's not like one of the problems that -- they do look at it, but it's not a continuous problem. The last outage, there was very little problem --

MEMBER ABDEL-KHALIK: Are those chambers considered a part of the containment?

MR. REYNOLDS: Yes, sir, they're part -- we consider them part of the containment.

MEMBER ABDEL-KHALIK: So how frequently do you open them to see whether or not there's water in there or corrosion in there?

MR. REYNOLDS: From my understanding, they're looked at on a five-year basis.

MEMBER ABDEL-KHALIK: So you can't open these on line?

MR. REYNOLDS: No.

MEMBER ABDEL-KHALIK: No.

MR. REYNOLDS: It would be during a refueling outage, yes, sir, or an outage.

MEMBER ABDEL-KHALIK: And what is the extent of the corrosion of these chambers?

MR. REYNOLDS: It's surface corrosion.

CHAIR STETKAR: There wasn't any indication of severe corrosion. I was just curious because they've done several inspections, and this -- that item, in their operating experience, seemed to come up repeatedly. But there wasn't any indication of severity, you know, severe condition. It's just curious why, because of their environment or --

MEMBER ABDEL-KHALIK: Is there a leakage to the valve stems inside those chambers or what? What is the source of water that causes the corrosion?

MR. REYNOLDS: I'm not sure I can answer that off the top of my head. It may be the plant has some idea better than I do on that, but I can go back and ask the question.

CHAIR STETKAR: Those lines are stagnant. They're the containment spray injection lines.

MR. REYNOLDS: That's correct.

MR. BURTON: And they're not in an unusual environment of any kind. They're in the same --

CHAIR STETKAR: That's why I was curious about --

MR. BURTON: They're not down on the floor.

CHAIR STETKAR: No, no.

MR. BURTON: I mean they're huge but --

MR. SIEBER: But it's important because part of containment boundary and, you know, it's the same effect as having your liner corroding in the upper part of containment. It's a pathway to the outside. So you do a ten-year containment pressure test, right?

MR. REYNOLDS: Yes. These tanks are included as part of the Appendix J program and the IWE programs as well.

MR. SIEBER: Okay. So if it leaked, you would at least know it every ten years?

MR. REYNOLDS: That's correct.

MR. BURTON: We'll try and get some characterization of --

MEMBER ABDEL-KHALIK: Have you done a root cause analysis of the cause of the corrosion?

MR. CAVES: I'd be surprised. I do not believe we've done a root cause analysis on that.

MR. SIEBER: You probably would be hard-pressed to do that because it's underground. If the corrosion's on the outside of the liner, had to come through the concrete.

CHAIR STETKAR: These are -- if the -- I used to work at Zion and if they're anything like ours was, they're below grade, but you can look at them. They're out in the open.

MR. REYNOLDS: You can look at the exterior --

CHAIR STETKAR: Exterior --

MR. REYNOLDS: -- surface of it and it's

observable in the bottom of the reactor auxiliary building, yes, sir. And --

MR. SIEBER: Okay. Ours are really under --

CHAIR STETKAR: No, this is -- they're below grade, but you can see -- you can touch the exterior of these things.

MR. STEWART: You can take -- you can actually go inside. You can take off the manhole cover and go inside as well.

MEMBER MAYNARD: I would just like to have a brief discussion with the fatigue analysis and with the issues that have come up with several of the other plants that it's my understanding for your fatigue analysis, you're using a different program than what Vermont Yankee, Wolf Creek and some of the others have used, so you're not susceptible, I guess, to some of the same issues that had come up. Can you just confirm that a little bit or briefly --

MR. STEWART: Yes, we can. Would you like to hear it from us or would you like to hear it from Dr. Chang?

MEMBER MAYNARD: Well, either one. I just want to get a little bit of discussion on the record, and if staff's going to address that, that'll be fine. I just -- since it is an issue, I think it's something that we need to have a discussion either this afternoon or a little bit on.

MR. MALLNER: This is Mallner again. I can talk about that a little bit. Westinghouse did our evaluations for us for license renewal, and they typically used ANSI software to do the evaluations, and they used their WESTMs software also. Their WESTM software uses all six components of stress. We were asked during the audit to provide a benchmark of WESTMs versus the ANSI analysis to show that we were getting the same results we provided, that the reviewers were satisfied that we were okay as far as the software we were using, and the issue that applies to the other plants, which is the concept of virtual single stress to represent all the stresses in that particular location don't apply to us.

CHAIR STETKAR: That's fine and we can hear from the staff later.

MR. LEE: This is Samson Lee. The staff will go over that also in case you still have questions.

MEMBER MAYNARD: I just wanted to get some discussion on the record on that.

CHAIR STETKAR: I notice that you've

established the boundary between your -- the boundary for inspection program for your offsite power supplies as including the circuit breakers out in the switchyard and everything in from that. Who owns the circuit breakers? Is it yours?

MR. CAVES: Yes, sir.

CHAIR STETKAR: Okay. You own it. You control all of the equipment out there? You operate the equipment from the control room or from -- you operate the establishment.

MR. BARTON: Doesn't the transmission department have some culpability here someplace?

MR. STEWART: Progress Energy owns the plant, the switchyard, the transmission. There is an interface agreement between the plant and the transmission department in terms of how they do work in the switchyard. That's controlled by an interface agreement and the control room, and the plant has say on what they do. So they don't go in and do things without the plant knowing.

CHAIR STETKAR: But you're all the same company?

MR. STEWART: Yes, we are the same company.

CHAIR STETKAR: Okay.

MR. BARTON: They own the oil fuel high voltage cables out in the switchyard, right? That's what I got out of the literature someplace. And you're going to have an aging management program on those cables. Who will actually implement that program, the transmission department under your overview, or how is that going to work on this interface agreement?

MR. STEWART: I don't know if worked the specifics out on that yet. We talked -- my recollection is we've talked with the system engineer and transmission and come up with some proposed methodology, but we have not worked out the specifics yet.

MR. CAVES: I'm very confident it'll be the transmission department that actually does the maintenance under the watchful oversight of what we call the PTAC, the plant system engineer that's responsible for --

MR. BARTON: Okay. Understand.

MR. SIEBER: You need to be careful because transmission departments, in general, don't go through the paperwork and sign-offs and everything, that you need to document what's going on. I think they do the work okay. On the other hand, they are not paper oriented.

MR. CAVES: Right. And we've actually had significant efforts over the last several years increasing the interaction between our staff and transmission issues like that, compliance wtih procedures --

MR. SIEBER: So the plant is really only responsible for manning the output breakers and its auxiliary transformers and the main unit transformer. Everything else belongs to transmission.

MR. CAVES: But we still assume our own responsibility for that. You know, we don't delegate that responsibility. We describe it as 200% accountability at that interface.

MEMBER BONACA: You're running an 18-month cycle you said. Is it a low leakage core?

MR. CAVES: Yes, it is.

MEMBER BONACA: Okay.

MEMBER SHACK: Why? You seem to have ample margin to diffuse --

MEMBER BONACA: Yes, that's why I was asking that question.

MR. SIEBER: Yes, but they don't have AB (phonetic) margin. They have margin in the core.

CHAIR STETKAR: One last question, from

me, anyway since, amazingly enough, we're running well ahead of schedule. Do you have any comments on your plans to resolve the open issue? You describe the issue quite well to us. I think we understand what the issue is. Is there progress being made on it?

MR. STEWART: There is progress being made. We've been in discussions with the staff, and we have a path to resolution.

MEMBER BONACA: Okay. The issue does not affect the scope. I mean still it's components are in-scope.

And so the issue has to do with ancient history. I mean --

CHAIR STETKAR: Well it's whether they're in-scope under (a)(1) or (a)(2) is the issue, and the fact that they're in a non-seismically qualified open to the environment building is the problem.

MEMBER MAYNARD: I think this probably has generic imprint. Is there something unique about Shearon Harris? Actually, a lot of Westinghouse plants' feed reg valves are not safety-related.

MR. STEWART: That's correct.

MEMBER MAYNARD: So I think this is probably more a generic issue to Shearon Harris.

MR. STEWART: That's right.

MEMBER BONACA: It goes back to the original categorization and so it's more of an issue of defining and understanding of how the plant was licensed than an issue affecting, really, license renewal scope. I mean --

MEMBER MAYNARD: Yes. I had a number of questions for the staff on this, because I felt that this was a generic item about any Westinghouse --

CHAIR STETKAR: I was just curious, from your perspective, whether this is a real sticking point or --

MR. STEWART: From our perspective, we have a path to resolution.

CHAIR STETKAR: Okay. If nothing else, I guess before we close, I'll just go around the table just to make sure that there aren't any lingering items. We typically do this at the end of the afternoon also. Jack, do you have anything for them?

MR. SIEBER: So far, nothing.

CHAIR STETKAR: John?

MR. BARTON: I don't have anything major. I have a question on the refueling water storage tank. It's an enclosure, like could accumulate raw water undefined, maybe rain water, whatever else.

You have an aging management program that you're proposing a one-time inspection. Does this include inspecting tank bottom or something? I don't understand how the tank is maybe sealed from water in the enclosure getting underneath it or whatever, so I don't understand what you're one-time inspection program on that refueling water storage tank and system.

MR. STEWART: Let me explain the configuration of the tank. The tank is an outdoor tank, and there's an enclosure around the tank. The tank sits on a concrete platform inside the enclosure, and the concrete platform is approximately six inches high.

MR. BARTON: Okay.

MR. STEWART: There is capability of draining the enclosure. However, for environmental considerations, we do not drain the enclosure without sampling it. And what we typically do is monitor during operator rounds. If we get a rainstorm or something, you will accumulate water in there. If the operators see water accumulating, they will get it drained down but not until we sample the water and make sure that we can discharge it.

So what we're talking about is there --

is you can accumulate water that might come over that. It's not a normal occurrence.

MR. BARTON: But it could happen?

MR. STEWART: It could happen and in terms of the proposed inspection program, recognizing that it's a stainless steel tank and it's potentially -- it's raw water, there are some potential corrosion mechanisms, and we are going to look for those.

MR. BARTON: Okay.

MR. CAVES: Just a clarification. When we talk about an enclosure, it's enclosed on the sides but not on the --

MR. BARTON: I understand. It's in a concrete kind of box. I got you. I understand what you're talking about.

CHAIR STETKAR: You mentioned operators. Do the operators go in there once a day, once a shift, once a month? How frequently does someone look in there? You said they look at it when it rains but --

MR. COLLETT: It's on the normal rounds so it's at least once per day.

CHAIR STETKAR: Once per day. Okay.

MR. COLLETT: And they look in there and specifically look for standing water.

CHAIR STETKAR: Okay.

MR. BARTON: That's it.

CHAIR STETKAR: Bill?

MEMBER SHACK: No.

CHAIR STETKAR: Mario?

MEMBER BONACA: No issues.

CHAIR STETKAR: Okay. This is amazing. We'll close this session and reconvene at 1:30.

(Whereupon, off the record at 11:50 a.m., and back on the record at 1:29 p.m.)

CHAIR STETKAR: Okay. I guess we're back in session. This afternoon, we're going to hear a presentation from the staff on the SER, but first, I understand that applicant has some answers to a few questions, I guess, that were raised this morning, so I'll turn it over to Progress Energy.

MR. CAVES: This is John Caves. Appreciate the opportunity to do some research, get the answers to your questions. The first thing is we talked this morning about the lake level, and I wanted to clarify that the license amendment request that we've got submitted to the Nuclear Regulatory Commission is to change the lake level from our current tech spec limit of 215 feet to the originally licensed level of 206 feet.

Back in the late 90's, as a result of net positive suction head concerns with the emergency service water pump, we'd actually increased the minimum lake level. Now we have subsequently upgraded those pumps, put in different design pumps and, therefore, went back to the originally licensed 206 feet. So I just wanted to clarify that.

Also, related to the lakes, the question was what is the size of the main lake, and that's 4,000 acres, so that's several square miles. The aux reservoir is 317 acres. So the main reservoir is huge. The aux reservoir is 317.

There was a question about the T-hot, operating T-hot for the plant. The design T-hot right now is 621 degrees Fahrenheit. There is a slight variation from loop to loop depending on, you know, actual heat transfer characteristics across the various three steam generators. But 621 degrees Fahrenheit is the design T-hot, and we normally operate right in that general area.

As I go through, if you need any additional clarification, just stop me. Okay? The next question was related to FAC, flow-accelerated corrosion. Over the last ten years, Harris has experienced six through-wall leaks in piping that's monitored for FAC. In all of those cases, it's been small-bore carbon steel piping, and small-bore is defined as three inches or less in our program. And the primary degradation mechanism is actually erosion that's causing the degradation. FAC is present but it's not the primary contributor to these particular degradations that we've discovered.

When we found those cases, they had been repaired and replacement is with FAC-resistant material. Typically, it's chrome-moly. Sometimes we use stainless steel or Incanel. Okay? But, you know, the original findings occur in carbon steel piping, small-bore and replaced with FAC-resistant material. Okay?

MEMBER BONACA: Is the small-bore piping the one that is a subject of one-time inspection?

MR. CAVES: NO, this is this not.

MR. STEWART: No, this is not that. No, this would be on a secondary side.

MR. CAVES: This is all -- in fact, the primary system that does experience this is the extraction steam system.

We talked a little bit about CheckWorks, and CheckWorks is normally not used, is not recommended by EPRI to be used for the small-bore piping. We do use it for the large-bore, three inches or greater. We do not use it for the small-bore piping.

Okay. Any other questions about flow accelerator corrosion?

MR. SIEBER: What do you use for small-bore piping?

MR. CAVES: Actually, it's operating experience. We use measurements, you know, to some extent, but even the measurements we found to be unreliable, because there can be times when you, you know, find adequate wall thickness in one area, and it turns out that, you know, some number of pipe diameters downstream of a control valve or something like that, you can find more susceptible areas.

MR. SIEBER: So you'd have eddy's that form in these pipes?

MR. CAVES: Yes. So because --

MR. SIEBER: -- the hands -- in general, the number of pipe barriers through-wall leaks that you find is going to be in small-bore piping?

MR. CAVES: In the --

MR. SIEBER: Now you can't kill anybody, I don't think, with small-bore piping unless they're up close, but you can damage equipment or make equipment inoperable in a cubicle, so you need to pay attention to the small-bore piping.

MR. CAVES: Yes. We're absolutely paying attention to it, and we have got an aggressive program, you know, continuing to move in that direction. Your counsel is well taken.

Anything else on the flow accelerator corrosion questions?

Okay. Another question that came up is do we credit the check valves in the feed line for containment isolation. And the answer is no, the framework isolation valve is the only valve that we credit for containment isolation in the main feed system.

MR. SIEBER: How do you deal with single failures?

MR. CAVES: I believe that what we've got is because the system is normally filled and normally flowing, I believe that that meets the requirements.

MR. SIEBER: I don't think so.

MR. CAVES: Closed system inside containment.

MR. SIEBER: I don't think so. We'll let the staff --

CHAIR STETKAR: I'm sure they'll come up

--

MR. SIEBER: Yes, I can just keep saying I don't think so.

MEMBER MAYNARD: Well, I don't think it's need -- it's not applicable for probably the accident of concern. There's other accidents where it is, so I think it depends on which accident you're looking at there.

MR. CAVES: Gotcha.

MR. SIEBER: Well, the problem is, as I see it, is using a feed reg valve and its bypass as an isolation valve is probably not good, because they always leak through. On the other hand, I think you're supposed to be single failure-proof which means takes two valves to do that. The check valve in this configuration won't do it.

MR. CAVES: Right.

MR. SIEBER: The staff can tell us more about that when it's their turn.

MR. CAVES: Okay. There was a question about the alarm set point for the spent fuel pool high temperature alarm. And the alarm set point is 105 degrees, so we -- the low temperature alarm was 80 -- I believe eight-five. So we control between 85 and 105. The design temperature is higher than the

105, but we don't have that number, you know, right now. If you need that number, we can find it for you.

The next question was related to the manholes and cabling. The manholes that we have are typically ten feet from the manhole cover down to the floor. The cables normally start about three feet above the floor. And what we found, there's 180 manholes that are on the site. And of those, we've got them categorized as nonsafety-related, safety-related, and for the safety-related, whether it's energized or not energized.

If the cable is normally energized, we inspect the manholes every 45 days. That would be typical of the cable that goes out to the emergency service water pumps and the structure.

The cables that are not normally energized, such as the cables to the emergency diesel generator, those manholes are inspected on a quarterly basis.

There's six manholes that we frequently find water levels in the neighborhood of three to four feet deep. So we mention that, normally, the cables start about three feet off the ground. So we've got six manholes that we do find routinely, you know, at or close to the surface of the water. It's certainly not appropriate to say that those cables are always dry. All right? So that is, you know, the condition at the Harris Plant.

The majority of the manholes, the typical level is less than 30 inches. Some are in the 2 to 3 inches every time we look. Some are normally about 2 feet to 2-1/2 feet. Okay, but that gives you a feel for the distribution of what we find when we do the inspections for water in these manholes.

CHAIR STETKAR: These -- let me make sure I understand. You said that your -- if the cables are normally energized, you check them once every 45 days, and if they're normally de-energized, the manhole is checked quarterly. Is that only for the safety-related cables?

MR. CAVES: I apologize. I don't have that answer.

CHAIR STETKAR: Okay.

MR. CAVES: I think it's primarily safety-related, but I can't answer it for sure.

CHAIR STETKAR: We're curious because some of the -- the AMP for the medium-voltage cables that aren't included under the quality assurance requirements, I'm not sure how they span safety-related -- they're probably nonsafety-related cables, so I was curious to how frequently you inspect those manholes.

MR. CAVES: Yes. I'll have to get back to you on that. I apologize.

CHAIR STETKAR: Okay. Thanks.

MEMBER ABDEL-KHALIK: Did I hear you correctly that you said there are six manholes where you frequently find water and the level of the water is three to four feet from the bottom?

MR. CAVES: That's correct.

MEMBER ABDEL-KHALIK: So that the cabling is --

MR. CAVES: May be --

MEMBER ABDEL-KHALIK: submerged?

MR. CAVES: -- under water.

MEMBER ABDEL-KHALIK: Are all these cables de-energized normally or ---

MR. CAVES: No.

MEMBER ABDEL-KHALIK: -- some of them are normally energized?

MR. CAVES: Some are normally energized. Some are normally de-energized.

MEMBER ABDEL-KHALIK: Any problems with the cables that are normally energized when these walls flood?

MR. BARTON: Have you had any failures in any of those cables?

MR. CAVES: We have had some failures of a line going out to the motor-driven fire pump. We had that a couple cycles ago. We are in the process of implementing a cable monitoring program, but that's not fully developed at this time. The testing methodology that we're using for that is Tan-Delta testing, and we're in the start phase of that monitoring program.

MR. BARTON: I would ask you then what are you doing about trying to eliminate that amount of water in that area, because those cables are going to be energized at times, and they're going to be submerged. So what are you doing about eliminating the water? The water is the problem.

MR. CAVES: That's correct. We asked that ourselves that same question over lunch. I don't have an answer for you at this point.

MEMBER ABDEL-KHALIK: Has this problem been observed from day one?

MR. CAVES: Yes, it has.

MR. BARTON: It's only a 20-year-old problem.

MR. CAVES: The cables are designed for the moist environment, okay, and --

MEMBER ABDEL-KHALIK: But not submerged environment.

MR. CAVES: Well, you know, that's where the submerge -- the cable definition of submerged -- you know, rated for a submerged environment is actually used for cables like -- that are buried -- or not buried but transatlantic cables, so there's not really a classification, as I understand it, for cables in this particular environment. But this environment's not abnormal for these types of cables. But cable manufacturers, you know, recommend monitoring. We've got that process being started, yet there is potential degradation associated with that. And what we have to do is we have to monitor for that degradation.

MEMBER MAYNARD: I think it's fair to say, at least from my perspective, that at the full committee meeting, we'll probably want to explore this a little bit more as to what you're doing to eliminate the water or what your plans or justification for leaving it there.

MR. CAVES: Sure. We'll be prepared for that. Okay. At this point, any other questions about the cabling? I think I'd like to turn it over to Chris Mallner then for the next questions.

MR. MALLNER: Yes. The next question was what systems contain the Class 1 small-bore socket welds and about how many are there. There's approximately 150 small-bore socket welds that will be within the scope of the inspection of one-time small-bore piping. They're in the Reactor Coolant System, Safety Injection System, CBCS System, and the RHR System. And currently, those things are pressure-tested. They get a VT-2. Every time you come out of an outage, you do the pressure test. And we'll do visual inspections on those. That's currently what we're doing with those right now. But that's basically the population, about 150 socket welds are in that program.

MEMBER ABDEL-KHALIK: If I may go back to the manhole water issue. Could you give us an idea what other systems may be affected by the cabling in those six manholes that you've observed frequently water accumulation?

MR. CAVES: Yes. The engineer that I talked to didn't have that information over lunch, so I'll have to get back to you on that. And that can be something we follow-up on when we bring it back to the ACRS --

MEMBER ABDEL-KHALIK: Okay.

MR. CAVES: -- you know, which systems are potentially affected by that.

MEMBER ABDEL-KHALIK: All right.

MEMBER SHACK: Have you had any history of those socket weld failures in those systems?

MR. MALLNER: I don't have that information. I can't answer specifically.

CHAIR STETKAR: You mentioned CBCS is your high head safety injection system in this plant?

MR. MALLNER: Yes.

MR. SIEBER: Now these are vents and drains for the most part?

MR. MALLNER: There are some. I mean we have some -- there are some generic small-bore lines that are attached for vents, drains, valve leak-offs, things like that, but obviously, that's not all of them.

MR. SIEBER: It sounds like a number that I would attribute to just the Reactor Coolant System as far as socket welds.

MR. MALLNER: Well, for example, for RHR, there's only two. So the great majority are part of the Reactor Coolant System, but again, you're going to have some offshoot into CBCS and in SI for the same reason.

MR. SIEBER: I remember a number like for a 3-loop plant, 167. They're almost all vents and drains or instrument lines or impulse lines.

MR. MALLNER: Right.

MR. SIEBER: The big trick on those is when you weld them up to pull them out a little bit before you weld it so that the gap isn't closed until you heat it up, and then --

MR. MALLNER: Crack the weld.

MR. SIEBER: Crack the weld when the --

MR. MALLNER: And anything else on the population of socket welds?

(No response.)

MR. MALLNER: The other item we had -- I'm going to turn over to Bob Reynnolds -- concerned the containment spray valve chambers, and Bob has the information on that.

MR. REYNOLDS: Okay, I'm Bob Reynolds, and I would like to say that this was a question -- really a question we also got on the whole IWE program during the audits. And there was a letter that pretty much documented the containment liner and all the other things including the valve chambers as well. And that letter is HNP-07-112. And what I was going to do is just mention some of things that we found, kind of history of the valve chambers.

In 1993, there was an indication on the outside of the alpha containment spray valve chamber and it was due ground water intrusion. As I mentioned this morning, these chambers, these tanks are partially embedded and it's not at a joint basically on the building. It's between the reactor building and the containment building. So there is some ground water intrusion in that area. So there was some minor corrosion on the surface, on the outside of the tanks. There was UTs done and cleaned up and recoded, and although we still do have some drainage in that area, there's not been any further corrosion issues with that area. That was in 1993.

We've also had -- and I'll just say now the frequency of inspections on the valve chamber for the IWE program is every other outage. So it would be basically every three years is the frequency that's been established for inspection. It's actually one period, but you get -- but you have to do it every other outage in order to achieve that according to the IWE engineer.

The second occasion that we have some

information and this information that we reported in this letter, but it's also part of the ISI summary reports that we did send to the NRC. In refueling outage nine which was in 2000 -- and I'll read this here -- there was some rust and pitting was identified inside the alpha containment spray valve chamber. Metal thickness was above nominal thickness as determined by UT, and that was -- of course, that was again corrected, repaired and recoated and all that at that time.

Again, in -- that was in 2000 -- in 2004, they also had some history on that as well, and let me just get to that. Okay. There was some visual inspection in side the alpha containment spray valve chamber and it was performed. No recordable indications were observed. In addition, a visual examination inside the three remaining valve chambers was performed, but no recordable indications. And there was one small damaged coating area in the alpha containment spray valve chamber area, but that was basically because they damaged the coating getting in and out of the tank, and that was due to a ladder, I think, that was inside there they had installed. So they recoated that and so that's the history of it.

And in 2006, when the last inspection was done, there were no recordable indications inside the valve chambers as documented in the IWE ISI inspection reports and also in the ISI summary report that we sent to the NRC.

The atmosphere inside the tank, as we use for the license renewal, is a dry -- inside air environment. It's not normally -- I wouldn't be went unless there was some leakage of a valve in there, but in discussions with the coatings engineers, he never noted any water inside the tank when they were going in for the inspections.

Any other questions on that?

MEMBER ABDEL-KHALIK: The determination in 1993 that the water was caused by ground water intrusion --

MR. MALLNER: Yes, sir.

MEMBER ABDEL-KHALIK: -- what was that, the detail --

MR. MALLNER: That would be we have non-aggressive groundwater at the Harris Plant, but there is some areas where water does leak into the buildings, and one of these locations is a location between the reactor building and the containment building where these containment spray valve chambers are located and there was water. It doesn't really say how much was coming in, but you could see evidence of the rust on the outside of the tank due to the water drippage in that area.

MEMBER ABDEL-KHALIK: But how is that ameliorated that would allow you to say that in 2006, there was no visual indication of any corrosion or water intrusion?

MR. MALLNER: Well, in 2006, I mean when they looked at the tank, there was no corrosion on the inside or outside of the tank. In other words, the surfaces have all been -- anywhere there was any damage have always -- have been repaired. And although there may be some drippage on it, there's not any corrosion.

MEMBER ABDEL-KHALIK: But my question pertains to what actions did you take in 1993 to ameliorate ground water intrusion?

MR. CAVES: I'll have to get back to you on that.

CHAIR STETKAR: Okay. Thank you.

MR. CAVES: I think that's all the responses that we have. Is that correct?

CHAIR STETKAR: Okay. Great. Thank you very much for the very, very responsive, quick. We appreciate it. And with that, I guess I'll turn it over to Maurice and the staff and tell us what you have.

MR. HEATH: Thank you. Good afternoon. My name is Maurice Heath, and I'm the Project Manager for the license renewal application at Shearon Harris. To my right is Mr. Caudle Julian who is the Lead for the Regional Inspection. He's out of Region II. And also in the audience, we have the staff that -- our reviewers that are in the audience to answer any questions that you might have with any of the issues.

Introduction -- I just want to step through briefly what we're going to go over today, a brief overview. Then we'll step into section two, scoping and screening review followed by Caudle will go over license renewal inspections. Then we'll go back to section three, aging management review results an then we'll go to section four, time-limited aging analysis.

As a brief overview, as the applicant stated earlier, but I'll just step through it a little bit, the LRA was submitted by letter dated November 14, 2006, Westinghouse three-loop PRW, 29 megawatts thermal, 900 megawatts electric. The operating license expires October 24th, 2026, and the plant is located approximately 20 miles southwest of Raleigh, North Carolina.

Safety evaluation report with open items was issued March 18th, 2008. We had one open item and two confirmatory items. During the audit process, we asked 346 audit questions. And during the review, we also had 75 requests for additional information --

MR. BARTON: That's a low number of RAIs. Is that -- can you explain that? I know the audit team did a real good review of all the aging management programs and had lots of questions. Would that have affected the number of RAIs the staff issue, because this seemed to be a number of RAIs on an application, I thought.

MR. SIEBER: Yes. It's about a third of --

MR. BARTON: Right.

MR. HEATH: Possibly, because during the audits, we covered the majority of section four and section three which is the majority of the application, so that could possibly be one reason why the RAIs are such. That's why we have quite a few audit questions, because we did amount of work during those three audits.

MEMBER BONACA: Those other questions were through reactive change or they were formally written?

MR. HEATH: They were written and they were actually -- we submitted, with the audit summary report, a database with the --

MEMBER BONACA: So everything was pretty much documented --

MR. HEATH: Yes.

MEMBER BONACA: -- in fact, to replace the RAIs?

MR. HEATH: Yes.

MEMBER SHACK: Those are face-to-face and then you record them basically, right? I mean that's the --

MR. HEATH: Correct. We interviewed the site staff engineers onsite and everything, so.

MEMBER SHACK: So there is a record but you get more immediate direct feedback --

MR. HEATH: Correct. And we also had 35 commitments in the SER, and right now, because of the two confirmatory items, the applicant estimated a letter that had two additional commitments which brings it the total now to 37, and I'll go over those a little bit later.

This is just a brief highlight of the weeks we were onsite for audits. I won't read each step. Now starting with section two. Section one was scoping and screening methodology, and after the staff's audit and review, the conclusion was that the applicant's methodology is consistent with the requirements of 10 CFR 54.4 and 54.21(a)(a).

And that's where we'll go to section two, which consists of the one open item. I'll just go through a brief summary of the open item. In the license renewal application, the applicant states that the feedwater regulating and bypass valves are nonsafety-related. Chapter 10 and 15 of the Harris FSAR credits these valves for a redundant isolation function in the event of a main steamline break. The applicant's methodology referred to the industry guidance NEI 91-10 rev. 6 which infers that these components would be in scope per 10 CFR 54.4(a)(1). And in the application, it was designated they were in-scope with 54.4(a)(2).

MEMBER BONACA: Let me understand now and if you go to line break -- in a steamline break, whatever analysis you're doing on a steam generator, if you're assuming that the main steam isolation is the main -- if water isolation fails, do they isolate through the bypass? Is that what the second bullet means?

MR. JONES: This is Steve Jones in balance-of-plant branch of NRR. The main fed reg valves are credited to reduce the amount of main framework flow delivered to the steam generators to prevent excessive cool down allowing the boration of the primary to maintain a negative or a shutdown condition within the core. I guess they're not fully required to be leak tight, but -- and they also serve a secondary function of preventing over-pressurization of containment in the event of too much mass edition to containment during a steamline break.

MEMBER BONACA: So they're used in the analysis, in the Chapter 15 analysis?

MR. JONES: Right, in the event of a single failure of the main feedwater isolation valves.

I guess the staff's concern here was predominantly regarding whether or not additional components surrounding the valve should be brought into scope in the possibility that some type of age-related degradation could cause the valves to have a -- be in a latent condition where they would not close on demand. Since typically the feed reg valves have a separate solenoid valve that would relieve air pressure and allow the valves to close, that would not be indicated as operational during routing operation.

And I guess a statement from the licensee such as that if air pressure is lost, the valves would fail closed or if water were introduced into any of the electrical connections, it would cause the valve to close, that would be sufficient to resolve the issue as well as, I guess -- or otherwise evaluating the components surrounding the valve. That's the real focus, not really whether or not it's (a)(1) or not.

MEMBER MAYNARD: I'm sorry, I just need to -- okay, the major concern is for a steamline break and in coincidence with a failure of the main feed isolation valve? From that point on -- I'm trying to understand a little. We're dealing with a license renewal issue here or a current licensing issue?

MR. JONES: Well, from the current licensing basis, the staff understands these valves were configured, and in a number of plants, are configured as nonsafety-related valves in that they're not protected from tornado missiles, from missiles generated within the turbine building and high-energy line breaks. And the basis for that was that the probability of those events occurring coincident with a steamline break within containment is low enough that they need not be considered.

But in the area of aging management, we're talking about potential for these carbon steel piping systems that are all around. The feedwater system could be leaking or that the air lines going to these valves that typically have raised connections could be aging and weakening over time and just verifying that that age-related phenomenon doesn't cause some latent condition that would prevent these valves from serving their backup function.

MEMBER MAYNARD: I'm still struggling, though, current licensing basis versus license renewal. And I understand your aging, but what you're really doing is saying for an extended 20 years, these should be safety-related.

MR. JONES: No. We're saying that aging management programs should be applied to the feedwater system if there is a way for those types of failures to cause a failure of the reg valve to actuate and it's a safety-related or -- I don't want to get into safety-related, nonsafety-related -- but in its Chapter 15 functioning.

MEMBER MAYNARD: Well, I'm trying to understand that. So you're not saying that these have to be reclassified to safety-related?

MR. JONES: No.

MEMBER MAYNARD: Okay. By then putting it into the (a)(2) versus the (a)(1) part of it, doesn't that accomplish what you're needing or -- I --

MR. JONES: It would --

MEMBER MAYNARD: I'm trying to understand what --

MR. JONES: It would with an additional step. I guess we're looking for, okay, it's in-scope for (a)(2). I believe there was an addition or a modification to their initial application to call the valves (a)(2), and then we -- that was my understanding. And then the -- a statement -- I think we've accepted in the past a statement that if the valve -- if the air system fails, the valve fails closed. If the electrical components that would cause the valve to close for the Chapter 15 function, loss of voltage there would cause the valve to close, then we don't need to look around the valve for any other failures.

MR. HEATH: I'm going to step in and get the record straight for one thing. In the application, those valves are actually in-scope for (a)(2). So that was actually in the application. I just wanted to make sure that was -- I think it just misspoke --

MEMBER MAYNARD: I'm trying to figure out whether they're --

MR. HEATH: And to answer your other question, that kind of gets into a COB question, because the rule for license renewal states that safety-related SSC, so their COB says that these are nonsafety-related, so that --

MEMBER MAYNARD: Most Westinghouse plants have this design, you're saying?

MR. HEATH: Correct.

MEMBER MAYNARD: But you're saying they don't have to be reclassified as safety-related, right? But I'm just trying to see how close we are here on the delta here as to what -- you know, they proposed (a)(2), and you're saying in addition to that, what?

MR. JONES: Well, as I had indicated, if

you apply the NEI methodology, you would typically call it (a)(1). The key point about that is that if you call it (a)(1) and continue to apply the NEI methodology, you would look around for spacial interactions. But I guess if you go back to the baseline rule, the (a)(2) part of 54.4 states that if a component failure could cause an age-related failure, could cause failure of the function, an (a)(1) function, then it should be within scope per (a)(2).

Since the feed reg valve performs essentially an (a)(1) function, then it's credited for a Chapter 15 accident. That's why we're looking around that -- is there something that could cause a failure of that valve performance function. I guess that explains the open item --

MEMBER ABDEL-KHALIK: In a steamline break, what is the signal that causes the people at a reg valve to modulate close --

MR. JONES: The same signal --

MEMBER ABDEL-KHALIK: -- and what is the signal that causes feedwater isolation?

MR. JONES: It's the same safety-related signal, I mean steam isolation --

MEMBER ABDEL-KHALIK: Which is what?

MR. JONES: Main steam isolation signal at Harris.

MEMBER ABDEL-KHALIK: And that's based on what parameter?

MR. JONES: I think I'd have to defer to Harris. I believe it gets inputs from containment pressure and feed flow/steam flow mismatch. I'm not sure.

MEMBER ABDEL-KHALIK: Is the peak containment pressure that you calculate in this scenario based on the fact that the feedwater reg valve will modulate closed?

MR. JONES: Excuse me, I didn't hear that full question.

MEMBER ABDEL-KHALIK: The peak containment pressure that you calculate during that scenario assumes that you will reduce feedwater flow so that the total amount of water or steam discharge into the containment is reduced?

MR. JONES: Correct.

MR. SIEBER: One steam generator full.

MEMBER ABDEL-KHALIK: So the calculated peak containment pressure is predicated on these valves working correctly?

MR. JONES: On feedwater isolation

working, yes, whether it's this valve or the main feedwater isolation valves.

MEMBER BONACA: Or if you assume the failure of the main steam -- main feedwater isolation valve, then you rely on this to get the peak pressure.

MEMBER ABDEL-KHALIK: Okay.

MR. SIEBER: In effect, if we imply the -- or if we look at the implications of the licensing renewal rule, that changes your current licensing basis for this plant?

MR. HEATH: Can you state that again, I'm sorry?

MR. SIEBER: Between (a)(1) and (a)(2), if you apply the way the license renewal rule is written to this plant, it seems to me that it changes the current licensing basis for nonsafety-related to safety related. Is that true?

MR. LEE: Yes, this is Samson Lee from License Renewal, Dr. Sieber. Yes. We heard your comment but license renewal does not change the current licensing basis.

MR. SIEBER: It should not.

MR. LEE: Okay. It's not a safety or statement on safety in your licensing basis, but the thing is that for license renewal, we define a scope for license renewal. So anything that meets that scope definition, okay, that performs its function and is defined in the rule, if you perform the function, you're in (a)(1). Okay? If your failure can prevent something else from performing the (a)(1) function, you're in (a)(2).

MR. SIEBER: Okay. Thanks.

MR. HEATH: Do we have any more questions on this open item?

CHAIR STETKAR: Yes. As long as it's open, I'll ask you the same question that I asked the applicant this morning, and that is they said they believe they see a path forward to resolving this. Is that your interpretation also? Do you feel --

MR. HEATH: Yes. That's our interpretation that we do have a path forward, but until we get, you know, the documentation in-house, we really don't now exactly what it says, so we can't -- I can't comment further on that. But we do believe that we have a math.

MEMBER BONACA: We're going to hold our breath?

(Laughter.)

CHAIR STETKAR: Apparently, we need to

wait for chapter two.

MEMBER MAYNARD: I think there's two issues and one's a legal issue.

CHAIR STETKAR: That's right.

MEMBER MAYNARD: You know, the other is what are the real safety implications and everything there. And, you know, I'm not sure what needs to be done to assure, but, you know, most things are going to cause the valves to close, pumps are going to trip. There's a number of ways to stop the -- I'm not overly concerned from the safety standpoint. You know, what's been done in the past, I think, is going to be fine for the future. But I think you got to work through the legal issues of that and, you know, what needs to be done aging management wise to provide that.

MR. SIEBER: Well, there is a potential for an accident, as Said said. If you have a steamline break and you keep pumping water into a hot steam generator, pressure and containment is going to go up and up and up until something stops it. What you're relying on in a single failure is that feed reg valve.

MEMBER BONACA: Right.

MEMBER MAYNARD: Well, the feed reg valve tripping the -- you know, you also trip main feedpumps and you have other things that trip themselves from going in there.

MR. SIEBER: Yes.

MEMBER MAYNARD: Yes. You're relying on a nonsafety system to provide an important function.

MR. SIEBER: But you got to pick something and that's -- they picked on the valve.

MEMBER BONACA: You have they just liked the single feature and you can credit the system here to give you the results, yes?

CHAIR STETKAR: These valves at Shearon Harris are air operated valves, air to open, they'll close?

MR. SIEBER: Yes, solenoids operate the air. They fail closed.

CHAIR STETKAR: Do you normally operate -- I'm trying to thing a big about things that could prevent them from closing which is basically what we're talking about here. Obviously, the feed reg valves are normally operating. The bypass -- do you ever use the bypass valves?

MEMBER MAYNARD: You also have manual isolation valves, but normally, it takes a while to set the manual isolation valves.

MR. SIEBER: You have to get somebody to go out there.

CHAIR STETKAR: Just to find -- okay, thanks.

MR. HEATH: Section 2.3, Mechanical Systems. There were 110 mechanical systems identified, 72 of which are balance-of-plant. One hundred percent were reviewed during this. Now the balance-of-plant review, there is a Tier 1 and Tier 2 review. The Tier 1 review took into account 41 systems, and the Tier 2 review took into account 31 systems, and the difference between Tier 1 and Tier 2 is that Tier 2 reviews the detailed review of the boundary drawings.

Now during the scoping and screening review, the staff a few areas which were difficult on the boundary drawings. It was difficult to assess the non-safety systems interacting with safety which is 54.4(a)(2), so the staff requested that the regional inspection team verify these areas to ensure that the applicant properly implemented criteria for 10 CFR 54.4(a)(2). And the inspectors found no potential for space or interaction between nonsafety and safety-related SSCs at these locations.

CHAIR STETKAR: Maurice, I only had one

question reading through your decisions for Tier 1 verus Tier 2, and that is I notice that the steam dumps and I've forgotten what else -- main feedwater system certainly was in your Tier 2 review which is more detailed -- but the condensate system -- the steam dumps, circulating water and feedwater system were included in Tier 2 based on their risk significance. That's the words I found. However, the condensate system was not included in Tier 2, the implication that, for some reason, the condensate system is much risk significant than those other systems. And that struck me as a bit odd since the condensate system feeds the feedwater system. Do you know why that decision was made?

MR. HEATH: Not -- I have to let balance-of-plant, Steve to answer if he knows the answer to that one.

MR. JONES: This is Steve Jones in balance-of-plant branch. The -- I guess typically with regard to -- you mention like the circulating water system would get a more detailed review because often it's associated with internal flooding scenarios that could affect large parts of the plant. Feedwater is a little more safety-significant with respect to while it does provide the same function as condensate in terms of providing a normal heat sink to the steam generators, it also is a potential high-energy line break source, more so than the condensate system. And typically, it goes in areas of the plant where there are more -- there's more equipment that could be vulnerable to high-energy line break issues. I think that's the distinction or was there another system that --

CHAIR STETKAR: Steam dumps -- against the steam dumps.

MR. JONES: Steam dumps -- again, they're credited as a normal heat removal path. I guess -- was it the atmospheric steam dumps or just the turbine?

CHAIR STETKAR: You know, they're only called steam dumps in the thing that I read, so -- I thought they were probably the condenser steam dumps but I'm not sure.

MR. JONES: I believe they're meant to be atmospheric steam dumps, and those are safety-related components.

CHAIR STETKAR: Okay. I was just -- you know, the implication in what I read said because of risk significance, and I was curious what type of risk significance rating was used to make those decisions. But I understand the high energy line break. That could throw things into one category or another. Okay. Thanks.

MR. HEATH: And Section 2.4, the Structural Systems, during the review, we brought one component into scope which was the insulation on low-temperature, small-diameter containment penetrations. And Section 2.5, Electrical Instrumentation and Control Systems, there were no omission of electrical and instrumentation and control system components within the scope of license renewal.

In summary of Section 2, applicant's methodology, scoping and screening methodology meets the requirements of 10 CFR 54.4 and 54.21(a)(1), and the scoping results, as amended and pending open item 2.2 resolution includes all SSCs within the scope of license renewal and subject to AMR. Now with that, I want to turn it over to Caudle to discuss the Region II inspections.

MR. JULIAN: You've seen these slides before. They're the generic ones that I usually use to talk to you. The scoping and screening inspections, the objective of what we're trying to do there is to confirm the applicant has included in-scope all appropriate SSCs. And we, if you recall, a year or so ago rewrote our manual chapter to decrease our work in the area of scoping and screening when we recognized it was somewhat of a duplication of the work that NRR is doing that you just heard described in Tier 1 and Tier 2. We primarily have looked at things that are in doubt. The focus of those is on the 54.4(a)(2) situations where nonsafety-related could affect safety-related. We're asked to look at those sometimes.

Our license renewal program is described n manual chapter 2516 and the inspection procedure itself is 71002. We developed a site-specific inspection plan for each applicant, and it's scheduled to support NRR's review, usually six to nine months after the application comes in. Region II uses a consistent team of five inspectors to do these inspections. We kept the same people on them as best we can all the time. And when we lose somebody, we have a training program for their replacement, inspectors.

The objective of these inspections now is mainly focusing on aging management programs, to confirm that the existing aging management programs are working well and to examine the applicant's plans for establishing any new aging management programs or enhancing the existing ones.

Inspection is two weeks in length and with a week off in between and a week onsite -- a week off in between and the second week onsite.

We examine the records of past tests, surveillances, operating experience for the equipment in question and corrective actions that have been taken for existing aging management programs. And we examine implementation plans for new and standard AMPs, verify the inclusion of any future tasks into an established site task-tracking system, make sure that they track the things that need doing in the future before entering the period of extended operation. And we do system and plant walkdowns to verify that the material condition of the plant is being adequately maintained.

MEMBER BONACA: Do you share experience with the other Regions regarding the --

MR. JULIAN: Yes, we do.

MEMBER BONACA: You do, right?

MR. JULIAN: Yes, we do. We started out that way by using inspectors interchangeably between Regions I and II and then between II and III and II and IV, and we've kept that up. We loan people back and forth for cross pollination of information and issues, and that's still going on today.

We have the option -- this slide just talks about an optional inspection to follow-up on any open items. If we end up at the end of two weeks and there are things that we don't feel we have enough information, we can do that. We have determined that we don't thing that's necessary in the case of Harris. We think things came out very clean and we do not intend to follow-up inspection on open items from this current inspection.

The results at Shearon Harris -- our inspection was conducted the dates you see, July 9th through the 27th. Our conclusions, big picture, were the existing programs to be credited is aging management programs for license renewal are generally functioning well. And in walking down plant systems and examining plant equipment, the inspectors found no significant adverse conditions. And it appears to us that the plant equipment was being maintained adequately.

MR. BARTON: What does that mean? I see that all the time. What does it mean when I see it's maintained adequately? What's your definition or what's your criteria for using that terminology?

MR. JULIAN: I guess everyone would have

a different perspective on it. I think our perspective is that our inspectors go to most of the Region II plants. They're mainly out of Division of Reactor Safety. And we see the condition of the equipment in the plant the same as the other power plants that we see. We're continually comparing --

MR. BARTON: One of the definitions of adequate is that it's barely sufficient or satisfactory, so I want to know where you're spectrum is. I don't ever remember seeing the words that the team has used that says that equipment is well-maintained. I only see maintained adequately. So every plant in the country is maintained adequately, and I don't really understand what that means.

MR. SIEBER: Well, you have a choice of two.

MR. BARTON: What?

MR. SIEBER: It's a choice of two. It's either adequate or inadequate.

MR. BARTON: All right.

MR. JULIAN: I tend to use the terminology of adequate, because I think that adequate is satisfactory, and it's not outstanding.

MR. BARTON: Okay. It meets the regulations?

MR. JULIAN: That's correct.

MR. BARTON: Or it meets your standards?

MR. JULIAN: That's correct. And it --

MR. BARTON: That's what that means. Okay.

MR. JULIAN: That's correct. And it's based on our -- all my people's observations from other plants. I'm hesitant to use the word outstanding when it comes to plant --

MR. BARTON: I didn't say outstanding. Well-maintained would be something that would mean more to me than maintained adequately.

MR. JULIAN: Okay.

MEMBER BONACA: And I just never see that. I'm just trying to get your feeling of what you meant by that. Okay. So it meets the regulations, I guess.

MEMBER ABDEL-KHALIK: Has any of these regulators seen inside the containment spray valve chambers?

MR. CAVES: I do not think we have -- the containment spray valve chambers. I remember when we were looking in that area, that condition, I saw the external surfaces, I did, of those chambers if it's what I'm thinking of. It's a valve chamber. I believe it's hooked up to the containment. It contains the isolation valves inside there. And we talked about the history of those valves and what --

MEMBER ABDEL-KHALIK: Well, you've never seen the inside?

MR. JULIAN: I have not, no. I don't know if our -- maybe if Progress has any information on it. Have there been any of our ISI inspectors happen to be there when those were open? We do an ISI baseline inspection to every unit every outage for a one-week inspection, in-service inspection.

MR. BURTON: I cannot answer that question.

MR. JULIAN: Don't know.

MR. SIEBER: But that's inside containment so for you to see it when the plant's running, you have to go through the containment and down to it?

MR. JULIAN: These penetration capsules that we're talking about have a portion inside and outside. Right.

MR. REYNOLDS: This is Bob Reynolds, Progress Energy.

MR. JULIAN: Yes, Bob.

MR. REYNOLDS: The -- same as we were

speaking of earlier, they're partially embedded in the containment wall and also in the lower area of the reactor auxiliary building which we did observe when we walked down to the lower area. Yes. They're not accessible to my understanding here in operation. You'd have to look at them during an outage.

MR. JULIAN: Can't look inside of it --

MR. REYNOLDS: That's correct.

MR. JULIAN: -- but you can see the external surface.

MR. BARTON: When you did your inspections, was the plant not in an outage? Were you able to inspect material conditions inside containment?

MR. JULIAN: When we did this team inspection, the plant was running, but as part of our inspection -- I didn't put it in the slides -- Luis Reyes has always insisted that we include a look see inside at least one unit of a two-unit site. And so we relied, in this case in Harris, on our previous ISI baseline inspection.

MR. BARTON: Which was during a refuel --

MR. JULIAN: During an outage, right. And we send one of our inspectors in with the licensees to go a complete walk of the containment, top to bottom and --

MR. BARTON: So part of his inspection is looking at material condition of the equipment inside containment?

MR. JULIAN: That's correct. He knows that he's part of the license renewal inspection team. We have just completed that, for example, on Vogel's last outage.

CHAIR STETKAR: When was that walkdown done for Harris?

MR. JULIAN: I'm sorry, I don't have the dates. I would say it was before this inspection, so it would have been the previous outage before --

CHAIR STETKAR: Within the last couple of years or --

MR. JULIAN: Oh, yes, it's --

CHAIR STETKAR: Okay.

MR. JULIAN: We try to set it up just before the team inspection if we can, and so we have to catch the previous outage. And we used to go do a totally separate look see, but then it came to us, well, we're doing in-service inspection anyway, and that inspector's going to go inside containment looking for boric acid. The boric acid program has received a lot more emphasis in the last few years, and so while he's doing that, we put him on our team. He's also inspecting for evidence of aging inside the containment, and he goes with the licensee folks. So we're jotting down anything we see and we get an explanation for it.

MEMBER BONACA: So you're also looking at the corrective action program in a way?

MR. JULIAN: Yes.

MEMBER BONACA: Because you're looking at conditions that you might find. Do you go back to see the effectiveness of their corrective action program?

MR. JULIAN: When we run upon things of that nature, we've pursued them.

MEMBER BONACA: Of course, you have the results of previous inspections anyway. I mean so --

MR. JULIAN: We've -- very seldom have we run upon a real serious condition that needs attention so far. There have been some leakage in, typically, component cooling water lines and leakage inside containment's a problem. And, of course, like I say, we're putting a lot of emphasis on boric acid deposits these days.

What we saw at Shearon Harris, I'll just give you a few examples. The applicant had established and implemented plans in their plant -- they call it their action request system -- to track the committed future actions for license renewal to ensure that they get completed. And we thought they did a good job of that at Harris. That's something we worked on with Robinson and then Brunswick, and we thought they did a real good job at Harris.

And Region II, of course, will follow-up on these things during the follow-up inspection. NRC's intentions are we're getting a lot of promises that so and so is going to be done before entering the period of extended operation. And so we intend to do another round of inspections using inspection procedure 71003. That'll be starting shortly before they enter the period.

Specifics -- I picked a few examples. The NRC inspectors identified several areas where enhancements could be made in the performance of existing programs. An example I use happened to be one you talked about this morning -- when I looked into their manholes checking for water, and they had a quarterly preventative maintenance task of pumping out existing water. And the folks that were doing that were craftsmen, and they were dutifully writing down what they saw out there. And I asked well, where does that information go, and he didn't know.

And so I started asking the system engineer, and the system engineer was fairly new in that particular assignment, and he wasn't getting that information. And so after we discussed it, now they're routing those completed PM tasks back to the system engineer so that he gets the information automatically and has it there for tracking and trending purposes.

They measure, my recollection is, the water in the manholes with something very simple like a dip stick, as I remember, that they do quarterly. And so they're looking to see if there's water there, and the craftsmen do it routinely. And so they have a memory of what's there. Periodically, they go actually lift the heavy concrete lids and look inside there. And these are more like cabled vaults than manholes. They're very big, huge concrete vaults.

And we looked inside, asked them to open them,, and we opened one on the cable run that goes from the aux building to the diesel generators, vice versa, diesel generators to the aux building, and one on the run that goes from the aux building down to the service water intake structure. And both of those looked in good condition to me relative to what

I've seen other places based on my experience there. I have seen some places where the darn things are flooded when we open them up.

MR. SIEBER: So these were adequate?

MR. JULIAN: But these were adequate. I'm sorry. NRC also learned that the applicant had previously identified that there had been problems with the past management and implementation of the in-service inspection program. The applicant had an improvement plan in place and were committed to add resources to recover the ISI program. And Region II followed up on that issue.

The ins-service inspection program is a very important one we think. It's credited as an aging management program, and when we came upon the scene there, we thought that due to people's retirement that had been doing that work for a long time and replacement with people who had just come on the scene that the program had kind of fallen a little bit behind. Their program records are not up to date.

And there was a commitment that they made way back when in the FSAR to do an augmented inspection on the feedwater lines as they come into the containment and the steamlines, and it looked like they could find no record that that had ever got done. And so they went to work and got some new folks on the scene and brought those programs up to date and performed those augmented inspections.

And we went back during our next baseline ISI inspection and followed up on those and think that Harris corrected that matter in good shape.

MEMBER ABDEL-KHALIK: If the water levels in these wells had not been trended, where is that OE recorded? Where is that information?

MR. COLLETT: The information is recorded in the work orders.

MR. JULIAN: They have plan --

MR. BARTON: Where does that go?

MR. COLLETT: Work orders are simply the orders for the guy to pump out the manhole --

MR. SIEBER: Yes and there's blanks that say what you find.

MR. JULIAN: They've simply been filed.

MR. SIEBER: They're permanent documents.

MEMBER ABDEL-KHALIK: If one is trying to find out if any of the MSPI systems had at one time been affected by this, how would one go about doing that?

MR. CAVES: We'll be doing that in

preparation for the full ACRS meeting, so what we will have to do is go back, as I had mentioned earlier -- this is John Caves one more time -- the initial inspections were performed in the 2003 timeframe. Okay, prior to 2003, we did not have the PMs in place that we do right now. Once we put the PMs in place, though, you know, the information then recorded in the work orders and the system engineer will go back to those work requests that are in the records management system as QA records and pull that information out and present that to us. That's the mechanism that we'll use to get that data.

MEMBER ABDEL-KHALIK: How far back does that --

MR. CAVES: 2003.

MEMBER ABDEL-KHALIK: Okay.

MEMBER BONACA: So before 2002, this was not considered a condition corrected?

MR. CAVES: Prior to 2003, we didn't have a formal program to monitor and measure the actual water in the manholes.

MR. JULIAN: I think this kind of started to surface as an industry issue in 2001 --

MR. CAVES: Yes. It was about that timeframe.

MR. JULIAN: -- 2003 and people who had no program at all but were starting to come around to build such a program.

MEMBER ABDEL-KHALIK: Thank you.

MR. JULIAN: And unless you have further questions, that concludes what I brought to say -- oops, one more. Pardon me. Often, the Subcommittee is asked about what is the current performance of Shearon Harris, and so I pulled up our slide that's on our external website for performance indicators, and as you can see, all the performance indicators are green. And I consider Shearon Harris to be a good operating plant at the current time, and their history is good with us. That's all I have. Maurice?

MR. HEATH: All right. Now I want to start with Section 3, Aging Management Review results, and these are the sections in Section 3. What I'm going to do is just highlight portions of the review. First, Section 3.03 is the aging management programs, and there were 40 aging management programs, 12 which are new programs, 1 which was added as a result of review which I'll discuss next slide, and there were 28 existing programs.

As I said, the program that was added as a result of the onsite audit is the oil-filled cable testing program. During that audit, one of the NRC staff asked the question about the 230 kV cables from the switchyard to the startup transformers. There appeared to be an aging effect for these oil-filled cables. However, there is a lack of an aging management program, so the applicant added an oil-filled cables testing program to address this need. And this program will periodically test the cable to determine the cable insulation properties.

MR. SIEBER: This is just a Megger exam?

MR. HEATH: I'm sorry, I didn't hear you.

MR. SIEBER: Is this just a Megger examination?

MR. HEATH: Well, with this, they have options on how they want to do the examination, so I mean --

MR. HEATH: This is Mike Heath. We currently do Dolby testing every four years on --

MR. HEATH: One of our two confirmatory items come from Section 3.4 and this is basically, the applicant credits managing changes in materials and cracking of elastomeric and thermoplastic piping and piping components with the external surface monitoring program. Now the GALL AMP does not specifically address these components or provide any provisions for inspection methods. So the applicant has proposed to use a preventative maintenance program which will periodically replace these components based on operating experience and vendor recommendations.

MR. SIEBER: Where do you use elastomeric and thermoplastic pipe? Is that bed plate drains or -- I've seen it used there but I'm curious as to where you use it.

MR. MALLNER: This is Chris Mallner from Progress Energy. the components in question were some -- we had some hoses on the main steam PORVs. We had a breather cap. We had a polyethylene sample line in the sampling system, and there was a rubber hose and -- that connected air to the feedwater reg valve tanks. And the other component was another plastic that went to flow instrumentation associated with the condensate system. That was it. Those are the components we're talking about.

So instead of trying to age-manage them, as Maurice said, we've decided we're just going to replace them.

MEMBER BONACA: So really, you're taking

them out of the aging program?

MR. MALLNER: Correct.

MEMBER BONACA: They're not part of license renewal anymore?

MR. MALLNER: Correct.

MR. SIEBER: Yes. I'm not sure how you'd determine the remaining life of a rubber hose.

MR. HEATH: Section 3.5 is aging management of inaccessible concrete. Now what this table shows is readings from two wells, 57 and 59 and just gives the pH, chlorides and sulfate values and showing that they have met the acceptance criteria, so they're below grade environment is nonaggressive. But looking forward in license renewal, the ground water testing will be performed in a yearly interval by the Structures Monitoring Program in the period of extended operation.

MEMBER BONACA: Do you have any idea why you have the difference in chlorides --

MR. BARTON: Chlorides in two wells, yes.

CHAIR STETKAR: Well, it's not only -- to interrupt here for a second, the things that I read were that during early life, there were several more wells that they monitored and the chlorides and all of those wells were substantially lower than this 290 also. So that 290 seems to be a real singularity.

MR. REYNOLDS: This is Bob Reynolds with Progress Energy again. I can answer that. We selected these two wells based on their proximity to the plant. The closest one is of the over wells that we had established back during -- maybe during the construction period of time. And so we just sampled these particular two. When you saw all of this, a question came up about the variation between two wells, 290 and 42 on the chlorides. We wen back last week actually and did another test. And actually, we came up with the same readings again on the same two welds. So we thought maybe we might have had a decimal place off or something, so we went back and did check it.

In addition, the site of Harris is a proposed for some new plants, so we've started some well monitoring north of our existing plant just a few hundred feet, and we -- I think there's five or six wells there that we're starting to examine over the last two years. And all of them fall in the range of the lower numbers here except for I think there was one weld that also had a high reading of like 260. So we talked to our chemistry person on site who's an expert in this area. He said possibly it's just an area where there's maybe salt deposits or something where this particular well is.

So although we do have a little disparity, we also -- like I said, we found another well that had a little higher reading as well, so we think we -- the fact that we went back and retested the same well, it was the same reading, and the fact that we found another well with a high reading, you know, we felt like that was -- it proved that, you know, it could Exhibit a variation in the wells.

MEMBER BONACA: The other well with the higher reading, is it in proximity of this one?

MR. REYNOLDS: Actually, it was not. The other reading -- this particular well is south of the plant, not too far from the emergency service water intake structure. And the ones -- the other reading we just recently took last -- I mean of the ones in the new plants is actually north of the plant several hundred feet.

MR. HEATH: Next, we're going to Section 4 or the TLAA portion, and I'm just going to highlight briefly a couple things in that section. First, in Section 4.2 is reactor vessel neutron embrittlement, upper shelf energy. And what this graph -- it's upper shelf energy assessment is based on a one-fourth t fluence value at 55 effective full power years and the copper content in the limiting beltline material using the methodology in Reg Guide 199 rev. 2. Acceptance criteria comes from Part 50, Appendix G for maintaining upper shelf energy values of reactor vessel beltline materials above 50 foot-pounds. And as you see on the graph, the staff has done an independent calculation to verify that this value is within the acceptance criteria.

And next is the reference temperature for the pressurized thermal shock values. And 10 CFR 50.61 defines a screening criteria for the embrittlement of reactor vessel materials and pressurized water reactors and for plates, forgings and axial welds, the PTS screening criteria is 270 degrees. And the staff did an independent calculation to verify tht they are within the acceptance criteria.

Section 4.3 --

MEMBER BONACA: The numbers you're showing here, they're there the licensee's number, right, like 199?

MR. HEATH: Yes, which was verified by the staff. Yes, they did it independently and also came up with that.

MEMBER BONACA: And it came first?

(Off the record comments.)

MR. HEATH: Now Section 4.3 is metal fatigue and let me give you first a brief methodology and we'll talk about the confirmatory item. The applicant used a special-purpose computer code in calculating the stresses for temperature transients. The code is benchmarked for pressure, external movement and thermal transients. Sixty-year fatigue re-analysis were completed for all NUREG 6260 components with two components having 60 years CFUen greater than 1. Harris will use fatigue monitoring program AMP to manage according to 10 CRF 54.21(iii) for all reactor coolant pressure boundary components including the surge line and pressurizer lower head penetration for 60 years CUFen greater than 1.

The confirmatory item -- Harris will update the piping design specifications to reflect the current design basis operating transient which is currently commitment number 37. And the FSAR will be updated to reflect Harris' crediting fatigue monitoring program AMP to manage aging for reactor coolant pressurizer components according to 10 CFR 54.21(iii). And all confirmatory items are closed by LRA Amendment 7 dated April 23rd, 2008.

Next slide we actually briefed on in the morning session, talked about -- Mr. Robert Hsu clarified and pointed out how this works.

MR. HSU: This is Robert Hsu. I was the audit team leader for the Shearon Harris an responsible for the metal fatigue analysis. When we went to Harris, we found the applicant used this stress-based software to calculate their stress. Things we just finished the current right now in the U.S. market -- there are two software. They both use the stress-based fatigue evaluation. They used the same theory which is one called Green's function. And they also could be called a transfer function. So the concept is as long as you get the stress -- you get the temperature, you can convert the temperature to the stress immediately.

So we asked both software user the same question -- how you mark your software, how you do the benchmarking. And Shearon Harris provided us the benchmarking. And this one provide us the benchmarking result which is a complete report which include about 29 pages. And this is just one of the examples they provided to us which they pick up a random transient and compared their result with NSYS result, and which everybody can see that this shows that pretty good match, and the other software which we have a question relate to was the other plants -- okay, those lines are the Sxx, Syy, Szz, which the one is coming from the NSYS result. Another one is coming from their software result, so that's the comparison. And the solid line is from the NSYS. All those low points are coming from the WESTEM which shows a pretty good match.

And so which thermo-phase (phonetic) says their benchmark is pretty successful. And the other one, we have the problem is the other one doesn't have the -- when we asked the question, they say they never do a benchmark. And so from that point, we are asking for the detail. And the detail is they say they only use one stress value to calculate the stress time history result. So we ask them to do the benchmark. Their benchmark shows they cannot have the match. They can - -they create like a fatigue result, like 40% off, underestimate.

And for this one, we found this is a pretty good match. You use the WESTEM to calculate this result. Because this one they use exactly six stress tensor to perform the Green's function integration. The Green's function integration basically from the theory or concept wise is valid.

The only two -- both software, they use the same thing. The only difference is one, the input is different. This input uses all six stress tensor. The other one, they only use one value, this value which is based on their determination to determine how could one stress can represent all stress tensor.

So the other one's problem is their input. Their input problem is that they use a simplified input.

MEMBER SHACK: When they do these calculations for like the 60-year CUF, are these still based on an assumption of a number of design basis cycles from the original history, or are they now extrapolating using their observed 20-year history? Are these realistic amounts of numbers of transients?

MR. HSU: The first time they did analysis, they used a projection. Then after we asked the question how they justified their projection and because some of the things that they are based on the 18 years history, they say this transient never happened. So they 60 years, this never happened. They use this kind of logic. Then we asked this kind of question and then they changed it. They go back to the design basis.

MEMBER SHACK: Oh, and that's what the -- the bullet that says they will update the typing design specification?

MR. HSU: The design -- the piping design specification, that's a different story, because when they're doing a surge line on the NSYS, the original surge line was not considered. There's this insurge/outsurge and a stratification. This thing was come out at 8811 and 8808, so they updated their analysis but they did not update their original design spec. So we are asking things. You have a design analysis. Your design spec should be matched with your design analysis. So that's the reason they're going to do the update.

MEMBER ABDEL-KHALIK: Where is this node located?

MR. HSU: This node located? I'm not quite sure which nozzle this one is. This is their benchmark report. This is come out from the software benchmark report.

MEMBER ABDEL-KHALIK: How do you know that this representative?

MR. HSU: How do I know this is representative? This is a software tool.

MEMBER ABDEL-KHALIK: No, no, no. I mean

you're showing a comparison for a specific node, a specific location.

MR. HSU: This is not a specific location. This one is the benchmark and benchmark to make sure this tool is valid and this tool is valid. This tool can be applied to any random transient and applied to any location, any -- it doesn't matter, okay, what kind of geometric it's come out. This is just trying to represent this methodology. It's perfect. And --

MEMBER SHACK: No, but he's asking if you selected another node on the nozzle, would you get as good agreement.

MEMBER ABDEL-KHALIK: Thank you, Bill.

MR. HSU: According to the Green function, development, theory and concept, you are supposed to get exactly match result, which is good.

MEMBER ABDEL-KHALIK: Okay. Let me ask the question a different way. Why was this node selected to generate this plot?

MR. HSU: Why is the node selected to generate? This is -- doesn't matter it's a pipe or it's nozzle or anything. This is just a random and try to prove the program is good. This is just a tool.

MEMBER ABDEL-KHALIK: How many nodes are there in the finite element code, in the finite element model?

MR. MALLNER: This is Chris Mallner. If I can just interject for a second.

MEMBER ABDEL-KHALIK: Thank you.

MR. MALLNER: As part of the response to the audit question we got, we didn't generate one plot. We generated like for about 18 different locations, 18 different series of plots we came up with including an explanation of how each one of these -- when I see we, our NSSS supplier did the calcs for us -- and how these things were generated, and we presented that to the audit team for their review as part of the audit review process. So it's we didn't give them just one plot. We gave them, I think it was, 18 plots which covered a range of evaluations so they could see that for a particular evaluation that we would get good agreement between the results form the ANSYS software and the results from the software that we were using at the plant which would be WESTEMs.

MEMBER ABDEL-KHALIK: Thank you.

MEMBER MAYNARD: Now, were they all in about the same agreement?

MR. MALLNER: I'll leave the characterization to the staff.

MR. SIEBER: It was adequate.

CHAIR STETKAR: The implication is the staff has something like 17 or 18 more of these plots available. I think we might be interested in seeing those.

MEMBER MAYNARD: Basically, we're saying that this is representative.

CHAIR STETKAR: That's right. I mean this is -- since it's become an issue quite recently, if there is a broader sampling at least for -- from the runs that Harris has made --

MR. CHANG: This is Ken Chang. I'm the Engineering Review Branch 1 Branch Chief. When we were there asking this question, we got a benchmarking report on the next day. So this benchmarking was made for proving that a computer code is doing the right thing. Okay? And we look at the various plots. As far as I can remember, all the components and stress intensity comparison is within plus/minus half a percent, all the plots. And I have a copy of the plots here if anyone is interested in taking a look.

CHAIR STETKAR: Okay. That's the answer.

MEMBER SHACK: That's the answer.

MEMBER SHACK: That was the answer we were looking for. This is representative of a reasonably large sample.

MR. CHANG: That's correct. The computer code, before you use, you should benchmarking on a selected configuration and then you apply it. That's the standard way of doing it.

MR. SIEBER: Very good agreement raises questions.

MR. HEATH: Do we have any more questions on this graph? In conclusion, pending resolution of open item 2.2, the staff determined, on the basis of it's review of the LRA, the requirements of 10 CFR 54.21(a) have been met. With that, I'd like to open it up for any additional questions for the staff.

MEMBER BONACA: I have a question. We have addressed it in the past, but suppose that a few years from now Shearon Harris decided to uprate power level by a significant amount, 5%, 10%, I don't know, something, is there a process by which some of the commitments which may be affected by the power uprate are going to be revisited? For example, assume that you have now much higher exit temperature from the core.

MR. SIEBER: It would be even higher.

MEMBER BONACA: Yes. You would have probably some impact on some inspections of internals and you would have -- is there a mechanism by which they would go back and look at their commitments?

MR. STEWART: This is Roger Stewart. Let me address that. Earlier this morning, we talked about we were doing the NFPA-805 commitment or the change. That's going to be a license amendment. The process that the staff has under the rules, under 54.37 Bravo, if there's any changes to our license or anything that impacts license renewal, we report that back to the staff in the form of our FSAR update that we do after every refueling cycle. So any changes that we make that potentially impact anything in the license renewal, we report back to the staff. That's the process.

MEMBER BONACA: And so you have a communication management program, really tentatively, to track these commitments and determines whether or not some changes --

MR. STEWART: Well, it requires internally that anything that we do that would result in a change in the licensing basis that might affect license renewal by the rule, we have to report it back to the staff. It's already a requirement.

MEMBER BONACA: So you would have to have an evaluation of your programs, right, after you have the power uprate --

MR. STEWART: That's correct.

MEMBER BONACA: -- to determine if there is any impact on --

MR. STEWART: That's correct. We would do that.

MR. SIEBER: These are changes under 50.59. Any change that does affect one of the three conditions, you have to go to the staff before you make the change, get an amendment to do it. So this is just 50.59 changes that end up reported through the --

MR. STEWART: What we're talking with the power uprate or with NFPA-805 type change, you're actually talking a license amendment.

MR. SIEBER: That's right.

MR. STEWART: And we haven't been looking as much up front on the 805 because until you actually issue that amendment and it becomes part of the COB, we haven't saw -- I haven't tried to see what systems that might bring in or bring out that we credit safe shutdown.

MR. SIEBER: Right. Well, until you get the amendment, it's not official.

MR. STEWART: That's correct.

MEMBER SHACK: But typically in power uprates, you know, the ones that we've looked at the constant pressure, constant temperature ones, there is an emphasis at looking at things like flow-induced vibration and FAC. If you had one where you raised the temperature, that would raise a whole new set of things to look at.

MR. SIEBER: Well, PWRs raises temperatures. BWRs are constant pressure. The other way to do it is lower T-aves. The T-h stays the same.

MEMBER BONACA: On the other hand, I mean there is a bunch of programs here which have been keyed to the needs of a client, as understood now, and with power uprates, you may have some changes out there that would have an affect. And I think it would have to be to be almost like almost like a small project to go back and review these programs and say, yes, this is impacted by the power uprate or no, it's not, nothing changes.

CHAIR STETKAR: I think that the NFPA-805 that he mentioned could affect the scoping of things, for example, for the license renewal, because depending on what -- if I'm correctly interpreting what you said as a result of that NFPA-805 assessment, you might wind up taking credit for additional SSCs for mitigating fire risk. That could, in principle, extend the scope of items that would then fall under the aging management portion of the fire protection.

MEMBER BONACA: I could see that for an impact on Section 4 with your TLAAs. Most likely, they'd have to deal with it.

MEMBER SHACK: But that's typically evaluated in a power uprate analysis that we've seen, and people look at them and --

MR. SIEBER: Yes, right.

MEMBER BONACA: Yes, right.

MS. LUND: This is Louise Lund --

MEMBER BONACA: It's more like, you know, requesting a configuration map to show that you covered all grounds.

MEMBER SHACK: That's the thing. You know, are you going to miss something as you do it. I mean people look at some things, but the question of whether you're looking at it systematically may be another issue.

MS. LUND: This is Louise Lund. You're exactly right, we are, as far as the power uprate reviews. You know, you look at whatever information is there, and because a lot of times it's, you know, whether a power uprate comes before license renewal or after license renewal. and, you know, sometimes it's a benefit to have the additional information to look back, because when the tech or reviewer is actually looking at -- you know, there's a lot of overlap in the technical areas you look at, and it does provide more information, in fact, you know, operating experience and a lot of information you would find useful as a technical reviewer when you do look at this. So, you know, I think that there's a lot of things that go on vis-a-vis each other and need to be looked at, you know, in that way. But there is a lot of information that is made available through the license renewal process that can be looked at, you know, in any power uprate review as well.

MEMBER BONACA: Yes. I think we wrote something about it years ago.

CHAIR STETKAR: Okay. Thank you very much. Good presentation. I think let me just take the opportunity to give each individual one last hurrah. Are there any open questions? Jack, start with you.

MR. SIEBER: I have considered the questions that you asked, and I think things are in pretty good shape here. I think that both the applicant and the staff has done a pretty good job on this one.

CHAIR STETKAR: John?

MR. BARTON: The only thing I'd add that I think the full committee ought to hear is the what is the applicant planning to do about this water in the ducts and cable-wetting program and testing of those cables and a history and that whole thing. That's the only thing I've got outstanding against this application. I thought it was a pretty good application overall.

CHAIR STETKAR: Bill?

MEMBER SHACK: Nothing to add what John said.

CHAIR STETKAR: Mario?

MEMBER BONACA: I thought it was a good application. I thought it was a good SER. I have no further questions.

CHAIR STETKAR: I echo those sentiments. I think the staff did a really good job on this.

The audit team, I was really impressed with the audit team questions and the feedback, so sounds good.

MEMBER MAYNARD: I have nothing to add to what's been said.

MEMBER ABDEL-KHALIK: Yes. I echo this and, you know, we really want to understand what systems may potentially be affected by that --

CHAIR STETKAR: I think -- yes, that's --

MEMBER ABDEL-KHALIK: -- details of, you know, operational experience that you've had and just knowing exactly the systems that may be affected by those six locations in which you have had persistent flooding.

The other issue in my mind is that without a root cause evaluation to identify the cause of containment spray valve chamber corrosion, I'm not sure if this issue is completely off the table, and I'd like to find out more about what is -- after all, this is a part of containment. I'd like to find out of a root cause had been done and what actions had been taken to ameliorate the situation.

MR. BARTON: That's a good one.

MEMBER BONACA: These are good ideas for the full committee meeting.

CHAIR STETKAR: Yes, these -- just, you

know, staff and Progress making notes, heads up, you come prepared to discuss these things.

MEMBER MAYNARD: I might add for the full committee, it would be helpful if we got into discussion on the cooling system again, if you had a little bit bigger picture that showed the lakes, and you could point those out. I've looked it up on the internet. I think I understand it now but it's easier to understand it with a little bit bigger picture.

MR. STEWART: I have the full satellite view that I took that snapshot from on a jump drive if you want it.

MEMBER MAYNARD: No, like I said, I've looked it up on the internet, but for the full committee --

CHAIR STETKAR: For the full committee, it's kind of interesting.

MR. SIEBER: Yes. And it would also be good if you pointed out the names of the various buildings that are there, because I couldn't tell from the photographs.

CHAIR STETKAR: So a good cartoon with a site layout and some arrows showing buildings and locations of things. One last question --

MEMBER ABDEL-KHALIK: Is the issue with the feedwater reg valve --

CHAIR STETKAR: No. That's -- I was just going to mention that. Is -- have we set a full committee meeting date for this

MR. WEN: Not exactly.

CHAIR STETKAR: Not yet. Okay.

MEMBER SHACK: We won't have one until the --

CHAIR STETKAR: I was going to say for our planning purposes, is -- are you close? I mean are you talking about the next month or so or?

MR. HEATH: I think we'll have it done by -- I anticipate having it done by October, full committee.

MEMBER MAYNARD: I think the main thing for us is we -- that when we do have a full committee meeting, I'd like to know how that's resolved.

CHAIR STETKAR: How that's resolved and from my perspective, and I think somebody else mentioned earlier, more in the sense of effect on safety rather than just simply regulation. I wanted to make sure that the resolution, you know, addresses both of those topics.

Okay. Hearing nothing else, we're -- not bad on schedule -- we're closed.

(Whereupon, at 3:08 p.m., the foregoing matter was adjourned.)