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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

SUBCOMMITTEE ON PLANT LICENSE RENEWAL

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WEDNESDAY

SEPTEMBER 8, 2010

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 1:30 p.m., Mario V. Bonaca, Chairman, presiding.

COMMITTEE MEMBERS:

MARIO V. BONACA, Chairman

J. SAM ARMIJO, Member

SAID ABDEL-KHALIK, Member

MICHAEL T. RYAN, Member

WILLIAM J. SHACK, Member

JOHN W. STETKAR, Member

ACRS CONSULTANT:

JOHN J. BARTON

ACRS STAFF PRESENT:

MICHAEL BENSON, Designated Federal Official

EVELYN GETTYS

ALLEN HISER

BRIAN HOLIAN

WILLIAM HOLSTON

KENT HOWARD

NAEEM IQBAL

JAMES MEDOFF

NEIL O'KEEFE

GREG PICK

LISA REGNER

ABDUL SHEIKH

SIMON SHENG

DAVID WRONA

ALSO PRESENT:

ERIC BLOCHER, APS

WINSTON BORRERO, APS

DOUG COXON, APS

TOM GRAY, APS

JOHN HESSER, APS

MARK HYPSE, APS

MOHAMMAD KARBASSIAN, APS

ANGELA KRAINIK, APS

DONALD LYNCH, APS

REX MEEDEN, APS

GLENN MICHAEL, APS

SHABBIR PITTALWALA, APS

MARK RADSPINNER, APS

RICH SCHALLER, APS

KEN SCHRECKER, APS

P R O C E E D I N G S

1:27 p.m.

CHAIRMAN BONACA: The meeting will now come to order. This is a meeting of the Plant License Renewal Committee. I am Mario Bonaca, Chairman of the Subcommittee meeting. ACRS members in attendance are Said Abdel-Khalik, Sam Armijo, John Stetkar, Michael Ryan and Bill Shack.

ACRS consultant John Barton is also present. Michael Benson of ACRS staff is the federal official for this meeting. At this meeting, we review the license renewal application for the Palo Verde Nuclear Generating Station, and the associated safety evaluation report with an open item.

We will hear presentations from Arizona Public Service Company representatives, NRC staff and other interested persons regarding this matter. We have received a comment from a member of the public, Mr. Bob Leyse, challenging the technical phases of Part 54 for reactors.

There were no requests for time to make oral statements from members of the public regarding today's meeting. The entire meeting will be open to public attendance. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions appropriately for deliberation by the full Committee.

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

A transcript of this 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 that are located throughout the meeting room when addressing the Subcommittee.

The participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. Before I proceed with the meeting and pass on the meeting to Mr. Holian, I would like to ask him to, during the meeting at your convenience, it would be of interest to the Committee to hear about what the plans of the NRC are for handling changes to license applications that may occur in the next, for example in the case of Palo Verde, 15 to 17 years from now.

Given the time is so long, there is an interest in knowing how do we handle events, significant issues, operating experience and reflect those necessary changes to the commitments. I mean is it going to happen the way that we have seen today, or do you have any perspective on that? That would be of interest to us. With that, I'll pass on the meeting to you.

MR. HOLIAN: Thank you, Chairman, and good afternoon ACRS members. My name is Brian Holian. I'm the Director of the Division of License Renewal. I'll just briefly touch on the agenda and introductions today.

The agenda is we are here to discuss the draft safety evaluation report for the Palo Verde units. The agenda for today is we need to do brief introductions. I'll turn it over to the licensee for their lengthy presentation, we'll take a break and then again the staff will follow.

NRC staff that are here, just some that I'll mention right now. To my right is the Branch Chief in Projects for License Renewal, and it has the Palo Verde units, among others, Mr. Dave Wrona. To his right is Lisa Regner. She's the senior project manager and has had Palo Verde for the extent of this review, and you'll be hearing from her later.

Behind me is a senior reactor inspector from the region, Mr. Greg Pick. He'll be presenting the inspection findings, and his boss is here also, Mr. Neil O'Keefe, the Branch Chief from the Division of Reactor Safety, Region IV.

Just a comment on the draft safety evaluation that you've seen. There's one open item on metal fatigue. The members have probably seen it's not related to the normal Westinghouse issue that's been an open item on a lot of the Westinghouse-type plants.

It's still metal fatigue, but it's a series of questions we had kind of related to their background, their FSAR and how they were doing in some of their calculations.

So I know both the licensee and I will get into that. But it's different than the old regulatory issues summary we had on Westinghouse plants. I just wanted to highlight that, but still similar-type questions from the staff. There's also several confirmatory items that I know will be addressed today.

Chairman, regarding your question, I'll address that just briefly now and then maybe again, right before the staff's presentation. It's historically now we've had some plants that have come in 10 to 15 to 20 years before their licenses, original license expires.

So that question is very relevant for how do you progress now and in the next 15 years with lessons learned in aging management programs as it is. Well one, the rule allows the licensee to come in 20 years in advance. So the rule allows that, and we do our review to the best up to that point.

The rule, I think, was originally written with the idea that enough operating experience is present to understand the type of aging management issues that are present and could therefore formulate a good staff review. That's some of the theory behind the rule, as I've had to answer that in other public sessions.

The question of applying operating experience, assuming they get a license and then in the period before their extended period goes on, is an item we've worked with particularly close with the region, and our other Part 50 people. I've often said, you know, a lot of people will say, even sometimes in this committee we'll hear "Well that's a Part 50 question" or "That's a Part 54 question."

In reality, my answer is always "they overlap." I can -- a lot of Part 50 questions that are current day issues have an aging management issue, and if they do, I incorporate them in our review, and so that's why we often -- and yet this Committee often asks how are you doing, what are you doing on that for current day plants.

Then we'll answer that, because a lot of times we work with our other tech review branches and do that. On this question of applying operating experience, we work closely with the regions. The best hammer or review I have is the inspection that we do again with the regions, right before, the year or so before the period of extended operation.

We expect that their aging management programs are living documents, that when I give the license, the GALL says it's a ten element program. The tenth element is operating experience.

So we trust that a plant will learn from the operating experience, from the time they receive their license until the time of end of the period of extended operation, and we'll inspect that for their aging management programs, before they go into the period of extended operations.

That's a quick answer. I'll develop that a little bit more before the NRC presentation. But I just wanted to touch on that now.

CHAIRMAN BONACA: Okay.

MR. HOLIAN: With that, I'll turn it over to the licensee and John, Mr. John Hesser, Vice President for Nuclear Engineering at Palo Verde.

MR. HESSER: Thank you, Mr. Holian. Good afternoon. On behalf of the Palo Verde staff and its owners, it's -- we appreciate the opportunity to discuss with you, Mr. Chairman and the distinguished members of the ACRS, our license renewal application and our draft safety evaluation report.

My name is John Hesser. I am the Vice President of Nuclear Engineering and the executive sponsor for Palo Verde's license extension. Here with us today in attendance we have Mr. Bob Bement, our site Vice President of Nuclear Operations. Seated here at the table I have Mr. Mo Karbassian. He's our Director of Nuclear Engineering; Ms. Angie Krainik. She's our manager of License Renewal.

Eric Blocher; he's our project manager for our license renewal application at Palo Verde. Glenn Michael, seated down here, our lead licensing engineer for license renewal; and Rich Schaller. He's our Metal Fatigue lead.

In addition, we've brought several personnel with us, both leaders and front-line personnel from Palo Verde, to discuss various topics in anticipation of your questions of our application.

The people with us today are knowledgeable in aging management programs, engineering programs. We have folks from Operations, our Probabilistic Risk Assessment area, Environmental, Radiation Protection; also Engineering Design.

Also with us to be recognized is two folks from our STARS Center of Business, Mr. Tony Harris and Chalmer Myer. The Center of Business was established to establish a format, a consistency for the seven Westinghouse plants that will apply for license renewal, so we give you a standard application, apply operating experience and lessons learned for the quality of those applications.

In addition, Palo Verde has brought along seven new members of our staff that represent Operations, Maintenance, Engineering, Licensing and Chemistry. These folks are new hires to Palo Verde. They're new to the industry.

Mr. Chairman, you asked the question about sustainability. We brought these folks along as part of a knowledge transfer and learning, to learn the ACRS process and what license renewal is all about. They represent the future staff at Palo Verde who will own the plant and own the responsibility to operate it safely as those of us who age and leave the business. So we brought them along for that learning experience.

Here's the agenda for our presentation today. I will give you a brief plant history and background. Mr. Karbassian will talk just briefly about major improvements and long-range planning, how we're taking care of our plant and plant equipment.

Ms. Krainik and our staff will talk about the license renewal application, our open item in metal fatigue and our confirmatory items, mention some of the regional inspection items and, if time allows, I'll make some concluding remarks.

Our mission in Palo Verde, which was established in 2007, prior to our license renewal application in December 2008, was to safely and efficiently generate electricity for the long term. As you can tell by the underscored words, we put strong emphasis on safely generating for the long term.

With regards to license renewal, we feel it's important that for the long term, we establish good, solid programs. We've already begun to implement those programs at Palo Verde. We are not waiting until we get near the end of the license period, but we've begun to implement some of those programs, and again by evidence of bringing new staff, it's important that the people are there and knowledgeable about the designed licensing basis and requirements of the plant to operate it safely.

CHAIRMAN BONACA: You used the word "implementing." So you're not only developing the program. But on some occasions you do implement them now?

MR. HESSER: Yes. When we get to Ms. Krainik's presentation, she will illustrate exactly the progress we have made to date and what progress we still have to go. But yes, we are intending to implement several aspects now into our current programs.

CHAIRMAN BONACA: Good.

MR. HESSER: Okay. So Palo Verde, the initial construction permit was issued in May of 1976. The initial full power operating licenses are listed here in '85, '86 and '87. This represents 72 years of reactor operating experience.

Each unit at Palo Verde is rated approximately 3990 megawatts thermal and 1390 megawatts electrical. At Palo Verde, we use reclaimed waste water for our condenser cooling cycle. We have no lake, no ocean and no river that we sit on, and we use spray ponds as our ultimate heat sink.

Palo Verde was designed and built on the emphasis that is three units of common design. We have common operating procedures, common design and licensing basis, and we try to maintain the configuration as close as possible with each other. That's why you have one licensing submittal application for all three units.

With regards to aging management though, there are differences in the plant, and we want to illustrate that, that the differences in the plant pertain to things like type supports, electrical conduit supports. When a plant is built, you do field routing and there's common design criteria and requirements that these supports are built to, and in one case in the SER, it's noted that we have things like drain valves that were put in that were used for things like maintenance or special testing that was done.

So you will find some minor differences. But as far as significance in the systems, there are -- we maintain commonality. Our nuclear steam supply system is a combustion engineering system 80 design. Our turbine generator was supplied by General

Electric. Bechtel Power was our general contractor and architect. They built Palo Verde.

Again, we have a large water reclamation facility and we take the secondary treated reclaimed water, and remove hardness and store it for the plant. We have our plant picture coming up to illustrate that for you, and of course we're a zero liquid discharge plant, not again having the river or ocean lake. We discharge to evaporation ponds, and I'll show you that in a second.

Just to give you a sense or feel for what Palo Verde is in relationship to the state of Arizona. We're approximately 26 miles from the western edge of metropolitan Phoenix. We're about 57 miles from downtown Phoenix and we're in the Sonoran Desert.

Palo Verde has seven owners. There are seven licensees. The number in parentheses underneath the names of the owners represents the percent of ownership. Arizona Public Service is the largest owner. We are the operating agent and we are listed as applicant in the license renewal application.

Here's the aerial view. I'll just touch on this real quickly, to give you a feel. The property of Palo Verde is over 4,000 acres. It's a large plot of land that the numbers encircled here on the slide represent the three units, Unit 1, 2 and 3.

You can tell the little rectangular circles there represent the spray ponds, the ultimate heat sink, down to the lower, your lower right-hand corner would be the water reclamation facility, where the reclaimed water comes to the plant.

It is treated and then put in the reservoirs that are listed there. There's an 85 acre reservoir and a 45-acre reservoir, and then as it goes through and cycles through the condenser cooling cycle and we discharge out from the sedimentation basin over to the evaporation ponds. We have three evaporation ponds.

Just to point out a little bit different coloration of the evaporation ponds. We have made, increased the capacity of those for future growth of the plant, the long-term operation of the plant by adding Evaporation Pond No. 3, and also in the reservoir. We used to have the 85-acre reservoir. We added recently the 45 acre reservoir for the long term operation.

MR. BARTON: The source of your water reclamation facility, what's the water sourcing? Where does it come from?

MR. HESSER: The water source, we actually purchase the Water from -- actually the metropolitan area of Phoenix. There are seven cities, Phoenix being one of them and some other local communities. Recently, we just renegotiated a contract that extends beyond what would be the 60 year life of Palo Verde if we were granted a license extension, sir.

MR. BARTON: Thank you.

MR. HESSER: You're welcome. Yes.

MEMBER STETKAR: On that, I think I read somewhere that that water comes through this like 35-mile pipeline? It supplies the water to the site.

MR. HESSER: Your information is fairly correct. It's actually 37 miles.

MEMBER STETKAR: I didn't want to seem that precise. It's kind of an off the top --

(Laughter.)

MEMBER STETKAR: I have 37 written down.

MR. HESSER: 37 miles.

MEMBER STETKAR: I know that's your normal cooling water supply. What's the capacity of your reservoirs? In other words, how long can you operate? Suppose that water supply disappears, like the pipe disappeared?

MR. HESSER: If ever we would have a trouble with either the water reclamation facility or the pipeline that supplies it, our reservoir, depending upon the time of year of course, it's probably about 13 to 16 days of operation that we can, which gives us ample time --

MEMBER STETKAR: It would be April through October when it's 100 plus?

MR. HESSER: When it's hotter, it's the lower number, yes.

MEMBER STETKAR: So about two weeks roughly?

MR. HESSER: Yes, roughly two weeks.

MEMBER STETKAR: And who controls that water pipeload, the aging of that water pipeline? Who monitors, who owns that pipeline?

MR. HESSER: Well, we actually own the pipeline and we have a right-of-way across the 37 miles that it spans across, and we maintain it, and actually we have quite a history of maintaining that pipe. We have PM programs and we have a long-range plan where we go out and almost every time we have a refueling outage in the units, where the water demand goes low, we actually do work on that pipeline. We go out and do inspection and repair.

MEMBER STETKAR: Is that, I didn't check. Is that pipe in scope for your license renewal?

MR. HESSER: No sir, it is not in scope for license renewal.

MEMBER STETKAR: Thank you.

MR. HESSER: All right. So this slide here is just to give you the information that today at Palo Verde, all three units are operating at 100 percent power, and you can tell here that Unit 1 and Unit 2 is in its 16th operating cycle. Unit 3 is in its 15th operating cycle and we're excited to have it slated, scheduled to have a refueling outage starting on the 1st of October in Unit 3.

So we do two refueling outages a year. We're on an 18-month cycle. With that, I will turn it over to Mr. Karbassian, who will talk about major improvements in long-range planning. Thank you.

MR. KARBASSIAN: Mr. Chairman, members of the Committee, I would like to take this opportunity to go over examples of the improvements that we've made at Palo Verde. Then I'll cover our long-range planning process and our top ten process, that helps us in identification and resolution of our technical issues.

Here are some of the improvements that we've made at Palo Verde. These improvements are either equipment reliability related. Some of them are improvement in efficiency, and some of them help with reduction in overall plant risk.

An example of the improvements that we've made on equipment within the scope of the licensing renewal are replacement of our steam generators, our replacement of reactor vessel heads as well as our management of Alloy 600 and similarly developed metals.

Relative to replacement of the steam generators, we replaced them to gain efficiency, improve reliability and resolve operating experience with Alloy 600. Our new steam generators have Alloy 690 and tube material, as well as a divider plate.

We've replaced our reactor head and we've replaced our reactor heads in Unit 1 and 2, and we will be replacing it in Unit 3 coming this fall.

MEMBER STETKAR: Was that -- did you have cracking, or you just did that as a proactive measure?

MR. KARBASSIAN: We did that as a proactive measure, sir. Once the reactor heads are replaced, then we will have replaced or mitigated susceptible components in our high temperature application.

MEMBER STETKAR: You don't have instrument nozzle penetrations or something like that still left?

MR. KARBASSIAN: We have replaced our instrument nozzles in high temperature application. Relative to our site top ten process, it's designed to involve personnel from each department to identify and prioritize their technical or equipment reliability issues.

For example, replacement of the feed waters steam admission valve was identified by our Operations, by our Maintenance, as well as Engineering Department, in their department top ten. Once it was identified, then it went, rolled over to the site top policy process, and then we replaced the valve from solenoid-operated to a motor-operated, to improve reliability.

We've completed several of these departmental and site top ten issues, and we have several planned. Intended in this was to show our approach in resolving the equipment issues, not to list every one of the site top ten's.

MEMBER STETKAR: Are you going to talk later about the spray ponds and their condition, or is this the time to ask about those?

MR. HESSER: We did not have any planned part of our presentation, but we are prepared to talk about it if you'd like to. Anything in particular?

MEMBER STETKAR: Yes. Two questions came up. Apparently you had some chemistry problems in the spray ponds. I haven't found the point in my notes here, so I can't cite the specific dates.

MR. HESSER: A few years ago.

MEMBER STETKAR: A few years ago, 2005, 2006 time frame, I believe. What were they, and what -- are there any lingering effects from whatever those problems were in terms of piping systems or heat exchangers that are connected to the spray pond water?

MR. KARBASSIAN: I'd like to ask Mark Radspinner, our System Engineering section lead, to address it.

MR. RADSPINNER: Hi. My name is Mark Radspinner. I'm in System Engineering at Palo Verde. I'm not in the Chemistry Department, so I'm not going to get into great detail on the chemistry aspects.

MEMBER STETKAR: That's okay. I'm not a chemist, so I wouldn't know what you were saying anyway.

MR. RADSPINNER: The following issues and the chemistry problems we did have was as a result of the combinations of chemicals that we would use to --

MEMBER STETKAR: There's one over here. It might be easier for you if it's on. Is that one on?

MR. RADSPINNER: Okay. As I indicated, the combination of chemicals that we were using to treat the spray ponds did result in a fouling mechanism.

It did affect our heat transfer capability in our essential cooling water heat exchangers. Extensive evaluation was performed and those have all been corrected. The performance of the essential cooling water heat exchangers has returned to normal.

MEMBER STETKAR: It was a fouling. It wasn't, it didn't enhance corrosion?

MR. RADSPINNER: The chemistry, of course, was intended to prohibit the corrosion, but it had a side effect that has since been corrected.

MEMBER STETKAR: Okay, and what about -- I don't know if you're the appropriate person while you're up there. There apparently is some evidence of, and I don't know whether it's spalling or cracking on the spray pond concrete itself.

MR. KARBASSIAN: Yes. Mr. Ken Schrecker will address the cracking of the concrete.

MEMBER STETKAR: Okay.

MR. SCHRECKER: Ken Schrecker, Palo Verde. I'm with system engineering and I have responsibility for spray pond component monitoring. Yes, there is evidence of some cracking above the water line on our spray ponds, both vertical and horizontal, but by far the vast majority of the cracking is horizontal.

The top layer of reinforcing steel, that has had the least amount of concrete depth, of concrete overage is, experienced some corrosion from the chemicals in the spray pond water. It's non-structural degradation at this time, and as was shown on our slide for the top ten program, we do have plans on making those concrete repairs by 2015. That's one of our commitments in the draft SER.

MEMBER STETKAR: Do you have any evidence of below-water line cracking or any evidence of leakage? I mean it's pretty dry there. You can see if it leaks; grass will grow.

(Laughter.)

MR. SCHRECKER: Below the water line, based on our last underwater inspection, nearly all of the cracking is -- we have this very hairline, just hairline cracking below the water line.

We really don't have the degradation mechanism below the water line. Above the water line, it's really the wet-dry issues, and we don't have the oxygen below the water line to promote the degradation.

We do have one crack on each spray pond. It's a vertical crack below the water line. It's in a very -- it's in the same location of each one of the six ponds. We don't have -- I don't have a good explanation as to why, but we monitor that crack. That crack has been repaired in all six ponds. In fact, we just had to repair one again earlier this year the Unit 3 spray pond.

MR. BARTON: That was a through-wall crack, wasn't it? That was a through-wall crack, the one you're talking about?

MR. SCHRECKER: It's -- you see, concrete is not -- I can't say that it's watertight. Water is going to meander through concrete and maybe seep, okay. So I would -- I would classify this as seepage.

MEMBER STETKAR: Do you have the -- a question I was going to ask later, but I might as well while you're up. It's less of a concern on concrete but it is on rebar. The soils at the site are fairly aggressive, caustic soils. My basic concern about water leakage is related to interaction with the soils, and then getting into rebar and structural members.

So the question is do you have any evidence of external seepage from the spray ponds?

MR. SCHRECKER: From the spray ponds? We have, we have no evidence of -- well, we've had occasions where we've seen minor seepage, and especially this one vertical crack that I've mentioned. We have no other evidence of seepage below the water lines from the spray ponds.

MEMBER STETKAR: Okay.

MR. KARBASSIAN: All right, thanks. Going through, relative to our long-range planning, we've institutionalized this process to help us lay out a ten-year look-ahead at overall major modifications and maintenance activities that we need to do to keep Palo Verde operating safely and efficiently for the long term.

What you're looking at is some of the examples of items that are identified in our long range plan. Once again, the intent is not to show all of our long range plan, but just to show the overall approach on resolving equipment issues. I'd like to turn --

MEMBER SHACK: The high pressure turbine will be associated with the power-up rate?

MR. KARBASSIAN: No sir. High pressure

turbine is a replacement for long range, that's correct. I'd like to turn it over to Angie Krainik, Department lead of License Renewal.

MS. KRAINIK: Thank you. Mr. Chairman and members of the ACRS, I'd like to provide an overview of the Palo Verde license renewal application.

We submitted our application in December of 2008. The Palo Verde application was prepared, was the second one prepared by the STARS Center of Business, which is a consortium of the seven plants that John mentioned earlier, and we created the Center of Business in order to create the license renewal applications.

One of the things that we've learned throughout our evaluation, based on staff input and feedback, is we are providing those kind of lessons learned for some of the other applications that are prepared by the Center of Business as well, and I'll talk about some of those as we go forward.

We're actively involved with the NRC in the industry as we go through things that are being modified. The generic aging lessons learned report, we were -- started from Rev 0 through Rev 1 and are actively involved in Revision 2 that's ongoing right now.

Some of the recent industry items that we're addressing through our application right now is things such as the low voltage cabling, which we're in the process of evaluating and adding to our inaccessible cables program, as well as some additional requirements for our buried piping and tanks program.

Throughout the submittal, development, review and then supporting the staff review, Palo Verde has maintained the ownership of the application all the way through, and as we work towards implementation, which I'll talk a little bit further about in a moment, we will continue to maintain that ownership throughout.

This provides an overview of the basic process that we followed using Part 54 and the guidance of NEI 95-10. We started with the scoping and screening of the Palo Verde systems, structures and complements, using the design basis documents and information. The aging management review was then performed following that, and evaluated against not only the generic aging lessons learned, but also Palo Verde operating experience.

In that -- in informing our aging management programs, we included over 13 years of Palo

Verde operating experience, which also includes industry operating experience, as well as a review of the generic communications from the NRC documentation.

As a result, our AMR lines show a pretty high degree of consistency with the generic aging lessons learned report.

Moving on, this is an overview of the time limited aging analysis section of our application. We have evaluated the analyses at Palo Verde for those that are at time dependency, and could be affected by operation beyond four years, and they're presented in this portion of the application.

I will be discussing, we will be discussing the metal fatigue open item just briefly later in the discussion.

Moving on, there was a question earlier talking about the implementation of the aging management program.

MEMBER SHACK: I had a particular question, since you're not going to really discuss these in any details. You have this half nozzle repair to the Alloy 600 material in the reactor coolant hot leg, and there's always --

There's an analysis for the fatigue crack growth and fracture mechanics stability, but nobody seems to mention stress corrosion possibilities in this Alloy 600 and the hot leg. I was just curious as to why that's not considered in the TLAA.

MS. KRAINIK: Richard, could you respond?

MR. SCHALLER: Yes, I can.

MS. KRAINIK: Let me turn it over to Rex Meeden for staff.

MR. MEEDEN: Rex Meeden, Palo Verde Engineering. I understand the question is with respect to our pressurizer small bore penetration repairs we've done, in consideration of stress corrosion cracking.

MEMBER SHACK: Right. The TLAA just talks about fatigue, and there's no discussion of PWSCC. It's in the hot leg, so I assume the temperature is high enough.

MR. MEEDEN: Yes. Are you talking about the -- specifically about the remnant original Alloy 600 material that was left in place?

MEMBER SHACK: I assume that's what it is. I have no real notion of exactly what it is. I'm just assuming --

MR. MEEDEN: Okay.

MEMBER SHACK: 4.741 in the SER.

MR. MEEDEN: Similar to -- you're correct, and on the hot leg, when we did the small bore penetrations in that location and it's the INCONEL 600, Alloy 600 issue. We did address stress corrosion and cracking on the inside surface of the hot leg, and we also did, take a look at stress corrosion cracking for the places where it was applicable on the pressurizer.

The reason I say "the places where it was applicable" was on the lower head of the pressurizer, we did heater sleeve repairs where we left a section of Alloy 600 in place. Whereas in the mid-90's, we actually did a full nozzle replacement and removed the original Alloy 600 material in its entirety, that were --

MEMBER SHACK: So that's what I'm looking at here, is the half nozzle repair means there's some Alloy 600 left?

MR. MEEDEN: Yes. If you would point me to which specific drawing you're looking at?

MEMBER SHACK: It just says for the half nozzle repair of the Alloy 600 nozzles in the hot leg, there was a flaw removal and successive inspection requirements in 1992. Then you're doing fatigue analysis. Is this material still in contact with the coolant?

MR. MEEDEN: Yes, it is on the hot leg, and on the pressurizer, if I can ask, if I can be allowed to pull up a backup slide to speak to?

MEMBER SHACK: Sure.

MR. MEEDEN: Brian, could we please pull up Slide 63? This sketch here reflects the bottom head of the pressurizer, and this is one heater sleeve penetration. And to address the question specifically, the section on the inside surface of the pressurizer depicted in red there is a section of Alloy 600 material that was left in place. It was originally a pressure boundary welded on the inside surface.

The repair of this was actually an external pad repair depicted in gray on the lower surface of the vessel. There was a weld prep that was there and then a new Alloy 690 sleeve depicted in blue, with a fill-up weld establishing the new pressure boundary.

MEMBER ARMIJO: So it has no function anymore? That 600 is just there?

MR. MEEDEN: That's correct. However, the point I'd like to make is Mr. Shack is correct, in that we did look at crack propagation with respect to that, to show that was left in place.

MEMBER SHACK: Okay. But it's not the pressure boundary any longer?

MR. MEEDEN: That's correct.

MEMBER SHACK: Okay, and just another topic. One of the confirmatory items, again since you don't seem to be discussing it anywhere, was essentially erosion/corrosion possibilities in the steam generator. You talked about the feed ring being a resistant material.

Now is that genuinely a resistant material or is this one of these things where you're depending on trace amounts of chromium to give you some resistance?

MR. RADSPINNER: Yes. Mark Radspinner from Palo Verde. That is a chromoly.

MEMBER SHACK: That is chromoly?

MR. RADSPINNER: It's chromoly, yes.

MEMBER ARMIJO: And is it half chromoly, two and a quarter chromoly? How much?

MR. RADSPINNER: Do you recall the percentage? One and a quarter.

(Off mic comment.)

MEMBER SHACK: And just again, on this operating experience, one of the things I noticed in one of the inspection reports is you were still using a lubricant on your bolts that had molydisulfide. And again, 25 years now of experience says that's not a thing to do.

I just, is that a conscious decision on Palo Verde's part, or is that somehow an oversight that you didn't know that you had molydisulfide in that lubricant?

MS. KRAINIK: I'd like to go ahead and ask Vincent Guerrero to respond please.

MR. GUERRERO: Vincent Guerrero, Design Engineering, Palo Verde, and you're correct. We're still utilizing molydisulfide on the reactor vessel, and the reason for it is because that is the best product for --, and that was what was recommended and endorsed by the NRC in the early 70's.

We have committed to removing the use of that lubricant, and switching a graphite-based lubricant. We did some evaluations and we do have enough control that we don't have to worry about stress, corrosion or cracking.

MEMBER SHACK: Okay. So that was a conscious decision to continue using the molydisulfide, despite the experience of the early 80's, that sort of said it wasn't a good idea?

MR. GUERRERO: Yes sir, and we did it in

the guidance of our corrective action process.

MEMBER ARMIJO: But you never had any cracking problems with that lubricant?

MR. GUERRERO: That is correct, sir.

MEMBER ARMIJO: Okay.

MS. KRAINIK: So these are the type of things that we just talked about here, as far as operating experience, that you know, we're going to continue to gather as a result of our aging management programs that we've developed as part of our license renewal application, and then moving on into the actual programs, the procedures, the station procedures that we'll -- we will use to implement the aging management programs.

So the question that came up earlier about starting, having, using the aging management program, starting to gather information even before we're required to, is part of our process of starting, because there is information that we will learn, as we gather information about aging management, that we will factor back into the program.

So we intend to start using it, and then factoring it into the programs going forward. So out of the 59 procedures that we already have on site that we are using, we have incorporated a number of the aging management program requirements into those. That status is provided as well as six new procedures that we're halfway completed on those. So we're just kind of -- from a matter of accounting, out of the 11 new procedures, six of those are -- go into one actual procedure.

CHAIRMAN BONACA: I have some questions about your management programs, but I believe we have an opportunity later for discussing those, right?

MS. KRAINIK: Yes. I'm going to discuss commitment management.

CHAIRMAN BONACA: That's right. So maybe I'll raise that issue later.

MS. KRAINIK: Okay. Let's go right into that now then.

CHAIRMAN BONACA: Huh?

MS. KRAINIK: I'll just go right into it now then.

CHAIRMAN BONACA: Okay.

MS. KRAINIK: So the procedures that I mentioned earlier are the process by which we are incorporating the requirements of the aging management programs and the commitments that we have made into the station procedures.

We're tracking all the commitments that we have made as a result of the license renewal application in our regulatory commitment tracking system. It's the same system that we use or have been using for years to track all the other NRC commitments that we have made, and the purpose of that obviously is to make sure that, as time marches on, changes are made to procedures and documents, that we'll continue to make sure that we maintain those commitments.

In addition to the procedures I mentioned that are in our regulatory commitment tracking system, also future actions that we've made as a result of the application as in there as well. Things like the update of the equipment qualification binders and some future inspection commitments that we've made, we've captured those in our regulatory commitment tracking system.

Between that system and the change management system for procedures, that will help ensure that as changes are made to those procedures, the commitments that we have made are evaluated against those changes.

Moving on to the piece of implementation and sustainability, we're already starting with that. We have implementation staff that we are filling positions at Palo Verde to do that. We'll continue to be engaged in the industry. The NEI License Renewal Working Group for implementation, we are engaged with that.

You know, as others before us work through their implementation, we intend to stay engaged with them as well, and also following backup on the STARS Alliance and sharing experience, operating experience in particular across all the seven stations.

Moving on, I'd like to transition to a discussion of the open item in the Palo Verde SER with open items. The issue has to do with metal fatigue, and as Brian mentioned earlier, our -- the open item that we have is comprised of the 18 most recently received RAIs on Section 4.3 or Metal Fatigue.

Responses to these RAIs have been submitted to the staff, and I believe they are under review at this point.

I want to just kind of provide an overview of our application, and in particular metal fatigue. We had a number of feedback questions and concerns expressed by the staff. As a result of that, we recognized that we needed to fundamentally rewrite that section to make it clearer and provide clarification that was not originally there.

Even to that end, when we originally put it together, we had used a peer review process before we submitted it. But we even look back on that and realize that we had not given them all the information they needed to help us end up having a more effective review, and ultimately a better product.

So we continue to take those as a type of lessons learned, to make sure that future applications have that incorporated in.

Some of the actual changes that we had to make as a result of our application were things like more common terminology. When we prepared our original application, we did not use in some cases the exact same terminology that we have in our current licensing basis or our UFSAR. We went back and provided that clarification, so there was a clear alignment between the way it's described in the UFSAR and then our application.

Another example is our transient count. When we originally provided the application, we had done a transient recount for Units 1 and 2, and provided that in the application. After we had provided the application, we completed the review for Unit 3 as well. That also was included in some of our amendments.

Additional information we provided were

details on the fatigue analysis as well. As the staff asked questions, we realized that we didn't have the level of detail that the staff needed. We've provided that as well.

So we do appreciate the support and the questioning on the part of the staff, and do believe that we ended up with a much better application and a metal fatigue monitoring program than what we originally had to start with.

As I mentioned, I think that one of the largest substantial changes that we made as a result of it was to more clearly talking about and describing the fatigue monitoring program during the period of extended operation, and demonstrating that that is essentially an extension of our existing fatigue monitoring program that's in play today.

I'd like to turn it over to Rich Schaller, our metal fatigue lead, and he'll provide more discussion about the fatigue monitoring program for the period of extended operation and further discussion of the open item itself.

MR. SCHALLER: Mr. Chairman and members of the Committee, good afternoon. I'll be covering three topics related to metal fatigue. The first of the three topics will be metal fatigue program, both the current and the enhanced program and going over the changes that we're making.

Also, I'll be discussing the three commitments in the LRA that are related to metal fatigue topics, and finally we talk about the one SER open item. I'd like to take this opportunity to echo what Angie said, that the comments that we received from the staff were very helpful as far as improving our application and improving our program, and we found that to be very constructive.

This next slide here really is the heart of my discussion about the metal fatigue program. What this shows you is the attributes of the program and how they fit into the current program and the enhanced program.

The first three attributes there, as you can see, describe the bulk of our current program. Our current program fully meets our current licensing basis, and the changes that we are making, which are highlighted there in the lower right-hand corner in those green shaded boxes, those enhancements are necessary to meet the requirements of NUREG 1801, Generic Aging Lessons Learned, going into the period of extended operation, and do not reflect upon the adequacy of the current program. For the --

MEMBER SHACK: Why do you feel that you had to -- you seemed to miss the mark. Is the industry guidance, the NRC guidance lacking, or somehow that -- what was the problem?

MR. SCHALLER: When we wrote the original application, and I was involved in that from really day one, we allowed ourselves to fall into the trap of describing really how the FatiguePro package worked, instead of --

We lost sight of the fact that this is a basis document, to show how we meet current licensing basis, and we had a very technical discussion of basically how FatiguePro worked. We used a lot of the terminology from FatiguePro that really wasn't commonly accepted. Like instead of the cycle counting, we used a thing called "global monitoring." We used a bounding approach.

So really when we wrote it, we wrote it around FatiguePro, and that was one of the central comments that we received from the staff, is that show me how you're meeting your current licensing basis, and that was really at the heart of the rewriting of the section that we did this spring.

And again, because of that major rewrite, we realized that we impacted the staff and one of the major reasons that we had these 18 RAIs that are not closed yet is because they received that last spring and needed time to look at it.

So if, we go back to the table here, the current program is basically a cycle counting program. There's one location, the pressurizer spray nozzle that we perform a usage factor calculation on using cycle-based fatigue. And as you can see there going forward, we will retain all those attributes. We'll continue to have a cycling counting program. We'll continue to monitor that location.

But when you go down to the action limits, you start to see the differences between the current program and the enhanced program. In the current program, we have a generic, 90 percent of design cycles is our action limit. We also have, as specified in our UFSAR, a .65 cumulative usage factor limit on our pressurizer spray nozzles. So that's specified right in the FSAR.

Going forward, we will have specific limits tailored to the individual transients, rather than a 90 percent across the board as a trigger, and we will have component-specific limits for those components that we monitor by cumulative usage factor.

In the corrective actions, our current

program today, the procedure tells the individual that if you reach the action limit, to initiate a corrective action program document we call PVAR, Palo Verde Action Request. That's the first step in our process.

Then that would go to probably one of these gentlemen over here at this table. That's our metal fatigue experts and they would, based on their skill and experience, they would do an evaluation and resolve the issue.

Going forward, we'll still use the corrective action program, but we're providing some predetermined guidance of specific things to look at, to help them with that evaluation and give them some more structure.

The next attribute is the NUREG 6260 locations. That is not a current licensing basis issue, so we don't have any environmentally assisted fatigue monitoring going on right now. Going forward, for our 6260 locations, we will monitor those by a combination of methods. Cycling counting for a very low usage factor location on our reactor vessel, and the rest of them will be monitored with cumulative usage factor calculations, either cycle-based fatigue or stress-based fatigue.

And the final attribute is the fatigue monitoring software package, and we will use two fatigue monitoring software packages. The first one we will use will be FatiguePro, and FatiguePro will provide us with three functions. First of all, FatiguePro, because it's tied into the plant computer, will automatically identify transients and count those. Not all of them; they'll still be some manual supplementary actions to be done to cover all the transients.

Next, it will provide our cycle based fatigue calculations, and finally it has a projection module in it that will allow us to project ahead and see if we're approaching our action limits.

The second software package we'll have is a yet-to-be determined. But it will be a six element stress tensor model that we will apply to our stress-based fatigue locations. All of these enhancements, in fact, all of these attributes are covered in Commitment 39 in the LRA.

We have three fatigue commitments. Commitment 39, which I basically discussed in the last table there are a result of the attributes of the enhanced program. And then we have Commitment 57 and 58. Commitment 57 and 58 resulted from discussions with the staff, when we had done some screening of locations for environmentally-assisted fatigue.

We performed some calculations for both environmental factor and environmentally-assisted fatigue, using some what turned out to be dated methods that had been used in the industry, but had since been superseded by a NUREG that was actually issued for new plant guidance.

After discussion with the staff, we agreed that it would be appropriate for us to go back and re-perform those calculations prior to the period of extended operation, to confirm the conservatism of the calculation we did or, if necessary, to redo the environmentally-assisted fatigue calculation using that approach.

Finally, I'd like to talk about the open item in the SER. The open item is one open item, based on 18 RAIs, and these RAIs are not based on areas that we're necessarily in disagreement with the staff, although they haven't completed their review yet.

It's basically the timing, and it goes back to the discussion that I had about our rewriting of Section 4.3 in the spring of this year. The responses to those 18 RAIs have all been submitted, and they were submitted on the dates that you see there, June 29th and August the 12th.

For the purpose of discussion today here with the Committee, Palo Verde's group goes into three categories to give you some feel for what was covered in those. The first of those would be items for clarification, and as an example of that, let me guide you to 4.3-10. 4.3-10 was a question received from the staff.

When they reviewed our cycle counting, we had very low accumulated cycles for our primary system leak rate test, and they expected to see more, since as you saw, we're in our 16th operating cycle in Unit 1 and 2, and they saw low numbers like 5 and 4 and 2 for the units.

Since the staff quite correctly identified that we do that test after refueling, they wondered why the count was so low. The reason the count is there is because the way we actually perform that test in the plant is we do it in parallel with the normal heat-up and pressurization.

So we don't double-count the test. The counts that are in there are from pre-operational days, when we actually heated the plant up to do system leak tests. But once we began operation, it became part of our normal recovery after a refueling outage. So rather than count, double-count a transient improperly and with more usage than you actually incurred, you count the heat-up and pressurization transient.

The second group there is additional technical information. There are really two examples I would give you there: 4.3-3, 4.3-18, and they're related. They both refer to a stress calculation that we performed on a plastic piping.

By going an extra 20 years of operation, we increased the number of cycles on sampling system and steam generator downcomer piping, and we had to go back and do some stress range reduction factor calculations to show that we could go the extra 20 years.

We presented the conclusions of that analysis to the staff, and the staff said to us that's good, but we want to see the actual numbers. So we provided the stress range numbers to the staff, and we also provided some information on equations that we used as far as what part of the code we were using, to go back as a reference.

The final grouping would be those that -- where we took an alternate approach, based on discussions with the staff. One of those I've already discussed on the previous slide, that's related to Commitment 57 and 58, where we agreed that we would go back and use the methodology in NUREG 6909 for nickel alloy environmental factors and recalculate that.

The other one is related to 4.3-13, which is our steam generator tube fatigue calculations. We had initially taken the position that our replacement steam generators have a fatigue calculation where the stress range is less than the endurance limit. So the cumulative usage factor reported in the design report is zero, and we said if it's zero, then it doesn't need to be TLAA.

We discussed it with the staff, and we agreed that well, it may be zero but there is analysis there and the guidance says if you have the analysis, then it's a TLAA. So we agreed to change our position on that, make it a TLAA, and then we just positioned it with validation, single i.

So in conclusion, I'd like to say that we have provided all the information that's been requested for these 18 items, and the staff has it now for review.

CHAIRMAN BONACA: So you have an answer to the question that I had in my mind, which is explain why the coolant usage factor for the instrument nozzles in Unit 1 and 2, or Unit 1, are five times greater than Unit 2 and Unit 3?

MR. SCHALLER: It's basically due to analysis differences, and we brought a gentleman that can address that today, Mr. Brett Lynch.

MR. LYNCH: Hi. Brett Lynch, speaking for Palo Verde. The question was what's the difference between the Unit 1 instrument nozzles versus Unit 2 and 3. The difference in the modeling was mostly due to how it was dealt with -- excuse me -- how it dealt with vortex shedding.

MEMBER ARMIJO: Is that the answer? You know --

MR. LYNCH: Excuse me. Would you like me to elaborate?

MEMBER ARMIJO: Yes. Why isn't the vortex shedding the same in Units 2 and 3? I mean if it's the same design, there's got to be more to it than that.

CHAIRMAN BONACA: Unit 1, five times higher.

MR. LYNCH: Well, can you please clarify the question?

CHAIRMAN BONACA: Yes. I can read it to

you. It says explain why the cumulative usage factors for the instrument nozzles of Unit 1 are five times greater than Units 2 and 3.

MR. LYNCH: All right. The reason why the Unit 1 was vortex shedding. The engineer decided to analyze each vibration caused by flow as a cycle, which caused a large increase in the number of cycles, which drove the usage factor higher.

MEMBER ARMIJO: So why wasn't that applied, that same analysis applied to the other units for consistency? If these are identical units --

MEMBER SHACK: At least the two guys talk to each other and figured out which analysis was correct.

MEMBER ARMIJO: Well, if they resolved it that way, that's fine. But I'm just trying to find out is this a real difference, or is this among the three plants --

MR. SCHALLER: There are no differences as far as material or design between the plants. When we looked at this, and we kind of scratched our heads ourselves when we saw this, both of these are valid ASME Class 1 fatigue analyses. They're differences that were made in the assumptions between analysts. Both were produced under an Appendix B program, and under a quality assurance program.

Differences are there. They're just -- come down to a difference in analyst assumptions.

MEMBER ARMIJO: It can be very satisfying, you know. The materials are the same, the design's the same, the plants have operated pretty much the same, and you have a factor of five difference in the usage factors. Something is wrong. Something has got to be closer to right than --

MEMBER SHACK: One is more right than the other.

MR. RADSPINNER: Mark Radspinner from System Engineering, Palo Verde. Again, we don't have the luxury of having the two analysts here. But it is clear from that the Unit 1 analysis, the analyst who performed that was, wanted to make sure he had a conservative treatment of vortex shedding and the method that he used to superimpose those mechanical excitations onto the thermal fatigue cycles, he tried to do that in the most conservative manner that he could do that.

MEMBER ARMIJO: So with the management of the three units, have you applied the more conservative analysis to all three units?

MR. RADSPINNER: In terms of fatigue

management, again, we managed to the thermal cycles that go into that analysis. We don't attempt to monitor the mechanical excitations of vortex shedding. That aspect is treated in the analyses. We monitor the thermal fatigue cycles that go into those analysis.

MEMBER SHACK: Yes, but if the usage is real, which one is the controlling one?

MR. RADSPINNER: And it's less than 1.0, and would -- and as long as we stay below the design values that go into those reports, we would continue to be less than or equal to the calculated projections.

MEMBER ARMIJO: I guess what I'm trying to get to is let's say you're getting to an action limit in Unit 1, because the CUF is five times greater than the other units. Would that -- wouldn't you say "Well boy, I must have -- to be conservative, I'll assume that Units 2 and 3 are the same and I apply the same action" --

(Simultaneous discussion.)

MEMBER ARMIJO: That's your --

MR. RADSPINNER: Yes, I understand your question would be if we reach an action limit, how would we treat the differences between the two analyses of record. Yes, and at that point, we would have to reconcile the differences, and we would most likely go back to Combustion Engineering or Westinghouse and get an analysis that would still be bounding and conservative, and still be able to demonstrate that we're below the 1.0 cumulative usage factor.

We would have to do that the first time we reaction an action limit that influences that particular analysis of record.

MEMBER SHACK: Yes, but I heard you say that you were counting only thermal cycles, not usage factor for this particular nozzle. Did I understand that correctly?

MR. RADSPINNER: Yes, that's correct, and --

MEMBER SHACK: So that would mean that you sort of ignore this factor of five difference, since they're not due to thermal cycles?

MR. RADSPINNER: Well no. I guess I would convey it, and I appreciate the question. But the analysis of record basically sets aside the fatigue effects for the vortex shedding, and then the various thermal cycles that go into it, the design cycles divided by the allowable cycles, each one of those make up the rest of the fatigue usage.

And so the mechanical excitation is allocated. We would, as soon as we reach an action limit for any single transient that feeds into that cumulative usage factor, we would then be in a reconciliation mode on how are we going to make sure, and of course, that action limit would be most applicable to Unit 1, because that's the analysis that is the most conservative.

We would then have to demonstrate that with this action limit, let's just say it's heat up and cool downs that we reach the action limit on, we would then have to project forward and reconcile how is the analysis of record going to be demonstrated to still stay below 1.0?

MEMBER ARMIJO: I guess I'm going to have the same series of questions for the staff when they come up, to see if they can explain why all three units don't have the same -- if you assume the designs are the same, materials are the same, environment's the same. It's kind of strange.

(Off mic comments.)

MEMBER STETKAR: We're doing okay for time.

CHAIRMAN BONACA: That's right.

MEMBER STETKAR: And since you bought up cycle count, I like counting things. As I went through your table of -- it's Table 4.3-3 of transient cycles, I understand that you've reconstituted that, the information prior to 1996. A couple of things.

Except, I guess, before or for six types of transients, that you still use the original 25 percent of design numbers, and I know the staff had a question about which particular six. I could guess which six, but that's really not my question.

The question was actual operating experience for the units. A couple of transients that I've kind of stumbled over was, one of them is Item No. 31 in the table. It's arbitrary load rejection from 100 percent to 15 percent power shows Unit 3 has had 14 of those events.

That's a pretty substantial load rejection, compared to six for Unit 1 and seven for Unit 2. What's going on with Unit 3? How come you've had more than, twice as many load rejections on Unit 3? You're just unlucky?

MR. RADSPINNER: No. I think in some respects, that there is a tendency to conservatively account whenever we -- because our design has a reactor power cutback and a driven runback feature that a lot of plants don't have, and so --

MEMBER STETKAR: Can you accept 100 percent load reject?

MR. RADSPINNER: Yes.

MEMBER STETKAR: Okay. That explains another question that I had, because you had zero events.

MR. RADSPINNER: And then, and also in Unit 3, in some of our earlier start-up days, we did have a series of --

MEMBER STETKAR: Okay. So there really was -- okay. The one that was a much larger difference, I have no idea. Sam, you'll have to tell me, because I don't understand materials. Item No. 37, charging cycles during an extended loss of letdown lists 64 events for Unit 1, one event for Unit 2 and two events for Unit 3. That's a really big difference.

MR. RADSPINNER: Yes.

MEMBER STETKAR: Now I know in early years, people didn't control their charge in the let down systems, you know, as well as they do now, but the age of the three units really isn't substantially different. So why, why 60 times as many events?

MR. RADSPINNER: Yes, and that is because in Unit 1, we had an extended loss of let down duration, where we had a petite failure of a pipe support that impacted the integrity of the let down line. So it was taken out of service for a substantial amount of time, and during that time, the charging pump had to cycle on and off to make --

MEMBER STETKAR: Okay. So that's essentially the result of a single operational event?

MR. RADSPINNER: Yes. Okay.

MR. HESSER: Mr. Stetkar, Mr. Doug Coxon from our Operations Group would like to provide some clarity, I believe.

MR. COXON: Yes sir. Doug Coxon, Palo Verde Operations. Yes sir, we did have an issue in Unit 1 that resulted in an extended loss or let down, and that route, by our procedures and processes, we're allowed to basically whatever result cycling, charging off and on for periods of time.

MEMBER STETKAR: Yes, yeah, yeah. Okay. That explains -- that certainly explains that difference. Thank you.

CHAIRMAN BONACA: I have a couple of questions on your problems, and I think since you're closing, your presentation is nearing close, I would like to ask now. The first one is on structural monitoring problem. There is a discussion in this inspection report regarding the monitoring that you have done.

Essentially the requirement seems to be that internal containment and external surfaces should be inspected once every five years, and internal surfaces should be inspected every ten years. But really what was done was that you inspected only part of the internal after ten years, and then another part of Unit 2 after ten years.

Then in 30 years, you haven't got a full plant inspected. You provide an explanation for that. But then the text is moot regarding the five year inspection to the internals, your containment, okay, which has never happened.

Could you explain to me what you're going to do about this? I mean what's the frequency, what plant is going to be done and how would you justify considering the three units identical to one, and inspecting just part of each one of them? I'm trying to understand the logic.

MS. KRAINIK: Let me start with it. This came up during, this is part of our current design basis, and we originally had, as you described, a provision by which we would look at a representative unit every ten years.

CHAIRMAN BONACA: Yes.

MS. KRAINIK: As a result of the inspection, the regional inspection, we did get feedback on that, had a good discussion with them, talked about where the rest of the industry was as well.

So we have made a commitment to change the way that we do our structures monitoring program, so that between now and when we started our period of extended operation, we will complete two full inspections of the full scope of the structures monitoring program for each unit.

CHAIRMAN BONACA: Fifteen years is a long time, and the time we're talking about here is ten years in inspections. So I would like to know how soon you think you're going to inspect this plant in the near future?

MS. KRAINIK: Let me ask Ken Schrecker to give you that. He is the program owner for the structures monitoring program, and we've had some very good discussions about scheduling.

CHAIRMAN BONACA: I would like to know about the five-year inspection, because that's moot in the inspection report, and there is almost an expectation that you would provide the information, but it hasn't been provided to us.

MS. KRAINIK: Okay.

MR. SCHRECKER: Okay. Ken Schrecker, Palo Verde, System Engineering. I think I understand the question to be to talk about the periodicity of our structural monitoring program for the current licensing period?

CHAIRMAN BONACA: Yes. What I'm trying to understand is, you know, you recognize that they should have done more than what you have done, and you're doing it. The question is what you're doing and by when will it be done. Then considering that this instrument is issued, it attaches on the commitments in the current period of operation.

MR. SCHRECKER: Okay. What we're doing is by 2015, we're going to complete the first pass-through, the inspection of all Palo Verde structures that are included in the monitoring program for all three units.

CHAIRMAN BONACA: Okay.

MR. SCHRECKER: And then between 2015 and 2025, the period of extended operation, we'll do another complete inspection of the entire plant.

CHAIRMAN BONACA: Okay. What about the

five-year inspection of the internal containment?

MR. SCHRECKER: Are you referring to the containment liner?

CHAIRMAN BONACA: Yes.

MR. SCHRECKER: Inspection program?

CHAIRMAN BONACA: Well, I'm referring to the inspection report of, I think that's what is meant, in fact, the internal surface of the containment.

MR. SCHRECKER: We will be -- we will be looking at -- the structural monitoring program looks at all the internal structures, separate from the IWE program for the liner. We will again finish all that by -- actually, I can say that the internal structures of all three units' containments have already been looked at, as part of the monitoring program.

But we will be looking at it again, between now and 2015, and then --

CHAIRMAN BONACA: In five years or ten years?

MR. SCHRECKER: We are going to be inspecting structures on a ten year periodicity in the current license.

CHAIRMAN BONACA: Because I mean what is confusing is that, you know, we have a special report.

It raises an issue and says if they do this, it's okay. Well, that's why I'm asking if you are going to do that, in determining on my own whether or not that's okay, and you know, they refer specifically to the five-year inspection for internal containment.

But you're not talking about that. You're talking about a ten-year inspection.

MR. SCHRECKER: Yes. We're talking about a ten-year inspection between now and the period of extended operation, and once we get to the period of extended operation, we are going to a five-year period, five-year periodicity for primary containment, all the exterior of our safety-related structures, as well as our essential spray pumps.

CHAIRMAN BONACA: So they're going to do that?

MR. SCHRECKER: Yes.

CHAIRMAN BONACA: Okay, thank you. All right. The other question I had was regarding the inaccessible cables. In the inspection report, again it points out that you've had watering manholes that you have checked, and that you have started a program now to monitor, and to -- although you have no failures yet. You never had a failure of tables.

The question I have is, sounds like you're going to have an inspection every ten years, and then that was not sufficient. So therefore you agreed to do it every two years. But the question I have is if you find water in the manhole, okay, why would you consider two years acceptable for the next time you look at it?

MS. KRAINIK: Let me go ahead and ask Mark Hypse, who is the Aging Management Program owner for the inaccessible cables program, and answer your question sir.

CHAIRMAN BONACA: Okay.

MR. HYPSE: My name is Mark Hypse, Palo Verde Electrical Engineering. I understand the question to be what do we do when we find water --

MR. HESSER: Mark, Mark. Would you turn the microphone down so they can hear you please? Thank you.

MR. HYPSE: Oh. Mark Hypse, Palo Verde Electrical Engineering. I understand the question is what do we do when we find water in manholes and the cables submerged?

CHAIRMAN BONACA: Yes.

MR. HYPSE: Okay. We do a few things. We issue a condition report, and Engineering -- well first of all, let me say the water's pumped out of the manholes, okay. We issue a condition report. Engineering goes out and does an inspection of the cables and the manholes.

We also have a PM program that has two components to it. The first component is a periodic inspection, which inspects the manholes on a six-month and a two-year frequency. We also have an element of the manhole inspections that's event-based. We essentially inspect all the manholes when it rains .3 inches in a 24 hour period.

So when we find water in a manhole where it's submerged the cables, we will move that manhole to a more frequent inspection, to ensure that the water doesn't accumulate -- the water doesn't accumulate in the manhole and does not submerge the cable.

MEMBER ARMIJO: Okay. What's the source of the water in your manholes for most of these events? Is it rainwater?

MR. HYPSE: I believe it to be rain. You go in and inspect the manholes, we see water stains, water stains on the rings of the manholes coming from the lids.

MEMBER RYAN: Have you done any confirmatory radiological measurements to see if there's any tritium or radionuclides of interest in it?

MR. HYPSE: I'd like to turn that over to Tom.

MEMBER STETKAR: Mark, before you sit down, let me ask you. Are you currently performing this PM program with the kind of graded inspections?

MR. HYPSE: Yes, it is in place working right now.

MEMBER STETKAR: Okay, thanks.

MR. GRAY: Okay. Tom Gray, Palo Verde Radiation Protection, and I understand your question was do we analyze for tritium --

MEMBER RYAN: Or other radionuclides.

MR. GRAY: Yes. If it is in the radiological controlled area yard, then the protocol is for the sample to be delivered to radiation protection so we can analyze it for tritium.

MEMBER ARMIJO: And what are the results? It's a range or are they positive or all negative?

MR. GRAY: I do not have that information currently.

MEMBER RYAN: Okay. Does anybody know what the ranges are?

MR. GRAY: Right. Mark, do you have any

knowledge?

MR. HYPSE: I didn't hear the question.

CHAIRMAN BONACA: Tritium.

MEMBER ARMIJO: What I asked.

MR. HYPSE: No, I do not know of any results of any tritium in that water.

CHAIRMAN BONACA: You spoke to the interval as one every two years and one six months?

MR. HYPSE: Yes.

CHAIRMAN BONACA: Would you tell me the difference between the two, what triggers one or the other?

MR. HYPSE: Yes. Engineering keeps a database of inspections of manholes, and we look at the history of water intrusion into those manholes. Based on that history, we put it into the frequency of inspections. So the water, so the manholes that have been the most vulnerable to water are the most frequent, inspection frequency.

The six month frequency of inspection actually has all the manholes that are in the, what we call the "rain PM." That's the PM that inspects when it rains. That's to ensure that those manholes are always inspected, because Palo Verde being in the desert, we have long periods of time when there's no rain. So we'll inspect it at the six month frequency.

The two year inspection frequency are manholes that have been dry.

CHAIRMAN BONACA: Okay.

MR. HYPSE: That's not explained, I'm sorry.

MEMBER RYAN: And I guess, is that difference based on topography or have you tried to sort out why some are wet at the six month interval and others are right on the two year interval and the rainfall is pretty much the same on all of them at the same time, I guess?

MR. HYPSE: It does have to do with topography.

MEMBER RYAN: Yes.

MR. HYPSE: You know, I've gone out there when it rains, and tried to, you know, catch them when water's flowing, and last year we found a manhole where essentially when it rained there was a stream above it, and we corrected that, and that's part of our work is looking at all these manholes and trying to find where the source of the water is.

CHAIRMAN BONACA: Is this program what you had regionally or something you had have modified now because of the preparation for license renewal?

MR. HYPSE: Could you repeat the question?

CHAIRMAN BONACA: Yes. I'm saying is this the program that you used to have before license renewal, or is it the program that you have because of license renewal?

MR. HYPSE: We had it before license renewal. It's been enhanced over the years, but we had it before license renewal.

CHAIRMAN BONACA: Yes. There's no description in your Appendix B of the details. That's why we end up with the observation of the inspection and we have to rely on those observations to deliver our conclusions. But I appreciate your presentation. Thank you.

MEMBER RYAN: Just one follow-up question. You mentioned radiological areas weren't really focused. Have you done any work at all looking for environmental radioactivity or tritium or do you have any more that are outside of the radiological areas that are on your property?

MR. GRAY: Again, Tom Gray, Palo Verde Radiation Protection. The question is have you done any more looking for radioactivity in water on site at Palo Verde, and the answer to that question is yes, we have done quite a bit of work at Palo Verde.

As we pointed out earlier, we are a zero liquid release facility, and so we release tritium through the airborne pathway, and we do that by operating the boric acid concentrator in the release mode and we release that as a vapor.

That prevents or represents a couple of challenges, and that is that you don't release during periods of rain, and we know by our operating experience, we learned that to not operate the VAC and release during a period of rain to prevent washout from occurring.

In addition, you can have reentrainment of tritium in other systems as well, and a good example is in our circulating water system and our cooling towers, we can have some reentrainment of tritium.

The NRC staff has acknowledged that in Regulatory Issues Summary 2008-03 for the return reuse of radioactive effluents, that it is okay to have that radioactivity in those systems, as long as they meet certain concentrations and you don't have to consider that as a new release pathway.

MEMBER RYAN: Okay, and you had -- I'm going to guess you had pretty good experience meeting those requirements, as specified by the NRC?

MR. GRAY: Yes. We do, as I said, have

some reentrainment in some of the systems for more airborne releases, yes.

MEMBER RYAN: Okay, okay.

MR. GRAY: We have also had other instances. In February of 2006, we discovered some tritium in some subsurface area of the plant, specifically Unit 3 and Unit 2. It was in a relatively shallow area, less than 15 feet in depth, confined to a shallow basin area around hard packing piping.

In this case, it was around the spray pond pipes. We pressure-tested piping systems in that area, identified no active leaks in that area, and the water was estimated to be somewhere between 800 and 1,000 gallons, a relatively small amount confined to a shallow basin area.

So that cause was attributed to past practice of operating the VAC and releasing during periods of rain. As I said, we do not do that anymore.

MEMBER RYAN: Okay.

MR. GRAY: Also, we had some condensation leakage from the ventilation system under the wall, and we've made improvements there as well. We have installed a drainage system for the ventilation system, and also humidity monitoring, so we don't release when it's greater than 80 percent humidity.

MEMBER RYAN: Have you seen the environmental levels go down because of the improvements you have made --?

MR. GRAY: We've established welds in all three yards, in Units 3, 2 and 1, and we have seen the levels of radioactivity change. We also did some improvements. We re-asphalted and sealed the area behind the water intrusion, and that kind of changed the dynamics.

MEMBER RYAN: Yes.

MR. GRAY: So we did have some changes in the levels of --

MEMBER RYAN: For 2008 and 2009, that's a fairly recent change, so you'll need to see how that behaves over time, I guess.

MR. GRAY: That is correct. We are continuing to monitor that as time goes by, yes.

MEMBER RYAN: Okay, great. Thanks a lot.

MR. GRAY: You're welcome.

MR. BARTON: Can I piggyback about the electrical question that Mario raised? You found in your medium voltage cables some low negative readings, where you had water in your splices. Now what was the root cause of that, leaving water in the manhole? I mean what was the root cause of those low negative readings, the water in the splices?

MR. HYPSE: Mark Hypse, Palo Verde Electrical Engineering. The root cause, the formal root causes were not done on those splices. However, the field engineering reported back that they felt that these were heat-shrinkable tubing type splice, that it was not sealed completely.

MR. BARTON: Any recent occurrences of that?

MR. HYPSE: No.

MR. BARTON: Okay. Have you had any failed medium voltage cables?

MR. HYPSE: We have not had any failed medium voltage cables underground at Palo Verde.

MR. BARTON: Thank you.

MEMBER STETKAR: It was reported generic letter 2007-1 that you have two failed 480 volt cables though?

MR. HYPSE: And just to clarify on that, those were mega-installation resistance --

MEMBER STETKAR: Yes. They were not -- they were testing failure?

MR. HYPSE: That's correct.

MEMBER STETKAR: Were those the same ones for the splices, or were those different?

MR. HYPSE: Different cables.

MEMBER STETKAR: Different cables

MR. HYPSE: Yes.

CHAIRMAN BONACA: Okay. Let's proceed.

MS. KRAINIK: Very good. I would like to discuss briefly two of the five confirmatory items that we have in the SER with open items. In particular, the first one on the list having to do with the application of the scoping criteria for the spray chemical addition tanks.

We had scoped the spray chemical addition tanks. It's a subsystem within our containment spray system. We had originally scoped it into the scope of license renewal and removed it as we had, it was an abandoned system. It's a system that had been cut and capped. So as we did our review, we had assumed that

We recently became aware that there was a small amount of liquid that still remained in those subsystems. So we made a commitment, as a result of our license renewal application, to have that completed, and we are on track to having that completed now by November 30th of this year.

MR. BARTON: But you originally committed to August to do that.

MS. KRAINIK: We're going there. But yes, we did.

MR. BARTON: All right. I beat you to the punch.

(Laughter.)

MS. KRAINIK: We did. But we did -- you're correct, and I was going to explain that we originally had made a commitment to have it completed by August 30th, and we've continued to do our review of the work to do it.

The actual fluid, it's a relatively small amount of fluid that's in the system, is a dilute hydrazine. So in doing our planning and review, we identified that we needed some additional time to complete the review. Again, to complete the review and the planning for the activity.

So we, as I've mentioned, we now have a commitment for the end of November, and we will -- we are going to start completing the work this month and plan to have it completed prior to that, which is prior to the final issuance of the SER, which is currently scheduled for mid-December.

MEMBER STETKAR: This was originally identified in October of 2009? It was.

MS. KRAINIK: Yes, I think so. I was thinking --

MEMBER STETKAR: I'm just curious why it takes more than a year to figure out how to drain the tank?

MS. KRAINIK: Well, we're doing the scoping of the work, and as I mentioned --

MEMBER STETKAR: I understand, I understand. Just move on.

MS. KRAINIK: Okay. The other items, as well as this one that we have provided all the information that the staff requested on the docket for these additional confirmatory items.

MEMBER STETKAR: Okay. Flow-accelerated conversion program. You've removed from scope the high pressure safety injection system piping for all three units, where you've had flow-accelerated corrosion through all leaks, because now you're going to -- now you said you're going to replace that piping every seven and a half years. So it's a replaceable item.

That's a strange way to kind of get around solving the problem, isn't it?

MS. KRAINIK: Let me first start with it is within the scope of license renewal certainly. But you're right, in that the fact that we are doing routine replacements of it, you don't have the aging effects of it because we're evaluating the cavitation itself, and resolving it --

MEMBER STETKAR: What analyses have you done to show that those are the only sections of pipe that are susceptible to this type of flow-accelerated corrosion or erosion, whatever you want to call it?

MS. KRAINIK: We'll go ahead and ask Mark Radspinner to address that please.

MR. RADSPINNER: Yes. Mark Radspinner, Palo Verde System Engineering. I understand that the question is what extent of condition evaluations have we done with respect to the --

MEMBER STETKAR: Other systems.

MR. RADSPINNER: Other systems, yes.

MEMBER STETKAR: Because it's unusual to have that extent of --

MR. RADSPINNER: Okay. Initially, when this occurred in our Unit 1, we did an immediate transportability extended condition to the other units, and then we extended that evaluation using EPRI methodology for anticipating, damaging or incipient cavitation, and we extended that to the primary side safety-related systems.

That evaluation did not identify any other locations that were particularly susceptible to cavitation damage of that nature. As a result of this exercise, the license renewal, the question was asked well, what about in scope systems on the secondary side?

So we have done an initial evaluation of the condensate storage tank transfer system, the auxiliary free water system and the main steam system, and that evaluation, as indicated, that there are often no areas that would be susceptible to that, and we expect to document all that in an engineering evaluation.

MEMBER STETKAR: Okay.

MEMBER ARMIJO: On that subject, I'm a little confused. In the SER, there is a discussion of a through-wall leak in a stainless steel high pressure safety injection system. But you're talking here about cavitation in carbon steel piping. Are these two different incidents, or is it -- or is one incorrect and one's correct?

MR. RADSPINNER: That's no. I just, I threw in a curve ball. I brought in the stainless steel.

MEMBER ARMIJO: Yes. Well, are we talking about two different things here?

MEMBER SHACK: There's a disagreement between the slide and what the SER is saying.

(Simultaneous discussion.)

MEMBER ARMIJO: The actual confirmatory item is indeed on the stainless steel.

MS. KRAINIK: It is an extended -- they are connected. It is, as described earlier, the original cavitation was in our operating experience. As we did our review for the aging management program, got captured in from the stainless steel.

So the question here with regard to cavitation in stainless steel, as Mark described, was the addition extension oft he evaluation that we did from -- into the stainless steel or carbon steel systems within the scope of license renewal. So this confirmatory item here had to do with the evaluation of the carbon steel systems within the scope of license renewal.

MEMBER ARMIJO: Okay, and the stainless steel systems that have suffered cavitation, erosion or whatever, those are just dealt with by replacement, period replacement?

MR. RADSPINNER: Yes.

MEMBER ARMIJO: There is no better

solution than that?

MR. RADSPINNER: Yes. Our evaluation, it is very localized, immediately downstream of a heavily throttled valve on our pump recirculation line. The alternate fix would have been --

MEMBER ARMIJO: Some sort of design change?

MR. RADSPINNER: Yes. A drag valve that's particularly, specifically designed for, to prevent that cavitation. Our evaluation concluded that it was an appropriate response to simply cut it out and replace it. You know, it was done very quickly. It's not a difficult job. We feel we can establish a very conservative frequency, and our evaluation was that that was an appropriate way to deal with that.

MEMBER ARMIJO: So how conservative do you think your frequency is between having a structural problem?

MR. RADSPINNER: Yes. We attempted to develop a wall loss rate, based on the operating experience, and we applied a conservative factor. I believe it was a factor of two on top of that and then rounded it down to the next operating cycle.

Then in this first interval, we also took half of that and inserted an inspection interval. So we'll be doing volumetric inspection one-half of the time by which we expect to do the replacement.

MEMBER ARMIJO: Okay, thank you.

MR. RADSPINNER: Okay.

CHAIRMAN BONACA: A question on the small bore piping. If you can go to the previous -- this was supposed to be a one-time inspection, because you did not expect to have problems. But you found two welds which have failed, and now you have an inspection of ten percent of those welds which are committed to.

Is it going to be a one-time inspection of the ten welds, or is it going to be a periodic inspection?

MS. KRAINIK: At this time, the plan is to do the inspection during, as a one-time inspection.

CHAIRMAN BONACA: Just one.

MS. KRAINIK: And depending on the results of that, then as a result of that and we identify aging management, then we make the evaluation and determine whether you need to include it in the period of extended operation.

CHAIRMAN BONACA: Would you give me a feeling for what is the number of ten percent of the socket welds?

MS. KRAINIK: The socket welds that we have per unit that fit within this category, in the neighborhood of about 320 per unit. So the ten percent would be about -- would be 32 welds?

CHAIRMAN BONACA: So it's a sizeable sample. Thank you.

MS. KRAINIK: Moving onto a discussion of our, of the regional inspection. During the regional inspection conducted in February, the inspection team identified two items for additional review, classified as unresolved items. Both of these items have been closed by the region in August.

The first item had to do with the staff review of the operating experience for a -- review our investigation for Palo Verde Unit 1. We had a unit trip following a water intrusion and subsequent flashover in a metal-enclosed bus during a severe storm in March. The staff performed their review and concluded that there were no additional aging effects identified as a result of the event.

The second item we talked about just briefly with regard to the structures monitoring system program, pardon me, and we addressed both aspects of it that we've talked about previously, one of which being the fact that we are going to conduct two complete inspections prior to the period of extended operation.

The second one had to with the frequency of the inspections themselves during the period of extended operation and our ACI-349.

MEMBER STETKAR: Your metal-included buses. I've read a couple of things about that. Number one, during the walk-down, the staff apparently saw a crack in one of the bellows connections. You did have the unit crypt, and apparently you were already doing augmented inspections of the buses due to a previously-identified insulation problem.

Yet in your license renewal program, you're just committing to one inspection every ten years. Could you briefly explain to me why the plant-specific operating experience doesn't justify a more frequent inspection interval than once a year, every ten years, given the fact that you know you have problems?

MS. KRAINIK: Let me start it a little bit and then go to Mark. We'll go back to the event itself. We did --

MEMBER STETKAR: Well, this is kind of the -- I'm looking at the cumulative evidence of operating experience. You have apparently some problem with a particular type of insulation, that has prompted, I guess, an increased -- I don't know whether it's a preventive maintenance or some sort of inspection program. Mark can probably elaborate on that, and you did have a flashover event.

MS. KRAINIK: Uh-huh.

MEMBER STETKAR: Which is relatively unusual. There aren't too many plants that have flashovers in their bus ducts. So I'm curious why looking at the operating experience, you still take sort of the generic approach in saying well, we're just the same as everybody else, and we can inspect our bus ducts once every ten years, which is pretty much what everybody else does who hasn't any problems with their bus ducts.

MS. KRAINIK: Mark.

MR. HYPSE: Mark Hypse, Palo Verde Electrical Engineering. I guess to answer your question, I need to elaborate a little bit on the fault itself. I think that would help.

MEMBER STETKAR: Well, the fault, but also what was -- apparently, maybe I've misread the history, but were you doing -- I read something here that says you were doing thermography already on portions of the bus ducts and transformer connections every six months, because of previously-identified problems and ground faults that had occurred.

Maybe not necessarily on every specific section of bus duct that you've identified as in scope, but bus ducts.

MR. HYPSE: In those thermography inspections, we were looking at overheated connections. Really, that was the primary purpose of that. At this point Glenn, I'd like to pull up Slide No. 80, and maybe if I go through this real briefly and tie this into our inspection program, it will come together what we're doing.

When the root cause team took a look at -- well, this is a graphical depiction of the Calvert bus section that had the fault in it, and when the root cause team looked at this Calvert bus, they found open bolt holes; they found a gasket, like a seal that was missing, and they found an indication of water inside the Calvert bus, corrosion that had occurred, and they could track -- by following the corrosion, they could track the water through the bus.

Up at the top of the bus on the horizontal section there, there's the first arrow shows the pooling, where they found pooling of water. Then the black arrows are is how the water flowed down to each one of the bus supports.

At the bottom bus support is where the failure occurred, between the Alpha bus section and the enclosure. What the root cause team found was the inspections that we're doing, that you're referring to were pretty much focusing on the Noryl, cracks in the Noryl, the industry experience with Noryl. There wasn't a lot of focus in maintaining the weather-tight design of the metal-enclosed bus.

What they also found was they saw on that support a bus where the failure occurred. They saw some minor indications of cracking up there, and they found that really to have this fault, you needed both the water and the cracking of the Noryl. So even though the lower support there was damaged so significantly, they didn't have any evidence the Noryl left.

It was pretty clear that there had to have been some minor cracking there. As I spoke before, the root cause was that the -- those inspections that we were doing were not focusing on -- were only focusing primarily on the NOryl, not on maintaining that weather-tight design.

So they've made enhancements to that inspection, to ensure that now when they look at it and they close it back up, it's back to design configuration and it's weather-tight. The other thing --

MEMBER STETKAR: How frequently are you doing those inspections now, with the enhancements?

MR. HYPSE: Right now it -- this particular bus is a 13.8 bus. That's being inspected at a 2C inspection frequency. The 4 kV buses are being inspected as a 6C, I mean six cycle inspection frequency.

But the other part of the -- one of the corrective actions out of this was to get all the Noryl replaced, and we've written CMs to do that. Those are being planned and outages accordingly.

MR. HESSER: CMs are corrective maintenance work orders, just for people to know.

MEMBER STETKAR: Thanks. It also helps the transcript.

MR. BARTON: Is this the March 7th Unit 1 trip that --

MR. HYPSE: Yes, it is.

MR. HESSER: Yes.

MR. BARTON: The NRC's inspection report wrote that up as a loose cover or missing gasket or something like that. My question is who, when you do this inspection, who's doing it, plant people or switchyard people?

MR. HYPSE: The plant people are doing it, our electrical maintenance team.

MR. BARTON: Electric maintenance people are doing it?

MR. HYPSE: Yes.

MR. BARTON: Good.

MR. HYPSE: These buses are not in the switchyard.

MR. BARTON: Okay. So this is a work control issue within the Maintenance Department?

MR. HYPSE: It's a maintenance issue.

MEMBER STETKAR: Thanks.

MS. KRAINIK: I'd like to turn it over to John Hesser for some concluding remarks.

MR. HESSER: So this right here just depicts the current license end of period for Palo Verde, to give you a reference of 2025, 26 and 27 for Unit 1, 2 and 3 respectively. If granted license renewal, there would be the period of extended operation to 2045, 46, 47.

In closing, Mr. Chairman and distinguished members of the ACRS, we appreciate the time to come here today and discuss the license renewal application, have the opportunity to answer your questions. And again, I'd like to recognize, as there has been, the hard work and rigorous review of the NRC staff.

We believe being a learning organization is important. Palo Verde has come a long way to where we are today from where we've been in the last few years. We are committed to the long term safe operation of Palo Verde, and with that, I'll turn it back to you, Mr. Chairman, in case you have any other questions you'd like to ask us that we didn't get a chance to cover.

CHAIRMAN BONACA: Any questions?

MR. BARTON: Yes, I've got one. During the NRC, one of the NRC inspection programs, it was during their audit program, they found condition report requests on a leakage in the spent fuel pool water, through these TellTale drain valves being closed and backed up, and you had water leaking, I think, through the concrete.

MR. HESSER: Yes. Actually --

MR. BARTON: The question I have is we inspected the concrete and said there's no damage. But what about the rebar inside the concrete? Was that looked at, because that was exposed to boric acid for, I think, a couple of years these TellTale valves were closed or something? How long?

MS. KRAINIK: Five months.

MR. BARTON: How much?

MS. KRAINIK: Five months, sir.

MR. BARTON: Okay. Well, was the rebar looked at for any degradation due to the boric acid soaking?

MS. KRAINIK: Yes, it was. Would you like further --

MR. BARTON: All right. That's all. It was looked at. That's okay, all right.

MS. KRAINIK: Yes sir.

MR. BARTON: All right.

MEMBER STETKAR: Before you close, and this is going to be quick, when did you replace the bunch of fire protection piping? When did you do that?

MR. HESSER: We can --

MEMBER STETKAR: Or has that been a continuing process, or was it --

MR. HESSER: Yes, it's ongoing. Actually, Pittalwala, would you come to the podium please? We have a slide here we can actually illustrate what we've done and what we currently plan to do.

MR. PITTALWALA: Shabbir Pittalwala for Palo Verde, Lead Piping team. We did it in two phases. Our first phase was around 2002, and then our second phase was, I believe we completed that in 2009.

MEMBER STETKAR: Have you replaced -- all is a big word, but I'll use it. Have you replaced all of the underground buried fire protection piping?

MR. PITTALWALA: No sir. We have replaced approximately 11,000 feet out of the 18,000 feet of the main header.

MEMBER STETKAR: 11,000 feet of 18,000 feet?

MR. PITTALWALA: Of the main header.

MEMBER STETKAR: All right. What are you doing about the other 7,000 feet, which --

MR. PITTALWALA: We have a field approach. We have it in the long-term plan. There are plans to go and look at that. We focused on the ones that had most degradation.

MEMBER STETKAR: Okay. But there is a plan to monitor and/or replace it, and you replaced it with fiberglass pipe?

MR. PITTALWALA: Fiberglass reinforced plastic pipe, yes sir.

MEMBER STETKAR: It was scheduled?

MR. PITTALWALA: It's a UL listed bond strand of pipe manufactured by Ameron. It beats the NFPA requirements and our design criteria.

MEMBER STETKAR: Okay, thanks. Yes, there was a rather confusing sentence in the SER about the 7,000 feet.

You've done the remote eddy current testing and it says that several sections had localized degradation in excess of the minimum wall thickness. That didn't sound too good, but I assume it meant it had degradation that reduced you to somewhere below the minimum wall thickness?

MR. PITTALWALA: Yes sir. We did remote eddy current testing in the year 2000. That was the first application of RFEC within the industry, and the indication showed us that we had several locations where we had exceeded minimal degradation, and in some cases through wall, although the interior concrete lining and the exterior earth pressure held it. There were no leaks in those locations.

Up until then, we had been able to manage all these for isolating sections of the piping, because we have post isolation valves in-stream. So we took the decision for actively going and replace those sections.

MR. BARTON: Okay. I guess I want to ask you, why do you think that replacing with fiberglass is the best option, because if you look at what's going on in the industry, failed buried piping also includes fiberglass piping as failed.

MR. PITTALWALA: Let me address that. My understanding is that you're asking why we chose fiberglass piping. At the time when we made the decision, we wanted to go use material that is corrosion-resistant, and we looked at two materials. One was high density polyethylene, and we looked at fiber-reinforced plastic.

Both of them had to meet the NFPA requirements, National Fire Protection Association requirements and had to be UL-listed. Both did. However, the high density polyethylene did not meet our pressure requirements because of downgrading it for pressure, because of our high temperatures in our fire protection tank.

MR. BARTON: Okay.

MR. PITTALWALA: That's the reason we chose fiberglass reinforced plastic.

MR. BARTON: Thank you.

CHAIRMAN BONACA: Any other questions?

(No response.)

CHAIRMAN BONACA: I thank you for the presentation. We'll take a break now until 3:35.

(Whereupon, a short recess was taken.)

CHAIRMAN BONACA: Okay. So let's resume the meeting and now we have the presentation of the NRC.

(Off mic comment.)

CHAIRMAN BONACA: What?

(Off mic comment.)

CHAIRMAN BONACA: Okay. So the presentation by the NRC.

MR. HOLIAN: Good, thank you. Thank you, Chairman and my name's Brian Holian again. I'd just add a couple of introductions and then I had a couple of other follow-ons on your original question Chairman, that I'll take now and we can either discuss that now or if the members have questions on that later.

I wanted to mention other introductions. I mentioned Greg Pick. He's the senior reactor inspector. Lisa Regner is the senior PM. Also at the table is Evelyn Gettys. She's currently the project manager for Columbia Station and is there assisting Lisa, and Dr. Allen Hiser, our senior level advisor on materials and other structures, is also at the table.

I would also like to introduce Dr. Don Naus, one of our contractors from Oak Ridge. He's sitting behind the Chairman there. He's in. He's also participated in the audit out at Palo Verde and looked at a lot of the structure issues. He looked at the spray ponds when he was out there. So I want to highlight his attendance here today.

Just back on that original question you had, Chairman. I said I might expand on it and that's the question of, you know, a plant coming in so early for license renewal and how you're sure or how the staff kind of verifies operating experiences incorporated as the years ago on, even before PEO.

I did mention that Part 50 and Part 54 overlap, and you know, Part 50, the maintenance rule, covers a lot of these systems, and then Part 54 and our aging management programs pick up on other areas that the maintenance rule might not cover.

You know, I mentioned the overlap is something that I think is good personally and, you know, honestly sometimes the industry will complain of that overlap a little bit. I'll get questions of, you know, isn't that a current licensing issue and maybe not a license renewal issue.

I think those questions occur mainly

because license renewal sometimes leads in the issues, because we have a licensing issue in front of us in-house. So we do take the time to get as best of a commitment that we can out of an issue, and get in our safety evaluations.

Sometimes that even causes delays in the application process, and the industry normally hasn't complained too much about that, you know. What's a couple of month delay in a couple year process?

An example of that is even currently now on buried piping. We are still upgrading commitments that were made even a couple of years ago. I might even have a couple of supplemental SERs for a couple of the older plants that are still in-house that haven't been issued yet. But I'll issue an updated commitment and we're still working with those plants on upgrading those commitments.

So that's the plants that are still in-house I'm able to do that. Your question went further, and what happens when a license is issued and you've got such an extended period, say 15 years, before the plant goes into PEO.

I mentioned the 7103 inspection. I just wanted to highlight that again. That's the number designation that we use for that inspection. We've done maybe eight of those or so now, you know. It started with Oyster Creek and we do those before, the outreach before they go into the extended period.

We look at the commitments, a large majority of the commitments. We only just recently, within license renewal, kind of collated all those findings from those inspections, just to trend to see how well the plants are picking up on those commitments. We have quarterly meetings with the industry and we give them that feedback.

One of them I'll highlight was out of Region III at the Dresden plant. There were a couple of ROP findings, green findings in the 7103 inspection that fed back into the ROP program and into the corrective action process. So we haven't often talked about that follow-on license renewal inspection.

It does occur before they go into PEO, and we have the option of following up after their NPEO also, with an aspect of that inspection, that Oyster Creek is still being held this fall on a follow-up to their original 7103 inspection. So I wanted to highlight that as an option.

There's one other way Part 50 and 54 overlap. I think we've talked about an open item on a couple of plants that the Committee might remember.

It's not on this plant. Boral is an issue that plants using their spent fuels, a lot of plants used, and there has been some degradation in that type issue.

As a matter of fact. Dr. Heiser's been tracking that for license renewal. But that's an area where we do send out. We sent out a new interim staff guidance on that issue, and for the license renewal plants to realize that this is area, I think.

Under Part 50, we've also sent out generic correspondence on that, and we work with the Division of Engineering in NRR to apply that, not only plants that have been renewed but these are plants that are in Part 50 that haven't come in yet on that aging issue.

So I wanted to expand on those options, you know. It's kind of like a multi-pronged fork. We have to ensure that corrective actions are maintained in these aging management programs. How well we do that is, you know, is a good question, and we interface routinely with the regions on that.

The last item I'll mention is we actually keep what we call a hot list of topics that we give to the regions when they go out on that 7103. Here are some items in the last four or five years that have, I think we've highlighted in our SERs that we want you to check on previous plants. So I wanted to highlight that information and we can come back to that later if the Committee members have additional questions.

CHAIRMAN BONACA: Thank you.

MR. HOLIAN: Okay. With that, I'll turn it over to Lisa Regner, senior project manager.

MS. REGNER: Thank you, Brian. I'd like to recognize the staff, the review staff in the audience here today. I will probably call on them as the presentation progresses. I'm very pleased to be presenting to you today.

As Brian said, my name is Lisa Regner. I'm the project manager for the Palo Verde Nuclear Generating Station license renewal application, and I'm going to discuss today the staff's findings associated with the review of this license renewal application, as presented in the staff's safety evaluation report with open items.

Feel free to ask questions at any time, but as a preview here are the main topics I plan to discuss. I'll try not to repeat information that's already been covered by the Palo Verde staff. They've covered a good bit of information, so maybe my presentation will only be two or three minutes.

(Laughter.)

MS. REGNER: Let's see. I do want to ensure that you receive adequate information associated with the staff's review and findings so far. The overview will be brief, since this information was previously discussed. I'll then follow the basic structure of the safety evaluation report and cover topics of interest in each section. Mr. Greg Pick will also discuss the license renewal inspections and findings.

So starting with the overview, the only points that I do want to add, beyond what Palo Verde covered, is that the application was not initially accepted for review by the staff, as it lacked complete information on cumulative usage factors for certain ASME Class 1 valves.

Once the applicant submitted a supplement with this information in April, the staff then began its review.

And the second point I do want to make is associated with the power-up rates. The applicant had requested two separate smaller, you know, about two percent power-up rates for a total of five percent above the original license thermal power, and the staff did evaluate the effects of the steam generator replacement and power-up rate on several time-limited aging analyses, such as the reactor vessel neutron embrittlement analysis, leak before break analysis, and the ASME-3 fatigue analysis of Class 1 vessels, piping and components.

The staff review, the staff's review included two audits and one inspection. The license renewal staff audits and regional staff inspections are designed to minimize duplication of efforts.

While common were identified by both license renewal and regional staff during the Palo Verde assessments, staff communicated frequently to share information and worked collaboratively to ensure a comprehensive review.

And two areas where staff worked well together were issues identified with fire zone scoping and structural monitoring program issues, which Mr. Pick will discuss shortly in his presentation.

The staff completed its review of information submitted by the applicant by July 9th of this year, and we issued the safety evaluation report with open item in August. One open item remains outstanding, related metal fatigue. There are also five confirmatory items.

There are also two additional issues which have emerged, and all of these have been touched by the applicant. But I can certainly answer additional questions and we'll cover those very briefly.

MEMBER STETKAR: Lisa, before -- could you explain to me what the rationale is for calling something an open item versus a confirmatory item?

MS. REGNER: Sure.

MEMBER STETKAR: On this particular application, there were at least three things that are classified as confirmatory items, that seem to say "Gee, we have this question and we're waiting for a response, and depending on whether or not the response is acceptable, we deem this to be a confirmatory item," where that's usually --

MS. REGNER: An open item.

MEMBER STETKAR: An open item.

MS. REGNER: Absolutely.

MEMBER STETKAR: So --

MS. REGNER: Absolutely, and you're correct. Confirmatory items are the applicant and the staff have agreed on a resolution, and we're merely waiting for the documentation, the formal documentation of that resolution. So in all five of those confirmatory item cases, we did have a clear path forward, and it was merely a matter of Palo Verde submitting --

MEMBER STETKAR: Okay, because that doesn't really come across in the SER, because I read things saying, you know, "pending review of the applicant's responses, the staff finds this acceptable," which to me sounds a bit --

MS. REGNER: Right, and that's also kind of leaving us open to the idea that it's not official until it's official.

MEMBER STETKAR: I understand something like a commitment to drain a tank, you know. That I can understand.

MS. REGNER: Yes, yes.

MEMBER STETKAR: But okay.

MS. REGNER: That's true, and actually --

MEMBER STETKAR: The first one I've come across, where there seemed to be sort of questions about which side of that nebulous line, something --

MS. REGNER: And an open item is somewhat tricky as well, the idea of calling it one open item versus --

MEMBER STETKAR: And no. I understand the bundling of the metal fatigue. That's okay. I was just --

MR. HOLIAN: This is Brian Holian. The only other thing I'd add, since I don't see the OGC lawyer in the room yet, is I'll blame that wording on them. But that might be part true on the conclusion aspect of it. You know, we need to do a final review. But it is as Lisa mentioned. Sometimes I read them and I say this is almost an open item.

MEMBER STETKAR: I mean in principle, I'm left to say that if their response was not satisfactory, what happens then? A confirmatory item becomes an open item?

MR. HOLIAN: Becomes an open item then, and yeah, we'd get back to you or we'd tell you that if that --

MEMBER STETKAR: Okay.

MR. HOLIAN: If we actually did some more work on this, then we'd highlight that to you.

MEMBER STETKAR: Okay, thanks.

MS. REGNER: Section 2 of the SER concerns structures and components subject to aging management review. During its review, staff identified several scoping concerns which resulted in amendments.

For example, during a material and environmental audit, staff noted an error in the material for the Deville generator system pre-lube oil pump, and staff -- that was as a direct result of staff walking out into -- this was a new audit that staff implemented, and they identified the pump was, pump casing was carbon steel versus stainless steel, as identified in the LRA.

And I also wanted to point out that as a result of staff reviews of license renewal drawings, plant walk-downs, over 50 aging management review items were added to the license renewal application. The majority of those were in the balance of plant systems.

In the area of scoping, one confirmatory item remains outstanding. We discussed what, how we define confirmatory item. The applicant did discuss that that has to do with the draining of the containment spray chemical addition tanks. New information has emerged since we issued the SER. The applicant changed their date, their commitment date to November 30th.

Concerning Section 2, once the confirmatory item associated with the containment spray chemical addition tanks is resolved, the staff will be able to make its finding concerning Section 2. I'll now turn the presentation --

MEMBER STETKAR: Lisa, before you turn it over.

MS. REGNER: Uh-huh.

MEMBER STETKAR: A couple of probably small items, but maybe it can help with some confusion that I had. The applicant screened out fire protection systems for a number of in-scope outdoor transformers, high voltage transformers, even medium voltage transformers.

And apparently, and it was a response to an RAI on that, and apparently the response said well because these transformers are located more than, I don't know what it is, 50 feet away from something else or they have a fire barrier with a rating of three hours, we don't have to protect them against fire. Even though they're in-scope transformers. In other words, they provide an in-scope power station blackout recovery function.

MS. REGNER: Uh-huh.

MEMBER STETKAR: It struck me as rather odd. Essentially you're saying it's okay to burn them up, but I can't have an electrical fault on them or I can't have some structural failure of them. Can you explain why it's okay to not include the fire protection for those transformers?

MS. REGNER: I've got my technical reviewer, who just walked in, and I will turn it over to Mr. Naeem Iqbal.

MR. IQBAL: I'm Naeem Iqbal with the Fire Protection Branch, NRR. The Palo Verde outdoor transformers are not in the scope because they are 50 feet away from the circulated area. So that's a requirement for the ground technical provision that Palo Verde has. The fire protection system, dilute system for transformers is only for the insurance processes.

MEMBER STETKAR: Well, that's what confuses me, because these transformers are in scope for other elements of the license renewal process.

MR. IQBAL: For the fire protection system, the dilute system is only for the loss prevention purposes, not the regulatory, you know, purposes.

MEMBER STETKAR: So it's okay to burn them out, but I can't electrically fault them or I can't trip them over because of structural failure?

MR. IQBAL: Because 50 feet away, the 3R fire barrier in the terminal building. So there's no requirement for the fire protection program.

MEMBER STETKAR: Apparently you're not picking up on the irony. These transformers are required to be in scope to restore off site power. They must physically be there, meaning their structural components must be intact. They must electrically be there, meaning things like electrical insulation must be intact, and I would assume that they must be there not a molten pile of burned up stuff.

MR. IQBAL: Right.

MEMBER STETKAR: I'm curious if they have to be there physically and electrically, why only because of insurance purposes don't they have to be there in terms of not being consumed by fire?

MR. IQBAL: But if they have the system there, right? They have the system but not in the scope, the fire protection system not in the scope because of the --

MEMBER STETKAR: I can rest that fire system, I can plug it up so that it never works.

MR. IQBAL: I don't think so, because they already have maintenance program there. They're looking at it, so --

MEMBER STETKAR: But there's no guarantee under their aging management programs that that system remains intact.

MR. O'KEEFE: I think I can answer this question. This is Neil O'Keefe. I'm the branch chief for not only license renewal in Region IV but fire protection.

The question you're asking is mixing initiating events. If you had a fire in one of these transformers, then a plant has the ability to power the equipment they need to safely shut down the plant. So it doesn't matter, as long as that fire doesn't spread to other stuff, you're okay. So it's just a --

MEMBER STETKAR: That may be a good answer. However, I've seen, I believe, in other license renewals, where the fire protection for the in scope transformers is in scope. That's really the reason I raised this.

MR. O'KEEFE: The spatial relationship. Fire protection always about spatial relationships.

MEMBER STETKAR: Okay.

MR. HOLIAN: And this is Brian Holian. The only thing to add on some licensees putting it in scope, makes sense from a logic standpoint, not this irony aspect. I think they just volunteered to put it in scope for their own methods or ease of --

MEMBER STETKAR: I'm just saying if you justify it from the sort of multiple initiators, perhaps I can rationalize that way.

MR. HOLIAN: Well, you don't, when they don't offer it, and then we do fall back on well, you know, it might cause the plant to shut down. You know, if it's not needed for plant shutdown, sorry.

MEMBER STETKAR: Okay, thanks.

MS. REGNER: Thank you.

MEMBER STETKAR: One other question I had on scoping and screening, and this is probably -- this is more a question for the licensee or applicant.

The compressed air system is -- most of the system is not in scope for license renewal, as it's currently characterized. Exceptions being parts of the system that are required for containment isolation functions, those containment isolation valves, for example.

However, it's noted that -- and it's sort of noted briefly that compressed air is a support system for fire protection pre-action deluge spray valves that are definitely in scope for license renewal.

If you look at the -- some them are in, some of them are not in. Not the transformers; these are other in-plant. The question is is air pressure required to operate? Is clean actual pressure required to operate those valves?

In other words, do I need nice clean, dry air at a certain amount of pressure to operate those in scope fire protection valves? So as I said, it's probably more a question for the applicant.

MS. REGNER: I certainly will have to let the applicant answer that one, if they're willing.

MEMBER STETKAR: I'm sure they're willing. It's whether they're able.

(Laughter.)

MR. COXON: Doug Coxon, Palo Verde Operations, and the question was is compressed air air-support the deluge system? Primarily the answer is no. It's there from a supervisory standpoint, to get line function to stop there.

(Simultaneous discussion.)

MEMBER STETKAR: Okay, understand. I just wanted to make, confirm, because I couldn't tell from the drawings. Thanks.

MS. REGNER: Okay. So I'll turn it over to Mr. Greg Pick, the Region IV lead inspector, who will discuss the license renewal inspection planning.

MR. PICK: Thanks, Lisa. Good afternoon members of the ACRS Subcommittee, applicant personnel and members of the public, and fellow NRC personnel. As was described earlier, we performed our inspection in February of this year. The inspection team consisted of two generalists, an electrical engineer, a civil engineer and a mechanical engineer. Next slide please.

This was the second plant review whose application was processed by the STARS Center of Business. Our on-site inspection team reviewed 26 of the aging management programs, which included five of the new aging management programs.

When we conduct our inspections, we walk-down the structures and the components in-field. We review the relevant programs and process documents if they've been developed. In this instance, there were a lot of documents that allowed for a thorough review. We consider operating experience and we interview the program owners.

Our inspections focused on conditions at the plant and how they have implemented the existing aging management programs. We also performed a vertical slice evaluation. What I mean by that, we kind of took the whole application on three systems, and looked to see if they had considered proper environments and the materials similar to what the aging management review and aging management program of headquarters does. But it's from an implementation viewpoint.

MR. BARTON: And what was your conclusion?

MR. PICK: For the systems we selected?

MR. BARTON: Uh-huh.

MR. PICK: That they had properly included, considered the appropriate environments, assigned the appropriate AMPs and had the proper material, based on the records we reviewed.

There were outstanding questions related to structures monitoring and the scope, and right after we left site, they had that bus duct failure. We decided we needed to look at the root cause. Next slide, please.

We found their scoping of structures and components thorough and generally accurate. The drawings were well-developed, clearly identified what was included for A-1, A-3 and A-2. As inspectors, the applicant used a fire zone approach and a mitigative method, as allowed by NEI 9510, to exclude some components from the aging management review.

When you use a mitigative method, you have to have a thorough evaluation for any component in the area, so that you can exclude it. During our field walk-downs, we found some pressure transmitters and other items that they had no evaluation for, and had not included in their review.

The applicant's response for these areas was to just fall back on the preventive approach and include them all in the scope of aging management review. Any questions?

In the area of aging management programs, for structures, they already described that they had a 30-year period where they were going to look at a representative unit. If they found in a problem in one unit, they would have looked at the same locations in the other unit, to try to find out what the cause was.

In my experience in maintenance rule, many plants look at their structures every five years. So that seemed to be a long period of time, and I challenged it from their maintenance rule aspect. In response to that, for license renewal, as they said, they're going to follow the ACI standard and all of its periodicities for Category 1 structures.

For the current license basis, as they said, they'll have two complete 100 percent inspections prior to entering the period of extended operation. We found that response, for both license renewal and the current period of operation, satisfactory.

Some other items from the inspection that we identified. For the overhead and light load cranes, they properly included all of their cranes. For the 25-ton diesel crane, they did not have a PM developed. So they had, I cannot say they had not inspected; they did not have an existing PM.

They promptly initiated a corrective action document, began developing a PM and they're going to include the aging management aspects of monitoring for rust and corrosion on the I-beam and the trolley wheels.

For inaccessible medium voltage cables, as the applicant said, the large -- most of the water source is following rainfall. They had a typo in their procedure, where they needed three inches in a 24-hour period before they would begin their -- but that was not conservative. It was really .3 inches. So it's really not very much rain for the desert, and they're going to start looking for water in their electrical manholes.

Similar to the questions by the ACRS Subcommittee, they had an error in their application related to selective leaching. It was a wording error. They were going to credit their review of selective leaching monitoring beginning now, and going up to the PEO.

They're still going to do the monitoring, but the GALL requires that within ten years of their period of extended operation, so you have more operating history. You'll start crediting those to figure out what you're going to do in the area of selective leaching, and whether you needed a program.

Once we pointed that out to them, they promptly corrected that.

MEMBER STETKAR: Greg, they mentioned, I don't know, this selective leaching or just general corrosion. But they mentioned problems with the fire water, fire protection system in replacing pipe. Do they have any other in-scope cast iron or that type of pipe that would be --

MR. PICK: By the material. I don't know the answer to that question.

MEMBER STETKAR: Do you have any other varied in-scope cast iron piping?

MR. HESSER: Mr. Pittalwala will address your question.

MR. PITTALWALA: Shabbir Pittalwala, Palo Verde. Yes sir. The balance of the portion of the fire protection system that is not replaced is ductile cast iron.

MEMBER STETKAR: Got that. Any other in-scope systems?

MR. PITTALWALA: Not to my knowledge.

MEMBER STETKAR: Okay, thanks. That's what I was asking. Thanks.

MR. HOLIAN: We've got one other clarification. Bill Holston, the senior reviewer, has a clarification.

MR. HOLSTON: There is a portion of the make-up water system that's got ductile cast iron in it also, that's in scope.

MEMBER STETKAR: Any enhanced inspections planned for that?

MR. HOLSTON: We would, and actually it's domestic water, I'm sorry. We've evaluated their buried pipe program in relation to the current OE out there, and compared it to the GALL AMP that we were developing, AMP 41.

Because that's non-safety related piping, it would be in scope for preventive measures, but we would not require inspections of that piping.

MEMBER STETKAR: I'm not quite sure I understood all of that, though. It's in scope for -- I understand it's not safety-related piping. Is it in scope for license renewal?

MR. HOLSTON: Yes. There is a portion that's in scope for license renewal.

MEMBER STETKAR: Under --

MR. HOLSTON: As I recall, that's -- it's either A-2 or A-3.

MEMBER STETKAR: It's A-2 or A-3. Yes, it would have to be.

MR. HOLSTON: That is correct, and what I was saying is the applicant committed to meet GALL AMP M-34. We've gone to all the current applicants and asked them to look at their plant-specific operating experience, industry operating experience, and look at augmenting their programs as necessary to account for that.

MEMBER STETKAR: Uh-huh, okay.

MR. HOLSTON: And so we've been evaluating each plant on an individual basis, but using the new AMP 41 as kind of a philosophical basis for that evaluation of each of these plants that are Revision 1 GALL plants but not Revision 2. In Revision 2 of the GALL, which will be AMP 41 for buried piping, non-safety-related piping, you have to implement the preventive measures.

So we want to see cathodic protection. We want to see coding. We want to see backfill. But we don't require inspections of non-safety-related piping.

MEMBER STETKAR: Got you, okay.

MR. HOLSTON: We focused our inspections on -- piping.

MEMBER STETKAR: Okay, okay. But you do require -- that explains the preventive measures. Thanks.

MEMBER ARMIJO: Yes. I noticed that you, there was a lot of cathodic protection applied to the buried piping and maybe some other components. But I was wondering how effective that is in a desert environment where there's no electrolyte. Is that just belt and suspenders, or is it something that's really effective?

MR. VALLE: Dean Valley, Division of Component Integrity. Cathodic protection is a very effective means of preventing corrosion in buried systems.

Properly designed, you will either have good current good voltage of conditions, or in a very, very, very dry environment, where you may have difficulty in achieving those potentials because of a lack of electrolyte, you'll have very, very little corrosion due to the, again, lack of the electrolyte.

So in the case of a dry environment, it's still a very effective tool to have in place for either the reasons of being effective or because the environment is not sufficiently moist to cause a problem.

MEMBER ARMIJO: Okay, thank you.

MR. PICK: The other unresolved item in the inspection report dealt with review of their bus duct failure, from review of the root cause. I agreed that it was a maintenance-related failure, and you needed the cracking of the Noryl. The purpose of the unresolved item was to see if the event would cause them to revise their AMP, since the cracking of the Noryl was the condition.

We were looking at the bus ducts at many facilities, it added no new information. That satisfied us. Next slide, please.

The applicant remains in the licensee response column of the NRC action matrix of the reactor oversight process. They did exit Column 4 the first quarter of 2009. When we were on site, they were still implementing some of the corrective actions from their site improvement program. That was an ROP finding, that allowed them to leave that Column 4.

Being in the licensee response column, in the column Inspection Findings and Performance Indicators, are of very low safety significance.

While we were on site, we performed many walk-downs of the structure systems and components, particularly the Ultimate heat sink, building and tank exteriors, station blackout turbine generator. We found those items to be in good condition.

We have some minor items identified in the report, where there were some dirt in pull boxes and lack of gaskets. We identified that to them. They wrote a corrective action document and put them in their work control process and were having those items replaced.

We did not have an opportunity to go inside the containment. I talked to a former resident and called the residents. They find the interior of the containment to be in good condition; no major, no spalling, no rust and no delamination of the coatings.

MEMBER ARMIJO: Is that the result of just the casual observations, or is it a formal inspection?

MR. PICK: They were casual observations.

MEMBER ARMIJO: Okay.

MR. PICK: They did not go into the containment looking for those sort of things.

MEMBER ARMIJO: Okay.

MR. PICK: Next slide, please. So the conclusions from the inspections was we found the scoping of non-safety structures, systems and components and application of the AMP to those components acceptable, after the one item was corrected.

Reasonable assurance exists and aging effects will be managed and intended functions maintained during the period of extended operation, and for the structures monitoring, we feel that the applicant established a schedule for structural inspections to provide data for comparison prior to entering the period of extended operation.

Unless there's any questions, I'm going to turn the lectern back over to Lisa.

MS. REGNER: Thanks, Greg. Moving onto Section 3, Aging Management Review Results, Section 3 covers the staff's review of the applicant's aging management programs and aging management reviews, evaluated against the criteria in the GALL report.

For a given aging management review, the staff reviewed the intended function material environment aging effect requiring management, and delegated aging management program combination for a particular system component type, whether it aligned again with the GALL report AMRs.

If an AMR, aging management review, did

not align or was not addressed in the GALL report, the staff conducted a full technical review to ensure adequacy. The staff reviewed 40 AMPs and over 2,500 aging management review items. This included 29 existing programs and 11 new programs.

MEMBER STETKAR: Lisa, before we get to the confirmatory items, I don't need the body count there, I had a question. There was one issue. In fact, it was the subject of an Information Notice 2009-04, regarding -- I can't read my own typing here reduced support force in main steam line supports in each unit.

There were questions that you raised about that. The original Information Notice identified the cause of this problem as due to wear caused by cyclic loading and vibration, which was characterized as an age-related degradation mechanism.

The applicant apparently concluded that it was not age-related. It was a design problem. Conclusion: Design issue involving configuration of the structural supporting members. This problem was identified after about 22 or 23 years' worth of operation.

At what point does something not become a design issue and suddenly become an age issue? You know, if the thing is installed and it had been working fine for 20 years, apparently not so fine, wearing out, just because somebody said well, this is a problem with the original design, that's justification for not enhancing the inspection of that or similar items?

That bothered me a little bit, because it says pretty much anything that I can say well, it was part of the original design, even though it failed after 30, you know, 57 years, but wasn't at all age-related.

MS. REGNER: Uh-huh, and I assume you're talking about the small bore piping --

MEMBER STETKAR: No, no, no. I'm talking about supports for the main steam line piping.

MS. REGNER: Okay.

MEMBER STETKAR: We'll talk about the socket welds later, because the design issue is also invoked under that. It's a completely different topic.

MS. REGNER: Okay.

DR. HISER: Well, I think one could claim everything in the plant, that it is -- it's a design problem. You used the wrong material, the wrong stresses.

MEMBER STETKAR: It wore out. I should have used a better one.

DR. HISER: Right. But I think --

MEMBER STETKAR: If corroded, I should have used more corroded resistance.

DR. HISER: I think the one distinction that we make is that if the plant makes design changes as a result of the finding, you know, they redesign the supports, they use new material, they do something that's different and they take remedial actions for similar locations, then the conditions are different in those locations.

Now presumably one would go to the similar locations and they would do an examination.

MEMBER STETKAR: Well, and yeah.

DR. HISER: The same problem exists there. If that same problem exists, then they would do a repair, some sort of -- and along with the design change. So that from that perspective, if one has changed the conditions, then one could look at it as no longer an aging-related failure but one that has been fixed through a modification.

In this specific case, I'm not sure exactly what Palo Verde did. Maybe Palo Verde or our structural reviewer could comment on the specifics.

MR. SHEIKH: Abdul Sheikh, NRC staff. I looked at this thing and the reason appears to be the design error, because it's the cyclical loading which caused that problem, and that -- because the same kind of supports didn't fail in other areas. You know, they are hundreds of spring hangars of the similar characteristics in the plant. But only have those steam line supports failed.

And that happened because of the cyclical loading. So, and they have redesigned the system there.

MEMBER STETKAR: So that those supports won't fail?

MR. SHEIKH: Correct. This has happened in some other plants also, because when the steam line comes out in that area, there is dynamic loads which cause those spring hangars to fail.

MEMBER STETKAR: I just thought that there may be a rationale for any individual repair, redesign, new installation that you want to call it. But it strikes me that at some point in time, you know, as I said if these things had been discovered during the second or third year of operation or the first inspection, fine. I understand that.

But these were in for 20 years of

operation, and at some point, it strikes me that the line between well, it was a design problem so we're going to replace it in year 59, versus it really was a cumulative -- yeah, perhaps the design should have been better, but that was a cumulative effect of aging and fatigue.

But I think, I think what you really need to look at is what do you do going forward? I mean once you have identified that the purpose of aging management is to try to capture things before you get failures, before you impact plant safety. If you've identified the problem, you know, hopefully you haven't caused an accident or anything like that.

But once you've identified it and you have taken corrective actions, you've taken maybe preventative actions, mitigative actions, design changes, presumably you've restored the condition, and you have improved the situation. Now there may be additional monitoring in the short term as necessary, with -- Lisa mentioned socket welds. That's one of the things -- with plants.

But when they make changes, they'll go in and they will do some periodic inspections to ensure that the, you know, cycles, the amplituder cycles have been dampened, things like that, to ensure that the design change has really taken care of the conditions that led to the problem.

So I think maybe looking forward is really more important as opposed to, you know, is it a design change or aging management overall.

MEMBER STETKAR: Okay, thanks.

MR. HOLIAN: This is Brian Holian. It's Brian Holian. Just to add, that question is very good and it sits there maybe without proper definition by us in our standards, but it's clearly something we think about on all the operating experience issues. We wonder whether the industry, you know, tends to not call them age-related, to get out of that designation of op experience.

We wonder that. We talk about that with our regional people. They bringing up small bore piping because in an example, that was a case where we were head to head with the industry on that. They said no and it's no aging issue here, and you can see both sides of the coin sometimes.

But I'm just trying to say that we are trying to push that line, to include it from the staff's perspective, where you can into an aging management program. I don't know if that helps, but --

MEMBER STETKAR: That helps.

MR. HOLIAN: I mean you know we can talk about individual examples and things like that, but --

MEMBER STETKAR: Okay, thank you.

MS. REGNER: All right. so as you know, there is an open item related to metal fatigue in Section 4. The open item is linked to Section 3, since the staff discusses it in its review of the metal fatigue AMP. However, I would like to wait until Section 4 and discuss that open item in just a moment.

There are four confirmatory items in Section 3. the applicant did cover most of these, but I'll go ahead and go over them. Cavitation erosion of infrequently used high pressure safety injection minimum flow piping resulted in questions concerning the extent of condition analysis and other infrequently operated systems that could be susceptible to the same aging effect.

We did also ask the same question that I believe Mr. Stetkar, Dr. Stetkar, I apologize.

MEMBER STETKAR: No, it's Mister.

MS. REGNER: Mister, sorry, about effects on other materials as well, not limiting -- not limiting the material to stainless or carbon steel.

Other concerns, another confirmatory item concerns the sample size and statistical justification of the one-time inspection of small bore piping socket welds.

MR. BARTON: Well haven't they come forward and agreed to do ten percent of all the socket welds on each unit, which is going to be, you know --

DR. HISER: Yes. That's part of the confirmatory item, that we're reviewing their submission.

MR. BARTON: Oh, you're reviewing that?

DR. HISER: Yes, to see whether that -- well, that's a lot more than anybody else has committed to, so it ought to be all right. The number of welds that they have and the number that they will inspect are fairly significant, and that's why it's found -- that's why we found it --

MR. BARTON: A lot of people are arguing over one weld, so you know.

DR. HISER: Correct.

MEMBER STETKAR: Let me ask something different, because this is something I've been asking sort of in several, and Brian knows what's coming. There's kind of consistency in the staff's approach to this issue across the different applicants.

For example, in this particular case, you've accepted a fairly large sample of volumetric examinations, but only in terms of a one-time inspection. In other current license renewal applications that are in progress right now, you've pressed quite strongly for going forward periodic volumetric programs.

Perhaps a smaller sample, and in some cases it's a risk-informed sample, but the sense is that this is not a one-time inspection process, that there is -- staff feels that it's important that it should be an ongoing periodic inspection activity.

So I'm curious about why on this one, even though it might be a large sample, that a one-time inspection is adequate, where for other applicants, apparently a one-time inspection, regardless of the sample size, is not adequate?

DR. HISER: In general, it comes down to the plant operating experience, and plants that have had a history of failures --

MEMBER STETKAR: They've had two failures here.

DR. HISER: They had two failures, three design changes. They have been remediated. One of the reasons, one of the reasons that we have balanced the ten percent, the large sample size at one time is that they will examine a lot of the welds, ten percent of the welds overall. If they do find problems in those 100 inspections, then they will go -- they will revert to a periodic inspection program.

MEMBER STETKAR: I guess I'm thinking going forward to the next applicant, what is my expectation when I read their proposal, to give me a level of comfort or to give them a level of comfort that they're going to satisfy what the expectations are?

MR. HOLIAN: I don't worry about their level of comfort. I'm just kidding you, but --

(Simultaneous discussion.)

MR. HOLIAN: It's the complaint I get. This is Brian Holian. On a couple of these evolving issues, I'll call them evolving issues, if we had that word there, and small bore piping is one of them. We do have a table in-house.

MEMBER STETKAR: You do? Okay.

MR. HOLIAN: Just to satisfy you with how we're addressing all 15 plants in-house, and there is some variability. Dr. Hiser brought up one. We won't trade off a larger sample now for maybe less. Here's where we'll then credit, okay, your corrective action program, your Appendix B program.

We will expect that if you find some on these samples, that my inspectors or my Region IV inspectors go out and see that you had some and you didn't follow on with some progressive inspection, you know, come up with a corrective action finding in that case.

But to answer why I don't have it satisfied in stone here, is I don't have the Rev 2 of the GALL out yet. I don't, I can't kind of officially tie them to the new buried piping AMP that you heard us in Part 41. So I'm getting a little bit of variance in the in-house ones.

But as Dr. Hiser said, you know, kind of we are trying to balance what operating experience this plant has had compared to the industry experience.

MEMBER STETKAR: Is there -- Brian, is there a reasonably settled set of internal, I don't know if criteria is probably too strong a word, but internal guidance that you use, so that a particular applicant, through discussions with you, can understand what the expectation may be?

In other words, I'm coming from the applicant's standpoint here. I don't want to go through subtle iterations of RAIs and confirmatory items or open items, if I had some better confidence going forward.

MR. HOLIAN: The GALL serves that purpose when we get it solidified again. But in the meantime, we do rely on rating the RAIs of other plants and our acceptance. I mean they --

MEMBER STETKAR: Yes, but I mean I've been doing that, and I'm confused.

MEMBER ARMIJO: For this component, there is no volumetric inspection that's qualified?

DR. HISER: Well, yeah. I think we discussed during Kewaunee that if EPRI has a technique that they developed for one plant, for one socket weld geometry. They're looking at expanding that to a broader sample. You know, the use of the word "qualified" may not be the right word. I mean I think the wording we like is one that's demonstrated capable of detecting the conditions that you're worried about.

MEMBER ARMIJO: But given that, that the technology isn't really ready for wide use --

DR. HISER: Not for today.

MEMBER ARMIJO: Not for today, given that, but then you're going with a visual inspection, and it would seem to me that what Palo Verde's going to do is preferable, because since it's a visual inspection, I'd rather have. What are you going to look for? You're going to look for leakage or any indication.

I think a large sample now is better than periodic samples over a longer period of time, to understand where you are in the plant. So I think this is a good inspection. In fact, I would prefer it over, you know, an even larger sample taken over a longer period of time.

But they're going to do a one-time early inspection and then periodics. I think it's --

MR. BARTON: As long as you don't find a lot of failures.

MEMBER ARMIJO: Well, if you find a lot of failures, that's what you -- then you're better off to find them now than later.

MEMBER STETKAR: I think Allen, aren't they committing to a ten percent volumetric examination?

DR. HISER: That's correct, yes.

(Simultaneous discussion.)

MEMBER ARMIJO: No, I think it was just visual. They were going to do it if a qualified or --

MEMBER STETKAR: That was the Kewaunee.

DR. HISER: That was Kewaunee.

MEMBER ARMIJO: Then I misread the --

MEMBER SHACK: Kewaunee and then --

(Simultaneous discussion.)

MS. REGNER: That was their original commitment, and they've updated. They've changed that commitment.

MEMBER STETKAR: This is the most aggressive one-time inspection, I think, that we've seen --

(Simultaneous discussion.)

MEMBER ARMIJO: That we've seen so far.

MEMBER STETKAR: --of massive weld material.

DR. HISER: The number of welds, I think, at Palo Verde is maybe much larger than other plants have had. So the number of welds they're going to sample --

DR. HISER: That was 40 socket welds, I think, they said.

MR. BARTON: Yes. So about 1,000. So about 100 overall between the three units.

MEMBER ARMIJO: Allen, set me straight. They're going to use some sort of a UT volumetric inspection on these socket welds?

DR. HISER: Yes. That is our expectation, yes.

MR. HOLIAN: As volumetric, so and it may be --

MEMBER ARMIJO: Well, I guess you can X-ray it, but I don't think you would want to --

MEMBER SHACK: Presumably it's UT, but it's certainly volumetric.

DR. HISER: But I think our, the NRC's expectation is that within a couple of years, there will be an industry-accepted UT technique that will be available for everyone to use.

MEMBER SHACK: Okay, okay.

DR. HISER: So a lot of the prior applications that have said things along the lines that we'll use UT if it's available or do destructive, you know, our expectation is that those are going to default to UT.

MEMBER ARMIJO: Yes, okay.

MS. REGNER: Okay. The staff also requested confirmation that the steam generator feed rings are not susceptible to flow-accelerated corrosion. Finally, information was requested to confirm that aging from loss of material and degradation were going to be adequately managed for PVC and elastomer-lined piping in raw water environments.

I've received the information on all four of those confirmatory items.

Okay. Section 4. This section contains the staff's review of time-limited aging analysis. The staff's review is complete for all sections except 4.3, Metal Fatigue Analysis, which contains an open item. Concerning the metal fatigue analysis open item, how did we get here?

As stated previously, the initial license renewal application review was stopped in February and resumed in April, due to incomplete cumulative usage factor information for Class 1 valves. Following acceptance review, the original staff concerns were covered well by Palo Verde, and they were related to design basis information inconsistencies; also inconsistencies between the metal fatigue subsections in the license renewal application, and also disposition issues.

The staff conducted ten conference calls. We held a public meeting in May with the applicant, and we've issued a total of 70 questions in all related to metal fatigue to resolve these issues. In addition, seven amendments were associated with the metal fatigue unlimited aging analyses.

As stated, the applicant has submitted answers to all of the staff's current questions, issued questions. The staff's original concerns have largely been resolved and the remaining areas of concern can be classified into slight variations from how the applicant classified them.

We classified them into three areas such as cycle counting issues, fatigue analysis, disposition and environmental factors. The applicant submitted the last two amendments related to metal fatigue at the end of June and in August, to answer these questions and staff has not fully completed its review yet.

The issuance of the SER, and we'll cover these in the issuance of the SER scheduled for December of this year. If there are no questions on Section 4, I can discuss the additional -- okay.

MEMBER ARMIJO: I have a question. Lisa, you heard the discussion earlier related to Dr. Bonaca's question on the, why the cumulative usage factors for the instrument nozzles in Unit 1 were five times greater than Units 2 and 3.

MS. REGNER: Uh-huh.

MEMBER ARMIJO: And it raises the issue with me of consistency and the analytical process used for the three plants.

MS. REGNER: Uh-huh.

MEMBER ARMIJO: And I still don't understand why it's okay to have this discrepancy, if in fact the plants operate in the similar way, the designs are similar or identical, and the materials were identical. I wondered how the staff explains this inconsistency?

MS. REGNER: We don't yet. We have that in question. We're still evaluating, and Dr. Hiser, do you want to talk to that?

DR. HISER: This is one of the items that is still open, and we haven't completed our review of what they've submitted. But from the discussion earlier, my guess is they just use different assumptions, and they have a sharper pencil.

MEMBER ARMIJO: Well, I heard in Unit 1, the analyst treated vortex shedding, whereas in the other two units, that wasn't considered. Well, if it's a real mechanism of fatigue, it should have been treated the same in all three units.

DR. HISER: We will do a detailed review of that response, and if we need to follow up with them.

MEMBER ARMIJO: Okay.

MEMBER ABDEL-KHALIK: I have a more general question. If you have three units, single application, can you have different analyses of record?

DR. HISER: They have three separate licenses.

MEMBER ABDEL-KHALIK: But in this case, it's a single application. I mean where do you allow differences? The methodology is the same, but the data used in the methodology is different, depending on the unit, or do you allow completely different methodologies, given the fact that they have a single application?

MS. REGNER: It's a single license renewal application. However, there are three separate licenses for each unit.

DR. HISER: And I think in this case, there's three separate licensing bases for this calculation. So from a CLB perspective, they're all equally valid.

Now since we're reviewing the license renewal application, we want to -- it would be nice if we, those three analyses could be brought together, so that they -- you know, there really is one analysis. That's partly what we will take a look at in our review.

MEMBER ABDEL-KHALIK: Okay.

DR. HISER: The Unit 1 analysis really is the more technically defensible one, and we will --

MEMBER ABDEL-KHALIK: But is the only case where the analyses of record are dramatically different?

DR. HISER: I'm not sure from other. I know we have seen differences.

(Simultaneous discussion.)

MR. HOLIAN: This is a little unusual, because the plants are so close together in age to have a difference. So it makes the staff wonder, you know, was there an issue on Unit 1 that needed, you know, a different calculation and why would that be.

So that's the question we're asking. But your general question, we see differences in plants, licensing basis, especially if they're several years apart for one reason or another.

That one plant, it had analysis done, you know, at a different time frame, that would cause a different set of assumptions to be made. It's a little more unusual here on these three units.

MEMBER ABDEL-KHALIK: Okay.

MS. REGNER: Any other questions on

Section 4?

(No response.)

MS. REGNER: Okay. I'd like to cover the two additional issues. They were discussed briefly previously. The first involves inaccessible low voltage power cables. The applicable GALL report aging management program specifies medium voltage cables, that if energized and subjected to significant moisture, could be susceptible to failures.

This position was consistent with industry operating experience identified up through 2005, the 2005 time frame, when Revision 1 to the GALL was issued. Subsequent to Revision 1, Generic Letter 2007-1, which is inaccessible or underground power cable failures that disable accident mitigation systems or cause plant transience, requested licensee to provide additional information on cable failures over a wider range.

Licensees' responses to this generic letter identified cable failure events at lower voltages and, as a result, the staff determined that lower voltage power cables should also be part of the aging management program.

Staff is working on the issuance of and because of that operating experience, those plants currently under review, the staff is questioning those plants on how they're going to address this operating experience, and if they've had plant-specific operating experience as well.

MEMBER STETKAR: We've --

MS. REGNER: I'm sorry?

MEMBER STETKAR: I'm trying to phrase a question here.

MS. REGNER: Okay.

MEMBER STETKAR: When you say "plants currently under review," right at the moment, we have two other applicants that we've had our Subcommittee meetings for the SER with open items.

MS. REGNER: They are included.

MEMBER STETKAR: The low voltage cables are for those other applicants? So that has happened between the time that we had those Subcommittee meetings and today?

MS. REGNER: The staff is evaluating those plans.

MEMBER STETKAR: You should expect for those applicants --

MS. REGNER: You're talking Vermont Yankee and --

MEMBER STETKAR: No. I'm talking about

Cooper. In fact, I'm talking about three. Cooper, Kewaunee and Duane Arnold.

MR. PICK: Cooper already received the RAI and responded.

MEMBER STETKAR: So when we hear the presentation in a full committee meeting in October, a month from now on Duane Arnold and Cooper, we'll hear about low voltage cables?

MR. HOLIAN: Yes. That's the intent. This is Brian Holian. They have things to send to staff on a couple of issues on the new GALL, low voltage cable, buried piping, small bore --

MEMBER STETKAR: The small bore and the buried piping were what we saw. This is a new wrinkle.

MR. HOLIAN: It is, it is, and we think it's a relatively easy fix for the units to add in low -- they're already doing medium voltage, their low and medium voltage.

MEMBER STETKAR: Some units may have a relatively large number of those 480 volt cables, though.

MR. HOLIAN: Yes.

MEMBER STETKAR: So --

MR. HOLIAN: That's right, and the new

GALL is picking it up. The industry has seen the new GALL since January of this year. So I mean they -- at least out in draft format. So in general, the industry is accepting that. They realize a good aging management program should include -- there's some failures on low, so go ahead and include it.

They are arguing a little bit with maybe my timing. Brian, do you need -- it may be causing me some pain in my license renewal by adding it in now. Our answer has been yeah. It's, we think it's the right thing to do to get the SERs as current as possible, you know, for issuing them now.

We expect -- this goes back to the initial discussion, that were Cooper to go out and it not be in there, we would expect their corrective action program to pick it up. But --

MEMBER STETKAR: I was going to say, that's the way you've got to handle all pre-approved --

MR. HOLIAN: Pre-approved, that's right, and inspect them and look at that. And you know, I do have Part 50 backfit, because the public's asking me these same questions now on several plants that are out there, and you know, if it's a significant safety issue, can I go through my backfit process, to make sure I get it in to previous plants earlier?

Yes, I have that available also. But if it doesn't hit that threshold, I will be using a corrective action process in my inspections to ensure that their aging management programs keep abreast of operating experience.

MEMBER ABDEL-KHALIK: How about the 7103 inspections that they have already completed?

MR. HOLIAN: Yes. Oh, they've already been completed. Well, good. I can pick it up in a maintenance rule inspection. I can pick it up in a regular ROP corrective action inspection. So I have the ability, and I'm talking with my ROP inspectors, counterparts, to ensure that their sample size, that the inspectors.

As you see here, the branch chief of License Renewal is the branch chief for Fire Protection. He's the branch chief that does maintenance rule inspections. He can pick from a sample size of any commitments on inspections from here on out. That's how we approach that.

MS. REGNER: Any other questions on low voltage, inaccessible low voltage power cables? The second and final additional issue has to do with buried piping and tanks inspection program, also related to recent industry operating experience.

Staff is entrusted in efforts to incorporate operating experience into plant programs. Palo Verde has revised their AMP to include 15 excavated visual inspections of pipe. The applicant has not yet addressed hazardous material piping inspections or details on backfill.

So the staff still has unresolved questions and plans to issue an RAI on this additional issue.

MEMBER RYAN: I think in some discussions at a break, I also heard they have some information about radiological constituents. So I guess I look forward to them doing that.

MS. REGNER: You're not talking -- you want the applicant to provide additional information.

MEMBER RYAN: Yes.

MS. REGNER: Okay. Should I conclude mine, my presentation, or do you want to go ahead and let them speak on this topic?

MEMBER RYAN: No. They'll have to provide some documents.

MR. HOLIAN: It's outside this meeting, yes.

MS. REGNER: Oh, I'm sorry. I thought you were saying you wanted them to speak now.

MEMBER RYAN: No. Thank you.

MS. REGNER: Okay, uh-huh. Any other questions on buried piping and tanks? Okay. You'll note that the staff normally presents slide on reactor vessel neutron embrittlement and groundwater chemistry.

Neither of these issues was of concern to the staff, since groundwater levels in the Sonoran Desert, where Palo Verde is located, are 20 feet below the level of building foundations and dropping.

Also, there's significant margin in the reactor vessel neutron embrittlement analyses. However, I can show you that slide if you do want to see the margin. I'd be happy to do that.

MEMBER ARMIJO: Sure, I'd like to see it.

MS. REGNER: Okay.

MEMBER ARMIJO: I always like margin.

MS. REGNER: All right, right. Slide 25 please. Okay. So here, Section 4.2 of the SER covers reactor vessel neutron embrittlement analyses. There were three reviews performed to evaluate neutron embrittlement, as documented in the SER. Neutron effluents and adjusted reference temperature, upper shelf energy and pressure temperature limits. Yes, pressure temperature limits review, and the staff concludes that neutron embrittlement analyses exceed the review criteria as specified in the standard review plan for license renewal, and in accordance with the rules. Staff has no concerns, as stated. Any questions?

MEMBER SHACK: Well, since we brought up the vessel; I was going to let it go. I was just curious. You're going to make them withdraw the remaining capsules at an exposure not exceeding 72 effective full power years, as expected, for a possible 80 year second period of extension.

Why don't you let them exceed it, just in case they want to go to 100 years? Because I was worried about that.

MS. REGNER: Simon? Mr. Sheng. Do you need the question repeated?

MR. SHENG: I think I understand the question.

MEMBER SHACK: My question is just how you're going to sort of look at surveillance capsule withdrawals, as people look forward to extended life beyond 60, I guess, is really a general question. But --

MR. SHENG: Right. For Palo Verde, I

think we allowed them to put from their withdrawal, you know, in accordance with GALL requirements, and the reason is that because now we take a look at all the PW RPVs, and though -- oh sorry, sorry.

This is Simon Sheng from the Department of Component Integrity, and nowadays we surveyed a lot of RPVs, and we found out a lot of capsules has been withdrawn at a certain fluents level. They are not very uniform. So for -- according to current assessment, that the some, some capsules has been withdrawn at a certain fluents level, with certain embrittlement, and some in other points is integrated together.

So now that the -- I don't know whether it's because of NRC encouragement or it's because of the industry's initiative. A lot of plants are now participating in the industry's integrated surveillance program, and they try to basically have a balanced situation, so that we have information at kind of an evenly distributed embrittlement, so we can get information.

MEMBER SHACK: I just sort of wonder whether current regulations are interfering with that ability to do that, is sort of my concern.

MR. SHENG: That's right. The current is.

However, we are revising the GALL and try to reflect on that philosophy. Thank you.

MEMBER SHACK: Okay.

DR. HISER: I think, Dr. Shack, that for 60 years, if there's a limit of 72, if they want to go to higher fluents, or if they're more out in the years, say if they're 100 years, they can always reinsert the capsules and bump up fluents.

MEMBER SHACK: Not if they've -- oh.

DR. HISER: Presumably they're not -- well, it just says "withdraw the capsule."

MEMBER SHACK: Yes.

DR. HISER: Well withdraw, but not necessarily capped. So if they withdraw it and if they can reinsert it. The other thing that it gains the advantage of is some of the exposure then is using the fuel management that's in place at that point in time. So it's not all, you know, the first 20 years' worth of fuel management operations.

MR. MEDOFF: May I make a clarification? This is Jim Medoff of the Division of License Renewal, but I used to do pressure temperature limits and neutron embrittlement assessments for the Division of Component Integrity, including Appendix H surveillance capsules scheduled review.

If you'll look at the requirement for the final capsules pulls in those reviews, they're required to pull them at fluents that's been one and two times the projected end of life, 40 year life fluents for the plant. So depending on when they pull them, they may cover the fluents at 60 years or even 80 years. That's one thing.

So it may already be accounted for in the capsule schedule. The other thing, as Al said, in the all -- in Rev 1 of the GALL, we had provisions that even if they had pulled some capsules that for license renewal they were supposed to put those capsules in storage and there's a license condition that we've been imposing on the applications.

So if they need to cover that fluents of your concern, they have the ability to reconstitute the capsules and reinsert them so they can pull them out, and then do an amendment of their capsule schedule. So I think that should address your concern.

MS. REGNER: Thank you. Other questions on neutron embrittlement? Okay. Back to Slide 22, okay.

CHAIRMAN BONACA: Any questions?

(No response.)

MS. REGNER: And the staff's conclusions will be presented in the SER in December, scheduled for December.

CHAIRMAN BONACA: Thank you for a very, very informed presentation, and we're going to go around the table now and see if there are any points that the members want to make. Bill? Mike?

MEMBER RYAN: No. No additional comments, Mr. Chairman. Thank you.

MEMBER STETKAR: Nothing additional. I'd like to thank both the applicant and staff. I thought you came very, very well prepared.

CHAIRMAN BONACA: Sam?

MEMBER ARMIJO: Yes. I echo what Mark said. Very good presentations, well-prepared, covered everything. The only thing remaining is the resolution of the open item.

CHAIRMAN BONACA: Said?

MEMBER ABDEL-KHALIK: I have no additional questions.

CHAIRMAN BONACA: Okay, John?

MR. BARTON: Good job by all. Of course, the open item on the wheelbarrow full of RAIs on fatigue --

(Simultaneous discussion.)

MR. BARTON: And I just want to say one thing. The socket welds, you know, you talked about it before with Brian, and I think that's something we've got to come to grips with, because we've been all over the field with it. Now we come in with ten percent, so I think somewhere we've got to -- because this comes up every, every time.

So I think in some way we've got to come to closure on that one.

MEMBER SHACK: But actually I think this is historic. I mean when we started license renewal, small bore piping wasn't one inch socket welds. It was --

MR. BARTON: Yes, right.

MEMBER SHACK: So that we resolved that one as we went along, and now we've -- I mean it just keeps getting better as far as I'm concerned.

MR. HOLIAN: It keeps getting better, and we'll take more where they proffer more. But I understand that comment, and we're working on consistency in GALL. Thank you. Thank you, Committee.

MR. BARTON: That's all I have.

CHAIRMAN BONACA: Okay. I agree with the comments being made. I think it was a good application, practical questions on that issue of fatigue.

MEMBER STETKAR: Is there -- this is a leading question, but in terms of our planning our activities, is there reasonable confidence that that open item will be resolved, and if scheduled for a full committee meeting in December that we won't need another short perhaps, but focused Subcommittee meeting to --

MS. REGNER: The correct answer is yes.

MEMBER STETKAR: Okay.

CHAIRMAN BONACA: Yes what?

MS. REGNER: The answer is yes.

MEMBER STETKAR: There's good confidence that we will not need a --

CHAIRMAN BONACA: We will not. Be thankful. I would like to conclude on that base, on the feedback I got from the members. We do not need any letter to the full committee. Well thank you everybody, and is there any other questions from the public?

(No response.)

CHAIRMAN BONACA: If none, the meeting is adjourned.

(Whereupon, at 4:52 p.m., the meeting was adjourned.)

Palo Verde Nuclear Generating Station

ACRS License Renewal Subcommittee Meeting

September 8, 2010

John Hesser

Vice President
Nuclear Engineering

Palo Verde Nuclear Generating Station

Personnel In Attendance

- **Bob Bement –** Vice President, Nuclear Operations
- **Mohammad Karbassian –** Director, Nuclear Engineering
- **Angie Krainik –** Department Leader, License Renewal
- **Eric Blocher –** Project Manager, STARS
- **Glenn Michael –** Licensing Engineer
- **Rich Schaller –** Metal Fatigue Lead

Palo Verde Nuclear Generating Station

Personnel In Attendance (continued)

Metal Fatigue / TLAA
- Mark Radspinner
- Rex Meeden
- Gene Montgomery
- Winston Borrero
- Doug Berg
- Curt Carney
- Dave Gerber

Civil / Structural
- Ken Schrecker
- Chris Wandell

Engineering Programs
- Doug Steinsiek
- Doug Hansen

Buried Piping
- Shabbir Pittalwala

Operations
- Doug Coxon

Electrical
- Mark Hypse

Probabilistic Risk Assessment
- Zouhair Elawar

Environmental / Radiation Protection
- Tom Gray
- Harvey Lesan

Support
- Ron Barnes
- Mike Green
- Mark Fallon

STARS
- Tony Harris
- Chalmer Myer

Agenda

- Plant History and Background
- Major Improvements and Long-Range Planning
- License Renewal Application
- Safety Evaluation Report Open and Confirmatory Items
- Regional Inspection Items
- Concluding Remarks

Our Mission…

SAFELY and efficiently ***generate*** electricity for the ***long term***.

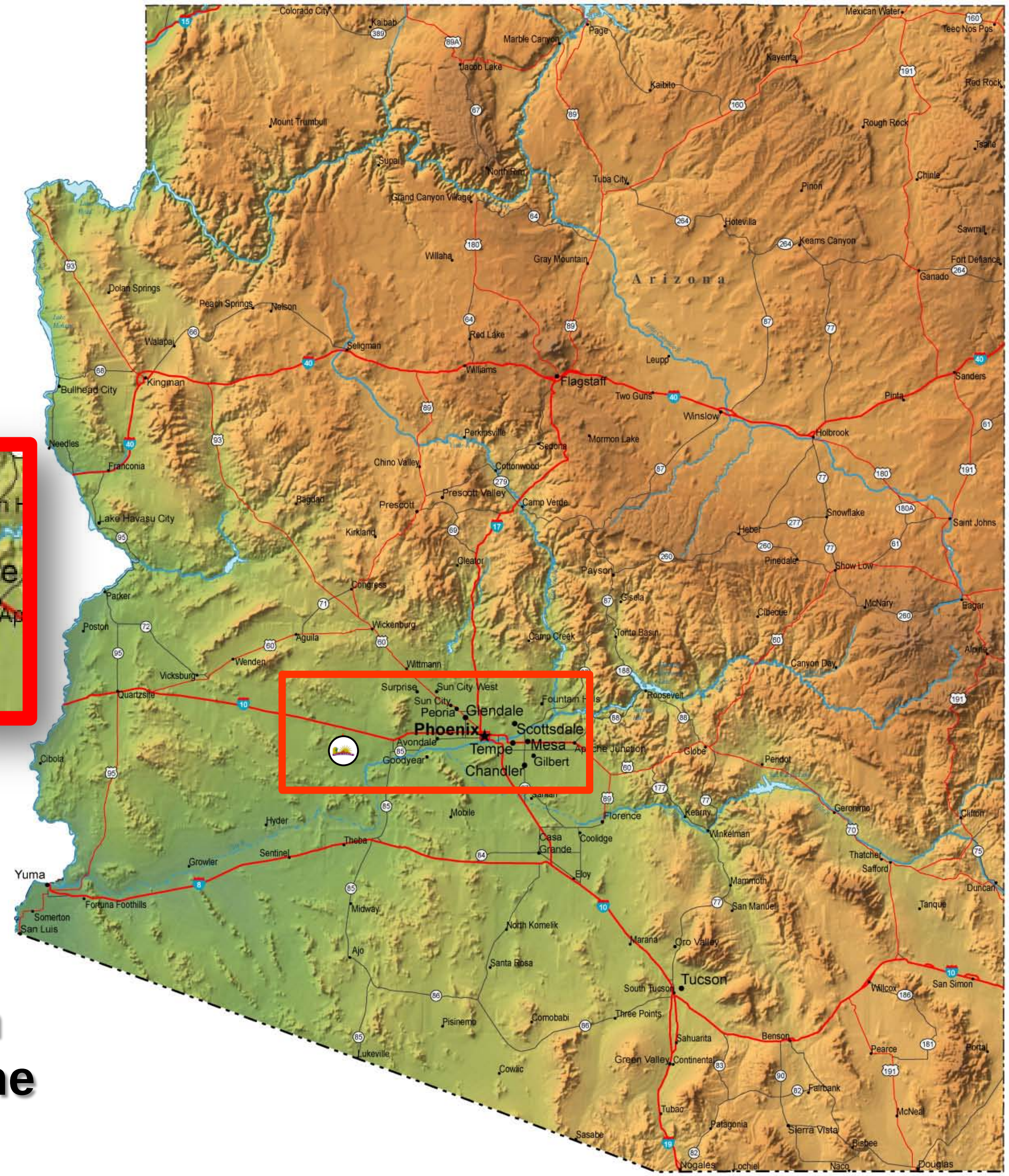
Plant History and Background

- **Initial Construction Permit — May 1976**
- **Operating Licenses for:**
  - Unit 1: June 1, 1985
  - Unit 2: April 24, 1986
  - Unit 3: November 25, 1987
- **3990 MWt / 1390 MWe per Unit**
- **Reclaimed Wastewater Utilized for Condenser Cooling — No Lake, Ocean or River Available**
- **Essential Spray Ponds are Dedicated Ultimate Heat Sink**

Station Description

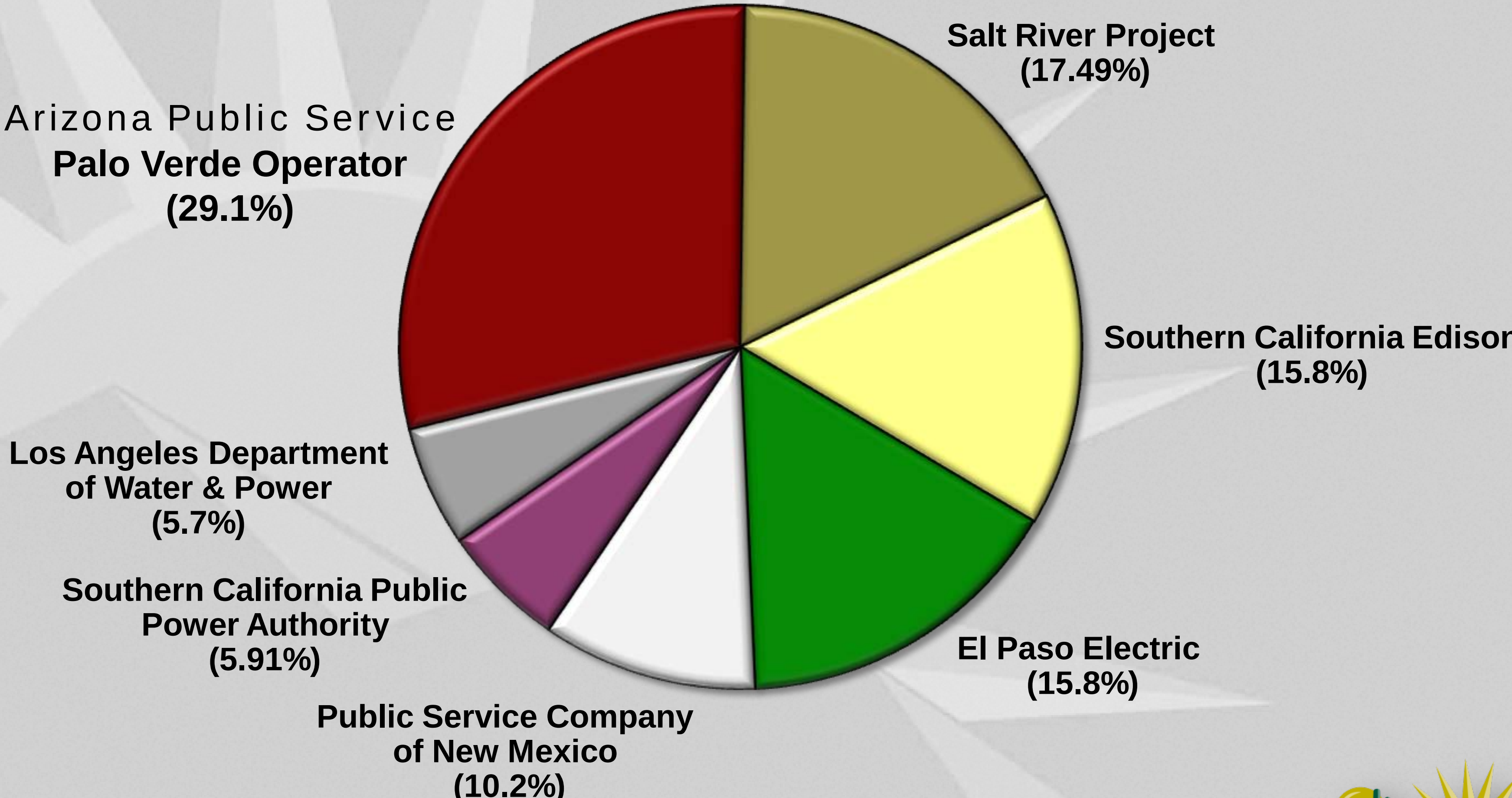
- **Three Common-Design Units**
  – Common Operating Procedures
  – Maintain Common Design
- **Combustion Engineering System 80 — Nuclear Steam Supply System**
- **General Electric — Turbine Generator**
- **Bechtel Power Corporation — Architect and General Contractor**
- **Water Reclamation Facility**
- **Zero Liquid Discharge Plant**

PALO VERDE



Approximately 26 miles from the Phoenix Metro Area, in the Sonoran Desert

Palo Verde Owners



W
S
N
E
Evaporation Pond #3
180 Acres
Evaporation Pond #1
250 Acres
Evaporation Pond #2
220 Acres
Spray Ponds
3
2
1
Water Reclamation
Facility
Reservoirs
PALO VERDE

License Renewal

Mohammad Karbassian

Director
Nuclear Engineering

Major Improvements

- **Steam Generator Replacement**
- **Power Uprate (5% total)**
- **Low Pressure Turbine Rotor Replacement**
- **Digital Feedwater Control System**
- **Core Protection Calculator (CPC) Replacements**
- **Reactor Vessel Head Replacement**
  - Unit 3 in Fall 2010
- **Alloy 600 Replacement / Dissimilar Metal Weld Management**
- **Evaporation Ponds, Reservoirs**

Equipment Reliability

- **Site Top 10 Process**
  - Completed
    - Auxiliary Feedwater Pump Steam Admission Bypass Valve Replacement
    - Control Room Chart Recorders
  - Planned
    - Essential Spray Pond Chemical Addition
    - Charging Pump Reliability
    - MSIV/FWIV Accumulator Margin
    - Essential Spray Pond Repairs

Long-Range Planning

- **Main Generator Stator and Rotor Rewinds**
- **High Pressure Turbine Upgrades**
- **Cooling Tower Life Cycle Management**
- **Transformer Refurbishment / Replacement**
- **Large Motor Refurbishment / Replacement**
- **Polar Crane Modifications**

Angie Krainik

Department Leader
License Renewal

License Renewal Application STARS Center of Business

- **Strategic Teaming and Resource Sharing (STARS) Alliance "Center of Business"**
  - Seven large PWR stations in Region IV
  - Center of Business created to prepare License Renewal Applications for the member utilities
- **Involved with Generic Aging Lessons-Learned Report (GALL) Updates (Rev 0, Rev 1 and Rev 2)**
- **Leadership, Oversight and Ownership by Palo Verde Personnel Throughout the Development and Review Phases, Continuing Through Implementation**

License Renewal Application Development

- **Scoping and Screening**
  - Consistent with 10 CFR Part 54 and NEI 95-10
  - Utilized site component design databases, controlled drawings, design and licensing documents
  - In-scope structures, systems and components screened to determine if Aging Management Review required
- **Aging Management Review**
  - Consistent with 10 CFR Part 54 and NEI 95-10
  - Utilized GALL Report (Revision 1) and other industry reports
  - Incorporated Operating Experience
    - Plant-specific (13+ years)
    - Industry (NRC Generic Communications)
  - Results are greater than 94% consistent with GALL Report

Time-Limited Aging Analyses (TLAAs)

- **Reactor Vessel Neutron Embrittlement**
- **Metal Fatigue Analysis**
- **Environmental Qualification**
- **Concrete Containment Tendon Pre-stress**
- **Containment Liner Plate and Penetrations**
- **Plant-specific TLAAs**
  - Cranes, Lifts and Fuel Handling Equipment
  - Corrosion Allowance – Pressurizer Nozzle Repairs
  - Building Settlement

License Renewal Program Status

- **Aging Management Programs**
  - 29 existing
  - 11 new
- **65 Procedures Required to Implement Aging Management Programs**
  - 59 existing procedures
    - 45 currently revised
    - 12 revisions in progress
    - 2 revisions yet to start
  - 6 new procedures
    - 3 complete
    - 3 in final review

License Renewal Commitments

- **Tracked in Palo Verde Regulatory Commitment Tracking System (RCTS)**
- **Tracked Commitments Include:**
  – Current ongoing programs and procedures credited for License Renewal implementation
  – Future actions to be completed prior to and during the period of extended operation
- **RCTS and Procedural Controls**
  – Ensures changes to Implementing Procedures and Programs are reviewed for License Renewal impact

Implementation and Sustainability

- **Implementation Staff**
- **Participating in NEI License Renewal Implementation Working Group**
- **Benchmarking Others in the Industry**
  - Lessons-learned captured
- **Leveraging STARS Alliance Knowledge and Experience**
  - Self-assessments
  - Audits
  - Share Operating Experience

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Safety Evaluation Report

Open Item

- **Metal Fatigue**
  - "The staff requires further information to reach a conclusion on the proposed metal fatigue analysis as discussed in detail in SER Section 4.3."
- **Clarification of Metal Fatigue Analysis**
  - Common terminology with Current Licensing Basis and Updated Final Safety Analysis Report transients
  - Transient cycle count updates
  - Details of fatigue analysis
- **Metal Fatigue Aging Management Program is an Extension of the Existing Fatigue Monitoring Program**

Rich Schaller

Metal Fatigue Lead

PALO VERDE

Metal Fatigue Topics

- **Current and Enhanced Metal Fatigue Program Attributes**
- **Commitments**
  - Program enhancements (Commitment 39)
  - RAI response related (Commitments 57 and 58)
- **SER Open Item 4.3-1**
  - Status of responses
  - Palo Verde's grouping of request for additional information (RAI) responses

Program Enhancements

Commitment 39

ATTRIBUTE	CURRENT PROGRAM	ENHANCED PROGRAM
UFSAR 3.9.1 Transient Counting	Cycle Counting (CC)	No Change
Pressurizer Spray Nozzle Cumulative Usage Factor (CUF) Calculation	Cycle-based Fatigue (CBF) Partial Cycle	No Change
Class 2 and 3 Components with Class 1 Fatigue Analysis Monitoring	CC	No Change
Action Limits	90% of Design Cycles and 0.65 CUF for Pressurizer Spray Nozzle	Specific to Design Cycles and Component CUF
Corrective Actions	Evaluation (CAP)	Predetermined (CAP)
NUREG/CR-6260 Location CUF Monitoring	Not Required	CC, CBF and Stress Based Fatigue
Fatigue Monitoring Software	NO	YES

Metal Fatigue Commitments

- **Commitment 39**
  – Implement enhancements to Metal Fatigue of Reactor Coolant Pressure Boundary Program
- **Commitment 57 and 58**
  – Confirm conservatism of nickel alloy environmental factor using NUREG/CR-6909 methods and use appropriate value to evaluate pressurizer heater penetration weld environmental fatigue usage

Metal Fatigue

Requests for Additional Information (RAIs)

- **Responses to the 18 RAIs on Metal Fatigue Were Provided in Correspondence**
  – June 29, 2010 and August 12, 2010
- **Palo Verde Grouped RAIs into Three Categories:**
  – Clarification
  – Additional technical information
  – Alternate approach
- **Palo Verde Has Provided Information Requested**

Angie Krainik

Department Leader
License Renewal

Safety Evaluation Report

Confirmatory Items / Submittal Dates

- **Application of the Scoping Criteria**
  - Spray Chemical Addition Tank Draining / August 27, 2010
- **Flow-Accelerated Corrosion Program**
  - Cavitation in Carbon Steel Piping / September 3, 2010
- **One-Time Inspection of ASME Code Class 1 Small Bore Piping**
  - Small Bore Socket Weld Inspections / September 3, 2010
- **Wall Thinning Due to Flow-Accelerated Corrosion**
  - Steam Generator Feedring Material / July 30, 2010
- **AMR Results Consistent with GALL Report**
  - Elastomeric Components in Auxiliary Systems / July 30, 2010

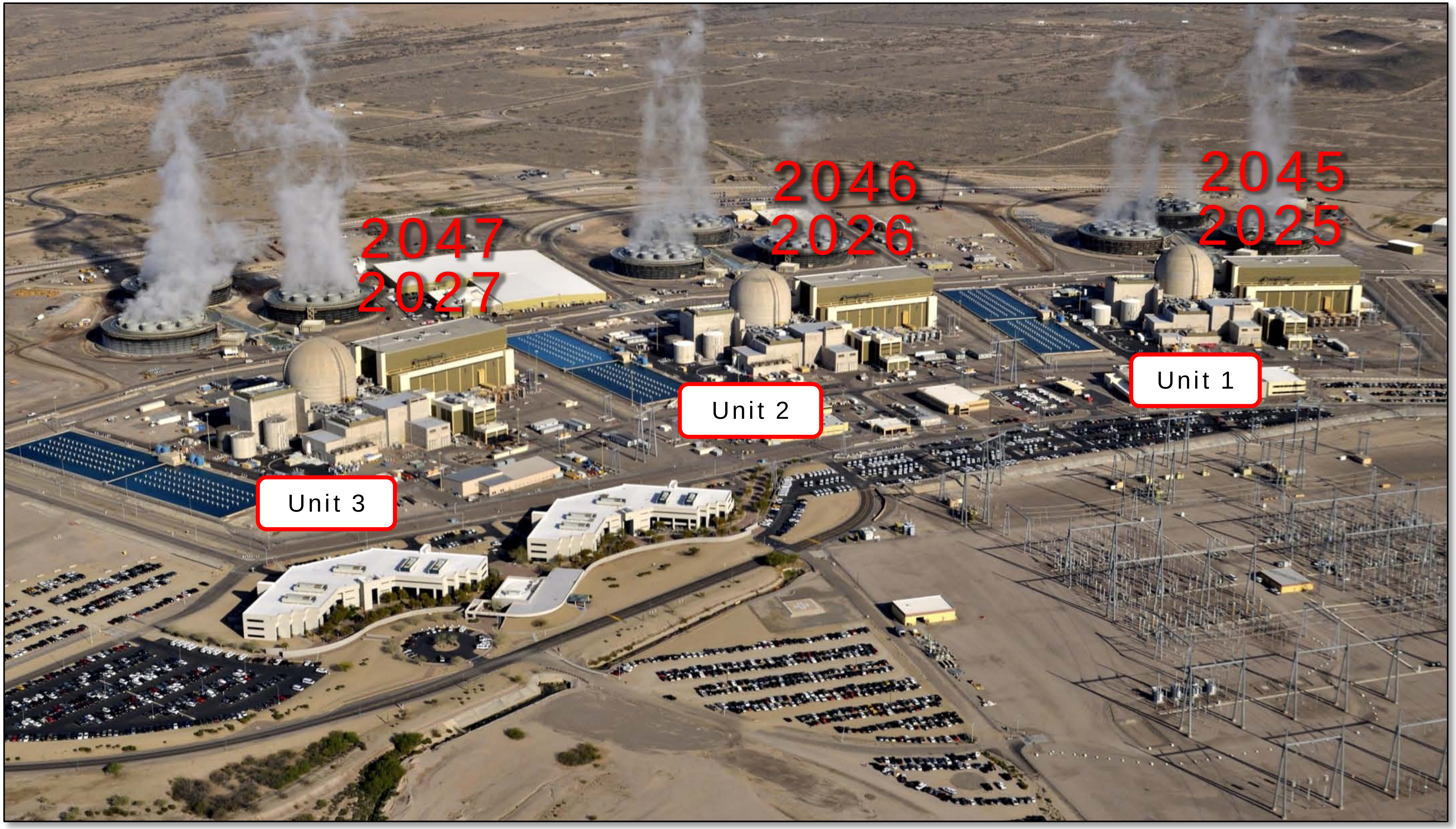
Regional Inspection Unresolved Items

- **Unresolved Items Closed — NRC Inspection Report Number 2010010, Dated 8/5/2010**
  - – Impact of Recent Operating Experience on Metal-Enclosed Bus Program (2010007-01)
  - – Structures Monitoring Frequency and Scope (2010007-02)

John Hesser

Vice President
Nuclear Engineering

License Renewal



Our Mission…

<u>SAFELY</u> and efficiently ***<u>generate</u>*** electricity for the ***<u>long term</u>***.

PALO VERDE

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Protecting People and the Environment

Advisory Committee on Reactor Safeguards

License Renewal Subcommittee

Palo Verde Nuclear Generating Station

Safety Evaluation Report with Open Item

September 8, 2010

Lisa Regner, Project Manager
Office of Nuclear Reactor Regulation

Introduction

- Overview
- Section 2: Scoping and Screening Review
- License Renewal Inspections
- Section 3: Aging Management Program and Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)

Overview

- LRA Submitted by letter dated December 11, 2008, as supplemented on April 14, 2009
- Power Uprates – 5 percent from original licensed thermal power
- Operating licenses expire:
  - Unit 1: June 1, 2025
  - Unit 2: April 24, 2026
  - Unit 3: November 25, 2027
- Located about 26 miles west of Phoenix, AZ

Overview

- Scoping and Screening Methodology Audit
  - October 19 – 23, 2009
- Aging Management Programs (AMP) Audit
  - December 7 – 11, 2009
- Regional License Renewal Inspections
  - February 1 – 5, 2010
  - February 22 – 26, 2010

Overview

Safety Evaluation Report with Open Items was issued August 6, 2010

- 1 Open Item
- 5 Confirmatory Items
- 2 Additional Items

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Section 2: Structures and Components Subject to Aging Management Review

Section 2.1 - Scoping and Screening Methodology

Section 2.2 - Plant-Level Scoping Results

Section 2.3 - Scoping and Screening Results: Mechanical Systems

Section 2.4 - Scoping and Screening Results: Structures

Section 2.5 - Scoping and Screening Results: Electrical and Instrumentation & Control Systems

Confirmatory Item

- Containment Spray Chemical Addition Tanks
- Piping cut, capped and abandoned in place
- Not verified dry, found to contain liquid hydrazine
- Applicant committed to drain by August 30
- Modified the commitment to drain by November 30

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Section 2: Structures and Components Subject to Aging Management Review

Staff concludes that, **pending resolution of the confirmatory item**, the applicant has appropriately identified the systems, structures, and components in accordance with 10 CFR 54.4(a), and those subject to an AMR in accordance with 10 CFR.54.21(a)(1).

License Renewal Inspections

Greg Pick

Region IV Inspection Team Leader

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Regional Inspections

Overview

- Five Inspectors for 2 weeks
- Scoping & Screening Inspection
- Aging Management Programs Inspection
- Follow-up In-office Inspection

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Regional Inspections

Inspection Results

- Scoping of nonsafety-related systems
- Aging Management Programs
- Structural Monitoring

Plant Performance

- Licensee Response Column
- Good material condition

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Regional Inspections

Inspection Conclusions

- Scoping of non-safety SSCs and application of the AMPs to those SSCs were acceptable.
- Reasonable assurance exists that aging effects will be managed and intended functions maintained.
- Applicant established a schedule for structural inspections to provide data for comparison prior to entering the PEO.

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Section 3: Aging Management Review Results

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

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Section 3.0.3 - 40 AMPs Evaluated

	Plant Specific	Consistent with GALL	With Exception	With Enhancement	With exception & enhancement
Existing 29	1	9	5	10	4
New 11	0	7	4	0	0

Confirmatory Items

- Cavitation Erosion
- Small Bore Piping Socket Welds
- SG Flow Accelerated Corrosion
- Aging Management of PVC Piping and Elastomer-Lined Piping

Section 4: Time-Limited Aging Analysis

- 4.1 Introduction
- 4.2 Reactor Vessel Neutron Embrittlement
- 4.3 Metal Fatigue Analysis
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Concrete Containment Tendon Prestress Analysis
- 4.6 Containment Liner Plate, Equipment Hatch and Personnel Air Locks, Penetrations, and Polar Crane Brackets
- 4.7 Other Plant-Specific TLAA

Metal Fatigue Review

- Original LRA Incomplete
- Numerous Follow-up Discussions
- Public Meeting, May 6, 2010
- 7 LRA Amendments

Metal Fatigue TLAA Open Item

- Cycle Counting Issues
- Fatigue Analyses Disposition
- Environmental Factors

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Additional Issue

Inaccessible Low Voltage Power Cables (Non-EQ)

- Current AMP covers <u>medium-voltage</u> cables (2KV-35KV)
- GL 2007-01 indicated <u>low-voltage</u> cables have aging-related failures (480V – 2KV)
- Staff concern that inaccessible low-voltage cables need to be part of an AMP
- Staff plans to issue RAI to the applicant

Additional Issue

Buried Piping and Tanks Inspection Program

- Given recent industry OE related to leaks from buried and underground piping, staff is interested in efforts to incorporate OE into AMPs
- Staff issued an RAI, applicant responded
- Applicant revised AMP for visual inspections
- Staff plans to issue follow-up RAI for details

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Conclusions

The staff's conclusion regarding the LRA for PVNGS will be provided in the SER scheduled to be issued in December of 2010.