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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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PLANT LICENSE RENEWAL SUBCOMMITTEE

DIABLO CANYON POWER PLANT

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WEDNESDAY

FEBRUARY 9, 2011

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2-B1, at 1:30 p.m., Dennis C. Bley, Chairman, presiding.

COMMITTEE MEMBERS:

DENNIS C. BLEY	Chairman
SAID ABDEL-KHALIK	Member
J. SAM ARMIJO	Member
SANJOY BANERJEE	Member
MICHAEL L. CORRADINI	Member

HAROLD B. RAY Member

MICHAEL T. RYAN Member

WILLIAM J. SHACK Member

JOHN D. SIEBER Member

JOHN W. STETKAR Member at Large

ACRS CONSULTANTS PRESENT:

JOHN J. BARTON

NRC STAFF PRESENT:

NATHANIEL FERRER, NRR

MELANIE GALLOWAY, NRR/DLR

STAN GARDOCKI, NRR/DSS

ALLEN HISER, NRR/DLR

BRIAN HOLIAN, NRR/DLR

WILLIAM HOLSTON, NRR/DLR

JAMES MEDOFF, NRR/DLR

NEIL O'KEEFE

GREG PICK, Region IV

JEFF POEHLER, NRR/DSI

DAVE WRONA, NRR/DLR

MICHAEL BENSON, Designated Federal Official

ALSO PRESENT FROM PG&E

MICHELLE ALBRIGHT

CHRIS BEARD

JIM BECKER

DAVID GERBER, Structural Integrity Associates

DAVID GONZALEZ

JOE GORYANCE

LEE GOYETTE

TERRY GREBEL

DANIEL HARDESTY

MARK MAYER

DAVE MIKLUSH

CHALMER MYER

LOREN SHARP

MIRANDA TAN

RYAN WEST

DAVID WONG

MIKE WRIGHT

TABLE OF CONTENTS

AGENDA ITEM	PAGE
Opening Remarks, Dennis Bley, ACRS	6
Staff Introduction, Brian Holian	7
PG&E Company - Diablo Canyon Power Plant:	
Introductions; Site & Station Descriptions, Jim Becker	13
History/Major Improvements, Loren Sharp	18
License Renewal Application; Open and Confirmatory Items, Terry Grebel	20
Flux Thimble Tube Inspection Program (Open Item), Mike Wright	29
Flaw Growth Evaluation for RHR (Open Item), Dave Gonzalez	39
Scoping and Screening (Open Items); Buried Piping and Tanks Inspection Program (Open Item), Dave Miklush	55
TLAA Identification and Metal Fatigue (Open Items), Michelle Albright	66
NRC STAFF: Nathaniel Ferrer, Greg Pick	
SER Overview and Scoping and Screening Results; Onsite Inspection Results	81
Aging Management Review; and Time Limited Aging Analyses	102
Subcommittee Discussion	141

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

Time: 1:30 p.m.

CHAIRMAN BLEY: The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee of the Advisory Committee on Reactor Safeguards.

I am Dennis Bley, Chairman of the Subcommittee. ACRS Members in attendance today are Bill Shack, Mike Ryan, John Stetkar, Said Abdel-Khalik, Sam Armijo, Harold Ray and Jack Sieber.

We have Tom Barton as our consultant, and Michael Benson is the Designated Federal Official for this meeting.

The Subcommittee will review the License Renewal Application of the Diablo Canyon Power Plant, Units 1 and 2, and the associated SER with open items. We will hear presentations from the NRC staff and Pacific Gas and Electric, PG&E.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting. I will mention that the next-door conference room is also following this meeting on the TV

screens. There is an overflow audience today.

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, as appropriate, 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 the meeting is being kept, and will be made available as stated in the Federal Register Notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee. The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

We will now proceed with the meeting, and I call upon Brian Holian to begin.

MR. HOLIAN: Thank you, Chairman, and thank you -- Good afternoon, Subcommittee. My name is Brian Holian. I am the Director of the

Division of License Renewal, and we are here today for the Diablo Canyon Subcommittee meeting.

I will make brief introductions and then quickly go over the agenda and turn it over to the licensee for their part of the presentation.

To my left is Melanie Galloway, the Deputy Director for Division of License Renewal. Behind us -- I will just make a couple of introductions, and we will repeat a few and add a few for when our people come to the table, but I wanted to mention that Dave Wrona is the Branch Chief for Diablo Canyon sitting over there behind the stanchion.

The Project Manager, you will hear more from later, is Nate Ferrer, and we do have two individuals who escaped Region IV and a quarter-inch of snow or whatever they got. The office is closed today, but they got out yesterday on a plane, and that is Mr. Greg Pick, the Senior Inspector from Region IV -- the Committee has seen him before; he had presentations -- and Neil O'Keefe, his Branch Chief. So I welcome them in from the cold of Dallas.

The agenda today, as I mentioned, is to look at Diablo Canyon, the third STARS plan to come in for an application for a license renewal. We had Wolf Creek several years ago, and then Palo Verde, and the full committee will be hearing from Palo Verde tomorrow morning for their final SER and the closure of their open items.

I mention that, because, in particular, some of the items you will see both in Diablo's presentation and the staff's. We have a couple of open items that are still related to scoping, and the Subcommittee might wonder about that.

We did see some issues on Palo Verde's scoping, if you remember back on draft SER, and so I just highlight that. The STARS -- The alliance, the STARS group, was learning from the Palo Verde. Folks are here in the audience from Palo Verde for tomorrow, and we know that, through our license renewal quarterly meetings, those lessons learned get passed on, but their application was already in, and our audits were already going when you see a lot of those RAIs. So I think the Applicant will speak to that a

little bit, but I wanted to mention that.

The second item that I wanted to really mention overall for the Committee -- the Committee is probably aware of it from general correspondence, but I just wanted to highlight it here at the opening. Diablo, being in California, seismic issues are of concern to the local population there and, of course, the staff also.

Last year, as the application came in for Diablo, we got several letters in to the staff requesting a delay, requesting more information be done first. Even the State of California was interested, besides local interested stakeholders, on new information on potential faults or differences in the design basis.

I just wanted to highlight that to the Committee. We addressed that in a July letter from the Director of NRR to the stakeholders, saying that those issues would be best dealt with under Part 50. They are current issues. Right now, their current licensing basis is -- although there might be questions on it -- not called into effect.

The staff even looked at a new potential fault back in the '09 time frame. That was the subject. So I just wanted to make the Committee aware that we and the Region have had several public meetings out in the California area to address that potential stakeholder item. So you will see correspondence on that as you look through the docket, but we consider it a Part 50 issue.

If at anytime that design basis changes, we would be able to either -- if it happened during the license renewal, be able to supplement an SER, if that was needed to be, or after the fact still do it under Part 50 processes to address their licensing basis.

With that, I will turn it over to the Applicant, who has the first part. Go ahead.

MEMBER SHACK: Can I ask you a generic question. I was looking. You know, they came in with the usual language about PWR internals, and I was trying to remember. I saw Ginna submitted an inspection plan. Was that approved?

MR. HOLIAN: Allen Hiser, I will have address that during -- or Jim Medoff, if you want to wait for our staff presentation.

MEMBER SHACK: Yes.

MR. HOLIAN: During our staff presentation, we will address that. I know it has come up recently in the GALL.

MEMBER SHACK: Yes. The GALL actually has guidance, and that was the next question, is when were you expecting licensees to actually pick up that GALL guidance and incorporate it in their documents?

MR. HOLIAN: Yes. We have been -- I will address that more in depth in our presentation, but in general, Diablo has come in here, and now there are seven to nine open items. I know the committees have seen us recently taking our time and asking additional questions to get plants that are in-house up to the significant items of GALL, Rev. 2, which we issued last December.

The staff did a kind of an in depth look through the significant items in there, and for the plants in-house, we thought it most appropriate, while we have the SERs in process, to ask those additional requests for information, even if they submit it under GALL Rev 1. We just thought it is the right thing to do.

Utilities have responded well to that. So in general, we have done that, bringing all the plants in-house up to that. So I will address it in particular on the MRP and internals during our presentation.

With that, I will turn it over to Mr. Jim Becker, the site VP for Diablo Canyon.

MR. BECKER: Thank you, Mr. Holian. So I am Jim Becker. I am the site Vice President at Diablo Canyon, and on behalf of the STARS and PG&E team, it is our pleasure to be here today. We look forward to a good presentation and some good questions and answers, and that is our purpose here today.

I would like to start off with some introductions. As I said, I am Jim Becker, the site Vice President.

MR. SHARP: I am Loren Sharp, Senior Director of Technical Services.

MR. WRIGHT: Mike Wright, Mechanical Systems Engineering Manager.

MR. GREBEL: Terry Grebel, License Renewal Project Manager.

MR. BECKER: Thank you. And in addition to the folks up here in front of you, we

have a fairly large contingent that has come out to Washington, D.C., with us, and those are members both of the STARS Center of Business and of our own plant staff, and they have been very instrumental in preparing the application, responding to the requests for information, and will assist us in our presentation and answering questions here today.

Our agenda for the day: We are going to start off with Loren and I giving the Subcommittee an overview of the site, our history, major improvements, etcetera, that have occurred at the site.

Then Terry Grebel will briefly cover GALL consistency and commitments, and with that complete, we are then going to go into some more detailed presentation about the open items, and those are the items you see in front of you there on the agenda.

Then when we are done with that, I will have some brief concluding remarks. So that is the agenda that we have planned for you today.

This slide shows a site description, and I thought it would be good for the Subcommittee to review with us some basic facts

about the site.

Diablo Canyon is located on the central California coast. It is about halfway between Los Angeles and San Francisco. What you see here is the coastline at the site. Miranda has highlighted the Diablo Canyon site itself there.

There are about 13,000 acres in the Diablo Canyon lands that PG&E now owns, and the boundary for the company owned property is shown as the dark black line there. The closest town of any size is the town of Avila Beach, and Miranda is now highlighting that.

That is a quick overview of our location on the central coast of California.

DR. BARTON: What is the population of Avila Beach?

MR. BECKER: As a resident of Avila Beach, I will tell you that the population is, I believe, three to four thousand people. It has grown a fair amount in recent years into the hillsides outside the direct village.

Okay. Moving on to this site description slide, this is an aerial photograph, and I thought it would be worthwhile to review

the basic layout of the site here.

So what you see here are the containment structures, Units 1 and 2. Unit 1 lies to the north. They share a common turbine building that you see laid out there in the picture.

We take suction at the intake, and the units share a common intake structure, and they also share a common discharge structure that you see in the picture. Of course, we have an administration building.

Most of the make-up water to the plant -- Actually, all the make-up water to the plant flows through the raw water reservoirs, which are on the hill to the east of the plant, and we recently began dry cast storage operations. So the ISFSI, or interim spent fuel storage installation, pad is just to the south of the raw water reservoirs. We have completed two ISFSI campaigns thus far, one for each unit.

Now a brief station description. So there are two units at Diablo. They share a common operating set of procedures and design. The units are not identical, but they are highly similar. They are both 4 loop Westinghouse units

with a core rating of 3411 megawatts thermal.

PG&E was the architect/engineer for Diablo Canyon. We were assisted in the latter stages of the construction time period by Bechtel, and that got us to the point of an actual operating license.

It is a once-through cooling facility. Each unit has two circ water pumps. At full power, we pump about 1.5 million gallons per minute of ocean water through the condensers and then back out through that common discharge structure that I showed you earlier.

Our containments are free standing, as you see on that slide, steel-lined, reinforced concrete buildings. PG&E is the sole owner and operator for Diablo Canyon.

I mentioned that the plant is on the central California coast. We are at the southern end of the PG&E electric service territory. We do own and operate the switchyards and the high voltage transmission system. PG&E's service territory extends from the Oregon border down to about 50 miles south of where Diablo Canyon is located.

So that competes my overview of the

facility.

MEMBER RAY: Did you say anything about the California ISO?

MR. BECKER: We are subject to -- Our generation is subject to the jurisdiction and regulation of the California Independent System Operator, as has been the case for a bit over 10 years now.

MR. SHARP: Thanks, Jim. I am Loren Sharp. I also welcome the opportunity to appear in front of you to talk about license renewal today. I am the Senior Director of Technical Services, and I will discuss some of the STARS Center of Business, plant history and major improvements at Diablo Canyon.

Slide 9. So the Center of Business was created to form a format of consistency for the seven PWR plants that are getting ready to apply or have applied for license renewal. Therefore, we are providing a standard application with additional quality stemming from applying our operating experience, lessons learned from the other STARS plants.

Diablo Canyon personnel have consistently provided oversight, leadership and

ownership of the licensing renewal process, as well as the implementation of that process continuing into the future.

Slide 10. Unit 1 was issued an operating power license in 1984, with Unit 2 in 1985. There was a change to increase power for Unit 1 to 3411, so that both units are essentially equal, and that is one of the reasons why we have a common license renewal application for both units. We have -- Currently, license expires in 2024 and 2025.

Slide 11.

DR. BARTON: What is the status of the two plants today? Both at 100 percent power?

MR. BECKER: Yes. Both units today are at full power.

MR. SHARP: For the Slide 11, we have done a number of major improvements. I won't go through the list in total, but I would say we have done significant improvements to make sure we maintain our facility. I will discuss just the steam generators and reactor heads that were recently completed to make sure we have the quality of plant that we need as we go into license renewal as well as the continued

operation of our current license.

Now I would like to turn it over to Terry Grebel, our Diablo Canyon License Renewal Project Manager to discuss GALL consistency and some of the commitments made at Diablo Canyon.

MR. GREBEL: Thank you, Loren. Good afternoon. My name is Terry Grebel. I am the Diablo Canyon License Renewal Project Manager. My portion of the presentation today covers the highlights of our license renewal application, including the aging management programs, commitments, open items and confirmatory items.

Slide 13, please. In preparing our license renewal application, we used the GALL Rev. 1 and NEI 95-10 Rev. 6 guidance with the goal of making the application as consistent with this guidance as possible.

In addition, as Brian talked about earlier, the staff has recently asked several RAIs based on recent operating experience. We have been responding to these RAIs as well.

We have a total of 42 aging management programs, 31 of which are existing. Nine are new, and we have two plant specific programs.

Our aging evaluations are greater than

93 percent consistent with GALL Rev 1 (standard notes A through E).

We have 64 license renewal commitments, and these commitments are being tracked through our Diablo Canyon commitment tracking system, which implements the guidance of NEI 99-04.

Slide 14, please.

MEMBER SHACK: There is only 55 commitments listed in the SER. Are these new?

MR. GREBEL: These reflect the latest updated members' responding to the --

MEMBER SHACK: RAIs.

MR. GREBEL: -- to the open items.

MEMBER SHACK: The open items. Okay. Thank you.

MR. GREBEL: We have -- Diablo Canyon SER has eight open items and two confirmatory items. PG&E has submitted responses to all open and confirmatory items. As Brian talked about earlier, the staff is in the process of reviewing these responses.

The eight open items will be discussed further by the other members of the Diablo Canyon team.

MEMBER STETKAR: Terry, I know you are going to discuss the open items. I would like to ask you a couple of questions about confirmatory items, if I could.

MR. GREBEL: I was going to jump into that next.

MEMBER STETKAR: Oh, were you? Okay, I didn't see a slide. Go on. I'm sorry.

MR. GREBEL: The first item dealt with the confirmatory to change our cable testing frequency from 10 years to six years. This aligns it with the GALL Rev 2.

The second item dealt with our spent fuel pool leak chase. We have a leak in Unit 2, a minor leak. We have done some inspections of the leak chases, and we have committed to do another inspection.

The staff had asked -- We said we would do that during the period of extended operation. The staff asked that, to be in the one-year prior, the period of extended operation, and we have since made that commitment.

MEMBER STETKAR: Now my questions. Start from the back first then. Have you made -- You have not made any commitments to do any

inspections, at least from what I have read in the SER, of the Unit 1 spent fuel pool leak chase.

Now I recognize you don't have any identified leakage, but you don't have any identified leakage. So are you confident that indeed the Unit 1 spent fuel pool leak chase is open? I don't know how you measure the flow, through drains or whatever -- that they are indeed open?

In other words, what I am concerned about is do you have leakage that you don't know about and haven't confirmed that indeed your monitoring systems are available over on Unit 1?

MR. GREBEL: We are prepared to address that. Mike, could you address that question, please?

MR. WRIGHT: Sure, Terry. Mike Wright, Engineering.

Both units leak chase systems were visually inspected in the 2006-2007 time frame area, and both units' leak chase valves are opened weekly to verify that we measure the flow, if there is any leakage past the spent fuel pool liners.

Both units' leak chase systems were verified to be free of boron clogging. There was no evidence of blockage on either unit at that time.

MEMBER STETKAR: I know that the amount of leakage on Unit 2 is pretty small, and the amount of leakage, at least what I read on Unit 1, is yet much smaller. But when you open the Unit 1 valves, do you get --

MR. WRIGHT: You get nothing.

MEMBER STETKAR: -- any flow?

MR. WRIGHT: No, sir. When we open the Unit 1 valves on a weekly basis, we get zero flow.

MEMBER STETKAR: You know those lines are open?

MR. WRIGHT: Yes. We inspected them in 2006 time frame with boroscope.

MEMBER STETKAR: With boroscope? Okay. Thanks. That's what I was looking for.

On the cables, I know that you have committed -- With that confirmatory of the six-year testing, you are essentially consistent with GALL Rev 2, I think, with the exception that you are not doing inspections based on event driven

events. If I recall correctly, just you said that there was no evidence of event driven water accumulation. So I believe you took an exception to that element of the inspection program.

I guess my question was: You have had water accumulation in the past, years back. I recognize not in recent years. What was the source of that water, if it wasn't event driven?

MR. WRIGHT: I think, in general, I would like to ask my Engineering Manager, Ryan West, to address that question.

MR. WEST: Ryan West, Engineering Manager, Diablo Canyon.

In the early Nineties, we identified that our pull boxes were full of water resulting in submergence of the cables. The causes that were identified were basically that our pull box drains and sump pumps were not being maintained adequately, resulting in rainwater backing up in the boxes.

MEMBER STETKAR: So it was rainwater?

MR. WEST: That is correct. It was rainwater. We have not seen any evidence of groundwater leaking into the pull boxes.

MR. WRIGHT: Ryan, could you address

the inspection frequency?

MR. WEST: Yes. Right now, we have a bi-monthly inspection of the pull boxes looking for evidence of water in the pull boxes. So it is not quite event driven, but during the rainy season we do look in the boxes on a bi-monthly frequency. We have the ability to defer those once we get out of the rainy season and we are not getting rain.

MEMBER STETKAR: So in a sense, you do some -- if I understand what you just said, you do inspections more frequently in the rainy season.

MR. WEST: That is correct.

MEMBER STETKAR: Okay, thanks. I had one other question on cables, which -- I have too many notes here. Oh, I just wanted to confirm. Do all of your underground cable ducts, conduit runs -- I don't know what the configuration is there -- including whatever low voltage cables that are now in scope, positively drain to low points where you have sump pumps installed?

What I am asking is: Are you confident that you don't have any intermediate low points where water can collect and remain

stagnant without positively draining to some location that you can either inspect or have an installed sump pump?

MR. WEST: So our operating experience has identified that we have some low points in our conduits. Here on Slide 78 is a general layout of our conduit arrangement where there are drains that drain from pull box to pull box to a low point out to a sump area which is drained out to the building sumps.

We have identified dips in the pull boxes. We have done -- We are in the process of completing all of them, but we are doing inspections of the accessible portions of the underground loops. We are also removing the seals at the buildings, and it is promoting air flow through the conduits, which is also helping to keep the conduits free of water, and we are going back after we have done all the inspections in the locations that were identified as containing water, we will verify that we are not getting any in-leakage from damage in the conduits.

MEMBER STETKAR: Thank you. One last question. In your Generic Letter 2007-1

response, you identified a number of cable failures due to water in-leakage. Now I understand that since then you have replaced, I think it said, all of the in-scope medium voltage cables. Have you experienced any underground cable failures since 2007, in other words since that report was filed?

MR. WEST: We have experienced degradation on underground medium voltage cables that had not been replaced. Of the replaced cables, we have not seen any repeat degradation or failures.

MEMBER STETKAR: Thanks.

MEMBER ABDEL-KHALIK: The degradation that you referred to was measured by, what, the 10 delta test?

MR. WEST: Seven of the 11 identified degradations or failures were identified by ground alarms. We have a high resistance grounding system. So we have a single phased ground fault. So it was identified, and the equipment was removed from service, and then subsequently we verified through high-pots that the cable was degraded.

MEMBER ABDEL-KHALIK: Are you sure it

is cable degradation versus a connection degradation?

MR. WEST: Can you clarify that a little bit for me?

MEMBER ABDEL-KHALIK: The connections between cable segments -- Are you sure that, really, the problem is with the cable segments themselves or with the connections between segments?

MR. WEST: So we are confident it was the cables themselves. We don't typically have splices in the underground portions of the cables. So we are able to isolate and validate that it is the cable itself.

MEMBER ABDEL-KHALIK: Okay, thank you.

MR. SHARP: So, Mike Wright is the next presenter on flux thimble tube.

MR. WRIGHT: Thank you, Loren. Good afternoon, Mr. Chairman, Committee members. My name is Mike Wright, Mechanical System Engineering Manager at Diablo Canyon. I have been at the plant for 22 years and in Engineering for the last 10, for 10 years.

I will be presenting some background information on a flux thimble tube leak that

occurred in 2006, a status one open item associated with flux thimbles.

Slide 16, please. Unit 2 thimble tube L-13 leaked approximately four months following refueling outage 2R-13 in 2006. The tube had been in service for a little more than three cycles. This graphic depicts the approximate location of thimble tube L-13, and the magenta boxed area would be the approximate location.

Historically, L-13 was capped in 1990 following refueling outage 2R-3, remained out of service for over 10 years until it was replaced in 2001 with a tube having a 15-inch chrome band designed to be centered around the highest wear location, which is the bottom nozzle of the fuel assembly.

Slide 17, please. More history: In 2004, 2R-12, we measured approximately 47 percent wear outside of the chrome band of this thimble tube, approximately five feet below the bottom nozzle, and the tube was pulled out five inches to relocate the wear spot.

Again in 2006, the subsequent outage, 2R-13, we measured 44 percent wear in the same thimble tube in a similar location, and the tube

was pulled out an additional five inches, again to move the wear spot.

These two pulls resulted in exposing the non-chrome plated portion of the thimble tube to be bottom nozzle, the higher wear area of the fuel assembly. Approximately four months following 2R-13, L-13 leaked. The leakage was isolated by closing a valve at the seal cable.

Slide 18, please. Now I will address the open item. There are two aspects of the open item, the first being that the Diablo acceptance criteria does not specifically include a value for instrument and wear scar uncertainty. We were asked to verify that we have the appropriate margin to account for them.

Resolution: Diablo wear methodology was compared to the Westinghouse industry standard, the WCAP-12866 or thimble tube eddy current testing using our site specific wear data. The result of that analysis is that Diablo wear projection methodology was slightly more conservative than the WCAP.

The Westinghouse war projection methodology acceptance criteria is 80 percent, which does include instrument uncertainty, and

currently our wear projection methodology or acceptance criteria is 68 percent, which does not include uncertainty.

The difference between those two is 17.5 percent, more conservative than the Westinghouse industry standard. Typical values used for uncertainty are 10 percent. We believe our 17.5 percent margin from the industry standard represents adequate margin to account for instrument and wear scar uncertainties.

As a result of the L-13 cause analysis, again from cycle 14, we have added additional nonlinear wear acceptance criteria that I will describe in a couple of slides. In total, we believe that the combination of the 68 percent wear in addition to the nonlinear acceptance criteria is both conservative and comprehensive.

MEMBER STETKAR: Mike, let me just make sure I understand this slide, and from what I read in the SER.

You are now proposing a 68 percent wear acceptance criteria, and is that -- I know, from what I read, you used to have that, and then the WCAP was issued, and it sounded like you had

increased it to -- I don't know whether it was 78 percent or 80 percent or something like that.

As a resolution of the open item, you are now dropping back to the 68 percent. Is that correct?

MR. WRIGHT: No, sir. We have had 68 percent the entire time. We got the WCAP in the Nineties, which said 80 percent. We did not adopt that number.

MEMBER STETKAR: Oh, I guess I misunderstood what I read in the SER, because it sounded like you had increased that limit, and that is what the staff was concerned about, that that 80 percent wear limit did not adequately account for the uncertainties, but you have --

MR. WRIGHT: We have got the 68 percent number. What we did do was remove the uncertainty penalty, and that is the area that we are still working with the staff to --

MEMBER STETKAR: So you are actually still negotiating with the staff over this. It is still an open item.

MR. WRIGHT: Still working with the staff to get a resolution.

MEMBER STETKAR: Thank you. That

helps.

MR. WRIGHT: Slide 19, please. The second aspect of the open item requests the additional information on the L-13 cause evaluation and corrective actions.

In 2R14, L-13 was removed from the plant in 2$14 following eddy current testing examination. There were two high wear locations that were identified greater than 90 percent on the L-13 with eddy current examinations.

One was in the highly radioactive region at the bottom nozzle of the fuel assembly, and the other about five feet below the lower core plate in the vicinity of the previously identified wear.

When we cut the tube out to remove it from the plant, we inspected both portions, the highly radioactive one by video camera since it was highly radioactive, the other one by touch, by feel. Due to the feel of the tube at the location five feet below the lower core plate, we felt that was the wear or the through-wall leak, and that is the piece that we sent off to Westinghouse to be examined by destructive testing.

During that examination by Westinghouse, it was determined that the three-foot section we sent to them did not contain the throughwall leak. However, it did contain the 90 percent wear location leak as well as both the 47 and 44 percent wear location.

The signatures on the eddy current test of both the 90 percent, the graded 90 percent locations, were similar, and the cause of the wear of the tube that we did send to Westinghouse was determined to be flow induced wear.

Based on this determination and the similarity of the two 90 percent wear locations of the tube and previous Diablo tube violations that we had sent back to Westinghouse -- we sent tubes back to them in the early Nineties in the development of the WCAP-12866 -- the cause was determined to be flow induced wear and plant practices that allowed multiple repositioning of thimble tubes.

Repositioning of L-13 exposed the non-chrome plated portion of the tube to the bottom nozzle, and then we have been doing eddy current testing since 1R3, 2R3, and in all that time flow

induced wear is the only degradation mechanism found at Diablo. Cracking has not been identified in any of the eddy currents examinations performed.

Slide 20, please. In resolution, this is the slide that I referred to previously. The corrective actions to prevent reoccurrence from the root cause evaluation resulted in additional acceptance criteria to address the non-linear wear. They include: A thimble must be removed from service or repositioned if we experience greater than 25 percent wear per year, or a tube has two wear scars greater than 40 percent.

Additionally, a tube may only be repositioned six inches, and they may only be repositioned once. I note that each of --

MEMBER ABDEL-KHALIK: If the mechanism is indeed flow induced wear, do you have any idea what the extent of your lower plenum anomaly is?

MR. WRIGHT: Well, we detect the degradation through 100 percent eddy current testing. So we know the status of --

MEMBER ABDEL-KHALIK; Lower plenum flow anomaly was in the core.

MR. WRIGHT: I'd like to get some help

from Mr. Mark Mayer, please.

MR. MAYER: My name is Mark Mayer. I am at the Diablo Canyon staff.

We have some information on the lower plenum anomaly, but we do not really see any indications of a strong lower plenum anomaly, and we can get you additional information, if you would like that.

MEMBER ABDEL-KHALIK: And what would be your indications that you are looking for?

MR. MAYER: I would have to get back to you on that particular question.

MR. SHARP: The current charts we do have that shows the number of them that are still at that same --

MR. BECKER: Yes. I think that would give you some information about it.

MR. WRIGHT: Miranda, if you could move to slide Number 70. Slide 70 depicts the current status of all 58 thimble tubes in both units. It represents that approximately half of the thimble tubes in both units are original, non-chrome plated thimble tubes with minimal wear located in various locations, and the remaining half are locations where we have replaced them

with either 15-inch chrome plated thimble tubes or a full 12-foot chrome plated thimble tube, and then 11 of the tubes, total tubes, are either capped or the guide tube is attached.

So the flows vary in the lower portion of the lower internals. Again, essentially we used our eddy current testing to determine the locations where we need to put the hardened outside thimble tubes.

I would like to go back to Slide 20, please, Miranda. In addition, the -- Each of these four acceptance criteria individually would have resulted in removing thimble tube L-13 from service in 2R13.

Since application of these new non-linear acceptance criteria, 31 tubes have been removed from service in the last five refueling outages. Of these 31 tubes, 67 percent were due to this exceeding the non-linear wear criteria. So the message here is the additional criteria we put in place has been effective in identifying tubes to replace.

When we do replace them, we replace them with Westinghouse supplied 12-foot chrome plated band to cover the entire area in the lower

head up through the bottom nozzle.

Diablo Canyon, again, has not observed any wear in a chrome plated portion of thimble tubes.

Slide 21, please. In conclusion, PG&E is confident that the 68 percent acceptance criteria, in combination with the additional non-linear acceptance criteria, is both comprehensive and conservative.

MR. SHARP: the next presenter is David Gonzalez, my ISI supervisor at Diablo Canyon.

MR. GONZALEZ: Good afternoon. My name is David gonzalez, and I am the ISI Supervisor at Diablo Canyon. Today I am going to discuss the open item addressing the 1997 flaw analysis for Unit 1 piping weld, and the reason that this flaw analysis did not address the stress corrosion cracking.

In support of this discussion, I will present PG&E's basis for concluding that this flaw was not service related and, hence, did not need to be analyzed for a stress corrosion cracking flaw growth.

Please note that we had previously

submitted and discussed additional information regarding this open item.

MEMBER ARMIJO: This is a stainless steel pipe?

MR. GONZALEZ: Yes, and I will discuss the characteristics and the isometric drawing.

MEMBER ARMIJO: And what grade of stainless steel is this?

MR. GONZALEZ: It is 304, and that will be depicted on the following slide. So first I would like to describe this piping system. Miranda, Slide 24, please.

So this line is the residual heat removal system, stainless steel pipe, 12 inches diameter, and about .4 inches thick. The specific weld I am addressing is identified as WIC-95, and is pipe to tee weld and as shown on this isometric drawing, Miranda is highlighting that location now.

It is located in our auxiliary building in our 100-foot penetration room. This RHR's line's function is to supply flow to the reactor coolant system, hot legs 1 and 2, in the event it is needed post-accident.

This line would not normally see flow,

as it is not a standard at-power or refueling outage alignment. I would only see check valve testing operations, and that is typically one time per outage.

A routine ISI -- ultrasonic examination in 1997 discovered an indication in this weld. The indication was ultrasonically dimensioned as approximately .4 inches long and approximately .2 inches in through-wall dimension, and it was plotted to be in close proximity to the ID of the pipe.

Slide 25, please. This slide is a graphic representation of the pipe to tee configuration and the location of the indication I am discussing.

So in answer to your question, sir, the tee is 403 wrought 304 stainless steel. So it a wrought tee, and the pipe is also, as depicted there on the righthand side. That is a 12 inch Schedule-40 stainless steel, also 304, and the weld material would be our ER 308.

So the indication we are discussion as at approximately 90 degrees on the pipe side of the tee, on the pipe side of the weld. This 12 inch line would eventually tie into the

containment flow path and into the loop 1 and 2 hot legs.

So at the time of the indication's discovery, Diablo Canyon's UT level 3s compared the recorded dimensions of this reflector to ASME Section 11 Code acceptance criteria.

MEMBER ARMIJO: Now that flaw was not detected during post-fabrication inspection?

MR. GONZALEZ: Actually, there was flaws, and I will discuss that also. There was flaws detected for insufficient penetration during the initial construction radiography, and there was notes that there had been repairs on that weld for insufficient penetration, and that factored into similar confusion regarding the nature of this flaw.

So when the dimensions of the reflector were compared to the ASME Section 11 Code acceptance criteria, it was found not to be within the standard code table acceptance limit. At this time, supplementary ultrasonic and radiographic examination techniques were applied to attempt to ascertain the size and the nature, the character, of this reflector.

Construction period radiographs were

also reviewed. As I had noted, there had been repairs on this weld during construction for insufficient penetration. However, we were not able to positively match up the RT number belt locations and the repairs to this reflector that we had recently recorded.

This information was immediately entered into our corrective action program, and an engineering analytical evaluation, as allowed by ASME code, was performed. This evaluation considered relevant material properties, operating loads, and degradation mechanisms using fatigue as a dominant driver.

The result of this assessment was that the weld was suitable for continued service. As part of the evaluation actions, Engineering stipulated a repeat UT examination during the next refueling outage.

In 1999, the first follow-up UT exam was performed, and no flaw growth was measured. This was also entered into our corrective action program. Again, in the next refueling outage in the year 2000, another successive UT exam was performed, and no flaw growth was measured.

Note that ASME Code rules for this

Class II system would have only required one single follow-up examination, but we have performed two.

MEMBER SHACK: What is the exact UT method you used?

MR. GONZALEZ: This was sheer wave -- At the time of its initial examination, a performance demonstration initiative or PDI, Appendix -- Section 11, Appendix 8, requirements were not in effect. So it was standard appendix 3 flaw sizing rules. However, at that time, we used what we considered state of the art techniques, which were the Appendix 8 techniques with multiple search units and multiple mode of propagation.

Miranda, would you put on Slide 66, please. This is just a graphic representation of some of the UT techniques we applied at that time over a period of a few days, trying to characterize that indication. So we did not rely solely on the specified ASME techniques.

We used what we considered state of the art with qualified UT examiners. So you can see, we used 70 sheer waves, 60 degree L-waves, etcetera, focused dual-element transducers,

creeping longitudinal waves. We threw everything we had at it, trying to characterize it.

MEMBER SHACK: And in the subsequent exams?

MR. GONZALEZ: At that time, PDI requirements were in effect. So we used PDI qualified procedures, including PDI qualified examination of personnel. Yes.

MEMBER ABDEL-KHALIK: Is there any vibration monitoring of this line?

MR. GONZALEZ: Not to my knowledge. I would expect not, and I would be correct. No, sir. This line, as I noted earlier, would not normally see flow. It would only be used after a post-accident or to flow RHR into loop 1 and 2 hot leg, and that is an evolution that would not occur for a number of hours after an accident.

MEMBER ARMIJO: So during normal operation then, is that a dead leg? Is there --

MR. GONZALEZ: During normal operation, that would not see any flow, and actually, that would be at ambient temperatures with no elevated temperatures and no flow and no pressure or minimal pressure, if any.

MEMBER ABDEL-KHALIK: But during

periodic testing of the pumps, would this line be vibrating?

MR. SHARP: No. During non-outage situations, we run the RHR pump on recirculation. So it wouldn't see flow, and during outages we mostly flow into the cold legs, not so much the hot legs. So typically, no flow period in those -- in the RHR hot leg line.

MR. GONZALEZ: So the fracture mechanics analysis conducted in 1997 considered fatigue as a degradation mechanism. The ultrasonic examination had concluded that this flaw did not have the nature of stress corrosion cracking due to the characteristics of the UT signal envelope and, as had we illustrated, we applied various UT techniques in trying to ascertain the reflector's attributes.

So the multiple UT techniques and precisely aligned radiography shots that we employed to characterize this flaw, and in concert with each other, they had concluded the reflector was not stress corrosion cracking. This was a degradation mechanisms that we had reported to Engineering for their flaw analysis was that it was not stress corrosion cracking.

The UT exams had plotted the position of this flaw to be at or near the ID of the pipe. The proximity rules for flaw sizing in ASME Section 11 Code required it to be considered surface connected at this point, regardless of whether it had an actual opening to the ID of the pipe or not. So by default, this placed the reject criteria in the more conservative column of a surface connected flaw for Section 11.

Due to the configuration of the piping system, however, there was no practical method for examining the ID of the weld to determine if it actually was or was not open to the surface.

Slide 23, please.

MEMBER SIEBER: This is a low pressure line. Right?

MR. GONZALEZ: It would see maximum RHR pressure, which would be approximately --

MR. SHARP: In piggyback mode, less than that, 350 pounds, yes.

MR. GONZALEZ: So normally, it would not see extreme pressures, yes.

MEMBER SIEBER: Right.

MR. GONZALEZ: And normally -- excuse me. It would see a maximum pressure as 350.

MEMBER SIEBER: Schedule 4, right?

MR. GONZALEZ: That is correct, 12 inch diameter, .4 inches thick, and UT measurements actually measure it slightly thicker than .4 inches thick.

So we are back on Slide 23. So a new Engineer analysis has recently been performed on this flaw using both stress corrosion cracking and fatigue as a degradation mechanism. These results continue to find the flaw is currently acceptable.

An ISI exam scheduled for the Unit 1 refueling outage in 2012 will determine if this indication has experienced any growth. If growth is detected, this information will be immediately entered into our corrective action program system for disposition in accordance with ASME Code requirements.

MEMBER ARMIJO: How did you conclude that the -- if the stress corrosion cracking evaluation was acceptable, because of the low temperature of the environment or some other?

MR. GONZALEZ: The new engineering analysis, and if we want some detail, I will ask for some assistance on this. But the new

engineering analysis used the material properties and the time at temperature that this would typically see during a normal operating cycle, and it used those inputs to determine what the propagation rate would be for stress corrosion cracking and when we would achieve unacceptable progress.

MEMBER ARMIJO: So you had very limited time at temperature.

MR. GONZALEZ: That is correct.

MEMBER ARMIJO: And you used the crack growth correlation.

MR. GONZALEZ: That is correct.

MEMBER SHACK: And the crack growth correlation came from what?

MR. GONZALEZ: Let me ask Mr. Lee Goyette, who has been very much involved with the fracture mechanics analysis to discuss that.

MR. GOYETTE: I am Lee Goyette. I am with PG&E, and we have the calculation done according to -- by Structural Integrity Associates, and they used the latest criteria that was available in the literature for crack growth rates under stress corrosion cracking concerns.

So there is quite a bit of discussion over the crack growth rates that were appropriate in this situation, and --

MEMBER SHACK: Yes, I can imagine.

MR. GOYETTE: Yes. And the fellows that did the analysis sit on the code committees, and they are aware of the latest what is the best stuff to use. So the analysis was done in a conservative way at the high temperature, the highest temperature that we determined the system to be operating at for a limited time during each refueling outage, and we turned out to have acceptable results, and we will look at the indication again during the next outage and confirm.

MR. GONZALEZ: So the information that we have gathered indirectly via the ultrasonics, and using the signal envelope characteristics that are mentioned, that are noted in the PDI approved procedures are used to determine the nature of the flaw, and a linear rise and fall rate, nonspecular reflection, very uniform positioning of the ultrasonic responses, all tell us that it is not stress corrosion cracking.

As I had noted earlier, we have done

some specifically aligned radiography to look at this flaw. Aside from the construction period radiography, we have done some specifically aligned radiography to see if we could see a flaw there, and we saw nothing, also telling us that it could be nothing but either lack of fusion or lack of penetration.

My experience in construction industry, a repair on a weld -- sometimes they do get the flaw. They do get all the insufficient penetration out or lack of fusion out, and sometimes they will leave a little residual bit of it, but the subsequent radiography will accept it. So it is not uncommon to see a reflector in a previously repaired area.

MEMBER ARMIJO: Now you did have instances of IGSEC in your plant early on, 1987, and in your LRA you mentioned some accumulator nozzles, again signature 304 conventional carbon, high carbon. So you detected that by your ISI program?

MR. GONZALEZ: Yes, actually, it was spotted visually, and then we had -- WE have implemented a long term program where we ultrasonically examined these accumulator

nozzles, and we were able to see incipient cracking in these accumulator nozzles.

A mechanism there was different. Metallurgy found there was considerable contaminants, and we determined that it was due to the original manufacturer.

MEMBER ARMIJO: Was that furnace sensitized or heat treated with any other components?

MR. GONZALEZ; I believe those nozzles were installed -- and I will be corrected if I am wrong. Those nozzles had been installed prior to the heat treat of the accumulators, and that was a contributor to their cracking.

MEMBER ARMIJO: And what did you replace them with?

MR. GONZALEZ: With a partial fillet weld accumulator nozzle. They were bored up. These had been full penetration fillet welds on both sides in the accumulators, and we replaced them with a partial penetration fillet weld, and the material is -- I am going to have to ask Chris Beard, who is our Materials Engineer, also of the ISI group.

MR. BEARD: Yes. My name is Chris

Beard. I work for PG&E, and we replaced them with 304 L-grade stainless steel.

MR. GONZALEZ: And our subsequent exams on those accumulator nozzles have not found any repeat incidences of cracking, and it appears we are over the curve where we saw a lot of cracking early on in these accumulator nozzles, but subsequent examinations have found those, and we actually do those early in every outage.

MEMBER ARMIJO: Okay. thank you.

MR. GONZALEZ: Non-replaced outage -- non-replaced nozzles only.

MEMBER ARMIJO: Right. You still monitor the non-replaced.

MR. GONZALEZ: That is correct.

MEMBER ARMIJO: But you don't have to do it with the 304 L-grade?

MR. GONZALEZ: That is correct.

MR. WRIGHT: We monitor them with visual inspection only. Yes, sir?

MEMBER ABDEL-KHALIK: I understand that this pipe is essentially empty during normal operation and refueling.

MR. WRIGHT: No, it would remain full.

MEMBER ABDEL-KHALIK: I mean there is

no flow. Excuse me. So what is the state of stress on this pipe, first under normal conditions when there is no flow, and in the event that flow is started?

MR. GONZALEZ: I will have to ask Mr. Goyette to answer that.

MR. GOYETTE: Lee Goyette. Well, the state of stress during normal plant operation would be dead weight and whatever temperature effects, and in a design seismic event. So a very low state of stress, plus pressure.

With the system in service, during an accident mode, normal -- emergency and faulty conditions, it would be at temperature for long term cooling.

MEMBER ARMIJO: Do you put in a weld residual stress into your stress analysis when you evaluate for stress corrosion cracking?

MR. GOYETTE: Weld residual stress? I think not.

MEMBER ARMIJO: That is typically the initiators of stress corrosion cracking compared to dead weight load, but these cracks haven't grown. You have monitored them.

MR. GONZALEZ: That is correct. We

have had two subsequent examinations. There has been no measurable change in growth -- in size, excuse me.

Continuing on: So the ISI examination that is scheduled for the next refueling outage in 2012 will monitor this flaw for any change in dimensions. If growth is detected, this information will be immediately entered into our corrective action system for disposition in accordance with the current code requirements.

If no growth is experienced, this weld will revert to the standard ASME inspection frequency, as specified by the ISI program which will require an examination every 10 years, and examination results from those future inspections will be evaluated against the existing code requirements at those times.

So this concludes my presentation on the WIC-95.

MR. SHARP: Next presentation is by Dave Miklush of our License Renewal Project.

MR. MIKLUSH: My name is Dave Miklush, and I am a member of the Diablo Canyon License Renewal Team. I will be presenting the open items for the scoping and screening portion of

our submittal.

Slide 27, please. The first open item deals with non-safety related fluid-filled piping near safety related systems.

In our first series of walkdowns, we missed two things. One was we didn't look hard for rainwater entry at the systems, and the second one was the proximity of low pressure piping near a safety system, specifically in the Turbine Building.

So we instituted another set of walkdowns, and found that our HVAC ducting, exhaust ducts from Unit 2's 480V switchgear room had an outlet that was oriented upward that could collect rainwater. So it looked like it might be a problem, but when we inspected it further, we found out there were drain holes inside. However, there was some rusting going on where the water had been collecting.

So we have elected to add more drain holes in there. I would point out that we have never had a water problem getting into our 480V switchgear rooms from the ventilation system.

The second two items had to do with firewater piping near control pressurization,

pressurization fan controls. On our first walkdown, we saw this piping. It was low pressure, and it wasn't very close.

After the RAI, we went out and recalibrated our walkdown and said, if we could see low pressure piping within line of sight, we will add it into scope, and that resulted in these two items that we added into scope on the control pressurization fans and on the exhaust opening for the 4kV switchgear rooms, which had firewater and domestic water pipes within 50 or 60, again line of sight, of the equipment.

Slide 28. slide 28 had to do with the electrical pull boxes and whether or not the pull boxes had pressurized piping going through the pull boxes.

Now Ryan West earlier talked to you a lot about the configuration of the drainage and the gravity drains and the external sumps, and we have just confirmed here that there are no pressurized sump pump piping returning into the pull box, electrical pull box. So that was a clarification on that one.

Slide 29. Slide 29, in another walkdown we found water trapped in the instrument

air system that was near the exhaust ducting of the fuel handling building supply fans.

Although the instrument air system is a very dry system and it is monitored for dew point, we have elected to keep the inlet valve to that water trap closed, because the valve that it supplies is a heating steam valve to the flow handling, and we have never used the system and don't expect to ever use it in the future. So that is how we resolve that one.

Slide 30 is a different topic. It is the scope boundary between non-safety related and safety related instrument air tubing. Again, this is a clarification that our scope boundary extends beyond the safety related to non-safety related isolation device to the solenoid valve or check valve into the non-safety related tubing at the first seismic anchor or equivalent seismic anchor.

That has been noted on the instrument air system drawings for license renewal scope boundary. That explains to future engineers where the scope boundary ends for the safety related instrument air tubing.

Slide 31. This issue had to do with

the pressure boundary status of the air start compressor unloader line, which connects the air compressor directly to the instrument air receiver. The diesels are air start. Motors air start, air receiver.

The line as non-safety related, very small line, quarter inch in diameter. In the past, it had been evaluated as acceptable as is, meaning if it had failed, the air receiver could still do its duty. However, in an effort to clean up this design situation, we have rerouted this unloader line upstream into the non-safety related portion of the system, upstream of the safety related isolation device.

That modification work has been completed on Unit 1. All three diesels are complete. One Unit 2, one diesel is complete, and two more to go, and that will complete in April of this year.

Slide 32 is two items concerning buried valves and piping. The first one had to do with copper valves in the makeup water system that are in contact with soil, and the question that was asked is how we aging manage those valves, and our answer is we will be using the

Buried Pipe and Tank Program to aging manage those copper valves.

The second item had to do with the branch line off our raw water reservoir line coming into the plant. There is a branch line that feeds industrial buildings. No safety systems on that branch, and to limit the scope of our license renewal program, we have elected to revise operating procedures to isolate valves to the branch line in case of a branch line leak or the raw water reservoirs are aligned for long term cooling, then we will go out and close those valves to preserve the water supply in the raw water reservoirs.

In that way, we have taken that branch line out of scope.

DR. BARTON: Do you have cathodic protection on your buried piping?

MR. MIKLUSH: There is some cathodic protection on the aux saltwater system. We do not have any on the make-up water system.

DR. BARTON: And what is its availability?

MR. MIKLUSH: Its availability is very good. I don't have the exact --

DR. BARTON: What is very good? Ninety, 95 percent?

MR. SHARP: Mr. Lee Goyette, could you answer that?

MR. GOYETTE: Lee Goyette with PG&E. The availability of cathodic protection is monitored monthly, and it is over 90 percent, according to the NACE standards.

MEMBER STETKAR: Before you leave, if you are the cathodic protection person, the staff's inspection report noted that you have recently -- that is the term they used -- upgraded cathodic protection system. If that is the case, when was that upgrade performed?

I understand you are now claiming it is 90 percent available today, but what has it been historically, and if it was indeed improved, when were the improvements made?

MR. GOYETTE: That is a good question.

MEMBER STETKAR: I thought so.

MR. MIKLUSH: The cathodic protection system was installed approximately 1995.

MEMBER STETKAR: Installed?

MR. MIKLUSH: The aux saltwater system.

DR. BARTON: The original or the upgrades?

MR. MIKLUSH: It was installed on the entire supply system from the intake to the turbine building, including the bypass section, which was new pipe at the time, and the old pipe that remained in service. The old pipe was above the ocean tide level.

MEMBER ARMIJO: On this chart about --

MEMBER STETKAR: Hold on a second. I don't think I got the answer to my question. I heard when it was installed. I asked had it been upgraded at sometime since it was installed, and when was that upgrade performed or was the installation considered an upgrade, going from zero to something?

MR. MIKLUSH: When the insulation went in in 1995, that was the upgrade at the cathodic protection system on the aux saltwater system. Now the plant has had other non-safety related cathodic protection systems in service since the early Eighties, and we have had a surveillance program written for those cathodic protection systems for the entire life of the plant.

MEMBER STETKAR: Okay, I guess I will

wait and ask the staff.

MEMBER SHACK: We have a commitment here to install cathodic protection for the ASW discharge piping.

MR. MIKLUSH: There is a portion of the discharge pipe from the turbine building to the intake that is in contact with soil that does not have cathodic protection on it, and --

MEMBER SHACK: So that will be an upgrade when it is installed.

MR. MIKLUSH: That will be an upgrade.

MEMBER SHACK: And that is going to happen when? Prior to the period of extended operation?

MR. MIKLUSH: Prior to the period of extended operation. That is right.

MEMBER ARMIJO: Now your makeup water system, you said, is not covered by your cathodic protection, or is?

MR. MIKLUSH: No, it is not.

MEMBER ARMIJO: It is not? Now a copper valve -- I have never heard of such a thing, but there may be. But are these bronze or brass or are they truly copper valves?

MR. MIKLUSH: I am not sure of the

exact alloy that they are made of.

MEMBER ARMIJO: Maybe some of your people could say. And are they attached to carbon steel piping, bolted or something like that?

MR. MIKLUSH: The piping and the firewater makeup water system is concrete asbestos piping..

MEMBER ARMIJO: Concrete?

MR. MIKLUSH: Concrete asbestos reinforced.

MEMBER ARMIJO: With copper valves attached to that?

MR. MIKLUSH: And where -- Well, most of the valves in the system are carbon steel. There's a few valves that are copper or bronze material, and those were these three valves that were part of the RAI.

MEMBER ARMIJO: so you wouldn't have any galvanic corrosion, because these are concrete that they are attached to, because copper and steel --

MR. MIKLUSH: There is not a piping issue, but there is an issue with the metals that are in the ground. So every valve location,

there is a question of long term performance. So those will have to be managed in the inspection program.

MEMBER STETKAR: Someplace in the SER I read that you have had problems with some leakage in gray cast iron buried piping in the firewater system, and apparently the corrective actions have been to replace the piping with -- to replace the piping.

Do you still have buried gray cast iron firewater piping on site or has all of that been replaced?

MR. SHARP: Lee Goyette, could you answer that?

MR. GOYETTE: Yes, sir. The majority of the underground firewater piping is asbestos concrete, and the risers that go to the hydrants, those are gray cast --

MEMBER STETKAR: Okay. So it is only the risers --

MR. GOYETTE: -- and they are being replaced with ductile iron.

MEMBER STETKAR: They are being replaced?

MR. GOYETTE: Yes, sir, they are.

MEMBER STETKAR: But you also have PVC piping in the firewater system. Right?

MR. GOYETTE: We do have PVC piping in the firewater system. Yes.

MEMBER STETKAR: So you said it was concrete. So it is both.

MR. GOYETTE: Both.

MEMBER STETKAR: Is one a replacement for the other or you use them in different --

MR. GOYETTE: Don't know. I cannot answer that question.

MR. SHARP: I can say that the majority, 95+ percent of the buried pipe in the fire protection system is the asbestos concrete pipe. As Lee said, some of the risers have the cast iron that we are replacing with ductile iron. There are small segments of PVC, but primarily the asbestos -- ACP pipe.

MR. MIKLUSH: That concludes my presentation.

MR. SHARP: The next speaker is Michelle Albright.

MS. ALBRIGHT: Mr. Chairman and members of the Committee, good afternoon. I am Michelle Albright, and I am part of the Diablo

Canyon License Renewal Team, and I will be discussing the two open items that we have TLAAs.

The first one that I will discuss is on TLAA identification, which consists of two RAIs. Secondly, I will be discussing the open item on metal fatigue, which is on nine RAIs.

Responses to all of these RAIs have been submitted to the staff. We believe that we have provided adequate responses to address the staff's concerns, but they still are under review.

Slide 34, please. Open item 4.1-1 is on two topics. The first of these is on the design codes for the reactor coolant pressure boundary valves, and secondly is the managing of the baffle and former bolts.

To address the first open item, we reverified that the design codes for our reactor coolant pressure boundary valves do not require a fatigue or any time dependent analyses, and we clarified it in the response to the staff.

Secondly, for the baffle and former bolts, we revised the license renewal application to choose Option III, which is to use an aging management program to manage the potential aging

of those baffle and former bolts, and that is the Reactor Vessel Internals Program.

MEMBER SIEBER: Do we have any evidence of baffle jetting?

MR. SHARP: The answer is yes. We have two over the time frame. We did have evidence of baffle jetting, and that has been remedied with modifications performed -- upflow modifications performed in the last five to eight years.

MEMBER SIEBER: And that is replace bolts modification?

MR. SHARP: It was to cut some holes in the upper portion of the baffle.

MEMBER SIEBER: So you lowered the pressure differential?

MR. SHARP: Yes, sir.

MEMBER SIEBER: Does that reverse the flow? Does that reverse the baffle flow?

MR. SHARP: It does in some cases, yes. Dan Hardesty, could you please come to the microphone and answer that question.

MR. HARDESTY: My name is Dan Hardesty, Primary Systems Engineering. In 2R10 we performed what is called an upflow mod to the

internals, lower internals and upper internals of the reactor for Unit 2, and that corrected -- It lowered the pressure in the inside of the baffles so that it would jet in the opposite direction.

Westinghouse designed and performed the modification.

MEMBER SIEBER: Did you have fuel damage associated with the baffle flow?

MR. HARDESTY: Yes, sir, we did. In the Nineties we had some damage.

MEMBER SIEBER: That is why you did the mod, but the mod did not change the bolting. What it did was reverse the flow.

MR. HARDESTY: That is correct.

MEMBER SIEBER: Thank you.

MS. ALBRIGHT: Slide 35, please.

There are nine RAIs associated with open item 4.3-1. For the purposes of discussion today, we categorized the resolution of these nine RAIs into four common areas to give you a feel for the types of responses that we had to these RAIs.

The first of these areas would be items that required additional information. For example, in our license renewal application we

provided the conclusions that the replacement reactor vessel head replacement CRDMs and the replacement CETNAs were good past the period of extended operation. However, we did not provide the actual cumulative usage factor values in the application to demonstrate that.

So in response to the RAI we merely provided those CUF values, which showed that we had adequate margin.

In the second group we provided clarifying information based on four RAIs that we received. An example here is a clarification for the metal fatigue program. Basically, we clarified that we were going to be using the FSAR number of transients in our metal fatigue program. These are lower numbers than are used in the analyses for the upper and lower core plate. So they are more conservative to count to.

In the next group of RAIs, we will be enhancing our current licensing basis.

MEMBER STETKAR: Before we go to the enhancement, have you completely updated Table 4.3-2 in the license renewal application, because all I have is the table from the original LRA,

and looking at the responses to some of the RAIs and the numbers in that table, there are a number of instances where I couldn't make numbers add up.

So, for example, your example on charging cycle estimates for auxiliary spray during plant cooldown, in the SER it is noted that -- I have to find my notes; bear with me here -- that there would be -- You are counting two of those events per cooldown, and that resulted in an estimate of 146 occurrences for Unit 1 and 102 occurrences for Unit 2. But if I use the number of cooldown events tabulated at least in the license renewal application for Unit 1, I count 176, because there are -- I'm sorry, 174 -- I can't read my own writing -- because there are 87 cooldown events projected for Unit 1, and 63 for Unit 2, which gives me 126.

So I am curious how you got 146 and 102. Is it a big deal? Are you close to the margin? I am just interested in multiplying X times 2 and being able to understand how that counting is done.

MS. ALBRIGHT: I understand. i would like to ask Mr. Chalmer Myer to address that

question.

MR. MYER: This is Chalmer Myer with the Star Center of Business. We are going to need to take it offline and respond later, because it is going to take some review, but we will get you an answer.

MEMBER STETKAR: There were some others. In the interest of time, I would encourage you and also the staff when they come up to look at things like consistency. If you are using 2 times X, make sure that X and 2 times X are equivalent numbers. There are a number of those things that I have come across.

As I said, in the grand scheme of things, you are well below the margins, but I am talking about consistency, because you are using methods to develop those cycle counts. Thank you.

MS. ALBRIGHT: Thank you. For the next group of RAIs, we will be enhancing our current licensing basis and, namely, this is the FSAR. For example, the staff questioned why our FSAR didn't provide the technical basis for us not counting load-following transients. While they agreed with the technical basis of why we

aren't counting them, we didn't have that actually documented in our FSAR. So we will be updating our FSAR, and committed to do so in our response.

The last category here is on environmentally-assisted fatigue. For our license renewal application, we performed the environmentally-assisted fatigue analyses per NUREG/CR-6260 using the locations for an older vintage Westinghouse plant.

The staff did question why we did not consider other locations than those originally in our application. After discussions with them, we did agree that it would be -- that we would commit to review our existing fatigue analyses to determine if the analyses that we performed for environmentally-assisted fatigue are limiting for the Diablo Canyon reactor cooling environment.

Through those evaluations, if we do find more limiting locations, then the most limiting component will be evaluated for environmentally-assisted fatigue through our metal fatigue program, and we will be doing that prior to the period of extended operation.

This concludes the presentation on

TLAA open items.

MEMBER SIEBER: Have you had any issues with control rod drive mechanism tube split pins that hold the tubes in place within the control rod drive?

MR. GREBEL: Dan Hardesty, have we had a previous history with split pins? Dan, could you answer that?

MR. HARDESTY: Sorry, I didn't catch the question all the way.

MEMBER SIEBER: The question is: In your class of plants around the time this plant was built, there was an issue of cracking of split pins that hold the control rod drive mechanism tubes at the top of the core plate into position so that you would not delay the dropping of the control rod during a reactor SCRAM.

Have you examined your split pins or have you replaced them?

MR. HARDESTY: We replaced our split pins. I believe we have two different replacements at different times, but the last one was in 2R10 when we did the upflow mod. We took advantage at the time and replaced the split pins with the new versions.

MEMBER SIEBER: And so baffle jettings issue solution is pretty recent?

MR. HARDESTY: It was a convenient time to do it, because we had --

MEMBER SIEBER: So you did split pins -- some split pins and baffle jetting, flow reversal at the same time, same outage?

MR. HARDESTY: Yes.

CHAIRMAN BLEY: Any other questions? Yes? Go ahead.

MEMBER STETKAR: Thank you. A couple of quick ones. You have apparently had some problems out in the intake structure, because it is a pretty harsh environment on the coast there, and I have noted that it was placed into a higher category of attention with the plans for remediation because of deterioration, I guess, in the structural concrete and things like that.

According to the SER anyway, it said that the Applicant had developed a repair plan to return the intake structure to A2 inspection status under the maintenance program by 2010, which implies that it should now be in much better shape. Is it?

MR. SHARP: I would say -- a

preemptive comment, and then I will let David Wong answer.

We have indeed done repairs on the intake structure to take it back to a better condition. We had some additional degradations identified as we were making those repairs, and so there has been a little bit of delay. That won't be completed now until this spring in 2011.

MEMBER STETKAR: Thanks. One more. Let me just make a note on that. This, again -- You apparently in Unit 2 during RO-15 identified -- they are characterized as gaps between the concrete floor and the steel liner in the containment, and apparently you have made a commitment to seal the gaps.

The way I read the material, it sounded to me as if there had never been any sealant in the gaps. Is that true?

MR. SHARP: Yes. The Diablo Canyon design does not include a moisture barrier component seen in other plants. The concrete runs up to the containment liner at the base of containment.

MEMBER STETKAR: A couple of questions. If you have now made the decision to

seal the gaps, does that mean you are only going to seal the places where you found the gaps or are you going to actually install circumferential moisture barrier?

MR. WONG: This is David Wong, Civil Engineering Supervisor. We are intending to seal only the gaps at this time. The concrete is very hard pressed up against the liner. We inspect them every outage. We have a couple of programs that look at that every outage, our Coatings Monitoring Program, and also the Civil Maintenance Rule Program.

DR. BARTON: How do you know you have never had any leakage between the concrete and the liner or there is any corrosion down underneath the floor?

MR. WONG: We have never seen any leakage or any signs of degradation of the concrete, any kind of degradation which would re-collect through the liner as popping and spalling the concrete or cracking it.

MEMBER STETKAR: Thanks. I am finished.

CHAIRMAN BLEY: Any other questions?

DR. BARTON: Yes.

CHAIRMAN BLEY: Yes, John?

DR. BARTON: The Appendix A, your final safety analysis supplement and also Append B, aging management program, when you talk about your one-time inspection of code Class 1 small bore piping, I don't get what your final commitment is on volumetric testing of socket welds.

MR. SHARP: Chris Beard, could you please respond to that?

MR. BEARD: Chris Beard. Our final commitment, as responded to in our latest request for additional information, is: Diablo Canyon will volumetrically examine 10 percent with a maximum of 25 welds of each weld type socket and butt welds for ASME Class 1, less than four inches. That is our final commitment.

DR. BARTON: Okay. I didn't get that. So I am glad to hear you committed to do that.

Also, you have got an opening in containment where you had strain gauges installed for initial structure integrity tests, and those openings are still there on both units. How do I know that you don't have environment gotten into there, and you have got rebar, concrete

degradation enclosed in your environment?

MR. SHARP: David Wong, could you respond to that?

MR. WONG: This is David Wong. These strain gauge boxes -- Yes, they were originally installed during construction to monitor the strain on the rebar. They are thin gauge 4 x 4 by 4 inch in depth thin gauge carbon steel boxes embedded on the exterior part of the containment structure.

They were banded in place after testing. The strain gauge access boxes, which were called openings, are actually covered with plastic covers and sealed around with caulking.

Due to the age weathering effects, we have seen some damage. Either the covers are missing or they are broken, and we plan on repairing those thin gauge boxes that we find damaged in our next containment exterior concrete inspections.

DR. BARTON: How do you know you haven't had any corrosion since then, since you know that you are really not sealed right now?

MR. WONG: We would see signs of the concrete spalling or cracking, which we have not

seen.

CHAIRMAN BLEY: No further questions? Thank you very much for your presentations. I think we will take a break now, and I would ask everybody to be back at 3:15. We will recess now.

(Whereupon, the foregoing matter went off the record at 2:57 p.m. and went back on the record at 3:15 p.m.)

CHAIRMAN BLEY: The meeting will come back to order, please. Brian, back to you.

MR. HOLIAN: Thank you. Sorry. Waiting for the rest of the NRC staff. This is Brian Holian, Director of License Renewal.

Our staff did take good notes during some of the questions there. I know Mr. Shack had a question early on about MRP. Let me just -- So we will be addressing those as part of our staff response to the SER and the open items.

Once again, up at the table we have Stan Gardocki. Stan is one of our members from another technical region, DSS, Division of Safety Systems, and he helps out a lot of scoping.

You have heard from him before from the floor on this particular plant. We had

issues with the plant walkdowns, and Stan is here to support our discussion of that.

Bill Holston, a senior engineer in License Renewal, there for the buried piping issues. You have heard him on previous plants.

Alan Hiser, a senior level advisor in Division of License Renewal, will be talking to some of the metal fatigue items there, thimble tube issues.

Greg Pick, I mentioned, a senior inspector from Region IV, and Nate Ferrer, our Project Manager. With that, I will turn it over to Nate.

MR. FERRER: Thanks, Brian. Good afternoon. As Brian said, I am Nate Ferrer. I am the Project Manager for the Diablo Canyon License Renewal Review, and I am pleased to have the opportunity to present the staff's review, as documented in our Safety Evaluation Report or SER with open items.

Before I actually get into the presentation, Allen will address the question that we had earlier on the vessel internals.

DR. HISER: I guess, Bill, could you restate the question?

MEMBER SHACK: Two things. One, I know Ginna submitted an inspection plan, and I never saw whether you guys accepted it or not. Since MRP 227 is all over GALL, I assume it was finally accepted, but I haven't really seen that.

Then just since you now have the guidance, you have presumably got somebody who had one inspected. When are we going to see people coming in with inspection plans rather than, you know, we are going to follow the industry sort of thing that we see standard here.

DR. HISER: A number of plants have come in with inspection plans, because they have already entered the extended period of operation, and those plans are generally due two years ahead of that time.

I am not sure of the status of the Ginna plan, but --

MEMBER SHACK: Okay, but you have accepted other plans then.

DR. HISER: I don't -- I am not sure that we have accepted any. There were some plants -- for example, Calvert Cliffs had proposed specific inspections in their initial application, and so they do not have that type of

commitment and do not owe us a plan.

So I will verify the status of Ginna and some of the other plants. I am not aware, though, that we have approved any MRP 227. The SER has not been issued yet, but that will be forthcoming.

MEMBER SHACK: Well, GALL-2, as I read it, it seems to imply that you accept that guidance. GALL-2 incorporates a lot of information from MRP 227, the recommendations that are in that report, but also some additional items that the staff thinks is necessary for applicants. There is no a GALL section for it.

DR. HISER: Yes, that is correct, and after probably the current set of plants, we will expect plants to come in with a GALL consistent program. Once we finalize the SER for MRP 227, we may modify the GALL program to be consistent with the staff positions that come out of that review. Jeff?

MR. POEHLER: Jeff Poehler, Materials Engineer from the Vessel Integrity Branch, Division of Component Integrity.

We have not issued an SER or an SE on any of the plant specific reactor vessel

internals inspection plans. We have accepted for review quite a few of them. I can't tell you the exact number. So it is basically waiting on the SE for MRP 227 Rev 0, which is the basis for all these inspection plans, which is supposed to be issued in the next month or so.

DR. HISER: Is that the final SER?

MR. POEHLER: Correct.

MEMBER SHACK: So soon.

DR. HISER: But there will be a point at which the commitment is no longer an acceptable method to demonstrate aging management for vessel internals. That answers my question. Thank you.

MEMBER SHACK: That answers my question. Thank you.

MR. FERRER: Getting back to the presentation for today, I will begin with an overview of the Diablo Canyon review, and I will keep it brief, since this information was previously discussed by the applicant.

We will then follow the basic structure of the SER, covering topics of interest and open items on each section. Greg Pick will be presenting the license renewal regional

inspection, as Brian mentioned, and we will try not to repeat all of the information that the applicant has presented. We just intend to ensure that you receive adequate information associated with the staff's review and findings, and as always, feel free to ask questions at anytime.

This slide just provides the general details of the license renewal application. The applicant has previously covered all this. So unless there are any questions, I will move on at this time.

Staff review teams conducted audits and inspections of the application during the period shown on the slide. I will highlight that issues raised and discussed during the scoping and screening methodology audit led to two LRA amendments related to scoping and screening submitted in the summer of 2010.

They provided the applicant's additional scoping and screening evaluations for various plant systems, structures and components. San Gardocki will be covering these topics in more detail during the discussion of Section 2.

In preparing the Safety Evaluation

Report and in addition to the audits and inspections already mentioned, the staff conducted in depth technical reviews. We issued approximately 200 Requests for Additional Information to which the applicant responded.

The SER was issued to the applicant on January 10, 2011, and contains eight open items and two confirmatory items. The first three open items relate to scoping and screening, which Stan will cover in his discussion of Section 2.

Two open items relate to aging management programs. Allen Hiser will cover one, and Bill Holston will be covering the other in discussion of Section 3. The last three open items relate to time limited aging analyses, and Allen Hiser will be covering those in our discussion of Section 4.

Two confirmatory items also relate to aging management programs, and again we will cover those in Section 3.

CHAIRMAN BLEY: Have you had time to review the responses to these issues?

MR. FERRER: We have.

CHAIRMAN BLEY: So that is included?

MR. FERRER: Yes. We will be

discussing those once we get into more detail on each one.

Moving on to Section 2 of the SER. This section concerns structures and components subject to aging management review. The staff has completed its review of scoping and screening methodology and results, with the exception of the open items mentioned earlier.

I will now hand it over to Stan Gardocki to discuss the open items and other items of interest from this section.

MR. GARDOCKI: Good afternoon. Stan Gardocki. I work in the Balance of Plant Section, Division of Safety Systems, as Senior Reactor System Engineer. I have been involved with the scoping of the plants, and I was on site with the audit conducted in March.

The staff reviewed the applicant's scoping and screening methodology and implementation utilizing the resources in the application, the drawings, and the staff augmented that with a physical walkdown of the plant systems during the scoping and screening audit done in March of 2010.

During the on-site audit, the staff

walked down selected non-safety areas where the plant people identified where the applicant said there was no or limited safety related components. The staff focused mainly on non-safety related Turbine Building to verify whether there was any additional safety related components in this area.

The staff also walked down the safety related areas, mainly the emergency diesel generator rooms, the component cooling heat exchanger room, and the auxiliary building, to verify whether there were any unidentified non-safety related components in these areas that could potentially adversely affect the safety related components.

The staff identified several instances where the applicant's scoping of these components did not align with the proposed methodology.

In the non-safety related Turbine Building, the staff identified additional safety related components that did not have an adequate evaluation or 10 CFR 54.4(a)(2) for potential adverse effects from the failure of nearby non-safety related components.

The additional safety related

components identified in the Turbine Building included control room pressurization system and exhaust ducts for the switchgear HVAC system. Additionally, the staff looked at the safety related cables in the Turbine Building where the applicant credited its mitigation of the conduit, but that was only for the low and medium line breaks, but they didn't evaluate for high energy line breaks.

In the safety related areas, the staff identified additional non-safety related components in the vicinity of the safety related components that did not have an adequate (a)(2) evaluation. Some of these examples were inside the Diesel Room and the component cooling heat exchanger room. There were overhead drain lines, and there was additional service water lines in the diesel room.

Outside in the yard there were underground vaults and electric pull boxes, which the staff identified sumps and pumps that didn't have an adequate (a)(2) evaluation.

In the auxiliary building there was water traps and compressed air system near safety related components. The staff also identified

instances where the applicant did not include into scope non-safety related piping that was directly attached to safety related components past the safety/non-safety related boundary up to the first qualified anchor and, as the applicant said, these were mostly in suppressed gas systems to clean the air, and the nitrogen systems.

The staff also identified instances where the applicant stopped its (a)(1) scoping at the code class break on safety related piping at an open valve. The failure of the downstream piping could result in loss of the pressure boundary of the safety related system.

One instance of this that was mentioned is the EDG air start system where the unloader line transitted back from the safety related air receiver back to the non-safety related air compressor.

After the site out was completed in March of 2010, the staff issued about 17 RAIs to the applicant. The applicant's preliminary response indicated that additional systems components, especially in the Turbine Building, would have to be added to the scope of license renewal. As Nate said, there were two responses,

LER and maintenance.

Later, the applicant submitted the changes to the application to include these components in the scope of license renewal, and after reviewing the additional material, the staff was able to resolve all the issues except for three open items identified in the SER.

The staff has received the applicant's responses to these open items on January 12, 2011. The applicant has already described their proposed resolutions. In conclusion, the staff has reviewed those and their responses, and has now the necessary information from the applicant to satisfactorily resolve these three open items in the final safety evaluation.

Do you have any questions on this matter?

CHAIRMAN BLEY: I am just curious. When staff does the walkdown you describe, would you consider it a spot check or would you consider it a thorough walkdown?

MR. GARDOCKI: We systematically look at the application, look at areas of interest. In this particular application, we looked at they excluded the Turbine Building, and they said

there was nothing safety related in there. so we would focus on something like that.

We always walkdown general areas where we find deficiencies in the application, EDG rooms, and we identified some --

CHAIRMAN BLEY: So the areas that drew your interest, you did a pretty thorough walkdown?

MR. GARDOCKI: Oh, absolutely, and you can tell from the level of detail that we identified quite a significant amount of components.

DR. BARTON: What is your assessment of the material condition of the parts of the plant that you looked at in detail?

MR. GARDOCKI: The material condition was very good. We walked down the aux building, turbine buildings, and everything had a good coat of paint. We didn't see any spalling or dirt conditions. There were some areas we tried to get around in the aux building to the back of the containment to look at some penetrations, and we just couldn't get to it. So --

MEMBER ARMIJO: In the SER there was a mention of a removal of cracked coating on the

liner, and it is a small area, but apparently about two square feet were not re-coated after this repair. I just wondered what the logic was for that. Are you familiar with that?

MR. GARDOCKI: I cannot address that matter.

MEMBER ARMIJO: Maybe the -- I will read it to you: Defect areas were cleaned and coated at the end of cycle 15, 1R15 and 2R15, total of three square foot cluster; liner plate coatings was found cracked and delaminated at the 185 foot and 195 foot elevations. The loose coatings were removed without repair. Two square feet of the three square foot area were left as bare steel after cleaning. This area will require continuous monitoring.

I agree with all of that, and I know it is a small area, but I don't understand the logic of not repairing it.

DR. HISER: I am not sure that we can address why they didn't repair it.

MEMBER ARMIJO: Why does the staff think that is okay?

DR. HISER: Well, from our perspective, as long as they ensure that it

doesn't degrade, then we are -- As long as there is aging management program in place to address that and to monitor that, then I think we are satisfied.

CHAIRMAN BLEY: I think Diablo Canyon wanted to say something.

MEMBER ARMIJO: Does the applicant have a response?

MR. WRIGHT: I will start off. This is Mike Wright from Diablo. We do have an aging management program for containment coatings. There are -- Part of that program is to identify all degraded coatings at the start of the outage, and we have remedied as much as possible during that refueling outage, and then we identify coatings that would have to be subsequently re-coated in the following outage.

So that will be a remedy. It just wasn't fixed at --

MEMBER ARMIJO: So it was just an interim problem?

MR. WRIGHT: Yes, sir, that is correct.

MEMBER ARMIJO: Oh, okay. I just thought it was some experiment you were running

or something else, and up at that elevation it may not be the most convenient place to repair it. I don't know. Okay, you answered my question.

MEMBER STETKAR: Staff, in the SER there are statements like "the applicant applied its evaluation of non-safety related SCs inconsistently throughout the LRA." Quite honestly, there are more RAIs issued and more applicant responses to those RAIs regarding scoping and screening than I have seen in the last two or three years of license renewal applications.

Since your walkdowns -- As you said, the areas that you walk down are pretty thorough, and those resulted in rather extensive RAIs that were focused on the areas you looked at. But since there are only selected areas, how do we have confidence in the areas that you didn't walkdown, that there aren't similar kind of scoping and screening issues; and when you found the relatively large number of issues, at least by counting RAIs and looking at the responses to those RAIs -- for example, in the Turbine Building -- did you make any conscious effort to

expand the scope of your samples and audits and walkdowns to inspect other areas to see whether or not it simply was focused out in the Turbine Building and that the scoping and screening of (a)(2) type issues in other parts of the plant had, in fact, been done?

MR. GARDOCKI: Okay, I will try it. We looked for -- like if you got the aux building, they say everything in the aux building is in scope of license renewal.

MEMBER STETKAR: Okay, that is pretty easy.

MR. GARDOCKI: So that was a pretty easy area. So we go in there, and we walkdown something just to make sure scoping values were correct. We were trying to find some penetrations of the makeup water system going through there. We are limited to the radiological areas, and we couldn't access anymore than we could.

There was an area between -- Now the areas that stand out is what we have tried to focus on in this very limited time we were out there, and between the aux building and Turbine Building there is another building in between it.

So we asked them, do you classify it as the aux building or do you classify it as the Turbine Building? So those are the areas we kind of focus on and try to clarify that area: Do you classify it as aux building? Everything in scope. For the Turbine Building, nothing in scope.

Then we refocus our review when we get back to the office to see if there is anything in that area that has particular interest. So we follow to the main steam piping out there. We asked some RAIs to clarify the boundaries on those.

The Turbine Building, when they said they excluded it initially, I mean, we focused right on that area to see if there was anything else in that area, and we found some safety related in there. And if you didn't scope it initially, you don't have any basis to evaluate to. So we had to wait for that additional scoping to come in.

Then we focused on the particular lines they called conduit with safety related. They said, well, we use the conduit for mitigation, but then you didn't use it for all

mitigations. So then you had to scope the entire Turbine Building for high pressure piping.

So there was a very substantial amount of additional components put in scope after our audit. So we focused our audits mainly on areas where we would think we would find some problems, based on previous audits where we find problems. Then those areas that stand out, like here the Turbine Building or that building between the aux buildings, or if they have main steam piping and feedwater piping that is routed outside of the aux building to go into containment, we would walk those particular areas down to see how they are managed for aging management, or in scope.

MR. HOLIAN: This is Brian Holian. I wanted to add to the question maybe and the answer. On the question, it is a question we ask during review, branch chief review and senior management review of the SER for that purpose.

Staff -- We are still pushing the staff. But when you ask an RAI on an item, get that right, but ask the Part B to the RAI, which is: We found this one or think we found this one; give us some assurance that you have sampled other areas or you have gone there.

I think we are pretty good on doing that in RAIs. Sometimes we don't also translate that to the SER write-up that says that we kind of asked that second part of the question or during discussions, it had that.

So I don't see it all the time in the SER write-up that we are asking the extent of condition question of them to also do that. Stan and -- you know, even in the past week sitting in here, as I have looked back this year -- kind of reiterated that some of those items -- you know, the very specific ones, caused other issues to be found by them as part of that extended condition.

So a lot of the detail items came out of that type of questioning, but I agree with you that the staff can be even more overt in translating it into the SER. I have told them to tell the story a bit better about what did you find, and then what did the applicant have to do.

MEMBER STETKAR: That helps. Thanks, Brian, because the way I read the SER is there was a large number of individually identified, as you said, focused items, a large number of which were resolved by very focused responses of a handful or whatever, which are still being

discussed, and then there is the overall conclusion that says, with the exception of this handful, everything is fine.

MR. HOLIAN: That is right, and it leaves out the in between. Why did the staff have a good feeling that we didn't need to go do a second audit. But we ask ourselves those questions.

MEMBER STETKAR: Thank you.

DR. BARTON: Along those same lines, in the SER it talks about the external surface monitoring program, and the inspection team noted that the training program for the personnel performing these inspections did not meet the commitment the applicant made for training. So I wonder if the people that the applicant had out there doing external surfaces monitoring weren't probably trained.

How was this ever resolved? Did these guys get requalified? Did you guys go look at that?

MR. PICK: As an inspection team, during our interviews the system engineers and the people doing aging management -- they had a lot of criteria for what was aging management,

but they weren't comfortable that they had enough background. They were using common sense and their procedures, which were quite good, and they all commented to the external surfaces program reviewer that they would like more training.

When we brought that to the applicant's attention, they went and did their own survey, and I will let them respond to what they found.

MR. WRIGHT: This is Mike Wright from Diablo. We agreed with the Region IV inspection team. We have committed to doing extensive training for all system engineers prior to the December of this year to close the gap on training, and for sustainability, include that training as part of the qualification for system engineers.

DR. BARTON: Thank you.

MR. GARDOCKI: Well, if there's no more further questions, that concludes my presentation.

MR. FERRER: Thank you, Stan. I would like to highlight just one item on open item 2.3.3.14-1. The topic of this item actually became an inspection finding, as documented in an

inspection report dated September 9, 2010.

I just highlight that, because just to show sometimes when we are doing the license renewal reviews, we find things that we can pass on to regional staff or residents in current operating space.

With that, I would pass it on to Greg Pick from Region IV.

MR. PICK: Thanks, Nate. Good afternoon, members of the ACRS Committee.

I led the inspection team, and we conducted an extensive review using one of our most experienced teams. The six inspectors shared 170 years of inspection experience. We looked at 60 percent of the aging management programs, instead of the nominal 40 to 50 percent.

We reviewed 24 of the 40 aging management programs that were in existence at that time, and this included six of the nine new aging management programs.

We evaluated whether the applicant properly scoped non-safety related structures, systems and components that could affect safety related structures, systems and components, and

whether they developed aging management programs consistent with the GALL report.

We focused on the conditions that existed at the plant and how the applicant implemented their existing programs that were going to be aging management programs, and their plans for implementing their new aging management programs.

We also performed a vertical slice evaluation of three systems to assess whether the identified aging management programs could be expected to effectively manage the effects of aging.

We also looked at the applicant's treatment of latest industry aging issues and several site specific issues. Next slide.

During our reviews, we looked at the conditions of the structures, systems and components needed to withstand a seismic event. These included the supports and restraints, the applicant's program for evaluating the effects of non-safety related equipment affecting safety related equipment and their Class 2 equipment, an the structural inspector also considered the seismic design in his review of the walls -- the

design information.

We looked at the buried pipe program with a focus on environmental monitoring. We looked at inaccessible medium voltage cables, because the plant had documented aging experience problems with those cables, and we looked at their metal enclosed bus program because they had experienced bus part failures in their past. Next slide.

Related to scoping, when we arrived on site the applicant was in the process of incorporating lessons learned related to scoping from a previous STARS plant, similar to the scoping team.

IN addition, I had talked with Stan in detail prior to going to the site to see how I might assist him in getting eyes on some of the requests for additional information responses and verify the information being provided.

The items that we assisted headquarters reviewers in resolving included: We verified the configuration of non-safety related service water cooling piping that went into the room; we verified that no safety related electric cables were present in the oily waste sump room.

We verified that the water spray from a service cooling water pump in the Turbine Building would not have affected the control room pressurization system components. We verified the physical configurations reflected in their Turbine Building reviews, that in fact the cables were in conduits, the safety related cables for the high energy line break.

During our vertical slice review of the compressed air system, we identified examples of items that had not been considered for aging management.

The unloader valves for the diesel generator air compressors -- they were made of two materials, stainless steel and copper, and we asked how they monitored for aging effects. Well, they did, in fact. They have a five-year PM, and they have a line item to look for evidence of corrosion when they do that five-year PM. But they had not included it in their evaluation in their license renewal application. So they updated that.

The other one was they had flexible hoses attached to their back-up nitrogen bottles. That was identified as a steel line on their

drawings when, in fact, it was flexible hoses, and they put that in a 10-year PM.

In regard to the aging management programs, we already discussed that training was required for the system engineers. We also discussed the one instance related to age related degradation of the silicon seal for the abandoned containment screening stage cover plate, which allowed rain to enter the metal box.

We identified this through review of test reports where they did a containment integrated leak rate test in the inspections. They took photographs of the abnormal conditions and had it included as part of the report. So we asked, what are you doing as far as aging management of this, and they have agreed to monitor it, seal them, and then eventually perform a plant modification to seal the metal boxes.

For the inaccessible medium voltage cables in the cable vaults, they were routed on supports. They didn't have any criteria when we were on site for looking at the support structures for the cables. So they issued a corrective action document to add that to their

structures monitoring program anytime the vaults are opened.

MEMBER STETKAR: Greg, when you did the inspection -- I don't have my notes here complete -- did you actually look in some of those?

MR. PICK: We did not look in the vaults.

MEMBER STETKAR: Didn't look in any of them?

MR. PICK: But we gave the residents criteria, and they agreed to look in the vaults.

MEMBER STETKAR: But you didn't actually?

MR. PICK: But we did not put eyes on them, no.

MEMBER ABDEL-KHALIk: What is the span over which the cables were supported?

MR. PICK: It appeared to be about four feet. I am not sure. But the droop based on the span couldn't be anymore than 12 inches. The electrical inspector determined that.

The last one, the location selected for fouling: For the closed cooling water inspection criteria, they selected two valves to

look for fouling, because we already had a PM when they opened it.

We asked the question, is that a low flow area, because when you read all their experience, they were about closing in the low flow areas. They wrote a notification, took a look, discovered it is not a low flow area. So they are looking for alternate locations as a result of it being in their corrective action program.

We also found a couple of minor procedure issues. With their heat exchanger program, right now Generic Letter 13 allows you to do maintenance and did not require heat exchanger testing, but their license renewal application said we will do heat exchanger testing.

Their procedure said it was prudent. Well, the fixes are going to take out the option of it being a prudent test, and it is now a required test.

The second one was they do predictive maintenance thermography of their metal enclosed bus stops. Well, predictive maintenance isn't required. It is something that they do, but

again the license renewal application said we will do this as our way of monitoring aging. So they now have to keep them as records. They are required, versus being an option of keeping those records.

DR. BARTON: Don't most people do that anyhow?

MR.PICK: They do the thermography for other plants. I can't answer whether they keep them as quality records. That is why it is minor. They might keep the record, but they are not required to.

DR. BARTON: I got you.

MR. PICK: Next slide. Overall, we also found that the plant had good material condition. We would go in one of the diesel fuel vaults. Didn't find any issues with that.

The applicant had developed procedures for many programs, and it had initiated plans to incorporate aging management evaluations into their day to day activities.

They are developing a long term plan that looks to be implemented over the next several years. By the time they get to the period of extended operations, it will just be

part of their routine way of doing business, and the procedures were drafted when we were there. So as inspectors, we had lots of information to review where we could make decisions and comment on whether we thought it would do -- the procedure would accomplish what was expected of it.

They already identified that they had replaced several major components, and essentially resets the clock on aging. And you already discussed the intake structure. They also replaced some high voltage insulators on their station blackout lines. Yes, sir?

MEMBER SIEBER: What was the reason that they replaced insulators? Was it -- Some insulators have manufacturing --

MR. PICK: I do not -- It may have been cracking, but I do not recall.

MEMBER SIEBER: Another thing is that plants that are located at salt water collect salt on the insulators.

MR. PICK: I know they do. They do spray on their insulators, but I believe they --

MEMBER SIEBER: I would sure like to know what steps you go through periodically to

make sure the insulators are not building up salt and capable of flashovers.

MR. GORYANCE: My name is Joe Goryance, Diablo Canyon License Renewal, 5R kV, 230 kV system engineer and supervisor.

Our program is based on General Order 95, which is a California order. We have to, by California law, inspect our insulators. Based on our local climate, we have -- We are at a high salt spray area, being close to the ocean, high winds. So we have an inspection program for that.

For our 5R kV insulators, we do a hot wash every six weeks. Based on rainfall, we can defer that if we get one inch of rain in a 24-hour period. So that is our program.

During the inspection part, we noticed that we started having some rust. The galvanizing on porcelain insulators was starting to show signs of rust. So then we replaced that string of insulators on the 5R kV system, and our 230 kVs also have been replaced.

MEMBER SIEBER: Thank you.

MEMBER ABDEL-KHALIK: You mentioned you do hot wash on the 500 kV, and that is what I

read in the report. I didn't hear anything about hot washing the 230 kV. Do you do that?

MR. GORYANCE: Our 230 kV are polymer insulators. They are not porcelain. So we can't wash those. The polymer types have a better creepage distance. So they are not required.

MEMBER ABDEL-KHALIK: Thanks.

MR. PICK: Thank you. The scoping of -- Our overall conclusions from the inspection: The scoping of non-safety structures, systems and components and the application of the aging management programs to those structures, systems and components were acceptable.

Applicant personnel had incorporated actions to manage their aging effects into their programs, and reasonable assurance exists that aging effects will be managed and intended functions maintained.

With that, I am going to turn this back over to Nate, unless there are any additional questions.

MEMBER STETKAR: Yes, Greg. Since I beat up the applicant, I might as well beat you up. The inspection report says the team determined that the applicant had recently

upgraded the cathodic protection system and programs.

Words like recently always send a flag forme, especially because your inspection was done in 2010. What does that phrase mean, since you guys did the inspection? Was the recent upgrade the actual 1995 installation, 15 years before you did the inspection?

MR. PICK: I do not know the exact time frame reflected in that phrase.

MEMBER STETKAR: You want to ask Diablo. You heard the answer that, well, they installed it in 1995, and its current reliability is 90 percent or better or whatever the requirements are. But this seems to imply that the inspection team discovered something that had been done, quote, "recently," which implies that, before recently, whenever that was, it wasn't so good.

DR. BARTON: Depends what you timing is. Is 15 years recent?

MEMBER STETKAR: Yes, recent in geologic time perhaps.

MR. HOLIAN: Bill, do you want to answer?

MR. HOLSTON: Yes. I was just waiting for the discussion. Yes, the applicant had noted corrosion in their aux salt water system that was down in the lower basin. So in that mid-late Nineties, they bypassed a whole lot of that piping, put new piping in, upgraded the cathodic protection system to ensure that they would protect the newly installed piping.

There were some other modifications, too. They had some corrosion of diesel fuel piping. Now instead of cathodically protecting that, they replaced that diesel fuel piping and ran it in underground vaults. So now it is exposed to air. So that is what they have done.

Currently, their cathodic protection system is available greater than 90 percent of the time. They conduct annual NACE testing to ensure that the system is effective by measuring the pipe-to-soil potentials.

MEMBER STETKAR: Right. I read and heard, and I understand all of that. The question, I guess, then is still: Is 1995 the recent upgrade, and indeed has the cathodic protection system, if that is the recent upgrade, been available 90 percent of the time or better

since 1995 then?

MR. HOLSTON: That is my understanding. Yes, sir. And that is from talking to the applicant, working through the request for additional information. I am not aware of any period of time where, once they put the new cathodic protection system in, which again was mid- kind of like '95-'96 or it might have been '94, that they had a period where it went out of effective monitoring.

MEMBER STETKAR: I am just triggering on the word recently, you know. That, to me, implies maybe in the last year or two rather than 15 years ago. So, thanks.

I actually know how some of the people prepare for the license renewal applications, and recent sometimes means six months ago. Thanks.

MR. PICK: Any other questions?

MR. FERRER: Thanks, Greg. I will now move on to Section 3, Aging Management Review results.

Section 3.0 covers the staff's review of the applicant's aging management programs. I will just note that the open and confirmatory items in Section 3 are all discussed in this

section.

Sections 3.1 through 3.6 cover aging management review items, and each of the systems within the scope of license renewal. For a given aging management review, the staff reviewed the items to determine whether it was consistent with the GALL report and, if an aging management review is not consistent, then the staff conducted a technical review to ensure adequacy.

As the applicant previously stated, they submitted 42 aging management programs, and there were approximately 3,000 aging management review items. Of the 42 aging management programs, 31 were existing, nine are new, and two plant specific.

As I noted earlier, there are two open items related to aging management programs. Allen Hiser will discuss the open item related to the flux thimble tube inspection program at this time.

DR. HISER: Thanks, Nate. The flux thimble tube inspection program is a GALL program. During the staff's review, the one item that really stuck out to us was the operating experience at Diablo Canyon.

I don't want to rehash much of what the applicant provided earlier, but a lot of the RAIs in the open item relate back to that finding. The one area I guess I did want to highlight was the concern that the staff has that the wear rate projection methodology employed by the applicant may be nonconservative.

So it may not give conservative estimates of wear that would be measured after the current operating cycle, and that is one area that we still have the open item that we will review applicant's response to, and we will reach a determination on the acceptability of the program based on that review.

MEMBER STETKAR: Allen, the way at least I read the SER, the concern seemed to be focused on the thinning threshold, and I was under the impression it was different from what Diablo said, that they are using 68 percent rather than 80 percent.

What is the real concern? Is it the methodology on how they project the rate or that actual acceptance criterion -- the staff's concern.

DR. HISER: It really is a combination

of all pieces. The project methodology does not incorporate explicit uncertainty considerations.

MEMBER STETKAR: Let me ask you then what is different in Diablo's methodology compared to other previously approved license renewal applications that indeed have used an 80 percent thinning acceptance criterion?

DR. HISER: Jim Medoff is here.

MEMBER STETKAR: Is their methodology different?

DR. HISER: The main reviewer on a lot of this.

MR. MEDOFF: This is Jim Medoff of the staff. I was the peer reviewer for the flux thimble tube inspection program for Diablo Canyon.

The big difference is some of the other applicants have adopted the WCAP 12866 methodology. So their acceptance criteria is set to 80 percent on that basis, and then the Westinghouse methodology included uncertainty to derive that 80 percent through-wall wear acceptance criteria.

For Diablo Canyon, it is a little bit different. They have a certain procedure that

refers to a different Westinghouse plant specific calculation for them, and that calculation set the acceptable wear criterion to 68 percent through wall, including uncertainty.

Then later on, the applicant had done a 50.59 to that Westinghouse methodology to remove the uncertainty based on a comparison to the WCAP methodology, even though it is not really part of their licensing basis.

CHAIRMAN BLEY: Compared to the new WCAP methodology?

MR. MEDOFF: Yes. Yes. So that is what we are trying to figure out, whether that is an acceptable basis or not, and we are looking that over.

The other matter is the wear projections, including whether it should have uncertainties in it, and to figure out whether the way they do wear projection is conservative. Their current program does wear projections on a linear basis, but some of the wear history that we have audited for the program may indicate that they are getting some non-linear wear, and we are wondering whether the linear basis is conservative at this point.

They have given us access to some non-docketed information that we are doing sort of an informal audit of now to see whether we can accept their projected basis. So it is under review right now.

MEMBER STETKAR: Is that non-linear wear history specifically focused on that L-3 flux thimble tube?

MR. MEDOFF: I think there are two others that may have non-linear basis, and that is why we are checking the data right now.

MEMBER STETKAR: I will tell you, I plotted out the actual wear history on that tube and, although it is not a perfectly straight line, it is pretty doggone close to a straight line. So a linear projection didn't look too bad to me at least -- well, and the four years of data they had.

DR. HISER: But those are three different areas that have worn. It is not the same area.

MR. MEDOFF: And the other thing is that the one outage that they had some wear, they have not stated in their slide projection. They had replaced that tube in outage 10, and they had

a certain amount of wear in outage 11. They didn't do any corrective action, because it was so low, and then the subsequent outage, they found even more wear. So it went from like 16 percent up to somewhere in the thirties or forties. Then they repositioned the first time.

DR. HISER: And then it went up to about 46 percent in the third year, which is another 16 percent.

MR. MEDOFF: So this tube was a real anomaly, I think, for the facility. We are looking at some of the other tube data to see if this is happening in other tubs.

MEMBER STETKAR: My only concern in terms of consistency in these reviews is that I recognize they had a failure which was an anomaly. You wouldn't have expected a failure after that short a period of time.

I hope the staff is not overreacting to that singular event and applying consistent criteria for these programs across the entire fleet, because the small sample that I took seemed to be -- Now I am not familiar with the actual detailed methods. There may be some subtleties in the methods that they are using

that is the concern, because the way I read the SER, it was strictly on the acceptance criterion, whether or not you have applied uncertainties on it. To me, a 68 percent wear without uncertainty probably adequately applies -- you know, covers uncertainty up to an 80 percent that probably does include uncertainties.

DR. HISER: Yes. I guess the one concern was the inconsistency within their procedures. The procedure referred to a calculation that said 68 percent, and included 10 percent uncertainty. They were not including the 10 percent uncertainty, and that basis was what we were seeking.

MEMBER STETKAR: So you would have expected them to use 58 percent?

DR. HISER: Well, that is what their calculation would have indicated, that that is what they should have used.

MEMBER STETKAR: Well, had you earlier looked at the 59.59 that, I think, I heard changed that?

DR. HISER: No.

MR. MEDOFF: No, and we may -- It is still an open item. We may accept their basis,

but it is under review, at least on the uncertainty. The projection -- The wear projection methodology is something we are going to have to look in a little bit deeper, based on the inspection data that they have given us access to.

DR. HISER: I didn't mean to indicate that we overreacted to the one tube that leaked, but we do want to understand from their comprehensive data whether their wear projection methodology is conservative of nonconservative, and just to ensure that they do get conservative projections.

MEMBER ABDEL-KHALIK: Now you stated that this is unusual OE. If that is the case, and if the cause is flow induced wear, has the staff asked what would be the possible implication beyond just the impact on wear of the flux thimble tubes?

The example would be does that mean that the lower plenum anomaly in this particular plant may be much more severe than what is predicted by the scaled experiments performed by Westinghouse, so that there may be an impact on core design calculations?

MR. MEDOFF: May I address that, Allen? One of the reasons the GALL program is written the way it is, is back for a previous application they did apply the Westinghouse -- they were applying the Westinghouse methodology, and I reminded the applicant that the bulletin has directed that you are supposed to use your own plant specific data in coming up with your wear projections and setting your acceptance criteria.

MEMBER ABDEL-KHALIK: I think that you and I are talking about different Westinghouse data.

DR. HISER: Let me take a crack at that. The excessive accelerated wear in this thimble tube, the applicant has indicated through their failure analysis was due to the tube being repositioned outside of the chrome band, and I think that is the cause of the failure.

I am not aware that any lower plenum anomaly would have impacted that. Since that tube was capped, as far as we know, there has not been any other excessive wear locations identified.

MEMBER ABDEL-KHALIK: This is a highly

localized phenomenon.

DR. HISER: Yes.

MEMBER ABDEL-KHALIK: So if that is the case, could be some sub-assemblies that would be relatively starred for flow at the inlet to the core?

DR. HISER: I am not that familiar with the thermal hydraulics.

ME. MEDOFF: Yes. To get into that, we would have to go back to some of the guys at Division of Systems here at DSS and talk to them about that.

MEMBER ABDEL-KHALIK: You promised to give us some information later on. so we will wait for you information then.

MR. MEDOFF: He has that information now.

MEMBER ABDEL-KHALIK: You do? Well, thank you. Please.

CHAIRMAN BLEY: We will let Diablo Canyon tell it.

MR. MAYER: My name is Mark Mayer. We checked back with our people back at the plant, and we have had an evaluation performed by Westinghouse, and the conclusion was that our

internals are not susceptible to the phenomenon known in the industry as lower plenum anomaly.

What we do have is a fair amount of cross-flow like at the entrance of the core, which does result in some excitation of the flux thimble tubes.

MEMBER ABDEL-KHALIK: And that would be the cause of the wear?

MR. MAYER: That is correct. Going back to your other half of your question, the indications that we would see for lower plenum anomaly would be a combination of sudden changes in core exit thermocouple indications in conjunction with step changes in the indicated RCS flow.

MEMBER ABDEL-KHALIK: You could resolve lower plenum anomaly with core exit thermocouples?

MR. MAYER: They correlate.

MEMBER ABDEL-KHALIK: Thank you.

CHAIRMAN BLEY: Said, you accept that, do you?

MEMBER ABDEL-KHALIK: No, I don't, but it is not important to this.

MR. FERRER: If there is no other

questions, we will move on. Bill Holston will be discussing the buried piping and tanks inspection program open item.

MR. HOLSTON: So we discussed some of this in standard pieces throughout the presentation, but to summarize it all, without going through how the applicant adjusted their program based on recent operating experience, they have confirmed that their backfill won't damage coatings or the piping.

Steel piping is coated. The soil conditions are acceptable for no coatings on their stainless, their copper, and their asbestos concrete pipe.

We have already discussed that they have cathodically protected the steel piping, with the exception of 40 feet of the salt water piping. That is going to be cathodically protected by the period of extended operation and, given that it is not currently cathodically protected, they are augmenting their number of inspections from one to four for that system until it is cathodically protected.

Overall, they increased the number of inspections from originally proposed, which was

two over the 30-year period, to 12 inspections.

The two items that were still open at the time of the SER, we have talked about, and that was the resolution of where the copper valves in scope are not copper alloy, the bronze valves, and the steel piping that was in the makeup system that was buried, and the applicant talked about how they changed their isolation point and less their boundary of the license renewal such that the steel piping was no longer in scope. They appropriately modified their operating procedures to use that as a boundary valve. Are there any other questions?

MEMBER STETKAR: Yes. Simple. I couldn't follow all the bits and pieces. So let me just ask you: Rev 2 of the GALL report has fairly detailed tabulations of the number of inspections and the types of inspections as a function of all of the different parameters you have mentioned, backfill, cathodic protection type of pipe, etcetera, etcetera.

With the exception of the current issues that are under discussion, is Diablo's proposed inspection program consistent with those recommendations?

MR. HOLSTON: Yes, sir, it is. And including the 40 feet of piping that is not cathodically protected.

MEMBER STETKAR: I just couldn't -- I didn't know the piping lengths. Fine. That is all. Yes is a good answer. Thank you.

MR. FERRER: Thanks, Bill. I will now cover the two confirmatory items. Confirmatory item 3.0.3.2.14-1 relates to the inaccessible medium-voltage cables not subject to 10 CFR 50.49, Environmental Qualification Requirements Program.

The staff requested additional information on how the program would account for recent operating experience. In is response, as the applicant stated previously, they increased the scope of the program, removed the significant voltage screening criteria, and increased their manhole inspections to one year.

The staff had identified that we needed clarification on the applicant's justification for not performing the event-driven inspections as well as the use of the 10-year testing frequency, and since then the applicant has, as they stated, submitted a response by

letter dated January 7th. They have provided the additional details, and the staff believes we will be able to close it.

Are there any additional questions on this?

The structures monitoring program confirmatory item: Again, to recap a little bit, the staff noted that the Unit 2 spent fuel pool has the persistent but minor leakage. As part of the response, the applicant clarified that the leakage is contained within the leak chase system, and that they were inspected in March 2010 and were not blocked.

Then they initially committed to perform that follow-up inspection, and our concern was about the timing. They have since then submitted their commitment to perform the inspection one year to prior to entering the period of extended operation. So the staff believes it will be able to close this item as well.

Are there any questions on that?

DR. BARTON: The structures monitoring: Is there any example of exterior containment cracking at the site?

MR. FERRER: Abdul Sheikh can speak to that.

MR. SHEIKH: This is Abdul Sheikh on the NRC staff. When we did the audit, we looked at this closely, and the first thing we noticed was the applicant's program for inspection, and we found that they were inspecting the concrete every 10 years instead of the requirement of five years. So we discussed this with the applicant, and the applicant has changed their procedures, and they are inspecting every five years.

Then we looked at their criteria for inspection on how they record the degradation of concrete, and we found that it was not consistent with the industry criteria, which is ACI-349. So we asked the applicant about it, and applicant has agreed to change their procedures to inspect it according to the industry criteria.

Then we asked them to look at all the discrepancies they have for spalling and degradation in concrete which they have recorded based on the new criteria, and their engineers have looked at it and found all of them are accepted within the criteria.

DR. BARTON: Thank you. The reason I

bring that is, in the SER Structures Monitoring Program, the operating experience section of that describes instance of concrete delamination, spalling exterior containment, corrosion of containment and liner, cracking at Turbine Building concrete piers to the turbine pedestal, and conditions of the concrete intake structure.

I guess my overall question is: Does the staff feel that the applicant has got all this under control or is the plant crumbling around it?

MR. PICK: During our on-site inspection, looking at that same inspection report where we noticed the strain gauge boxes, there were also photographs of cracks on the exterior of the containment, but they were -- Many of them did not have a gauge to figure out how wide they were, but a couple of them showed a pop-out the size of an eighth of an inch.

So there is some small cracking on the exterior of the containment. But the answer of the concern of whether it is falling down around us, the staff felt that the material condition of the areas that we reviewed looked good.

DR. BARTON: That section just

describes a lot of misery in inspector concrete cracks and stuff like that, not just in the containment but turbine piers at a pedestal and stuff like that. So just wonder whether you guys looked at all that and you've got some concern about those areas, or not. That is all I am asking.

MR. PICK: Our structural inspector also looked at the base of many of the tanks, even up to the raw water ponds. Basically, everywhere that he could physically walk and access, he did, and he reported back that he did not have any concerns with the concrete.

MR. FERRER: Any other questions? We will now move on to SER Section 4, which contains the staff's review of time-limited aging analyses. In this section, we will focus mainly on the three open items and any additional items of interest.

Section 4.2 of the SER documents the staff's review of the reactor vessel neutron embrittlement time limited aging analyses. With regard to the pressurized thermal shock, Diablo Canyon has one insensible weld not meeting the 10 CFR 50.61 pressurized thermal shock screening

criteria, and this slide provides the information on the Unit 1 lower shell longitudinal weld noted up there.

The applicant stated that it would either implement 10 CFR 50.61(a) at least three years prior to exceeding the PTS screening criteria or, if it cannot meet that, it would implement alternate options, such as flux reduction.

So unless there are any questions, Allen Hiser will now discuss the three open items.

MEMBER SHACK: Is this the first time that they have asked for 50.61(a)?

DR. HISER: I believe it is the first time any applicant has asked for it.

MEMBER SHACK: Has Beaver Valley come back? I mean, they had sort of committed to something like flux reduction. Right?

DR. HISER: I am not sure what their measures are. Within the 54.21(c)(iii) EV management, they have a variety of options that they could implement.

MEMBER SHACK: But they haven't come back for them?

DR. HISER: No, I don't believe so at this point. And, generally, they would have flexibility within the PTS rule, for example, to wait until three years before they would exceed the PTS screening criteria before they would have to identify to the staff additional actions that they were going to take.

During the staff's review of Section 4 on time-limited aging analyses, the staff identified two TLAAs that the applicant had indicated that there was no TLAA, the first area on reactor coolant pressure boundary valves.

The staff routinely reviews the application and the design codes that are cited in the application to ensure that there are no TLAAs that relate to those analyses. In the case of this application, there was insufficient information for the staff to do that review, and at this point that is still an open item.

We have received a response, but we have not completed our review of that response.

On the baffle and former bolts, there is an existing ASME Section 3 cumulative usage factor calculation on fatigue. The applicant indicated that that was not a TLAA, because they

would be providing aging management using MRP-227 inspection criteria.

Although that is technically one way to manage fatigue, it is not consistent with the Section 3 requirements that you maintain your design basis and maintain a cumulative usage factor. The applicant has provided a response, and again we are evaluating the acceptability of that response.

If we move to the next slide, metal fatigue is another area where the staff identified the need for additional information. Even after reviewing that additional information, we ended up with an open item, 4.3-1. It had several parts to it.

We have binned those, as indicated here, under cycle counting, environmentally assisted fatigue, and cumulative usage factors. I believe the applicant did a fairly thorough review of the various pieces of this open item. So I don't want to go into anymore detail than that.

We have received the open item RAI response, and we are still reviewing that.

If there are no other questions?

MEMBER STETKAR: Yes. Let me ask you about cycle counting, because I got a chance to ask Diablo. In the SER, Diablo used some sort of methodology to infer the number of feedwater cycle events, I guess, going to hot shutdown or at hot shutdown transients based on the number of pressurizer heat-up events. So there was some sort of inferred correlation there.

I didn't quite understand how they did that, because when I -- this again is a consistency issue, because when I project the number of pressurizer heat-ups using the correlation that I thought they did, I come up with a different number of projected feedwater transients. So I am not quite sure what they did. Do I care? Yeah, I do, for consistency.

They are well in the margin, but I like consistent numbers. However, I noted in the SER it says the staff also independently confirmed that the applicant's basis yields a projected feedwater cycling event value of 685 events for Unit 1 -- yada, yada, yada.

In a separate paragraph, the staff has independently calculated the number of feedwater initiating events to be 685 initiations. Well, I

could independently calculate those, because I can multiple 14 times X and get those numbers. Is that the independent calculation that you did to confirm that 14 times X is --

MR. MEDOFF: We take the data they give us, because they are doing --

MEMBER STETKAR: It is not an independent calculation, is it? It is a sort of can I multiply check. I am led to infer that you had some other data and did some different type of analysis on that.

MR. MEDOFF: We use the cycle counting data they provide for us.

MEMBER STETKAR: So you check whether their calculator could multiply. Thanks. I get concerned about independently verified or independently calculated numbers versus audited their calculation and indeed confirmed that they multiplied correctly.

MR. MEDOFF: But this is similar to what we do for the PTS assessment that we gather data.

MEMBER STETKAR: Well, but in some cases, for example, in other parts of the reviews and audits that the NRC staff does, they actually

run separate, independent analyses; for example, thermal hydraulic analyses or things like that, that are actually independent calculations to confirm an applicant's projections or analysis.

MR. MEDOFF: This is more of an independent verification.

MEMBER STETKAR: Okay, thanks. I just wanted to make sure I wasn't missing something.

DR. HISER: Okay, we are ready for the next slide. Open item 4.7.5-1 covers the RHR piping weld that the applicant described earlier.

During the staff's review, the staff noted that the applicant did follow ASME code requirements and that the location of the flaw that they identified met the proximity rule requirements of IWA 3300 of the ASME code and, therefore, in their fracture stability calculation they assumed that it was a throughwall flaw.

The staff felt that it was inconsistent then for the applicant to not use -- or not assume a stress corrosion cracking or a water environment for that flaw, and asked the applicant to justify its position. As indicated by the applicant, they have gone ahead and done

the stress corrosion cracking calculation and had submitted that to the staff. We have not completed our review of that, but will do so and we will document that in the final SER.

So that is the open item related to the RHR weld.

MR. FERRER: In closing, the staff is working to resolve the open items and, pending resolution of these items, the staff is working to issue the SER. Again, thank you for the opportunity to discuss the staff's review of the Diablo Canyon license renewal application.

CHAIRMAN BLEY: Anymore questions from the Committee? Thank you very much for the presentations.

At this point, Diablo Canyon has some answers to questions we had asked earlier.

MR. SHARP: Loren Sharp from Diablo Canyon. If I could have David Gerber answer the question on cycles.

MR. GERBER: My name is Dave Gerber. I am with Structural Integrity Associates, and I am on the Diablo Canyon License Renewal Team.

The question, as I understood it, is why is the baseline number of the aux spray

during plant cooldown events not two times the number of plant cooldown events?

MEMBER STETKAR: Yes.

MR. GERBER: The answer is that we took two different periods of time to make this evaluation. The first period of time there was no -- The plant data available to do counting was not available. The second period of time, the plant's data was available.

For the first period, we applied the two times rule, aux spray during plant cooldown equals two times plant cooldown. For the second period we actually counted both plant cooldowns and aux spray during plant cooldowns. Thus, the projection could and did divert.

MEMBER STETKAR: Thanks. Thank you.

MR. SHARP: Thank you. I believe that answers all, but we still owe you one, I believe.

CHAIRMAN BLEY: At this time, I would ask if there are any comments from the public attending the meeting.

I would like to go around and have members of the Committee provide any comments on what we have heard today, and then we get our consultant after that. So if we can start with

Jack Sieber.

MEMBER SIEBER: I think that the level of review and the quality application is consistent with most of the plants that we have reviewed. I think there are unanswered questions and, obviously, there are open items, RAIs that we will have to look at before we get to the final meeting, but I think the actions taken for the issues that I am concerned about are consistent with the ways that industry has basically solved the problems at hand, and I think that the applicant is basically aware of the issues that exist with this type of plant and this environment.

So I am reasonably satisfied that progress is being made.

CHAIRMAN BLEY: Thank you. Harold?

MEMBER RAY: I don't have anything to add.

CHAIRMAN BLEY: Sam?

MEMBER ARMIJO: Yes. I thought it was a very good presentation. I think the plant, based on the inspection results and all the information provided, is in good shape. The arguments about the weld flaw and what it means

and whether it is going to grow are very persuasive to me, particularly when the temperatures are as low as they are, but the UT examination technique, I thought, was very good. So I don't think that is a big concern.

Although it wasn't presented, I did review the material on the water chemistry and the material degradation in the plant over the lifetime. I think, based on that information, it has been excellent, and I think the very few stress corrosion cracking events attest to that very good control of the operating environment, and I think that will continue during the period of extended operation.

So overall, I think it is in very good shape.

CHAIRMAN BLEY: Thank you.

MEMBER ABDEL-KHALIK: I have no additional remarks.

CHAIRMAN BLEY: John?

MEMBER STETKAR: Nothing. Nothing at all. I think the staff did a really good review. So I congratulate them on another good job well done.

MEMBER RYAN: I second what has been

said before, and I also appreciate the applicant bringing, I think, promising weather from the plant here today.

CHAIRMAN BLEY: There is nothing in the store, Mike. Come on.

MEMBER RYAN: I appreciate the fact that you brought everybody here to answer any question we might have. Thank you.

CHAIRMAN BLEY: Bill?

MEMBER SHACK: Nothing additional.

CHAIRMAN BLEY: Mike?

MEMBER CORRADINI: Nothing additional.

CHAIRMAN BLEY: Nothing more from me, although just to check my counting on the questions that Jack raised, did I count right? Are there only two open items left that still need resolution, the flux thimbles and the stress corrosion cracking?

MR. FERRER: Also, the TLAA identification of metal fatigue, we are still reviewing those as well.

DR. HISER: We just have not completed our reviews of those items, the TLAA.

CHAIRMAN BLEY: Did we have a phone line open? I don't think so.

MR. BENSON: Yes, we did have some people call in.

CHAIRMAN BLEY: Want to open it up and see if we have public comments from them? Can we do that?

CHAIRMAN BLEY: Oh, I am sorry. John Barton. I forgot. I just slid right by. Please. You should have yelled at me.

DR. BARTON: I usually don't give out kudos, but I got to give that to the staff. I mean, after seeing the number of RAIs, follow-up RAIs, conference calls -- I mean, it had to get pretty tough.

You know, we are doing -- this is 62, 63, somewhere in there, in license --

CHAIRMAN BLEY: Sixty-three.

DR. BARTON: And I guess I have looked at about 42 of them. This application looked like it was the initial plants when GALL was out, before NEI came on board, and I just thought it was not very good quality.

I feel a lot better today after hearing the applicant's presentation and the staff's work that they have done in reviewing this thing. But I just expected at this stage of

the process a lot better application than what you people received, and I think those are -- I don't see any major issue that says that this plant doesn't deserve license extension after all the issues are resolved. It just didn't look good from the get-go. That is all I am going to say.

CHAIRMAN BLEY: Thank you, John.

I think the phone line is open now. If anybody is on the phone, please just say a word so we know you are there, hello or something. Oh, there is somebody there. So if anyone listening in on the phone line cares to make a comment, we would be glad to entertain that at this point in time. Identify yourself and make your comments, please. I take nobody wants to.

I want to thank the applicant and the staff for very good presentations and discussions. We appreciate it a lot, and this meeting is adjourned.

(Whereupon, the foregoing matter went off the record at 4:31 p.m.)

DIABLO CANYON POWER PLANT
LICENSE RENEWAL

Jim Becker

Site Vice President

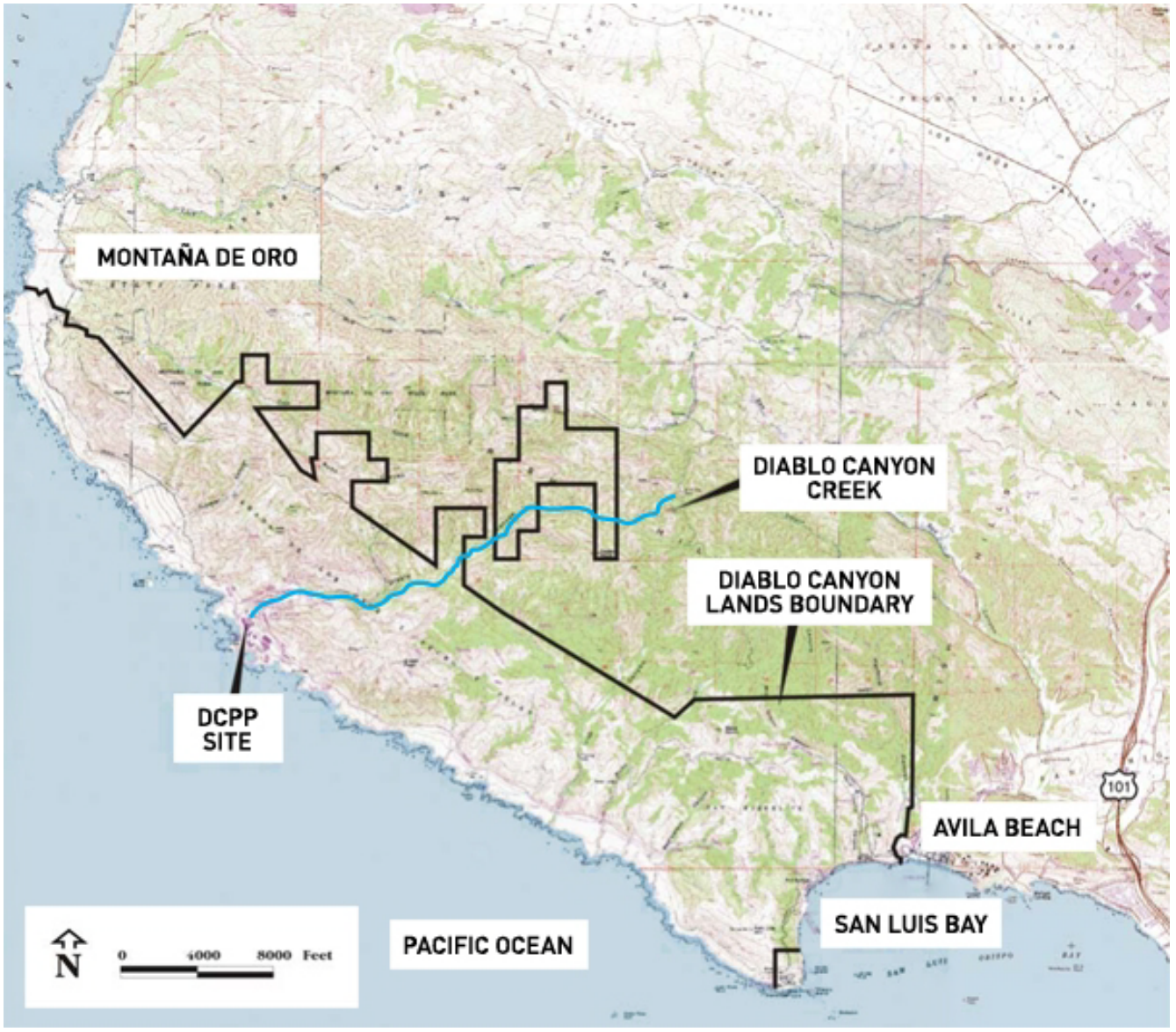
DIABLO CANYON POWER PLANT
PERSONNEL IN ATTENDANCE

- Jim Becker, Site Vice President
- Loren Sharp, Senior Director Technical Services
- Mike Wright, Engineering Manager
- Terry Grebel, License Renewal Project Manager
- STARS Center of Business and Plant Staff

AGENDA

- Introductions
- Site and Station Description
- Plant History
- Major Improvements
- GALL Consistency and Commitments
- Safety Evaluation Report Open and Confirmatory Items
  - Flux Thimble Tube Inspection Program
  - Flaw Growth Evaluation for RHR
  - Scoping and Screening
  - Buried Piping and Tanks Inspection Program
  - TLAA Identification
  - Metal Fatigue
- Concluding Remarks

SITE DESCRIPTION



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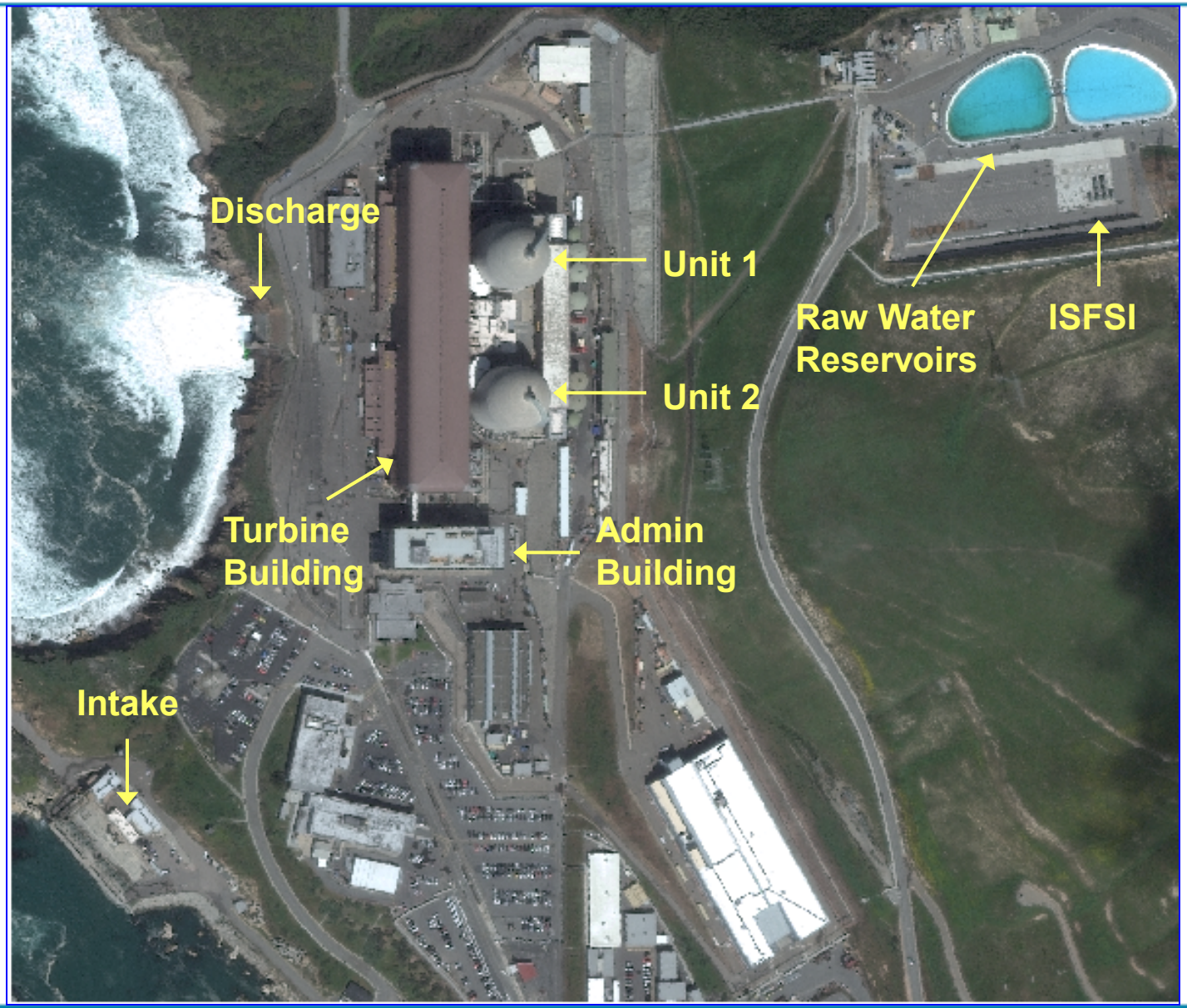


STATION DESCRIPTION

- Two Units
  - Common operating procedures/design
- 4 loop Westinghouse NSSS 3411 MWt
- PG&E was architect/engineer with Bechtel support
- Once-through cooling
- Containment – free standing, steel-lined, reinforced concrete building
- PG&E owner and operator
- PG&E owns and operates the switchyards and the high voltage transmission system

Loren Sharp

Senior Director, Technical Services

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

- Leadership, oversight and ownership by Diablo Canyon personnel through the License Renewal development and review phases, continuing through implementation

PLANT HISTORY

- Unit 1 full power operating license issued November 2, 1984
- Unit 2 full power operating license issued August 26, 1985
- October 2000, Unit 1 increased licensed power to 3411 MWt
- Unit 1 operating license expires November 2, 2024
- Unit 2 operating license expires August 26, 2025

MAJOR IMPROVEMENTS

- Steam Generators replaced
- Reactor Heads replaced
- Auxiliary Saltwater System piping bypass
- Diesel Fuel Oil tanks replaced
- Low Pressure Turbine rotors replaced
- 4 kV cables replaced
- 6th Emergency Diesel Generator added
- Main Generator Rotors replaced
- Feedwater heaters/MSR copper tubes replaced with stainless steel
- Main Bank and Start-up Transformers replaced
- Analog to Digital Control Systems upgraded
- Extensive FAC piping replacements

Terry Grebel

License Renewal Project Manager

GALL CONSISTENCY AND COMMITMENTS

- Total Aging Management Programs – 42
  - Existing Programs – 31
  - New Programs – 9
  - Plant Specific – 2

- Aging evaluations are greater than 93% consistent with GALL Rev 1 (standard notes A through E)

- License Renewal commitments – 64

- License Renewal commitments managed through the DCPP commitment tracking system which implements the guidance of NEI 99-04, Revision 0, “Guidelines for Managing NRC Commitment Changes”

SAFETY EVALUATION REPORT

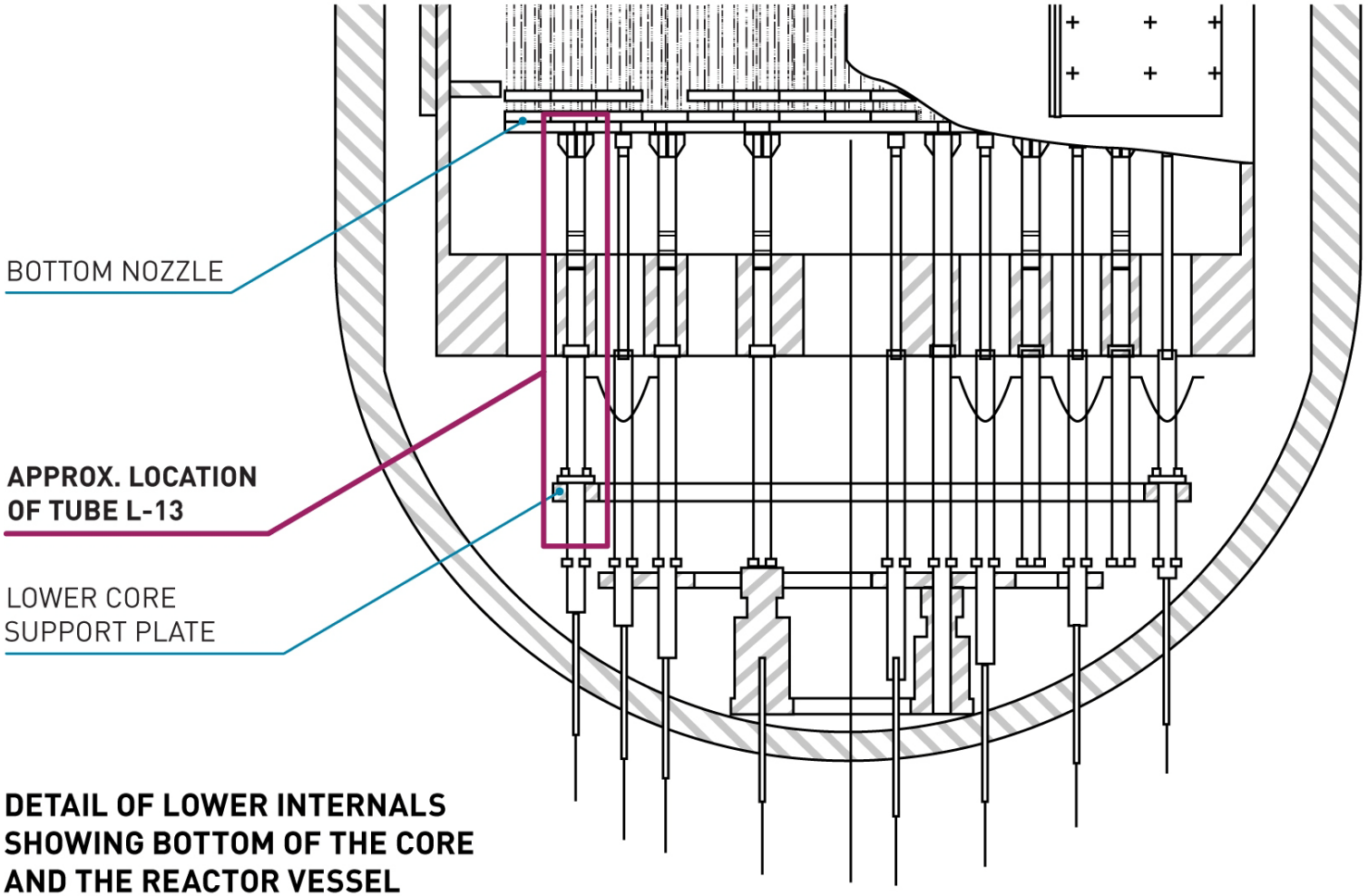
- OPEN ITEMS – 8
  - Flux Thimble Tube Inspection Program
  - Flaw Growth Evaluation for RHR
  - Scoping and Screening (3 Open Items)
  - Buried Piping and Tanks Inspection Program
  - TLAA Identification
  - Metal Fatigue

- CONFIRMATORY ITEMS – 2
  - Cable Testing 6 Years Frequency
  - Spent Fuel Pool Leak Chase Inspection Schedule

Flux Thimble Tube Inspection Program

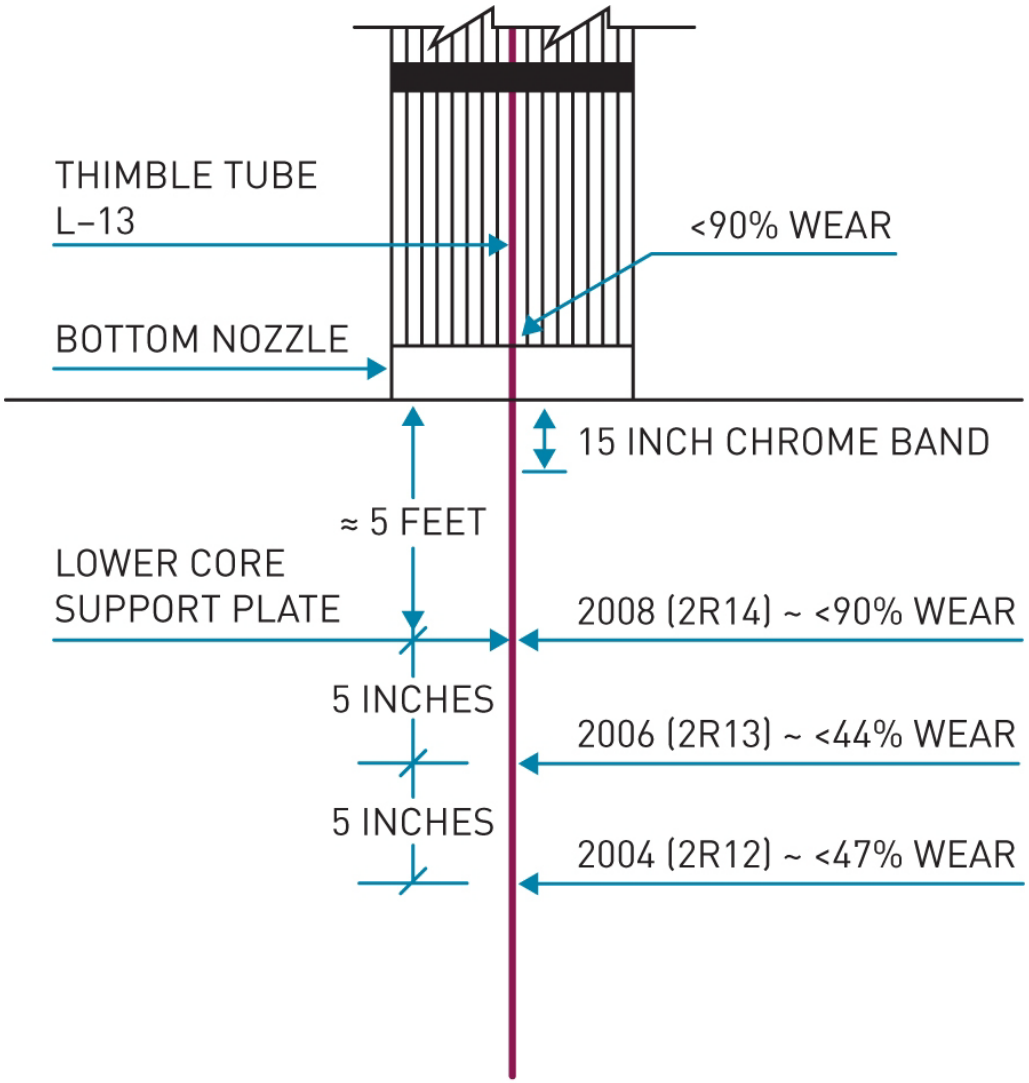
Mike Wright
Engineering Manager

DCPP THIMBLE TUBE BACKGROUND



DETAIL OF LOWER INTERNALS SHOWING BOTTOM OF THE CORE AND THE REACTOR VESSEL

DCPP THIMBLE TUBE L-13 HISTORY



NOTE: NOT TO SCALE

FLUX THIMBLE TUBE INSPECTION PROGRAM

OI 3.0.3.2.12-1 - RAI B2.1.21-1

- Issue:
  - Based on Unit 2 thimble tube L-13 operating experience, justify an appropriate margin to account for NDE measurement and wear scar uncertainties

- Resolution:
  - DCPP wear projection methodology was compared to Westinghouse WCAP-12866 using site-specific wear data
  - WCAP methodology acceptance criteria is 80% wear (including uncertainties)
  - DCPP acceptance criteria is 68% wear (17.5% margin from WCAP)
  - DCPP acceptance criteria is conservative and comprehensive

FLUX THIMBLE TUBE INSPECTION PROGRAM

OI 3.0.3.2.12-1 - RAI B2.1.21-2

- Issue:
  - Additional information regarding L-13 FTT failure causes and corrective actions

- 2R14 (2008) L-13 actions & cause determination

  Cause of Failure:
  - L-13 thimble tube failure caused by flow-induced wear and plant practices that allowed multiple repositioning of thimble tubes
  - Repositioning practices exposed non-chrome plated portion of the thimble tube to the bottom nozzle
  - No cracking has been identified in any thimble tube eddy current examinations

FLUX THIMBLE TUBE INSPECTION PROGRAM

OI 3.0.3.2.12-1 - RAI B2.1.21-2

- Resolution: Non-Linear Wear
  - Procedure acceptance criteria revised to require capping or replacing tubes:
    - > 25% wear per year, or
    - Any tube with multiple wear scars, any two of which measured > 40% wear
  - In addition:
    - Tube may only be repositioned 6 inches, and
    - Tube may only be repositioned once
  - Replacement thimble tubes are supplied by Westinghouse with a 12 foot chrome plated band

FLUX THIMBLE TUBE INSPECTION PROGRAM
CONCLUSION

- PG&E is confident that the 68% acceptance criteria in combination with the additional procedural acceptance criteria is comprehensive and conservative

Flaw Growth Evaluation for RHR Piping Weld

David Gonzalez
ISI Supervisor

Flaw Growth Evaluation for RHR Piping Weld WIC-95

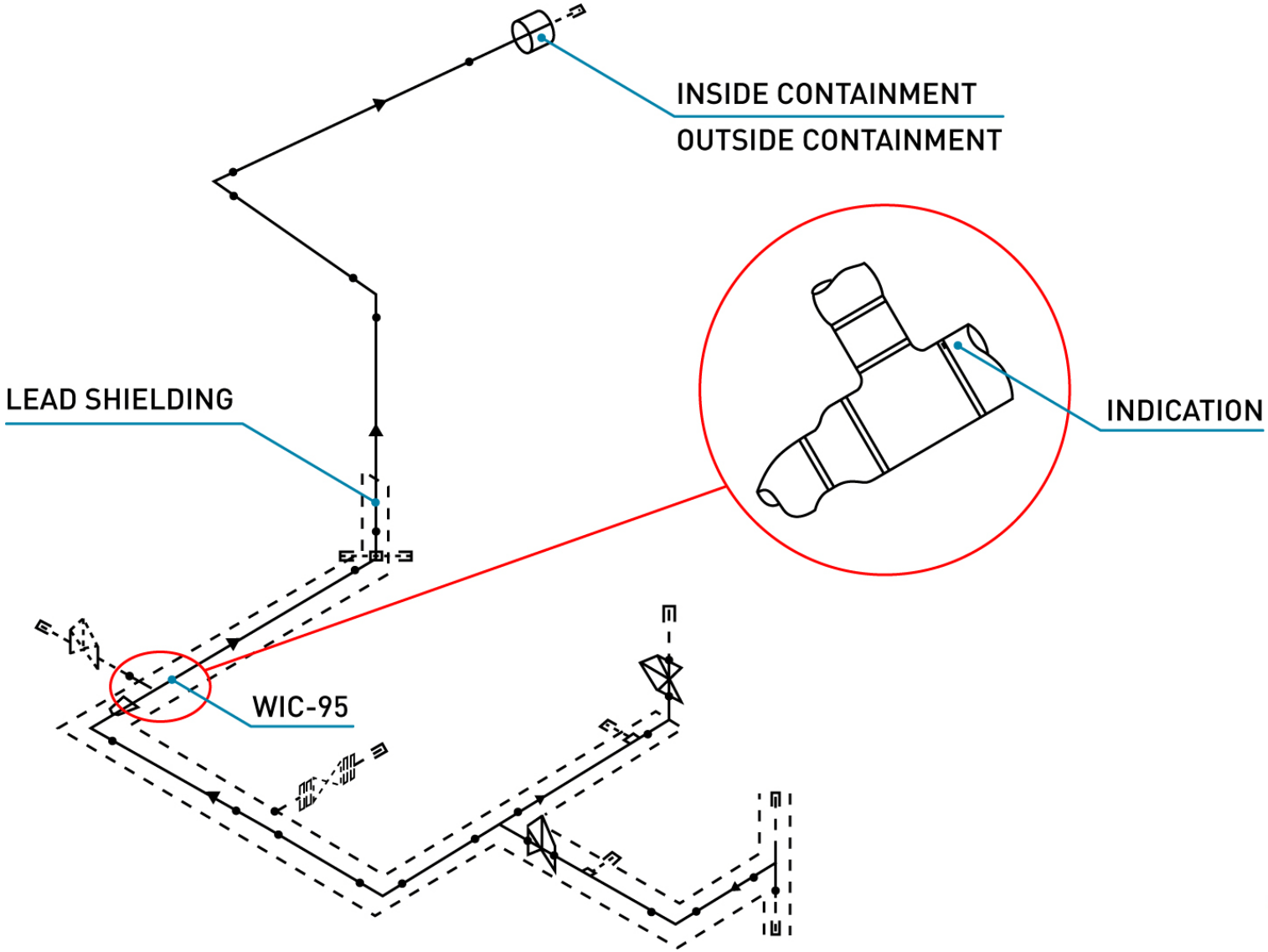
OI 4.7.5-1 – SER 4.7.5

- Issue:
  - PG&E's basis for concluding that the flaw in Unit 1 RHR piping weld WIC-95 is not service-related
  - PG&E's flaw analysis for this weld did not address stress corrosion cracking (SCC)

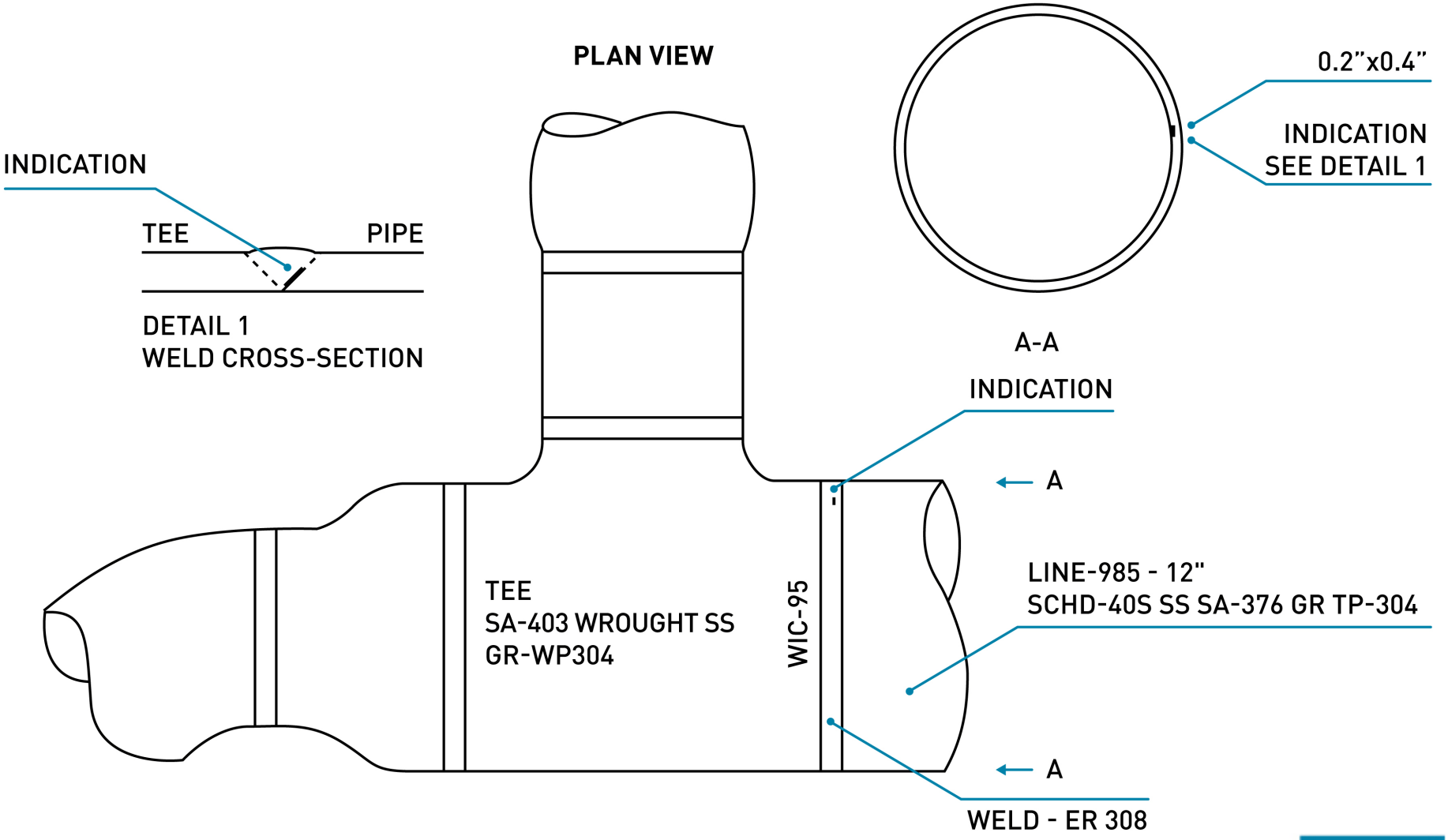
- Background:
  - Evaluated the characteristics of the flaw as non-service induced
  - Fatigue crack growth evaluated with acceptable results
  - Subsequent 2000 UT inspection result consistent with non-service induced (no growth)

- Resolution:
  - SCC evaluation performed with acceptable results
  - Confirmatory UT inspection of WIC-95 during the 2012 outage

Flaw Growth Evaluation for RHR Piping Weld WIC-95



Flaw Growth Evaluation for RHR Piping Weld WIC-95



Dave Miklush

Diablo Canyon License Renewal Project

SCOPING AND SCREENING

OI 2.1-1 – SER 2.1.4.1.2

- Issue:
  - NSR fluid-filled components in the vicinity of SR components

  (1) Rainwater entering HVAC ducting to vital 480V switchgear room

  (2) Firewater piping in the vicinity of the Control Room Pressurization System I&C

  (3) Firewater piping and domestic water piping in the vicinity of HVAC exhaust openings to 4kV switchgear room

- Resolution:

  (1) Enhanced water drainage provisions in Unit 2 HVAC exhaust ducting

  (2) Include in scope firewater piping under 10 CFR 54.4(a)(2)

  (3) Include in scope firewater and domestic water piping under 10 CFR 54.4(a)(2)

SCOPING AND SCREENING

OI 2.1-1 – SER 2.3

- Issue:
  - NSR fluid-filled components leaking or spraying onto SR cables in electrical pull boxes
- Resolution:
  - Pull boxes drain to building sumps or in-ground sumps
  - In-scope pull boxes are physically separated from the sumps and from the pumps and discharge piping

SCOPING AND SCREENING

OI 2.1-1 – SER 2.3.3.7.2

- Issue:
  - NSR fluid-filled water traps spraying onto SR components
- Resolution:
  - This portion of system is not used
  - Commitment to close the upstream isolation valves and drain any contained water from the traps

SCOPING AND SCREENING

OI 2.3-1 – SER 2.3

- Issue:
  - NSR tubing directly attached to SR solenoid valves in the compressed air system

- Resolution:
  - All NSR tubing directly attached to SR solenoid valves in the compressed air system is included in scope up to the first seismic or equivalent anchor on the NSR side of the code break

SCOPING AND SCREENING

OI 2.3.3.14-1 – SER 2.3.3.14.2

- Issue:
  - Scoping methodology of Diesel Generator compressor unloader line endpoint for pressure boundary function

- Resolution:
  - Design change relocates unloader tubing to the compressor discharge piping upstream of the pressure boundary isolation check valve
  - After design change unloader line is no longer in-scope
  - Completed on Unit 1; Unit 2 scheduled for April 2011

BURIED PIPING AND TANKS INSPECTION PROGRAM

OI 3.0.3.2.8-1 – SER 3.0.3.2.8

- Issue:
  - Management of aging effect for buried copper valves in the Makeup Water System
  - Clarification of in-scope steel pipe in the Makeup Water System

- Resolution:
  - Buried copper valves will be managed by the Buried Piping and Tanks Inspection Program
  - Commitment to enhance operating procedure to close Makeup Water System isolation valve in event of a pressure boundary failure and removed steel piping and components from scope

Michelle Albright

Diablo Canyon License Renewal Project

TIME-LIMITED AGING ANALYSES IDENTIFICATION

OI 4.1-1

- RAIs:
  - Reactor coolant pressure boundary valves
  - Baffle and former bolts

- Resolution:
  - Confirmed DCPP design codes for the reactor coolant pressure boundary valves do not require a fatigue analysis
  - Fatigue of the baffle and former bolts is managed by the Reactor Vessel Internals AMP

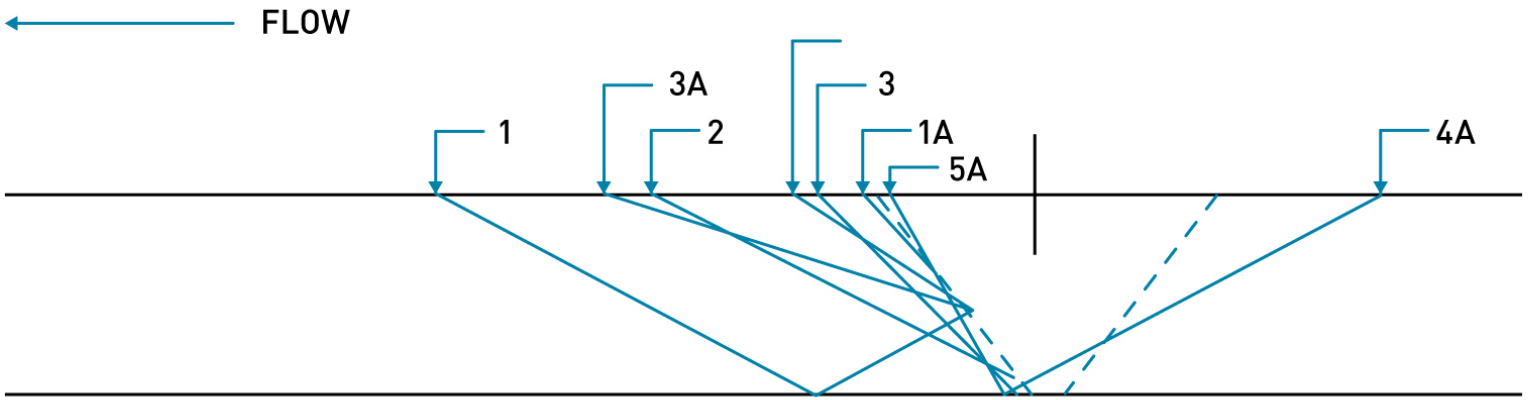
METAL FATIGUE
OI 4.3-1

- **Additional information**
  - Replacement reactor head CUF values
  - AMR revisions for piping system cumulative fatigue damage
- **Clarification**
  - Cycle counting for upper and lower core plates
  - Cycle estimates for the “Auxiliary Spray during Plant Cooldown” transient
  - Charging system cycle estimate methodology during unmonitored periods
  - Electrical raceway seismic evaluation requirements
- **FSAR/CLB enhancement**
  - Load-following transients used in design analyses and the FSAR
  - Monitoring transients in non-CUF type analyses
- **Evaluate DCPP Environmentally-Assisted Fatigue analyses**

Concluding Remarks

Jim Becker
Site Vice President

Flaw Growth Evaluation for RHR Piping Weld WIC-95



WIC-95

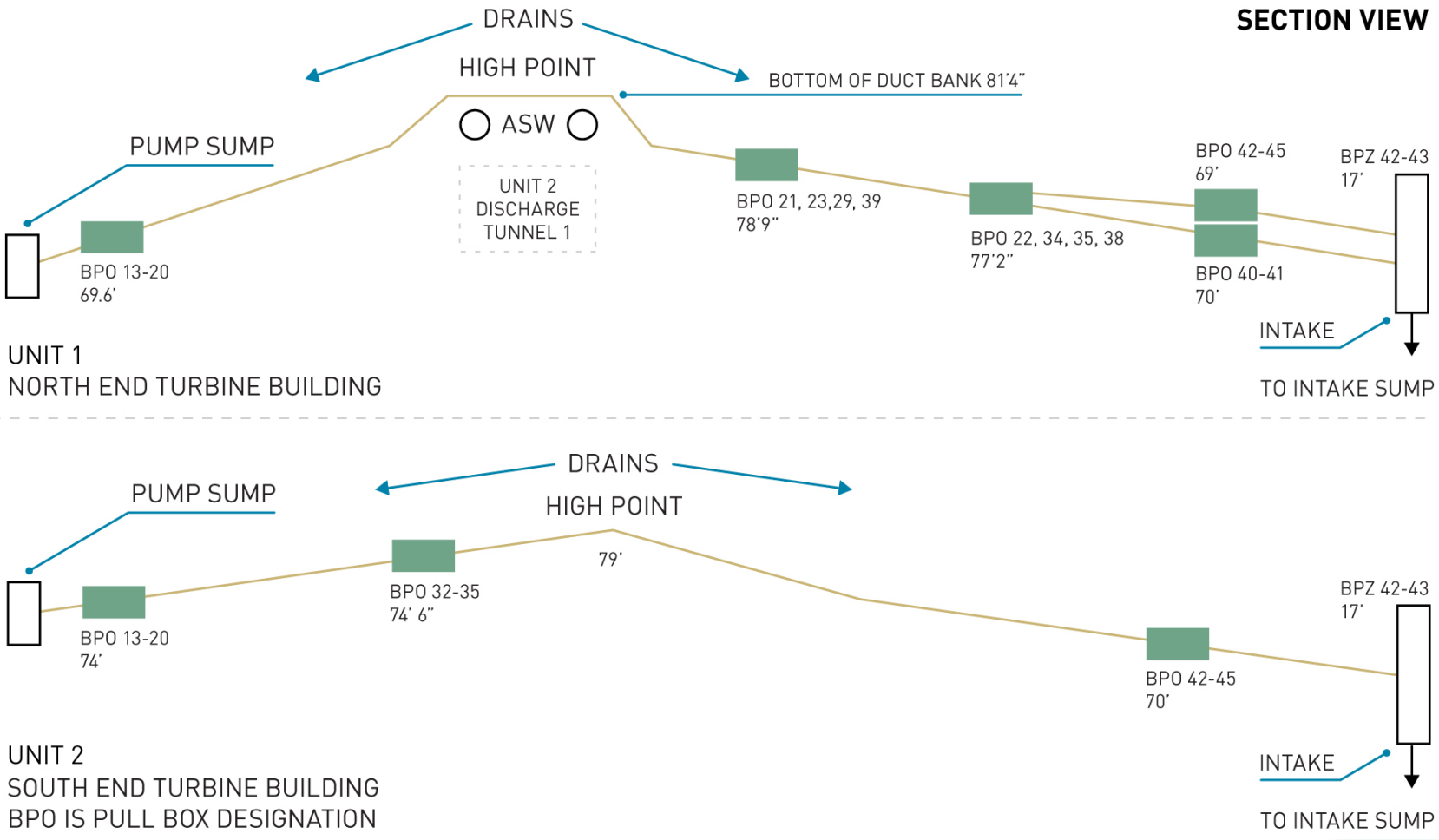
1=70S	(63°)	4/29/97
1A=45L	(41°)	5/02/97
2=70S	(63°)	4/29/97
2A=60L	(58°)	5/02/97
3=45L	(41°)	4/29/97
3A=OD	CREEPER	5/02/97
4A=70S	(63°)	5/02/97
5A=WSY		5/02/97

(XX°)= ACTUAL ANGLE

FLUX THIMBLE TUBE

	Unit 1	Unit 2	Wear Potential	Notes
Original (No Chrome)	24	33	Minimal	
Chrome: 15 Inches	9	7	Minimal (Outside Chrome Band)	No Wear on Chrome Band
Chrome: 12 Feet	21	10	Minimal (Outside Chrome Band)	
Capped	4	7	None Observed	Scheduled for Replacement in 2R16, May 2011
Guide Tube Capped		1 (L-13)	N/A	Thimble Tube Removed
Useable	54	50		44 Needed for Tech Spec Flux Map

CONDUIT LAYOUT (SECTION VIEW)



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Protecting People and the Environment

Advisory Committee on Reactor Safeguards
License Renewal Subcommittee
Diablo Canyon Nuclear Power Plant, Units 1 and 2

Safety Evaluation Report with Open Items

February 9, 2011

Nate Ferrer, Project Manager

Office of Nuclear Reactor Regulation

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Protecting People and the Environment

Presentation Outline

- Overview of DCPP License Renewal Review
- SER Section 2, Scoping and Screening review
- Region IV License Renewal Inspections
- SER Section 3, Aging Management Programs and Aging Management Review Results
- SER Section 4, Time-Limited Aging Analyses

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Overview of LRA

- License Renewal Application submitted November 23, 2009
  - Applicant: Pacific Gas and Electric Company
  - Facility Operating Licenses DPR-80 and DPR-82 expire November 2, 2024, and August 26, 2025, respectively
- Approximately 12 miles west southwest of San Luis Obispo, CA in Avila Beach, CA
- DCPP units are Westinghouse four loop PWRs

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Audits and Inspections

- Scoping and Screening Methodology Audit
  - March 15-18, 2010
  - Led to submittal of 2 LRA amendments related to scoping and screening
- Aging Management Program Audits
  - April 12-15, 2010
  - April 26-29, 2010
  - Over 20 technical reviewers, including contractors from ANL and ORNL
- Region IV Inspection
  - August/September 2010

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Overview of SER

- Safety Evaluation Report with Open Items issued January 10, 2011
- SER contains 8 Open Items:
  1. 10 CFR 54.4(a)(2) evaluations for nonsafety-related, fluid-filled structures and components (SCs) in the vicinity of safety-related SCs (Open Item 2.1-1)
  2. 10 CFR 54.4(a)(2) evaluations for nonsafety-related piping directly attached to safety-related components (Open Item 2.3-1)
  3. Endpoint for the diesel air start unloader line (Open Item 2.3.3.14-1)

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Overview of SER (cont.)

- SER contains 8 Open Items (cont.)
  4. Buried Piping and Tanks Inspection Program (Open Item 3.0.3.2.8-1)
  5. Flux Thimble Tube Inspection Program (Open Item 3.0.3.2.12-1)
  6. TLAA Identification (Open Item 4.1-1)
  7. Metal Fatigue (Open Item 4.3-1)
  8. Flaw Growth Evaluation for RHR piping Weld (Open Item 4.7.5-1)

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Overview of SER (cont.)

- SER contains 2 Confirmatory Items
  1. Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program (Confirmatory Item 3.0.3.2.14-1).
  2. Structures Monitoring Program (Confirmatory Item 3.0.3.2.18-1)

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SER Section 2 Summary

- Structures and Components Subject to Aging Management Review
  - Section 2.1, Scoping and Screening Methodology (open item)
  - Section 2.2, Plant-Level Scoping Results
  - Section 2.3, Scoping and Screening Results - Mechanical (open items)
  - Section 2.4, Scoping and Screening Results - Structures
  - Section 2.5, Scoping and Screening Results - Electrical

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SER Section 2 Open Items

- 10 CFR 54.4(a)(2) evaluations for nonsafety-related, fluid-filled components in the vicinity of safety-related components, Open Item 2.1-1
  - control room pressurization system/HVAC exhaust ducts
  - electrical pull boxes
  - compressed air system water traps
- 10 CFR 54.4(a)(2) evaluations for nonsafety-related piping directly attached to safety-related components, Open Item 2.3-1
  - compressed gas systems
- 10 CFR 54.4(a)(1) evaluations for scoping boundary of safety-related piping, Open Item 2.3.3.14-1
  - EDG air start system – unisolated unloader line from air receiver back to the air compressor
- Applicant has submitted additional information
- Staff is finalizing its review of the response

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Regional Inspection - License Renewal Inspections Program Implementation

Greg Pick

Region IV Inspection Team Leader

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Regional Inspection Overview

- Six inspectors for 2 weeks
- Scoping & screening inspection
- Aging management programs inspection
- Several focus areas

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Regional Inspection Focus Areas

- SSCs needed to withstand a design basis seismic event
- SSCs and programs that prevent leaks to the environment
- Treatment of the latest industry aging concerns
- Prior site-specific aging issues

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Regional Inspection Results

- Scoping of nonsafety-related systems
  - Spatial interaction issues
  - Some material types incorrect or omitted
- Aging management programs
  - Training required
  - Degraded silicon seal
  - Reviewed electrical vaults
  - Location selected for fouling
  - Procedures developed but some errors

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Regional Inspection Observations

- Overall, good material condition
- Procedures developed for the programs reviewed
- Major component replacements
  - 230 kV & 500 kV insulators
  - Intake structure

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Regional Inspection Conclusions

- Scoping of non-safety SSCs and application of the AMPs to those SSCs were acceptable
- Applicant personnel had incorporated actions to manage aging effects into their programs
- Reasonable assurance exists that aging effects will be managed and intended functions maintained

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Section 3: Aging Management Review

- Section 3.0 – Aging Management Programs (2 open items & 2 confirmatory items)
- Section 3.1 – Reactor Vessel & Internals
- Section 3.2 – Engineered Safety Features
- Section 3.3 – Auxiliary Systems
- Section 3.4 – Steam and Power Conversion System
- Section 3.5 – Containments, Structures and Component Supports
- Section 3.6 – Electrical and Instrumentation and Controls System

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SER Section 3

3.0.3 – Aging Management Programs

- 42 aging management programs (AMPs) presented by applicant and evaluated in the SER

	Consistent with GALL	Consistent with exception	Consistent with enhancement	Consistent with exception & enhancement
Existing (31)	16	5	5	5
New (9)	5	4	N/A	N/A
Plant-specific (2)	N/A	N/A	N/A	N/A

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SER Section 3 Open Items

- Flux Thimble Tube Inspection Program, Open Item 3.0.3.2.12-1
  - Justification for not including measurement and wear scar geometry uncertainties
  - Wear rate projection methodology and the capability of program to detect degradation in a flux thimble before the occurrence of a through-wall failure
  - Applicant has submitted additional information
  - Staff is reviewing the response

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SER Section 3 Open Items

- Buried Piping and Tanks Inspection Program, Open Item 3.0.3.2.8-1
  - Staff requested additional information on how the program would account for recent operating experience
    - Backfill is acceptable
    - Cathodic protection provided
    - Coatings utilized
    - Increased inpsections
  - Applicant's initial response did not provide details for:
    - Management of buried copper and steel valves and piping in the makeup water system
    - Alternate methods used for inspections
  - Applicant has submitted additional information
  - Staff is finalizing its review of the response

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SER Section 3 Confirmatory Item

- Inaccessible Medium-Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Program, Confirmatory Item 3.0.3.2.14-1
  - Staff requested additional information on how the program would account for recent operating experience
  - Applicant's initial response did not provide sufficient details for absence of event-driven inspections or use of a 10-year testing frequency
  - Applicant has submitted additional information
  - Staff is finalizing its review of the response

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SER Section 3 Confirmatory Item

- Structures Monitoring Program, Confirmatory Item 3.0.3.2.18-1
  - Applicant initially committed to perform video inspection of the Unit 2 spent fuel pool leak chase during the period of extended operation but did not specify the timing of the inspection
  - Applicant revised its commitment to perform the inspection within 1 year prior to the period of extended operation
  - Staff is finalizing its review of the response

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SER Section 4: Time-Limited Aging Analyses

- Section 4.1 – Identification of Time-Limited Aging Analyses (1 open item)
- Section 4.2 – Reactor Vessel Neutron Embrittlement
- Section 4.3 – Metal Fatigue (1 open item)
- Section 4.4 – Environmental Qualification of Electrical Equipment
- Section 4.5 – Concrete Containment Tendon Prestress
- Section 4.6 – Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis
- Section 4.7 – Other Plant-Specific Time-Limited Aging Analyses (1 open item)

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SER Section 4

SER Section 4.2.2: Pressurized Thermal Shock

Limiting Beltline Material - Unit 1 lower shell longitudinal (axial) weld 3-442C

%CU %Ni	EOLE Fluence (E>1 MeV) 10^{19} (n/cm^2)	Initial Charpy RT_{NDT} ^0F	RT_{PTS} ^0F	Acceptance Criterion per 10 CFR 50.61 ^0F
0.203 1.018	2.04	-56	280.4	$\leq$270^{o}F

The applicant stated in that it will implement 10 CFR 50.61a at least three years prior to exceeding the PTS screening criteria of 10 CFR 50.61. In the event that the provisions of 10 CFR 50.61a cannot be met, PG&E will implement alternate options, such as flux reduction, as provided in 10 CFR 50.61.

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SER Section 4 Open Items

- TLAA Identification, Open Item 4.1-1
  - Justification for absence of TLAAs for:
    - Reactor coolant pressure boundary valves
    - Baffle and former bolts
  - Applicant has submitted additional information
  - Staff is reviewing the response

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SER Section 4 Open Items

- Metal Fatigue, Open Item 4.3-1
  - Issues related to Metal Fatigue TLAAs
    - Cycle counting
    - Environmentally-assisted fatigue
    - Cumulative usage factors
  - Applicant has submitted additional information
  - Staff is reviewing the response

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SER Section 4 Open Items

- Residual Heat Removal Piping Weld WIC-95 Flaw Evaluation TLAA, Open Item 4.7.5-1
  - Applicant did not consider the potential of stress corrosion cracking for a flaw that may be connected to pipe inside surface
  - Applicant has submitted additional information
  - Staff is reviewing the response

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Conclusion

- The staff is continuing review to resolve the open and confirmatory items regarding the LRA for DCPP. Pending resolution of the open and confirmatory items, the staff is working towards issuing the SER.