# Official Transcript of Proceedings

# NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee
Callaway Plant, Unit 1

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Thursday, May 22, 2014

Work Order No.: NRC-802 Pages 1-208

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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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PLANT LICENSE RENEWAL SUBCOMMITTEE

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CALLAWAY PLANT, UNIT 1

+ + + + +

THURSDAY

MAY 22, 2014

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ROCKVILLE, MARYLAND

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

COMMITTEE MEMBERS:

GORDON SKILLMAN, Chairman

RONALD BALLINGER, Member

STEPHEN P. SCHULTZ, Member

JOHN W. STETKAR, Member

ACRS CONSULTANT:

JOHN J. BARTON

DESIGNATED FEDERAL OFFICIAL:

KENT HOWARD

T-A-B-L-E O-F C-O-N-T-E-N-T-S

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

(1:27 p.m.)

CHAIRMAN SKILLMAN: This meeting will now come to order. Good afternoon. I'm Gordon Skillman, Chairman of the Plant License Renewal Subcommittee. The subcommittee will review the license renewal application for the Callaway Plant, Unit 1.

ACRS members in attendance are John Stetkar, Ron Ballinger and Steve Schultz. Our ACRS consultant, John Barton, is also in attendance. Kent Howard of the ACRS staff is the designated federal official for this meeting.

This afternoon we will hear presentations from the Division of License Renewal and Ameren Missouri regarding this matter. This subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the 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.

We have not received written comments or requests for time to make oral statements for members of the public regarding today's meeting. This entire meeting will be open to public attendance.

There will be a phone bridge line and to preclude interruption of the meeting the phone will be placed in a listen-in mode during the presentations and committee discussion.

A transcript of this meeting is being kept and will be made available as stated in the Federal Register notice, therefore I request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee.

Participants are requested to please identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

I request that attendees please silence your electronic devices for the duration of the meeting.

We will now proceed and I call upon John Lubinski to begin the presentation. John.

MR. LUBINSKI: Thank you, Chairman Skillman, and welcome. Thank you, members of the ACRS. I appreciate the opportunity to be here today.

With me I have Yoira Diaz sitting at the table with me today as well as other members of the Division of License Renewal, our management team, technical staff project management team who are here to support our presentations and answer questions.

As I said during our informational briefing

this morning, our last meeting with the ACRS was a full committee meeting in February of 2013. We're looking forward to a very productive discussion today about the Safety Evaluation Report that was issued with open items for Callaway Plant, Unit 1.

The staff issued the Safety Evaluation Report with open items in April of 2013 and we had five open items at that time. The reason we issued the Safety Evaluation Report at that time is we were scheduled at that time to have this meeting, the ACRS Subcommittee Meeting, in May of 2013.

After we issued the Safety Evaluation Report, Callaway had requested a postponement of the meeting to deal with issues that they have from an operational standpoint at the plant and requested delaying the meeting.

We continued to work issuing RAIs and getting responses with Callaway to address those technical issues as we've continued to move forward towards today's meeting.

We believe at this point we have information from Callaway that they believe adequately addresses all of the issues that they had as far as open items and we're in the process of reviewing those responses.

We expect prior to coming back for a full committee meeting that we will address all of those satisfactorily and if not we'll get more information from Callaway to do so before coming back for a full committee meeting.

The five open items that are summarized in the SER with open items will be presented today. They have to do with the scope of the fire protection SSCs, the reactor head closure studs, the pressure vessel internals program, ASME code requirements for small-bore socket welds and then environmentally assisted fatigue on the reactor coolant pressure boundary.

A few other issues also arose after issuing the SER with open items as part of the review. We outlined these additional items in addition to the first five in a letter we issued to the ACRS on May 12th of this year.

The staff is prepared to discuss these and any other areas that the ACRS has questions or would like to explore this afternoon.

What we'd like to do is start with having Callaway have their presentation. So what I'd like to do is turn it over to the site vice president, David Neterer, so he can introduce his team and start the

presentation.

MR. NETERER: Thank you. My name is Dave Neterer. I'm the site vice president, Callaway Plant. We really appreciate the opportunity to be here to talk with you today on our license renewal application. It's been a long journey. This is just one milestone in the journey to extend the plant life.

I'd like to introduce our main team, front team today, have them introduce themselves. Sarah.

MS. KOVALESKI: My name is Sarah Kovaleski. I'm the director of design engineering.

MR. WINK: Roger Wink, supervising engineer of our license renewal project.

MR. BLOCHER: Eric Blocher, STARS license renewal.

MR. HOEHN: Mike Hoehn, supervising engineer, engineering program within Ameren.

MR. BURGESS: And I'm Andrew Burgess, license renewal project engineer.

MR. NETERER: Okay, with us today we have many subject matter experts. I'd like our team to stand up so those in the room can see who our team consists of. So these are our subject matter experts that will help us with this discussion today. Thanks, you guys.

MR. BARTON: Anybody left behind at the

site?

(Laughter)

MR. NETERER: We have three times as many at the site waiting on us.

MR. BARTON: You had me nervous there for a minute.

MEMBER STETKAR: It's on auto.

MALE PARTICIPANT: Okay, go ahead.

MR. NETERER: So we're going to go through today a little bit on plant history and background. Roger Wink will talk about major modifications and Sarah Kovaleski will talk about the license renewal application and safety evaluation open items. Then we'll have a few closing comments from our end.

The Callaway Plant received our initial construction permit in April 1976, we received our operating license in October 1984 and we went online, commercial in December 1984.

We're licensed to 3,565 megawatts thermal. Our rated output is 3,579 and the difference there is reactor coolant pump thermal heat. We start our 20th refueling in October this year.

We sit on about a 7,000-acre plateau. It's about 300 feet above the Missouri River. We're a single Westinghouse 4-loop PWR. We were part of the original

SNUPPS project back in the '70s, you know, late '60s, early '70s.

We were going to be a two-unit site. Unit 2 was canceled in 1981 as a result of economic conditions and Three Mile Island outfall and only two plants were built, us and Wolf Creek in Kansas, so we're sister plants.

We're the only two SNUPPS plants with the exception of over in England one plant was built that's similar to SNUPPS but they have four trains of protection instead of two. Go ahead.

So give you an idea how we sit. You can see the power block there right in the center of the photo. In the lower right quadrant is our ultimate heat sink pond. That's the pond that supports 30-day safe shutdown.

In the foreground on the lower right quadrant is our switchyard. We generated 25,000 volts. We transmitted 345 volts. And we own and operate and maintain the switchyard with our Ameren people and procedures.

MR. BARTON: That's not the plant people? This is your T&D people?

MR. NETERER: We, Ameren, maintain everything in the switchyard with the exception of

relays. Relay services from St. Louis corporate maintains that using our procedures and some transformer work is done by our transformer group out of our corporate in St. Louis using our procedures.

MR. BARTON: What role does the plant play when they do maintenance in the switchyard? Does the plant know what's going on? Does the plant have to approve it, --

MR. NETERER: Yes, yes.

MR. BARTON: -- let people into the switchyard or can those people just come in and start working?

MR. NETERER: No, we have very strict switchyard access controls. A senior reactor operator has to allow permission and do a face-to-face brief before any work is allowed.

Also operations does a walkdown of the work area and, you know, make sure they have no vehicles, nothing in the switchyard they don't need to have in there.

They do work to our procedures under our oversight and I'll give you an example. The relay work, our planners plan that work and our electrical department oversees that work.

MR. BARTON: Okay, thank you.

MR. NETERER: You're welcome.

CHAIRMAN SKILLMAN: Dave, a follow on to John's question. What role does your QA program and specifically your corrective action program have for activities in the switchyard?

MR. NETERER: That falls entirely under our QA and corrective action program. We call them CARs. Most plants call them CRs. Any activity that does not meet standards or conditions goes in our corrective action program in switchyard. It's entirely under the CAR system, corrective action program.

CHAIRMAN SKILLMAN: So for the transient workers that come in from corporate to work on relays and other gear, how do they know how to utilize your corrective action program?

MR. NETERER: They are under direct supervision of people that are qualified to use our corrective action program. The relay services supervisors have access and are qualified to use our corrective action program.

CHAIRMAN SKILLMAN: Do they do it?

MR. NETERER: And they're trained. All workers are trained, the general employee training, 10 CFR 50 Appendix B training, corrective action program.

All employees that enter the plant are trained on that also.

CHAIRMAN SKILLMAN: Do they do it?

MR. NETERER: Oh yes, sir. They may not do it themselves, put their hands to the keyboard to put in the document, but they report to a supervisor and generally a supervisor will put that in the program.

CHAIRMAN SKILLMAN: Okay, thank you. Thank you.

MR. NETERER: Let's move to the next slide. Just to give you a perspective on where we are from where we take our water from Missouri River. In the foreground is the Missouri River and the river flow is from left to right.

Right in the middle is our intake structure. We have three intake pumps that pump water. You see the cooling tower in the background and then the power block. That's five miles as the crow flies. So we pump water up the hill. That provides our essential service water, emergency cooling, our normal service water and our circ water.

MR. BARTON: Now is that a pipe, a conduit, aqueduct? What travels the five miles across country to get the --

MR. NETERER: It's underground piping.

MR. BARTON: Underground piping?

MR. NETERER: Underground piping.

MR. BARTON: Have you ever had any problems with leakage on that piping?

MR. NETERER: Up coming the hill? No.

MR. BARTON: Okay.

MR. NETERER: To the left there you'll see another concrete road it looks like. That's our unloading dock for when we do major component replacement such as steam generators, transformers, reactor vessel head. Things that we have to barge up the Missouri River are unloaded there and then hauled up to the plant.

MR. BARTON: Have you ever had any fouling issues in that piping, the five-mile pipe on the intake?

MR. NETERER: What's that pipe made of? It's not steel. It's --

MR. WINK: Supply piping from the intake structure. I'm not exactly certain the material.

MR. NETERER: It's not a metal pipe. It's a --

MR. BARTON: You got nothing that attacks it, no growth, no --

MR. NETERER: No.

MR. BARTON: -- sands or anything like

that? You've had no problems with that piping?

MR. NETERER: No and it's a high-flow piping so you don't get any microbiologically induced corrosion or anything like that.

MR. BARTON: Okay, thank you.

MR. NETERER: You're welcome.

CHAIRMAN SKILLMAN: Speak to us please about flooding on that intake structure.

MR. NETERER: Okay, flooding. 1993 was what we called the 500-year flood in Missouri and the river was the highest it's ever been. I've got that number here. Let me find it. Thank you. In 1993 the river was at 535.8 feet above sea level and the site sits about 840 feet above sea level so we had lots of margin.

CHAIRMAN SKILLMAN: Well, to the site I'm sure because you're 300 feet above the river, but the question is that intake structure.

MR. NETERER: Yes. Yes, we had no problems. It never threatened the intake structure at all, that high water level and that's the highest we've ever seen in Missouri since the plant's been in operation.

CHAIRMAN SKILLMAN: Thank you.

MR. NETERER: You're welcome. Go on. This is a map of the state of Missouri. The red dot is

Callaway Plant. So our nearest population center from Callaway is Fulton, Missouri. That's about 12 miles away from the plant.

The nearest large centers are St. Louis to the east and that's about 80 miles and Kansas City to the west, about 175 miles just to give a perspective where we sit in the state of Missouri. And the capital of Missouri is Jefferson City. It's about 30 miles away.

Okay, I'm going to turn it over to Sarah Kovaleski or, excuse me, Roger Wink to talk about some major modifications we've done. You don't want to skip you, do you?

MR. WINK: No, I'm ready. Good afternoon. Andrew, take the next slide please.

On this slide we have a number of bullets demonstrating -- didn't intend to go through each one of these bullets. I certainly can. Just an indication of the investment Ameren Missouri has made into the plant and our commitment to hardening the plant as well as, you know, being here for the long run.

I do want to talk about a couple of these items. The very first bullet, replacing the main condenser tube bundles.

MR. BARTON: Why? What did you have

before and what did you change it to?

MR. WINK: We had copper-nickel tubes before and we changed to a SEA-CURE material, stainless steel material.

MR. BARTON: Reason being? Fouling?

MR. WINK: Steam generator performance primarily, the copper carryover and what that modification allowed us to do is raise our pH following replacement of the condenser tubes which also lowered our flow-accelerated corrosion issues in the secondary so that provided a number of beneficial items for the plant.

MR. NETERER: And, Roger, if I may, that was a strategic replacement because the next refuel we put new steam generators in and we didn't want to have that copper carryover to the new steam generators when we replaced them.

MR. BARTON: Okay, thank you.

MR. WINK: Another modification I'll bring to your attention, midway in the screen there you'll notice that we've replaced the majority of our essential service water piping with high-density polyethylene piping.

MR. BARTON: What's the difference between that piping and the five-mile cooling tower blowdown

piping?

MR. WINK: The essential service water piping is an ASME Safety Class 3 piping system, whereas our blowdown piping from the circulating and service water system is non- --

MR. BARTON: I just wondering why one was -- Safety related because the system is safety related? What's the difference between your regular --

MR. WINK: The material's the same. One's safety grade, one's not.

MR. BARTON: Okay. The difference being the spec requirement or something? One's from Home Depot and one has got a spec that you actually had to meet?

MR. WINK: The essential service water piping went through some stringent quality assurance qualification requirements, NDT methods, et cetera, whereas the piping --

MR. NETERER: And the fusion process was validated.

MR. WINK: Correct.

MR. BARTON: Okay, thank you.

MEMBER STETKAR: Roger, I haven't looked forward in your slides so just tell me to be quiet and we'll get to it but will you be able to give us an idea

of what fraction of all of your essential -- I know you replaced the underground piping and the essential service water system. Have you replaced any of the other essential service water piping?

MR. WINK: Yes, sir. Of the buried piping that's approximately 1,700 feet of HDPE piping. Inside the power block itself we replaced approximately 3,500 feet of mostly four-inch carbon steel piping.

MEMBER STETKAR: Okay. I read those numbers. Can you give me an idea of what fraction of all of the essential service water piping is, I mean, is it ten percent, is it -- It's hard to, you know --

MR. WINK: I do not have that percent committed to memory.

MEMBER STETKAR: -- linear feet of small-bore pipe is difficult.

MR. WINK: It's significant and the reason -- It's a significant percentage. The reason those four-inch lines were a challenge was we found historically that our piping in the smaller piping didn't receive the chemical treatment we necessarily needed to keep the nodules from growing and pitting and that sort of thing. The areas that get a lot of flow are in very good shape.

MEMBER STETKAR: Inside the building is

stainless or what did you replace it with inside the building?

(Crosstalk)

MEMBER SCHULTZ: Roger, you've got those couple of items identified as not in the license renewal scope. Can you describe the difference between the listings that you have, the other bullets, and those two items as to why you designated those?

MR. WINK: The other items are in scope of license renewal. I wanted to bring out the main condenser tube bundle modification because it did have a subsequent impact on other components that are in scope.

MEMBER SCHULTZ: Okay. But they're all part of the aging management program, GALL?

MR. WINK: Main condenser is not. The other items are.

MEMBER SCHULTZ: Okay, thank you.

CHAIRMAN SKILLMAN: Why did you change the heat exchangers on the emergency diesel generator?

MR. WINK: Performance testing showing there's some pitting going on and having to tube some plugs, plug some tubes, excuse me. It was a proactive replacement with a corrosion-resistant material.

CHAIRMAN SKILLMAN: And the containment

coolers and the safety-related room coolers, were you running at times inoperable on those heat exchangers, on those coolers?

MR. WINK: No. Our original containment coolers were not cleanable and that posed some issues over time with maintaining enough flow. They've always maintained operable but we were losing margin so we proactively replaced those coolers with a cleanable containment cooling design.

CHAIRMAN SKILLMAN: Okay, thank you.

MR. WINK: Andrew, next slide. On this slide we have some near term plant improvements, probably most notably in Refueling Outage 20 which is coming up in October we are replacing our reactor vessel head.

MR. BARTON: Is that a Davis-Besse follow on or did you have some boric acid issues yourself?

MR. WINK: We had no issues. This is a proactive replacement.

MR. NETERER: We're replacing it because it does have susceptible material for stress corrosion cracking.

CHAIRMAN SKILLMAN: Why aren't you replacing your stud in that outage?

MS. KOVALESKI: The reactor head

replacement has been treated separately from removal of the stud. That stud is still tensionable and it still fully performs its function.

So we will, as we'll discuss later in the presentation, we do have a commitment to remove that stud fully before we enter the period of extended operation.

CHAIRMAN SKILLMAN: So do you use it as a guide stud?

MS. KOVALESKI: No, it is a functional stud.

CHAIRMAN SKILLMAN: Oh, I understand that. It's a functional stud that isn't supposed to be there when all the other studs are removed.

MS. KOVALESKI: It is not removed, that's true, with the other studs, yes.

CHAIRMAN SKILLMAN: I got that. Because normally what you do is you remove your studs and you put in guide studs and you put your head on those guide studs.

MR. NETERER: We still have the three guide pins to put, that ride down on the head, just not using the guide stud.

CHAIRMAN SKILLMAN: Not using. It just seems odd that you're going to do a head replacement and

with all of the work that will occur in and around that area that this wouldn't have been a most convenient time to address that stud. I understand that you can justify its use and it's fully tensionable and it's within ASME code. I understand that.

MR. NETERER: Yes, and we'll follow up about it little more later but really was a learning for us on aging management. That's an uninspectable area, area of thread engagement, and that's why we chose to replace it at a future date. We're not geared up to do it this refuel. We don't have everything set up to do it and do it right.

MR. BARTON: But you're doing it prior to license approval, right?

MR. NETERER: Yes, sir. We tentatively have it scheduled about four and a half years out.

CHAIRMAN SKILLMAN: Okay, thank you. Okay.

MR. WINK: Also note that on this slide we do have two of our motor-driven auxiliary feedwater pump coolers. Those are scheduled for replacement in upcoming outages and that's part of our long-term process for maintaining maximum operability of our room coolers.

CHAIRMAN SKILLMAN: At the next set of

bullets there, cathodic protection system modification. I read the inspection report and the other data about your cathodic protection system. What is protecting your underground tanks and buried piping right now?

MR. WINK: We have a cathodic protection system installed right now. It --

CHAIRMAN SKILLMAN: But is it fully functional or is it doing what it's supposed to be doing?

MR. WINK: The current NACE criteria requires a current of negative 850 millivolts. And the NACE criteria also acknowledges other acceptable means of protection. We do meet those other means of NACE protection. Going forward we do plan to upgrade our system so we get the full 850 millivolts.

MR. BARTON: Is it in service at least 95 percent of the time?

MR. WINK: I'd like to ask Neil Fisher to help.

MR. FISHER: Any particular system?

MALE PARTICIPANT: Yes.

MALE PARTICIPANT: Name, Neil.

MR. BARTON: Your cathodic protection system.

MR. FISHER: I'm sorry.

MR. BARTON: Overall, do you do a --

MALE PARTICIPANT: He has to identify himself.

MR. FISHER: I'm sorry. Neil Fisher.

MALE PARTICIPANT: That's all right.

MR. FISHER: System engineer, Callaway, cathodic protection.

MR. BARTON: Cathodic protection system, what's its availability number? Is it greater than 90 percent or is it up and down, a lot of maintenance required or what?

MR. FISHER: Overall, all of the in-scope piping, we're about 88 percent availability over the past ten years.

MEMBER BALLINGER: Is it active or is it passive?

MR. FISHER: It's active.

MEMBER BALLINGER: It's active?

MALE PARTICIPANT: Okay, thank you.

MALE PARTICIPANT: Thank you, Neil.

MALE PARTICIPANT: Thanks, Neil.

MR. WINK: Andrew, next slide.

MEMBER BALLINGER: Oh, wait. I have a question.

MR. WINK: I'm sorry. Go ahead.

MEMBER BALLINGER: Can we back up one?

MR. WINK: Absolutely.

MEMBER BALLINGER: You say PWSCC mitigation of reactor nozzle and bottom mounted instrumentation tubes. What's happening with the bottom mounted instrumentation tubes?

MR. WINK: In refuel 21 we're planning on mitigation of the bottom mounted instrumentation tubes as well as our eight --

MEMBER BALLINGER: Which is what technique?

MR. WINK: We're looking at doing the water jet peening process.

MEMBER BALLINGER: Okay, so peening from the inside?

MR. WINK: Correct.

MEMBER BALLINGER: Okay.

MR. HOEHN: Well, and this is Mike Hoehn, supervising engineer, we're also pursuing water jet peening of the actual J-welds outside of the actual tubes as well. They're both Inconel base material.

MR. BARTON: I want to go back an item. You put a manhole sump in to keep your area where your cables are running dry, right? You had a flood in 2007 that the cables were submerged. Did you have any of

those cables fail upon testing or just fail during normal operation?

MR. WINK: Ken Sandstedt, could you please help with this? We had no failures and Ken can explain the modifications we performed.

MR. SANDSTEDT: I'm Ken Sandstedt, cable engineer. Can you restate the question please?

MR. BARTON: Yes, you had a flood in your manholes in 2007. You committed to do something about putting in dewatering, keep them dry or whatever. You finally in 2013 installed a pump, a sump pump in the manhole to keep it from collecting water, drain water or whatever.

MR. SANDSTEDT: Yes.

MR. BARTON: Did you have any cables that failed from the submergence issue?

MR. SANDSTEDT: No, we've not had any cables fail.

MR. BARTON: You haven't had any of those cables that failed?

MR. SANDSTEDT: No.

MR. BARTON: Okay. All right, thank you.

MR. WINK: This is a correction. In 2007 when you say flood, we did not have a flood at the site. We did have maybe a lot of rain but --

MR. BARTON: It said all the cables in the manholes were submerged. That's what I read. Okay.

CHAIRMAN SKILLMAN: Talk to us a little bit about the independent spent fuel storage installation. This is a new build or a new construct? Will it be built and then entered into service or built and waiting for service later with a fuel offload? Tell us a little more about this please.

MR. WINK: The modification is underway right now. We plan on 2015 starting to move some of the spent fuel assembly canisters into that ISFSI in the year 2015. We lose full core offload capability in the year 2020 so we're doing that modification to make some room in our spent fuel pool.

MEMBER SCHULTZ: That's after outage 21 that you'll be moving the fuel?

MR. WINK: Next year. It'll be before.

MEMBER SCHULTZ: Before outage 20?

MR. WINK: Correct.

MEMBER STETKAR: You're on an 18-month cycle?

MR. WINK: Yes, sir.

MEMBER STETKAR: Thanks.

CHAIRMAN SKILLMAN: And if we look at the image from, looks like maybe 900 feet. That is your

opening image that shows your site. Where will the ISFSI be please?

MR. NETERER: Let's go back to the slide so I can explain that to you.

(Off microphone discussion)

MR. NETERER: Okay, see the power block and up to the upper left quadrant it looks green. That's actually the Unit 2 excavation. At the time this picture was taken, there was water in the bottom of it. We kept that water pumped out to a low level. We are filling that hole.

And the ISFSI project, the spent fuel storage project, will go in the plant, the north end of that to the right. And then our Fukushima FLEX storage building will be in the southern end of that pond area.

CHAIRMAN SKILLMAN: Thank you. Thank you.

MALE PARTICIPANT: We're back to 13.

MALE PARTICIPANT: Thank you.

FEMALE PARTICIPANT: Thank you.

MR. WINK: Andrew, go ahead and next slide please. Turn this over to Sarah Kovaleski to continue discussion about the license renewal application.

MS. KOVALESKI: Thank you. Callaway's license renewal team has been working on this since

2007. We are the fifth of the STARS license renewal applications, that's Strategic Teaming and Resource Sharing alliance.

One of the things that we have made a priority throughout this project is maintaining involvement with the industry as well as our STARS peers.

And we've utilized the NEI working groups, industry peer review process and we've made a significant effort to incorporate these lessons learned into our application.

CHAIRMAN SKILLMAN: Sarah, who are the other, not participants. What are the other plants that are involved here please?

MS. KOVALESKI: The other plants in the STARS alliance?

CHAIRMAN SKILLMAN: Yes, of these five.

MS. KOVALESKI: Of these five Wolf Creek was the first to submit, followed by Palo Verde. The next two were Diablo Canyon and South Texas and Callaway is the fifth.

CHAIRMAN SKILLMAN: Thank you.

MS. KOVALESKI: You're welcome. Next slide. We submitted our application to the NRC on December 15, 2011. We are a Generic Aging Lessons

Learned, or GALL, Rev 2 application.

We have 42 aging management programs in our license renewal application. This involves over 3,900 aging management review lines and we are 98.8, so nearly 99 percent consistent with GALL Rev 2.

CHAIRMAN SKILLMAN: What does that really mean? What does the percentage mean?

MS. KOVALESKI: It refers to the number of exceptions to GALL. It means that for the recommended material and environment combination we 98.8 percent of the time follow the recommended aging management program.

CHAIRMAN SKILLMAN: So for the 1.2 percent where you do not, what is the remedy?

MS. KOVALESKI: Those exceptions are not -- They are both positive and negative. It does not necessarily imply that a remedy is required but it is an exception and Eric Blocher can explain some of the details for those.

MR. BLOCHER: Yes, if I could have backup Slide 39 or 36, excuse me.

MR. BURGESS: 36?

MR. BLOCHER: 37, sorry, 37. The lines that we're talking about involve Notes F through J and those, as Sarah indicated, don't necessarily require a

remedy. Those lines simply aren't in GALL.

For example, the lines that are labeled as Note F, they're not in for material considerations. Like, for example, two of those lines are the cellulose silica cement splash panels on the cooling tower. That material just simply is not in GALL.

Another one is the fiberglass reinforced plastic for the cooling tower fan stacks. Again, that material simply is not in GALL so we had to come up with an acceptable aging management evaluation that staff evaluated and approved, both in terms of the aging effect and aging management program.

Similarly, for the other ones, Note G is environments, are not within GALL. Note H is our aging effects that are not within GALL. Note I are the aging effect that is not applicable in GALL, and those are used primarily for electrical items to review. And Note J is where the component material environment is not in GALL at all.

CHAIRMAN SKILLMAN: Thank you, Eric. Thank you. Okay.

MS. KOVALESKI: Slide 16 please. The other aspect that I'd like to point out with our application is the incorporation of the license renewal interim staff guidance documents. In our application,

we addressed eight of these ISGs. That's seven final issued ISGs and one draft.

The commitments in our license renewal application will be included in our FSAR supplement and they are found in Appendix Alpha of our license renewal application.

These commitments will be managed by our commitment tracking system at Callaway which is consistent with the NEI 99-04 guidelines.

MEMBER SCHULTZ: Sarah, are you expecting any license conditions at this point in time or are you trying work those through so that they become commitments?

MS. KOVALESKI: We have tried to work everything through but through discussions with the staff we understand that the removal of our stuck stud and the other associated commitment to do inspections of the stud holes may be a license condition.

MEMBER SCHULTZ: Thank you.

MS. KOVALESKI: Next slide please. Of the 42 aging management programs that I mentioned, 32 are existing programs and ten are new. Of the 42 in total, there are 16 enhancements and five exceptions.

With regards to implementation and sustainability, this is something that we have learned

throughout this process, that it's very important to be focused on implementation while we're preparing the license renewal application. It isn't something to pick up later on down the road.

So through this we have designated specific program owners and maintained a license renewal staff on site. We continue to participate within the various working groups and benchmark others in the industry.

One of the ISGs that we incorporated was 2011-05 for the ongoing review of operating experience, and I wanted to highlight this because this is one of the ISGs that we thought we would benefit from by implementing immediately.

Specifically we improved our operating experience program and procedures to focus on aging management issues and we now have the written guidance to our entire site so that when aging management topics are identified, whether it's internal operating experience or external operating experience, it is consistently entered into our corrective action program so that we can evaluate it.

The other piece of that is our operating experience coordinator on site has been trained on aging management and also keeps an eye on Callaway internal operating experience to ensure that we're sharing that

with the industry if it's related to aging or aging management issues.

MEMBER SCHULTZ: Sarah, the slide's labeled Implementation and Sustainability.

MS. KOVALESKI: Yes.

MEMBER SCHULTZ: So you characterize then the program owners as the sustainability part of the program?

MS. KOVALESKI: That is certainly a part of it but another piece is making sure that aging management practices are proceduralized and that way if we do experience turnover we, just like many in the industry, expect that that's going to happen over the future years, the next generation of employees who come in have, there's no question as to what those aging management practices are.

MR. NETERER: And it's embedded in our knowledge retention and transfer and training programs.

MEMBER SCHULTZ: The license renewal staff, is this programmatic now that you've entered into this process and program? You're years before you get into the implementation period but so, therefore, there's going to be some continuity after you get the license renewal approval?

MS. KOVALESKI: There will be and we

haven't made those transitions yet but what we found is that by having a staff on site when the specific license renewal application efforts draw to a close we have that embedded knowledge and we can move those people on to work on implementation issues.

MEMBER SCHULTZ: Good. Thank you.

MS. KOVALESKI: Next slide please. Thank you. At this --

CHAIRMAN SKILLMAN: Before we do that let me ask a question. We've touched on Appendix B and we've touched on corrective action couple times so far.

Could you please explain to us the degree of senior management involvement in discussions about emerging CARs, corrective action items, whatever they're called at your site, and the degree to which the senior leadership becomes directly involved and how quickly?

MR. NETERER: Every day. We have a meeting every morning and all the senior leaders, the directors, Sarah and above and VPs attend that meeting and we review every CR or corrective action document that was written and screened the previous day.

And the purpose of that, first of all, is keep us in the loop, keep us tuned in and also do we agree with the significance level of the issue. And we do,

we do on occasion go back and ask that the significance level be elevated if we don't feel it's getting the proper attention.

CHAIRMAN SKILLMAN: Okay. And for those items that are deemed to be more important or that require a root cause, what is the extent of senior leadership involvement in understanding, if you will, the accuracy of the root cause, the lessons learned from the root cause, the conclusion of the root cause?

MR. NETERER: Every CR of that level has a director assigned to it as the sponsor. Also our corrective action review board is made up of directors and there are directors from the corrective action review board assigned to monitor the progress of that root cause or, you know, to determine if the causes are correct.

Then, is the extended condition correct? Do the corrective actions line up with the causes? And then the effectiveness review, does it make sense and does it line up with what we're trying to achieve going forward? And are the effectiveness reviews extensive enough to ensure what Sarah talked about before, sustainability?

CHAIRMAN SKILLMAN: Okay, thank you. Let's proceed on Slide 19. Thank you.

MS. KOVALESKI: All right. At this point we'd like to transition to discuss the open items in the Safety Evaluation Report.

As John noted in his introduction, there are five open items and they're listed here. There were also several other open, I'm sorry, issues that arose after the SER with open items was published.

The first open item has to do with scoping of fire protection systems, structures and components. This open item really consisted of two parts. The first part had to do with exclusion of certain portions of the turbine building from the scope of license renewal.

Callaway resolved this issue by returning to license renewal scope the fire suppression systems located in the three locations listed there, the auxiliary boiler room and turbine bearings and other locations.

We did, following that, have our NFPA 805 license amendment request approved. That amendment request was approved in January of this year and we subsequently removed the auxiliary boiler room fire suppression system from scope based on the new 805 licensing basis.

MR. BARTON: But you maintained the turbine building locations and turbine bearings area?

There were three parts to this as I remember, auxiliary boiler room, the turbine building various locations and then turbine bearings area.

And I see that you removed from the scope the auxiliary boiler room suppression system. I don't know anything about the other two. Are they still maintained in scope?

MS. KOVALESKI: Understand. I'd like Mike Fletcher to elaborate a bit on the scope.

MR. FLETCHER: My name's Mike Fletcher. I was part of the NFPA 805 transition team and, yes, the main turbine bearings suppression system has remained in scope.

MR. BARTON: And were there some other areas in the turbine building because there was a turbine area various location description that wasn't very specific and I picked it up as something other than just the turbine bearings. Is it more than the turbine bearings area included?

MR. FLETCHER: Essentially all of the turbine hall main floor suppression systems stay in scope.

MR. BARTON: Okay. That's included?

MR. FLETCHER: That's correct.

MR. BARTON: Okay. The only thing is

auxiliary boiler room taken out. I got you.

MALE PARTICIPANT: Got to look at hydrogen and all that kind of stuff.

MALE PARTICIPANT: Everywhere hydrogen is you better have it.

MR. BARTON: Yes, that's what I'm thinking. All right. So it's all included except the auxiliary boiler room.

MR. FLETCHER: Correct.

MR. BARTON: Okay, thank you.

MS. KOVALESKI: Thank you, Mike.

CHAIRMAN SKILLMAN: Quick question before you change.

MS. KOVALESKI: Yes.

CHAIRMAN SKILLMAN: Excuse me, John.

MEMBER STETKAR: No, you were first off the block.

CHAIRMAN SKILLMAN: Okay, at the end of the write-up here for this open item, staff -- I'm going to read this so I will be accurate in what I say.

"The staff finds that the applicant should not perform a gap analysis of LRA Tables 2.3.3-20 and so on based on a draft NFPA 805 LAR SER. The staff finds that the gap analysis should be based on a final NFPA." Is there a date? Is this done? What's the status?

MS. KOVALESKI: Yes, it is done. We worked with the staff. At one point during the review of our application we had discussed performing a gap analysis on the draft that was available at that time and then through future discussions we determined that it was most appropriate to wait until the license amendment was finalized.

So with the license amendment being finalized in January of this year, we used that as the basis to submit both the gap analysis and then amend the LRA as appropriate.

CHAIRMAN SKILLMAN: Thank you.

MS. KOVALESKI: You're welcome.

MEMBER STETKAR: Sarah, I've got a question. Doesn't have to do with scoping but I just stumbled across something that was curious to me. There's a discussion about testing frequency for fire hoses.

And apparently if I walk up to a fire hose in the plant, that fire hose is either, knows that it's a fire brigade hose or it knows that it's an interior fire hose because if the hose is a fire brigade it's tested every year and if it's an interior fire hose it's only tested every three years.

And you've had one failure in 2011 of a fire

hose, I don't know what it was, it probably knew what it was, when it was charged for fire brigade training.

So my question is if I have a fire, how do the fire hoses know that they ought to be a fire brigade hose and that's a really good hose and that if I run up to a fire hose reel in the plant I better not use that hose because it might not work? I mean, I don't understand this distinction. It's the first time I've ever seen it in any of the plants that we've looked at.

MS. KOVALESKI: I understand your question is about the distinction between fire brigade hoses and installed hoses.

MEMBER STETKAR: Right, yes and the testing.

MS. KOVALESKI: Lee Eitel I think can address that.

MR. EITEL: Lee Eitel, supervisor, systems engineering. The fire brigade hose is specifically placed on our fire trucks and in locations that only the fire brigade uses. The hose stations are distinct locations in the plant so they are completely separated and distinct fire hoses.

MEMBER STETKAR: Okay. Now if I am an operator or maintenance person or somebody who normally lives in the power plant and a fire starts and I run up

to some hose reel that's there and it's got a sign, it's painted red and all that good kind of stuff, and I grab that hose, it's most likely not going to be tested at an annual frequency. It's most likely going to be one of the secondary type hoses that may or may not work. I just don't understand that rationale.

MR. EITEL: The hoses that are permanently installed are for backup. The fire brigade always bring their own hoses to a fire scene and use those hoses via -- The hoses that are installed on the racks are replaced new every five years and that's why we do not perform as periodic of testing in compliance with code.

MEMBER STETKAR: Is that, because if I read things it says interior fire hose, meaning the second tier, is tested five years from installation and every three years thereafter. But if you're saying you replace them every five years, then they never get a chance to be --

MALE PARTICIPANT: Three year tested.

MEMBER STETKAR: -- tested, three-year tested. In fact, they never get a chance to be tested --

MS. KOVALESKI: Five years.

MEMBER STETKAR: -- you know, after installation. Is that true? You actually do replace

all of them every five years?

MR. EITEL: We do replace all of them. That is in compliance with code. The manufacturer tests them prior to --

MEMBER STETKAR: Thanks. The replacing them every five years solves my concern.

MR. EITEL: Okay.

MEMBER STETKAR: Thank you.

MS. KOVALESKI: Thank you. All right, next slide please. We touched on this a little bit. The second part of this open item had to do with the changes to license renewal scope that occur with the NFPA 805 transition.

To provide a bit of context, the license renewal application was prepared with our previous current licensing basis or previous licensing basis for fire protection. That's the more traditional licensing basis.

And it wasn't until January of this year that we were approved for the NFPA 805 licensing basis. The license renewal application has been amended to update the license renewal scope so that it is now consistent with the NFPA 805 licensing basis.

In addition, the gap analysis that we prepared and provided to the staff helps to explain the

changes for components that were either removed from scope of license renewal or added into the scope of license renewal and the basis for that and where it can be found in the NFPA 805 licensing basis.

MEMBER STETKAR: Just out of curiosity since I'm interested, put it that way, in NFPA 805, on a net basis, I mean, you mentioned that the auxiliary boiler fire protection system was removed. Did you wind up adding more equipment in scope as a result of NFPA 805 or did you wind up removing more?

MS. KOVALESKI: It was more or less even.

MEMBER STETKAR: Was it?

MS. KOVALESKI: Mike Fletcher could elaborate on that.

MR. FLETCHER: Again, it's Mike Fletcher. Look, just let's say specific to suppression systems we ended up pulling in eight suppression systems and there were six that were moved so then that change was a plus two.

MEMBER STETKAR: Okay. Was it? Okay, okay. Yes, and that's big-picture stuff. That's all. Thank you. I was just curious.

MS. KOVALESKI: Next item please. The next open item pertain to the reactor head closure studs. The question posed by the staff was that the

program may not be adequate to detect future wear, loss of materials, or assure that allowable stresses are not exceeded during the period of extended operation.

The specific concern related to the stuck stud, Stud Number 18. And as previously mentioned, we have a commitment to ensure that that stud is removed prior to the period of extended operation.

The other concern presented to us that we understand is that with that stud stuck in the position that it's in, the areas of thread engagement cannot be directly visually inspected and that there could be degradation going on within the threads of the reactor vessel flange that we're not able to detect right now.

So the second part of that commitment is to inspect the six stud holes that have the greatest amount of previous thread damage with a laser profiling technique so that we can determine if there has been any ongoing degradation.

The thread damage that previously occurred was not a result of aging but rather a result of poor stud handling practices and foreign material controls very early in plant operation.

It is not indicative of our current stud handling practices and we've not seen any sort of recurrence of this issue.

MR. BARTON: I'm glad you're using laser instead of the old thread plug we used to use in the old days where you put a tap in there and clean up the threads.

MS. KOVALESKI: Like a go gauge kind of thing? Yes, yes.

MEMBER STETKAR: How many studs do you have?

MS. KOVALESKI: Fifty-four.

MEMBER SCHULTZ: Sarah, in the various reports, the SER, 2013 SER and then in the written dialogue going back and forth related to request for additional information and so forth and the staff's inspection, there were a number of different stud locations that were identified.

You've indicated that these are the six with potentially the most damage and I was curious as to how that was determined. I mean, the numbers went from, I think you said six and they had a number that identified perhaps 10, 12, 13 locations and it seems to have been resolved to come back to six locations with the most thread damage.

How was it determined that these are the right ones to inspect, that have the most potential for damage and should be inspected versus a more

comprehensive inspection campaign?

MS. KOVALESKI: I think I understand your question. Andrew, Slide 49 please. We're going to bring up a table that shows the stud, 49 please. Thank you. This table shows the areas in the flange where we did have to remove and perform a Section 11 repair of the stud hole threads.

As you can see on this table, several of these locations are missing one or fewer threads and with that small number those have been excluded from the future inspection.

But the Stud Hole Number 2 missing 13.1 and Stud Hole Number 9 missing 15.12, at that point we really want to be monitoring that.

MEMBER SCHULTZ: Okay, that helps a lot. I appreciate that level of detail. Thank you.

CHAIRMAN SKILLMAN: Talk to us a little bit about the poor work practices that are identified on that slide.

MS. KOVALESKI: Certainly. Andrew, go to Slide 23. That's the next one that we would have pulled up. There were two issues that were going on concurrently. The handling practices had to do with the weighting of the stud and whether the weight was distributed onto the stud.

And concurrently there were four material issues. At the time that Stud Number 18 was stuck, there was an entry in our corrective action program indicating that overhead work had been dropping debris into that location.

And while we had inspected the stud before it was installed and it was a satisfactory inspection, it would appear that some sort of foreign material was introduced into the stud hole or on the stud at the time it was installed.

MR. BARTON: So you don't put covers on? When you remove the studs, you don't put covers over those holes?

MR. NETERER: Yes, we do. We do.

MR. BARTON: You do now?

MR. NETERER: Yes.

MR. BARTON: But when all this debris and stuff got in there, was that still your practice or, because I'm trying to figure out how this debris got in there. Overhead work, fine. But if you took the studs out and you had your covers on, how did debris get in there? That's what I was struggling with right there.

MS. KOVALESKI: I don't know the answer to that.

MR. NETERER: It seems to me we always used

stud hole covers but I can't commit to going back to Refuel 1 on that.

MR. BARTON: That's what I'm looking at, yes.

MR. NETERER: Yes. I can't answer when we, if we did always or started using them. David, do you know?

MR. GROSS: This is David Gross. I'm a consultant with Dominion Engineering and we've been working with Callaway on their reactor stud issues going back to 1987 and if Walt is on the phone he may also be able to address this.

But I believe the issues that happened in the 1990 time frame were more related to poor cleaning of thread lubricant in the holes and lessons learned about what good thread lubricants to use and what good cleaning procedures to use and just thread cleanliness on the female hole wasn't what it became in subsequent outages.

MS. KOVALESKI: Thank you, David. Let's pull up Slide 50 please. You had asked about the stud hole covers and I'm not in a position to elaborate on it right now. We could get more information on it. But there were some issues with the effectiveness of the stud hole covers.

Really the cleanliness issue, presence of foreign material, the lubrication issue and the detail, the level of detail associated with the procedures that were used were all not today's standards.

MR. BARTON: So it sounds like at the first refueling your work practices weren't up to snuff or what they needed to be and you messed up your threads.

MS. KOVALESKI: That's --

MR. BARTON: What it sounds like to me. That about it?

MS. KOVALESKI: That's pretty much it, yes.

MR. NETERER: Yes, we did do a root cause on that 1996 and changed our stud handling practices and stud hole cleaning practices.

MEMBER SCHULTZ: Okay. Is that what this reflects? You feel that this slide captures the results of the root cause in 1996?

MR. NETERER: Yes, yes.

MEMBER SCHULTZ: Thank you.

CHAIRMAN SKILLMAN: Let me ask this. It's easy to confuse proper cleanliness with ensuring that that stud hole's been chased properly with a deburring tool normally run by hand. It's where an individual takes it, drives all the way to the bottom, drives all

the way back up and then vacuums and then might put in a very light film of oil or something just to protect what could be bare metal surfaces.

Were you able to determine it truly was foreign material as opposed to a potential cross thread or a potential ding in the thread that resulted from, if you will, the stud insertion crew not knowing how careful they need to be when they feed those first one or two threads?

MS. KOVALESKI: When Stud 18 became stuck, we actually had found a small burr on two of the threads prior to that installation. We did remove the burr. We fully examined the stud threads as well as the stud hole threads, again prior to its installation, and did not identify any damage.

When the stud was inserted, it did turn freely past the locations where the removed burr had been located and that would be our evidence that the stud had been treated and inspected properly. That's for Stud 18.

As far as the damage that occurred earlier in plant life, we did after that implement stricter procedural instructions and guidance for stud and stud hole and nut cleaning, inspecting and lubrication.

CHAIRMAN SKILLMAN: Thank you.

MALE PARTICIPANT: Okay.

CHAIRMAN SKILLMAN: Thanks. Back to 23.

MS. KOVALESKI: All right, thank you. And next slide please. At this point I'd like to ask Mike Hoehn to discuss the open item related to reactor vessel internals and the MRP-227-Alpha report.

MR. HOEHN: Thank you. The next few slides we'll go over the licensee action items under MRP-227-Alpha which is associated with the reactor vessel internals program at Callaway.

This first topic, demonstrate MRP, which stands for material reliability program under Electric Power Research Institute, 227-Alpha bases/assumptions are applicable and bounding for design of Callaway reactor vessel internal components.

The 227 approach was intended to be a generic bounding approach for the U.S. fleet and we were required to ensure that we were bounding and that we were consistent with the recommendations and the guidelines within 227-Alpha and specifically MRP-191 which was the screening categorization and ranking of reactor internal components.

We completed that with support of our nuclear steam system supplier, Westinghouse, which we completed a very systematic review of our components and

verified we were consistent.

We also incorporated considerations for atypical fuel design and ensured that our procedures are appropriate to ensure that that atypical fuel design does not occur in the future.

CHAIRMAN SKILLMAN: Say that again please.

MR. HOEHN: We ensured, our core design procedures, we have procedure requirements in there now that we don't, when we do a design change that we are consistent with our, specifically the, we put the new fuel in the center and put the older fuel on the outside which is our standard core design practices so --

CHAIRMAN SKILLMAN: Had you been doing it differently in earlier fuel cycles?

MR. HOEHN: We were consistent with the design in/out practices as documented MRP-2013-025.

CHAIRMAN SKILLMAN: Thank you.

MEMBER SCHULTZ: Perhaps it's just the phrasing here, consistent with atypical fuel design parameters. Are you talking about core loading?

MR. HOEHN: Correct. Yes, we don't use the atypical fuel design parameter. We are consistent with the in/out method, new fuel in the center and the previously used fuel is placed on the outside. We're consistent with that approach.

MEMBER SCHULTZ: Okay. So the procedure is to ensure that you don't use atypical?

MR. HOEHN: Correct. There was an administrative measure to ensure that we don't do it in the future, that sustainability action moving forward.

MEMBER SCHULTZ: Okay, thank you.

CHAIRMAN SKILLMAN: So do your procedures for your reloads preclude something different than in/out?

MR. BLOCHER: Eric Blocher, STARS. If I can supplement Mr. Hoehn's answer, the MRP that's referenced up there, the 2013-025, has three fuel design parameters that are essential in the fuel design for limiting, if you will, potential for degradation in the core internals.

And those three parameters are for the active core plate distance. It has to be greater than 12.2 inches, and this is for Westinghouse plants now. And the average core density has to be less than 124 megawatts per cubic centimeter and the heat generation figure of merit has to be less than or equal to 68 watts per cubic centimeter. And those parameters have all been added in to the fuel design procedure.

And there's a timing limitation on this as well. Because of the way the MRP analysis was done,

this has to be applicable for your final 30 years of operation.

So those procedures were modified and as you're probably aware from the timing that Mr. Neterer presented in his opening remarks to the presentation, we are in Year 30 of plant operations so that was done just in time for the last few years --

CHAIRMAN SKILLMAN: Okay thank you, Eric. Got it. Understand. Thank you.

MEMBER SCHULTZ: But it doesn't mean that you've been operating with atypical fuel design approaches.

MR. BLOCHER: Correct. As Mr. Hoehn indicated, we use an in/out core loading sequence.

MR. HOEHN: Next slide. This next licensee action item associated with measurement techniques for our reactor vessel internals hold-down spring height.

This specific issue is only for Type 304 stainless steel hold-down springs. We have Type 403 stainless steel springs and, thus, this issue is not applicable to Callaway. That's been resolved. Next slide.

This Licensee Action Item Number 7 under MRP-227-Alpha is for determination, inspections for

loss of fracture toughness due to thermal and irradiation embrittlement for reactor vessel internal components, specifically CASS, cast austenitic stainless steel, martensitic or precipitate-hardened steel, if our inspections are adequate.

We looked at MRP-191 and 227-Alpha. We worked with our NSSS again and found no additional components for Callaway.

We did identify two locations with CASS components, bottom mounted instrument column cruciforms, a small section at the top, and one offset instrument column cruciform bolted to the underside of the lower core plate and those will be addressed with our current 227 inspection approach. Next slide.

This topic is associated with our cumulative usage factors, our fatigue analysis for our reactor vessel. We do have a section, ASME Section III NG, reactor vessel and internal set, and as a result we do have cumulative usage factors for the reactor vessel internals.

We were requested how, we needed to demonstrate how we're going to address that for the period of extended operation and we have committed to monitor and manage those cumulative usage factors and the fatigue usage on those locations into the period of

extended operation under our existing fatigue management program.

CHAIRMAN SKILLMAN: Explain to us what actions you might take to manage the fatigue.

MR. HOEHN: Right now the approach for managing the fatigue into the period of extended operation, basic fatigue monitoring, counting of transient cycle counting we believe at this point in time based on our projections will be sufficient to demonstrate that the current internal set of fatigue analysis is appropriate into the period of extended operation.

If we were to get into issues where the transient accumulation or the transient severity was outside of our original design basis, we would either have to do a refined fatigue analysis or we would have to look at a more drastic measure of replacement or in accordance with ASME Section XI, for example.

CHAIRMAN SKILLMAN: How do you know your cycle counting process is accurate?

MR. HOEHN: Understand. How do I know that our cycle counting process is accurate? We have a fatigue monitoring program, software installed at Callaway, FatiguePro. We actually had that system installed back in 1995 and we were one of the first

plants to have that system installed.

To support that input, we did a systematic review of our historical plant transients prior to 1995 in coordination with Westinghouse at the time. In support of the license renewal application, we rebaselined the entire fatigue transients to date and revisited that pre-1995 fatigue usage projections.

And, again, with Westinghouse structural integrity internal plant staff we went through that in systematic means and ensured that our cycle counting today is accurate.

And moving forward, it's automated from our plant computer system into our FatiguePro software and then if a bad day were to happen, the plant computer were to go down, we obviously have operator logs, the corrective action program and other entries like that that we can fill in the gaps if that were to happen.

CHAIRMAN SKILLMAN: So as you begin what would be Day 1 of your PEO, your additional 20 after 2024, what will your CUF be approximately at that point?

MR. HOEHN: What will our CUF be at approximately --

CHAIRMAN SKILLMAN: When you begin your PEO.

MR. HOEHN: On the reactor vessel

internals specifically?

CHAIRMAN SKILLMAN: Yes. You going to be at 0.8 or 0.999, 0.99999?

MR. BARTON: Well, that's for the boron injection nozzle. They're already there.

CHAIRMAN SKILLMAN: Well, let's let him answer the question.

MR. BARTON: Is that the same as one? It's --

MALE PARTICIPANT: No, no. You're going to start your --

MALE PARTICIPANT: Obviously you hope to start your PEO --

MR. HOEHN: It will be less than one.

CHAIRMAN SKILLMAN: And you would like to start your PEO with some margin to get to the end of that 20 years. So where are you going to be approximately on your internals when you begin Day 1 of your PEO, right, and you support --

MR. LYNCH: Hi. My name's Brett Lynch with WorleyParsons. We assisted with the license renewal, license amendment request as well as the baseline.

For these internal components, we can't give you a specific valuation on that specific day. We

still rely on the design CUFs.

What we do know is that you're less than your allowed number of transients so the amount of margin wouldn't be on the CUF. It would be on the margin to your design number of transients.

CHAIRMAN SKILLMAN: That translates into your CUF.

MR. LYNCH: Yes.

CHAIRMAN SKILLMAN: Right. Understand. So you're saying, hey, we think we got some running room based on not having utilized all of our cycles.

MR. LYNCH: Correct.

CHAIRMAN SKILLMAN: Got you. All right, thank you. Understand.

MEMBER SCHULTZ: So just let me add on a question. So the analysis that has been done has not taken credit for actual operation for the last 20 years?

MR. LYNCH: That is correct. It's based only on design transients, not actual operation.

MEMBER SCHULTZ: Still. Okay.

MR. HOEHN: Correct and we have committed to manage this, the internal set of cumulative usage factors under a fatigue monitoring program into the period of extended operation to ensure that we're appropriate into future plant operations.

MEMBER SCHULTZ: On the basis of that approach versus taking credit for actual operation and --

MR. HOEHN: Agreed. Yes, correct.

MEMBER STETKAR: When you did your transient counts, and I didn't look at all the RAIs so I don't know. That's why I'm asking. I'm assuming you did a linear projection out to 60 years. Is that right?

MR. HOEHN: Correct.

MEMBER STETKAR: Okay. That's what most people do. Did you develop any kind of histogram to show historically how those transients, I mean, does it look like linear projection is accurate or did you have a lot more transients early in life?

MR. HOEHN: Yes.

MEMBER STETKAR: Do you have that information?

MR. HOEHN: We had to develop histograms as part of our baseline report and justify the linear projection moving forward. And as is typical with most plants, most of these transients occur early in plant life.

MEMBER STETKAR: Most. Occasionally we see that things are a little more flat. That's why I was just curious.

MR. HOEHN: Correct, yes.

MEMBER STETKAR: But you had that information?

MR. HOEHN: Correct.

MEMBER STETKAR: Did you submit it to the staff? Was it requested or not? I was just curious because --

MR. HOEHN: I do not know that offhand. I know it was, we did provide that during one of the inspections. We discussed it.

MEMBER STETKAR: Okay, great. Thank you.

MR. HOEHN: Thanks.

MS. KOVALESKI: All right thank you, Mike. The next open item pertains to ASME Code Class 1, small-bore socket welds. This open item is frankly a disappointment to us. We --

MR. BARTON: I'd like to meet the person that did the counting from 2 to 19 to 77 to 23 to some other number. Did he use common core math for this or what?

(Laughter)

MR. BARTON: I'm totally confused how that progression grew and I don't even know what the final number is.

MS. KOVALESKI: The final number is 80 for

socket welds.

MR. BARTON: Eighty?

MS. KOVALESKI: Yes.

MR. BARTON: Wow. A new number.

MEMBER STETKAR: A different number.

(Laughter)

MR. BARTON: Okay.

MALE PARTICIPANT: I gave up.

MS. KOVALESKI: Yes. This was a result of miscommunication between the license renewal team and our subject matter expert. We did not clearly communicate that the scope of this program is piping that is less than four inches and greater than or equal to one inch.

And when the counting was first performed, we used an ISI database, and due to the filtering on that database, it excluded a number of one-inch welds and that was the first number that we submitted, was 19.

During one of the on-site audits, one of our staff engineers identified some welds that appeared to be part of the scope and when we checked against our original number we realized they weren't there. That was when we first identified the program, I'm sorry, the problem.

We communicated that to the staff who were

on site for the audit and we told them we found four more. That's how we get to 23. That was not a formally communicated number. That was the point of discovery on that.

We went back and recounted and then did an independent validation of that count and ultimately we ended up at our final number of 80.

MR. BARTON: You're going to inspect eight of them?

MS. KOVALESKI: Correct. Correct. We did take this error very seriously. It is in our corrective action program. We performed an extended condition review and as a result of that extended condition review we did adjust the number of butt welds also in this program.

MEMBER STETKAR: That's what I was going to ask. How confident am I in, well, a number that I can read on my screen here of 340 butt welds? Is that --

MS. KOVALESKI: I am 100 percent confident in that number. The reason for that --

MEMBER STETKAR: That's good.

MS. KOVALESKI: The reason for that is our extended condition review, we looked at the entire application to determine where we had generated a sample population and that narrowed it down to these two

categories.

At that point, when we revalidated the number, we went back to the original design drawings and performed a manual count on those. We did identify a few more.

The reason the butt weld number was adjusted is because the drawings had been updated because there were plant modifications and so on and we did add those into our ISI database. Although they are outside of the scope for the ISI program, if ever we are to reuse that database for this purpose, we want them to match.

However, we recognize that the right thing to do was to go back to the design drawings and we have even gone so far as to document a formal engineering evaluation so that if we ever have to develop this population again there is a methodology that is written there and that it has been independently validated and we will not repeat this error again.

MEMBER STETKAR: Three hundred forty versus 342 doesn't affect, for example, the 25 but it could affect, you know, the information about the exact locations of those welds could affect your sampling criteria which is more what I'm, you know, which 25 are you going to sample in terms of your estimated

susceptibility to failure?

MS. KOVALESKI: That's correct.

MEMBER STETKAR: So that's what I'm more concerned with that about.

CHAIRMAN SKILLMAN: Sarah, let me pull this string just a little bit more. You said you finally went back to the design drawings. I can appreciate the spirit behind that. Wouldn't you have been better off going back to the as-builts?

MS. KOVALESKI: We did look at the full population of drawings available to us to validate these numbers and Jerry Doughty, our ISI engineer, I think can elaborate a bit on the drawings reviewed.

MR. DOUGHTY: I'm Jerry Doughty, the in-service inspection program owner. We did go back to the construction drawings, the fabrication drawings to confirm that count. Thank you.

CHAIRMAN SKILLMAN: Did you have images, photographs that you could verify against your drawings?

MR. DOUGHTY: No, I didn't run across any photographs.

CHAIRMAN SKILLMAN: Thank you. Please proceed. Thank you.

MS. KOVALESKI: All right, thank you.

Next slide please. And Mike Hoehn will address the open item related to RCS environment effect on fatigue.

MR. HOEHN: Thank you. This next topic is associated with environmentally assisted fatigue screening and how we address environmentally assisted fatigue for the period of extended operation.

From GALL Rev 1 to GALL Rev 2, there was some wording changes in the section around environmentally assisted fatigue where we were required to demonstrate that the NUREG/CR-6260 locations were bounding at Callaway for the period of extended operation.

At that point in time, there was no systematic means in existence to perform that systematic screening of the components.

We, Callaway, worked with the Electric Power Research Institute to develop a technical report, a technical approach to screen our reactor coolant system pressure boundary locations and come up with a bounding set of sentinel locations that we could enter into our fatigue monitoring program managed into the period of extended operation. That technical report is 1024995.

This approach, some of the benefits of this approach is it utilizes fatigue curves for each material. It has a same level of rigor. We need to

make sure that the same level of rigor is applied throughout the CUF locations, the locations being managed.

An example of that would be making sure that if you have an elastic-plastic and you have a linear elastic on a component, that they're basically brought down to the same level of rigor, that you compare them both on a linear elastic approach.

Any transient lumping needs to be broken down or reconciled in the screening process so, again, you're consistent and you're uniform in your approach.

And we also wanted to evaluate each thermal zone on its own merit. For example, our chemical and volume control system contains multiple thermal zones. You have the letdown, you have the alternate charge, you have a normal charge, you have an auxiliary spray which you can see unique transient sets.

We wanted to evaluate each of those distinct thermal zones and come up with a bounding sentinel location that we could manage into the period of extended operation.

We went through the process with this consideration here, which was in the original EPRI report. We later backed off of this approach, but all materials are evaluated on their own merit.

One material in one thermal zone will not bound another material in the same thermal zone and one material in a thermal zone will not bound another material in another thermal zone, so each of the materials are evaluated on their own merit.

We came up with 22 locations, which is more than the original NUREG/CR-6260 locations, and we will be managing that into the period of extended operation.

In addition, when we refine our analysis, when we review baseline, when changing evaluations are performed, we revisit this analysis to ensure that those 22 locations are still bounding and we can manage those into the period of extended operation.

CHAIRMAN SKILLMAN: Thank you for that explanation. Let me ask a question. Sarah identified Wolf Creek, Palo Verde, Diablo Canyon and South Texas as other plants that you have been dealing with for life extension. At least I believe that's --

MS. KOVALESKI: Those are --

CHAIRMAN SKILLMAN: It's the fifth STARS plant for renewal. Would those plants have the same, approximately the same number of sentinel locations? Are you an outlier with those four other plants?

MR. HOEHN: Again, we're the first to apply this methodology to evaluate the bounded nature of the

NUREG/CR-6260 locations so --

CHAIRMAN SKILLMAN: So they'll probably come looking to you to figure out what you did.

MR. HOEHN: And we had shared this information with the industry in multiple fatigue presentations in the industry and we're actively engaged in the material liability to share the operating experience.

Again, we're unique in the sense that we were a rep to PWR and we were required to demonstrate the bounding nature and we know that with our approach, our 22 locations, we, per the process, we felt it was appropriate to include all the NUREG/CR-6260 locations so those are conservatively included. Some of those could have screened out based upon the methodology but we included that in that 22 count and will manage that moving forward.

CHAIRMAN SKILLMAN: Thank you.

MEMBER SCHULTZ: Michael, I want to appreciate the timing here. Was this work done in response to a question from the staff or are you providing this explanation as a result of the question and --

MR. HOEHN: This approach was we felt we needed, as a result of GALL NUREG-1801, we needed to

demonstrate to ourselves and to the regulator that we had a bounding set of transients we could manage into the period of extended operation. So we developed this approach with EPRI in a proactive fashion to address GALL Rev 2.

MEMBER SCHULTZ: Thank you. Appreciate that.

CHAIRMAN SKILLMAN: Please proceed. Thank you.

MS. KOVALESKI: Next slide please. At this point we're transitioning somewhat. The next four slides cover issues that have come up since issuance of the SER with open items.

The first topic has to do with operating experience related to clevis bolts. The request from the staff was for us to address the similarity of Callaway design to reported failures at another domestic Westinghouse-designed PWR in 2010.

This operating experience did become available to us a couple years ago and we did enter in our corrective action program and had evaluated it. Our design is different from the plant that experienced the failures although the materials used are similar.

We have performed numerous inspections as a result of this operating experience and we've not

identified any degradation or damage. We did provide that information to the staff for their review. Next slide.

CHAIRMAN SKILLMAN: Do you assign the geometrical difference to basis, why you have not had problems and others have?

MS. KOVALESKI: Mike, could you address that?

MR. HOEHN: Your question is related to do we attribute our lack of degradation to the geometry?

CHAIRMAN SKILLMAN: That's kind of what that first bullet infers, clevis insert assembly geometry different from design of plant with failures.

MR. HOEHN: Andrew, pull up Slide --

MALE PARTICIPANT: 116.

MR. HOEHN: 116 if you could.

MR. BURGESS: 116?

MR. HOEHN: Correct. Short answer, it was a factor and the difference and we saw the degradation if you know. This is our configuration. The clevis bolts are on the interior of the clevis location.

The plant in question where the OE was generated from, the clevis bolts are actually on the outside face of the clevis. It's a completely different configuration. The bolting pattern is

different and how the radial support key would contact the clevis insert location where it would slide into that is unique so the stresses would be different as a result of our unique geometry.

CHAIRMAN SKILLMAN: Thank you.

MR. HOEHN: And, again, we did provide inspections in last refueling outage, 2013, and saw no degradation or damage.

CHAIRMAN SKILLMAN: Okay, thank you. Back to 30 please.

MS. KOVALESKI: Next slide please. The next three topics cover generic questions, also cover generic questions asked of applicants.

This one has to do with an ISG-2012-02 which covered aging management of internal surfaces, fire water systems, atmospheric storage tanks and corrosion under insulation.

We implemented this ISG. Some of the changes that we've made is that we recognize that additional aging management is needed for recurring internal corrosion in raw water environments.

We have also recognized that the fire water aging management program will be revised to be consistent in applicable portions to NFPA 25 requirements.

We'll be making some changes, we did make some changes to our aboveground metallic tanks aging management program and outdoor insulated components and indoor insulated components that are exposed to condensation will have that insulation removed so that we can perform inspections of that external surface. This ISG has been implemented and we have provided that to the staff for their review.

CHAIRMAN SKILLMAN: Okay, and this is insulation removed for inspection and then replaced to maintain insulation?

MS. KOVALESKI: That's correct. It's for inspection purposes only.

MR. BARTON: I have a question on your fire water storage tank. I think you had some internal problems with that. I can't think of that right now.

But the concern I have is it apparently is set on a sand base. The bottom of the tank is set in sand. I've had experience with tanks like that that develop leakage, I mean, because there's something that's in the sand eats through, whatever. Have you ever done a UT inspection of the bottom of that tank?

MS. KOVALESKI: I think Lee Eitel could address that please.

MR. EITEL: Lee Eitel, supervisor systems

engineering. We have not performed a ultrasonic test to date. However, later this year we will be recoating the interior of those fire water tanks and as a part of that work evolution we will be performing some ultrasonic testing of that fire water tank.

MR. BARTON: Thank you.

MEMBER BALLINGER: That kind of leakage, corrosion from the bottom is very common in the oil industry.

MR. BARTON: Yes.

MEMBER BALLINGER: One of the most common problems with tanks.

MR. BARTON: Right, because use oil-based sand. It's something in the --

MEMBER BALLINGER: Yes, yes.

MR. BARTON: That eats through the bottom.

MEMBER STETKAR: While we're on fire systems, might as well get a couple of off-the-wall questions out of the way and I'll try to keep them short.

There's some discussion of -- and obviously there have been problems with the fire water systems. It was noted that in flow tests that you did in 2009/2011, you initially didn't pass the flow tests but you managed to be able to sharpen your pencils enough and check off the box and, indeed, you passed those tests

which you didn't have to sharpen your pencil before that so that's indication of degradation.

You've committed, I believe, to instead of doing the testing at three-year intervals to perform the tests every two years to see if there's any trend going.

The thing I wanted to ask about though is at least the information I could read said that the next flow test, again from the documentation I have, is scheduled for 2013. So I'm curious. How did you do in 2013 with your flow test?

MS. KOVALESKI: Lee.

MR. EITEL: Yes, Lee Eitel again. We did have some reduced flow in the 2013 test as well. The next test for the two-year frequency will be next year in 2015. We do still have margin with our flow results, even with the results we received in 2013.

MEMBER STETKAR: I don't know how one does the pencil sharpening for the calculations so did you have to sharpen the pencil more than you did in 2011 to show that you passed or -- in other words, apparently in 2009/2011 you had to get a bit creative in terms of defining what success was. Did you keep the same definition of success and still meet the criteria or did you have to get more creative in 2013?

MR. EITEL: We kept the same definition in

2013. The original change --

MEMBER STETKAR: But showed reduced margin compared to 2011?

MR. EITEL: Correct. Correct.

MEMBER STETKAR: Okay, okay. That's not necessarily okay but at least I understand.

MS. KOVALESKI: The next issue that we'd like to cover is issuance of draft ISG-2013-01. This covered loss of coating integrity for Service Level III and other coatings.

Through RAIs the majority -- I'm sorry. This draft ISG has been implemented into our license renewal application. We will be visually inspecting in-scope coatings that are installed in accessible interior surfaces and have criteria established for modifying that inspection frequency based on the results of those inspections.

The inspection of coatings will be performed by trained and qualified personnel in accordance with ASTM standards that are endorsed in Reg Guide 1.54.

MR. BARTON: Service Level III, does that include the containment liner or not?

MS. KOVALESKI: Containment coatings are Service Level I.

MR. BARTON: All right. Okay. Question on that is you have experienced during outages inspection of that liner some coating failures. Now, I don't know whether that's in certain areas or whether it's random around the surface of the containment. Which is it?

The reason I'm asking, it appears that you haven't done anything with it except scrape off the loose paint or something so I'm trying to figure out what's your program on maintaining the integrity of the containment liner, the painting?

MS. KOVALESKI: Justin Stollhans is our coatings engineer. He can elaborate a bit on our containment coatings inspections.

MR. STOLLHANS: This is Justin Stollhans. I'm the coating engineer. We do perform a coatings inspection of the containment liner every refueling outage. We do identify locations in which the coating has been degraded. We remove those coatings and we do not repair them. We remove the coatings and --

MR. BARTON: Well, what do you find? Bubbles or paint flaking off, peeling or what's the nature of the deficiency?

MR. STOLLHANS: They're normally, the indications are long striations approximately the width

of a pencil or your pinky finger, very linear.

MR. BARTON: How long?

MR. STOLLHANS: They depend. Some are couple inches. Some may be few feet.

MR. BARTON: May be what?

MR. STOLLHANS: May be a few feet.

MR. BARTON: Few feet. Now, do you have a program for repairing these at some point or what's the program? You look at these things and do what? You put them down in a log someplace and say I found some more during this outage?

MR. STOLLHANS: Yes, we --

MR. BARTON: What's your program for maintaining the proper painting integrity of the liner?

MR. STOLLHANS: We would track them and then reinspect them on our inspection every refuel and then we have yet to see any degradation in these locations.

MR. BARTON: You do what?

MR. STOLLHANS: We have yet to see any degradation on these locations of the liner.

MR. BARTON: So you don't have any paint flaking off?

MR. STOLLHANS: The paint, yes, the paint.

MR. BARTON: But the liner still is a nice

shiny carbon steel or whatever?

MR. STOLLHANS: In most cases --

MR. BARTON: Or is it all rusted? What's the condition of the liner now?

MR. STOLLHANS: It is not rusted. In most cases the primer is still intact.

MR. BARTON: The primer is intact?

MR. STOLLHANS: Yes.

CHAIRMAN SKILLMAN: Have you found where the primer is not intact?

MR. STOLLHANS: I am not aware of any indication, so.

CHAIRMAN SKILLMAN: Are those indications in your corrective action program?

MR. STOLLHANS: Yes.

CHAIRMAN SKILLMAN: Each one has a serial number or has a name tag?

MR. STOLLHANS: We do not track them individually, no.

CHAIRMAN SKILLMAN: So how do you know that one from one outage to the next hasn't grown or changed?

MS. KOVALESKI: The results of the inspections are we don't log each individual occurrence but we'll enter one corrective action program entry for those inspection results and then during the subsequent

inspections those previous images are printed out.

I have observed our coating engineers preparing for those inspections and they go print out the previous pictures of the indication so that they can have them with them during those inspections.

CHAIRMAN SKILLMAN: So they do have a unique ID so that an individual can go back to that same place and understand what has changed?

MS. KOVALESKI: Yes, they are logged. I couldn't speak to exactly how they are ID'd and logged but, yes, we have a way of tracking based on the position, the azimuthal position within the containment and height as to which indication is which.

CHAIRMAN SKILLMAN: My expectation is driven by having been at a number of plants where each and every spot of boric acid or each and every coating deficiency has its own unique ID.

And then an engineer, the program engineer is then accountable to keep track of each and every one of those until the boric acid is no longer there or until the holiday in the coating has been repaired. So I'm assuming you must have something similar to that.

MS. KOVALESKI: We'll have to get back to you with our exact tracking of it.

CHAIRMAN SKILLMAN: I'd like to know. I

think John Barton's question's a very good question.

MS. KOVALESKI: Yes, we'll get back to you with that.

CHAIRMAN SKILLMAN: Thank you. Okay.

MEMBER STETKAR: As long as we're on the liner, your good news is you don't have to inspect the moisture barrier seal at the liner penetration of the concrete in the containment floor because you don't have a moisture barrier seal. Do you have any pictures in your backup slides of that gap or that configuration?

The basic question is if you don't have a moisture barrier seal, how do you know you don't have corrosion occurring in that area below the concrete floor in the liner?

MR. BARTON: They said they have a fill plug or something which I don't understand.

MEMBER STETKAR: Oh, I didn't see a fill plug.

MR. BARTON: Where did I see that?

MEMBER STETKAR: Where did you find that?

MR. NETERER: We do have a photo we're going to pull up for you.

MS. KOVALESKI: Yes we do. Yes we do.

(Off microphone discussion)

MALE PARTICIPANT: Okay, there we go.

MR. JOHNSON: Hi, I'm Jim Johnson. I'm the lead engineer and I can speak to this. This is a picture of the interface between the liner and the concrete slab.

MEMBER STETKAR: Good.

MR. JOHNSON: You can see there, there isn't a moisture barrier but there is no gap.

MEMBER STETKAR: That's what I was looking for. Is that inspected every refueling outage to make sure that there hasn't been, you know, swell type openings of a gap?

MR. JOHNSON: There are actually three different aging management programs that look at that interface. Monitoring looks at the concrete, IDBE looks at the liner and the coatings inspection every outage looks at the coatings.

MEMBER STETKAR: Fine. Thank you.

(Crosstalk)

MALE PARTICIPANT: Yes, you don't want me to take up more time anyway, so.

CHAIRMAN SKILLMAN: Is that a fire line?

MALE PARTICIPANT: Pardon me?

CHAIRMAN SKILLMAN: Is that a fire line?

MS. KOVALESKI: In the photo it is conduit. We don't have identification of that available for this

picture.

CHAIRMAN SKILLMAN: Okay, thanks.

MR. JOHNSON: This was during an outage. We think that red one is some kind of a temporary water area or something for an outage. It looks like electrical conduit as best we can determine.

CHAIRMAN SKILLMAN: Okay, thank you. All right.

MS. KOVALESKI: All right. Thank you, Andrew. Moving on to the next slide.

CHAIRMAN SKILLMAN: 33, okay.

MS. KOVALESKI: Slide 33, yes. This topic has to do with submerged bolting and the request from the staff was for us to identify our method of detecting loss of material and loss of preload in submerged bolting.

For Callaway this affected five systems, essential service water where we will be inspecting our stainless steel bolts on a six-year sample basis and testing quarterly for pump performance, our emergency diesel generators where the fuel oil transfer pump bolts will be inspected on a ten-year sample basis and also tested periodically, the service water pump bolting which is replaced entirely during pump refurbishment on a six-year basis and waste water pump bolting. There

are two systems in there, oily waste system and our floor and equipment drain systems and that bolting will be inspected on a six-year sample basis.

MR. BARTON: Is this bolting underwater, it needs a diver to work on it? Or is it all above water, or what? DSW and service water pump bolting?

MS. KOVALESKI: Eric, could you please elaborate on the details?

MR. BLOCHER: Yes, the ESW bolting are on the ESW pumps, which are submerged pumps in the intake bay. The diesel generator fuel oil are pumps that are submerged in the fuel storage tanks.

And service water pump is similar to the ESW pump, only it's on the non-safety service water system. And the waste water pumps, for the most part they're submerged. That varies with the sump level and the waste water.

CHAIRMAN SKILLMAN: For the bolting that is in the intake bay, I assume that the surrounding water is the Missouri River? That accurate?

MR. WINK: For our central service water system, it sits in our ultimate heat sink water, which ultimately is clarified Missouri River water.

MALE PARTICIPANT: He asked about the intake, though.

CHAIRMAN SKILLMAN: Eric said it's at the intake structure.

MR. BLOCHER: The ESW is as Mr. Wink has described.

CHAIRMAN SKILLMAN: Okay. What I was going to ask is is the chemistry of the Missouri River adverse to that bolting?

MR. BLOCHER: It's not in scope.

MS. KOVALESKI: The bolting that is in the scope of this program is not at our intake structure at the river. Mr. Blocher, I think, was referring to where our central service water pumps are installed, the bolting at the intake of those pumps.

CHAIRMAN SKILLMAN: I see, so it's up at the site at the pond --

MR. NETERER: The ultimate heat sink pond.

CHAIRMAN SKILLMAN: -- at the heat sink pond?

MR. NETERER: Correct.

CHAIRMAN SKILLMAN: Okay.

MR. BLOCHER: Eric Blocher, that's one clarification we want to make. Early on there may have been some confusion where we're talking about the river intake structure. That structure is not within scope of license renewal.

MR. BARTON: So that means what, you don't look at it or you don't care, or what? You have to have some kind of thought about it. What's in the intake structure that you got to worry about? What equipment's in there?

MR. BLOCHER: It would probably be good to go back to the site picture and explain the ESW intake structure and the 30 day water supply that is used.

MALE PARTICIPANT: Slide 8 I think.

MR. NETERER: Okay, let me explain this. The river picture that we showed you, that is not in scope. That draws water up to the plant. It goes through a water treatment system.

And that water goes to the cooling tower, and it also can be used for make up to the alternate heat sink pond. The intake that he, that Mr. Blocher was talking about is a pump house on the ultimate heat sink pond. Those are in scope. And that's the bolting we're talking about here.

MR. BARTON: Okay.

MR. NETERER: Okay? And we did change those out from carbon steel to stainless steel several years ago for AG management purposes.

CHAIRMAN SKILLMAN: We worked at a plant where the intake structure problem was the spiders.

The spiders could eat the bolts. The spiders needed name tags. They were visiting on the Susquehanna River. So we've got some real understanding about risk phenomenon. Okay, next slide, please?

MS. KOVALESKI: All right. Next slide, please. At this point, I would like to turn it over to Mr. Neterer for closing remarks.

MEMBER SCHULTZ: Before we do that, I did want to go back to one question associated with the bolts, the stud work. And then we heard that it would most likely be planned, or is planned to be done in refueling out as 23, is that what it says? Four and a half years you mentioned, Dave.

MS. KOVALESKI: Excuse me, you're talking about the reactor height closure studs, stud 18?

MEMBER SCHULTZ: Stud 18, stud 18.

MS. KOVALESKI: Okay, okay. Okay, not submerged bolting.

MEMBER SCHULTZ: Back to that issue.

MS. KOVALESKI: I understand.

MEMBER SCHULTZ: That's correct. And I was wondering whether the stud holes were going to be inspected at that same time?

MS. KOVALESKI: The stud holes are inspected every outage.

MEMBER SCHULTZ: The six that we were talking about --

MS. KOVALESKI: They are all inspected --

MEMBER SCHULTZ: -- the detailed inspection.

MS. KOVALESKI: They are visually inspected --

MEMBER SCHULTZ: Right.

MS. KOVALESKI: -- every outage. And they are also in the scope of our RSI program. The laser mapping will be performed at the same time that we remove the stud so that we can also inspect the stud that's being removed.

MEMBER SCHULTZ: Have the equipment there to do the work --

MS. KOVALESKI: That's right.

MEMBER SCHULTZ: -- at that time.

MS. KOVALESKI: That's right.

MEMBER SCHULTZ: I appreciate that. And I also recall hearing earlier in the presentation that this was not considered to be an aging problem because it happened early in the life of the plant.

But I think in the spirit of aging management license renewal, that it's good to get this taken care of, moving forward. So I appreciate that,

thank you.

MS. KOVALESKI: Thank you, we agree. That was an important learning for us during this process.

CHAIRMAN SKILLMAN: Dave, back to you.

MR. NETERER: Thank you, Mr. Chairman. Callaway plant is a learning organization. One of the key learnings in the last seven years going through this process is we must learn to operate the plant differently for the next 30 years than we have the previous 30 years, particularly in the area of aging management.

We have institutionalized and internalized the aging management concept and principles through several things like training, corrective action program, operating experience, and our strong program owners. They've really grown into this aging management concept.

You can see our subject matter experts, a lot of these folks here are really new to Callaway in that last seven year period. So we've got a lot of younger people coming in.

And for them, aging management's not a new program. It's a way of life for them to help carry that on in the next 30 years of operation. So it's really good to see these young folks getting involved in this.

So I would just like to thank the committee, thank you Mr. Chairman for listening to our presentation. And thanks for the challenges. You gave us a couple things to go back and prove our programs on aging management to think about today.

CHAIRMAN SKILLMAN: Thank you. Colleagues, any other questions?

MR. BARTON: I've got a question.

CHAIRMAN SKILLMAN: Yes sir, John?

MR. BARTON: Fuel oil chemistry program, in your response to an RAI regarding inability to drain and clean the diesel generator, fire pump, oil day tank, and the security diesel generator, fuel oil day tank due to limited access, do you propose to periodically sample, you didn't say what frequency, the tanks to ensure there's no evidence of corrosion.

Question I got, if you can't drain and clean these tanks, how do you change the oil in them? Or don't you?

MR. BLOCHER: I just want to clarify, to clean the tanks requires physical access into the tanks. And the biggest opening, I believe, on the security tank is the order of magnitude of, like, a one inch or two inch connection. The piping would have to be removed from it.

MR. BARTON: Right. Okay.

MR. BLOCHER: So we physically cannot get in there. Many of the tanks do have connections that would allow draining down to the bottom of the tank. But again, that physical access for physical cleaning of the tank is not possible.

MR. BARTON: So you have the ability to drain and put oil in, but you can't get access to inspect it or clean it?

MR. BLOCHER: Correct.

MR. BARTON: Okay. That's about it.

CHAIRMAN SKILLMAN: John? Ron?

MEMBER BALLINGER: Good

CHAIRMAN SKILLMAN: Steve?

MEMBER SCHULTZ: No, thank you.

CHAIRMAN SKILLMAN: Ladies and gentlemen, we will take a 15 minute break. We will resume at 3:30, 15:30 on that clock.

(Whereupon, the foregoing matter went off the record at 3:12 p.m. and went back on the record at 3:29 p.m.)

CHAIRMAN SKILLMAN: We are back in session. Ladies and gentlemen, Ameren has a response from some questions that we asked, and I would like to give them an opportunity please to respond, to take one

or two minutes here, please.

MR. WINK: Yes, my name is Roger Wink, supervising engineer of the license renewal project. We had a question earlier about our containment coatings and how we track those individual items.

We do not assign specific location IDs to the defects that we may find in our containment liner. They are entered in our corrective action system. They are identified by location and height off the floor as met the around containment such as that.

And they are also tracked in the specific job that we would write against those location and also the program notebook for our coatings program.

CHAIRMAN SKILLMAN: Thank you.

MR. WINK: Yes.

CHAIRMAN SKILLMAN: Thank you very much. That ends that portion of our business. I now call upon John Lubinski to lead the NRC portion, please.

MR. LUBINSKI: Thank you, Chairman. What we hope to cover this afternoon is our portion of the review. As I said earlier, the SER with open items was issued in April of 2013. We did have a May 12th memo this year that discussed the status of the open items, as well as some additional issues that we were addressing.

Let me introduce the NRC staff that will address these this afternoon. John Daily is the Project Manager for Callaway. He will be doing our presentation this afternoon.

He is assisted at the front table by Dr. Allen Hiser, our Senior Level Adviser and Daneira Melendez who is our Project Manager within our division. And we have other folks in the audience who will help participate.

We do have on the phone line, and I'm going to do a check here, Greg Pick at Region IV. Greg, did you join us on the phone line? Okay, we still have a problem locating Greg. What we'll do is when we get to that --

MR. PICK: John.

MR. LUBINSKI: Greg, you're there.

MR. PICK: I have been here.

MR. LUBINSKI: Great, okay. Welcome. You've been here already. So when we get to your part, you'll hear John Daily introduce you. Thank you. With that, I would like to turn it to John Daily and have him do the presentation.

MR. DAILY: Thank you, John. Good afternoon Chairman Skillman and members of the ACRS License Renewal Subcommittee. My name's John Daily,

I'm the License Renewal Project Manager for Callaway Plant Unit 1 license renewal safety review.

We're here today to discuss the review of the Callaway license renewal application as documented in the Safety Evaluation report with open items issued in April of 2013.

And John Lubinski already introduced everyone so we can skip with that part. And of course, we have other staff members and reviewers in the audience which might be able to shed some light on things as we progress. Next slide.

Today we will present a general overview of the staff's review and then we'll discuss the main sections and the issues presented in the staff's SER as shown here. Greg Pick, in a few minutes, will present the results from the Region 4 on site inspection. Next slide.

This slide's provided for information only. The applicant has covered all the points that are presented here. And we also discussed what led us up to a May 2014 Subcommittee date.

I know there were several schedule changes. During those schedule changes however, the staff has continued to work on the open items and the other issues as they have arisen.

We have been issuing requests for additional information, holding conference calls with the applicant, and receiving supplemental information from them on these issues in order to make sure that we have resolution paths for each one of them. Next slide.

The staff conducted several on site audits and inspections for the application as shown here on the slide. During the scoping and screening methodology audit, the audit team reviewed the applicant's administrative controls governing the scoping and screening methodology and the technical basis for selected scoping and screening results.

The staff also reviewed selected examples of component material and environment combinations, reviewed information contained in the applicant's corrective action program that was relevant to plant specific age related degradation, reviewed quality practices that were applied during the development of the application, and reviewed the training of personnel who participated in the development of the LRA.

During the aging management program audit, a team of over 35 reviewers examined Ameren Missouri's aging management programs and related documentation to verify applicant claims of consistency with the corresponding AMPs in the GALL report.

The staff reviewed 42 AMPs and documented the results in an audit report that was dated August 9th, 2012. And I believe you have a copy of that, Mr. Chairman, that we provided earlier.

Finally, Region IV conducted its regional inspection from September 10th, 2012 through November 7th, 2012. And as we said, we'll present those results here shortly. Next slide.

In addition to the audits and inspections already mentioned, the staff conducted in depth technical reviews and issued requests for additional information, or RAIs. Staff completed its initial review of the Callaway license renewal application with the exception of five open items and issued the Safety Evaluation report with open items on April 23rd, 2013.

Subsequent to issuing the SER with open items, some other items did arise, and we'll deal with those towards the end of the slide presentation.

CHAIRMAN SKILLMAN: John, let me just exercise a little bit of prickliness here. Would it be accurate to say that those several items that came on to our agenda were really known before the SERI was issued? Our belief is that they probably were.

MR. DAILY: Well I can't speak directly to that, Mr. Chairman, because I wasn't project manager at

the time. But I do know that within our division, generally speaking, issues like this arise as an issue at one or two plants first, then we notice that it's something that needs to be developed generally.

And then at some point we decide to develop, for example interim staff guidelines. During that process, which was happening at the same time the SER with open items was prepared, there are times when information comes in after a cutoff date.

And I believe that was the case in at least two of these items. Now the third one actually resulted because of components that were added in August of 2013, which about four months after the SER with open items was issued.

So as things are going through the process, there is a cutoff date that we have to do in order to present information in the SER. So I'm pretty sure that those particular ones with the two ISGs probably evolved in that fashion.

CHAIRMAN SKILLMAN: Thank you.

MR. DAILY: Thank you. So as we mentioned, two of the items that were the other ones that arose, they came about as the result of this interim staff guidelines.

And then the third item which we'll talk

about, the submerged bolting which the applicant had already initially covered, that actually came up as new components that were added to the scope of license renewal after the SER was issued. So that's one of the reasons why it comes up the way it did.

Pending resolution now of these open items and the outstanding RAIs, our plan as a staff is to issue Callaway's final SER in September of this year, and in order to support, you know, the remaining parts of the schedule.

Let's now turn the presentation over to Greg Pick, the Region IV Inspection Team Leader on the phone. And Greg will discuss the license renewal inspection. Greg?

MR. PICK: Thank you, John. Can everyone hear me?

MR. LUBINSKI: Yes, we can hear you loud and clear.

MR. PICK: Good afternoon members of the subcommittee. As an overview of the inspection, we had five --

MR. LUBINSKI: Hey Greg? Greg?

MR. PICK: Yes?

CHAIRMAN SKILLMAN: Greg, this is Nick Skillman. We can hear you loudly and clearly. Would

you please back away from your microphone or from whatever instrument you're using because we're getting a double take and you're cutting out.

MR. PICK: Is this any better?

CHAIRMAN SKILLMAN: It is.

MR. PICK: I'll just talk normal then.

CHAIRMAN SKILLMAN: Thank you.

MR. PICK: Five inspectors had experience and expertise related -- mechanical systems and components -- electrical systems and components --

CHAIRMAN SKILLMAN: Greg, you're still breaking up. Are you on a speaker phone?

MR. PICK: Not anymore.

CHAIRMAN SKILLMAN: That's better.

MALE PARTICIPANT: That's much better.

CHAIRMAN SKILLMAN: Just speak in normal tone, I think you'll be all right.

MR. PICK: The scoping inspection was concerned with reviewing for proper disposition of components included in scope, and review of the excluded items to verify appropriate determination of non-safety related components affecting safety related components.

The aging management programs inspected, we reviewed seven new programs and 16 existing programs.

Next slide, please.

The team identified several issues, and these are all discussed in our inspection report. Some of the more significant ones are presented here to illustrate. For the condensate storage tank, the team identified that two of ten installed inaccessible anchor bolts did not have minimum thread engagement in accordance with ANCB 11 and the Callaway bolting manual.

The applicant demonstrated that the condensate storage tank could perform its design function with only 37 of the 56 bolts installed, and this lack of thread engagement did not render the tank inoperable.

The applicant planned to upgrade the cathodic protection sections for the buried piping in 2015 as they've already discussed. They would complete this modification nine years prior to entering the period of extended operation.

Their coatings and backfill were in good condition and consistent with the GALL report recommendations. This reduces the number of buried piping excavations to a single inspection each ten year period.

For the emergency fuel oil storage tank, plan operating experience described coating blisters in

the Train A tank. However, from review of the inspection records, the team determined that the applicant did not know the exact number or location, and had not tracked or trended whether these blisters had grown.

Following questions from the team, the applicant committed to repair and evaluate the blisters in the Train A tank during their next ten year inspection, which will occur prior to entering the period of extended operation, and the licensee submitted a revision to their license renewal application.

CHAIRMAN SKILLMAN: Greg, let me ask you a question. I'm on your inspection report, your Page 24. To what extent, when you found this item relative to the blisters in the fuel oil storage tank, did you chase the licensee's actions relative to the fuel oil filters, and what did they find?

MR. PICK: We did not address the fuel oil filters. So I cannot answer the question. But nothing in their corrective action program indicated they had any problems with their fuel oil filters. We did look through their corrective action program documents.

CHAIRMAN SKILLMAN: I'm thinking blisters is probably material wastage? And the consequence of

the wastage is some form of buildup on the filters, unless of course the filters are changed out once a year or once every six months or on some frequency that precludes any buildup from effecting operability of the diesel engines.

MR. PICK: Along those lines, and they would better be able to address this, but during our discussion on site, they believed the blisters were due to original application of the coating and poor adhesion. But they couldn't prove that to the inspection team.

So when they go in and inspect it, they're going to remove the blisters to see if it was an adhesion problem, and then do a repair.

CHAIRMAN SKILLMAN: Thank you, Greg.

MR. PICK: Related to the buried piping, there were several, I'm going to use the phrase deficiencies as an inspector. But there were enhancements required for their procedures.

Their buried and piping program engineers collected a soil sample as required. They did not keep it cool, so the bacteria would not remain alive for testing. That was a recommendation, to cool the samples when you take them.

Some other identified recommendations, the

low voltage holiday testing on newly applied coatings. There were inconsistencies on the environmental conditions, when to apply a primer related to the temperatures when you did the inspection.

One part of the procedure said below freezing, one part of the procedure said ten degrees Fahrenheit. They got with the vendor and corrected that in their procedure. It's any temperature below 40 degrees.

And at that time, the coatings engineer was not always called out to do an inspection. Now the coatings engineer will be called out to do a visual inspection versus sent photographs a couple days later. Because of the long delay, I've already reviewed the procedure and they've already implemented these enhancements. Next slide, please.

MR. BARTON: Hey Greg. Well hold up, hey Greg? John Barton here.

MR. PICK: Yes, sir.

MR. BARTON: On piping, buried piping procedure, in your inspection report it was noted, "Photographs of buried piping showed that pipe wrappings were not adhered to some piping. The applicant stated that had it been safety related piping, they would have replaced the wrapping."

Now I don't know if you are familiar with that, what the piping was. My concern is I don't care whether it's safety related or not, but I'm going for another 20 more years and I've got buried piping that's not protected, I would probably worry about that and do something about it.

But I don't know what the system is. Do you? Is that familiar with you? It was in your inspection report.

MR. PICK: If I recall, it was a fire water piping. And it was fire water piping going to a building outside the protected area fence.

MR. BARTON: So I don't care about that, right?

MR. PICK: That's correct.

MR. BARTON: Okay.

MR. PICK: That is in fact clear in the report, but that's the point being made.

MR. BARTON: So if that piping develops a leak, it doesn't affect the rest of the fire protection system? That piping can burst open and there's no problem?

MR. PICK: If it had burst open and they had a fire and needed to fight the fire, the furthest away sprinkler they have sufficient capacity.

MR. BARTON: Okay. All right, that answers my concern. Thank you.

MR. PICK: You're welcome. So for my final slide, Slide 8 please. The inspection concluded, the team concluded they would properly scope a non-safety structure system and components in the application of the aging management programs to those structure system and components were acceptable. So in all locations, non-safety would not affect safety.

And the team concluded that reasonable assurance existed that aging effects will be managed and attended functions maintained for the period of extended operation. This concludes my formal presentation. Any additional questions?

MR. BARTON: Yes, this is John Barton again. Your team did inspect certain areas of the site and certain buildings. I always ask this question and you guys don't like it. But what's your assessment of material condition of the site?

MR. PICK: John, we love hearing that question.

MR. BARTON: Thank you. Some guys, you know, have a problem with that question.

MR. PICK: For the period of time that we were on the site for this inspection, knowing that you

do ask this question, we made sure we covered every square inch of the site we could to be able to give you the most reasonable answer.

The condition of the concrete, the piping, the coatings that we could see, that site is in very good condition, in the team's opinion.

MR. BARTON: I appreciate that, thank you.

MR. PICK: You're welcome. I'm going to turn it back over to you, John Daily.

CHAIRMAN SKILLMAN: Thank you, Greg.

MR. DAILY: Thank you, Greg. Next slide. Let's now move on to Section 2 which describes the scoping and screening of structures and components that are subject to aging management review.

The staff reviewed the applicant's scoping and screening methodology procedures and quality controls applicable to the license renewal application development, as well as the training of project personnel. We mentioned this a little earlier.

Staff also reviewed the various summaries of the safety related systems, structures, and components, or SSCs, non-safety SSCs effecting safety related components and SSCs relied upon to perform functions in compliance with the Commission's regulations for fire protection, environmental

qualifications, station blackout, pressurized thermal shock, and anticipated transience without scram.

Based on these reviews on the results from the scoping and screening audit, and on additional information provided by the applicant, the staff concludes with the exception of one open item that the applicant's scoping and screening methodology was consistent with the standard review plan and the requirements of 10 CFR Part 54.

If there are no real questions on this slide, we'll turn to the next one which will discuss the open item associated with scoping and screening.

CHAIRMAN SKILLMAN: John, let me ask this question on that slide.

MR. DAILY: Yes, sir.

CHAIRMAN SKILLMAN: The processes that are employed for scoping and screening really constitute the IPA under 54, NCFR 54. Is that accurate?

MR. DAILY: Well, Bill Rogers may want to step up to the mic.

DR. HISER: Yes, scoping and screening are part of the IPA. The IPA includes how are you going to manage aging effects. So that's the part, scoping and screening is the --

CHAIRMAN SKILLMAN: Front end.

DR. HISER: -- the part where you identify components that are within the scope and are screened in because they're long lived and passive, then you need to do the aging management review.

And then the aging management determination, how will you manage the aging effects that require management. So just to express that equivalence, that scoping and screening equals IPA is not correct. So the screening is a portion.

CHAIRMAN SKILLMAN: It's a portion, it's the front end.

MR. DAILY: Right. In essence it is the front end. And the first thing that we look at under this section is the actual methodology that is used to establish the scoping and the screening. And then we also do samples of the actual results. And that's done during the audit, which you know, our audit team leader leads and then writes a report on.

But yes, that's the front end. Aging management review and the final determination of the 3,900 line items, you know, the 42 programs and so forth, this then becomes the integrated plan assessment, the entire book or the license renewal application on the safety side.

CHAIRMAN SKILLMAN: Thank you.

MR. DAILY: Okay, you're welcome. Let's see, where were we here? So we're going to go to the next slide and we'll talk about the open item associated with scoping and screening.

Open item 2.3.3.20-1 is related to the scoping of fire protection structure systems and components. The staff's initial review of the applicant's compliance with the fire protection rule included reviewing the documents as listed in the Callaway license and the then current final safety analysis report, which represents Callaway's licensing basis at that time.

This open item involved two aspects of the scoping and screening of these fire protection SSCs. For the first aspect that was based on its review, it was not clear to the staff whether the fire suppression SSCs in the auxiliary boiler room, the turban building, hydrogen seal oil unit, and condenser pit were within the scope of license renewal.

The applicant's initial response was that these fire suppression components were not within the scope because they were not required for safe shutdown. Staff found that this was contrary to the applicant's current licensing basis which did include these SSCs as necessary for compliance with the fire protection rule.

The staff noted that without additional justification, these SSCs should not be excluded from the scope. And by letter late in April, basically at the end of April 2013, Ameren Missouri added these areas and SSCs back into the scope of license renewal and resolved the staff's concerns.

And of course, as mentioned earlier, and we'll go on into the second aspect, that was under the traditional, what I would call a more traditional fire protection program based upon the deterministic fire protection programs at 50.48.

However, the second aspect which involved conversion over to the NFPA standard, NFPA 805, regarding this aspect now backtracking just a little bit.

In August of 2011, so just shortly before the license renewal application was submitted, the applicant had submitted a license amendment request to transition its existing program to a risk informed performance based program based upon NFPA standard 805.

Therefore, these two amendment request reviews were essentially running in parallel with each other during this period of time. It was unclear to the staff then during the safety review for license renewal as to which fire protection program modifications were

going to be planned for the transition to NFPA 805, which might in turn effect the existing fire protection program SSCs within the scope of license renewal.

The staff requested Ameren Missouri to identify and discuss any of the changes associated with this NFPA 805 transition. The applicant ultimately committed to provide a gap analysis upon issuance of the final license amendment for the NFPA transition.

So the NRC staff issued this then as a license amendment to Ameren Missouri in January of this year, January 2014. And that granted the approval and the authorization to change over to the NFPA 805 based program.

The applicant then submitted a gap analysis to the staff for this open item in February, so shortly after that of this year. The staff's initial review found that this February submittal lacked some sufficient details in order to be able to reach conclusions to the adequacy of the analysis and the changes.

Through some follow up requests for information and conference calls, the applicant agreed and has subsequently submitted a supplement to this gap analysis, which now provides the staff with the desired level of detail.

The staff expects to close this open item pending completion of its review. Final resolution will be documented in the final SER and presented to the ACRS full committee.

One thing I might add on this, I know there was some discussion during the applicant's presentation of why not submit that while the review was ongoing. And of course, our license renewal review is based upon what we call the current licensing basis.

At that time, before the amendment was granted, it was the traditional basis. And so therefore, there was some time lapse involved in order to get this settled so that the new licensing basis could then be addressed. And that's what they addressed in their gap analysis. And the staff therefore expects to be able to close this open item.

CHAIRMAN SKILLMAN: Thank you.

MEMBER SCHULTZ: John, then at this point in time you're not anticipating the need for further interaction with the applicant? You feel that the responses that you have received recently have addressed your issues. But you need to finalize your review of what you now have?

MR. DAILY: Yes sir, that's our caveat. We don't expect to see any other details. But obviously

when you're writing your final input and you're crossing your t's and dotting your i's, something might come up.

MEMBER SCHULTZ: But you're not waiting for anything.

MR. DAILY: We're not waiting for anything right now. We have that information in hand and therefore we can say we expect to close this. We're pretty confident.

MEMBER SCHULTZ: Thank you.

MR. DAILY: Next slide. Let's now move on to Section 3, Aging Management Review Results. Section 3.0 of this section covers the staff's review of the applicant's aging management programs, or AMPs.

Sections 3.1 through 3.6 cover the aging management review items for each of the general system areas within the scope of license renewal. For a given aging management review, the staff reviews the item to determine whether it's consistent with the GALL report.

If an aging management review is not consistent with the GALL report, then the staff conducts a technical review in depth in order to ensure adequacy of managing the effects of aging for that particular component material and environment condition.

Three of the five open items in the SER do relate to the AMPs in Section 3.0. And so we'll go on

and discuss those here in the next slides. Next slide.

As Ameren had presented, 42 aging management programs are presented in the license renewal application. Thirty two of them are existing, ten are brand new. There was some back and forth related to how many would wind up being fully consistent with the GALL report and how many might have exceptions or enhancements.

Bottom line following the review and the adjustments that the applicant has made to them, the staff concluded that 23 AMPs are consistent with the GALL report and 19 are consistent with enhancements and/or exceptions. And there were no plant specific aging management programs for this review. Next slide.

The first of the three open items associated with the AMPs, open item B2.1.3-1 is related to the reactor head closure studs and associated reactor vessel flange threads.

On multiple occasions starting with Callaway's first refueling outage in 1986, the applicant has experienced difficulties either inserting or removing its reactor vessel head closure studs. In addition, multiple closure studs have been stuck at one time or another.

Because of these evolutions, some of the

corresponding reactor pressure vessel flange hole threads have been damaged in a total of ten out of the 54 locations.

MEMBER STETKAR: John, just for the record, at one time or another was before 1992, right?

MR. DAILY: Yes.

MEMBER STETKAR: 1996 was number --

MR. DAILY: The single one, number 18.

MEMBER STETKAR: Eighteen. Nothing since '96.

MR. DAILY: And nothing as far as we can tell in the record that we have, right.

MEMBER STETKAR: Thank you.

MR. DAILY: Nothing beyond 1996. I believe 1992, we have some backup information, but I think 1992 was the last time that five of them were stuck. And they were subsequently able to free and, you know, do their repairs and examinations.

MEMBER STETKAR: Okay, thank you.

MR. DAILY: The damaged stud hole threads were not repaired by means of thread inserts, but instead were either machined down or ground off. Therefore, several of these flange locations have less than a full complement of threads.

The majority of the flange holes with

multiple missing threads are located basically in one quadrant if you were to look at the circumference from above. Most of the thread hole damage is located with flange holes down in one quadrant. Not all of them, there's a few that are in the other peripheries.

CHAIRMAN SKILLMAN: Have you explored why that pattern exists?

MR. DAILY: We did actually, I believe. During the AMP audit there was some dialogue back and forth. We've got Roger Kalikian who is the reviewer for that. And I believe he may be able to shed some light on this for us.

MR. KALIKIAN: Yes hi, my name is Roger Kalikian. I'm the primary reviewer. And when we looked into it we were interested in why they were in that quadrant.

Apparently when they were testing it before initial fuel up, there were some issues with a tight fit. So they were go gauging the holes and the gauger got stuck. So they had difficulty removing the gauger out of number 12.

And they decided not to gauge the rest of them. They just happened to be in that area. So out of the five that got stuck, four of them were not gauged.

CHAIRMAN SKILLMAN: Thank you.

MR. DAILY: The staff noted that the applicant's aging management program as proposed, which is basically it was based upon the GALL report AMP, may not be adequate for monitoring and managing degradation of the reactor vessel flange hole threads and based upon the applicant's plant specific conditions.

Now one of the reasons behind that is because the GALL report AMP more or less assumes rather normal studs, threads, and holes, and operating experience. This is, I guess in my experience this is a unique situation, this particular plant, you know, and the experiences that they've had. So the staff had some real concerns in that area as to whether this is really going to have enough adequate controls for them.

Furthermore, one stud, number 18 as had been mentioned before, became stuck during its installation in the 1996 refueling outage at 2.625 inches withdrawn. This stuck stud has not been removed since during any subsequent inspections our outages.

The applicant stated that it performed an engineering evaluation and determined that the stuck stud has sufficient thread engagement to be fully tensioned. And they reported that they've been able to fully tension and de-tension that stud from 1996 on up to present.

The staff was concerned that the existing reactor head closure stud bolting program here in this instance may not be adequate to detect future wear or loss of material to ensure that the appropriate acceptance of this criteria would continue to be met, and that the allowable stresses under the ASME code are not exceeded during the period of extended operation.

And so this became the two portions involved in this particular open item, the multiple stuck studs and then aging management, you know, in the future for stud number 18.

In order to address the staff's concerns, the applicant proposed two commitments. The first commitment would perform a one time inspection no later than six months prior to PEO for the six flange stud hole locations with the highest amounts of missing threads.

Each of these locations has more than one thread circumference missing, basically from four to 15 missing equivalent 360 degree threads. The proposed inspection method would use a laser inspection to provide accurate determination of whether wear or loss of material for the existing threads has occurred.

This inspection would be similar to, as reported by the applicant, would be similar to the original inspections that the applicant performed in

1989 and '92 in order to determine the number of fully engaged threads for each location with these damaged threads.

Staff believes that this inspection method should be able to provide an accurate evaluation such that if wear or loss of material in these locations is present, it could be detected and measured.

In addition, the results from prior inspections, if they are used as a baseline, a wear or a loss rate could potentially be calculated and projected then to the end of the period of extended operation. The staff believes that this inspection is necessary to verify that for these locations, appropriate acceptance criteria will be met.

The second commitment that the applicant has proposed would remove stud number 18 and inspect or replace it no later than six months prior to the period of extended operation.

Since the stud has been stuck since 1996 and the number of engaged threads are close to the applicant's minimum acceptance criteria, the staff believes that this action for stud number 18 is essential in order to establish that the appropriate acceptance criteria will be met and that the allowable stresses under the SME code for stud number 18 are not

exceeded throughout the period of extended operation.

The staff's conclusion is that with these changes added to the applicant's program as noted above, there's reasonable assurance that the aging effects that are associated with the reactor head and closure studs will be adequately managed. The staff will, however, consider whether to use a licensed condition in this regard.

The staff does expect to close this open item in the final SER, and the details of that closure and the results will be presented to the ACRS full committee.

CHAIRMAN SKILLMAN: John, you're wording was remove stud 18, Commitment number 2, remove stud 18 and inspect or replace it. Did you mean remove the remnant of 18 if it needs to be cut off, and replace 18 with a brand new 18 with good threads, is that what you meant to say?

MR. DAILY: I would love for that to be the case.

CHAIRMAN SKILLMAN: Is that what you intend the applicant to do?

MR. DAILY: I think maybe, you know, as far as the staff intent, our basic thing while Roger's coming up to the phone, we just don't think it's

appropriate to continue to operate with a questionable stud and we're concerned about PEO.

MR. KALIKIAN: Yes, the stud most likely, we don't know what the condition is. They never tried to remove it, so it may end up coming out. When it went in, it had just a few burrs on it. It buffed it out.

I think most likely it's going to be destructively removed, so it would be a new stud. And they have plenty of new studs, I think, from a unit that never got constructed.

CHAIRMAN SKILLMAN: Thank you.

MR. DAILY: Yes, I'm sure that the actual language, as we look at any licensing decision, that language is going to be important. But that's kind of the staff's position is we think that there needs to be a new stud there.

CHAIRMAN SKILLMAN: Do you feel like the commitment that the applicant has made is a sufficient commitment to solve the concern that you have?

MR. DAILY: Well, there is a discussion on that. I mean, commitment, the language of a commitment, a license condition which would become an obligation. And I think that's still something that we're talking about as a division internally.

MR. LUBINSKI: And if I could add to that,

I think your question is do we believe that the commitment that they've provided at this point is adequate. And what we've looked at is the commitment itself of what they plan to do, I'll say what their plans are for addressing the issue is adequate.

To be able to say they have to put a new stud in, that would be, you know, beyond what the current commitment is because if the stud is appropriate, if they're able to inspect the threads and the threads are fine and they're able to implement the aging management program, we're good.

The second part of the question of whether it becomes a license condition, as John said, that's something we may want to consider and we are considering with the idea being that if they want to vary from that, it would require an amendment to the program, and that's the reason we would want to require it as a license condition, if they wanted to vary in any way.

CHAIRMAN SKILLMAN: Well I guess what I'm trying to communicate is I listen to the licensee say we're going to fix this. We'll fix it in the future. We've got reasons we don't want to do it right now. We've already got our outage for 2014 set, so this is not a good time, but we will take care of it before six months before the PEO.

And I think it is appropriate that we take them at their word. My question is is their word good enough for you? They said they're going to fix it.

MR. LUBINSKI: I think when you say their word, as part of the application is, when we talk about the license condition, the license condition is if they decide to vary from that at all. And this would be if they were going to vary because again, it's not that they would just blow off the commitment and that's not what we're saying.

It's they might want to do it by an alternate method than what they're doing because again, between now and the time they enter PEO, there's a period of time. If they want to vary and do something different, we want to make sure that we have a chance to review what that difference is, and that would be the reason for the license condition.

Not that we don't think they'll do it, it's just the manner in which they do it may change and we would want to review that new manner.

MR. DAILY: Right. And the reason that I pause, I'm not a lawyer. So you know, I think there are some things when you get into talking about obligation and trusting their word and things, I do take them at their word, I think this is a serious business.

But on the other hand, again since I'm not a stud engineer and since we're not necessarily there when it happens, we might have to allow the possibility that stud removal is successful, you know, however large or small that probability might be. And therefore, it think we need to leave a certain amount of decision into the applicant's hands in that regard.

MR. BARTON: I mean, this is just big enough, why wouldn't you want to be there when it happens?

MR. DAILY: Well, that's a very good point. And I think probably at least one of the inspectors of the region probably will be there.

MR. BARTON: Will be there.

MR. DAILY: Because, you know, we're talking about the reactor vessel. That's the heart of the plant.

CHAIRMAN SKILLMAN: We're talking about reactor coolant system pressure boundary protection.

DR. HISER: And this would be an atypical evolution, unusual activity.

CHAIRMAN SKILLMAN: Well, there have been other utilities in other reactor plants, smaller, that have found a way to cut them out, skin them out, shine them up and put in a new stud and be as good as you can

be, although not as new. And it works, it works very well. People know how to do that.

MR. DAILY: And I do believe that, and I would have to defer to Callaway on this, but I do believe that they did have some destructive removals of some of the other studs and were successful in reusing those holes.

MR. DAILY: Sure.

CHAIRMAN SKILLMAN: So, you know, we have to allow all of those possibilities. We just don't want the status quo to continue. I guess, I think we would be safe in saying that.

MR. DAILY: I'm certainly not communicating any thought on my part that the applicant should destroy the lower flange heads, threads in order to do this. There is a way to get the stud out that will not hurt those threads, I understand that.

MR. KALIKIAN: Yes, in the past they haven't reused any of these stock studs. So they have always been replaced --

CHAIRMAN SKILLMAN: Oh yes, I would think the stock stud's got to go.

MR. DAILY: Right.

MR. KALIKIAN: And their practice has been if they have a flange hole that has some damaged threads,

they make sure the stud has zero damage on it.

MR. DAILY: This has been a pretty complicated issue. But I have faith in what the staff is doing and our conclusions. And I think that the applicant is serious about what they are doing. So I'm pretty confident that we are going to be able to come to a successful resolution for this particular stud just like, you know, the others have been.

CHAIRMAN SKILLMAN: Okay.

MEMBER SCHULTZ: John, the applicant presented earlier the detailed information that they that they had associated with the stud holes, and as a way to justify their choice of the worst conditions, the six worst that they were going to inspect.

And I presume that the staff's had an opportunity to review all of that material and conclude that their program for inspection is appropriate. Is that true?

MR. KALIKIAN: This is Roger Kalikian again. Yes, those six locations are the worst one. All the other ones have minor damage.

MEMBER SCHULTZ: So you're good with the program as it's proposed?

MR. KALIKIAN: Yes.

MR. DAILY: And I believe that diagram

showing the stud alignment is a diagram that was supplied as one of the responses to our RAIs. Is that --

MR. KALIKIAN: No, actually that was earlier response. Back when they got stuck, they provided some evaluations to us back in '87.

MR. DAILY: '87?

MEMBER SCHULTZ: Thank you.

CHAIRMAN SKILLMAN: The duration of this small discussion indicates that the concern that the subcommittee has. And so the transcript will show that we are concerned. But I will also offer, I heard the licensee speak the same type of concern. Thank you. Okay.

MR. DAILY: Yes sir, you're welcome. Next slide. Open item B2.1.6-1 is related to the applicant's reactor vessel internal's program for pressurized water reactors, or PWRs. This AMP is based upon conformance with both the GALL report AMP and the EPRI report MRP-227A, which again Ameren Missouri had referred to in their presentation.

This MRP report provides the PWR industry's recommended inspection and evaluation guidelines for PWR design, reactor vessel internal components, and was endorsed for use by the NRC and the safety evaluation

that the staff produced dated in December of 2011.

The scope of the AMP includes the applicant's bases for resolving what are called the applicant/licensee action items that were identified in the NRC safety evaluation and any applicable generic or plant specific operating experience.

The safety evaluation contains eight of these action items, one through eight, with action item eight being subdivided further into five separate sub-parts. The applicant's program as originally proposed did not address all of the applicable action items, therefore the staff sought further information.

Ameren Missouri's initial action item responses resolved most of the action items with the exception of items 1, 5, 7 and 8 sub-part 5. So four things were left open.

The applicant also needed to address the generic clevis insert bolt cracking experience that was identified in another PWR which had occurred in 2010, and to assess whether that operating experience should result in a change to the frequency of it performing its own ASME in-service inspections for the clevis insert bolts at Callaway.

We included this clevis insert bolt basically under the umbrella in our reviews of the

review for the reactor vessel internals. I noticed the applicant had split it out. It's the same issue, we're just kind of grouping it a little differently.

The applicant has resolved the action items that remained open and the clevis insert bolt experience by submitting various RAI responses provided to the staff over the period of May 2013 until the present. So the staff expects to close this particular open item in the final SER and will present it to the ACRS full committee.

CHAIRMAN SKILLMAN: Okay, thank you.

MR. DAILY: Next slide. Open item B2.1.20-1 is related to Callaway's ASME code Class 1 small-bore socket welds. The original application states that Callaway has 19 ASME code Class 1 small-bore piping socket welds less than 4 inches and greater than or equal to one inch nominal pipe size.

Based on its experience with previous LRA reviews of similar PWRs, staff noted that this population seemed considerably smaller than the typical quantity of in scope socket welds. Therefore, during the AMP audit, the staff requested the applicant to explain the reason for this low count.

The applicant stated that it had recounted the number of socket welds subsequent to submitting the

application, and now finds 23 Class 1 small-bore socket welds within the scope of the particular AMP. That AMP title is one time inspection of ASME code Class 1 small-bore piping program.

The staff noted that even this new number of 23 still was considerably low based on prior audit experience. Staff continued to pursue the issue of ascertaining a correct number of small-bore socket welds at Callaway and issued an RAI requesting a recount.

In response to the staff's RAI, the applicant did another recount and revised the number of socket welds this time to 77. In light of these events, population basically going from 19 to 23 to 77, the staff also requested a confirmation that similar errors had not occurred elsewhere in the license renewal application.

So the staff also noted that at that time the issue had not been entered into the applicant's corrective action program. So the staff issued an RAI to address those items.

In an August 2013 response, the applicant explained that the erroneous counts occurred essentially due to incorrect queries or filters as was described of its database, that it had entered this

issue into its corrective action program and that as a result of the extent of condition reviews, it had identified one other occurrence of this miscount, and that was with the small-bore butt weld population.

The applicant stated that in conducting these thorough re-verifications, it also supplemented the searches with drawing reviews to arrive at final within scope counts of 80 for the small-bore socket welds and 343 for the small-bore butt welds.

The staff's concerns therefore were resolved. Staff expects to close this open item in the final SER and will present the item again to the ACRS full committee. Next slide.

Moving on now to SER Section 4. This particular section covers the time limited aging analyses or TLAAs. Section 4.1 documents the staff's evaluation of the applicant's identifying of all the applicable TLAAs for its facility.

The staff evaluated the applicant's basis for identifying those plan specific or generic analyses that need to be identified and determined that Ameren Missouri has provided an accurate list of TLAAs as required by 10 CFR 54.21 C1.

Sections 4.2 through 4.7 document the staff's review of applicable Callaway TLAAs as shown.

Based on its review and the information provided by the applicant, the staff concludes with the exception of one open item that the TLAAs will satisfy one of the three requirements in 10 CFR 54.21C, that is they'll either remain valid for the period of extended operation or they have been successfully projected to the end of the period of extended operation, or as in III, the effects of aging for those intended functions will be adequately managed for the period of extended operation.

And so that corresponds to the I, II, and III criteria for TLAAs in the rule. Section 4.3 contains the TLAA open item which is 4.3.4-1. And so we'll go to that now here in the next slide. Next slide.

Open item 4.3.4-1 is related to the effects of environmentally assisted fatigue on reactor coolant pressure boundary components. This open item is similar to previous open items that the ACRS has seen in past meetings related to environmentally assisted fatigue or EAF.

As part of its evaluation of the effects of this on the fatigue life of reactor coolant pressure boundary piping and components, Ameren Missouri performed a review of all the applicable reactor coolant pressure boundary components with a class one fatigue analysis to show that the locations identified in staff

guidance are bounding. And that staff guidance primarily begins with a document called new reg/CR6260.

In addition, the applicant stated that it reviewed its components to also identify whether there were also other more limiting plant specific components to be evaluated for EAF.

However, the staff identified additional information that was needed on the applicant's approach that it took in its screening of EAF for these reactor coolant pressure boundary components.

The applicant stated that it performed a systematic review to determine the locations to be monitored by the fatigue monitoring program. This review involved identifying appropriate locations which need management for environmentally assisted fatigue.

However, in justifying its review, Ameren Missouri did not demonstrate that its methodology for identifying these EAF locations was appropriate and conservative for Callaway Unit 1.

The staff identified the following types of issues. A, questions in the applicant's underlying assumptions which required additional information about the consistency in the level of rigor for these fatigue calculations, B, questions on how EAF

cumulative usage fatigue factors were compared, and C, questions on the validity of comparing EAF across multiple systems and components.

Ameren Missouri's responses in April and August of 2013 provided additional information regarding these particular assumptions and demonstrated that its evaluations for EAF were sufficiently rigorous and appropriate for Callaway.

In addition, it enhanced its fatigue monitoring program to ensure that EAF susceptible locations are updated appropriately and remain bounded consistent with any updated or refined analysis.

Therefore, the staff concludes that the applicant has justified its approach and the locations that require monitoring for environmentally assisted fatigue during the period of extended operation. The staff expects to close this open item in the final SER and will present it to the ACRS full committee. Next slide.

Since the issuance of the SER with open items in April of 2013, several other issues have also arisen in the meantime. And of course we have discussed these in some part, but we'll just kind of go through them here. In these particular cases, the staff issued RAIs to address them for the applicable license renewal

application reviews and received the following responses.

Now we plan on presenting today three of the items in discussion here because they are a little more significant in terms of impact in the scope. The staff is also prepared to discuss any of the other items during the question and answer session if the subcommittee so desires.

Two of them, as we had mentioned earlier, are related to new staff, interim staff guidelines that were produced after the SER with open items was issued. One is related to new components which the applicant added to the scope of license renewal in an amendment submitted in August of 2013, which is about four months after the SER was published.

These issues and resolutions will be documented in the final SER and presented to the full committee. Next slide.

Loss of coating integrity of internal coatings. Based on recent industry operating experience, the staff identified issues related to managing the loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage of service level three or augmented coatings.

In addition to causing obvious degradation

problems for the components which are internally coated, coating fragments which break free can foul or damage downstream components as well. And that's where the primary concern here is internally, internal coatings.

Ameren Missouri responded to the original RAIs and the follow ups providing responses that included such things as the following, revising multiple AMPs to include all the internally coated in scope components, incorporating periodic visual inspections for these coatings, incorporating coating acceptance criteria into the relevant programs, establishing personnel qualifications and testing methods consistent with regulatory guide 1.54 which is titled the service level 1, 2, and 3 protective coatings applied to nuclear plants.

The staff is reviewing supplemental information in these regard, and expects to close this issue in the final SER. We will be presenting the resolution of course to the ACRS full committee.

CHAIRMAN SKILLMAN: John, this new information was communicated in a letter to Dr. Hackett on May 12th.

MR. DAILY: Yes, sir.

CHAIRMAN SKILLMAN: That doesn't give the

ACRS a whole lot of review time, but I think we're an able crew, and we reviewed this information and we understand what you're saying. But if you're going to have real information for the full committee, we request that we have ample review time, please.

MR. DAILY: We do, and we apologize for the late breaking of these informations. We actually were working all the way up until late April in order to even make a decision as to whether everything was sufficient to go forward with the subcommittee.

And as project manager, I was trying to push folks along towards that but understanding the safety, you know, we still need it. But we know that this was a short turnaround. And we do apologize for that.

CHAIRMAN SKILLMAN: Thank you.

MR. LUBINSKI: Excuse me, Mr. Chairman. If I could just ask --

CHAIRMAN SKILLMAN: Sure.

MR. LUBINSKI: To make sure that we meet the needs for the ACRS moving forward. These will all be addressed in the final SERs, as John said, that will be provided. Normally we provide that a month in advance of the meeting.

MR. DAILY: Thirty days.

MR. LUBINSKI: Would you be requesting

additional time?

CHAIRMAN SKILLMAN: No.

MR. LUBINSKI: Or is 30 days sufficient? There you go, thank you.

CHAIRMAN SKILLMAN: Yes, yes. Let's keep it 30 days or more.

MR. LUBINSKI: Thank you.

CHAIRMAN SKILLMAN: Thank you. Okay.

MR. DAILY: Next slide. Internal surfaces corrosion and corrosion under insulation. Based on recent operating experience and staff reviews, the staff identified several issues which existing guidance at the time did not cover related to aging management of internal surfaces of components and atmospheric storage tanks.

Some examples include things like the following, recurring internal corrosion, flow blockages whether from corrosion, silt buildup, or other mechanisms in fire water system piping, corrosion underneath insulation, and degradation of tanks and coatings near atmospheric pressure tanks.

This was all covered then in license renewal interim staff guideline 2012-02, and this was issued in November of 2013 to containing the updated staff guidance and details. So the staff issued RAIs

to all of our current applicants as applicable, including Ameren Missouri in order to address these issues from the ISG.

Callaway responded to the original and the follow up RAIs in addressing the staff concerns, and included such items or examples as the following, which we see up here on the slide.

They added several tests and inspections for detecting internal corrosion and flow blockages, they augmented tests and inspections for wetted but normally dry piping which cannot be easily drained. And of course this is one, kind of the fire water system that can be particularly problematic, especially as you've eluded to, when you've got river water as your source of water supply.

In addition to, they're also going to be incorporating periodic inspections of the fire water system tank coatings and the base material of that tank if that tank based material has been exposed.

Its added and revised periodic inspections of outdoor insulated and indoor insulated components that are operated below the dew point, and having sampling locations based upon the likelihood of corrosion underneath insulation occurring.

Also, several AMPs were modified or

enhanced to incorporate items resolving staff concerns. This actually touched several aging management programs, and I think was a pretty extensive review, you know, based on our experience that we've had from applicants in responding to these RAIs.

The staff is reviewing all the applicant's responses and we expect to close this issue in the final SER. We will also be presenting this to the full committee in the fall.

MR. BARTON: John, a question that this brings up. The water that's in the fire water storage tank, is that river water? Is that water that's been treated once it came in before it's pumped into the fire water storage tank?

MR. DAILY: It might be best to let Ameren speak to that.

MR. BARTON: I'm not asking, I'm asking just for whoever knows the answer.

MR. DAILY: Okay.

MR. EITEL: Lee Eitel, Supervising Engineer, Systems Engineering. The water comes from a well, it does not come from the river. It's in the fire water system.

MR. BARTON: All right, thank you.

MR. DAILY: So from a deep well, okay. Any

other questions then on this issue?

CHAIRMAN SKILLMAN: Yes. May I ask you to please come back to the microphone? What do we know of the chemistry of the water from that well, please.

MR. EITEL: The water does have some levels of mineral deposits. If I can refer to my colleague here, Joe Howard.

MR. HOWARD: Joe Howard, Chemistry Supervising Engineer. It is typical well water for mid-Missouri. It has some iron content, which is the predominant issue that we've had. It's got about one ppm iron content. It also has some minimal content for calcium carbonate and magnesium.

CHAIRMAN SKILLMAN: Thank you. Okay, please proceed. Thank you, John.

MR. DAILY: Thank you. Next slide. Inspection of submerged bolting. The applicant's license amendment number 26, which was submitted to the staff in August of 2013, added AMR line items for submerged carbon steel and stainless steel closure bolting associated with pumps in the central service water, service water, emergency diesel engine fuel oil storage and transfer pumps, the oily waste, and the floor and equipment drain systems.

The applicant stated that the bolting is

managed for loss of material and loss of pre-load. Given the inaccessibility of the normally submerged bolted connections, it was not clear to the staff what parameters would be monitored, what inspection techniques would be used, and/or the frequency of the inspections that would be used to detect aging effects on these bolts.

So we issued some RAIs in order to clarify these concerns. Ameren Missouri responded to the staff's RAIs most recently in April of this year. The RAI responses include adding in the inspections of bolt heads during dewatering of the environment, inspection of the bolt threads during disassembly and maintenance, and monitoring of pump performance.

Pending completion of the reviews of this information, the staff expects to resolve this issue in the final SER and will be presenting it to the ACRS full committee.

The staff's conclusion will be provided in the final safety evaluation report at the conclusion of staff evaluations, which as we had mentioned we are targeting for September of this year. Pending the satisfactory resolution of the open items, the staff will be able to determine whether the requirements of 10 CFR 54.29A have been acceptably met for the renewal

of Callaway plant Unit 1.

This concludes now the written portion of our staff presentation. So now we'll be available for any further questions from the subcommittee.

CHAIRMAN SKILLMAN: John, let me ask this key question relative to schedule. What confidence do you have that you will have your SER completed timely?

MR. DAILY: I'm pretty confident right now, Mr. Skillman because we already have a lot of our SER input written. Now there's other reviews, you know, there's an assembly that takes place.

But one of the reasons why we've set it up the way we have is in order to give us, you know, to give me some assurance basically as the schedule developer that we can get there. And I believe we can.

CHAIRMAN SKILLMAN: Thank you. Appreciate your input. To my colleagues around the table, gentlemen, does any of you have a comment or question, please?

MEMBER SCHULTZ: Yes, I have a comment both of the staff and for the applicant. Appreciate the presentations by the staff. And I particularly wanted to remark on the information that we heard but is also provided to us related to the inspections and audits.

I think the report we've heard was very

helpful today, but also the overall program review clearly has gained a high degree of credibility associated with the audits and the inspections that the staff has done, that the region has done, associated with this program.

That, in combination with the comprehensive technical review by the staff has really brought this overall program together. You know, a lot of good information was gained by both parts of that process, the comprehensive review of the technical review, in combination with the audit inspection. So I think that speaks well to the thoroughness of the overall review.

And then I just wanted to come back and comment to the applicant that Dave Neterer's remarks and his conclusions, really did appreciate his remarks that this overall program for license renewal and what they have done associated with aging management as a learning organization, that that has really helped them to bring together programmatically in a way to integrate the overall programs that the site already has ongoing, that that's been an opportunity for you to really provide a learning experience for the site, to think about the site not only as a 40 year plant, but a 60 year program, and that involving the management, training the

personnel.

And we've seen today a very comprehensive and thorough presentation by the applicant about their lessons learned associated with this program. So I appreciated that overview, as well as the details that we've learned today. Thank you.

CHAIRMAN SKILLMAN: Thank you, Steve. John?

MEMBER STETKAR: I would like to echo some things that Steve said. And I apologize, I had to duck out for another meeting, so I missed the first part of the staff's presentation.

But as I read through the SER and the inspection audit reports, I think the staff did a really good job on this one. It seemed to be one that was a bit more challenging in the sense of interactions compared to several others that I've seen over the last six, seven years.

And I think you did a really, really good job on tracking down issues and making sure that they were closed out to your satisfaction. So I would just like to add that.

MR. DAILY: This truly is a big team effort. And on behalf of the staff team, I'm sure John would echo, they all appreciate that. We do appreciate

that. But it is a team effort. There's so much that goes into it.

CHAIRMAN SKILLMAN: Thank you. John Barton?

MR. BARTON: For all the information that I received, including all the stuff from our last meeting which we didn't have, and all the material that Kent's been sending me over the past year window, and the presentations that I heard today, I have no concerns about proceeding with license extension at this point from what I heard, from where I am.

CHAIRMAN SKILLMAN: Thank you, John. Ron?

MEMBER BALLINGER: Great presentation. I'm going to try to follow with interest the corrosion issues related to the service water piping systems and things.

CHAIRMAN SKILLMAN: I thank you very much, both to the staff and to the licensee for a couple of things, the comprehensiveness of the review, the thoroughness of the presentation. It is clear that the applicant spent a lot of dry run time preparing for this. Thank you.

And I particularly appreciate the precision of the answers. I also appreciate the

thoroughness of Mr. Pick's review, that's the 71001 and the 71003 review. That I found very enlightening the degree to which his team detailed every piece of that review, so I give them a commendation. It was really good.

So thank you to each of you. Let me now communicate that the bridge line is open. And is there anyone on the bridge line that would like to make a comment, please? If anyone is on the bridge line, would you please identify yourself?

Thank you. If any members of the public or anyone in the audience, would you like to make a statement or a comment, please?

MR. LUBINSKI: Mr. Chairman, if I may.

CHAIRMAN SKILLMAN: Yes sir, John.

MR. LUBINSKI: I just want to thank the subcommittee for the comments that you made in closing here. Appreciate it. And I will echo what John Daily said is from the NRC standpoint, it's definitely been a team effort.

And as you mentioned, the region is also part of that team. And we appreciate their inspections and the coordination as well. And the team is not just in the division of license renewal, it's across the entire NRC. So I echo John's comment. My compliments

to them and my thanks to them, and thank you for your recognition.

CHAIRMAN SKILLMAN: Okay. To all, thank you very much. Safe travels and safe holiday. We're adjourned.

(Whereupon, the meeting in the above-entitled matter was concluded at 4:40 p.m.)

# Callaway Plant Unit 1
# ACRS Subcommittee Meeting – License Renewal

05/22/2014

Ameren
MISSOURI

# Dave Neterer
# Site Vice President

05/22/2014

## Plant History and Background

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# REPRESENTING CALLAWAY PLANT

- Dave Neterer – Site Vice President
- Sarah Kovaleski – Director, Design Engineering
- Roger Wink – Supervising Engineer, Plant Life Extension
- Andrew Burgess – Project Engineer, Plant Life Extension
- Michael Hoehn II – Supervising Engineer, Engineering Programs
- Eric Blocher – Project Manager, STARS Alliance



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# PERSONNEL IN ATTENDANCE

**Operations**
Fred Bianco

**Engineering Programs**
Greg Kremer

**Chemistry**
Joe Howard

**Steam Generators & RVI**
Kenneth W. Blair Jr.

**Electric Cable & Cathodic Protection**
Ken Sandstedt
Neil Fisher

**Civil/Structural**
Landon Bodenschatz

**NFPA 805/Fire Protection/PRA**
Mike Fletcher
Lee Eitel
Justin Hiller

**STARS Alliance**
Tony Harris
Jim Johnson
Ken Bryant

**LR Team**
Sharon Merciel
Dave Shafer

**Reactor Head Studs**
David Gross

**Inservice Inspection**
Jerry Doughty

**Metal Fatigue/TLAA**
Dave Gerber

**Buried Piping and Coatings**
Justin Stollhans

**Open Cycle Cooling Systems**
Tarang Parashar

**Flow Accelerated Corrosion**
Jeremy Claunch



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# AGENDA

- Plant History and Background
- Major Modifications and Near Term Plant Improvements
- License Renewal Application
- Safety Evaluation Report Open Items
- Concluding Remarks



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# PLANT HISTORY AND BACKGROUND

- Initial Construction Permit – April 16, 1976
- Operating License – October 18,1984
- Generation output:
  - Licensed output is 3,565 MWth
  - Rated output is 3,579 MWth
- Refueling Outage 20 begins October 2014



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# PLANT OVERVIEW – BASIC DESCRIPTION

- Callaway Unit 1 is situated on a 7,354 acre site, with the power plant site area containing approximately 2,765 rural acres on a plateau ~300 feet above the Missouri River (located 5 miles south)
- Callaway is a single unit Westinghouse 4-loop PWR
- Bechtel was the Primary A/E
- Daniel International was the constructor
- SNUPPS design (sister plant to Wolf Creek)



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# CALLAWAY PLANT UNIT 1- PLANT SITE



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# CALLAWAY PLANT UNIT 1- RIVER INTAKE STRUCTURE



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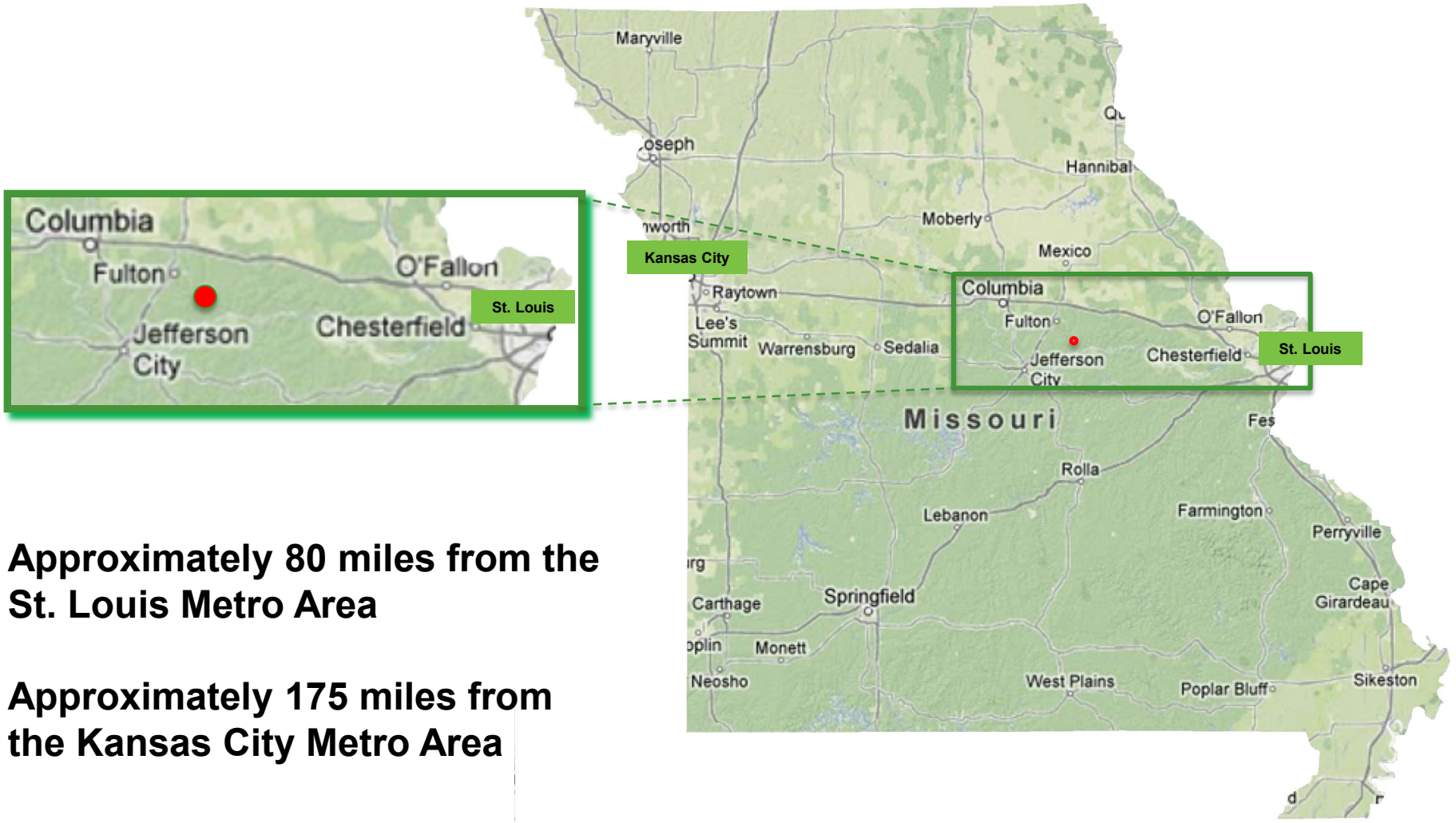
# LOCATION OF PLANT SITE




**Approximately 80 miles from the St. Louis Metro Area**

**Approximately 175 miles from the Kansas City Metro Area**



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Roger Wink
Supervising Engineer, License Renewal

05/22/2014

# Major Modifications and Near Term Plant Improvements

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# MAJOR MODIFICATIONS COMPLETED

- Replaced Main Condenser tube bundles (2004) *
- Replaced Steam Generators (2005)
- Pressurizer PWSCC-Resistant Full Structural Weld Overlays (2007)
- Replaced ~5 miles of Cooling Tower Blowdown Piping with High Density Polyethylene (HDPE) (2008)*
- Majority of buried Essential Service Water (ESW) piping was replaced with safety related HDPE piping (2008 to 2009)
- Replaced all Emergency Diesel Generator heat exchangers (2010 to 2011)
- Installed electrical cable manhole sump pumps (2013)
- Replaced ~3400 feet of small bore ESW system carbon steel piping with corrosion resistant material
- Replaced all containment coolers and 5 of 11 safety related room coolers

*not in LR scope



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# NEAR TERM PLANT IMPROVEMENTS

## Refueling Outage 20 (October 2014)

- Reactor Vessel Head Replacement
- Replacing ‘A’ Train Motor Driven Auxiliary Feedwater Pump room cooler

## 2015 & 2016

- Cathodic Protection System Modification
- PWSCC mitigation of reactor vessel nozzle and bottom mounted instrumentation tubes
- Replacing ‘B’ Train Motor Driven Auxiliary Feedwater Pump room cooler
- Independent Spent Fuel Storage Installation



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# Sarah Kovaleski
# Director, Design Engineering

05/22/2014

**License Renewal Application**

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# LICENSE RENEWAL APPLICATION – PROJECT

- Application Development
  - Callaway License Renewal Team active since 2007
  - Callaway Program Owners and Subject Matter Expert ownership
  - Fifth STARS License Renewal Application prepared as part of STARS Alliance

- Industry Interaction
  - NEI Working Group Involvement
  - Industry Peer Review Process
  - Incorporated Industry Lessons Learned



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# LICENSE RENEWAL APPLICATION - DETAILS

- Application Details
  - Application submitted on December 15, 2011
  - Developed using NUREG-1801 (GALL) Revision 2
  - Incorporated 8 License Renewal Interim Staff Guidance documents
  - 42 Aging Management Programs
  - 3919 Aging Management Review (AMR) lines
    - 98.8% consistent with GALL

- License Renewal Commitments
  - Included in FSAR Supplement (Appendix A of LRA)
  - Will be managed by Callaway Commitment Tracking System consistent with NEI 99-04 Guidelines
  - Total of 46 commitments
    - 34 associated with aging management programs (AMPs)
    - 11 commitments completed/closed



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# AGING MANAGEMENT PROGRAM (AMP) SUMMARY

42 AMPs Evaluated

| | Plant Specific | Consistent with GALL | With Exception | With Enhancement | With Exception & Enhancement |
|---|---|---|---|---|---|
| Existing 32 | 0 | 15 | 1 | 14 | 2 |
| New 10 | 0 | 8 | 2 | 0 | 0 |

Total of 16 enhancements and 5 exceptions.



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# IMPLEMENTATION & SUSTAINABILITY

- Designated Program Owners and License Renewal Staff
- Participation in NEI License Renewal Implementation Working Group
- Benchmarking others in the Industry
- Leveraging STARS Alliance knowledge and experience
  - Self-assessments
  - Audits
  - Share Operating Experience
- Implementation of LR-ISG-2011-05 for ongoing review of operating experience



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# SAFETY EVALUATION REPORT (SER) – OPEN ITEMS

- Callaway SER contains 5 Open Items
  - Scoping of Fire Protection SSCs/NFPA 805
  - Reactor Head Closure Studs
  - Materials Reliability Program (MRP)-227-A Report Applicant/Licensee Action Items (A/LAIs)
  - ASME Code Class 1 Small-Bore Socket Welds
  - Effects of the Reactor Coolant System Environment on Fatigue Life of Piping and Components
- Other issues that arose after the SER with Open Items
  - LR-ISG-2012-02, Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation
  - Draft LR-ISG-2013-01, Aging Management of Loss of Coating Integrity for Internal Service Level III (Augmented) Coatings
  - Submerged Bolting



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# SER– OPEN ITEM 2.3.3.20-1
# Scoping of Fire Protection SSCs

Topic (Part 1)

- Provide justification for excluding portions of the Turbine Building from the scope of LR

Resolution

- Fire suppression systems added to LR scope:
  - Auxiliary Boiler Room
  - Turbine Building Various Locations
  - Turbine Bearings

Considerations

- Auxiliary Boiler Room suppression system was subsequently removed from scope by NFPA 805

Status

- Submitted



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# SER– OPEN ITEM 2.3.3.20-1
# Scoping of Fire Protection SSCs

Topic (Part 2)

- Discuss the changes associated to the LR scope that will occur with the NFPA 805 transition and provide a gap analysis

Resolution

- LRA Amendment updated the LR scope to be consistent with NFPA 805
- A Gap Analysis was provided which described the changes to the LRA based on components added/removed from Fire Protection Program scope as a result of the transition to NFPA 805

Considerations

- The NRC approved the NFPA 805 amendment for Callaway on January 13, 2014

Status

- Submitted



Ameren MISSOURI

# SER– OPEN ITEM B2.1.3-1
# REACTOR HEAD CLOSURE STUDS

## Topic

- Program may not be adequate to detect future wear, loss of materials, or assure that allowable stresses are not exceeded during the PEO

## Resolution

- Commitments made to:
  - Remove Stud #18 prior to PEO
  - Inspect stud holes (6) with previous thread damage prior to PEO

## Considerations

- There have been no RPV stud issues since 1996
- Stud #18 is fully tensioned & proof tested each cycle in the tensioning process

## Status

- Resolved



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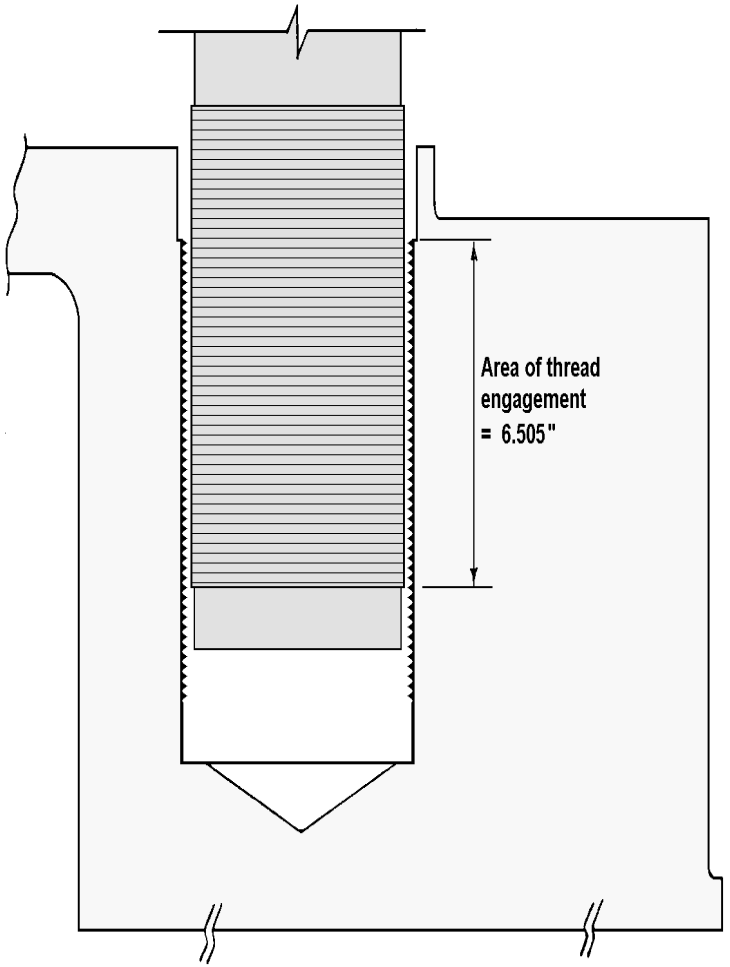
# CALLAWAY REACTOR VESSEL STUD #18

- Fall, 1996 (Refuel 8) – Stud #18 became stuck 2.625” withdrawn during installation.
- The cause for Stud #18 becoming stuck is debris in the stud hole.
- Current thread engagement: 6.505”.
- Minimum required thread engagement based on ASME Section III, Division 1 – Subsection NB is 5.54”.
- Stud #18 is fully tensioned and proof tested each cycle.
- We have committed to remove and inspect stud hole prior to PEO (LRA Commitment 41).



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# SER– OPEN ITEM B2.1.6-1 MRP-227-A REPORT APPLICANT/LICENSEE ACTION (A/LAI) ITEMS

Topic

- A/LAI No. 1, Demonstrate that the MRP-227-A bases and assumptions are applicable and bounding for the design of Callaway Reactor Vessel Internal components

Resolution

- MRP-191 & MRP-227-A are directly applicable to Callaway
- NSSS supplier verified all RVI components, as applicable for the design, are included directly in the MRP-191 component lists

Considerations

- Callaway is consistent with MRP-2013-025 atypical fuel design parameters
- Core design procedures revised to include MRP-2013-025 parameters
- Plant Specific material fabrication and design are consistent with MRP-191 for cold-worked materials.

Status:

- Submitted



Ameren MISSOURI

# SER– OPEN ITEM B2.1.6-1 MRP-227-A REPORT APPLICANT/LICENSEE ACTION (A/LAI) ITEMS

Topic

- A/LAI No. 5, Define physical measurement techniques that will be used to determine Reactor Vessel Internals hold-down spring height

Resolution

- Callaway Reactor Vessel Internals hold-down spring is fabricated with type 403 stainless steel that is not subject to stress relaxation

Considerations

- MRP-227-A physical measurements specifically apply to type 304 stainless steel hold-down springs

Status

- Resolved



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# SER– OPEN ITEM B2.1.6-1 MRP-227-A REPORT APPLICANT/LICENSEE ACTION (A/LAI) ITEMS

## Topic

- A/LAI No. 7, Determine if inspections for loss of fracture toughness due to thermal & irradiation embrittlement apply to Reactor Vessel Internals components fabricated from cast austenitic stainless steel (CASS), martensitic stainless steel, or precipitation hardened, martensitic stainless steel

## Resolution

- MRP-191 & MRP-227-A are directly applicable to Callaway.
- No additional components were identified for Callaway

## Considerations

- Callaway has two Reactor Vessel Internals CASS component groups:
  - Bottom mounted instrument column cruciforms
  - One offset instrument column cruciform bolted to the underside of the lower core plate

## Status

- Resolved



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# SER– OPEN ITEM B2.1.6-1 MRP-227-A REPORT APPLICANT/LICENSEE ACTION (A/LAI) ITEMS

Topic

- A/LAI No. 8, Item (5), Address those Cumulative Usage Factor (CUF) analyses for RVI components that are TLAAs for the impact of reactor coolant on metal fatigue

Resolution

- The fatigue monitoring program will evaluate the effects of the reactor coolant system water environment on the RVI components with existing fatigue CUF analyses

Status

- Resolved



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# SER– OPEN ITEM B2.1.20-1
# ASME CODE CLASS 1 SMALL-BORE SOCKET WELDS

Topic

- Number of ASME Code Class 1 Small-Bore Socket Welds in LR scope

Resolution

- Original count did not include welds on 1” piping
  - 1” weld exams not required for ISI Program
- Detailed recount performed with independent verification of results by ISI Program Owner to confirm final population of in scope socket welds
- ISI database updated to identify small bore socket welds in the scope of this AMP

Considerations

- Extent of Condition review performed
  - Confirmed ASME Code Class 1 Small-Bore Butt Weld population

Status

- Resolved



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# SER– OPEN ITEM 4.3.4-1 EFFECTS OF THE RCS ENVIRONMENT ON FATIGUE LIFE OF PIPING AND COMPONENTS

## Topic

- Justify the ranking and comparison used to determine that “sentinel” locations were appropriate for Callaway.

## Resolution

- Same fatigue curve for each material was used for the analyses
- The analyses have been performed using the same level of rigor
- Any transient lumping used in the various analyses have not skewed the screening and ranking results
- The comparison of Cumulative Usage Factors across multiple zones is valid

## Considerations

- Revised CUF and $F_{en}$ screening process to not allow: *One material in a Thermal Zone to bound other materials in the same Thermal Zone and one material in a Thermal Zone to bound other materials in another Thermal Zone*

## Status

- Resolved



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# ISSUES SINCE SER W/ OPEN ITEMS – CLEVIS BOLTS

Topic

- Address similarity of Callaway design to reported failures at one domestic Westinghouse-designed PWR in 2010

Resolution

- Clevis insert assembly geometry differs from design of plant with failures
- Materials used are similar
- Multiple inspections showed no degradation or damage
- Existing ASME Section XI Inservice Inspection program is capable of detecting cracking

Status

- Submitted



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# ISSUES SINCE SER W/ OPEN ITEMS – LR-ISG-2012-02

Topic

- Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation

Resolution

- Plant specific operating experience was reviewed & confirmed the need for additional aging management of recurring internal corrosion in raw water environments
- Fire Water AMP will be consistent with NFPA 25 requirements
- Aboveground Metallic Tanks AMP revised to be consistent with ISG criteria
  - Fire Water Storage Tanks now managed by Fire Water AMP
- Outdoor insulated components & indoor insulated components exposed to condensation will have insulation removed to inspect for external surface degradation

Status

- Submitted



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# ISSUES SINCE SER W/ OPEN ITEMS – DRAFT LR-ISG-2013-01

Topic

- Loss of Coating Integrity for Service Level III and Other Coatings

Resolution

- Visually inspect in-scope coatings installed on accessible interior surfaces
- Coatings with no degradation or with cracking/flaking evaluated as acceptable, will have inspections performed every six years
- Coatings with blisters, peeling, delaminations or rusting determined not to require remediation, will have inspections performed every four years
- Training & qualification in accordance with ASTM Standards endorsed in RG 1.54 including supplemental staff guidance

Considerations

- Scope: 6 heat exchangers, 5 strainers, 2 tanks, Circulating & Service Water pipe

Status

- Submitted



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# ISSUES SINCE SER W/ OPEN ITEMS – SUBMERGED BOLTING

Topic

- Method of detecting loss of material & loss of preload in submerged bolting

Resolution

- ESW pumps stainless steel bolts inspected on a 6 year sample basis & tested quarterly for pump pressure/flow/vibration
- Emergency Diesel Generator fuel oil transfer pump bolts inspected on a 10 year sample basis and tested periodically for pump pressure/flow
- Service water pump bolting is replaced during pump refurbishment (6 year basis)
- Waste water pump bolting inspected on a 6 year sample basis, visually inspected opportunistically during maintenance, & functionality verified each shift during operator rounds

Status

- Submitted



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# CONCLUDING REMARKS

In anticipation of extended operation, Ameren Missouri has:

- Improved our Operating Experience program to identify, learn from, and share information on plant aging
- Invested in plant hardening initiatives
- Selected plant modifications for safe, extended operations



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# COMMENTS AND QUESTIONS?



Ameren MISSOURI


# Advisory Committee on Reactor Safeguards
# License Renewal Subcommittee
# Callaway Plant, Unit 1

## Safety Evaluation Report (SER) with Open Items

May 22, 2014

John Daily, Sr. Project Manager
Office of Nuclear Reactor Regulation

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# Presentation Outline

- Overview of Callaway license renewal review
- Region IV License Renewal Onsite Inspection
- SER Section 2, Scoping and Screening Review
- SER Section 3, Aging Management Review
- SER Section 4, Time-Limited Aging Analyses
- Issues that arose after the SER with Open Items

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# Facility Facts

- **License Renewal Application (LRA) submitted December 15, 2011**
  - Applicant: Union Electric Company (Ameren Missouri)
  - Facility Operating License Nos. NPF-30
  - Current License Expiration Date: October 18, 2024
- **Approximately 25 miles east-northeast of Jefferson City, Missouri**
- **PWR (Westinghouse) with a carbon steel-lined, concrete structure containment**

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# Audits and Inspections

- Scoping and Screening Methodology Audit
  - April 16-19, 2012
- Aging Management Program (AMP) Audit
  - April 30-May 10, 2012
- Environmental Audit
  - May 22-24, 2012
- Region IV Inspection (Scoping and Screening & AMPs)
  - September 10-November 7, 2012

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# Overview (SER)

- Safety Evaluation Report (SER) with Open Items issued April 23, 2013
- Callaway SER contains 5 Open Items (OIs):
  - Scoping of Fire Protection SSCs
  - Reactor Head Closure Studs
  - PWR Vessel Internals Program Applicant/Licensee Action Items (A/LAIs)
  - ASME Code Class 1 Small-Bore Socket Welds
  - Environmentally Assisted Fatigue on the Reactor Coolant Pressure Boundary
- Other issues arose after the SEROI was issued
  - Related to recently-issued LR-ISGs and some recently-added SSCs
- The final SER is scheduled for September 2014

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# Regional Inspections

## Overview

- Five inspectors for 2 weeks
- Scoping inspection
- Aging management programs inspection

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# Regional Inspections

## Inspection Results

- Condensate Storage Tank: Lack of thread engagement for some accessible CST anchor bolts
- Cathodic protection for buried piping: Needs upgrade to be consistent with GALL Report recommendations
- Emergency fuel oil storage tank: Coating blisters not adequately tracked/managed
- Buried piping procedures: Improper exams, insufficient guidance in several cases
- The applicant initiated plans and corrective actions to address these items

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# Regional Inspections

## Inspection Conclusions

- Scoping of non-safety SSCs and application of the AMPs to those SSCs were acceptable
- Reasonable assurance exists that aging effects will be managed and intended functions maintained

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# SER Section 2 Summary

## Structures and Components Subject to Aging Management Review

- Section 2.1, Scoping and Screening Methodology
- Section 2.2, Plant-Level Scoping Results
- Sections 2.3, 2.4, 2.5 Scoping and Screening Results

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# SER Section 2 Open Item

## Open Item 2.3.3.20-1: Scoping of Fire Protection SSCs

- Issue:
  - Some SSCs incorrectly omitted from Scope
  - Changes to LRA due to NFPA 805 Amendment request unclear
- Applicant added SSCs back into scope
- Applicant provided gap analysis details for NFPA 805 impacts
  - Responses were over the period April 2013 – April 2014
- Staff expects to close this OI in final SER and will present to the ACRS full committee

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# Section 3: Aging Management Review

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

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# SER Section 3

## 3.0.3 – Aging Management Programs

- 42 Aging Management Programs (AMPs) presented by applicant and evaluated in the SER
  - 32 existing AMPs, 10 new AMPs
  - 23 AMPs consistent with the GALL Report (i.e., without enhancements and/or exceptions)
  - 19 AMPs consistent with enhancements and/or exceptions
  - No plant-specific AMPs

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# SER Section 3 Open Items

## Open Item B2.1.3-1: Reactor Head Closure Studs

- Issue:
  - Thread damage in 10 RV flange hole locations out of 54
  - One closure stud stuck partially inserted since 1996
- Applicant proposed 2 commitments to resolve:
  - to inspect flange holes with worst thread damage
  - to remove stuck stud
- Staff finds the changes to the program acceptable
  - Staff will consider whether to use a license condition
- Staff expects to close this OI in the final SER and will present to the ACRS full committee

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# SER Section 3 Open Items

## Open Item B2.1.6-1: Reactor Vessel Internals (PWR)

- Issue: Complete responses to MRP 227-A needed
  - Applicant/Licensee Action Items not complete
  - Address clevis insert bolts Operating Experience
- Applicant initially proposed to address before PEO:
  - Applicant has agreed to address in LRA and has provided additional information
- Staff expects to close this OI in the final SER and will present to the ACRS full committee

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# SER Section 3 Open Items

## Open Item B2.1.20-1: ASME Code Class 1 Small-Bore Socket Welds

- Issue: Large discrepancy among successive population counts of small-bore socket welds
  - Also confirmation that counting errors not encountered elsewhere
- Applicant conducted several counts, eventually confirming
  - 80 small-bore socket welds
  - 343 small-bore butt welds
- Staff expects to close this OI in the final SER and will present to the ACRS full committee

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# SER Section 4: TLAA

- 4.1 Identification of TLAAs
- 4.2 Reactor Vessel Neutron Embrittlement Analysis
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electric Equipment
- 4.5 Concrete Containment Tendon Prestress Analyses
- 4.6 Containment Liner Plate, Metal Containments, and Penetration Fatigue Analyses
- 4.7 Other Plant-Specific TLAAs

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# SER Section 4 Open Item

## Open Item 4.3.4-1: Environmentally Assisted Fatigue (EAF) in Reactor Coolant Pressure Boundary components

- Issue: Staff identified questions on methodology
  - Underlying assumptions
  - How various EAFs were compared
  - Validity of comparing EAF for multiple systems/components
- Applicant supplied additional information in April 2013 and August 2013 responses
- Staff expects to close this OI in the final SER and will present to the ACRS full committee

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# Issues Identified Since SER with Open Items

**Several issues arose between issuance of the SER with Open Items and this ACRS Subcommittee meeting.**

**Staff issued RAIs to address these and received responses.**

**The issues and resolutions will be documented in the final SER and presented to the ACRS full committee.**

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# Loss of Coating Integrity – Internal Coatings

## Loss of coating integrity of internal coatings

- Can expose the base material and foul downstream components
- Applicant Response
  - Revised multiple AMPs
  - Incorporated periodic inspections of internal coatings
  - Added acceptance criteria for coatings
  - Clarified personnel training
- Staff is reviewing supplemental information from the applicant and expects to close this in the final SER.
- Resolution will be presented to the ACRS full committee

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# Internal Surfaces Corrosion and Corrosion under Insulation

## Recurring internal corrosion, flow blockages in fire water systems, corrosion under insulation…

- Issues arising in recent OE, not addressed by (then) existing staff guidance
- Response included (examples):
  - Additional/augmented tests/inspections for fire water systems
  - Tests/inspections for flow blockages of wetted piping
  - Periodic inspections of outdoor insulated and indoor insulated components
- Staff is reviewing applicant submittals and expects to close the issue in the final SER
- Resolution will be presented to the ACRS full committee

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# Inspection of Submerged Bolting

## Bolting associated with submerged pumps and normally inaccessible for inspection

- LRA amendment added bolting on submerged pumps in several systems
  - Staff concerns regarding parameters monitored, inspection methods, and inspection frequencies
- Applicant response
  - Condition monitoring of bolt heads when accessible during dewatering, and of threads during disassembly
  - Performance monitoring of associated pumps
- Staff is reviewing applicant submittals and expects to close the issue in the final SER
- Resolution will be presented to the ACRS full committee

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# Conclusion

Pending satisfactory resolution of the open items, the staff will render its decision in the final SER on meeting the requirements of 10 CFR 54.29(a) for the license renewal of Callaway Plant Unit 1