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UNITED STATES NUCLEAR REGULATORY COMMISSION'S ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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LICENSE RENEWAL SUBCOMMITTEE

+ + + + +

TUESDAY,

JUNE 8, 2010

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ROCKVILLE, MARYLAND

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The Subcommittee convened at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, Rockville, Maryland at 8:30 a.m., Dr. Dennis Bley, Chairman, presiding.

SUBCOMMITTEE MEMBERS PRESENT:

DENNIS C. BLEY, Chair

J. SAM ARMIJO

MARIO V. BONACA

HAROLD B. RAY

WILLIAM J. SHACK

JOHN D. SIEBER

JOHN W. STETKAR

CONSULTANTS TO THE SUBCOMMITTEE PRESENT:

JOHN J. BARTON

NRC STAFF PRESENT:

KATHY D. WEAVER, Designated Federal Official

BRIAN HOLIAN

BRIAN HARRIS

BENNY JOSE

CLIFF DOUTT

ABDUL SHEIKH

ALSO PRESENT:

CHRIS COSTANZO

KEN PUTNAM

MIKE FAIRCHILD

CURT BOCK

CLARA RUSHWORTH

ERIC SORENSON

AL THOMAS

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

8:27 a.m.

CHAIR BLEY: Good morning. The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I'm Dennis Bley, Chairman of this Subcommittee meeting.

ACRS Members in attendance are: John Stetkar, William Shack, Harold Ray, Mario Bonaca, Jack Sieber, Sam Armijo.

I said Harold, right? Harold Ray.

MEMBER SHACK: You said William.

CHAIR BLEY: I did. I read it. John Barton our consultant is also present.

Cathy Weaver of the ACRS staff is the Designated Federal Official for this meeting.

The Subcommittee will review the license renewal application for the Duane Arnold Energy Center and the Associated Draft Safety Evaluation Report with Open Items.

We will hear presentations from NRC staff and FPL energy, Duane Arnold, LLC representative and other interested persons regarding this matter.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting.

This meeting will be open to public attendants.

The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full Committee.

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

A transcript of the meeting is being kept and will be made available as stated in the Federal Register notice. Therefore, we request the participants in this meeting to use the microphones located throughout the meeting room when addressing the Subcommittee.

The participants should first identify themselves and speak with sufficient clarity and volume so that they may be readily heard.

We will now proceed with the meeting. I call upon Brian Holian of the NRC staff to begin. Brian?

MR. HOLIAN: Good morning and thank you Chairman. My name is Brian Holian. I'm the Director of the Division of License Renewal. The agenda for

today's meeting is just brief introductions by myself of the NRC staff and then I'll turn it over to Duane Arnold's staff for their morning presentation which will be followed by the staff's presentation.

To my immediate left is Bo Pham, the Branch Chief that is responsible for Duane Arnold. To my immediate right we have Benny Jose, Senior Reactor Inspector from Region III and the Project Manager from the Division of License Renewal, Brian Harris. You will be hearing from both of them at the NRC presentation.

In the audience I have Dr. Allen Hiser, Senior Level Advisor, several DLR Branch Chiefs, technical staff on both license renewal and some of the technical divisions at NRR and they will be available for questions during the staff presentation.

I did want to just take a short minute, half a minute here to recognize to my immediate right Dr. Sam Lee. Sam, if you would stand up? Sam is moving on from license renewal. He has been a long time license renewal reviewer, branch chief and deputy division director. He has been my deputy for the last two years and of P.T. Kuo before that.

Sam is swapping over. He is still staying at NRR, but just broadening himself over to the

Division of Risk Assessment and he will be swapping with Melanie Galloway. You will meet her at next month's session.

And yesterday was Sam's last day in license renewal and I just wanted to highlight his, you know, participation in license renewal. He clearly is probably the single person with the most longevity in license renewal. He dates himself back to Calvert Cliffs and the rule before that, he has been, I didn't count up all the ACRS Subcommittee and Committee meetings that he has attended, but, to quite a few.

He has been involved in almost all of the 59 plants that have been renewed. He did take a stint in there when he went through his SES CDP and had a rotation away from license renewal for a couple of years, but then came back.

To cite his technical accomplishments, you know, Dr. lee from MIT, he has been involved in all our technical reviewers issues. You can ask the branch chiefs the level of detail he gets into. Besides that, which I know these are recognized, Sam has also been a key hirer, not only for license renewal, but for NRR.

And just within the last six months, he

has received a couple of awards from the Federal Advisory Committee for his hiring efforts. In the last 15 months, he has hired over 25 people at NRR.

And part of that aspect is really increasing the diversity of NRR. He has done just a super job. You know, he is already starting to talk risk assessment talk. He has repeated 10^{-7} if only a couple of times yesterday. And he is asking me to put a little more risk into license renewal, so we'll get that view from him and you will be seeing him from that side of the house.

But I did want to recognize him today in this setting. He, like all of us, think very highly of the ACRS. He uses these sessions to scare our staff to death at presentations and prepare them well. So he has always used that. But I wanted to highlight him today in this setting and thank him.

(Applause)

MR. HOLIAN: With that, I'll turn it over to Duane Arnold and Chris Costanzo, the site Vice President.

MR. COSTANZO: Thank you, Brian. And congratulations, Dr. Lee, and I wish you the best in your new endeavor.

Good morning and welcome, Mr. Chairman and

the Committee, and welcome everybody in the back. I think I can see everybody in the back.

I certainly appreciate the opportunity to discuss our safety evaluation report with this Committee and as well as the process reviews and license renewal, our future plans at Duane Arnold and the current plat status as well.

I have brought with me a great team. To my left is Ken Putnam from the License Renewal Project. He is the Project Manager. I have Ken Kleinheinz, who is the Director of Engineering at Duane Arnold. And Mike Fairchild who is the License Renewal Electrical Lead.

And in the back row, if you guys wouldn't mind, just raise your hand when I call you, Curt Bock. Curt Bock is our License Renewal Mechanical Lead. Ken Chew, which is our License Renewal Civil Lead, Clara Rushworth, which is our License Renewal Licensing Lead, Herb Giorgio, Environmental Lead, Eric Sorenson, our Program Engineer, and Al Thomas, who as well is a Program Engineer.

Today's agenda, we will be talking about a background of the site. We will be talking about an operation history and I'm going to have Ken Kleinheinz do that, our Engineering Director. And Ken Putnam

will do our License Renewal Project overview. He will include scoping discussions, our time-limiting aging analysis. He will go through the generic aging lessons learned and our commitment process.

As well, Ken will touch on our technical items of interest. In particular, we will be talking about the torus coatings, our buried piping system and our small bore piping system, which are open items.

The next slide that may seem odd that we are showing a picture, but I think it's a very good picture to depict where Duane Arnold is. And what this represents is what we call our excellence model, as Duane Arnold knows well, at our fleet.

And this shows, and it's no optical illusion, that both the prevention and the detection parts of the circles are slightly bigger than the correction model, because that depicts exactly how Duane Arnold operates. We tried to attempt to stay more in our prevention mode as well as our detection mode to be better prepared to not react to things and spend less time in correction.

And the reason I thought this is just one of those values that we use in our excellence plan. And this has been a journey that we have been on since 2008 and there is a series of values. But we picked

this slide in prevention correction detection, because I think it most accurately represents what we do in this license renewal process.

And when you look at our aging mechanisms and establishing goals and trying to get a head of the different aging issues that come up at Duane Arnold, it depicts exactly where we are at.

We set those goals. We establish a process to make those commitments and we go ahead and effect those changes before they become a correction mode.

And the next slide. Just a little bit of background from the site. We are, approximately, six miles northwest of Cedar Rapids in Iowa. We are a general electric plant. Bechtel was our constructor. We are a BWR. We are a Mark I containment. We have just upgraded to 1912 megawatts thermal power and, approximately, 630 megawatts electric.

The Cedar River is an ultimate heat sink and a water makeup source with forced draft cooling towers for condenser cooling. And our staff right now consists of, approximately, 650 people.

MEMBER SIEBER: What was your original licensed electrical output?

MR. PUTNAM: It's about 515.

MEMBER SIEBER: 515, okay.

CONSULTANT BARTON: Why did you have a restriction on your original license? Your original license, you didn't have -- you weren't licensed for your full power.

MR. PUTNAM: Yes, you license it to 1658 was the license and then the tech specs are restricted to 1593.

CONSULTANT BARTON: What was the restriction all about?

MR. PUTNAM: You know, I think that was for testing and power density. Duane Arnold has a small core, so there is a -- they wanted some operating time there on that before they allowed us to go up.

CONSULTANT BARTON: Okay.

MR. PUTNAM: And we did that in 1985.

CONSULTANT BARTON: Thank you.

MR. COSTANZO: Earlier in the slide that I used with prevention, detection and correction, I spoke of a fleet. And so just as a little bit of background, as we are a plant of five in our fleet, we do have Point Beach in Wisconsin, Seabrook in New Hampshire and we have the two southern plants, both St. Lucie and as well Turkey Point down in Miami.

And since 1974, and the reason I mention that is, when we were first connected to the grid, Duane Arnold has become a member of, you know, the third largest fleet for very small plant in Palo, Iowa just outside of Cedar Rapids. And with the inception of that fleet and the strength of that fleet comes a tremendous amount of governance and oversight.

So I just kind of wanted to mention that with regards to we are not that small plant in Palo, Iowa. We are actually a member of a much larger fleet with a good bit of governance and oversight.

MEMBER SIEBER: Is this a merchant plant?

MR. COSTANZO: Yes, it is. There is a portion. We do work with a PPA, which is a Power Purchase Agreement, with the State of Iowa, but yes, there is a portion of it that is a merchant.

MEMBER SIEBER: Okay. Thank you.

MR. COSTANZO: A little background on plant status. We did start-up from the refueling outage 21 and that was in March of 2009. The current plant status is it's operating very well. We are at 100 percent power. And I just will mention, I'm certain that the Committee is familiar with the Institute for Nuclear Power Operations, we were just rated as an excellence rating back in December, and we

are operating the licensee response column with the NRC.

We did have a mid-cycle outage that we concluded in May. We did have an issue with a drywell cooler leak. It was one of the last remaining copper-tubed coolers, which did have a very small leak. We did also identify that we did have -- actually, there was a small plug in one of our circuit-setter valves, which is the throttle valve on the outlet of the those coolers that did have some erosion that also caused that leak and it got up to almost 3.5 to 4 gallons a minute. And we did take the unit off and made those repairs.

And as well, there were several other, not several, but there were some other issues that we did take care of during that mid-cycle outage to get us ready for our outage this year.

MEMBER SIEBER: I take it you didn't replace the heat exchanger?

MR. COSTANZO: Actually, we did. I'm sorry.

MEMBER SIEBER: Okay.

MR. COSTANZO: Yes, we did. It was actually a job that was going to be done in this upcoming refueling outage, however, we did take the

opportunity to put a stainless steel cooler in, which is a much nicer design and much more reliable.

MEMBER SIEBER: So is that the end of the copper in that kind of application?

MR. COSTANZO: There is actually one set of coolers that still remain copper, but they are much different design. They are not like a U-tube type heat exchanger. They are a full flow with a tube sheet that haven't experienced that same type of corrosion on those coolers that we have had excellent reliability on. So with those two, there is no more remaining copper-tubed coolers in containment.

MEMBER SIEBER: Okay.

MR. COSTANZO: Our next refueling outage is in October of 2010.

CONSULTANT BARTON: You have what kind of cycle refueling cycle?

MR. PUTNAM: Variable.

CONSULTANT BARTON: Variable?

MR. PUTNAM: Yes, it's two years is the nominal, you know, like the tech spec surveillance frequency, but fuel loading decides exactly what it is, so we are a little under probably this year.

MR. KLEINHEINZ: We are averaging about 21 month cycles.

CONSULTANT BARTON: Okay. Okay.

MR. COSTANZO: And I'll turn it over to Ken to talk a little bit about the operating history.

MR. KLEINHEINZ: All right. Good morning. Again, my name is Ken Kleinheinz. I'm the Engineering Director at the plant. I'll be presenting slides 7 through 9. We'll go to slide 7 there.

On 7, we show a brief time line of the operating history of the plant with regard to its license. That history starts in 1970 when the Atomic Energy Commission granted a construction permit to Iowa Electric Light & Power and its two minority owners. And then four years later they issued License DPR-49, the operating license. And then just about one year after that, the plant went fully commercial in 1975.

In 1985, back to the question that Mr. Burton asked, we were approved for an uprate of, approximately, 5 percent in our tech spec to get us from that 1593 up to 1658.

And then in November of 2001, we were the first plant approved for extended power uprate. And that was to go to a full 120 percent of original rated thermal power.

The plant used a very deliberate phased

approach to implementing the extended power uprate. We implemented mods to equipment over several cycles. I'm going to describe some of those uprates in the next two slides, so I'll hold off on that now.

But as Chris mentioned, the final phase was completed at our last outage in the spring of 2009 and we did reach full extended power in March of 2009.

Let's see, in 2006, the plant was purchased by FPL Group, NextEra Energy and the license was transferred at that time. And then September 2008, we submitted our application for license renewal and that's what will extend our current license, which expires, as it states, in February of 2014.

Are there any questions on Slide 7 before I move on?

CONSULTANT BARTON: What kind of equipment did you have to change out for that large increase?

MR. KLEINHEINZ: I'm going to cover that--

CONSULTANT BARTON: Okay.

MR. KLEINHEINZ: -- on the next two slides.

CONSULTANT BARTON: Gotcha. All right.

MR. KLEINHEINZ: And if there is any questions after that, I'll --

CONSULTANT BARTON: All right. Thank you.

MR. KLEINHEINZ: Okay. On Slide 8, I mentioned a moment ago that the plant has implemented several upgrades to achieve power uprate. We have also made several upgrades in recent years to support long-term asset health of the plant and also to address several reliability and performance issues, such as the coolers we just mentioned.

I used the word deliberate earlier also in describing our approach to power uprate. I think that best characterizes how the plant operates in developing long-term life cycle management plans for the equipment and taken a very conservative approach implementing equipment upgrades and in achieving initiatives like the license renewal, which is one of extended power uprate.

Okay. So on Slide 8, the first two bullets list improvements the plant made to ensure the long-term health of the recirculation system piping, stainless steel piping. In 1987, the plant was the pilot for boiling water reactor, hydrogen water chemistry.

And since 1987, we have been injecting 6 standard cubic feet per minute of hydrogen continuously into our feedwater system to protect that piping.

In order to stay in the detection phase and monitor the effectiveness of that hydrogen water chemistry, we also installed, at that time, a rather unique system called a crack arrest verification system, so I can point on my slide and you can read through yourself.

But basically, that's a continuous monitor using precracked, stressed metal specimens typical alloys like Alloy 600, 304 stainless steel and A182 filler material, so we can measure the effectiveness and verify that our cracks are not growing.

Also at that time, we installed another system, an electrochemical potential monitor monitoring system. And basically, that's also a continuous system monitoring reactor coolant to make sure the electrochemical potential stays below the value that assures that cracks won't grow. So that has been in place since that time also.

MEMBER SHACK: What percent of the time is that operable?

MR. KLEINHEINZ: Well, it's got to be --

MEMBER SIEBER: Good question.

MR. KLEINHEINZ: It is operable more than 98 percent of the time.

MEMBER SHACK: Oh, that's good.

MR. KLEINHEINZ: It is very rare for that system to come out of service.

MEMBER SHACK: This is the electrochemical potential monitor?

MR. KLEINHEINZ: Oh, I'm sorry.

MEMBER SHACK: Not the hydrogen water chemistry.

MR. KLEINHEINZ: Oh, I'm sorry. I don't have -- I can't say I have a percentage of time.

MEMBER SHACK: Is it something that is reliable or as I suspect it takes a lot of coaxing and care?

MR. KLEINHEINZ: Not a lot of coaxing and care when the electrodes wear out, we do have to go in and replace, which is no small evolution because of dose concerns mostly.

What we have shown is there are other monitoring systems like dissolve hydrogen and oxygen, which are kind of backups to that, so that's not the only system that kind of tells us, you know, based on our start-up test and we know as long as we have a certain result, load of dissolved oxygen, dissolved hydrogen, these --

MEMBER SHACK: The hydrogen water chemistry is 98 percent?

MR. KLEINHEINZ: That system is in service greater than 98 percent of the time.

MEMBER SHACK: Okay.

MR. KLEINHEINZ: That was one of the conditions for our risk-informed ISI Program.

MR. COSTANZO: Actually, we were one of the first plants to put hydrogen water chemistry in their very reduced power and actually, we are looking to do that even further down in the reduction of power as you start to come up to increase the effectiveness of the hydrogen water chemistry. It was recognized by INPO as one of our strengths.

MEMBER ARMIJO: Do you still have the original stainless steel piping in your recirc system in coarse braids or have you changed that out?

MR. KLEINHEINZ: No, we have the original.

MEMBER ARMIJO: You are protecting that with the water chemistry?

MR. KLEINHEINZ: That's correct.

MEMBER ARMIJO: Okay.

MR. KLEINHEINZ: And that's a good question. The purpose of hydrogen water chemistry is to mitigate intergranular stress corrosion cracking of the piping.

Now, in 1996, we implemented another

process, noble metals application.

MEMBER SIEBER: Right.

MR. KLEINHEINZ: Because hydrogen water chemistry only provides mitigation for the piping itself. No metals is applied to the piping and to the reactor internals. So that extends the coverage of IGSCC protection into the vessel internals. So we first injected platinum and rhodium in 1996 during that outage and our last application was in the 2005 refueling outage.

Starting next year, 2011, we will be doing on-line noble metals application, which is now the industry standard. It reduces outage time. It can be performed with the plant at full power. So we look forward to that next year.

MEMBER SHACK: Did you do some residual stress improvements? Since you have risk-informed inspections, you somehow got out of the 03-13 enhanced inspections, but you needed two methods.

MR. PUTNAM: We did induction heat stressing improvement.

MEMBER SHACK: Okay.

MR. PUTNAM: And --

MR. KLEINHEINZ: Certain welds.

MR. PUTNAM: -- in '86 or so. I don't

recall.

MR. KLEINHEINZ: Roughly, yes. In the mid-'80s, yes.

MEMBER SHACK: So it is two methods. SO you have some welds that you did the heating.

MR. KLEINHEINZ: There are some welds we did the heating, not all.

MEMBER SHACK: Yes.

MEMBER ARMIJO: And your shroud, did you have any cracking of your shrouds and did you have to, you know, clamp them, since some plants did?

MR. KLEINHEINZ: No. We have had no incidents of cracking in our core shroud to date.

MEMBER ARMIJO: Okay.

MR. KLEINHEINZ: We will be doing another inspection in our next outage.

MEMBER ARMIJO: Good.

MR. KLEINHEINZ: Back to the noble metals application. Are there any questions on that, I mean, any further questions?

Okay. Just again, back to the monitoring phase. Along with the noble metal application, we did install a coupon system also in that crack arrest verification, the sampling system, we installed coupons that are treated with noble metals, so we can

track the wear rates. Make sure the metals are still present protecting our vessel.

So we have a routine sampling program where we remove those coupons. And every time we apply, we install new coupons.

Okay. Moving on to 19 --

MEMBER SHACK: Did you sign up for continuous injection?

MR. KLEINHEINZ: Of noble metals?

MEMBER SHACK: Yes.

MR. KLEINHEINZ: That's platinum and rhodium are not inexpensive, but no, I know of no continuous injections.

MEMBER ARMIJO: It lasts a long time though.

MR. KLEINHEINZ: They do last a long time, that's right.

MEMBER ARMIJO: Yes.

MEMBER SIEBER: Need a stimulus program.

MR. KLEINHEINZ: In 1998, the plant did install larger emergency core cooling system suction strainers on our low pressure ECCS system that is inside of our torus. We did that to increase our margin in the case there is a pipe break inside our containment that blows debris into the containment and

that gets washed to our torus. So that increased the surface area of those strainers significantly. That was a preemptive measure.

In 2001, we implemented the first component upgrades.

MEMBER SHACK: When you did that, did you replace --

MR. KLEINHEINZ: Okay.

MEMBER SHACK: How much fiber insulation is left?

MR. KLEINHEINZ: We did not replace the fiber insulation in our drywell, at least not at this point. Now, the BWR Owner's Group is taking a significant look at that and we are a part of that group. As a matter of fact, we'll be doing some significant walk-downs of our containment next outage to, basically, get a feel for how much fibrous insulation is in our containment.

MEMBER SHACK: Okay. On the piping you have got reflective metal?

MR. KLEINHEINZ: Jacketing on some of it. I don't know if anyone wants to add to that over there, but it is fibrous insulation.

MEMBER SHACK: Oh, okay. So it's the packaged kind of fibrous insulation that you can take

off to inspect?

MR. KLEINHEINZ: Right.

MEMBER SHACK: Right.

MR. COSTANZO: But as Ken mentioned, we are on the BWR Owner's Group Committee. We are going to stay ahead of that in prevention, so that we don't have to react to that. And as the other Ken had mentioned, we are doing some walk-downs to this outage to be able to better understand that, so that when we do have to take some actions, that we would be better poised to do that.

MEMBER SHACK: Okay.

MR. KLEINHEINZ: In 2001, we implemented the first round of upgrades to support our Phase I of power uprate and that included new high pressure turbine internals, new moisture separator heater internals and then two new circulating water pumps.

In 2003, we mentioned, we replaced 10 out of 12 of our copper drywell coolers, those were the original coolers.

CONSULTANT BARTON: So one of the two that are remaining leaked?

MR. KLEINHEINZ: Yes. We had replaced those in 2001, like-for-like, they were the first ones that caused us an issue and, at that time, we were

replacing like-for-like. So we had planned for a later replacement of them, an upgrade, and --

CONSULTANT BARTON: It gotcha though.

MR. KLEINHEINZ: -- it got me. It got us, yes, sir.

MR. COSTANZO: Really, the leaks were very minimal --

MR. KLEINHEINZ: As it turned out.

MR. COSTANZO: -- on those coolers themselves. We had anticipated that it was going to come from those, because of the history of those coolers. But as I had mentioned, it was actually in the downstream circuit setter valves that had a quarter inch plug that actually caused some turbulent erosion on that plug and it was a hollow plug that actually caused the leak.

MR. KLEINHEINZ: So it was the same system, different component that actually affected --

MR. COSTANZO: And we did do an extensive condition and root cause analysis and did some mitigating, put some solid plugs in and we will take a look at any other extent of condition we have to do this outage.

MEMBER SHACK: Okay.

MEMBER ARMIJO: Do you still have the

original condenser? Did you have stainless steel condensers or did you have --

MR. KLEINHEINZ: Yes, we have stainless steel condensers.

MEMBER ARMIJO: So you never had the copper Admiralty-brass problem?

MR. KLEINHEINZ: No, that's right. We had stainless steel, three or four stainless steel since we began.

MEMBER BONACA: In your extended power uprate, did you need credit for accident pressure?

MR. KLEINHEINZ: Yes.

MEMBER BONACA: Okay.

MR. KLEINHEINZ: I don't recall the number.

MR. PUTNAM: But as a matter of fact, you know, we credited over pressure in the original license for the plant, you know, in power uprate the number changed a pound or two, and we continued to credit over -- containment over-pressure.

MEMBER BONACA: All right.

MR. KLEINHEINZ: Okay. I'll move on to Slide 9. 2005 included equipment upgrades to support the second phase of power uprate. 6 of 12 of our feedwater heaters replaced in that outage. We

replaced both of our condensate pumps with new pumps and motors. And then we installed condenser isolation valves on our circulating water system and that allows us to isolate individual trains of these circ water going into our condensers and do repairs or cleaning of the tubes on-line, if necessary, at lower power.

Previously, we had had to shut down any time we had an issue with condenser leaks or fouling.

In 2007, we replaced a significant number of the instrumentation and power cables inside our heater bay. We hadn't encountered any failures of these non-safety cables, but it's a higher temperature, ambient temperature in that area and had noted some cracking and brittleness of those cables.

So in the prevention mode, we went in and replaced about a third of all the cables in that area to ensure continued reliability.

CONSULTANT BARTON: With different cable insulation?

MR. KLEINHEINZ: Well, I'll ask Mike. I don't believe there is anything significantly different than what we had.

MR. FAIRCHILD: This is Mike Fairchild. No, it was basically the same type of cable, XLPE installation.

MR. KLEINHEINZ: Okay. In our 2009 outage, our last refueling outage in the spring of '09, we implemented several upgrades to our emergency diesel generators, replaced the governor on the Bravo Generator. We will replace the Alpha Governor in this coming fall outage. Then we also replaced both regulating systems on those engines for reliability purposes.

MEMBER SIEBER: What kind of governors were originally on and what did you replace them with?

MR. KLEINHEINZ: Woodward.

MEMBER SIEBER: Okay.

MR. KLEINHEINZ: Both.

MEMBER SIEBER: So it's --

MR. KLEINHEINZ: An upgrade.

MEMBER SIEBER: -- the new one is an upgrade or just a replacement?

MR. KLEINHEINZ: No, it is an upgrade. It makes the engines a little more responsive.

MEMBER SIEBER: Okay.

MR. KLEINHEINZ: Then we installed the last large upgrade to achieve full power uprate and that was a replacement of our main transformers.

And then just a couple more enhancements we did during that outage. We put new more reliable

Jordan positioners on our recirc pump MG Set Scoop Tube Positioners. And then lastly, replaced our ultrasonic feedwater flow measuring system during that outage to get us a little more accurate calorimetric for measuring reactor power.

CONSULTANT BARTON: Transformer upgrade was just because of power uprate? It wasn't because of transformer failures?

MR. KLEINHEINZ: The transformers are not failed. We had basically four individual phases. One was a spare and any time could be swapped out.

CONSULTANT BARTON: Okay.

MR. KLEINHEINZ: So they were all operable at the time of the change out.

CONSULTANT BARTON: All right.

MR. KLEINHEINZ: The one showed some signs of gasing, I think, so early signs of degradation.

MR. COSTANZO: Now, Mr. Barton, one of your questions was, you know, we talked a little bit about the power upgrade and what were those modifications we did. The list is not, obviously, all due to those modifications required for power uprate, but they do represent a lot of our life cycle management, our system health reporting systems for obsolescence and some, unfortunately, for instance the

tube position upgrade we did in correction, because we did have some issues and some problems with the previous ones with regard to reactivity control.

But it does represent a little bit about the slide that I was trying to show you earlier, our value with regard to prevention and protection.

CONSULTANT BARTON: Thank you.

MR. KLEINHEINZ: Any other questions on Slides 7 through 9? Okay. Hearing none, then I'm going to turn the presentation over to our License Renewal Project Manager, Ken Putnam who will cover the remaining slides.

MR. PUTNAM: All right. Thanks. I'll give a brief overview of our License Renewal Project for Duane Arnold and then cover the three technical items of interest, including two open items we have with the staff.

Shortly after FPL purchased Duane Arnold, we kicked off the project to renew the operating license. The decision was made then that we wanted the bulk of the work done on-site at Duane Arnold, that would allow us to have good site ownership and oversight to support both the quality of the project as well as ensure we had site ownership of the programs as we went forward in implementing license

renewal.

We staffed the project with a very experienced team. It included people who had been long-term employees at Duane Arnold. We also had several people who had been involved from corporate at St. Lucie and Turkey Points License Renewal, so we had their experience and then we augmented that with contract staff, who had been at an awful lot of the plants that have renewed their license in the past.

To ensure we tapped into the most current experience with respect to renewing the license for a BWR, we sent our team up to Monticello who was just wrapping up their License Renewal Project, at that time, to do benchmarking for a week there, that was a great leaning experience for us. We picked up a lot of things from them.

And we have continued to be engaged with the industry throughout the project, sending team members to observe audits at other sites during -- who were slightly in front of us. And we have also participated in industry working groups throughout the period.

We did have peer reviews of both the technical products being produced by our individual disciplines. And we also had a peer review of the

integrated application at the end. We did also use our QA folks to perform independent audits midstream as we were developing our analysis to check us to make sure we were following our own processes.

Next slide. The scoping process is pretty standard. We followed NEI 95-10. We categorized the entire plant in terms of major system structures and components and we tried to stay as close as practical to the existing plant system nomenclature.

We went through each of the systems and cataloged the system level functions then evaluated these functions against the scope and criteria specified in 10 CFR 54.4(a)(1) for safety-related (a)(2) for non-safety-related equipment that could affect safety-related and (a)(3) for the regulated events of EQ fire protection at loss, ATWs and station blackout.

Then we went down to the component level and identified those components supporting an intended function under the license renewal.

Next slide.

MEMBER STETKAR: Ken, on that, I don't think you are going to cover it later, so stop me if you are. But I noticed there was some discussion about the intake trash racks and the rakes on the

trash racks. And they are currently not in scope.

They do provide protection for safety-related service water intake traveling screens. The discussion seemed to focus on the fact that failures of the trash racks themselves would not block the intake, because the trash racks would collapse down into the intake. Well, I can buy that, they are steel or whatever they are made out of.

On the other hand, what they do is they keep large debris from coming in and jamming up the traveling screens which then causes smaller debris to collect on the screens, which then plugs the intake.

So I was curious why the maintenance of the function of those trash racks is excluded from the scoping.

And also the second question is it probably gets pretty cold in Palo in the wintertime. Do they block ice from coming in from the river?

MR. PUTNAM: I'll let Curt Bock, our mechanical lead, maybe answer that.

MR. BOCK: Yes. This is Curt Bock for the applicant. Our main reasoning there was that the flow that is the inner velocity through those racks is so small that we felt that the racks would fall directly down and would not impact our safety-related equipment

that is in our intake structure.

MEMBER STETKAR: I understand that. As I said, they are steel. They will go down.

MR. BOCK: Right.

MEMBER STETKAR: The stuff that is floating in the river will not go down. So I'm curious about if the trash racks disappear, what protection does your safety-related intake have from debris in the river? Large debris.

MR. BOCK: Well, if we no longer have the trash racks, then larger debris would be able to -- you are assuming a failure of the trash racks?

MEMBER STETKAR: Yes.

MR. BOCK: Which would then -- the material could then enter that area in the intake structure.

MR. PUTNAM: That configuration though at the intake rake, Curt, the screen flow pulls the stuff away. You know, it is kind of angled toward the downstream, so that debris tends to not sweep into that intake. And then, you know, our operating experience certainly is we don't get trash on those trash racks oddly enough. We have a trash grate there that is intended to like remove that. It was never getting used. We had to put a PM in place to cycle

the motors, because it was never used.

MEMBER STETKAR: That's good experience. I mean, that's odd, but that's good experience.

MEMBER SIEBER: Well, usually the screen house is built with the outer shell submerged, so the trash actually stays out in the river.

MR. PUTNAM: Right.

MEMBER SIEBER: While the water flows in, that's why it doesn't freeze in there provided you heat the building, which is the other question, I think, you asked.

MEMBER STETKAR: Yes.

MEMBER SIEBER: On the other hand, that doesn't happen all the time.

MR. PUTNAM: Yes, we do have deicing out there as well where we circulate circ water, I guess--

MR. BOCK: Yes.

MR. PUTNAM: -- back to the -- to spray on those in that area.

MEMBER SIEBER: Screen wash pumps, right.

MR. PUTNAM: To keep things in place.

MEMBER STETKAR: But basically your operating experience is that you don't have periods of large --

MR. PUTNAM: That's correct.

MEMBER STETKAR: -- things coming in, tree limbs.

MR. PUTNAM: No.

MEMBER SHACK: Even when you had Cedar Rapid flooding?

MR. PUTNAM: We inspect them.

MEMBER STETKAR: I mean, you know, riverine locations in northern climates tend to get affected, you know, in the autumn we have severe storms in the autumn and brings down tree limbs and lots of debris in winter.

MR. PUTNAM: And as Curt said, the approach velocity is really slow there. The river speed is actually, I think, faster than the approach velocity of the pumps pulling it in, so it's --

MEMBER STETKAR: Okay.

MR. PUTNAM: -- not competing with the river in terms of flow over there.

MEMBER STETKAR: Thank you.

CONSULTANT BARTON: In the recent floods, did any of that equipment at the intake get flooded?

MR. PUTNAM: You know, we had some backup discussion of the flooding, if you would be interested in jumping clear to that now?

CONSULTANT BARTON: Oh, if you are going

to cover it, that's fine.

MR. PUTNAM: Well, we intended. Mike, why don't you pull that up and let's just jump to that now.

MR. FAIRCHILD: Okay.

MR. PUTNAM: Go ahead, Mike.

MR. FAIRCHILD: This is Mike Fairchild for Duane Arnold. This is a picture of the plant before the flood. This is during the flood and this is actually from the opposite direction. This is the intake structure.

CHAIR BLEY: Could you go back to when the orientation changed in it?

MR. FAIRCHILD: Yes, the orientation changed.

MEMBER SIEBER: Oh, okay.

MR. FAIRCHILD: You can see the intake structure is over here.

MEMBER SIEBER: So that was that little island over there, right?

MR. FAIRCHILD: Yes.

MEMBER SIEBER: Okay. Got it.

MR. FAIRCHILD: None of the safety-related components in the intake structure got water in it. The level was above it and the next slide has the

actual levels, one of the next slides.

MEMBER SIEBER: I take it that was inaccessible, your intake structure, during the whole period of the flood. So if you got debris, you couldn't do anything about it anyway, right?

MR. FAIRCHILD: Right. There was --

MR. COSTANZO: Well, you would have had to send some boats out there and mitigate by boat.

MEMBER SIEBER: Maybe you can go.

CONSULTANT BARTON: Yes, but could you take big equipment to get the chicken coops and stuff off the trash racks?

MR. FAIRCHILD: The river was actually relatively debris free.

CONSULTANT BARTON: Was it?

MR. PUTNAM: At Duane Arnold.

MR. FAIRCHILD: Yes, at Duane Arnold.

MR. PUTNAM: Down the street at Cedar Rapids --

MEMBER STETKAR: Before you flip to the next one, is that your switchyard in the lower left hand?

MR. FAIRCHILD: No, the switchyard is actually right over here.

MEMBER STETKAR: Oh, back there? Okay.

MR. FAIRCHILD: This is a parking lot.

MEMBER STETKAR: Oh, that's a parking lot. Okay. I couldn't see.

MR. FAIRCHILD: Okay.

MEMBER STETKAR: Thank you.

MEMBER SIEBER: The insurance company solves --

MR. FAIRCHILD: This is the flood levels for Cedar Rapids. You can see the 2008 flood was significantly higher than the previous records, over 11 feet.

MEMBER SIEBER: Yes.

MR. FAIRCHILD: So that was quite an experience for us. The maximum probable flood is 764.1 and the intake structure floor level where the safety-related equipment is is actually 767.

MEMBER STETKAR: Okay.

MR. FAIRCHILD: And that's what the plant is designed to withstand. The main plant area actually has stop logs and things to block entrances up to that level.

CHAIR BLEY: What was the level in this last part?

MEMBER SIEBER: 730 he said.

MR. FAIRCHILD: 751.

MEMBER SIEBER: 751.

CHAIR BLEY: 751.

MEMBER STETKAR: It's right here.

CHAIR BLEY: The flood zone.

MR. FAIRCHILD: That was the highest flood level.

CONSULTANT BARTON: So your flood design is higher than what you experienced in this flood?

MR. FAIRCHILD: That is correct.

CONSULTANT BARTON: All right.

MR. FAIRCHILD: And then this is 15 plus years of records, river level rev and you can see that the 2008 was significantly higher than anything we had had previously. The closest was like 2003. And our records, computer records didn't go back that far. This is just a trace of how it went up and the length of time of the flood.

The purple line below is the average river level and the green line on top is the plant floor level.

CONSULTANT BARTON: Okay.

MR. FAIRCHILD: To show how much spare we had, margin.

MEMBER SIEBER: 17 feet.

MR. COSTANZO: We had some renewed

advocacy by the entire Cedar Rapids area, because we were one of the only stations that stayed on producing electricity.

CONSULTANT BARTON: That's good for you.

MR. FAIRCHILD: We operated at 100 percent power. If we had to back down it was because of lack of load, not lack of any problems in the plant. And only a couple of out buildings got water in them. Just a little bit on the floor. Any further questions on the flood?

CONSULTANT BARTON: Thank you.

MEMBER SIEBER: I think they have already had their 100 year flood.

CONSULTANT BARTON: I think so.

MEMBER SIEBER: So they don't need it inspected.

MR. PUTNAM: Yes, it was beyond the 100 year flood levels in Cedar Rapids. You know, it certainly was a traumatic event for our community, I think, more than for our plant.

MEMBER SIEBER: Yes.

MR. PUTNAM: A lot of people affected by it.

MEMBER SIEBER: Right.

MR. PUTNAM: All right. Sorry, where was

I? On scoping, right? Let me think where I cut off here.

MR. COSTANZO: At the fourth bullet down.

MR. PUTNAM: All right. Yes. We mapped this stuff down to the individual component level. Let's go to the next slide, Mike.

MEMBER STETKAR: I'm not going to let you off the hook --

MR. PUTNAM: Okay.

MEMBER STETKAR: -- quite -- well, yes, I am. Get to the next slide.

MR. PUTNAM: I've got one more slide of scoping.

MEMBER STETKAR: Okay. I'll let you get to the middle bullet on this one.

MR. PUTNAM: We use site component databases and controlled drawings and all controlled documents for performing the scoping reviews. For safety-related and the regulated events, those databases they were easy, you know, it was one-to-one, straightforward match-up on the definition of safety-related. That was pretty straightforward stuff.

They weren't really constructed to evaluate non-safety affecting safety that is kind of a different concept from our current licensing basis.

So to compensate for that, we took a conservative spaces approach. Like I said, we had good databases on where our safety-related equipment is, so we took a spaces approach where anything that had -- any area that had safety-related equipment in it, we assumed that the non-safety-related equipment located in that same area could affect that safety-related equipment and evaluated it for scope.

To confirm that there wasn't anything unique about the physical location that doesn't show up in the database or on a drawing, we did send our -- we have a couple of former shift managers on the team. We sent them out to walk-down those areas we excluded to make sure there wasn't something going on in the plant where there was more interaction than we realized from the drawings. And so that gave us a good comfort that we had the right scope there on non-safety affecting safety.

For things like electrical really aren't-- isn't information so much down to the component and tag number, level, so those we treated as commodity groups in performing the evaluation at the commodity group level, that's how we performed our scoping. I assume you've got a question for me now?

MEMBER STETKAR: Yes, I do. And this is

the appropriate place to ask this one, I guess. There was a question, I think, about scoping of the main generator hydrogen coolers. And I'm assuming it was under (a)(2). I didn't go back and check my notes this morning.

MR. PUTNAM: Yes.

MEMBER STETKAR: But the response to the staff's question said that the floor generator hydrogen coolers are tube heat exchangers that are entirely contained within the main generator shell.

MEMBER SIEBER: Right.

MEMBER STETKAR: Your hydrogen coolers are inside the main generators?

MR. PUTNAM: Yes.

MEMBER STETKAR: Inside the main generator?

MR. PUTNAM: Yes.

MEMBER STETKAR: That's -- okay.

MEMBER SIEBER: It is water in.

MEMBER STETKAR: A lot of plants don't do that though. They don't like service water --

MR. PUTNAM: Yes, you don't want them to leak.

MEMBER STETKAR: You don't want them to leak. Okay. But yours are inside. Okay. Thanks.

CONSULTANT BARTON: It's a typical GE design, if I remember correctly.

MEMBER STETKAR: Is it?

CONSULTANT BARTON: Yes.

MEMBER STETKAR: Okay.

CONSULTANT BARTON: I have seen GE plants that have the hydrogen coolers down below.

MEMBER STETKAR: Okay.

CONSULTANT BARTON: Thanks.

MEMBER STETKAR: Is it these older GE plans?

CONSULTANT BARTON: That could be, yes.

MEMBER STETKAR: Okay.

CONSULTANT BARTON: The ones I have seen are newer ones.

MEMBER SIEBER: One thing, Westinghouse had that, too, in some plants.

MEMBER STETKAR: Okay. Thanks. I just hadn't seen one. Thank you.

CONSULTANT BARTON: Okay.

MEMBER STETKAR: Another question. This is kind of scoping or -- I guess it is. You have excluded monitoring of hot insulated piping that is located indoors, because the argument that hot piping will not have corrosion, because there is no way that

moisture can collect on that hot piping.

Although I noticed your operating experience said you had had some corrosion on the external surfaces of the turbine stop-valve piping, which is usually pretty hot.

So I was curious what the basis for excluding hot piping --

MR. PUTNAM: No, we didn't exclude it from scope. It is in scope.

MEMBER STETKAR: It is in scope, it's just not part of the -- but I looked at forwarding your --

MR. PUTNAM: For one of the aging effects there.

MEMBER STETKAR: Right.

MR. PUTNAM: Corrosion on the exterior surface and I forget the details. If you remember more, Curt, feel free to correct me. You know, so that is really about evaluating one aging effect there.

MEMBER STETKAR: Okay. I was looking ahead and there wasn't a convenient place to ask you about it in the next couple of slides.

MR. PUTNAM: I don't recall that operating experience you are talking about off-hand, so I really -- we can check into that, but I don't --

MEMBER STETKAR: I was just -- the main question that I had, of course, is that if the piping is always hot, above 212 degrees, 365 days a year, there's no much chance to get water between the insulation and the pipe.

On the other hand, if the pipe is cooled down for extended periods of time, like during outages, you might have some type of corrosive effects. So I was curious. I was sort of interested to know what systems or what piping sections are excluded from that aging management program due to that consideration?

MR. PUTNAM: Well, you know --

MEMBER STETKAR: It's probably something you have to go back and take a look at.

MR. PUTNAM: Yes, we would have to look that up.

MEMBER STETKAR: That's fine.

MR. PUTNAM: I'm sure it would be quite a number of them.

MEMBER STETKAR: Yes, that's what I was --

MR. PUTNAM: That was in our methodology as you work through evaluating each of the aging effects, if it was above 212, and I don't remember if there was a material restriction on that evaluation or

not, but if it was, if it fits the box that we defined in our methodology using the EPRI tools, that's how we treated it.

MEMBER SIEBER: But that's just the external surface?

MR. PUTNAM: Correct.

MEMBER SIEBER: You still have the corrosion taking place inside the piping.

MR. PUTNAM: That's correct.

MEMBER SIEBER: Which I'm sure you do examine UT or whatever method you use. That is where I would expect the most significant wall thinning from the inside.

MR. PUTNAM: And that would depend on the system again.

MEMBER SIEBER: Yes.

MR. PUTNAM: What we were doing on the inside.

MEMBER SIEBER: Yes.

MR. PUTNAM: Next slide.

CONSULTANT BARTON: Let me ask you a question on scoping. Can you explain to me what your safety-related air system is? I was confused in your application. The instrument air is not included. Do you have a safety-related air system?

MR. PUTNAM: Yes.

CONSULTANT BARTON: What is it and what are the components of it?

MR. PUTNAM: Curt, do you want to answer that?

MR. BOCK: Yes. This is Curt Bock for the applicant. Our safety-related air system, it's a system designed to provide a reliable source of compressed air to operate components in the standby gas treatment system, control building standby filter unit and the control building ventilation system and other containment isolation valves.

We have two independent redundant motor-driven air compressors that are powered by the vital buses. Dryers, receivers, instrumentation and the distribution piping. The air receivers are normally supplied by the plant instrument air system. And then if, you know, air pressure falls below the set point, they will kick on.

They are normally cooled by well water with emergency service water backup. And the compressors and dryers and receivers are located in a portion of a standby gas treatment system room in our reactor building on the second level.

CONSULTANT BARTON: Are some of the

components in the instrument air system also part of the safety-related system or is the safety-related air system entirely separate?

MR. PUTNAM: You know, typically, you know, most of the safety-related components that are supplied by air are fail-safe.

CONSULTANT BARTON: I understand that.

MR. PUTNAM: If there is a loss of air, it will fail to -- like an isolation valve, it will fail to close. For a handful of equipment, that's not true. You need active air to make it work right. And that's the component that is supplied by that safety-related air.

CONSULTANT BARTON: But what is the air source for that? Is it instrument air or is it nitrogen bottles? You know, what is the source?

MR. PUTNAM: No, it's instrument air. It's compressing atmospheric air and drying it. And there is a, you know, redundant path with check valves that your normal instrument air system is supplying it 99.9 percent of the time. If for some reason that non-safety-related air went away, a check valve would close and these compressors would start up and provide air to that limited number of components.

CHAIR BLEY: So the safety-related air

system is a standby system that only supplies some of the components supplied by instrument air?

MR. PUTNAM: Correct.

MR. BOCK: Correct.

CHAIR BLEY: Okay.

MR. PUTNAM: A very small subset.

CHAIR BLEY: Thanks.

CONSULTANT BARTON: Now I understand it. All right.

MEMBER STETKAR: Does the safety-related air system come into the instrument air head or downstream from the outlet of the air receivers or does the -- do the safety-related air compressors charge the air receiver, the main air receiver from the plant air system?

MR. PUTNAM: Downstream.

MEMBER STETKAR: They are downstream. Okay. Okay. Now, you had problems with corrosion in your instrument air system. Corrosion inside the air receiver.

MR. PUTNAM: Yes.

MEMBER STETKAR: And apparently, corrosion in the piping from the air compressor building --

MR. PUTNAM: Yes.

MEMBER STETKAR: -- wherever it is

located, because you replaced that.

MR. PUTNAM: Yes.

MEMBER STETKAR: When did that happen? When was that all of that? When was the piping replaced? And when did you -- you repaired the corrosion on the inside of the air receivers with weld grounded down and put weld overlays or something like that. When did that happen?

MR. PUTNAM: I don't have that information.

MR. BOCK: Approximately, 2007.

MEMBER STETKAR: 2007. So about three years ago. Okay. I don't need a precise date. I was looking for, you know, 1980 versus 2010. So a couple of years ago.

MR. BOCK: Correct.

MR. PUTNAM: And that stuff, obviously, is upstream of the dryers.

MEMBER STETKAR: That's right. But on the other hand, you now, corrosion products and moisture from those events can be carried through the system and eventually deposit down in little solenoid operated values. And having worked at a plant that had a problem that way, your fail-safe valves don't fail-safe if the solenoids don't move when they are

de-energized.

So I was curious whether you have had any problems in the intervening three years with operation of any of the air operated equipment or whether you actually checked the eventual consumer lines, you know, blew down the lines at the final endpoint to see whether you had corrosion products and moisture out in there?

MR. PUTNAM: We do routine periodic blow downs.

MEMBER STETKAR: You do.

MR. PUTNAM: With the system in place and check for exactly that.

MEMBER STETKAR: Good.

MR. PUTNAM: And we didn't -- we haven't had any problem with the dryers.

MEMBER STETKAR: If you are doing the blow downs --

MR. PUTNAM: Currently, you know, in the way-back times we have had problems back in the early '80s there with, I think it was, desiccant carrying over and getting in there and causing problems. So that, you know, we definitely know exactly what you are talking about in terms of causing problems downstream. And we do have -- we upgraded our dryers

to get rid of the desiccant moving downstream. And we do do periodic blow downs --

MEMBER STETKAR: You do periodic blow downs out at the end --

MR. PUTNAM: -- to check the quality of that area.

MEMBER STETKAR: -- of consumers.

MR. COSTANZO: And part of the prevention system is an operator can't go stroke a valve for an IST. If it was an IST stroke, if he doesn't know the history back two to three years and therefore can monitor that, and if there is any change in that prevention protection model, that gets incorporated into the risk model and then you plan the work orders. You get yourself prepared. And that feeds back to the monitoring program. So we would have early indication to be able to stand prevention in that.

MEMBER STETKAR: Okay. Thank you. Thanks.

MR. PUTNAM: Does that hit on where we are at on scoping? Any other questions on that? All right.

Time-limited aging analysis. We do have to take a look at time-limited aging analysis under the regulations in place that our analysis relies on

on a component of time to determine its adequacy. We have a very good electronic file system of our licensing basis for the facility. Every piece of communication we ever had with the NRC is in a nicely searchable format. We are able to do keyword searches on that and definitely find anything in that realm that mattered for licensing that depended on time.

We also went through all our calculations and looked for anything there that was depending on time and we also interviewed our engineers for anything we might miss and compared ourselves against similar plants to see what was in their time-limited aging analysis.

So we think we have a good list of those things where time matters in terms of 40 years of time to take a look at.

Some of the things we did need to relook at definitely neutron fluence, obviously, changes as you go to 60 years, so we did reperform our analysis for that. We went to the RAMA methodology. We hadn't previously had that. That was a good improvement for us, because it allowed us to do a lot better modeling of our internals. We had good modeling, I think, of the shell, not so good of the reactor vessel internals. So by going to the RAMA methodology, I

think we improved quite a bit there.

We selected 54 effective full power years as the endpoint for the analysis. That will take us out several years past the 60 year life. We can't quite get to 54 effective full power years yet. So we picked a conservative value there.

And then using that neutron fluence value, we did recalculate pressure-temperature curves for the vessel and confirmed that we could get acceptable results for those.

MEMBER SHACK: You mentioned that you didn't have any cracking on your core shroud yet. What's your fluence at those high fluence welds?

MR. PUTNAM: Clara, do you actually have numbers for that? They are high.

MEMBER ARMIJO: I was going to add to something, Bill. They did have, they mentioned, a fluence of 5 times 10^{20th} for the top guide.

MEMBER SHACK: Well, that's their trigger for inspection.

MEMBER ARMIJO: That's their threshold for IASCC.

MR. PUTNAM: That's written down.

MEMBER ARMIJO: But I believe that's a threshold for conventional water chemistry, not a

threshold when you are doing hydrogen water chemistry. Really, in a sense, that's my question. You are going to have to do some additional inspection of that top guide, because you are already there as far as that threshold.

MEMBER SHACK: Right.

MEMBER ARMIJO: And then at 50 years or 54 years, you will be two orders of magnitude higher in fluence. So my question is do you believe that the threshold that you are using is valid for hydrogen water chemistry plant?

MR. PUTNAM: Conservative.

MEMBER ARMIJO: Should you be doing something else?

MR. PUTNAM: That is a question I don't recall looking at. Clara, do you?

MS. RUSHWORTH: This is Clara Rushworth for Duane Arnold. And no, I'll need to specifically go back and see if I can get some more information for you on the top guide. But as far as the core shroud, I have the fluence numbers here. Is that what you were asking?

MEMBER SHACK: Yes, that was. I was curious.

MS. RUSHWORTH: Here we go. For 54

effective full power years, for example, for the H4 welds, there is a value of around 4 times 10^{21st} neutrons per centimeter squared. And did you want more specific numbers?

MEMBER SHACK: No, that's fine.

MS. RUSHWORTH: Okay.

MEMBER SHACK: You know, so you, you know, clearly have the fluence, so we can attribute some benefit perhaps to the hydrogen water chemistry.

MEMBER ARMIJO: Well, that was the original intent for that whole water chemistry change is to protect the internals without having to replace them. And I just wondered if the Owners Group or someone else has come up with an IASCC threshold that is appropriate for hydrogen water chemistry and noble metals or whether you are just going to stick with the conventional threshold, which I think is the 5 times 10^{20th}?

MR. PUTNAM: The way we did the method, that's what we compared it to.

MEMBER ARMIJO: Okay. So you will be doing augmented inspections to look for any evidence of cracking?

MR. PUTNAM: That's correct.

MEMBER ARMIJO: Okay.

MEMBER SHACK: So since Sam brought this up, I had a question on your Commitment No. 46.

MR. PUTNAM: Okay.

MEMBER SHACK: And since that's not in your document, the only verbiage I have on it is in the staff's SER. And the staff's text makes sense to me, because it talks about BWR VIP-100 and fracture toughness and reevaluating that fracture toughness for higher fluences.

The actual commitment as it reads says "Plant-specific inspection and rules we develop for Duane Arnold core shroud welds that are exposed to a neutron fluence equal or greater than a 1 times 10^{21} as needed."

So my question is are you still using the 5 times 10^{20} fluence threshold for inspection, and this really only applies to the fracture toughness evaluation, or have you changed the fluence threshold for inspection?

MR. PUTNAM: I'm going to have to defer over there to the --

MS. RUSHWORTH: This is Clara Rushworth for Duane Arnold again. And in our administrative document for the vessel internals and as we mentioned before, we will be doing the core shroud UT

inspections this coming outage. And as you said, the 1E to the 21st, that's for the VIP-100, and the flaw evaluation, should they occur, and for the reinspection role that is given in the VIP, that value is still 5 times 10^{20th} neutrons per centimeter squared.

MEMBER SHACK: Okay.

MS. RUSHWORTH: Does that answer your question?

MEMBER SHACK: That answers my question.

MR. PUTNAM: All right. Thermal cycle projections. If we are done with fluence here. Thermal cycle projections, we did update those for a 60 year life. We used where we were at at the time we performed our analysis in terms of actual events we had experienced to that point.

Then we projected forward to 60 years using the current rate that we are accumulating thermal cycles. For those events that are very infrequent where we would have been projecting zero, of course, we didn't project zero, we continued to project that those will occur and kept the same number for analysis purpose for those infrequent events.

And also for scrams, we had pretty good performance in the period we used for projection. And

we were worried that that might be too optimistic, so we added some cushion on there of about a little over 30 scrams to make sure that we didn't flirt with problems there at some point downstream.

And regardless of the number selected for projection, we will monitor those on an ongoing basis. And if we approach one of those assumptions, in terms of thermal cycles, we will take action before getting there, not after getting there.

MEMBER STETKAR: Ken, on the thermal cycle projections, I noticed that you have been monitoring actual plant transients since 1998.

MR. PUTNAM: Yes.

MEMBER STETKAR: So you have, let's say, real-time data since 1998.

MR. PUTNAM: Right.

MEMBER STETKAR: You went back and reconstructed the operating history prior to 1998. And I know that there was some discussions about cycles that were used in the power uprate analyses and, apparently, those have been reconciled for the license renewal process.

Do you have any -- I know the staff asked for it and I was curious whether you had any more detailed information that shows how your trip history

or your transient history has changed over time?

I mean, typically, you will see a reduction from early years and improved performance in later years. I'm curious where -- you typically find a knee in that performance. So I'm curious about where that knee is relative to the experience that you use to project out into the future.

MR. PUTNAM: We didn't bring along a histogram of scrams. You're really asking scrams --

MEMBER STETKAR: Yes, that's --

MR. PUTNAM: I think we do have one in the background of shutdowns there. Our data gets a little bit skewed because we had an extended outage in '78 and '79, so we got like a one year period there with extraordinarily good performance and we were never operating.

MEMBER STETKAR: Not many scrams, yes.

MR. PUTNAM: I don't think they thought it was good at the time. You know, so it gets a little bit flatter at the beginning of life than maybe --

MEMBER STETKAR: Than you would --

MR. PUTNAM: -- you would guess. But yes, I think in the first --

MEMBER STETKAR: I would be curious.

MR. PUTNAM: -- 10 years, we had a high --

MEMBER STETKAR: Oh, yes, I mean, that's typical performance.

MR. PUTNAM: Clearly, we had a high number of scrams. We had extremely good performance in the mid '80s out there.

MEMBER STETKAR: What particular period of time for your operating history did you use as the basis for your projection?

MR. PUTNAM: Yes.

MEMBER STETKAR: In other words, you know, the years that you used to calculate your average number of transients per year going forward.

MR. PUTNAM: I think that we used like '98 to 2005, something like that, you know, it was roughly seven or eight years --

MEMBER STETKAR: About seven years.

MR. PUTNAM: -- there in the --

MEMBER STETKAR: Perhaps, you know, you could put together or maybe the staff may have the histogram and I can get it from them. We typically don't get all of the RAIs.

MR. PUTNAM: If you want to pull up that histogram on shutdown, I don't think we put a histogram of scrams in there.

MEMBER SIEBER: Well, the interesting

thing about the curves of transients over the years is that there is a knee in the beginning. There is also a knee at the end, that's why they call it --

MEMBER STETKAR: Not in this one. There is not a knee here.

CHAIR BLEY: Bending over gradually.

MEMBER STETKAR: I'm used to seeing kind of an inverse of this, but --

MR. PUTNAM: Well, you know, in terms of scrams, you know, that's the one thing -- that's the main reason we added that.

MEMBER STETKAR: Your recent performance really --

MR. PUTNAM: We had a bad year in 2003.

MEMBER STETKAR: Yes, I see a bad year in 2003. But, you know, on kind of a straight-line averaging here, your recent performance is not tremendously better.

MR. PUTNAM: Well, you know --

MEMBER STETKAR: In terms of accumulated numbers.

MR. PUTNAM: -- I think you probably had twice as many in the first -- or we had 47 in the first 10 years and you have had roughly 60 since -- in the preceding 25 years. So I think there is --

MEMBER STETKAR: There is improvement. I mean, it's --

MR. PUTNAM: -- clearly improvement. And I'll tell you, I think was it '84 to '88, some time in there we had a string of 40 months without a scram. Which at those days was --

MEMBER STETKAR: That's unusual.

MR. PUTNAM: -- pretty remarkable.

MEMBER STETKAR: That's unusual.

MEMBER SIEBER: That's remarkable.

MR. PUTNAM: That's freakishly low. We had people coming up saying what are you doing out there?

MEMBER STETKAR: I was mostly --

MR. PUTNAM: Then we immediately in '88 had a spike again of scrams and that's where I learned the lesson that scrams aren't actually that predictable. You need to leave some cushion in there for the scram rates.

MEMBER STETKAR: Yes. And that's exactly why I asked the question to see whether there was a dramatic change in the operating history and this says not as dramatic as some plants have recognized. And to see the year-to-year variability in that transient experience. And there is some, but not a huge amount.

You said you used 1998 through 2005.

MR. PUTNAM: 2005, yes.

MEMBER STETKAR: So you saw a couple of spikes in there. Okay.

MR. PUTNAM: Yes.

MEMBER STETKAR: The other question I had in terms of projecting events, and this is in the experience-base there were a couple of events in, I think, 2006 where -- and I don't know the dynamics of the process. I'm only reading from the experience that apparently events occurred where you had an unusual cool-down in the bottom head and experienced an unusual cooling of the reactor coolant water, you know, bottom head draining line. I'm assuming that is what it was.

It is kind of interesting that you experienced two of those kind of events in six years, given your operating experience. You then go on to say that that particular piping, although it is, you know, an external piping from the vessel, has been qualified for more severe transients and many more cycles.

When you went back and reconstituted the operating experience from day one up through 1998, did you make any attempt at all to capture those types of

events that might have caused similar types of over-cooling down in the bottom head area?

MR. PUTNAM: Well, we definitely were looking for that sort of thing. We didn't find a whole lot of information there. And I guess, you know, I think we put in the application as we came across.

MEMBER ARMIJO: In your application you do point out that the vessel shell and lower head will have a cumulative usage factor, including environmental effects, of .996 at the end of year, which one comment is that's remarkably precise, .996.

MR. PUTNAM: Yes.

MEMBER ARMIJO: Which it's slightly lower than one. But so I'm not sure you believe that number to that --

MR. PUTNAM: Accuracy?

MEMBER ARMIJO: -- accuracy. But the question is were those unusual cooling events the main reason for that usage factor being so high? It's surprisingly high.

MR. PUTNAM: They have a big environmental penalty there. Those were actually ones with relatively low cumulative usage factors before you applied the environmental penalty, you know, so those,

I think, are unrefined calculations, because they had such a low number initially and then they had a high environmental penalty you put on there and that's how we got up there as high as we were.

MEMBER ARMIJO: Aren't these clad, stainless steel-clad on the vessel at the bottom head? And that's part of --

MR. PUTNAM: Clara is bending her head there. I don't think that will make it into the transcript, Clara.

MS. RUSHWORTH: Yes.

MEMBER ARMIJO: You have seen unusually high, because there were a couple of other locations, outlet nozzles and safe-ends for the same period of time, including environmental effects, the usage factors are like .19 or .2, but just the lower head seems like unusually high. I still don't understand what is going on there.

MR. PUTNAM: Well, Clara?

MS. RUSHWORTH: This is Clara Rushworth for Duane Arnold again. As Ken said, the lower head, those calculations were not refined. And the calculations you are looking at, I believe, are for the recirc outlet nozzle, feedwater nozzle and the coarse spray nozzle. We had those calculations

refined ASME Code, the six stressors calculations redone, finite element analysis by structural integrity and environmental factors applied and with those refinements, it shows much lower numbers.

MEMBER ARMIJO: So are you telling me that the .996 is just very, very conservative?

MS. RUSHWORTH: That's correct.

MEMBER ARMIJO: And if you had applied similar refinements, it would be less? You don't know how much, but it should be less.

MR. PUTNAM: Correct.

MS. RUSHWORTH: That would be correct. And we have not done, so, of course, we can't say for sure, but that's based on the 40 year usage factor, which was based on a lot of conservatisms and then that adjusted for the cycles for 60 years and then the environmental factors placed on.

So that was not using a finite element analysis.

MEMBER ARMIJO: Okay. Thank you.

MR. PUTNAM: Mike, can you get us back to the presentations here?

CHAIR BLEY: I'm going to interrupt you for just a minute. We are running a bit behind. You have a lot of slides left and we want to make sure we

get to your open item discussion at the end, so I'm going to ask you to go ahead. Staff doesn't need quite as much time as they have budgeted, so you can go over, but let's aim for a quarter after or 20 after, something like that. See if we can get there.

MR. PUTNAM: Okay. We have already talked about environmental fatigue adjustments. We made those adjustments and we were asked by the staff about new data on Alloy 600. We didn't reperform the calculations using that new rate for new plants, but we did check to see if the data in there, if we just plugged that in in a conservative way, would it move us above CUF < 1.0. And the conclusion was no, it wouldn't alter the conclusions if we used that.

Environmental qualification calculations are all updated to 60 year life without any real problems here.

Next slide, Mike. Ultimately, our whole point here, of course, is to get aging management programs that make sure we manage aging in the plant in the renewed term.

We tried to stay as close to the goal as practical. We ended up with 43 aging management programs. 19 of those are existing ones that just will keep doing. They don't need enhancements.

10 of the programs are existing, but they do need enhancements. Typically, those are places where we had to add more restrictive acceptance criteria or we need to apply the program to more pieces of equipment than we currently are.

And then we had 14 new programs, some of which aren't entire new. We may be doing individual maintenance tasks out in the field that are remarkably similar, but they weren't organized in a programmatic way, so we called those out as new programs.

In terms of GALL consistency, we ended up with 28 programs consistent. 11 that were consistent with exceptions and four that were plant-specific. A couple of those are ones that could become issues with ISGs that were consistent with and a couple are unique to us.

Next slide. We did a number of industry issues during our project. Station blackout boundary, for some plants that's kind of a hard one if their switchyards are a long way away from the plant. For us, it's easy. During that flood part of the show there, the switchyard is right next to our power plant, so that wasn't a problem for us to go out to the breakers in the switchyard.

Clara mentioned that we did any

refinements to calculations. We didn't use simplifying assumptions. We did full bore ASME calculations for those.

Generic Letter 2007-01 came along during our project where we were a lot more focused on the status of power cables underground. We thought we were in pretty good shape there, but we did find we needed to do some improvements to our sump pumps to make sure those were as reliable as we thought they should be and we also had to add some inspections for manholes without sump pumps to make sure even though they are at higher elevations and shouldn't be as likely to get water in them, we do need to inspect to make sure we keep those in good shape.

CONSULTANT BARTON: Do you have any experience of any cables that have failed as a result of being submerged or wetted?

MR. PUTNAM: No power cables. Mike, do you want to?

MR. FAIRCHILD: No, we have had some inaccessible cables, 125-volt dc control cables.

CONSULTANT BARTON: Okay.

MR. FAIRCHILD: That have failed, but we haven't pulled any of them out to do any recross testing on them other than one that we could see and

that was an installation error.

CONSULTANT BARTON: Okay.

MR. FAIRCHILD: The bend radius was too tight.

CONSULTANT BARTON: Okay.

MR. FAIRCHILD: But none of them have failed coincident with water.

CONSULTANT BARTON: Okay. Thank you.

MR. PUTNAM: Then Information Notice 2009-26 on degradation of neutron absorbers came out during our review and we had to adjust our program there to add a Boral Surveillance Program. We ended up with 50 commitments for license renewal, even though we are numbered up to 51, I notice you counted our number there. We have one of the commitments we ended up not using as it changed during the course of the review.

The commitments are entered into our site commitment tracking system, just like any other commitment. We are relatively close to the end of our period of extended -- or to our period of our license, so we are moving straight into implementation activities. We are not waiting on any of those. So our goal is to be ready well in advance of the period of extended operation.

We will retain a portion of our project

core team to support the implementation activities with the program owners on the site. And for some of the bigger commitments, we have set up specific projects for running those and making that step change for us to make sure those get the right oversight and management attention for those hard ones to get accomplished.

Any questions on that?

MEMBER STETKAR: Just one, sorry. Your operating experience says you have had a leak in your spent fuel pool since 1994. And you are confident that you are currently collecting all of that leakage. What are you doing to stop the leak? Do you know where it is coming from?

MR. PUTNAM: No.

MEMBER STETKAR: And what's the leakage rate?

MR. PUTNAM: The leakage rate is about 280 milliliters a day. And so about a little over a cup. We have looked for it. We have not found a source for that very, very small leakage.

CONSULTANT BARTON: Is it affecting any equipment in the sortability?

MR. PUTNAM: No, no. It goes into a case and then it goes to a series of drains that our

operators check every day. I think it's every day or is it every week? Frequently.

CONSULTANT BARTON: Are you trending it?

MEMBER STETKAR: Is there any indication that it is increasing?

MR. PUTNAM: No. It has been pretty stable for years and years.

CONSULTANT BARTON: Okay.

MR. PUTNAM: Unchanged.

MEMBER STETKAR: Okay. Thank you.

MR. PUTNAM: There are two open items. Buried piping and small bore piping. We will talk about those later. And there were no confirmatory items in the safety evaluation. Okay.

The first item here and it's not an open item, but it is an item that has been of some interest I know and a lot of interest to us, our torus coatings. Our IWE Program has identified numerous areas of zinc depletion on our torus coatings and minor pitting.

I think the staff's main concern with it is there is not really anything defined in the ASME Code for when do you got to go replace those coatings or restore those coatings. And so they were interested in how we were going to manage that.

Our torus was last coated in 1985. It is a zinc oxide coating with a belly band of phenolic at the water line. We do perform routine inspections, obviously, under the IWE Program and we touch up any areas of problems during the outage.

CONSULTANT BARTON: The original coating only lasts about 10 years?

MR. PUTNAM: Correct.

CONSULTANT BARTON: Wow.

MEMBER ARMIJO: And it was replaced with the same coating?

MR. PUTNAM: Yes.

MEMBER ARMIJO: Now, in the previous review, somebody stated this was a zinc metal coating in the phenolic. Is it zinc oxide or is it zinc metal?

MR. PUTNAM: Eric, do you want to answer?

MR. SORENSON: The actual coating is a -- this is Eric Sorenson for Duane Arnold. The actual coating is a carbo-zinc 11. It's a zinc oxide coating.

MEMBER ARMIJO: Zinc oxide. In a phenolic --

MR. PUTNAM: The phenolic is only at the belly band, right?

MR. SORENSON: Yes, but there is a 2 foot belly band that has a phenole-lined 386 WG. It's a phenolic coating.

MEMBER ARMIJO: So that's plus or minus a couple of feet?

MR. SORENSON: Right. That's plus or minus a foot.

MEMBER ARMIJO: Okay.

MEMBER SIEBER: And you have only found one pitting defect below mid-wall?

MR. PUTNAM: It was beyond 10 percent. It wasn't below mid-wall.

MEMBER SIEBER: Okay.

MEMBER SHACK: The SER --

MEMBER SIEBER: Just one out of a potential of thousands, right?

MR. PUTNAM: Yes, yes.

MEMBER SIEBER: Okay.

MEMBER SHACK: The SER says you are going to replace the coating according to ANSI N101.2, which is a 1972 standard that has been withdrawn so long ago I can't find a copy of it in any of the databases. I'm just wondering, I mean, I can understand why you don't want to redesign your piping, but, you know, why wouldn't you use a more modern standard for your

coating?

MEMBER SIEBER: You might have trouble finding the coating.

MR. PUTNAM: Eric?

MEMBER SHACK: Is that the staff putting words in your mouth here?

MR. SORENSON: This is Eric Sorenson again. No. We are not committed to Reg Guide 1.154 Rev 0. And when we responded to Generic Letter 98.04 regarding our debris accumulation and how we were treating our coatings, that was the standard that we were using at the time and we still use. That's what we were originally committed to.

MEMBER SHACK: Yes, I realize that it's your original commitment.

MR. SORENSON: However, I will acknowledge that we have -- our program does recognize the more current standards for the ASTM, so our program is built around more current ASTM Standards as sub-documents to 101.4.

MEMBER SHACK: Okay.

CONSULTANT BARTON: Do you do outage sludge removal every outage? Get much man-rem out of that?

MR. PUTNAM: Man-rem?

CONSULTANT BARTON: Yes. If you are pumping your EMRVs in there occasionally and going and cooling down those engine causants, you know.

MR. PUTNAM: Is this radioactive? I don't recall that being a real --

CONSULTANT BARTON: Okay.

MR. PUTNAM: -- big dose.

MR. SORENSON: I don't believe. We don't desludge necessarily for the man-, this is Eric Sorenson again, rem exposure. We desludge to remove the potential for the pit growth underneath the sludge. We do the sludge removal every other outage with divers with mechanical pumps underneath and with brushes that they can remove it with. Otherwise the other outage we use people from the catwalk with extended vacuums doing it. So it's a much less efficient desludge, but we do do a full desludge and wall scrub basically every other outage.

And since we have this past outage when we went in and we observed a significant change in the amount of degradation we have seen in the torus due to zinc, pure zinc depletion. So we have now changed our program to an every other outage with divers going into our torus, during every outage with divers, and doing repairs to the torus that we find until we get

to a point where we do the full recoat.

CONSULTANT BARTON: So this is --

MEMBER ARMIJO: It seems to me for all the money that is spent on divers, you could recoat the torus.

MR. PUTNAM: I don't believe that math works. I'm sure it's an extraordinarily large project to recoat the torus. That is a major, major commitment.

CONSULTANT BARTON: There was a plant that did it.

MR. SORENSON: I would say we did. At Duane Arnold we did recoat the torus in 1985 and our cost back then was, approximately, $6 million. And we expect that it is significantly, at least twice that much --

MR. PUTNAM: Yes, double.

MR. SORENSON: -- or more to do it at this point.

CONSULTANT BARTON: Okay.

MR. PUTNAM: And we are scheduling to do that in the 2012 outage currently.

Recent industry events on buried piping, unless there were other questions on torus?

Buried piping, the issue is that recent

industry events involving leakage from buried and underground piping may warrant changes to the buried piping tanks inspection program.

CONSULTANT BARTON: Do you have any tritium issues at the site?

MEMBER SIEBER: If you're doing that kind of work.

MR. PUTNAM: Certainly we produce tritium.

CONSULTANT BARTON: Do yo have any --

MR. PUTNAM: We have a tad tritium --

CONSULTANT BARTON: Have you found any?

MR. PUTNAM: We haven't had tritium above the threshold reporting. We haven't had any indication of tritium for pipe leaks at this point.

CONSULTANT BARTON: Okay.

CHAIR BLEY: How much buried pipe do you have?

MR. PUTNAM: Oh, a lot. Al?

MR. THOMAS: How much buried pipe do we have? This is Al Thomas for Duane Arnold. I don't know the exact number off the top of my head. The vast -- a good piece of it is from the intake structure to the pumphouse.

CONSULTANT BARTON: Sure.

MR. THOMAS: Which there is three 24 inch

diameter line and they are about 1,800 feet long.

MEMBER STETKAR: What kind of pipe is that? Is it carbon steel? Normal steel, normal carbon steel?

MR. THOMAS: It's A16, Grade B, 24 inch diameter stain or scheduled 312.

MEMBER STETKAR: Coated and lined?

MR. THOMAS: It's externally coated. It's not lined on the inside.

CHAIR BLEY: Go ahead.

MR. PUTNAM: All right. I guess before I move on too far here, we talked about underground piping and buried piping and I want to make sure there is no miscommunication on that.

Underground piping is piping that is exposed to air that happens to be below-grade typically involves chases of some sort.

Buried piping is in contact with soil. We do have a limited amount of underground piping at Duane Arnold. Not very much. And all of that is accessible. There is not stuff that is difficult to get at and look at, so where appropriate in license renewal process, that that piping would be typically managed by external surface monitoring, not the buried piping program.

But I'll focus most of my discussion here on the buried piping program. The industry certainly recognizes that this is an important issue. So far, I don't think there has really been so much safety significance to the events, but certainly things that matter to our stakeholders.

In response to that, there is an NEI Initiative where they issued guidelines in January of this year and we do support that and have actively participated with them.

In addition, EPRI has issued out guidelines, kind of more technical guidelines on how to control degradation of buried piping in the yard following that.

CONSULTANT BARTON: So it is direct buried, it's not in vaults, right?

MR. PUTNAM: That's correct.

CONSULTANT BARTON: Okay.

MR. PUTNAM: Yes, anything that is underground for us, not in contact with soil is a couple of vaults for cross-connecting pipes and some manholes for the sump pump discharge piping and some diesel fuel oil lines happen to run through an access manway, where you can climb down to the top of the tank. So it's very limited underground. Most of it

is buried.

Our fleet-issued guidance is -- our fleet is participating actively with the industry in this. And mid-course, our fleet elected to issue guidance documents, upgrade our program with respect to buried piping and then DAEC, out of that fleet guideline, developed implementing procedures on-site where we are really going above and beyond the minimum requirements that are in the GALL or that had historically been out there for how you manage buried piping. It mentions underground is accessible.

Next slide.

CHAIR BLEY: Before you leave that one, oh, no, you still have more buried pipe. Go ahead.

MR. PUTNAM: Got more buried piping, yes.

CHAIR BLEY: Okay.

MR. PUTNAM: We haven't had a history of any leaks on our in-scope buried piping. We have had leaks on our well water piping that is not in scope. Those seem to be kind of unique to their material and the physical location of those well water pipes, but, you know, definitely one lesson that we can take from that well water piping issue is that we are not immune to problems on buried piping. It can happen to us and it's something we do need to manage.

We have had a fair bit of maintenance work on fire protection piping in the last couple of years. We took the opportunity to examine that piping when it was excavated. We are happy to have found that piping in very good condition, so that was a good indicator.

We performed torsional guided wave exams on our HR service water piping, emergency service water piping and river water supply piping. Last year on roughly 20 locations that identified -- and by the way, I might comment here, that's really a screening tool. It's not an absolute answer, but it gives you-- helps you pick what place do you want to go look harder at.

And so out of that, we identified four areas we wanted to go look at harder. We will be excavating those this year or doing some sort of examination, detailed examination of that piping this year.

MR. COSTANZO: Yes, we have considerable understanding of what this issue is, both at the fleet level and at the site level. And actually, you know, both the detection, the mitigation and the long-term strategy has been budgeted, you know, at least through 2015, which we have just approved just recently. We

will commit those resources. We will commit the time and effort to make sure that we stay ahead of this one in prevention.

MEMBER SHACK: How long a run can you do with the torsional guided wave?

MR. PUTNAM: It depends, I think. Al, maybe you want to answer that?

MR. THOMAS: This is Al Thomas. Would you repeat the question again, please?

MEMBER SHACK: How long a run can you do with the guided wave? How far will it penetrate?

MR. THOMAS: Basically, with the guided wave, it will basically go through two elbows. Okay. It will go a long ways in straight pipe.

MEMBER SHACK: Pipe.

MR. THOMAS: But basically the second elbow is about the end of your exam.

MEMBER SHACK: Okay.

MEMBER SIEBER: If you have a leak, a small leak, in your buried piping, would you really know it?

MR. PUTNAM: I don't know. It depends, I think, is the answer. I think if you had a few drops a minute coming out of an ESW pipe, you would never know.

MEMBER SIEBER: Would never know.

MR. PUTNAM: You would never know.

CHAIR BLEY: Use the mike.

MR. PUTNAM: Whoops, I'm sorry. Yes, I don't think you would see a tiny leak like a few drops a minute. I'm sure you would see a few gallons a minute, because you would be coming up to the surface floor area.

MEMBER SIEBER: Yes. On the other hand, you really can't say for sure you have no leakage, right?

MR. PUTNAM: That's correct.

MEMBER SIEBER: You really can't tell.

MR. PUTNAM: Yes. Well, what we have done with the operating experience is looked back in time of anything that we have seen in our Corrective Action Program.

MEMBER SIEBER: Okay. Have you seen any buildup of material inside of, for example, cooling water piping? That refers to a lot of plants where organisms from the river or where they are getting it from gets inside lines that are ordinarily very low flow, which during emergency testing provide much more flow and tend to clog those lines? Have you seen any evidence of that? That you know of.

MR. PUTNAM: In these buried pipes? You know, those pipes -- now, the river water supply, those are normally operating. They are running at a flow rate comparable to emergency conditions normally. ESW and HR service water, those we do full flow tests on routinely on a quarterly basis, so we would, you know, see it. If there was a flow blockage, we would definitely see that.

MEMBER SIEBER: But your detection of blockage is by periodically measuring flow and the flow is at full force as opposed to any kind of inspection or other means to decide what is actually inside the piping? Is that correct?

MR. PUTNAM: I believe that is correct, unless somebody -- you know, there is a lot of preventive maintenance out there on some of those downstream components. But I think in terms of those buried pipes we're talking about, definitely I would say it's by flow.

MEMBER SIEBER: Some plants have found that to be a problem. Some plants that I have worked at have found it to be a problem. Thank you.

MR. PUTNAM: Okay.

MEMBER STETKAR: Ken, you mentioned earlier we discussed the instrument or the compressed

air systems. You replaced the piping from the air compressor building wherever the air receivers are. Was there evidence of corrosion in that piping?

MR. PUTNAM: No, not really. I would say that piping was in pretty good condition.

MEMBER STETKAR: Okay.

MR. PUTNAM: It was a little different. You know, it wasn't in-scope piping.

MEMBER STETKAR: No, that's --

MR. PUTNAM: It's a little different coating, so I didn't include it on this slide.

MEMBER STETKAR: Yes, yes.

MR. PUTNAM: So it's --

MEMBER STETKAR: That's why I asked you about it.

MR. PUTNAM: But it was in good condition.

MEMBER STETKAR: Okay. Thanks.

MR. PUTNAM: All right. And we have checked the diesel fuel oil tank using UT and found that in good condition, so that's another positive indicator for us. And we will do another check of that, I think, in 2012 as scheduled.

MEMBER SIEBER: Did you find a lot of water or sludge in the bottom of the tank?

MR. PUTNAM: No. No, we check for water,

you know, routinely under that fuel oil. The program, the whole objective is to keep that out of there. You know, the withdraws they are a little bit above the bottom. It's the only place you would be really very worried about.

MEMBER SIEBER: Yes.

MR. PUTNAM: We are doing additional torsional guided wave exams and we started those, I guess, at the end of May there. We started doing some additional pipes there next to the condensate storage tank. And as I said, the ones we identified in 2009 for follow-up will be inspected yet this year.

You know, in terms of resolving the open item, we did submit a response to the NRC's questions on May 28th and we will work with the staff on anything more that needs to be done there.

But fundamentally, you know, re recognize that buried piping is something we need to continue to move forward with the industry in doing the best job we can with that component.

Next topic. Socket welds. The issue really is --

CHAIR BLEY: Oh, on the buried pipe --

MR. PUTNAM: Yes.

CHAIR BLEY: -- have you now responded to

the RFI on that?

MR. PUTNAM: We did.

CHAIR BLEY: You think it should close? You don't know, but you have submitted?

MR. PUTNAM: We have submitted it. You know, clearly, it's our objective to do that. I don't know whether some of the details will mean more. The staff hasn't finished their review on it.

CHAIR BLEY: Okay. So we will hear from them in a minute. But on your part, you have done what you think you need to do?

MR. PUTNAM: We answered their question.

CHAIR BLEY: Okay. Go ahead.

MR. PUTNAM: Yes, socket welds. This is a little more straightforward topic. NUREG-1801 recommends a volumetric exam of small bore Class 1 piping using qualified techniques. And right now, there is no qualified volumetric exam to technique for socket welds.

Surface exams, obviously, don't detect flaws coming from the inside out. And the staff is interested in -- regardless of the qualification of the examination, they feel that there are exams that can be done that would provide meaningful information, even if those socket weld configurations preclude a

perfectly qualified exam.

Since we have submitted our application, there have been ongoing industry efforts to improve those examination technologies and those seem to be actually making a fair bit of progress there.

CHAIR BLEY: Let me ask you a question. As I read the things going back and forth on this, it wasn't completely clear to me. Is your position on this one about the no industry-accepted qualified exam a, it's the wrong word, but, legal objection or is it a technical one? Do you think there is no good volumetric exam you can use that will give you good information?

MR. PUTNAM: I think when we submitted, I would say I would have been biased towards -- I don't think there are good exams. If you looked at the published data back in that time frame --

CHAIR BLEY: Yes.

MR. PUTNAM: -- they were very questionable, in my opinion. As a matter of fact in one study, I saw they had about -- and I'll mess up the numbers here, but, when they looked at socket welds with known flaws, they had about a third of the flaws they found correctly.

CHAIR BLEY: Yes.

MR. PUTNAM: About a third of the flaws they didn't find. And a third of the flaws that they couldn't distinguish them from other things going on there, which for me I was kind of worried that might be -- you might get false positives out of that.

CHAIR BLEY: Sure.

MR. PUTNAM: So I would say in 2008, I wouldn't have been -- I would have been uncomfortable sending people into the field to perform it or we would have had to restrict what they looked at very harshly.

CHAIR BLEY: Okay.

MR. PUTNAM: I think since then, and I'm not a UT guy at all, but our NDE Level 3 tells me he is pretty optimistic about some of the things that they are doing lately and so he is real interested in it and he thinks he can do good exams at some point here in the future with the right planning and the right equipment for it. So that's kind of where he is at. You know, he hasn't done it yet.

CHAIR BLEY: Yes.

MR. PUTNAM: So --

CHAIR BLEY: I understand. Okay. Thanks. Go ahead.

MR. PUTNAM: All right. Next slide, Mike.

In terms of operating experience, we did have one pin hole leak in 1989 on a Class 1 pipe. The apparent cause for that was fatigue cracking due to vibration and some apparent problems with initial fit-up. That pike was, of course, replaced, refabricated and replaced slightly differently and we verified that the vibration problems weren't present after that and we haven't experienced any further problems in Class 1 small bore piping since, in terms of socket welds, then.

So at any rate, with the operating experience, I'm directing we have to have a plant-specific program. We do have that.

Next slide, Mike. We did submit a response to the NRC's open item. We are proposing that we will do a volumetric exam of 10 percent of the Class 1 socket welds. If a qualified technique is available, we will use that, of course.

If one is not available, we will develop a plant-specific procedure for performing it and we will, you know, restrict the procedure to match the technology that is available to us under that. So that's socket welds. Unless there is more questions on that?

Okay. Are there any questions?

CONSULTANT BARTON: I got a question. You could tailor that, the story of years ago. And I know it's for -- beyond design basis accidents. So it's not included in your Aging Management Program.

The question I have is do you at least have a preventive maintenance procedure? Can you at least do something with that system on some periodic basis?

MR. PUTNAM: Yes, some of the components are actually in-scope. They happen to fall into, you know, some of the other containment systems and so those components out to the ruptured disk are in-scope. You know, how that sits once you have the isolation valve and a ruptured disk that go at a certain -- at a pressure above P_a but below the dent you are intending to mitigate, below the design pressure of the containment.

And there are PMs on those ruptured disks.

CONSULTANT BARTON: Okay.

MEMBER RAY: You have a turbine-driven RCIC pump?

MR. PUTNAM: Yes.

MEMBER RAY: Does anybody know how often it is surveilled?

MR. PUTNAM: Quarterly full blown test.

MEMBER RAY: What's your experience with that?

MR. PUTNAM: Recent experience has been very good. You know, if you went back to the '80s not so good.

MEMBER RAY: That's all I have.

MR. PUTNAM: No, I think recently it has been very reliable. I think that system is agreeing.

CHAIR BLEY: Anything more from the Committee? John, do you want to follow-up with something?

CONSULTANT BARTON: You had this dollar weld indication. I think it's on your vessel head failed ASME acceptance standard, but you think it's okay? What do you know about that? What can you tell me about that?

MR. PUTNAM: Well, I'm going to pull up another person from the background here.

MS. RUSHWORTH: This is Clara Rushworth for Duane Arnold again. And we had identified on indication in the dollar weld some years ago. We did a flaw evaluation on it, submitted it to the staff for approval and I believe we have an SE for that. And I could look that information up if you would like.

CONSULTANT BARTON: Okay.

CHAIR BLEY: Anything more? I think, at this time, we will recess for 15 minutes until 10:30 and come back and then we will hear from the staff. Thank you.

(Whereupon, at 10:12 a.m. a recess until 10:29 a.m.)

CHAIR BLEY: Okay. The meeting will come back in session, please. And we will proceed with the staff. I don't know who is starting this. Brian?

MR. HOLIAN: This is Brian Holian. Introductions again, we have besides Benny Jose from Region III, I just wanted to highlight he has had seven years as an inspector in Region III, has industry time at a couple of plants in Region III and also some time in Sargent 1 before coming to the NRC.

Brian Harris has been the lead Project Manager. His first project coming through license renewal, so we're glad to have him present.

And also up there helping him just mainly with the slides is John Daly. John has been with the Kewanee Plant, which will come next month to ACRS. And with that, Brian Harris.

MR. HARRIS: Okay. Good morning. Go ahead, John.

CHAIR BLEY: Morning.

MR. HARRIS: My name is Brian Harris. I'm the Senior Project Manager for the Duane Arnold Energy Center License Renewal Application.

So you have heard from Brian Holian, our Director of the Division of License Renewal. Also we have joining me today Bo Pham, Branch Chief of the Reactor Project Branch 1, and Benny Jose, Region III Inspection Team Leader.

Also seated in the audience are members of the Technical Staff who participated in the review of the license renewal application or in audits that were conducted at the applicant's facility.

So I'll begin by providing an overview of the LRA and the staff's review. Then we will discuss Section 2 of the SER. And Mr. Benny Jose will discuss the license renewal inspections and findings. And then I'll discuss the staff's review of the Section 3 and 4 of the safety evaluation report.

CHAIR BLEY: Okay.

MR. HARRIS: The LRA was submitted by letter dated September 30, 2008 and supplemented by letter dated January 23, 2009. The unit is a GE Boiling Water Reactor with a Mark 1 containment.

An extended power uprate was granted in November of 2001. And the operating license

expiration is in year 2014.

The plant is located near Cedar Rapids, Iowa.

For the staff issues, the SER open items, on May 7, 2010, there are two open items: The first is Open Item 3.0.3.3.3 that's related to socket welds in the small bore piping program and Open Item 3.0.3.1.7 is related to buried piping and Tanks Inspection Program, which we will discuss later in this presentation.

There are no confirmatory items.

So the NRC Review Team has conducted two audits and one inspection at the Duane Arnold Energy Center cited during the periods listed on the slide. The staff started the on-site review with the aging management audit in mid-August followed by a scoping and screening methodology towards the end of August.

The Region III conducted its inspections in November to review the applicant's scoping and screening and aging management programs.

I'll now move on to Section 2 of the SER. Section 2 discusses structures and components subject to aging management review.

Within Section 2 we have scoping and screening methodology; plant-level scoping results;

scoping and screening, excuse me, mechanical system; structures; and electrical and instrumentation and controls.

Based on review of the LRA and additional information submitted as a result of requests for additional information, the staff concluded that the applicant's methodology is consistent with the requirements of 10 CFR.54.4(a) and 54.21(a)(1).

Benny Jose, the Region III Inspection Team leader will now discuss the results of his inspection.

MR. JOSE: Good morning again. I'm Benny Jose. I'm the team lead for the regional inspection of the 71002 inspection.

As Brian mentioned in the previous couple of slides that we completed our inspection during November of 2009 and the first part of the inspection we concentrated on scoping and screening.

And we focused on the systems that -- non-safety-related systems that affected the safety systems and also the four regulated events which are fire protection, station blackout, ATWS and SBO.

During our review, we focused on, you know, the system or the scoping boundary line, scoping and screening reports. We did walk-downs of the systems. And just to observe the general condition

for us to verify the scoping of all the components.

And during our review, we did identify a few items that were not actually scoped in. Some of it due to drying errors and some of it due to simple mistakes by omitting.

One of the examples were the river screen house, we did find two of the recent dampers which were not scoped-in and due to our questioning, they were scoped-in.

And as part of our inspection, the licensee did send a letter subsequent to our inspection, which is NG-09-0823 and Enclosure 2 to that letter actually lists all our findings in that. And in general scoping and screening was found to be acceptable.

And after the scoping and screening we moved down to the Aging Management Program. They had about a total of 43 Aging Management Programs and we reviewed about 30 of them, which is roughly 70 percent, which is normally our norm. We couldn't possibly look at all of them.

We chose those 30 Aging Management Programs based on their safety significance. They also had a 70/30 percent difference in new programs versus existing programs. About 70 percent of them

were existing programs. And we chose the majority of our 30 systems did include a good percentage of existing systems and a small representation of the new programs, because we found that looking at new programs, we can't really add much value, because they are all promises to be in accordance with GALL just before the end of the -- just before the period of operation.

CONSULTANT BARTON: Well, on the Aging Management Program inspection, the Inaccessible Medium Voltage Cable Program --

MR. JOSE: Yes, sir?

CONSULTANT BARTON: -- the applicant stated that it is a new program using existing inspection monitoring activities, consistent with GALL. And they have done all the testing. Why is it that this is an existing program versus a new program, if they have already been -- they say they have been doing this testing.

MR. JOSE: Well, they categorized that as a new program which uses existing monitoring techniques or which uses existing monitoring in terms of testing that is just MEGGER. I believe the type of cables that they have are without -- what do you call that, those cannot be. The only available test right

now is MEGGER test.

CONSULTANT BARTON: Right.

MR. JOSE: You know. They don't have that shield. You require a uniform shield for our unit from ground for doing standout and other things.

CONSULTANT BARTON: Right.

MR. JOSE: So they were doing some kind of monitoring, but they took it as if it's a new program. And hoping that will be a state of the art test just before the --

CONSULTANT BARTON: Before the license expires?

MR. JOSE: -- license expires. Plus, they will have a one time test before the license expires and 10 years thereafter.

CONSULTANT BARTON: Okay.

MR. JOSE: Yes, Cliff?

MR. DOUTT: Cliff Doutt. I have a question as well.

CHAIR BLEY: Please, speak into the mike.

MR. DOUTT: Oh.

CHAIR BLEY: Just point it right at you.

MR. DOUTT: Is that better?

CHAIR BLEY: And give your name.

MR. DOUTT: Sorry. Cliff Doutt, License

Renewal. We asked the same question in an RAI. Our concern was taking credit for a program that didn't implement the AMP already.

CONSULTANT BARTON: Yes, that was my problem.

MR. DOUTT: And so what they did is they corrected the basis documents to remove that statement. And they are not doing that. But in reality, part of the issue was they wanted a credit for current testing. And since we don't know what we are going to do just yet, we've got four years to go, then it's prior to, and we ask that question and it's discussed in the SER as well. I think it is Section 3.0.3.1.1.9. There is a small paragraph on that.

There was another LRA revision, but the basis documents are correct. So that's more background.

CONSULTANT BARTON: Thank you.

MR. DOUTT: Sure.

MR. JOSE: Again, for Aging Management Program reviews, we did the program documentation. we also performed walk-downs of the underground cable vaults and switchyard and we also did -- interviewed plant personnel.

Operating experience was another piece of

our review also just to make sure that they do account for internalized industry operating experience. For that, we did look at their Corrective Action Programs and their reports on their Corrective Action Program, as well as system health reports and the program results.

Again, the Aging Management Program inspection results. The licensee also did a specific letter after our inspection called NG 10-009, which is dated January 14, 2010. And Enclosure 1 to that letter details all our findings.

And I did list a few here just for the highlights here. Like the BWR vessel ID attachment and BWR internal program, the licensee agreed to do some clarification of the water chemistry. We did have questions as to how increased sampling is going to help or is used to verify effectiveness, things of those nature and licensee has clarified they did take corrective action to correct those.

And external surfaces monitoring, again procedure enhancements that will include surface conditions and document retention requirements, except for those things that were not spelled out in their program.

Structural monitoring was a bigger piece

here. And the bolting integrity took credit -- was credited by several programs which also included structural monitoring and this was not explicitly stated in their program or their program procedures. So licensee did agree to revise their plan procedures to include inspection of bolting integrity.

And water chemistry program, we had a question about how, because GALL has specific steps and therefore monitoring hydrogen peroxide which was not very explicit and the licensee did agree to clarify to include this electrochemical potential method that they are using.

Those were the highlights. Yes?

MEMBER ARMIJO: The hydrogen peroxide monitoring, I'm not really familiar with that. Could you explain what is going on there? Is this a chemical additive that is in their system or is --

MR. JOSE: You know, I believe the water chemistry, hydrogen peroxide comes in as a byproduct. And again, this electrochemical potential is used to measure the oxidizing power of oxygen and hydrogen peroxide.

MEMBER SHACK: It's a radiolysis product, Sam.

MR. JOSE: Right.

MEMBER SHACK: It's just that oxygen isn't the only thing that raises the electrochemical potential. Hydrogen peroxide does, too.

MEMBER ARMIJO: But that is produced in the core?

MEMBER SHACK: In the core.

MEMBER ARMIJO: Yes.

MEMBER SHACK: Okay. Okay.

MEMBER ARMIJO: And so they monitor or track peroxide as well as --

MEMBER SHACK: Well, since they are monitoring electrochemical potential, you know, whether the potential is coming from oxygen or from hydrogen peroxide, it doesn't --

MEMBER ARMIJO: They don't care?

MEMBER SHACK: They don't care.

MEMBER ARMIJO: Right.

MEMBER SHACK: What they really worry about is the potential. And, you know, if they were just monitoring the oxygen, you would worry.

MEMBER ARMIJO: Yes.

MEMBER SHACK: Because they might be getting a potential increase from the peroxide. But since they are monitoring the potential, they got the right thing.

MEMBER ARMIJO: Okay. Thank you.

MR. JOSE: And with that, we concluded that the scoping and screening as related to the Aging Management Programs were appropriate. And documentation, you know, was supporting. The application was auditable and retrievable and we found the documentation to be to an acceptable level.

And our report was documented in 2009-10, that was the report number. Any more questions for me?

CHAIR BLEY: Okay. You can go ahead.

CONSULTANT BARTON: Oh, I'm sorry.

CHAIR BLEY: Go ahead. No, go ahead, John, do you have one?

CONSULTANT BARTON: In your report you noted material condition items during walk-down of the plant and, apparently, you guys submitted or made sure work orders were written as a result of some of your observations on material conditions.

MR. JOSE: Yes.

CONSULTANT BARTON: Did the team get a chance to go and look at the plants' list of the open work items and look for material condition issues and how long they may be open?

MR. JOSE: Yes. When we do the work, I

mean, we did the walk-downs. We identified like corrosion, for example, some oil leaks here and there. And the first reflection from the plant personnel to us was to write a corrective work order.

CONSULTANT BARTON: Yes.

MR. JOSE: Okay. And we questioned that, the threshold of writing CRs or IRs, corrective action documents instead of work orders. And things that they could repair with their team or whatnot, you know, they would generally write a work order.

CONSULTANT BARTON: Right.

MR. JOSE: But during that process, we did look at their work history.

CONSULTANT BARTON: Okay.

MR. JOSE: And their, I think, SAP-based program and corrective action documents again, you know, for system-based. And system health reports was another avenue for looking at, you know, what their standard problems were.

CONSULTANT BARTON: Okay.

MR. JOSE: And the focus was to get them to start thinking in terms of license renewal, basically. You know, something like corrosion or pitting, it's not just to correct it immediately, but you should be looking for long-term.

CHAIR BLEY: Thank you.

MR. HARRIS: Okay. Moving on to Section 3 of the SER. Section 3 of the SER consists of the following subsections: Aging Management Programs; reactor vessel and internals; engineered safety features; auxiliary systems; steam and power conversion systems; containment, structures and component supports; and electrical and instrumentation and controls.

So I won't cover each section, subsection, but will touch on those which either have an open item or items of interest.

Section 3.0.3 contains the staff's review of the applicant's Aging Management Program or AMPs. 43 AMPs were reviewed by the staff. 14 are new programs. 29 are existing programs. 20 were identified as consistent with the GALL Report. 8 were consistent with enhancements. 9 consistent with exceptions. 2 consistent with both enhancements and exceptions. 4 were identified as plant-specific.

So during the staff's review, an open item was identified related to the management of small bore piping socket welds. During the review, the staff indicated to the applicant our concern that a visual inspection would be inadequate, as it would not detect

flaws initiating from the inside diameter.

So this concern stemmed from the staff's review of industry operating experience for failures in small weld piping socket welds and resulted in unplanned shutdowns.

So we understand the applicant's initial concerns regarding the lack of industry-endorsed methodology for volumetric inspections. However, we have also pointed to them several instances where other applicants have been able to demonstrate flaw detection using different plant specific techniques.

So the staff's position remains that periodic volumetric examination is needed for small bore socket welds in order to be consistent with the recommendations of the GALL.

So as covered earlier, the applicant has provided an RAI response subsequent for resolution. And the staff has performed a preliminary review of the response related to socket welds and will confirm this item for the final SER.

Okay. Moving on to the next open item here related to buried piping and the Tanks Inspection Program. There has been a number of recent entry events involving leakage from buried and underground piping where the causes have included coating damaged

during backfill of piping; failure of fiberglass piping; failure of buried piping in and around the piping penetrations and failures of piping in trenches.

The applicant's program is a new program, which is aimed at managing the aging effect of piping in the right contact with the soil. The program credits incorporation of industry experience later during the period of extended operation.

So the staff needed further information to evaluate the impact that these recent industry events might have on the buried piping program.

The staff issued an RAI in May to complete its review. And the applicant has recently provided an RAI response, supplement for this resolution. So we are performing a preliminary review of this information related to buried piping and will confirm this item for the final SER review.

So I'm including the next set of slides, because they are items of interest that have come up in other reviews and I think that we are highlighting here in our presentation today.

So the torus coating is an issue that was also recently covered in the Cooper License renewal review last month. Like Cooper, Duane Arnold has a

Mark 1 containment. And the staff reviewed the applicant's operating experience and identified concerns with more than the 15,000 coating repairs in the torus, suppression pool documented since 1995.

One pit measured .25 inches in diameter and .056 inches in depth or 10.5 percent of the nominal thickness there. All other applications -- excuse me, all other locations of pit depths were less than 10 percent of the nominal thickness.

MEMBER ARMIJO: What is the corrosion allowance for that material?

MR. HARRIS: Corrosion allowance? I'll have Abdul from the staff talk in more detail.

MR. SHEIKH: This is Abdul Sheikh, NRC staff. As far as I know, there is no corrosion allowance in this torus. But the way the applicant is managing this torus is they are following the ASME procedures and they are managing the program as in regard with the ASME, the IWE Guidelines and GALL.

MEMBER ARMIJO: Well, that's kind of strange. Maybe the applicant wants to clarify something for me. If there is no corrosion allowance, then there is some margin in the design, in the structural design of the torus that is effectively a corrosion allowance.

You know, clearly, there has got to be some margin against predictable things like corrosion. So I wonder if the applicant can clarify that?

UNIDENTIFIED SPEAKER: Very little.

MR. SORENSON: Eric Sorenson for Duane Arnold again. With regard to pitting, we do have evaluations performed that are structural in nature that since pit is a discrete defect, we can evaluate the wall thickness with that discrete defect and consider it acceptable. So we are talking about small pits in a very -- you know, a single pit in a large area not affecting the structural integrity of the torus.

MEMBER ARMIJO: But that addresses other questions, because it's a coated structure, you don't really have a general corrosion allowance, do you?

MR. SORENSON: We do not have a general corrosion allowance.

MEMBER SIEBER: All right.

MEMBER ARMIJO: The presumption is that the coating protects you. Okay. I understand it now. Thank you.

MEMBER BONACA: You refer to 15,000 coating repairs.

MEMBER ARMIJO: A lot of pits.

MEMBER BONACA: What is this? This simply recoating?

MR. SORENSON: Yes, those 15,000 -- this is Eric Sorenson again. Those 15,000 coating repairs range from mechanical corrections to areas where we just observe zinc depletion to areas that have had actual pitting observed in there. And this is over five exam periods. So we average -- I think it's probably more exam periods in that. I have to look exactly, but that's over a long period of time, 10 to 15, 15 or so years of inspection where we have observed that many repairs.

MEMBER BONACA: Okay.

CONSULTANT BARTON: Does that mean there is 15,000 pits or just 15,000 failures of the coating?

MR. SORENSON: 15,000 --

CONSULTANT BARTON: Some are repairs.

MR. SORENSON: Yes. There are not 15,000 pits.

CONSULTANT BARTON: That's a good thing.

UNIDENTIFIED SPEAKER: There's only 5,000 pits.

CHAIR BLEY: Go ahead. Let me ask one. You said some of those weren't just touching up the coating, you actually did mechanical repairs?

MR. SORENSON: No, no. This is Eric Sorenson again. Some of those repairs that we had to correct were mechanical things where somebody -- were mechanical damage and we had to correct.

CHAIR BLEY: Oh, okay. I understand. Okay.

MEMBER ARMIJO: But just to make sure I understand, you never actually ground out the pit or anything like that?

MR. SORENSON: No.

MEMBER ARMIJO: You just --

MEMBER SIEBER: Painted over it.

MEMBER ARMIJO: -- cleaned it up and painted over it?

MR. SORENSON: That is -- this is Eric Sorenson again. That is correct. The pit was not deeper than the qualified coating thickness of the coating that we were going to apply, so we could just coat over the pit.

MEMBER ARMIJO: Okay.

CHAIR BLEY: Okay. Brian, go ahead.

MR. HARRIS: Okay. Yes. So basically, from a cumulative effect, with respect to staff concerns, the pitting corrosion rates are typically much higher and less predictable than the general

corrosion rate.

So in resolution of this item of interest, the IWE inspection procedure was revised to inspect the torus coating during every outage until it is recoated.

And a commitment was written to recoat the torus underwater surface prior to start-up of the first refueling outage during PEO.

An item of interest within Section 3.5 is groundwater sampling. The applicant's groundwater is non-aggressive as shown on the slide. All the sampling markers meet acceptable limits. The staff was concerned about the ten-year frequency of groundwater sampling. And the applicant enhanced the structures monitoring program to include groundwater--sampling of groundwater on the five-year frequency instead of the original ten-year frequency.

Moving on to Section 4 of the SER. Section 4 contains the staff's review of the time-limited aging analysis or TLAA. TLAAs are certain plant-specific safety analysis that involve time-limited assumptions defined by the current operating term. It must be listed by section 54.21(c)(1). And any plant-specific TLAA based assumptions per 54.21(c)(2).

The staff reviewed information in the LRA to determine whether the applicant has provided sufficient information pursuant to 54.21(c)(1) and (c)(2).

In Section 4.2, the SER covers the reactor vessel neutron embrittlement analysis. There were three reviews performed to evaluate neutron embrittlement as documented in the SER. Those three were neutron fluence and adjusted reference temperature review, upper shelf energy review and pressure-temperature limits review.

The staff concluded that the reactor neutron embrittlement analysis meet the review criteria in the Standard Review Plan in accordance with the rules.

In Section 4.3 of the SER, the staff documents its review of the metal fatigue and piping and the components TLAA. The 60-year environmentally assisted fatigue analyses were performed for plant-specific locations identified in NUREG/CR-6260 for an older vintage BWR plant. The resulting environmentally assisted fatigue cups were all less than 1.0 for these locations.

The applicant manages fatigue of all NUREG-6260 locations using the metal fatigue or

reactor coolant pressure boundary program in accordance with 10 CFR 5421(c)(1)(iii).

So in conclusion, on the basis of its review, the staff determines that pending resolution of the open items discussed, the requirements of 10 CFR 5429(a) have been met for the license renewal of the Duane Arnold Energy Center.

Staff conclusions regarding the LRA for Duane Arnold will be provided in the final SER scheduled to be issued on October 2010.

CHAIR BLEY: Okay. Thank you. Any questions from the Committee?

MEMBER RAY: Can we go back to 16, please? I did listen to the whole discussion. I got stuck here and the discussion moved on. So there is an average of 1,000 -- clearly, I'm getting confused between coating problems and the pressure boundary effects.

I take it that a pit or pitting corrosion rates is something that affects the pressure boundary? Is that right?

MR. HARRIS: Abdul?

MR. SHEIKH: This is Abdul Sheikh, NRC staff. Let me just explain the issues. There are 15,000 total repairs. There is only one pit which is

bigger than 10 percent and that's just slightly bigger than that.

MEMBER RAY: 10 percent of what?

MR. SHEIKH: 10 percent of about .553 of an inch.

MEMBER RAY: Okay. Let's try it this way. Is it 10 percent of the pressure boundary or 10 percent of the coating?

MR. SHEIKH: 10 percent of the pressure boundary.

MEMBER RAY: Okay. Thank you. All right. So but we repair the coating, we don't repair the pressure boundary. Is that correct?

MR. SHEIKH: That is -- about this 15,000, most of them are touch-ups of the coating. There are -- I don't have the exact number where there has been some loss of material. There is only one pit where there is a loss of material that's more than 10 percent. And that was evaluated and found that the structural integrity of the torus is maintained.

MEMBER RAY: Okay. Well, that's information that isn't here, at least explicitly. Maybe it is implicitly here. But the information on this slide it's hard to puzzle out exactly what we are talking about. But it sounds like most of the time

you are talking about repairs to the coatings, that's what it says, coating repairs.

MR. SHEIKH: Right.

MEMBER RAY: And very occasionally, I guess, you find there has been degradation of the pressure boundary, but not enough to require repair of the pressure boundary.

MR. SHEIKH: That is correct.

MEMBER RAY: Okay. Well, that's not easily discerned from this slide, to be honest with you.

MR. SHEIKH: Okay.

UNIDENTIFIED SPEAKER: It's not my slide.

MR. SHEIKH: We can -- I mean, at this time, we can't correct it, but I --

MEMBER RAY: That's fine. But I'm just telling you I can't -- it's hard to figure out what you are talking about here.

MR. HOLIAN: This is Brian Holian. We will take that comment. We are kind of following up on last month's Cooper that had similar types of coating repairs and probably more severe pitting in that area. And Duane Arnold had had it coated once, Cooper had not. So really, we were just shining a little bit of a spotlight on their operating

experience.

It hasn't been a significant issue for the regions. The regions have been following it pretty well. You know, we have even gone back to some plans at Nine Mile Point that is already in license renewal that had coated, but now, as a matter of fact, I think they are coating this outage. So just following up on operating experience and making sure they were long-range plan is really the message.

MEMBER RAY: Well, that's fine, Brian. I appreciate the clarification. I just think distinguishing between fixing the coating and fixing the pressure boundary is what I'm trying to get straight here. And this has generic applicability as you say. So I'm trying to figure out what information are we being given. Thank you.

MR. HOLIAN: Okay.

MEMBER ARMIJO: Yes, well, I don't disagree with the staff conclusion about the consequences of pits on the structural integrity. I just was looking to how much margin that the torus really had. And just assume that you had lots of pits, even though that's not the case, and if they were 10 percent of the wall, would that be a significant problem?

And normally, in components like this, there is often a corrosion allowance and so that's throw away material. I just wondered if effectively you have a corrosion allowance through some other margin in the design? And my guess is you do, but I don't know what it is. Maybe somebody can tell me.

MEMBER RAY: Well, I just accepted the statement that it didn't affect structural integrity and is consistent with what you are saying.

MEMBER ARMIJO: Yes, I'm sure that is the way it will turn out. I'm just trying to get a number of seeing how much could we have lost and still have plenty of margin.

MR. SHEIKH: The staff hasn't calculated that, but what we have looked, we have taken is that they have only one small pit --

MEMBER ARMIJO: No, I understand one small pit won't cause a problem.

MR. SHEIKH: Right, right.

MEMBER ARMIJO: Or even a lot of small pits if they are spread out. But I'm just trying to see how much margin that torus had in the original design.

MR. SHEIKH: As far as I think, there is plenty of margin in the torus, because the normal

corrosion, general corrosion rate in industry is about 2 to 4 millimeter, 2 to 4 mils per year. I'm sorry. 2 to 4 mils per year.

MEMBER ARMIJO: Okay.

MR. SHEIKH: So we have, you know, plenty of margin there.

MEMBER BONACA: Just a question I had was are the defects uniformly distributed on the torus or are they look at it in certain specific areas?

MR. SHEIKH: I didn't get the question.

MEMBER BONACA: My question is if this 15,000 repairs are for defects that are uniformly distributed over the torus area?

MR. SHEIKH: They are all in the area underwater.

MEMBER BONACA: Yes, I understand that.

MR. SHEIKH: All of them. That's why they are coating the bottom half of the torus.

MEMBER BONACA: But what are they? Are they uniformly spaced?

MR. SHEIKH: Probably the applicant can tell.

MR. SORENSON: This is Eric Sorenson again. The pits and the defects, defined defects are at every bay in our torus all the way underneath the

water line where we had -- those are areas we typically would find general zinc depletion.

MEMBER BONACA: Okay.

MR. SORENSON: We do find heavier pittings and damage in the bottom, in the actual bottom 12 inches of the ark of the torus where we would have the heaviest sludge accumulation, so that would create that pocket that we would have higher corrosion rates in there.

MEMBER BONACA: Okay.

MR. SORENSON: But we do see it completely around the torus, up on the walls.

MEMBER BONACA: Yes.

MR. SORENSON: Is where we would see all the damage.

MEMBER BONACA: All right.

MEMBER RAY: But I'm sorry, I'm going to pick at words again. You're talking about corrosion. I don't know if that's the right word to apply to the coating damage that you are seeing.

MEMBER SIEBER: Deterioration.

MEMBER RAY: Is that the correct term?

MR. SORENSON: This is Eric Sorenson again. Corrosion is probably not the correct term in here, because this is a sacrificial zinc coating that

is supposed to sacrifice. And when it does, you will see surface rust and then immediately when we see, we would go in and correct it.

There is a lot of cases where there is no depth to that. It's just we have seen the coating deplete.

MEMBER RAY: Okay.

CHAIR BLEY: Anything more? It looks like you will be coming back to the Full Committee some time around October?

MR. HARRIS: Yes, that's correct.

CHAIR BLEY: Okay.

MEMBER ARMIJO: How many open items do you still have?

MR. SORENSON: We have two open items.

MEMBER ARMIJO: Two. Okay.

MR. HOLIAN: This is Brian Holian. Just a comment on those open items. I could have stated that earlier, but those are 12 or 13 applications that we have in-house now. Both of those are current issues that we are kind of upgrading to the new GALL, both of them.

We just had a public meeting on the GALL last week, the revised GALL coming out. Buried piping is obviously one that we are increasing the amount of

sampling. A little push-back from the staff, you know. Not the staff, I'm sorry, the industry on that. The industry is worried a little bit about, you know, the increased sampling that we might require and the GALL will also then possibly cause opportunistic, you know, degradations or backhoe damage to the piping.

But we are working towards a resolution as is stated here. They stated they know they need to increase their looks at what is unseen down there. So not only are we picking those two up on these plans, those two open items, but on all plants in- house kind of finalizing and improving those commitments in the commitment table.

MEMBER ARMIJO: Thanks.

CHAIR BLEY: Anything more? Well, I'm going to go around the table, but I think before I get the Committee Members, I'm going to ask our consultant, John Barton, to give us your comments, please. John?

CONSULTANT BARTON: Well, I believe the staff did a good job in their inspection report, pretty thorough. The only issues I see is the resolution to two open items. I'm sure that they can give these out fairly easily. And the fact that they have committed to finally recoat the torus, that's the

last issue I had. So I don't have any other issues that would preclude license renewal in my opinion.

CHAIR BLEY: Okay. Great. Thank you. And as we go around for the Committee, if you would also mention anything, if there is anything here you want to make sure we bring to the Full Committee, please, do so.

Jack, why don't we go this way. Jack?

MEMBER SIEBER: Yes, I think that the application was appropriate. And the staff's review and their RAIs and resolutions are appropriate. But we still have two open items, which I think should be or must be resolved. And it is up to the staff to resolve those in the appropriate fashion which we will then review.

I think this plant compared to others of this age is in pretty good condition. And so I really don't have any issues that jump out at me that would cause us to raise new issues with respect to this application.

CHAIR BLEY: Thanks, Jack. Sam?

MEMBER ARMIJO: Yes, I share Jack's view. I think the applicant was very good. I think the staff has done a really good review. I think that the plant has benefitted from a very technically

aggressive program to deal with IASCC and IGSCC. I think the plant has done a very good job being the lead plant in the industry to apply hydrogen water chemistry and noble metals.

I think that's one of the reasons why they have such good experience with their core internals and their piping. That being said, you still have to monitor and you still have to inspect.

But overall, I think the plant's presentation is very good. I would try in the Committee, Full Committee, meeting try and just make it easy for the Members who aren't here to understand that this pitting corrosion of the torus is really a very minor problem. And you don't get that from word charts.

CHAIR BLEY: Thanks. Harold?

MEMBER RAY: I would just echo what Sam said and add nothing more.

CHAIR BLEY: Thank you. John?

MEMBER STETKAR: I don't have anything more, other than to thank the staff for aggressive reviews of operating experience and gaining a lot of insight from that.

I think that that helped an awful lot in their inspections and identifying potential issues.

So I'm glad to see the staff is continuing to do that.

CHAIR BLEY: All right. Bill?

MEMBER SHACK: I am just glad to see the torus is going to get recoated with a good modern coating. The one thing that is new to me, and maybe it has been here before, was the use of the torsional guided waves to look at some very frightening -- I mean, we have been sort of relying totally on opportunistic inspections up until now, you know, and if it isn't a perfect tool, at least any tool that would help you to get some insight into degradation of buried piping seems like a helpful kind of development.

And I hope other people will apply it and sort of get along.

CHAIR BLEY: All right.

MR. HOLIAN: This is Brian Holian again. Just a comment on that. I don't know if Bill Holston was here. He is a Senior Engineer and spent 20 years at Calvert. I know he is in the back, but I'll just state it for him.

Several plants are, you know, using that now and I guess we haven't highlighted as much, but even the staff is going down to Charlotte in a couple of weeks here to look at the latest techniques in

that.

And I know some Region I staff has already gone there to look at what aspects, you know, we heard that it can get out to the second bend or second elbow. There is other indications sometimes that external supports have also caused false issues, but it is an area not only we are looking at license renewal, but obviously the Division of Component Integrity is looking at NEI's submittal on buried piping and how far we can credit that.

MEMBER STETKAR: Brian, you said other plants are actually implementing or have committed to implement this?

MR. HOLIAN: Yes. I don't know if they have committed in their applications yet.

MEMBER STETKAR: Because I was going to say, I haven't seen it.

MR. HOLIAN: Yes.

MEMBER STETKAR: I think Bill is right, this is the first one.

MR. HOLIAN: Yes, the committed -- the word I might have used is verbally to us at times, but we are looking at trying to get it in writing where they are using it for their process.

MEMBER STETKAR: Good.

CHAIR BLEY: Excellent. Mario?

MEMBER BONACA: No further comments.

CHAIR BLEY: Okay. And I would like to thank staff and the applicant very much for very good presentations and discussions.

And we will look forward to seeing you in October.

At this point, the Subcommittee meeting is -- well, I guess I should ask, are there any public comments before we close the meeting?

Then we will close the Subcommittee meeting. The Subcommittee is adjourned.

(Whereupon, the meeting was concluded at 11:12 a.m.)

Duane Arnold Energy Center

ACRS License Renewal Subcommittee Presentation

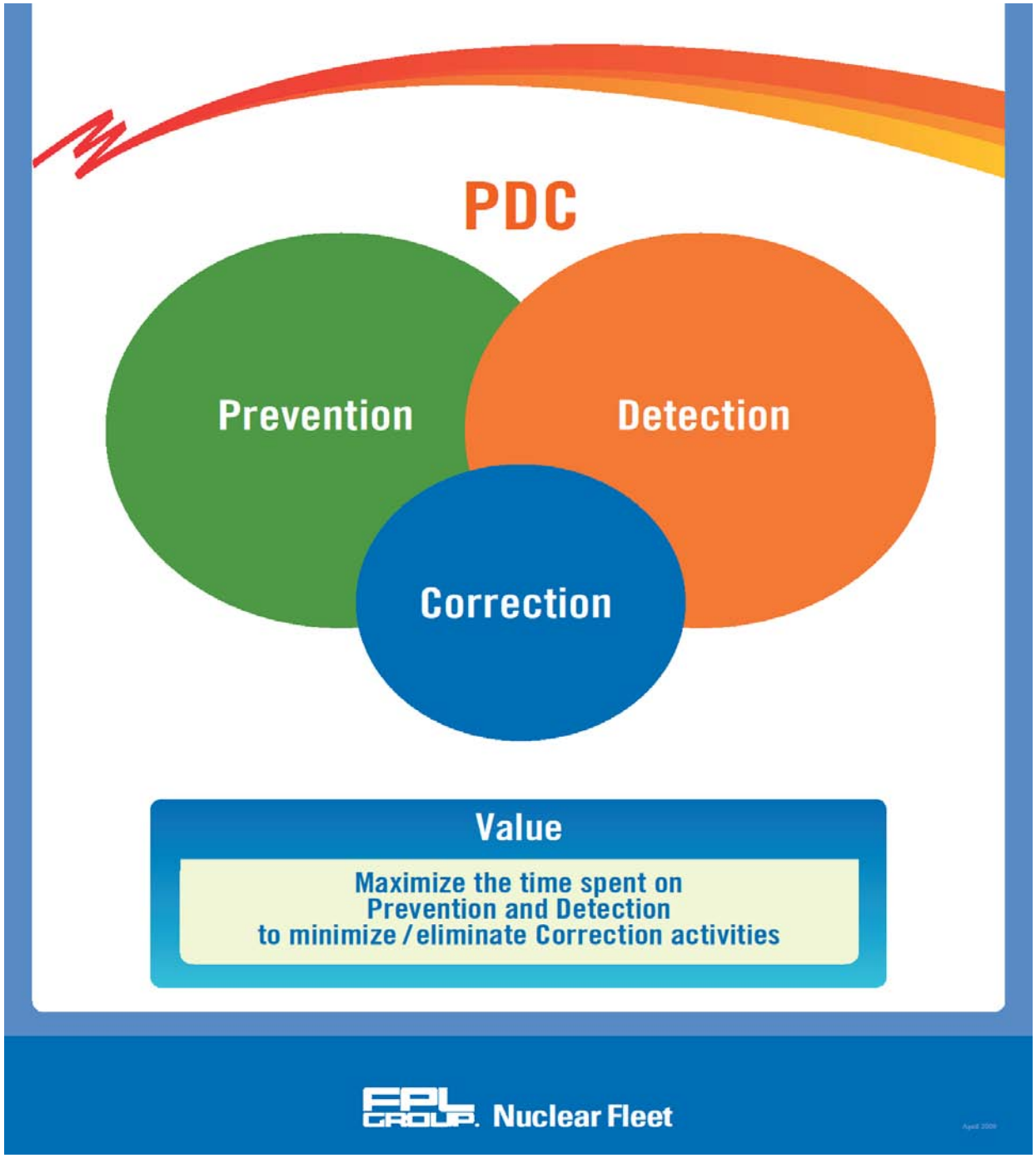
June 8, 2010

Personnel in Attendance

Christopher Costanzo	Site Vice President
Ken Kleinheinz	Engineering Director
Ken Putnam	License Renewal Project Manager
Curt Bock	License Renewal Mechanical Lead
Ken Chew	License Renewal Civil Lead
Mike Fairchild	License Renewal Electrical Lead
Clara Rushworth	License Renewal Licensing Lead
Herb Giorgio	Environmental Lead
Eric Sorenson	Program Engineering
Al Thomas	Program Engineering

Agenda

- **Background**
- **Operating History**
- **License Renewal Project Overview**
  - Scoping Discussion
  - Time Limited Aging Analysis
  - Application of GALL
  - Commitment Process
- **Technical Items of Interest**
  - Torus Coatings
  - Buried Piping
  - Small Bore Piping


PDC
Prevention
Detection
Correction
Value
Maximize the time spent on
Prevention and Detection
to minimize / eliminate Correction activities
FPL GROUP. Nuclear Fleet

Background – Site

- Approximately 6 miles NW of Cedar Rapids, Iowa
- General Electric (NSSS & Turbine Generator)
- Bechtel (AE and Constructor)
- BWR- Mark I Containment
- 1912 MWt Thermal Power; ~ 630 MWe
- Cedar River is ultimate heat sink and water makeup source. Forced draft cooling towers for condenser cooling
- Staff Complement: approximately 650

Background – Plant Status

- Startup from Refuel Outage 21 – March 2009
- Current Plant Status
- Next Refuel Outage – October 2010

Operating History – Licensing

Construction Permit	June 17, 1970
Operating License	February 22, 1974
Commercial Operation	February 1, 1975
Uprated Power License (5%)	March 27, 1985
Extended Power Uprate License (15%)	November 6, 2001
Operating License Transfer to FPL (NextEra)	January 27, 2006
LR Application Submitted	September 30, 2008
Operating License Expires	February 21, 2014

Major Improvements

1987	Hydrogen Water Chemistry and Crack Arrest Verification System
	Electrochemical Potential Monitor
1996	Noble Metals Applied
1998	ECCS Suction Strainers Replaced
2001	High Pressure Turbine Upgrade
	Moisture Separator Reheaters Upgrade
	Replaced 2 Circulating Water Pumps
2003	Replaced Drywell Coolers

Major Improvements (continued)

2005	Replaced Feedwater Heaters
	Replaced Condensate Pumps
	Installed Condenser Isolation Valves
2007	Heater Bay Cable Replacement
2009	“B” Diesel Generator Governor Upgrade
	“A” & “B” Diesel Generator Voltage Regulator Upgrade
	Main Transformer Replacement
	Recirculation MG Set Scoop Tube Positioner Upgrade
	Feedwater Flow Correction System Replacement

License Renewal Project Overview

- Site Ownership and Oversight
- Experienced Team (DAEC, Corporate, Contract)
- Benchmarking
- QA Audits
- Participation in industry working groups
- Industry Peer Review

Project Overview – Scoping

- Scoping process consistent with requirements of 10CFR 54 and the guidance of NEI 95-10
- Categorized entire plant in terms of major SSCs
- Identified system level functions
- Evaluated all SSCs against Scoping Criteria 10CFR54.4 (a)(1), (a)(2) and (a)(3)
- Identified SSCs that perform or support an intended function

Project Overview – Scoping

- **Utilized site component database, controlled drawings, design and licensing documents**
- **Non-Safety Affecting Safety (a)(2)**
  - Reviewed safety related equipment locations
  - Conservative “spaces” approach
  - Performed walk-downs for verification
- **Use of commodity groups used when evaluations were best performed by component type rather than SSC**

Project Overview – TLAA

- **Design and Licensing Basis reviewed for potential Time Limited Aging Analysis**
- **Neutron fluence was determined for DAEC operation out to 54 EFPY using RAMA methodology.**
  - Extended operation to 60 years will be bounded by 54 EFPY.
  - Fluence determined for vessel and internals.
  - Pressure/Temperature Curves created for 54 EFPY.
- **Thermal Cycle projections updated for 60 year life**
  - Used to evaluate fatigue for 60 year life.

Project Overview – TLAA

- **Environmental Fatigue evaluated for locations identified in NUREG/CR-6260 using NUREG/CR-6583 and 5704**
  - All locations confirmed CUF < 1.0
  - NUREG/CR-6909 for new plants has updated data for Nickel Alloys
  - NUREG/CR-6909 can result in higher environmental fatigue factor but it would not alter the conclusion that CUF < 1.0
- **Environmental Qualification calculations updated to 60 year life**

Project Overview – Application of GALL Programs

- **43 Aging Management Programs**
  - 19 Programs in place with out Enhancements
  - 10 Programs will be Enhanced
  - 14 New Programs
- **GALL Consistency**
  - 28 Consistent
  - 11 Consistent with Exceptions
  - 4 Plant Specific
    - Electrical Connections Program
    - Electrical Penetration Assembly Program
    - ASME Code Class 1 Small-bore Piping Inspection Program
    - Boral Surveillance Program

Project Overview – Industry Issues

- **Industry Issues During DAEC Project**
  - Station Black Out boundary – DAEC has included switchyard breakers, control circuits and associated structures within scope
  - Methods for fatigue evaluation – DAEC eliminated use of simplifying methods (Green's Function) in fatigue calculations
  - NRC GL 2007-01 – Inaccessible or Underground Power Cables
    - Sump pumps upgraded in three manholes
    - New inspections for man-holes without sump pumps
  - IN 2009-26 Degradation of Neutron Absorbing Materials in Spent Fuel Pool – DAEC Added Boral Surveillance Program

Project Overview – Commitment Process

- 50 Regulatory Commitments for License Renewal
- Commitments entered into site commitment tracking system
- Implementation activities underway to ensure completion well in advance of PEO
- Retain portion of project core team to support implementation activities with program owners
- Specific projects for larger items

Project Overview – Open Items

Draft SER Summary

- **Open Items – 2**
  - Buried Piping
  - Small Bore Piping
- **Confirmatory Items – None**

Technical Items – Torus Coatings

- **Issue**
  - IWE Program has identified numerous areas of zinc depletion on torus coatings and minor pitting
  - ASME Code does not specify when coatings must be replaced
- **DAEC Operating Experience**
  - Torus was last recoated in 1985
  - Zinc Oxide Coating with Phenolic Coating band at the waterline
  - Routine Inspections with touch up coating repairs
  - Sludge deposits minimized during feed and bleed of torus using torus cooling and by outage sludge removal
- **Resolution**
  - Recoat of underwater surfaces planned for 2012 Refuel Outage

Technical Items – Buried Piping

- **Issue**
  - Recent industry events involving leakage from buried and underground piping may warrant changes to the Buried Piping and Tanks Inspection Program
- **Background**
  - In response to industry events, the Nuclear Energy Institute issued an initiative on buried piping titled “Guideline for the Management of Buried Piping Integrity, NEI 09-14, in January, 2010.
  - The Electric Power Research Institute issued buried component guidelines per EPRI 1016456, “Recommendations for an Effective Program to Control the Degradation of Buried Piping” in December, 2008.

Technical Items – Buried Piping

- **DAEC Status**
  - NextEra Energy issued fleet guidance documents related to buried piping
  - DAEC developed the DAEC implementing procedures in accordance with fleet guidance document. This document lists all buried piping at DAEC and performs a risk ranking to prioritize piping sections for inspection based on likelihood and consequence of failure.
  - Underground piping is accessible and where applicable is managed by External Surfaces Monitoring Program

Technical Items – Buried Piping

- **DAEC Operating Experience**
  - No history of leaks on in-scope piping.
  - Buried piping leaks have occurred in well water piping sections constructed of gray cast iron.
  - Opportunistic examinations of fire protection piping found the piping in good condition.
  - Torsional Guided Wave exams have been performed on portions of the RHR Service Water, Emergency Service Water, and River Water Supply systems.
  - UT examination of buried Diesel Fuel Oil Storage tank in 2001 found tank in good condition

Technical Items – Buried Piping

- **2010 Planned Examinations**
  - Torsional Guided Wave examinations of HPCI CST suction piping, Core Spray CST suction piping, Condensate system makeup and reject, and Demineralized Water pump suction and transfer piping are scheduled for 2010.
  - Excavations to allow UT examinations of RHR Service Water and River Water Supply piping are also scheduled for 2010.
- **Proposed Resolution**
  - DAEC Buried Piping and Tanks Inspection Program has been updated to reflect recent industry operating experience.

Technical Items – Socket Welds

- **Issue**
  - NUREG-1801 Recommends a volumetric examination of Small Bore Class 1 Piping using qualified techniques
  - No industry accepted qualified volumetric exam technique for socket welds exists
  - Surface examinations do not detect flaws originating on the interior surface until component fails
  - NRC staff indicates volumetric examinations can provide meaningful information about many flaws even if the configuration precludes full qualification
  - On going industry efforts appear to be improving potential examination technology

Technical Items – Socket Welds

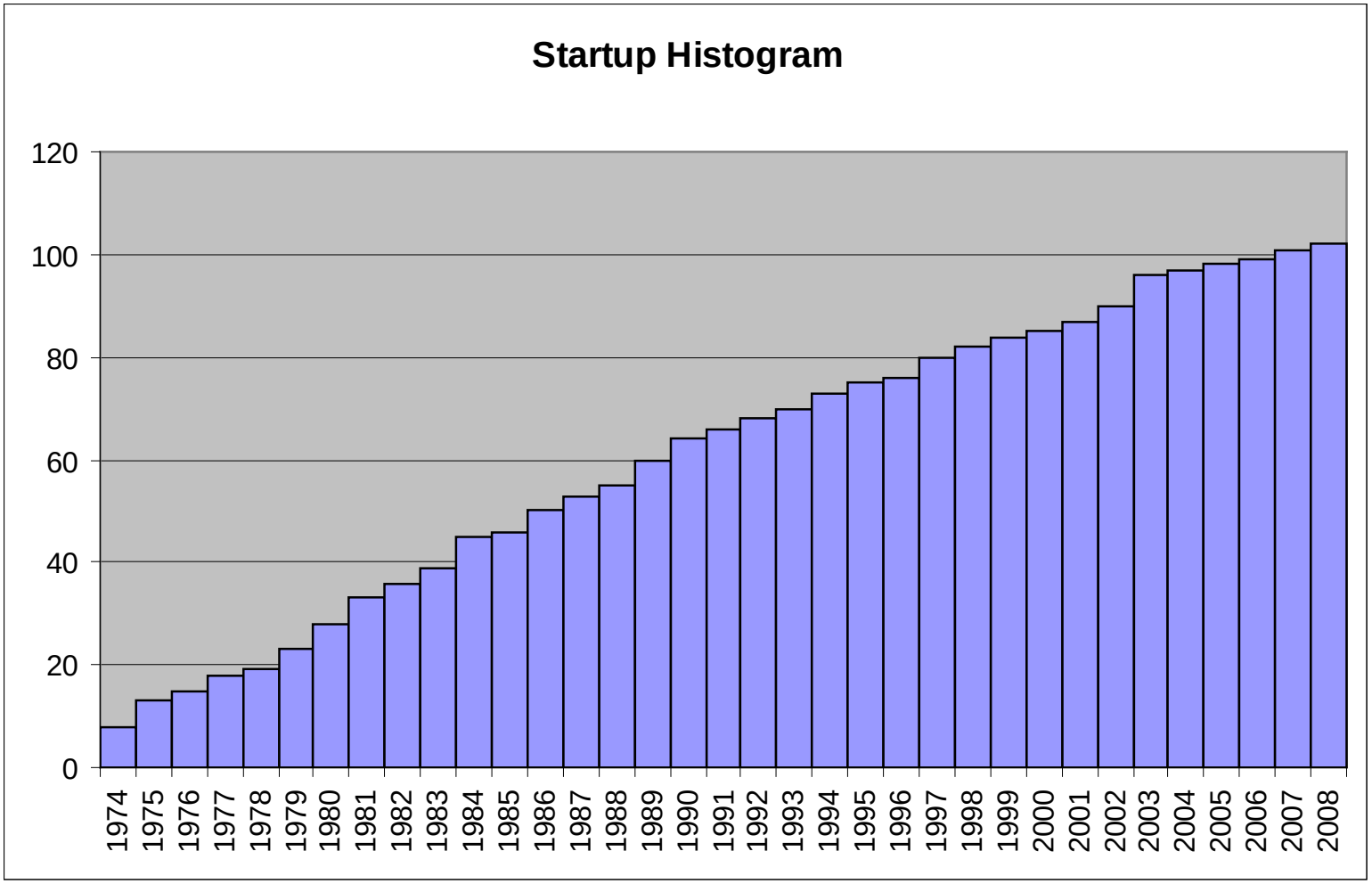
- **DAEC Operating Experience**
  - Pin Hole Leak in Recirculation Pump Drain Line Socket Weld in 1989 (Small Bore Class 1)
  - Apparent Cause – Fatigue Cracking due to vibration and initial fit up
  - NUREG-1801 Requires a plant specific program for Class 1 Small Bore Piping if plant has experienced cracking
  - No additional Class 1 socket weld issues since 1989

Technical Items – Socket Welds

- **Proposed Resolution**
  - Perform periodic volumetric exams of 10 percent of Class 1 socket welds using industry qualified exam technique if it is available at time of exam
  - If no industry qualified examination technique is available at time of inspections a plant procedure for volumetric examination will be used

Questions?

Histogram for Cumulative Plant Startups



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Protecting People and the Environment

Advisory Committee on Reactor Safeguards License Renewal Subcommittee

Duane Arnold Energy Center

Safety Evaluation Report with Open Items

June 8, 2010

Brian K. Harris, Project Manager

Office of Nuclear Reactor Regulation

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Introduction

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

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Overview

- LRA Submitted by letter dated Sept 30, 2008
- GE Boiling Water Reactor (BWR), Mark I containment
- Nov. 6, 2001 - Extended Power Uprate (EPU) was granted to DAEC to operate at 1912 MWth, 629 MWe
- Operating license for NPR-49 expires February 21, 2014
- Located approximately 8 miles NW of Cedar Rapids, IA

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Overview

- Safety Evaluation Report with Open Items was issued May 2010

- 2 Open Items

  OI-3.0.3.3.3 Socket Welds

  OI-3.0.3.1.7 Buried Piping

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Overview

- Aging Management Programs (AMP) Audit
  - August 10 - 14, 2009
- Scoping and Screening Methodology Audit
  - August 24 - 28, 2009
- Regional License Renewal Inspections
  - November 2 – 6, 2009
  - November 16 – 20, 2009

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Section 2: Structures and Components Subject to Aging Management Review

Section 2.1 - Scoping and Screening Methodology

Section 2.2 - Plant-Level Scoping Results

Section 2.3 - Scoping and Screening Results: Mechanical System

Section 2.4 - Scoping and Screening Results: Structures

Section 2.5 - Scoping and Screening Results: EI&C System

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

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License Renewal Inspections

Benny Jose

Region III Inspection Team Leader

71002 Inspection Scope

- 54.4(a)(2) Scoping & Screening Non-Safety SSCs
  - Non-Safety Affecting Safety was Acceptable
- Reviewed 30 of 43 AMPs
  - Program Documents & Procedures
  - Walkdowns of Plant Areas including Cable Vaults and Switchyard.
  - Interviewed Plant Personnel
- Operating Experience Review
  - System Health Reports and Program Results
  - Corrective Action Reports for Prior SSC Problems, associated with the 30 AMPs reviewed

71002 Inspection Results

- **Aging Management Program (AMP) Changes**
  - Buried Piping and Tanks Inspection Program (procedure revisions for opportunistic inspection of excavated pipes)
  - BWR Vessel ID Attachment Welds Program (Water Chemistry clarifications)
  - BWR Vessel Internals Program (Water Chemistry clarifications)
  - External Surfaces Monitoring (procedure enhancements include surface conditions, document retention etc.)

Aging Management Program (AMP) Changes contd.

- Structural Monitoring Program (procedure revisions to include acceptance criteria, inspection of bolting materials and fasteners)
- Water Chemistry Program (LRA revision to clarify monitoring of H_2O_2)

Inspection Summary

- Inspection results support a conclusion there is reasonable assurance that the effects of aging will be adequately managed
- Scoping of non-safety systems was acceptable
- Documentation supporting the application was auditable & retrievable
- Report 05000331/2009010

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Section 3: Aging Management Review Results

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

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Section 3: Aging Management Review Results

- Section 3.0.3 - 43 AMPs evaluated in the SER, consistent with GALL Report

	Plant Specific	Consistent with GALL	With Exception	With Enhancement	With exception & enhancement
Existing 29	0	14	5	8	2
New 14	4	6	4	0	0

Section 3.0.3.3.3 Small Bore Piping

OI-3.0.3.3.3

- DAEC proposed to use visual (VT-2) examination for socket welds
- GALL AMP XI.M.35 recommends volumetric examination
- Given previous operating experience of socket weld failures, GALL recommends that periodic volumetric examination is necessary for managing cracking in socket welds
- In recently docketed responses, DAEC committed to perform periodic volumetric inspections

Section 3.0.3.1.7 Buried Piping and Tanks Inspection Program

OI-3.0.3.1.7:

- Given recent industry OE related to leaks from buried and underground piping, staff is interested in efforts to incorporate OE into AMPs at DAEC
- Staff issued an RAI on May 2, 2010, regarding buried and underground piping at DAEC
- Recently docketed responses will be evaluated for acceptability in final SER

Torus Coating

- Staff Concern
  - Over 15000 coating repairs (5% of the underwater torus area) performed since 1995
  - One pit 0.25 inch diameter and 0.056 inch depth (10.5% of nominal thickness). All others less than 10%.
  - Pitting corrosion rates are typically much higher and less predictable than general corrosion rate
- Resolution
  - IWE inspection procedure revised to inspect the torus coating during every outage until it is recoated
  - Commitment to recoat the torus underwater surface prior to startup of first refueling outage during PEO

Section 3: Aging Management Review Results

Item of Interest: Section 3.5

- Groundwater sampling for pH, chloride, and sulfate concentrations will be performed on a 5-year periodicity.
- DAEC Groundwater is non-aggressive

Groundwater Monitoring Results from September 2007							
Sample Description		Shallow Wells					
	Acceptance Criteria	D111	D112	D113	D114	D115	D116
pH	**>5.5**	6.60	6.87	7.06	6.87	7.20	6.79
Chloride (ppm)	**<500 ppm**	77	62	124	48	14	110
Sulfate (ppm)	**<1500 ppm**	349	470	112	270	14	92

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Section 4: Time-Limited Aging Analysis

- 4.1 Introduction
- 4.2 Reactor Vessel Neutron Embrittlement of the Reactor Pressure Vessel and Internals
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Concrete Containment Prestress
- 4.6 Fatigue of Primary Containment, Piping, and Components
- 4.7 Other Plant-Specific TLAA

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Section 4: Time-Limited Aging Analysis

- **Section 4.2 - Reactor Vessel Neutron Embrittlement Analysis**

Reactor Vessel Limiting Material	Fluence at 54 EFPY	Predicted USE Decrease (RG 1.99, Rev.2)	EOL USE Acceptance Criteria—Maximum Drop in USE value allowed per the BWRVIP-74-A
Vessel Shell Ring #2, 1-20 Heat # B0436-2	5.74 X 10^{18} n/cm^2 E > 1 MeV	21%	23.5% Equivalent Margin Analysis (EMA) Performed per BWRVIP-74-A

Section 4: Time-Limited Aging Analysis

- **Section 4.3 – Metal Fatigue of Piping and Components**
  - NUREG-6260 locations
    - Eight plant-specific locations for DAEC
    - Environmentally adjusted CUF < 1.0 for all locations
    - Dispositioned in accordance with 10 CFR 54.21(c)(1)(iii)
      - Continued monitoring with “The Metal Fatigue of Reactor Coolant Pressure Boundary Program” for all NUREG-6260 locations during the period of extended operation

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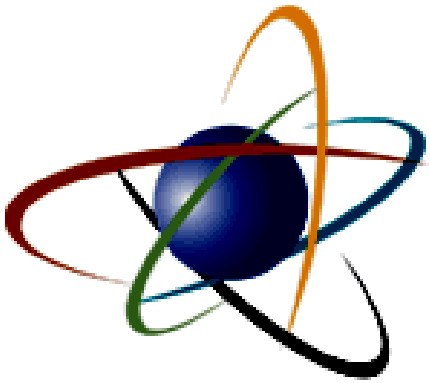
Conclusion

- On the basis of its review, the staff determines that, pending resolution of the open items, the requirements of 10 CFR 54.29(a) have been met for the license renewal of Duane Arnold Energy Center

- The staff's conclusion regarding the LRA for DAEC will be provided in the Final SER scheduled to be issued in October, 2010



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