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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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PLANT LICENSE RENEWAL SUBCOMMITTEE

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WEDNESDAY

FEBRUARY 5, 2020

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B10, 11545 Rockville Pike, at 8:30 a.m., Matthew W. Sunseri, Chair, presiding.

COMMITTEE MEMBERS:

MATTHEW W. SUNSERI, Chair

RONALD G. BALLINGER, Member

CHARLES H. BROWN, JR., Member

WALTER L. KIRCHNER, Member

PETER RICCARDELLA, Member

ACRS CONSULTANT:
STEPHEN SCHULTZ

DESIGNATED FEDERAL OFFICIAL:
KENT HOWARD

ALSO PRESENT:
PAUL AITKEN, Dominion
BRIAN ALLIK, NRR
ERIC BLOCHER, Dominion
LAWRENCE BURKHART, ACRS TSB
BOB CALDWELL, NRR
JOSEPH COLACCINO, NRR
DAVID DIJAMCO, NRR
JOHN DISOSWAY, Dominion
STEVEN DOWNEY, NRR
JAMES GAVULA, NRR
LAUREN GIBSON, NRR
DARRYL GODWIN, Dominion
ALLEN HARROW, Dominion
CRAIG HEAH, Dominion
ALLEN HISER, NRR*
GREG IMBROGNO, Dominion
JAMES JOHNSON, Dominion
JUAN LOPEZ, NRR

TANIA MARTINEZ NAVEDO, NRR
LOUIS McKOWN, NRR
KEITH MILLER, Dominion
FRED MLADEN, Dominion
SCOTT MOORE, Executive Director, ACRS
ERIC OESTERLE, NRR
SHIE-JENG X. PENG, NRR
PAUL PHELPS, Dominion
RICH PHILPOT, Dominion
BRET RICKERT, Dominion
TROY SCARBOROUGH, Dominion
CHUCK TOMES, Dominion
DAVID WILSON, Dominion
ANGELA WU, NRR

*Present via telephone

C-O-N-T-E-N-T-S

P R O C E E D I N G S

8:28 a.m.

CHAIR SUNSERI: Good morning. The meeting will now come to order. This is a meeting of the Plant License Renewal Subcommittee. I am Matthew Sunseri, Chairman of the Subcommittee.

ACRS members in attendance are Ron Ballinger, Walt Kirchner, Pete Riccardella. Charles Brown will be joining us in about an hour. And Steven Schultz, our consultant, is here for this meeting. I note that we have a quorum. Kent Howard of the ACRS staff is the designated federal official for this meeting.

The purpose of this Subcommittee meeting is for Virginia Electric Power Company, we will refer to them as either Dominion or the applicant, and the NRC staff to brief the Subcommittee on the subsequent license renewal application for the Surry Power Station's Units 1 and 2.

This is the third subsequent license renewal application to be reviewed by the Subcommittee. The Subcommittee will gather information, analyze relevant issues and facts, and formulate a proposed position and actions as appropriate for deliberation by the full Committee.

The ACRS was established by statute, and is governed by the Federal Advisory Committee Act. That means that the Committee can only speak through its published letter reports. We hold meetings to gather information to support our deliberations.

The ACRS reviews and advises the Commission with regard to the licensing, operation of production and utilization facilities, and related safety issues, the adequacy of proposed safety standards, technical and policy issues related to the licensing of evolutionary and passive plant designs, and other matters referred to it by the Commission.

The ACRS section of the USNRC public website provides out charter, by-laws, letter reports, and full. transcripts of all full and Subcommittee meetings, including the slides presented at the meetings.

The rules for participation in today's meeting were announced in the Federal Register. We have not received any written comments, or a request for time to make oral statements from members of the public regarding today's meeting.

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

Participants should first identify themselves, and speak with sufficient clarity and volume so they may be readily heard. A telephone bridge line has been opened for members of the public to listen in on the presentations and deliberations by the Subcommittee.

We have set aside time at the end of the meeting for the agenda to offer members of the public the opportunity to provide comments. We also have a separate bridge line for NRC staff that will not be muted, and allow them to participate in the meeting.

To preclude interruptions of the meeting please mute your individual lines during the presentations and Committee discussions. At this time I request everyone silence their cell phones.

We will now proceed with the meeting. And I call upon Bob Caldwell to make introductory remarks. But before I do that, is it Bob? Bob's going to do that? Okay.

I just want to note here that a little before 11 o'clock today I may have to step out. I will likely have to step out. And at that time I'll turn over the Chairmanship to Walt Kirchner. I mean no disrespect to the group presenting. It's just a unavoidable conflict. Okay, Bob.

MR. CALDWELL: Thank you, Chairman and Members of the ACRS Subcommittee on Plant License Renewal. I am Bob Caldwell. I am the Deputy Director of the Division of New and Renewed Licenses in NRR.

We sincerely appreciate the opportunity today to present to the ACRS Subcommittee on License Renewal the results of the staff's review on the third application for subsequent license renewal.

This application was submitted by Virginia Power and Electric, or Dominion, for the Surry Power Station Units 1 and 2, located in Surry County, Virginia.

By way of background, Surry Units 1 and 2 received approval for their initial renewal license from the NRC in March 20, 2003. The NRC review at that time was performed using guidance developed prior to the issuance of the generic aging license lessons learned report, or the GALL report.

The NRC guidance for license renewal over the years has evolved through enhancements and improvements based on the lessons learned from NRC reviews from both domestic and international industry operating experience.

The GALL report went through two revisions, and additional interim staff guidance was issued following Revision 2. The guidance for subsequent license renewal contains in the GALL-SLR built upon previous guidance, and included additional focus and enhancements where necessary on aging management and time limiting analysis for the operation in the 60 to 80 year period.

The staff's presentation today, in the staff's presentation today you will hear about some of the specific SLR issues as applied to the Surry Review.

The NRC project managers for the Surry subsequent license renewal application review are Ms. Angela Wu, and Ms. Lauren Gibson. Angela will introduce the staff seated at the table who will be presenting or addressing the questions regarding the staff's review of the Surry subsequent license renewal.

Part of the management team here with me today are Eric Oesterle, the Chief of the License Renewal Project Branch. And in the audience we have other members of the NRR technical review, branch chiefs. And Joe Colaccino is here. And Tania

Martinez Navedo is here.

We have with us representatives from Region II, Mr. Louis McKown, Acting Chief of the Engineering Branch 4 in the Division of Reactor Projects, Region II, and Dr. Steve Downey, Senior Reactor Inspector from the Division of Reactor Safety Engineering Branch 3.l Joining us by phone I believe is Mack Reed, Resident Inspector at Surry.

I'd like to note that the staff completed its review with no confirmatory or open items in the safety evaluation report. The staff will provide an overview of its safety plans, and highlight a few technical areas that may be of interest to the Subcommittee Members.

In addition, following the staff's presentation Mr. Brian Allik and Mr. James Gavula of the staff will share their technical positions on the SLR, followed by Eric Oesterle, who will present NRR's preliminary perspectives on the technical positions.

Finally, we will address any questions you may have on the staff's presentations. We look forward to a productive discussion today with the ACRS Subcommittee. And at this time I'd like to turn the presentation over to Mr. Paul Phelps, Dominion Engineering Director, SLR, to introduce his team and commence the presentation.

MR. PHELPS: Thank you, Bob. Good morning. My name is Paul Phelps, and I'm the Director, Nuclear Projects Responsible for Surry Power Station Subsequent License Renewal, or SLR project.

We appreciate the opportunity to speak with the Advisory Committee on Reactor Safeguards, ACRS Subcommittee today on Dominion Energy's application for subsequent license renewal.

This is a very important day. And we appreciate the support, and look forward to presenting the SLR application highlights to the Subcommittee.

By the way of my background, I have been in the nuclear industry for nearly 30 years. I am responsible for various SLR related projects that are currently under development in Virginia.

We have stood up an organization not only to perform the requisite work for the re-licensing of the station. But we also have a larger organization that is currently working on projects to improve the safety, reliability, and aging management for Surry Power Station through various modifications.

I will provide some of those insights in a couple of slides. First, my personal history is extensive at Surry. I have worked at Surry for 13 years of my career with Dominion Energy.

As part of my tenure at Surry I received my Senior Reactor Operator Certification, and worked in many engineering leadership roles. My last assignment on site was the Design Engineering Manager, which I held for six years before I moved to our corporate office and became the Manager of Fleet Projects. Next slide, please.

I want to take the time to introduce the team assembled with me here today. To my right is Paul Aitken, Engineering Manager responsible for the development of the Surry SLR application.

Paul was also involved in a leadership role in all of Dominion Energy's first license renewal projects dating back to 1999. Over the last few years he has been engaged with various organizations such as Electrical Power Research Institute, EPRI, Department of Energy, DOE, Pressurized Water Reactor Owners Group, PWROG, Nuclear Energy Institute, NEI, and various vendors to ensure alignment on various technical topics in the support of subsequent license renewal.

Next to Paul is Eric Blocher. Eric has been involved in various first renewal license applications in the industry. He brings his extensive knowledge to the team, and has been deeply involved in the development of the generic aging lessons learned, GALL, SLR, not only on behalf of Dominion Energy, but for the nuclear industry.

To the right of Eric is Chuck Tomes. Chuck is a principle engineer with Dominion Energy, with nearly 40 years of nuclear experience in various technical capacities.

Chuck has been working with various industry groups and vendors on establishing priorities on a needed basis, that would be benefit not only Dominion Energy, but our industry partners.

He is responsible for the time limited aging analysis portion, and will provide his insights later in the presentation.

On my far right is Allen Harrow. Allen is the site engineering manager at Surry Power Station, with nearly 30 years of commercial nuclear experience with Dominion Energy.

Allen started in the operations department, receiving a shift technical advisor and senior reactor operator certifications before serving in various supervisory and management roles at the station in engineering and organizational effectiveness, including --

(Technical difficulties)

CHAIR SUNSERI: Okay. Please continue, Paul. Sorry for the interruption. I apologize.

MR. PHELPS: Can you hear me? In conclusion, to my left is Craig Heah, who is the technical lead in the civil mechanical area, responsible for scoping and screening activities.

Craig has 12 years of nuclear experience. He was the last chairman of the NEI Mechanical License Renewal Working Group during the transition to GALL-SLR.

Craig will be assisting the team with the slide show, and will be available to answer any scoping and screening questions that you may have during the presentation.

Along with the team at the table we have several technical staff available in the audience, should we need some assistance on any questions you may have during our portion of the presentation. If needed they will identify themselves and address your questions.

(Technical difficulties)

MR. PHELPS: Lastly I would like to recognize Fred Mladen, in the front row. Fred is the site VP at Surry Power Station. Next slide, please.

I want to cover the agenda for today's meeting. We will discuss the station overview performance, SLR application development, GALL-SLR consistency, SLR aging management programs, technical topics, and closing remarks. Next slide, please.

Here's an overview of the station and the 50 mile radius, Surry Power Station. Surry Power Station is located in Surry County, Virginia, and is located on the south side of the James River, approximately 25 miles upstream of the point where the river enters the Chesapeake Bay.

The area includes both populated and industrialized areas, as well as expansive rural areas. And spans from the northern neck area of Virginia into North Carolina, and from the eastern shore over to our state capital, Richmond, in central Virginia.

Included in this area are many military installations, and airports providing international travel. Next slide, please.

Surry is a Westinghouse three loop pressurized water reactor, with an output net capacity of nearly 1,700 megawatts. Together these two units produce approximately 15 percent of Virginia's electricity needs. Unit 1 started commercial operation in 1972, and Unit 2 started commercial operation in 1973.

The independent Smithfield Storage Installation facility was one of the first in the country, and will have the capacity to store the fuel required for 60 years of operation.

A 4.3 power upgrade was implemented in 1995, prior to the initial license renewal. The renewed licenses were --

(Technical difficulties)

MR. PHELPS: -- power stations were issued in March of 2003. Lastly, Surry entered the period of extended operation in 2012 and 2013 for Units 1 and 2 respectively. Next slide, please.

Here's an aerial view of the station. I will highlight some of the more significant features, and I will ask Craig to superimpose a red laser marker to help the Committee get oriented.

Again, the orientation of the site and riverflow are from west to east, or upstream the James River, around Hogg Island, a state designated wildlife management area, to downstream James River towards the Chesapeake Bay.

Features from the plant I'd like to point out include the intake canal that provides the ultimate heat sink from the James River, the discharge canal, back into the James, about six miles upstream of the intake.

A unique feature of Surry is that the water from the James River is pumped into an intake canal, and the water flows over a mile, and is gravity fed through the plant without any pumps.

Also depicted are the Unit 1 and Unit 2 reinforced concrete containment structures, and the turbine building in the light blue. The switch yard is across the property on the other side of the intake canal. The administrative building, located on the bottom of this picture, is where many of the plant staff work. Next slide, please.

Here's some of the high level information on the performance of Surry. To note, Surry operates on an 18 month refueling frequency. The plant capacity factor has been very good, as reflected in the bullets.

As far as the regulatory oversight process, Surry is in Column 1, and has been there since 2007. Next slide, please.

MR. SCHULTZ: Excuse me, Paul. Staying at the high level. You've got some good information about what's happened recently with the, for the station.

What's the estimated average capacity factor since the facility entered the period of extended operation, or the decade in, that we've just passed? Just to get an appreciation for how the station has operated over a longer period of time than the three years you've posted here.

MR. TOMES: Good morning. My name's Chuck Tomes. Our refueling philosophy is that we typically operate a short refueling outage of about 20 days, a medium refueling outage of about 25 days, and then a longer refueling outage, maybe 30 days.

And we've had our capacity factors being able to support our objectives over the last three years.

MR. SCHULTZ: Okay. So, you haven't had any outage during this, outages during this period, forced outages that have been significant for the station?

MR. PHELPS: We've had no significant outages since our period of extended operation.

MR. SCHULTZ: Right. Thank you.

MR. PHELPS: Next slide, please.

CHAIR SUNSERI: So, just as a update, the entire phone system at the NRC is having trouble.

That's why we're being so disruptive. So, I'm not certain how long we're going to have to deal with that. But just please be patient, and proceed on with your, we'll work through it the best we can. Thank you.

MEMBER RICCARDELLA: Could I just ask for my education how you can have a capacity factor greater than 100 percent?

MR. PHELPS: The capacity factor is calculated all from, you know, we use the NERC requirements. And the NERC requirements are for periods of operation.

So, they don't take into effect if we have a fall outage or a spring outage. So, if you have no forced outages, and you operate breaker to breaker for one full year, you're going to be over 100 percent capacity.

MEMBER RICCARDELLA: Okay. Thank you.

MR. PHELPS: There has been nearly $1 billion in capital investments made to Surry since the first renewed license was issued in 2003.

As I mentioned in my opening remarks Dominion Energy will continue to invest in Surry to maintain safety and plant reliability for the current and subsequent period of operation.

I would like to highlight a few. Dominion Energy was very proactive to replace the reactor vessel heads at both North Anna and Surry Power Stations. In addition, Surry has replaced, or is scheduled to replace all of the high voltage transformers.

I will note the carbon fiber reinforced polymer installation is one of the first projects the SLR team implemented at Surry, to address longstanding aging management of large bore circulating water in service water piping.

Let me provide some additional details for the benefit of the Committee on this innovative, first of a kind carbon fiber reinforced polymer project. Next slide, please.

The carbon fiber patented technology is a multi-layered system that is applied to the internal surfaces of the carbon steel pipe that becomes the new pressure boundary.

This has been previously employed in the industry in non-safety related applications. But Dominion Energy was the first to receive NRC approval for the use in safety related applications.

In the picture this is a 96 inch circulating water discharge pipe that had the carbon fiber reinforced polymer installed for five years. Look at the condition of the surface, and how much of a change this means towards aging management.

This technology improves safety by reducing the amount of repairs that have been a chronic problem due to the brackish internal environment. But it also reflects Dominion Energy's commitment to address aging management.

I would also like to point out the carbon fiber reinforced polymer project was recognized as the best of the best of all top innovative practice awards last year at the NEI awards ceremony. Dominion Energy is extremely proud of this recognition and award.

In addition, we have plans to continue to invest in the station over the areas, to ensure continued safe and reliable operations for 80 years. Some of the projects include main electrical generator replacement, feedwater heater replacements, residual heat removal heat exchanger replacements, and the replacement of the in core instrumentation system.

I'm sure that you can appreciate that these are significant capital investments for the future operation of Surry Power Station. Let me pause, and ask if there are any questions, before I turn the presentation over to Paul Aitken.

CHAIR SUNSERI: Well, how much, so how much of an issue was the condition of the pipe for the aging, the degradation of the pipe before you initiated the carbon fiber?

MR. PHELPS: Well, our strategy to maintain the carbon, that pipe is, we go in and we blast it. And we do weld and coat it. It was in, you know, as pipe degrades it was in pretty poor condition. So, this fix, carbon fiber is good for 50 years.

CHAIR SUNSERI: And it was internal degradation?

MR. PHELPS: it was internal degradation. That's right.

CHAIR SUNSERI: Does this pipe have like a cathodic protection for the external protection?

MR. PHELPS: This pipe does not have cathodic protection installed on it.

CHAIR SUNSERI: Thank you.

MR. SCHULTZ: Okay. Paul, a question. The projects that you mentioned, how near term are they? The ones that are upcoming? You mentioned four of them.

MR. PHELPS: We have been working on these projects for two years. The carbon fiber is active right now.

MR. SCHULTZ: Right.

MR. PHELPS: We have one more line to install this year, and it will be done at the station. The other projects are five to seven years out. But we're actively working on them. We've cut contracts with them. So, they're in the plan to work in five to seven years.

MR. SCHULTZ: So, they're relatively firm commitments, given that you're working forward with them already?

MR. PHELPS: That is correct.

MR. SCHULTZ: Thank you.

MR. AITKEN: Okay? Thanks, Paul, and good morning. Again, my name is Paul Aitken, and I'm the engineering manager responsible for the development of the Surry License Renewal Application.

By way of background I've been in the nuclear industry for 35 years. And as Paul mentioned, was previously involved in the first renewals for the Dominion Energy fleet.

I'll be providing an overview of the application development process, and other considerations for the Subcommittee today. Next slide, please.

Dominion Energy team has worked closely with various research organization and utility sponsored groups to collectively represent the industry when working with the NRC staff during the development of the GALL-SLR and SRP.

We supported several public meetings over the last few years to finalize the GALL-SLR, as well as the industry guidance for SLR as reflected in NEI Document 17, excuse me, 17-01.

This integral involvement allowed Dominion Energy to benefit from the industry engagement, and use those insights during the development of the SLR application. We also reviewed previously issued REIs to incorporate additional lessons learned from the first license renewal applicants.

Dominion Energy participated in the peer reviews at Turkey Point and Peach Bottom. We were able to provide feedback on their respective applications, while also incorporating insights that we learned during those interactions.

We also conducted an industry peer review using the expertise in the NEI licensure civil, mechanical, and electrical working groups, and other SLR applicants. I personally found these peer reviews to be extremely helpful in our pursuit of a high quality application.

Dominion Energy had a pre-submittal meeting with the NRC on the safety portion of the application. The meeting provided a public forum that allowed additional clarifications and questions to be asked between Dominion Energy and the NRC staff. These insights were extremely beneficial during the development of the application.

Based on these collective interaction Dominion Energy submitted a high quality application, as reflected by fewer REIs, as compared to our first license renewal applications, and a safety evaluation report with no open items, and no confirmatory items.

MR. SCHULTZ: Paul, in a few sentences can you describe what entails industry peer review?

MR. AITKEN: Sure, yes. We --

MR. SCHULTZ: Very important, as you mentioned. But how is it conducted? And how are your results obtained?

MR. AITKEN: Yes. So, what we do is, we pull the application together internally. We review it as a project team. And then we send it out to the industry, to the working groups.

And the working groups meet a couple of times a year. And what we do is, we spend time, a day, a day and a half, on each portion of the application, have the interaction, and allow, you know, take the comments.

And then, we'll take the comments back to the office and go through and do a prioritization on what we're going to incorporate, and what we're not going to incorporate, and fold that in. And then, that's all done before we go up through the management review process.

MR. SCHULTZ: Do you report back to the peer review team?

MR. AITKEN: Yes. We, yes, we develop a spreadsheet, and we send that comment disposition back to the various organizations.

MR. SCHULTZ: Thank you.

MR. AITKEN: We have a lot of participation from a lot of utilities, which is very beneficial. And it's not just the SLR applicants. It's still first, you know, first licensure applicants that are still involved in the working groups.

CHAIR SUNSERI: Does that interaction result in lessons learned being re-factored into the program? I mean, the generic industry program?

MR. AITKEN: Yes. So, that process continues. And we've been working with Eric and the staff on areas for continued improvement. So yes, there's still lessons to be learned.

MEMBER KIRCHNER: Paul, on your last bullet you, I think you said that this provided a public forum?

MR. AITKEN: Yes, sir.

MEMBER KIRCHNER: Did you have much participation from the public in that meeting?

MR. AITKEN: We had some public participation. We had people calling on the phone lines. We had a lot of utility representation. We had vendor participation.

MEMBER KIRCHNER: Okay.

MR. AITKEN: So, we had over ten public meetings, I think that, even for the GALL-SLR development. So --

MR. AITKEN: Okay. Next slide. I want to provide a brief summary on the differences between the first license renewal and subsequent license renewal, with respect to the integrated plan assessment.

For scoping and screening there were minimal changes in the overall process approach. This is primarily because the established industry guidance hasn't changed very much since the first license renewal.

Having said that, one area that we expected to have adjustments was related to scoping and screening for Alpha 2. That's non safety related equipment which can affect safety related equipment. This change was due to the guidance evolving since the first license renewals.

As above noted Surry is a pre GALL plant, like the previous two SLR applicants. So, we were in the same situation of updating the methodology in scoping and in additional systems.

In the area of aging management reviews the expansion and number of aging effects we had to address significantly increased, due to the vintage of the previous application, and the overall evolution of the GALL over the years.

The biggest difference was in aging management programs. Currently, for first license renewal we have 25 aging management programs. Moving into subsequent license renewal there are going to be 47 aging management programs. And Eric will speak to the aging management program details after me.

Lastly, the time limited aging analyses were re-evaluated for 80 years. There was only one new TLAA identified since first license renewal. The new TLAA was related to high cycle fatigue concerns related steam generator tubes made from Alloy 600 thermally treated material that are potentially unsupported by an anti-vibration bar.

This concern was identified by Westinghouse in a nuclear safety advisory letter NSAL 12-7. The potential for tube fatigue was evaluated by Westinghouse, and concluded that none of the potentially unsupported tubes identified in the Unit 1 and Unit 2 steam generators would be at risk of fatigue related failure during the subsequent period of operation.

The remaining time limited aging analyses were disposition consistent with the GALL-SLR guidance.

MEMBER RICCARDELLA: Excuse me. Are these the original steam generators at the plant? Or were they replaced?

MR. AITKEN: They were replaced.

MEMBER RICCARDELLA: Thermally treated.

MR. AITKEN: Yes. We were the first in the industry to replace the tubes. And there was a modified steam generator replacement.

MEMBER RICCARDELLA: Thank you.

MR. AITKEN: Next slide, please, Craig. So, during the aging management review our alignment with the GALL-SLR was over 99 percent for the industry footnotes Alpha through Echo.

I believe that this high degree of alignment to the GALL-SLR was a result of the efforts by the NRC staff and the industry to broaden the GALL-SLR to capture the additional material, environment, and aging effect combinations that were identified during the first license renewal applications.

In terms of commitments, we have a total of 47. And they're primarily on a AMP by AMP basis, and are reflected in Appendix Alpha of the safety evaluation report. These commitments will be tracked in the Dominion Energy commitment tracking system.

I will leave you with a sense that these commitments were discussed with the station team, and agreed upon for implementation. Some commitment items have already been addressed. And Dominion Energy will ensure the proper time, talent, and resources are in place to implement the commitments as required.

That's all I had for my portion of the presentation. Are there any questions before I hand it over to Eric?

MEMBER KIRCHNER: Paul, I'd like to ask, of the AMPs that you have, now you're up to 47, how many of them are unique to your particular plant? Or are these pretty much following what the industry wide is doing?

MR. AITKEN: I think they're pretty consistent industry wide.

MEMBER KIRCHNER: So, there's nothing -

MR. AITKEN: Site specific.

MEMBER KIRCHNER: -- site specific or --

MR. AITKEN: No.

MEMBER KIRCHNER: Okay.

MR. AITKEN: And our -- Go ahead. I'm sorry.

MEMBER BALLINGER: Did you folks do an estimate of the probability of failure for steam generator tubes out to 80 years, using thermally, with the thermally treated tubing?

(Off microphone comment)

MEMBER BALLINGER: In other words, thermally treated tubing is --

MR. AITKEN: I mean, we --

MR. TOMES: The, this is Chuck Tomes. So, there's two aging management considerations related to the tubes. They would be intergranular stress corrosion cracking, and fatigue.

The fatigue is a time limiting aging analysis. So, that's been assessed through 80 years of plant operation. And the intergranular stress corrosion cracking is really managed through the ISI program.

MEMBER BALLINGER: Okay. So, it's really, you're not doing a projection? It's just an ISI?

MR. TOMES: For the stress corrosion factor.

MEMBER RICCARDELLA: Have you had to plug any tubes in the new generator?

MR. TOMES: Yes.

MEMBER BALLINGER: How much margin do you have?

MR. BLOCHER: This is Eric Blocher. We have not done a probabalistic assessment of the thermally treated tubes. Generators, the lower half was replaced in 1981.

And based on our trend to date in each of the units, less than one percent of the tubes are plugged. So, we've had excellent performance so far with the thermally treated tubes.

MEMBER BALLINGER: And you have a lot of margin?

MR. BLOCHER: Yes.

MEMBER BALLINGER: Thank you.

MR. AITKEN: So, at this time I'll --

CHAIR SUNSERI: I'm told that the phone lines are back in service.

MR. AITKEN: They're back in service?

CHAIR SUNSERI: Yes.

MR. AITKEN: Okay. So, at this time I'll turn over the next portion of the presentation to Eric Blocher to discuss aging management programs.

MR. BLOCHER: Thanks, Paul, and good morning. My name is Eric Blocher, and I am the SLR technical lead responsible for the technical content and assembly of the Surry SLR application.

By way of background, I've been in the nuclear industry for 43 years. And as Paul mentioned I was previously involved in numerous industry license renewal projects.

I will be providing an overview of the significant considerations associated with the aging management programs in the SLR application for the Subcommittee today. Next slide on SLR and considerations.

In addition to being responsive to GALL-SLR AMP program elements, effectiveness of the Surry SLR AMPs was influenced by involvement of our project team members, and industry activities, incorporation of operating experience, and the performance of AMP effectiveness reviews.

As part of our engagement with the industry several Surry SLR project team members have held leadership roles on the NEI task forces and working groups.

Other members collaborated with EPRI on activities such as guidance for aging management alkali silicate reaction, concrete irradiation evaluation, and reactor internals inspections. And others have participated in the PWR owners' group reactor vessel integrity and time limited aging analysis report projects.

Project team participation not only benefitted the Surry application, but provided guidance and technical reports that include several reports with NRC safety evaluations that are generically applicable to other SLR applications.

Review and incorporation of operating experience was performed for a ten year period, to inform the aging management programs. In addition to operating experience, recent license renewal REIs associated with the Turkey Point and Peach Bottom SLR projects, and recent first license renewal projects, were reviewed for insights and lead plant alignment.

Our project team also participated in

Turkey Point and Peach Bottom industry peer reviews to provide AMP insights, and share constructive comments.

Prior to submittal of the application the effectiveness of aging management activities was assessed using the evaluation elements identified in NEI 1412, the guideline for aging management program effectiveness. Next slide.

MEMBER BALLINGER: I'm sorry to go back again.

MR. BLOCHER: No problem.

MEMBER BALLINGER: What's your TH? What's your TH?

MR. BLOCHER: T Hot.

MEMBER BALLINGER: T Hot.

(Off microphone comments)

MR. HARROW: T Hot is 547.

MEMBER BALLINGER: 547?

(Simultaneous speaking.)

(Off microphone comments)

MR. WILSON: I believe the mic is on. So, too short. So, T Hot. I'm sorry, my name is David Wilson, Director of Safety and Licensing, Surry Power Station, a member of the Dominion Energy team. T Hot at Surry Power Station is 605 degrees.

MEMBER BALLINGER: Okay. There we go.

MR. WILSON: T Cold is 537 degrees.

MEMBER BALLINGER: Now I'm calibrated.

PARTICIPANT: T Cold 547?

MR. WILSON: That's correct.

MEMBER KIRCHNER: Eric, before you go on, just out of curiosity, when you participate in these peer reviews, obviously you get a more inclusive view. Did, as a result of these did, was something identified that wasn't already on, in your plan, or on your list, or so to speak?

Just curious to -- One could say, you know, you all worked together on this. And you get group think. So, did, as a result of the peer reviews did you get new insights that changed any of your planned AMPs or activities?

MR. BLOCHER: The peer reviews were quite helpful in gaining insights. For example, in the AMPs that we're talking about now, many of the insights dealt with ways of presenting some of the enhancements, innovative ways to get to an aging or inspection process that would satisfy GALL efficiently.

Some of the critiques relative to our exceptions that we took not only benefitted us, but the other team members. And that has helped when we go to NRC meetings where we talk about these changes with the staff, in terms of influencing of future ISG or revision to the GALL-SLR.

So, it not only benefits us, it benefits team members. And to the extent practical we usually share that information as practical with the regulator.

MEMBER KIRCHNER: Yes. I was actually thinking a little beyond just process, and helping expedite your way through the reviews and interactions with the staff to any technical findings as a result of your review group activities, peer group activities.

(Off microphone comment)

MR. TOMES: Good morning. This is Chuck. There were several helpful observations and input from our peer review process. One of, in particular when we worked on our environmental assisted fatigue.

We had experts from our vendors challenge the selection of the materials and the locations that we would use for fatigue monitoring. That's one area where we actually made changes.

MEMBER KIRCHNER: Thank you.

MR. BLOCHER: Okay. First license renewal AMPs. Twenty-five firs license renewal aging management programs were the starting point for the evolution and enhancement into subsequent license renewal aging management programs.

All first license renewal aging management activities were continued, and incorporated into SLR AMPs. None were discontinued. Several first license renewal AMPs were consistent with GALL, or required enhancement to be consistent with GALL-SLR.

Several first license renewal aging programs were subdivided into GALL AMPs. First license renewal programs such as containment inspection were subdivided into ASME Subsection IWE or IWL inspections, or structures monitoring that was subdivided into three GALL-SLR programs, or work control that was subdivided into five GALL-SLR programs. Next slide.

MEMBER KIRCHNER: Eric, pardon the interruption again. As a result of that, so you went from 25 to 47. And you just mentioned you subdivided some of the previous AMPs to be more consistent with GALL.

But going back to my prior question. Did the GALL report force you to add AMPs that covered activities of a technical nature that weren't previously in the SL, the first license renewal?

MR. BLOCHER: Yes. There were several new AMPs that were added. I'm going to cover that on a future --

MEMBER KIRCHNER: Okay.

MR. BLOCHER: -- slide.

MEMBER KIRCHNER: All right. Well sometimes, my question is more technical. Because sometimes new is just to be in conformance with process.

And sometimes new is because you actually discovered a technical issue, and then created something to address that. So, that, it's the latter I'm more interested in than the former.

MR. BLOCHER: I agree. I know where you're coming from. And you'll see that when I get to the new AMP slide. Okay. So, based on the slide that you see, this combination and subdivision process of first license renewal AMPs resulted in 47 GALL aging management programs noted on this slide.

There are 28 mechanical programs that evolved from 19 first license renewal programs. There are eight structural programs that evolved from four license renewal programs.

And there are eight electrical programs that started with splitting one of the first license renewal AMPs into two programs, then crediting two existing electrical programs. And then doubling the electrical programs with the addition of four new SLR programs.

And, Walt, I think there's a slide after this that will touch on this. I think the electrical area is an example of what you were thinking about.

There are three time limited aging analysis programs. And the subdivision process also resulted in varying degrees of GALL-SLR consistency, as noted on the next slide.

Looking at the left hand column, there are 40 existing AMPs that resulted from the combination and subdivision process of the first license renewal AMPs. The SLR existing AMPs were augmented by seven new AMPs.

The remainder of the columns provide perspectives on GALL-SLR AMP consistency. Approximately one-quarter of the 47 AMPs are consistent with GALL, without enhancement.

Approximately one-half of the 47 are consistent with enhancement. And approximately one-quarter of the SLR AMPs are consistent with one or more exceptions.

Now let me provide some context on the new

GALL-SLR AMPs, and the AMPs with exceptions on the next slide.

MEMBER BALLINGER: I was looking ahead. And the neutron fluence monitoring AMP, TLA, time limited aging is not one of the new ones. It's one of the existing ones I presume.

MR. BLOCHER: Correct. This is Subdivision 1.

MEMBER BALLINGER: Yes. Now, are you guys following the Reg Guide 1.99 review, or potential review process? And does that have any, would that have any effect on your fluence monitoring?

MR. BLOCHER: Chuck, would you like to ask, answer that?

MR. TOMES: Sure. We do follow the Reg Guide 1.190 process. And we have conducted calculations on the neutron shield tank. And we use the surveillance capsules that are in the reactor vessel to project our fluence.

MEMBER BALLINGER: Yes.

MR. TOMES: And we are following the changes that are being proposed by the staff --

MEMBER BALLINGER: Okay.

MR. TOMES: -- on the embrittlement curve, and also for assessing areas above and below the belt line region.

MEMBER BALLINGER: Thank you.

MR. BLOCHER: Okay. There are seven new SLR aging management programs. The first three aging management programs involve one time inspections. The next four electrical AMP programs involve inspections of inaccessible cables, cable connectors, and high voltage insulators.

So, Walt, I think you can see from this, in the electrical area there are new things that we had not previously done. Some are new components, like the high voltage insulators. Some involve additional inspections of instrument and control, and low voltage power cables.

CHAIR SUNSERI: But are any of those as a result of operating experience at Surry? Or is it just all industry generic?

MR. BLOCHER: None of those have significant operating experience at Surry. These were added by the GALL. We were a pre-GALL plant. So, they were added in, during our first license renewal interval.

CHAIR SUNSERI: And for the AMPs that were with enhancement, is it the same kind of story on that? They were enhanced because of the transition to the SLR AMP, versus --

MR. BLOCHER: Correct.

CHAIR SUNSERI: -- some operating experience?

MR. BLOCHER: Correct.

CHAIR SUNSERI: Thank you.

MR. BLOCHER: Okay. Okay. Next I'll provide a listing of GALL AMPs with exceptions. So, there are 12 SLR aging management programs with exceptions that include 14 exceptions. This number of exceptions is consistent with other SLR applicants. For example, Peach Bottom had 11 AMPs with 14 exceptions.

We can discuss any one of these enhancements noted on this slide. Or otherwise I can provide a summary of the general types of exceptions on the next slide. Next slide.

As noted previously, there are 12 aging management programs that include 14 exceptions as noted on this slide. There are six AMP exceptions that involve exceptions to GALL-SLR test frequencies, and are proposed inspection technique alternatives.

For example, the ASME Section 11, Subsection IWE program requires containment penetrations that are subject to cyclic loads that do not have current licensing basis analysis to be periodically inspected with a service and visual examination for cracking.

Dominion Energy prepared a fatigue waiver for containment penetrations with operating temperatures less than 200 degrees, to demonstrate that cracking due to cyclic loading is not an applicable aging effect requiring management.

There are five AMP exceptions that involve exception to GALL-SLR program elements due to plant specific configurations.

For example, the metal enclosed bus program requires a periodic ten year inspection of 100 percent of all metal enclosed busses. Inspection of metal enclosed bus between Unit 1 Foxtrot bus, and Unit 2 Foxtrot bus requires a dual unit outage.

Inspection of the other mechanical busses, coupled with opportunistic inspection of transfer bus Foxtrot are used to demonstrate that effective aging management of all metal enclosed busses.

Other more common plant specific configuration considerations not addressed by GALL-SLR include metal tanks encased in concrete missile shields, and double wall fuel oil storage tanks.

There are two AMP exceptions that are

required because the GALL-SLR references outdated EPRI chemistry guidance for PWR secondary water chemistry, and closed treated water systems.

We identified and evaluated each change in the new EPRI chemistry guidance for aging management effectiveness, and consistent with industry operating experience. EPRI chemistry guidance changes were found to be acceptable by the NRC staff.

The last exception was required to allow Dominion Energy to conservatively apply the elements of aging management activities associated with high voltage insulators to the medium voltage insulators on the Surry SBL recovery path. Next slide, please.

MR. SCHULTZ: Eric, before you leave that.

MR. BLOCHER: Yes.

MR. SCHULTZ: What is the, where does the reactor head closure stud bolting fall? Which of these categories does it fall into?

MR. BLOCHER: That's a configuration issue, based on the tensile strengths that are involved with our replacement studs.

MR. SCHULTZ: Okay. Thank you.

MR. BLOCHER: First license renewal AMPs have been, and will continue to be assessed for AMP effectiveness. Four AMP reviews, including NEI 1412

AMP effectiveness reviews confirm implementation of first license renewal commitments, and performed assessment of inspection schedules, inspection results, and trending data.

In addition, these reviews also ensured identified gaps were addressed or included in the corrective action program.

Program owners receive periodic training, and are required to complete AMP effectiveness reviews every five years, as well as perform systematic operating experience reviews on an ongoing basis, to inform AMPs and augment AMP effectiveness.

As an indication of regulatory acceptability of the Dominion Energy aging management programs, the IP 71003 Phase 4 NRC inspection identified no findings or concerns in the third quarter 2019 inspection. The NRC staff will provide details of the 71003 Phase 4 inspection during their presentations.

This is all I had for the AMP portion of the presentation. Are there any questions for me before I start the next portion of the presentation on --

MR. SCHULTZ: Eric, on this slide you talk about the training conducted periodically for program owners. What is that periodicity? Or is it on an as needed basis?

MR. BLOCHER: There's an annual training that's given by the license renewal coordinator on significant operating experience and industry updates. And then it's, after that it's as needed.

MR. SCHULTZ: So, it's really an opportunity for the program owners to get together and discuss where things stand, learn from what has been gleaned from the industry activity --

MR. BLOCHER: Yes.

MR. SCHULTZ: -- type of training?

MR. BLOCHER: Yes.

MR. SCHULTZ: Long course? A day's exercise, or --

MR. BLOCHER: It varies.

MR. AITKEN: I would say it's four to six hours.

MR. SCHULTZ: And the program owners have been in place generally for a real, a long period of time? Is it a rotational position? How would you characterize it?

MR. BLOCHER: Right. Each of the 25 first license renewal AMPs identified in the UFSR supplement has an assigned individual responsible for that. And then, as we rotate to the 47 first, second license renewal programs, those two will have program owners.

We work with individuals that were assigned to work with us as we transition, either subdivide or create the new ones. So, there are some new individuals that are spinning up on the --

MR. SCHULTZ: These are individual program owners?

MR. BLOCHER: Right.

MR. SCHULTZ: In other words, one person isn't assigned four programs?

MR. BLOCHER: Well, as you can see, like Section 11, there are, because GALL-SLR subdivided a lot of the Section 11 topics, there will be one program owner for that.

But usually when it comes to implementation of the inspections that overarching program owner might not be involved with the inspections.

For example, nickel alloys are all Section 11 code cases. The ASME Section 11 program owner is responsible for that. But another individual may be involved with the outage inspections for --

MR. SCHULTZ: Right.

MR. BLOCHER: -- nickel alloys.

MR. SCHULTZ: Okay. Thank you.

MR. BLOCHER: Next slide. In the next portion of the presentation I will cover technical topics dealing with concrete, reactor internals, and other aging management enhancements.

Chuck Tomes will then cover the technical topics of reactor vessel integrity and reactor vessel support steel.

Allen Harrow will conclude with technical topics, with a discussion of our recent operating experience associated with the buried fire protection yard loop piping. Next slide.

Concrete for Surry structures within the scope of subsequent license renewal is in good condition. There have been no loss of license renewal intended function due to aging since entering the period of extended operation.

Dominion Energy has recently implemented the EPRI Alkali-Silicate Reaction Inspection Guidance that was developed in part by members of the SLR team. The guidance uses identification of leading indicator structures, conduct of augmented examinations for pattern cracking, detection of water ingress, and identification of structural misalignment.

No effects of Alkali-Silicate reaction

have been identified. Aging management of the structural concrete is accomplished by aging management programs noted on the slide.

Surry reinforced concrete containments are also in good condition. Recent examinations of the concrete liner to concrete slab interface in October of 2016 for Unit 1, and May 2017 for Unit 2, did not identify any degradation.

Containment concrete biological shield wall gamma and neutron dose radiation remains conservatively below GALL-SLR radiation exposure levels throughout the subsequent period of extended operation.

Aging management of Surry reinforced concrete containments is accomplished by the aging management programs noted on the slide. Next slide.

MEMBER BALLINGER: I have questions on this.

MR. BLOCHER: Yes.

MEMBER BALLINGER: Do you know what the groundwater chloride concentration is at the site?

MR. BLOCHER: the GALL requires groundwater chloride to be less than 500 ppm.

MEMBER BALLINGER: Right.

MR. BLOCHER: Jim Johnson, could you

provide some additional trend details?

MR. JOHNSON: Yes. I'm Jim Johnson, with the SLR team at Dominion. The groundwater monitoring that's been done at the plant, we're committed to do it at a frequency no greater than five years. But they've actually been doing it quarterly.

And there has been one well point that had chlorides that exceeded 500 parts per million. This was in the turbine building. And it's kind of an anomaly, where they were pumping the water out, we feel like they're concentrating that.

And then they're inspecting, and haven't found any degradation due to the chlorides there. And they're continuing to monitor that. But overall the plant has had good quality water. And we haven't had any issues with chlorides or PH, or sulfates.

MEMBER BALLINGER: Okay. And now, just, this is, probably you don't know the answer to this. But with respect to the containment, is the rebar three or four inches deep? What's the cover amount?

MR. JOHNSON: There's five inches in most places.

MEMBER BALLINGER: Five inches?

MR. JOHNSON: Yes.

MEMBER BALLINGER: Okay. All right.

Thank you.

MR. BLOCHER: I am ready for the next slide, Craig.

MEMBER KIRCHNER: Eric? Could you just -- for the record, just define good condition?

MR. BLOCHER: Well first, from a licensure point of view, there's been no loss of intended function.

MEMBER KIRCHNER: Right.

MR. BLOCHER: And there's been no significant code degradation noted that would appear in the operating activities report.

MEMBER KIRCHNER: Yes. I think good just doesn't quite catch it. All right, thank you.

MR. BLOCHER: I understand your comment, thank you. Surry will manage reactor vessel internals at primary, expansion and existing examinations consistent with MRP-227, Rev. 1-Alpha, inspection and evaluation guidance that was issued in December of 2019 and includes NRC safety evaluation dated April 25th, 2019 -- for the first period of extended operation. In addition, the examinations for the 10 SLR reactor vessel internals compound as noted on the slide are also incorporated into PWR vessel internals program.

With exception to the control rod guide tubes sheathes and seed tubes, the additional examinations are identified in MRP 2018-022, interim SLR guidance, and are required in part due to where an irradiation related degradation that is very conservatively projected for the subsequent period of extended operation. In addition to the PWR vessel internals program, the neutron fluence monitoring program defines and monitors the projected fluence associated with the reactor vessel internals during the subsequent period of extended operation, and will supplement the MRP-227, rev. 1-Alpha, inspection and evaluation guidance. Next slide.

MEMBER RICCARDELLA: Excuse me, I don't see anything on baffle bolts. Have you had an issue with that? Had there been an inspection?

MR. BLOCHER: Chuck, would you like to answer that?

MR. TOMES: Yes. Our baffle bolts have been inspected at the Surry Nuclear Plant and we have one defect in one of the units.

MEMBER RICCARDELLA: Is it an up-flow or a down-flow configuration?

MR. TOMES: It's been converted.

MEMBER RICCARDELLA: It's been converted?

MR. TOMES: Let me re-speak -- let me re-speak -- let me clarify. We're in the process of working to convert. We will convert in a couple refueling outages. Thank you.

MR. BLOCHER: Next slide, please. Other aging management enhancements identified on this slide demonstrate the value of Dominion Energy industry leadership, EPRI collaboration and PWR owners-group participation. Dominion Energy's SLR team members contributed to the development of the draft ASME code case, and 871 examinations that will manage the aging and the pressure boundary for the newly installed carbon fiber reinforced polymer pipe lining consistent with the open cycle cooling water system program.

Surry program owners have implemented erosion monitoring that manages wall thinning due to cavitation, liquid drop impingement, flashing and solid particle erosion. The program is consistent with the EPRI erosion guideline and it includes erosion susceptibility evaluation, engineering evaluations to determine inspection locations, and the use of CHECWORKS erosion module to predict erosion inspection locations on susceptible lines.

MR. SCHULTZ: Eric, how long has that program been in place? You're using it, but how long has it been used? Is this recent? Or has it been longer-term?

MR. BLOCHER: This is a recent program change that we added due to requirements of the GALL-SLR. And we are in the process of getting that implemented for inspections coming up in this year and the following year.

MR SCHULTZ: Okay, thank you.

MR. BLOCHER: Soil surveys and analysis consistent with recent EPRI guidance that confirms soil environment corrosivity now supplements the varied and underground piping and tanks program aging management inspection criteria. Dominion SLR team members have participated in PWR owners group activities for development of time-limited aging analysis topical reports such as the report associated with the reactor coolant pump fatigue crack growth analysis, and reactor cooling pump code case N481.

These were recently also approved by the NRC safety evaluations. An NRC safety evaluation for the topical report of reactor vessel under-clad cracking associated with well deposit cracking, is in progress with an estimated March 2020 completion date. That is all I had for my portion of the presentation. Are there any questions for me before I hand over to

Chuck Tomes?

MR. SCHULTZ: Yes, one question on this slide, Eric. The soil surveys and analysis that you've incorporated from the EPRI program, can -- can you expand on -- on what is being done there? What I've seen in the -- what I've seen in the updates to the program is that you're -- you're incorporating soil sampling and testing in a couple of different ways. That is, you've got -- you've got a site-wide approach and a -- a specific approach, depending on what is happening on the site. Can you describe that? Or is that something that we ought to wait for the next section to discuss?

MR. BLOCHER: Now is an appropriate time to discuss that. So the initial soil surveys were done in 2012 on the station for the buried pipe program. And in 2018 they were revisited. The initial soil surveys were 44 points. The recent ones in 2018 were 11 points. The recent ones fully employ the EPRI guidance, which looks for soil characteristics, resistivity, pH, redox potential, sulfides, chlorides and soil consortium -- which is a check of the bacteria in the soil. Those parameters are all taken. They're scored on an index that awards up to 15 points. Anything under 10 points is not considered very corrosive. In fact, there's two grade categories under 10 points. Ten to 15 is considered moderately corrosive. Anything greater than 15 -- no, excuse me -- 10 to 15 is appreciably corrosive. And anything greater than 15 points is severely corrosive. Those would tend to focus our action on anything that scores 10 or greater.

MR. SCHULTZ: So with -- with that scoring system, are there areas of the site that are of concern? Or -- what -- what has been found? And --

(Pause.)

MR. BLOCHER: Yes --

MR. SCHULTZ: Are there programs moving forward as a result of that work?

MR. BLOCHER: Right, so you have to remember that the License Renewal Buried Pipe Program augments the industry NEI-09-14 program. So the 09-14 looks at other piping systems that are not within the scope of license renewal. So for some of those the corrosive areas fall under an 0914 concern. The license renewal piping is all either mildly corrosive or moderately corrosive areas.

MR. SCHULTZ: Okay. Well we'll -- we'll take a look at some pictures.

MR. BLOCHER: Thank you.

MR. TOMES: Before I cover the technical comp issues, I want to just finish clarifying the question that Pete Riccardella had on the baffle bolts. And we have one bolt that's non-functional for Unit 1 and two bolts that are non-functional for Unit 2. So I didn't get a chance to squeeze that in. Okay.

Good morning, my name is Chuck Tomes from Dominion Energy. And thank you for taking the time to review the Safety Evaluation Report issued by the Nuclear Regulatory Commission for the Surry subsequent license renewal application. During my career, reaching back to the early 1980s, I've had the privilege of working with NSSS vendors, owners groups, the Electrical Power Research Institute, ASTM committees and ASME committees on projects from managing reactor vessel integrity and reactor cooler pump issues. And these industry groups are the one that allowed us to move forward to where we're at today. And we're quite thankful for their help over the years.

My role on the Surry SLR project has been to work with these groups to ensure that the time limiting aging analyses are technically correct. At this time I'll discuss the two topics that Eric

Blocher mentioned -- dealing with reactor vessel integrity and reactor vessel support steel.

So the first thing that we did to assess reactor vessel embrittlement was to project the fluence values on the reactor vessel for 80 years of plant operation, using 68 effective full-power years as our target. This is conservative because the current fluence projection for 60 years of plant operation is 48 effective full-power years. Then we contracted the PWR owners group to assist Dominion in reviewing the reactor vessel certificate of material test reports for re-baselining the initial fracture toughness values in the accordance with the ASME code and branch technical position 5-3. The various reactor vessel time-limiting aging analyses for pressurizer thermal shock, upper-shelf energy, low-temperature over pressure protection, and the heat-up and cool-down curves were then revised through 80 years of plant operation using updated fluence and material property information.

MEMBER RICCARDELLA: Excuse me, Chuck. What is the end of life fluence? Peak end of life -- what is the peak end of life fluence?

MR. TOMES: The peak end of the license fluence for Unit 1 is on the -- is 6.35 E to the 19 and 7.22 -- for Unit 2.

MEMBER RICCARDELLA: Got it.

(Simultaneous speaking.)

MR. TOMES: E to the 19.

MEMBER RICCARDELLA: So would you -- would you be affected if the -- if the trend curve is revised to the ASTM trend curve?

MR. TOMES: We have margin on the PTS evaluation, the upper-shelf energy evaluation, the LTOP system. And so impact from the -- if we were to drive -- draw a new best-fit line through the data, so that some plants were above and some plants were below -- it would not impact us in these areas. But it would impact the heat-up and cool-down curves more than likely because we would end up with a new criteria on how to adjust margin and -- and shift.

MEMBER BALLINGER: Yes, I think 6 times 10 of the 19th is the -- where it starts to -- right where it starts to go off. So.

MR. TOMES: Okay, so we're going to talk about this a little bit more. But it would have a -- it would have a dramatic impact on our plant procedures. And what -- yes -- on the heat-up and cool-down curves. Yes.

Locations -- with upper-shelf energy

values that have less than 50 foot pounds of Charpy energy have been assessed using the equivalent margins method outlined in the ASME code. So the applicability of the existing heat-up and cool-down curves can be extended to 68 effective full-power years based upon using the updated material properties, the revised fluence values and application of the K1c methodology currently included in the ASME code.

Surry will use two aging management programs, which are consistent with GALL-SLR -- to manage fluence and embrittlement during the subsequent period of extended operation. And Dominion plans to remove and test one surveillance capsule from each of the reactor vessels during the period of extended plant operation. Next -- okay, next slide.

This next technical topic that I will discuss deals with reactor vessel steel. Dominion Energy created this sketch to provide an overview of the reactor vessel support configuration at Surry. The reactor vessel supports at Surry are different from the reactor vessel supports used at many of the other nuclear plants. At Surry, the reactor vessel support is provided by the neutron shield tank. At some other plants, reactor vessel support is provided by columns and cantilever beams.

This sketch shows the position of the reactor vessel and how it is supported by the neutron shield tank, relative to the location of the concrete biological shield wall. The reactor vessels located in the center of the sketch. The position of the core where the neutrons are generated within the reactor is shown by the blue and grey stripes. The neutron shield tank and the concrete biological shield wall surround the reactor vessel. The neutron shield tank is shown in blue. The tank is about 23 feet high, is filled with water -- with chromated water, which provides 34-inches of shielding. The inner and outer plates are 1.5 inches thick.

Next to the neutron shield tank is the concrete biological shield wall. The concrete biological shield wall was 4.5 feet thick. One of the purposes of the neutron shield tank is to provide shielding to protect the concrete, biological shield wall. The other purpose of then neutron shield tank is to transmit the loads from the reactor vessel, through the supports located under the nozzles of the reactor vessel, to the top of the neutron shield, and then to the lower elevation of containment. Okay, next slide.

Now that we've reviewed the general configuration of the neutron shield tank, I will discuss irradiation of reactor vessel support steel for Surry. At Surry the support steel of interest is the region of the neutron shield tank adjacent to the reactor core, where the neutrons are generated. The issue of irradiation of a reactor vessel support steel was originally assessed in 1986 using fracture mechanics in preparation of future license renewal considerations by Stone and Webster, under contract from the Department of Energy, Westinghouse Owners Group, EPRI and Virginia Power.

This original assessment used a Westinghouse discreet ordinance radiation transport fluence model for projecting fluence on the neutron shield tank through 100 years of plant operation. To address the irradiation of the neutron shield tank for subsequent license renewal, a new fracture mechanics evaluation was performed by Dominion Energy. The new fracture mechanics evaluation uses loads from dead weight, LOCA and seismic, press intensity formulas from the ASME code that are normally used for developing heat-up and cool-down limit curves for operation reactor vessel, and an infinite amount of fluence based upon the use of the lower-bound K1r curve, which is 26.7 KSI square root inches.

The analysis shows that the allowable stress is greater than the stress on the neutron shield tank, therefore brittle fracture will not occur. The fracture mechanics evaluation is bounding through the use of the lower-bound K1r value of 26.78 KSI square-root inches were not required because the fracture mechanics evaluation is bounding. It includes a margin of square-root of two consistent with the ASME code for pressure vessels, even though the neutron shield tank is not a class one vessel.

Thus the Surry fracture mechanics evaluation of the neutron shield tank is both bounding and conservative. And we have three programs for managing aging during SLR that are shown on the slide. Before we move on to the next part of the presentation, I want to provide an opportunity to answer questions.

MEMBER RICCARDELLA: The -- the 26.7 KSI root inches, that's the lower shelf of the KIR curve?

MR. TOMES: Yes, that's right. That's where it -- that's where it intersects, at the lowest toughness level.

MEMBER RICCARDELLA: And the -- the square root of two safety factor is --

(Simultaneous speaking.)

MR. TOMES: For fault --

MEMBER RICCARDELLA: -- for seismic --

MR. TOMES: For fault -- it's actually for LOCA. The seismic is insignificant in terms of the loads.

MEMBER RICCARDELLA: Oh, okay. Thank you.

(Pause.)

MR. TOMES: If there are no other additional questions, Mr. Allen Harrow will now provide a summary of the recent operating experience that occurred at Surry.

MR. HARROW: Good morning. My name is Allen Harrow and I am the site engineering manager at Surry Power Station. I have worked for Dominion Energy for nearly 29 years. In my current role, I provide management oversight of the various plant systems and engineering programs. I will be providing an overview of the recent fire protection yard loop pipe break, including failure analysis, current status, the highlights of the ongoing fire protection yard loop repair project.

The Surry Power Station fire protection yard loop completely circles the plant and consists of a 12-inches looped fire main, supplying fire hydrants, phone stations and deluge systems on the outside. And sprinklers, deluge systems and hose racks inside plant structures.

The fire main piping is cast iron with mechanical joints, and is cement mortar lined with a bituminous external coating. The loop is sectionalized to permit repairs without affecting any other portion of the loop. Next slide?

CHAIR SUNSERI: Allen, could you pull the microphone a little closer to you and just -- thank you.

MR. HARROW: A fire protection loop piping break occurred in July 2019, following the start of the motor-driven fire pump. Following the failure of the fire protection loop piping, the affected sections of piping were isolated to stop the leak. Upon excavation, it was identified that there were two sections of 12-inch fire protection loop piping that were degraded and leaking. The degraded sections of pipe and dislocation were replaced, but remain isolated and available if needed. Next slide.

MR. SCHULTZ: Allen, you mentioned that -- it occurred just after the fire pump start up. Was that a normal operation? The fire pump start-up? Was that a normal operation?

MR. HARROW: Yes, since the fire pump was started in collaboration with surveillance testing that was being performed.

MR. SCHULTZ: But nothing was out of the ordinary with regard to the operation of the pump? Or the system?

MR. HARROW: There was nothing out of the ordinary at that point in time.

MR. SCHULTZ: Thank you.

MR. HARROW: Uh --

MEMBER RICCARDELLA: I am sorry -- were they breaks or leaks?

MR. HARROW: I would classify it as a break because leakage -- you can classify it as a rupture.

MEMBER RICCARDELLA: Rupture -- you know --

MR. HARROW: The pipe -- the pipe was not severed.

MEMBER RICCARDELLA: Okay.

MR. HARROW: Okay, next slide.

(Pause.)

MEMBER KIRCHNER: This -- was this a water hammer effect? Or just it came up to normal operating pressure and then you figured out that you had a large leak?

MR. HARROW: There -- there was no water hammer impact here. So the piping is normally maintain solid. So when the motor-driven fire pump started, no impact from water hammer.

MEMBER RICCARDELLA: How did you detect the leak? Just from water?

MR. HARROW: So the leakage was detected multiple ways. First of all, we had annunciators in the Control Room that alerted the operating staff to the leak. And the leak was also readily identifiable in the field.

(Pause.)

MR. HARROW: All right. This fire protection pipe failure was entered into the Corrective Action Program, and an immediate review of the cause and extended condition was ensued by the station. Sections of the failed pipes were sent to the -- to the Dominion Energy Materials Laboratory for detailed analysis, in which the failure mechanism was determined to be graphitic corrosion.

The failure analysis concluded that the most notable corrosion was limited to the bottom section of piping between roughly the 5:00 to 7:00 positions. It was determined through metallurgical analysis that the identified material laws was a result of the cast-iron fire protection piping exposure to ground water over an extended period of time. The bituminous coating in the area of rupture locations on the bottom of pipe was noted to be degraded, allowing the water to have direct contact with the external surface of the pipe. The bituminous coating around the pipe that was not exposed to the ground water appeared to be in acceptable condition.

The scenario for the northern pipe failure, based on the lab observations, is that long-term external corrosion ultimately resulted in a reduction in wall thickness in the pipe. Once this area reached its current size -- approximately 4-inches long -- the pipe suddenly ruptured from the pressure surge associated with the starting of the motor-driven fire pump.

The second failure location on the southern section of fire protection loop pipe had a circumferential flaw approximately eight feet south of the northern fire protection loop pipe mechanical connection. This type of flaw is typically associated with bending stress and an overload condition. The flaw propagated from a small pocket of external graphitic corrosion located at the bottom of the fire protection loop pipe. The cause evaluation concluded that the circumferential flaw occurred as a result of an initial longitudinal flaw, and rupture in the northern piping.

The initial rupture created an uplifting force and motion in the southern pipe, which caused the circumferential flaw that was initiated at the weakened area of graphitic corrosion. Next slide?

MR. SCHULTZ: Excuse me -- the coating, it was hard to tell from the pictures what the condition of the coating was. But as you've indicated here, in -- on the one pipe with the longitudinal crack, that -- that was in that region of 5 to 7 -- excuse me, yes, 5:00 to 7:00, that coating was affected is what you're saying in that -- the -- in other words, the degradation of coating was regional.

MR. HARROW: Correct. The degradation of coating was regional in the 5:00 to 7:00 position. And we feel that that was a direct result of groundwater that was in the vicinity of the 5:00 to 7:00 position. In other words, we do not feel the groundwater completely encompassed the entire pipe.

MR. SCHULTZ: And as you looked at the other -- other section of pipe that had failures, what was the condition of the coating there? Or have you

-- have you noticed that there was a problem with coating condition otherwise as you've continued your corrective action program?

MR. HARROW: So -- so one thing that's very difficult to identify is, when we initially visually looked at the pipe, before you actually do destructive testing, it is very difficult to identify the acidic corrosion. It's a destructive testing modality to actually identify the graphitic corrosion.

MR. SCHULTZ: Okay, that's -- that was the problem I was having. Looking at it doesn't tell you.

MEMBER RICCARDELLA: In that photo, the coating is removed.

MR. HARROW: That's correct.

MEMBER RICCARDELLA: And it's obviously rotated.

MR. SCHULTZ: Right, right.

CHAIR SUNSERI: But for the -- for the segment of pipe that had the circumferential break, though, the galvanic corrosion initiating site was also in the 5:00 to 7:00 range? Or was it in a different place?

MR. HARROW: It was on the bottom of the pipe. And it was -- it was basically a line or a stem from the original graphitic corrosion that was identified.

MEMBER RICCARDELLA: What's the operating pressure when the system is operating?

MR. HARROW: The operating pressure of the fire protection system is approximately 100 pounds.

(Pause.)

MR. HARROW: Previously performed visual inspections and soil samples taken at various locations around the protective area in conjunction with additional excavations performed for this failure support dry or acceptable conditions in all areas where inspection and samples were performed. In order to determine the extent of the fire protection main loop that was exposed to ground water, exploratory holes approximately 10-inches in diameter were vacuumed at strategic locations around the fire water header around the station.

To identify strategic locations for the exploratory holes, a review of several previous buried pipe inspection results was conducted to identify any instances of ground water that were identified during other excavations. This review provided insights as to where ground water may be present and a methodology to plot where exploratory holes should be dug to determine if ground water was in contact with fire main piping.

The holes were then evacuated to a depth of 7 feet, or until water was located. Seven feet was chosen because it is below the depth of the fire protection piping, which is buried at 6 feet on center line. The water found in the holes was sampled, but was determined to not include chlorides, which eliminated the possibility that the higher-than-expected groundwater level is leakage from the station intake canal.

This information supports the conclusion that potential corrosion concerns were confined to a limited area near the recent failures. Soil analysis were taken at the repair locations of the northern and southern pipe sections that had failed. Analysis results determined that one sample was in the lowest level of corrosivity achievable based on EPRI's sole corrosivity guidance. The other sample was in the next-to-lowest classification. And this was as Eric previously discussed. To address the current condition of the fire protection yard loop piping, compensatory measures have been put in place to maintain fire suppression capabilities. Next slide?

MEMBER BALLINGER: I have another question. So does what you have done so far give you enough confidence that -- you know, this graphitic corrosion, you can't really see it until you see it, right? So do you have confidence that there are other locations on that loop that hadn't, at some time in their life, been -- had groundwater access? In other words, you drilled your wells and you don't see any water here and here and here. But does that mean that you haven't seen water there? And there may not be water at other places?

MR. HARROW: The -- to address -- I believe that question is going to be addressed on the next slide --

MEMBER BALLINGER: Okay.

MR. HARROW: If I can just hold off on that.

MEMBER BALLINGER: Yes.

MR. HARROW: Okay. I want to provide some context on the current actions that are underway in response to this event. The station is taking proactive action to replace the affected fire protection yard loop piping, including associated fire hydrants and isolation valves through the Corrective Action Program. Funding has been approved for the project.

A four-phased approach prioritizes

component replacement based on yard loop piping susceptibility, as well as other key factors such as piping location, with respect to the fire protection pumps. Their primary focus, or phase one, is on the area of the main fire protection loop piping nearest to the fire protection pumps where groundwater has been identified and is in contact with the pipe. As piping is excavated and replaced, samples of pipe will be analyzed to validate the extended condition of the graphitic corrosion is bounded.

The Corrective Action Program will be utilized if graphitic corrosion is identified in additional sections of piping beyond phase one. An on-site project manager is in place and is actively working to select vendors who have the experience and capability of working with materials such as high-density polyethylene piping, or pipe within a pipe technologies, as examples. In coordination with the vendor selection, a conceptual design of the overall project is underway. Exploratory holes in support of phase one is currently in progress, with weekly report-outs to the station leadership team on project status.

MEMBER BALLINGER: Is this system cathodically protected?

MR. HARROW: The fire protection system is not cathodically protected.

MEMBER KIRCHNER: Allen, on an earlier slide you mentioned compensatory measures. So could you just -- for the record, just explain a little further what you're doing --

MR. HARROW: Yes.

MEMBER KIRCHNER: -- while you're undertaking this project?

MR. HARROW: Okay, so we -- the compensatories we currently have in place are, while -- while the current fire protection pumps -- both the motor-driven and the diesel-driven fire pumps are capable of being started and supplying fire protection water to the loop, we have put in an additional pump that has similar pump capacity capabilities to supply fire protection water from a separate source completely -- from the fire protection tanks -- which is capable of providing the backup fire suppression capability that are needed.

MEMBER KIRCHNER: Almost like some of the post-Fukushima kind of equipment -- like, that's the idea I am getting.

MR. HARROW: Yes, very similar to post-Fukushima -- beyond design basis --

MEMBER KIRCHNER: Okay. Do you have to have the extended fire watches during this? Or any other special demands that are -- I don't want to say the word tech specs, but something that are -- you know, condition of operation?

MR. HARROW: We have no additional fire watches required. However, we do have compensatory actions in place to isolate certain sections of the fire protection loop within a specific period of time if needed. To allow the other -- the other backup fire suppression pump to -- to supply the loop.

MEMBER KIRCHNER: And you -- you mentioned that the -- the loop design is segmented in a way so you can tap into headers or risers -- like, for the turbine building and other important areas from the safety standpoint.

MR. HARROW: That is correct. The loop has multiple points at which you can feed the loop and still supply the entire fire protection yard loop.

MEMBER KIRCHNER: Thank you.

MR. HARROW: You can do that --

(Simultaneous speaking.)

MR. HARROW: -- applicable locations.

MR. SCHULTZ: Allen, we talked earlier about soil testing in accordance with the EPRI methodology. As you've taken these other samples from other regions of the site, have you done soil testing as well as groundwater identification testing?

MR. HARROW: Soil testing has been done from other areas of the site. And I think this is a great opportunity for us -- for us to have the program owner for the buried piping who can get up and speak to that -- to that point.

MR. SCHULTZ: I would appreciate that, thank you.

MR. SCARBOROUGH: Good morning. I am Troy Scarborough. I am the buried pipe program owner at Surry Power Station and I work with the Dominion Energy team. And we have taken many soil samples. I believe Allen mentioned in -- I believe it was Eric -- in 2012 and in 2018. And in 2018, you know, we didn't identify any water during those samples. And we didn't take samples specifically at this location on the fire loop piping, but we took them around the -- safety-related piping around the RCA in the plant.

MR. SCHULTZ: I would understand that moisture is obviously a component. But the other aspects of EPRI's evaluation, as Erik indicated, was the chemistry -- evaluation of the chemistry of the soil. So I am wondering what has been done there.

When I look at what has been proposed, or expanded, in the -- in the SLR -- I don't know what you call it. The requirements process in place -- license renewal commitments. You have in there that you're going to follow the EPRI program and that you're going to take samples across the site on a -- not -- not every day, but as you're going through the process now, I would have expected that you'd get a -- be getting some sort of baseline associated with the samples, given that you've got them and you could simply do some chemistry testing to match up with the EPRI. You said you did it right around the location of the -- of the event. So have you considered looking at that chemistry in other areas of the -- of the piping that surrounds the site?

MR. HARROW: Yes, so as we continue to excavate and dig up piping, we are going to take soil samples, have them analyzed -- as well as sending piping off for metallurgical analysis as well. To identify graphitic --

MEMBER RICCARDELLA: Do I understand that there's other piping systems that are potentially affected, other than the fire -- the fire protection system? Is that what you said?

MR. SCARBOROUGH: We have some lower-tiered systems such as some cast-iron drain piping. Mainly roof drains -- and one other piping -- that -- we're going to take a look at that as well. Yes.

MEMBER BALLINGER: I heard -- say that this groundwater and the things like that was 500 -- less than 500 ppm chlorides, but one other place a little bit above that. But I think the ACI requirements as well as the EPRI guidelines require not just chloride concentration sampling, but sulfide -- or sulfur -- sulfate or whatever -- and the pH. When you do these samples, do you take all those things as well so you have records of those values as well? Because there's some kind of an index which you can -- the rules for concrete degradation contain the chloride limit, but it also contains the suggestions about sulfide and pH. And you have all that information.

MR. SCARBOROUGH: Correct.

MEMBER BALLINGER: Yes, thank you.

MR. SCARBOROUGH: We do sample for all of those parameters, yes.

CHAIR SUNSERI: So just -- just a follow-up question for the program owner. In regards to Member Riccardella's question about other systems -- do you have safety-related piping, such as access to the ultimate heat sink that's buried also? Or affected -- potentially affected?

(No audible response.)

CHAIR SUNSERI: We -- when you said there's other piping, it was unclear what other piping is. And I am asking specifically if there's safety-related piping affiliated with access to the ultimate heat sink.

MR. SCARBOROUGH: There's no safety-related piping in regards to this cast-iron phenomena.

CHAIR SUNSERI: Okay, great. Thank you.

(Pause.)

MR. HARROW: Okay ,continuing. EPRI is sponsoring a selective leaching industry task force. And this group of industry experts has been working on these very issues. We are actively participating with this task force to remain engaged in developments that will ultimately promote effective methods for aging management.

In that spirit, Surry Power Station's program owner has shared this operating experience with the industry, as noted in recent and upcoming meetings on the slide, with the goal of increasing industry awareness. Dominion Energy has also sent sections of fire protection piping from the recent event to EPRI, who continues to research enhanced methods to detect graphitic corrosion. Dominion Energy will update the site programs and procedures as new information becomes available from the efforts of the research and industry groups.

In conclusion, Dominion Energy is committed to ensuring the appropriate resources are in place to maintain the integrity and aging management of the fire protection yard loop. I am open for any questions at this time.

MR. SCHULTZ: Allen, what's the schedule for the EPRI evaluation of the piping?

(No audible response.)

MR. SCHULTZ: Or, do you have a schedule yet? Or can you give an appreciation for what it would appear to be? Troy?

MR. SCARBOROUGH: Troy Scarborough again. Yes, so I went to a conference last week on that. And they expect to have some NDE results coming out later this year that they -- they believe to be, you know, effective in determining selective leaching.

MR. SCHULTZ: Thank you, Troy.

MR. HARROW: Okay. At this time I will now turn the presentation over to Paul Aitken, who will provide summary remarks.

MEMBER RICCARDELLA: Quick question -- before we move on. Just one question related -- it's kind of related to my question earlier about leakage versus rupture. Had you had a fire when you turned on that pump, would the system have supplied sufficient water to -- to fight that fire? Or would all the water be going out the brick?

MR. HARROW: Well, so the system was -- remained pressurized. The fire pump itself started to maintain the system pressurize. So the fire protection water would have been able to be supplied to a fire. It's interesting to note that, for this particular issue, that the -- the station who was -- you know, obviously -- obviously, this wasn't something that was anticipated that was going to happen. It was on a weekend. Saturday afternoon. That section of pipe was completely isolated within 19 minutes. And then the -- the fire protection tank water itself was completely restored in less than three hours.

The -- the capability of continuing to fight a fire existed at that time.

MEMBER RICCARDELLA: Yes, thank you.

MR. BLOCHER: Okay. On behalf of Dominion Energy, we first want to commend the NRC staff on their efforts over the last couple of years. The staff has worked very hard in developing the goal SLR and SRP and conducting the various public meetings which provided the appropriate forum for stakeholder involvement. This was not an insignificant effort. I can attest to that.

I would also like to recognize the NRC staff on the thoroughness of the safety review performed on the SLR application for Surry. I want to reiterate that Dominion Energy has been engaged and integrated with the work leading up to the GALL-SLR issuance. We have been heavily invested, along with others in the industry, over the last couple of years to ensure we have the appropriate guidance and have explored areas for optimization with the NRC staff based on the vast experiences during the first licensed renewals.

Dominion Energy has developed a high quality SLR application that benefitted from the GALL-SLR and SRP as well as the industry support. Dominion Energy will continue to invest in Surry Power Station now and into the future to ensure the continued safe and reliable operation for 80 years of operation. This ends our prepared remarks. And I would like to express our appreciation to the subcommittee for this opportunity to discuss operation of Surry for 80 years. Are there any remaining questions?

CHAIR SUNSERI: Do members have any other questions for them?

(No audible response.)

CHAIR SUNSERI: Okay, all right. Well we appreciate your presentation. Very thorough and informing. At this time, I would like to transition to the staff presentation. We would normally take a break, but we are tracking right along schedule and we have a hard stop at noon because there's other activities that we need to participate in. So I would ask that if anybody needs to take a biological break, that you do so individually and just quietly excuse myself and then come on back in. All right? So let's transition. Thank you.

(Pause.)

MR. MOORE: Mr. Chairman, we got a message during the presentation that Dominion and Exelon -- is that correct? Or, Southern and Exelon are on the public line. But they'll be muted with all the other members of the public until we unmute the public line.

CHAIR SUNSERI: Okay.

(Pause.)

CHAIR SUNSERI: Yes, you can't leave.

(Off microphone comments.)

CHAIR SUNSERI: Yes, we have a quorum. We maintain that quorum. Right, yes. Right. But I don't know if I am a warm body. I am kind of cold right now. My balding head -- it is chilly. So, Angela, are you leading this effort here? Okay, great. But we do have a quorum. And if you're prepared to get started, then we're ready. Yes.

MS. WU: Can you hear me over there? Okay, perfect. Can everyone hear me on the phone on the open line? Allen, can you say hello first?

MR. HISER: Good morning.

MS. WU: Great, okay. I think we're ready to get started. We just want checks --

(Simultaneous speaking.)

CHAIR SUNSERI: Yes, absolutely no problem.

MS. WU: Thank you, hello. Good morning, Chairman Sunseri and members of the ACRS Plant Licensed Renewal Subcommittee. My name is Angela Wu and I am one of the project managers for the Surry Power Station, Units 1 and 2 Subsequent Licensed Renewal Application -- or, SLRA. As you heard from Bob Caldwell at the start of the meeting, we are here to discuss the NRC staff's safety review of the Surry

SLRA as documented in the Safety Evaluation Report, or SER, that was issued on December 27th, 2019.

Joining me here at the table today are Lauren Gibson, the second safety project manager for the Surry SLRA. Dr. Steven Downey, Senior Reactor Inspector from Region II, and Lewis McKown, Acting Chief of Engineering, Branch 4, in the Division of Reactor Projects, Region II. In addition, joining us on the phone is Dr. Allen Hiser, Senior Technical Advisor for Licensed Renewal Aging Management, Division of New and Renewed Licenses -- who you just heard from.

Seated in the audience and joining in on the phone are members of the technical staff who participated in the review and conducted the audits. Next slide, please.

So we begin today's presentation with an overview of the -- safety review of the Surry SLRA before moving into the SER. Section 2, Scoping and Screening Review; Section 3, the Aging Management Review; Section 4, Time-limited Aging Analyses; as well as specific areas of the review. Then we will hear from Region II on inspections and plant material conditions before sharing the staff's conclusion on the Surry SLRA. Finally, we will have a discussion on some differing reviews. Differing views, sorry. Next slide, please.

Surry Units 1 and 2 were initially licensed in May 1972 and January 1973, respectively. In May 2001 the Applicant, Virginia Electric and Power Company -- or Dominion -- submitted the initial license renewal application. The initial renewed licenses were issued March 2003, extending the expiration dates to May 2032 and January 2033 for Units 1 and 2 respectively.

On October the 15th, 2018 Dominion submitted their subsequent license renewal application for Surry Units 1 and 2. The application was accepted for review on December 10th, 2018 and the draft safety evaluating report was issued on December 27th, 2019 with no open or confirmatory items. Next slide, please.

The Surry review is the third safety review performed by the staff using the GALL-SLR and SRP-SLR guidance issued -- since their issuance in 2017. For the review we conducted a total of three audits, as identified on this slide. During the operating experience audit, the staff performed an independent review of plant-specific operating experience to identify pertinent examples of age-related degradation as documented into Applicant's Corrective Action Program database. During the in-office audit, the audit team focused on two areas. First, the scoping and screening review. And second, the review of aging management programs -- or AMPs -- aging management review items, or AMRs -- or time-limited -- and time-limited aging analyses, or TLAAs.

An on-site audit limited to those technical areas that needed further review following the in-office audit was conducted at both Surry Power Station Units 1 and 2 in Surry County, Virginia and Dominion Headquarters in Innsbrook, Virginia. Next slide, please.

The Surry draft SER was issued with no open or performatory items on December 27th, 2019. During the staff's in-depth, technical review, a total of 71 requests for additional information were issued. Slide please. In the next few slides I will present the results of the staff safety review as described in the SER. SER, Section 2, describes the scoping and screening of the structures and components subject to aging management review. The staff reviewed the Applicant's scoping and screening methodology, procedures and results. The staff also reviewed the various summaries of the safety-related systems, structures and components -- or SSEs -- non-safety related SSEs affecting safety functions, and SSEs relied upon to perform functions in compliance with the Commission's regulations for fire protection, environmental qualification, station blackout, anticipated transients without scram, and pressurized thermal shock.

Based on the review, the results of the audits and additional information provided by the Applicant, the staff concluded that the Applicant's scoping and screening methodology and implementation were consistent with the criteria of the SRP-SLR and requirements of 10 CFR Part 54. Next slide, please.

SER Section 3 and its subsections cover this fast review of the Applicant's programs for managing the effects of aging in accordance with 10 CFR 52 -- 54.21 A-3. Sections 3.1 to 3.6 include the AMR items in each of the general system areas within the scope of subsequent licensed renewal, as shown on this slide. For a given AMR item, the staff reviewed the item in accordance with the criteria of the SRP-SLR to determine whether it is consistent with the GALL-SLR. For AMR items not consistent with the GALL-SLR, the staff reviewed the Applicant's evaluation to determine whether the Applicant has demonstrated that there is reasonable assurance that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis for the subsequent period of extended operation.

Based on the review, the results from the audits and additional information that was provided by the Applicant, the staff concluded that the Applicant's aging management review activities and results were consistent with the criteria of the SRP-SLR and requirements of 10 CFR Part 54. Next slide.

So the SLRA described a total of 47 AMPs -- seven new and 40 existing. This slide identifies the Applicant's original disposition of these AMPs, as stated in the SLRA in the left column, and the final disposition as documented in the SCLR in the right column. All of the AMPs were evaluated for consistency with the GALL-SLR. As a result of the staff's review, the Applicant made one change to the disposition of the AMPs. Based on the review, the results from the audits and additional information provided by the Applicant, the staff concluded that the Applicant's aging management program activities and results were consistent with the criteria of the SRP-SLR and requirements of 10 CFR Part 54.

SER Section 4 identifies time-limited aging analyses, or TLAAs. Section 4.1 documents the staff's evaluation of the Applicant's identification of applicable TLAAs. The staff evaluated the Applicant's bases for identifying these plant-specific or generic analyses that need to be identified as TLAAs, and determined that the Applicant has provided an accurate list of TLAAs as required by 10 CFR 54.21 C-1. Section 4.2 to 4.7 document the staff's review off the applicable TLAAs for the areas shown on this slide.

Based on its review and the information provided by the Applicant, the staff concludes that each TLAA is classified, as required by 10 CFR 54.21 C-1, as either I, the analysis remains valid for the subsequent period of extended operation; ii, the analysis has been projected to the end of this subsequent period of extended operation; or iii, the effects of aging on the intended functions will be adequately managed for the subsequent period of extended operations. So based on the review, the results from the audits and additional information provided by the Applicant, the staff concluded that the Applicant's TLAA activities and results were consistent with the criteria of the SRP-SLR and requirements of 10 CFR Part 54.

So because the draft SER was issued with no open or performatory items, we will now be highlighting some specific areas of the review that we think may be of interest -- as shown on this slide.

CHAIR SUNSERI: And before I forget and you move on, I did look at the audit report. And that was quite a thorough report. So you all did a nice job on that.

MS. WU: Do you have any questions on that? Or just -- making a comment?

CHAIR SUNSERI: No, no.

MS. WU: Thank you. So we're on slide 11. Irradiation fluence and dose -- experience through 80 years of operation by concrete and steel structural components located in the vicinity of the reactor vessel could be significant. For Surry, the concrete biological shield wall and reactor vessel steels supports were evaluated for these irradiation aging effects. This slide presents the staff's review of Dominion's evaluation for the concrete biological shield wall. And the next slide will then discuss the reactor vessel steel supports.

The staff reviewed Dominion's further evaluation of the irradiation aging effects of reduction of strength and mechanical properties of the concrete biological shield wall against the criteria of the corresponding SRP-SLR section. The figure on the slide shows the general configuration of the concrete biological shield wall relative to the reactor vessel and a neutron shield tank, which is shaded in blue.

Although not fully shown, the concrete biological shield wall extends above and below the neutron shield tank. Based on the review, responses to the REIs and the staff's audits, the staff finds that Dominion has met the further evaluation criteria in the SRP-SLR for the concrete biological shield wall concrete. Dominion's determination that a plant-specific AMP is not required to manage the aging effects of irradiation on the concrete biological shield wall during the subsequent period of extended operation is acceptable for the following reasons.

The calculated limiting neutron fluence and limiting gamma dose are less in the respective thresholds, as noted in the SRP-SLR. The use of 72 effective full-power years for fluence and dose estimates is conservative, whereas anticipated plant operation is 68 effective full-power years. There is no plant-specific operating experience noted to date of concrete biological shield irradiation degradation. And the accessible areas of the concrete biological shield wall will continue to be monitored by visual inspection in a five-year interval using the structure's monitoring program.

Slide, please. Dominion's SLRA Section 35-226 addresses Surry's reactor vessel steel support assemblies. Surry's reactor vessels are supported by six steel sliding foot assemblies on neutron shield tanks, as illustrated in the figure. The neutron shield tank skirt is supported on the containment base net floor, approximately 15 feet below the bottom of the angular tank. Based on the review, the staff finds that the neutron shield tanks will maintain their structural integrity. This is based on a fracture toughness evaluation, made in accordance with the ASME Code Section 11, Appendix A, and the fractured mechanics approach of NU-REG 1509.

The fractured toughness evaluation demonstrated that critical stress regions of the neutron shield tanks are not susceptible to brittle fracture due to irradiation embrittlement because the maximum applied stresses under design loads remain below the critical stress values for postulated evaluated flaws during the subsequent period of extended operation. In addition, accessible surfaces of the neutron shield tank and its sliding foot assemblies will continue to be periodically inspected externally for susceptible aging effects by one or more of the following programs -- the ASME Section 11, subsection IWF program at a 10-year frequency, and the structures monitoring program at a 5-year frequency.

The neutron shield tank is filled with chromated fluid. To prevent loss of material in the neutron shield tank, the closed treated water systems AMP specifies monitoring this chemistry of the naturally circulating chromated fluid every fueling outage. The staff determined that Dominion's evaluation for the neutron shield tank and reactor vessels support sliding foot assemblies meets the intent of the SRP-SLR for the evaluation criteria consistent with the GALL-SLR principles.

For the buried and underground piping and tanks program, the Applicant proposed using a one-time inspection along with groundwater and soil testing. To manage the effects of aging on the external surfaces of uncoated, buried cementitious circulating water piping. The staff notes that the Applicant's approach to manage the effects of aging differs from the GALL-SLR guidance.

The GALL-SLR recommends periodic inspections, as noted on the slide, for this component, material and environment combination. For the one-time inspection, the Applicant proposed a one-time inspection of the turbine building below subsurface concrete as the surrogate concrete structure if it is bare or uncoated. Otherwise, a one-time inspection of the buried cementitious circulated water piping will be performed.

The circulating water pipe has an inside diameter of 8 feet, a wall thickness of 9 inches and it is reinforced with rebar longitudinally and circumferentially on both the inside and outside surface. The staff evaluated whether the turbine building's subsurface concrete would be an appropriate surrogate concrete by comparing its properties and environment to those of the circulating water piping. It is noted that the surrogate concrete structure and the circulating water piping concrete were made to meet the same American Society for Testing and Materials Standards for a cement aggregates, water and reinforcing steel.

The staff also noted that, if the proposed concrete to be inspected for the turbine building is bare concrete, it will be exposed to the same environment as the circulating water piping. This is because both components are located at a depth that is below the groundwater level and freeze-thaw line. At this depth, the groundwater and soil is not aggressive for concrete. The staff also noted that the turbine building concrete has a higher water-to-cement ratio and a lower concrete strength.

Considering the concrete design standards and concrete properties of the turbine building and circulator water piping, the staff finds that the turbine building concrete is expected to be more susceptible to degradation than the circulating water piping concrete. Therefore, the staff finds that the turbine building concrete to be an adequate surrogate concrete structure that can serve as a leading indicator of potential degradation at the circulating water piping because its concrete properties are such that, if the environmental conditions were conducive of concrete degradation, signs of such degradation would also be present and identified at the turbine building surface concrete and corrective actions would be taken to evaluate the circulating water piping degradation before there's a loss of their intended function.

Regarding the acceptability of performing one-time inspections in lieu of performing periodic inspections as recommended in the GALL-SLR, the staff noted that the Applicant performed groundwater testing at every five years and soil testing at every ten years.

CHAIR SUNSERI: Regarding the surrogate sampling approach and the -- I understand the comparison of the ASME standard so that they're the same standard. But was the aggregate used to actually construct the two, I'll call them facilities from the same quarry because it's my, or similar because it's my understanding that aggregate can have a big effect on the degradation potential. So do we know if it was constructed from the same material, not only the same standard?

MS. WU: So is Brian Allik available to answer that question? Oh --

MR. JOHNSON: Excuse me. This is Jim Johnson again. The aggregate was not, as far as we know, from the same quarry because the pipe was manufactured offsite. But we haven't had any indications of ASR in any of the concrete. The ASR was studied.

There was some core-drills done. Back in '88 Virginia Tech did a study and actually the core-drills for several structures around site and did not find ASR at that time.

CHAIR SUNSERI: Okay. I'm satisfied. Thank you.

MR. SCHULTZ: But just for clarification, both of these inspections are one-time inspections?

MS. WU: So the groundwater testing is every five years, and the soil testing every ten years.

MR. SCHULTZ: Okay. I was thinking of the turbine building concrete. That's happening one time.

MS. WU: Yes, yes.

MR. SCHULTZ: And has that -- that's been done or it will be done?

MS. WU: It will be done.

MR. SCHULTZ: At what, on what time schedule? When will it be done, before, sometime before the --

MS. WU: A subsequent period of extended operation.

MR. SCHULTZ: Yeah, sometime before, yeah, to be defined?

MS. GIBSON: I don't have those details right now. Is Brian Allik available? Oh, Juan Lopez is.

MR. SCHULTZ: Right. Thank you.

MR. LOPEZ: This is Juan Lopez from the staff. The commitment right now is to do it one time before the subsequent period of extended operation.

MR. SCHULTZ: But no time has been specified at this point.

MR. LOPEZ: Not a specific time that it will be happening before.

MR. SCHULTZ: And we'll just see what happens with the one-time inspection. All right.

MEMBER BALLINGER: We were told that the containment building cover is five inches. What's the turbine building cover?

MR. JOHNSON: This is Jim Johnson. I don't know offhand. I think it's three inches at that point. That would be per ACI codes for the turbine building.

MEMBER BALLINGER: Okay. That's --

MS. WU: Thank you, Jim and Juan. Any other questions before I continue?

The staff notes that the GALL-SLR identifies the same groundwater and soil environment parameters as the main environmental stressors for below-grade concrete used in buried cementitious piping.

Based on the inclusion of groundwater and soil testing, the staff finds that a one-time inspection of either a surrogate structure or buried circulating water piping provides the staff reasonable assurance that the effects of aging will be adequately managed.

MEMBER KIRCHNER: Angela, is there any, pardon me, are there any aging effects internal to the pipe?

MS. WU: Oh, internal.

MS. GIBSON: I believe those would be handled --

MEMBER KIRCHNER: Like long-term erosion corrosion.

MS. WU: Yeah, that would be a different AMP than this one.

MEMBER KIRCHNER: Hmm?

MS. GIBSON: It would be handled under a different AMP.

MEMBER KIRCHNER: Different AMP.

MS. GIBSON: Yes. Would that be internal coatings?

MS. WU: Yes, internal coatings.

MS. GIBSON: Or internal surface.

(Off mic comments.)

MS. WU: Okay. So we're on slide 14. On October 14, 2019, Dominion submitted an annual update to the SLRA that identified two ruptures of the buried fire protection system piping which occurred in July of 2019.

Analysis concluded that the failure was a result of external graphitic corrosion and determined that it was a result of groundwater exposure of the cast iron fire protection piping.

In response to this operating experience, the applicant has augmented the new selective leaching program to address the graphitic corrosion that led to the ruptures by including requirements to drill exploratory holes to confirm the presence of groundwater.

These holes will be drilled in areas of suspected system leakage or elevated groundwater. For each hole identified with groundwater, the applicant will excavate and inspect the fire protection loop piping at each hole. Each excavation will include a soil sample.

The applicant will also drill additional exploratory holes to confirm the extent of any identified elevated groundwater along with the notice sample expansion activities.

For each excavation, a minimum of ten feet of buried fire protection main loop piping will be excavated and then cleaned using aggressive cleaning techniques sufficient to remove the alloyed material and visually examined for evidence of selective leaching.

A minimum of five destructive exams will be performed in separate, one-foot sample sections of fire protection pipe that exhibit signs of selective leaching.

If water in an exploratory hole is identified to be a result of fire protection system leakage or other plant system leakage and not due to elevated groundwater, then corrective actions would be initiated consistent with the selective leaching program.

Changes to the aging management programs to address possible issues, if necessary, would be identified as Dominion completes these corrective actions for the July 2019 pipe ruptures.

In conclusion, the staff has reasonable assurance that the newly augmented selective leaching program will be adequate to manage selective leaching. The required activities, drilling exploratory holes to confirm the presence of groundwater and excavating and inspecting fire protection loop piping, are capable of detecting adverse conditions due to groundwater immersion that may lead to graphitic corrosion.

Next slide, please.

MEMBER KIRCHNER: Before you go on, so is -- we heard from the applicant there are plans on this project underway to replace the fire loop piping. To what extent is that a commitment that you, the NRC, will have some oversight of or regulatory review?

MS. WU: So the selective leaching program, following the annual update that was provided on October 14, 2019, there was a subsequent letter that came in October 31, 2019 from Dominion that augmented the selective leaching program itself in the description of the AMP.

However, there was no change to the commitments. So, if that's what you're asking, there was no modification to the commitments in that matter.

Do you have something to add?

MR. DOWNEY: Well, I can speak from the perspective of oversight. So, if this were in the initial period of extended operation, our Phase 2 type inspection would be where we would go in and verify that the commitments made by the licensee had been appropriately implemented.

For subsequent license renewal, currently there aren't any inspections in the program for subsequent license renewal. We understand that the license renewal inspection program is being updated. So there may be some added in the future.

MEMBER KIRCHNER: And this initial fire loop system was in place since the plant was first licensed. So it had a lifetime of the, oh, now close to 50 years. Is that correct?

So one could expect that if they replace substantial parts of the piping, that would be a lifetime that might be well beyond the extended period of operation. Okay.

But it's through your inspection process, Steven, that you would stay abreast of what changes are being made and --

MR. McKOWN: In both the license renewal phase and in the normal baseline ROP, we have processes and procedures that would guide governance for long-lived passive systems being reviewed under that inspection phase. So it would fall --

MEMBER KIRCHNER: Through the inspection process. Okay. That answers my question.

MR. OESTERLE: This is Eric Oesterle from the staff. I'd just like to supplement the answer.

So there are two or three different processes involved here. One is the subsequent license renewal review that the staff is performing on the application. The other process is the inspection of the initial license renewal implementation of aging management programs.

And then there's the corrective actions program. The NRC always has oversight over the corrective actions program and --

MEMBER KIRCHNER: Okay. Thank you.

MS. WU: Thank you for your question.

MR. SCHULTZ: Steven, I'm looking ahead in the slides, so maybe it's being covered later in detail. But under the AMP inspections, there's one that's coming up in the first quarter of 2020 on the 2019 fire loop piping rupture burying piping program. So does that not enter into our discussion here?

MR. DOWNEY: Yes, you're talking about the focused PI&R.

MR. SCHULTZ: Yes.

MR. DOWNEY: PI&R meaning problem identification and resolution.

MR. SCHULTZ: Thank you.

MR. DOWNEY: So that's corrective action inspection.

MR. SCHULTZ: All right. So that's, what

you're describing here is the, is something that's upcoming. And what is the scope of that, if you don't mind covering it now?

MR. DOWNEY: So you're stealing my thunder a little bit here.

MR. SCHULTZ: Oh, I'm sorry.

MR. DOWNEY: That leads --

MR. SCHULTZ: I can --

MR. DOWNEY: Yeah, I'll cover it during the --

MR. SCHULTZ: Let's wait.

MR. DOWNEY: -- presentation.

CHAIR SUNSERI: Steve, is your mic on?

MR. SCHULTZ: Yes, it is.

CHAIR SUNSERI: Okay.

MR. SCHULTZ: Did you catch it?

CHAIR SUNSERI: Yeah, no, that's all right.

MR. SCHULTZ: The other question I had, Angela, you mentioned that there weren't any changes to the commitments related to the issues related to the --

MS. WU: To the new operating experience. But they did provide commitments, as they would for any AMPs, so when they would have submitted the application --

MR. SCHULTZ: Okay. Maybe I misunderstood how the process goes, because in the information that Surry provided in the, I think it was October, September timeframe, they included new, their commitment that dictates that they're going to follow for soil sample evaluation the EPRI guidelines. And they've talked about how they're going to identify soil corrosivity index networks that are in that document. So that's been added specifically --

MS. WU: Right.

MR. SCHULTZ: -- in their program going forward.

MS. GIBSON: So, correct me if I'm wrong, but I believe that that was added to their program description --

MS. WU: Yes.

MR. SCHULTZ: Okay.

MS. GIBSON: -- as opposed to the formal listing of commitments that's going to be incorporated into the FSAR.

MR. SCHULTZ: What's the difference, if you can help me?

MS. GIBSON: The difference is that the program is a procedure and the commitments themselves become part of the FSAR and under a change control program.

MR. SCHULTZ: Okay. So, then, does that mean that the procedure is under their control and not in the FSAR, which would be under NRC control? I'm trying to understand the distinction --

MS. GIBSON: Yes.

MR. SCHULTZ: -- in terms of implementation.

MS. GIBSON: There's a lower degree of control that we have over the procedures. It has to go through -- it's incorporated into the license through the FSAR updates with the commitments. And those commitments are subject then to the 50.59 process.

So it's under a changed control mechanism. But it is not like a tech spec where they would have to come in to change a word.

MR. SCHULTZ: I understand.

CHAIR SUNSERI: But would the requirements of 50.59 still apply though or not?

MS. GIBSON: Well, they would. But I'm not sure whether this would actually rise to the level of being --

MR. DOWNEY: So, if the license condition for subsequent license renewal is anything similar to the license conditions for initial license renewal, then it folds in that any changes to the activities described in programs, et cetera, would be evaluated using a 50.59 process. So that's how it ties in through the license condition.

MR. SCHULTZ: So, just to clarify, so this is under the topic of subsequent license renewal conditions, commitments, but it's a commitment to have procedures in place. Is that what you're saying?

MS. GIBSON: Yes.

MS. WU: Yes.

MR. SCHULTZ: So it doesn't change the FSAR.

MS. WU: No.

MR. SCHULTZ: Thank you. I got it.

MS. WU: The selective leaching program does have a commitment tied to it. It just was not revised as a result of the July 2019 pipe ruptures that was then reported to us on the October 14, 2019 annual update.

MR. SCHULTZ: So let me back up a bit. When you were talking about the turbine building concrete, you indicated that soil testing was going to be done as part of that program to make sure there wasn't anything else that was coming up. And that would be the going forward process to do a double-check or evaluation on a, going forward time basis versus the one-time inspection. So is that a commitment, or is that part of another procedure?

MS. WU: That one, Brian, do you want to --

MR. ALLIK: Brian Allik, NRC staff. Just to clarify a point, there's two specific commitments related to soil testing.

The first one, which references that EPRI report, is in context with carbon steel. And then there's another commitment related to, you know, the alternative approach that was previously described to do soil testing near the, in the vicinity of that concrete or cementitious piping. So I just wanted to clarify that point.

MR. SCHULTZ: I appreciate that.

MR. ALLIK: All right.

MR. SCHULTZ: I knew they were different. But it sounded similar. And it's also characterizing the soil, which is a good thing to do. Thank you.

MR. OESTERLE: So this is Eric Oesterle from the staff. Just wanted to supplement the responses. So there's different tiers of documents that we're talking about.

So the commitments for the aging management programs included in the application, in which they're also included in Attachment A to the SAR, often talk about a timeframe in which the AMP will be implemented. And there's the description of the aging management program itself, which gets included in the FSAR and, therefore, becomes part of the current licensing basis.

There are implementing procedures that are lower-tiered documents from that FSAR level information which the applicant will use to implement those activities.

Both things, the FSAR, compliance with the current licensing basis, and those implementing procedures are all part of NRC oversight.

MR. SCHULTZ: And subject to inspection.

MR. OESTERLE: Correct.

MR. SCHULTZ: Thank you, Eric.

CHAIR SUNSERI: I am going to interject right here. As I announced earlier at the start of the meeting, I'm going to have to excuse myself for a short period of time. And in my absence, Walt will be the chairperson running the meeting. And I note that even with my absence we do have a quorum still. So thank you.

MS. WU: Slide 15, neutron fluence monitoring. In its review, the staff identified a difference between the program elements that the applicant defined for the neutron fluence monitoring AMP and the corresponding elements defined in the GALL-SLR.

The difference is that the applicant will not monitor neutron fluence of the reactor vessel internals through an SLR period.

Appendix C of the SLRA included generic 80-year fluence ranges as part of the screening criteria for reactor vessel internals components in the MRP-227, Revision 1, gap analysis.

However, the applicant did not provide 80-year fluence values specific to the Surry reactor vessel internals.

Because the applicant will not be monitoring neutron fluence of the reactor vessel internals, the staff needed the 80-year fluence projections of the reactor vessel internals to verify if the fluence values of the reactor vessel internals fall within the generic fluence ranges as cited in Appendix C of the SLRA.

To do so, the staff issued an RAI

requesting for the 80-year fluence projections specific to the Surry reactor vessel internals.

In its RAI response, the applicant provided a proprietary report that included the 80-year fluence projections specific to the Surry reactor vessel internals and described the fluence projection methodology used in the report.

The staff reviewed the 80-year Surry-specific fluence values for the reactor vessel internals and the fluence methodology in the proprietary report. The staff found the fluence values acceptable.

Based on the 80-year fluence projections of the Surry reactor vessel internals falling within the specified ranges of The MRP-227, Revision 1, gap analysis, the AMP provides reasonable assurance that the effects of aging will be adequately managed.

MEMBER KIRCHNER: Angela, do you do a kind of assessment of their proprietary report through your own benchmarks or other look-up tables or even going as far as doing actual calculations to have confidence that their estimate is reasonably accurate so then you can draw the final conclusion that you have?

MS. WU: Do David Dijamco is going to speak to that since he did the technical review.

MR. DIJAMCO: This is David Dijamco from the staff. We basically just reviewed the proprietary report. We just made sure that the fluence values for the internals fall within the ranges.

And we also reviewed the methodology, the fluence methodology and that they were, made sure that they were consistent with the Reg Guide 1.190. But we didn't do actual independent calculations.

MEMBER KIRCHNER: But this is something that's been done through the industry quite frequently. So one could have some confidence just based on, I don't want to say back-of-the-envelope calculations, but, you know, other submittals and such in terms of whether it's a reasonable estimate or not, right? Do you do anything like that? When you said --

MR. DIJAMCO: No, we did not do that, no, yeah.

MEMBER KIRCHNER: But when you said you reviewed the methods, is this like -- I don't want to go into proprietary information here. But say they were using MC&P. That's a widely accepted tool for this particular application.

So you would look at the methods in terms of whether they were validated. Is that what you mean when you say you reviewed the methodology?

MR. DIJAMCO: Correct. Is Dr. Peng here? Dr. Peng.

DR. PENG: This is Shie-Jeng Peng from staff. I understand your question regarding the benchmark on the methodology.

Yes, they asked Westinghouse to -- time to have, it's a variance capsule come out with -- they used the same methodology to check the calculations with measurements with a certainty or not.

And this is a very good conclusions at, for both unit within the 1 Sigma, 20 percent uncertainty.

MEMBER KIRCHNER: Okay. Good. Thank you.

MR. SCHULTZ: It was noted by Surry that they are going to withdraw capsules during the period of extended operation and, on both units. So that has been taken into account in your evaluation as well?

MS. WU: We would have to -- was it? Yes, it was.

MR. SCHULTZ: Thank you.

MS. WU: Okay. Next slide, please.

In its review of the inaccessible medium-voltage cable AMP, the staff identified an issue with an enhancement. The applicant did not include a test matrix.

The applicant provides the inaccessible medium-voltage cable AMP to include a test matrix that includes inspection methods, test methods, and acceptable criteria for the inaccessible medium-voltage cables.

The staff reviewed this revision and finds it acceptable because it is consistent with the GALL-SLR.

Also, the applicant's proposed environmental qualification, or EQ program, excluded mechanical components. It is not clear that the interfacing mechanical components, such as seals, lubricants, and gaskets, will be age-managed as part of the EQ AMP.

The staff performed an onsite audit and verified that the mechanical interfaces are addressed in the EQ program.

The plant qualification evaluations document replacement components and their respective replacement schedules as well as routine maintenance to maintain qualifications.

The applicant used the provision of reanalysis per 10 CFR 50.49 to monitor and extend qualified life of the cables. The reanalysis methods and calculations are consistent with the current rules and regulations.

The staff, therefore, concluded that the EQ program is adequate to satisfy the TLLA, consistent with 10 CFR 54.21(c)(1)(iii).

Now, Dr. Steven Downey will discuss inspections and plant conditions.

MR. DOWNEY: Good morning. As mentioned, my name is Steven Downey. I'm a Senior Reactor Inspector.

MEMBER KIRCHNER: May I just -- yeah.

MR. DOWNEY: Yes.

MEMBER KIRCHNER: Bring your microphones closer to you. This room has, absorbs sound. So you have to speak loudly to be recorded for the record, please.

MR. DOWNEY: Okay. Thank you. So my name is Steven Downey. I'm a Senior Reactor Inspector in Region II, Division of Reactor Safety, Engineering Branch 3. I am one of the license renewal point of contacts for Region II. And I was the team lead for the recent Phase 4 license renewal inspection at Surry.

With me, is Louis McKown. He's Acting Branch Chief in Region II, Division of Reactor

Projects, Reactor Projects Branch 4.

And we are here to discuss Region II's review and assessment of the implementation of aging management programs at Surry, the material condition of the plant, and the overall regulatory assessment of Surry Units 1 and 2.

So, before I get started, the license renewal inspection program and the reactor oversight process baseline inspection program are both used to inspect aging management programs at Surry.

I'll start with activities performed under the license renewal inspection program and then discuss the baseline inspections and follow up with the material condition of the plant discussion.

So, in order to assess the adequacy of license, of the license renewal program for the initial period of extended operation, Inspection Procedure 71003 recommends a four-phased approach to license renewal inspection.

This slide details the license renewal inspections that we have performed at Surry. And as I discuss each line item, I will give a bit of detail on what the inspection entails.

So first item is the Phase 1 inspection, which we performed for both units back in April 2011.

This is an outage inspection that focuses on observing the implementation of select aging management programs and activities credited for managing aging, as well as any testing or visual inspections of structures, systems, and components that are only accessible at reduced power levels.

April 2011 was the spring outage for Unit 2, so the inspectors were able to maximize the observation of activities credited for license renewal that were performed on Unit 2 prior to entering its period of extended operation, while also observing license renewal activities performed on Unit 1, such as the external visual examination of the Unit 1 containment in accordance with ASME Section 11 requirements.

No findings of significance were identified as a result of the Phase 1 inspection.

Next, the Phase 2 inspection, which we performed on both units in July 2011, is our one-time major team inspection during which the inspectors assess the adequacy and effectiveness of the implementation and/or completion of the programs and activities described in regulatory commitments, the UFSAR supplement program descriptions, time-limited aging analyses, or TLAAs, and license conditions.

During the Phase 2 inspection, the inspectors also evaluate the need for additional follow-up inspections.

So no findings of significance were identified as a result of this inspection. However, the inspectors identified eight observations that were subject to a follow-up inspection in accordance with the IP, inspection procedure.

MR. SCHULTZ: Steven --

MR. DOWNEY: Yes.

MR. SCHULTZ: -- when you say a team inspection, what does that entail? How many --

MR. DOWNEY: So we --

MR. SCHULTZ: How many inspectors are incorporated?

MR. DOWNEY: For a Phase 2, we typically, six inspectors. We typically send our whole branch for a team inspection.

MR. SCHULTZ: Different areas of expertise.

MR. DOWNEY: Yes. And --

(Simultaneous speaking.)

MR. DOWNEY: So, for Surry, and this inspection happened back in 2011. So Surry has 30 license renewal commitments that can be bent into enhancements to aging management programs for license renewal, newly implemented programs, and stand-alone commitments that can be anything from following industry guidance to doing certain inspections.

And we just divide, we divide those amongst the team and --

MR. SCHULTZ: Do any of the observations that --

MR. DOWNEY: Yes.

MR. SCHULTZ: This is the one that has eight observations. Do any of them come to mind as something you'd share as an example observation?

MR. DOWNEY: So I have all of them. And typically observations are those items that -- well, first I'll say the Phase 2 inspection typically occurs prior to entering the period of extended operation.

As we discussed a little bit earlier, when the licensee commits to activities, they may commit to, that this activity is completed prior to entering that period.

So, during the Phase 2 inspection, let's say we identify that some one-time inspections under the buried piping program were not completed at the time of the inspection. That rose to the level of an observation, which we come back and follow up to verify technically acceptable completion. And that inspection for us happened in 2012.

So all of the observations have that flavor to them. And I can give some details on each one if you'd like.

MR. SCHULTZ: No, that's fine.

MR. DOWNEY: Okay.

MR. SCHULTZ: I just wanted to get a flavor of what they look like and --

MR. DOWNEY: Okay.

MR. SCHULTZ: -- what you were looking to do as you move forward in the different phases. Thank you.

MR. DOWNEY: Yeah. So the Phase 3 inspection, which is our follow-up inspection, was performed at Surry in June 2012.

At the conclusion of that inspection, the inspectors identified one minor violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action.

Otherwise, no findings of significance were identified. And the inspection team concluded that the licensee had completed all necessary actions to meet its license renewal commitments.

If you're interested in hearing more about the minor, I have the description of that here as well. Otherwise, I will proceed.

MR. SCHULTZ: Does it bear on the things that we have discussed today related to SLR?

MR. DOWNEY: Let's see. Not, it's -- so it was for inadequate corrective action related to a leak in the Unit 2 neutron shield tank.

MR. SCHULTZ: Thank you.

MR. DOWNEY: So, finally, the Phase 4 inspection, which typically occurs five to ten years into the period of extended operation, was performed at both, for both units at Surry in August 2019.

This, the Phase 4 inspection is intended to verify that the licensee is managing aging effects in accordance with the aging management programs described in the UFSAR.

No findings were identified as a result of this inspection. But I'll take a bit of time to explain what we looked at and our approach. Next slide, please.

For the initial license renewal period, the Surry UFSAR identifies 22 programs and activities credited for managing the effects of aging. Three of those were new aging management programs. And 19 were previously existing aging management programs.

For the Phase 4 inspection, the nine aging management programs shown here on the slide were selected for review using the criteria provided in Inspection Procedure 71003.

And for each program we selected, the inspectors reviewed the licensee's implementation of that program by selecting a sample of structures, systems, and components within the scope of the respective program and verifying that the aging of the selected items, I'm sorry, were being adequately managed.

To make that determination -- sure. Yes.

MEMBER KIRCHNER: Of that same, of the list that you have there, how did you -- I'm sorry. I thought I pushed it. Of the list, how did you come about picking those, for example, tank --

MR. DOWNEY: Sure.

MEMBER KIRCHNER: -- inspection, because back in 2012 you had a corrective action observation, et cetera? So --

MR. DOWNEY: So corrective actions is one component. And in Section 0302 of the IP, it gives a list of inspection sample attributes. But I like to use examples. So I'll use one here.

MEMBER KIRCHNER: Yeah.

MR. DOWNEY: So you're starting with 22

programs. And we'll say, okay, here are these programs that are long-existing and mature programs. So we'll cut off like in-service inspections, steam generator integrity. We'll cut off some of those.

MEMBER KIRCHNER: Right.

MR. DOWNEY: Then we'll say here, what subset of those programs have been subject to previous baseline inspections or previous license renewal inspections.

MEMBER KIRCHNER: Right.

MR. DOWNEY: Then we'll do those. Then we'll look at operating, recent operating experience, corrective actions associated with managing aging. And that will help us pick select samples.

The tank inspection program was selected because of some corrective actions.

MEMBER KIRCHNER: Right.

MR. DOWNEY: And in addition to that, we take input from our resident inspectors, as well as we took input from our counterparts in NRR to provide insights to selecting a sample for this inspection.

MEMBER KIRCHNER: And just one further question, the timing. So this was about seven years into the first extended period of operation.

MR. DOWNEY: Yes.

MEMBER KIRCHNER: So is there any, in your Inspection Procedure 71003 and the GALL and other things that you use as points of reference, is there any mandatory time to do that inspection, or that was just decided this is, it's time to do it, seven years into the extended period --

MR. DOWNEY: Just we --

MEMBER KIRCHNER: -- of operation?

MR. DOWNEY: In that window of five to ten.

MEMBER KIRCHNER: Okay.

MR. DOWNEY: Any other questions?

MEMBER KIRCHNER: So the interval for Phase 4 inspection would be at least five years?

MR. DOWNEY: Into, yes, into the period --

MEMBER KIRCHNER: Okay.

MR. DOWNEY: -- of extended operation, yes.

MEMBER KIRCHNER: Thank you.

MR. DOWNEY: So to, I was discussed the SSCs within the scope of their respective aging management programs and verifying that the aging of those items were being adequately managed.

And to make that determination, the inspectors performed the following activities as applicable to the items in their respective samples.

So we walked down all accessible structures, systems, and components to observe their general condition and identify any signs of aging-related degradation.

We interviewed plant personnel, reviewed completed work orders to verify that aging management activities were being performed in accordance with plant procedures and at the intervals prescribed in their respective programs.

We reviewed applicable monitoring and trending data and reviewed the acceptability of inspection and test results.

Also, for all programs here, the inspectors reviewed a sample of aging-related issues entered into the licensee's corrective action program to verify that aging-related degradation is being identified at an appropriate threshold.

Based on our inspection, no findings of significance were identified. And this inspection result provided us with a reasonable assurance that the licensee was appropriately implementing the selected aging management programs.

Now, while on site for the Phase 4 inspection, the inspection team also assisted the resident inspectors with the review of two current aging management issues, one related to the failure of reactor protection system relays and the other related to the degradation and failure of the fire protection system piping.

As we know now, pertinent details of the fire protection system issue were not available to the inspectors at the time of, until sometime after our Phase 4 inspection. So I have a later slide prepared to discuss that issue, the timeline, and the path forward for the region in more detail. Next slide, please.

MEMBER KIRCHNER: Can you elaborate on the other one that you looked at, the -- and I want to note for the record that Member Charles Brown has joined us. The, on the reactor protection trip relays.

MR. DOWNEY: Yes. And I should have mentioned that I have some talking points on that --

MEMBER KIRCHNER: Okay.

MR. DOWNEY: -- on the next slide as well.

MEMBER KIRCHNER: All right. I'll wait for it, then.

MR. DOWNEY: I'm sorry, on slide 20, not this slide. I'm sorry. Yep.

So, in addition to the inspections mandated by the license renewal inspection program, the inspectors have several baseline inspections that can be used to evaluate the implementation of aging management activities.

For example, the baseline ISI inspection, ISI meaning in-service inspection, which is performed in accordance with Inspection Procedure 71111.08 at every outage, gives the inspectors the opportunity to take a look at activities credited for managing aging that are within the scope of seven different Surry programs.

Another example is the heat sink inspection, which gives the inspectors an opportunity to look at the service water system, including heat exchangers, the service water intake structure, and both above-ground and buried or inaccessible piping and components, all of which are within the scope of license renewal.

Next is the design basis assurance, or DBAI, inspection, which procedure, that inspection procedure directs the inspectors to ensure that SSCs selected in the inspection sample that are subject to aging management review are being managed in accordance with the appropriate aging management programs.

At Surry, the inspectors have found no violations or findings of significance as a result of the inspections performed using these procedures.

I'll also note here that similar instructions to those provided in the DBAI procedure have been recently added to the tri-annual fire protection procedure. I didn't list that procedure here on this list because the most recent fire protection inspection was performed prior to that procedure update.

Additionally, the resident inspectors at Surry have performed maintenance effectiveness and PI&R, problem identification and resolution, inspections on samples that focus directly or indirectly on associated aging management programs.

These inspections resulted in two violations of very low safety significance, which you will hear me call green. And we'll focus, discuss more in detail on the next slide.

Also, we are planning to perform the focused PI&R inspection related to the recent fire protection system issue that I will be discussing on the slide next after next. Next slide, please.

So now I will speak to the material

condition of Surry from the resident inspector viewpoint.

Currently, Surry Units 1 and 2 are in the licensee response column and have all green findings and performance indicators. This indicates that the licensee has been able to effectively identify conditions adverse to quality and correct them in a timely manner.

We did want to highlight the output of some inspection results that related to the material condition of the plant.

As mentioned, no findings were identified as a, during the license renewal program inspections, which indicates that the licensee has established adequate programs to manage the effects of aging.

So, first, in 2016 the NRC issued a self-revealing green, non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, which is corrective action, for failure to promptly identify a condition adverse to quality associated with the material condition of the graded supports in the emergency service water pump house.

The issue was self-revealing because fasteners on one base plate for the service water pump diesel cooling water outlet valve seismic supports were found to be severed by corrosion. The failure of the seismic support led to the Bravo service water pump being declared inoperable, which made the violation more than minor. The degradation mechanism was wetting of the supports and base plates, I'm sorry, where the brackets wore.

Both the licensee and the residents also noted many more areas of the plant that had corroded supports which needed to be remediated to provide long-term reliability and seismic protection.

Over the course of several years, Surry has proactively remediated the supports by either coating or replacing with stainless steel.

Next, in 2018, following multiple relay failures, the NRC issued an NRC-identified green, non-cited violations of Surry technical specification 6.4 Delta, which is administrative controls over unit operating procedures, for failure to follow, I'm sorry, Surry's preventative maintenance procedure.

Specifically, many of the under-voltage and degraded voltage relays in the plant were past their service life of 20 years per the EPRI guidelines. Independent lab testing indicated that prolonged thermal damage was the cause of the failure.

Surry continues to replace these relays

and is scheduled to complete replacement by 2022.

MEMBER BROWN: What do they mean by thermal damage?

MR. McKOWN: So many of these relays are normally energized. So, in addition to their normal service life --

MEMBER BROWN: Those are, these are reactor trip? These are trip relays?

MR. McKOWN: Some of them are, yes.

MEMBER BROWN: But when they fail, they trip and give you a channel trip, if that's the case --

MR. McKOWN: They could give an individual channel trip.

MEMBER BROWN: And there's a 20-year life on those supposedly by guidelines?

MR. McKOWN: By guidelines, yeah.

MEMBER BROWN: What about thermal? Had they failed testing of any kind, or was it just based on a physical inspection?

MR. McKOWN: Some of them were based on physical inspection, identified embrittlement as the technician --

MEMBER BROWN: Like insulation of the --

MR. McKOWN: Yeah, they can actually

visually identify --

MEMBER BROWN: Insulation around the coil embrittlement?

MR. McKOWN: Yeah, they can identify visual degradation, or they will be identified during testing. And we've observed the plant being able to replace those on an individual basis and online. But more larger scale remediations are being performed during outages.

MEMBER BROWN: I was just surprised at the 20-year issue. In my past program, I had some of those trip relays normally energized. They lasted for 40 years, and we never had a problem with them, so a couple of projects. So, and just a --

MR. McKOWN: Yeah.

MEMBER BROWN: Just a point of information. That's why I asked. Thank you.

MR. DOWNEY: Thank you. So this issue is very similar to an issue identified back in 2010 when the relays in the reactor protection system, the safety injection system, and the consequence limiting safeguard system were identified as beyond their service life.

To address that issue, Surry has prioritized and scheduled relay replacements during every refueling outage since 2013 and continues to replace relays upon failure or as part of their prioritized replacement schedule.

MEMBER BROWN: You really don't mean upon failure. You mean not meeting the requirement. Are the relays failing, or are they just not meeting the 20-year requirement?

MR. DOWNEY: Some are failing, correct?

MR. McKOWN: When identified by failure, like when we were talking about online replacements during testing or a degraded condition as identified --

MEMBER BROWN: So, if they don't trip when asked to.

MR. McKOWN: Right, during testing, in addition to the lifecycle management plan of replacing the large scale --

MEMBER BROWN: Okay.

MR. McKOWN: -- lot during outages.

MEMBER BROWN: Okay. Based on lifetime expectations.

MR. McKOWN: Based on lifetime.

MEMBER BROWN: Okay. Thank you.

MR. McKOWN: So as required by maintenance or as required by --

MEMBER BROWN: I got it.

MR. McKOWN: -- lifecycle.

MR. DOWNEY: Okay. So the highest priority relays, which number approximately 570, will be completed in the next two years. And the licensee plans to replace an estimated 80 relays per refueling outage.

The residents note that the licensee is managing the relay replacement schedules and has demonstrated the ability to replace failed relays online and has not challenged any maintenance rule Alpha 1 goals, maintenance rule being 10 CFR 50.65.

MEMBER BROWN: I take it they're going to replace 80, but I presume the remaining ones are still operational even though they may pass the 20-year lifetime or --

MR. McKOWN: Yes.

MEMBER BROWN: -- the thermal doesn't appear to have -- I mean, it's anything that breaks or doesn't operate gets replaced immediately I would --

MR. McKOWN: They get replaced upon identification. And then --

MEMBER BROWN: Okay. Thank you. That's all, that's -- you answered my --

MR. McKOWN: Yes.

MEMBER BROWN: Just the way phrased it, I wanted to make sure I understood what was going on.

MR. McKOWN: Yep.

MR. DOWNEY: So, if there are no other questions, finally, we'll get to the July 2019 rupture of a section of the Surry fire protection loop. This issue is currently ongoing. And I'll provide more details on the next slide. Next slide, please.

So the Surry fire protection loop is made of cast iron piping and is buried approximately six feet below grade throughout the site. In July 2019, two fire protection piping failures occurred at the west end of the old administration building and below the road leading to the turbine building track bay.

The first rupture was a ten-foot long longitudinal crack along the bottom surface of the pipe. And the second failure was due to a circumferential crack on an adjacent pipe section.

I'll note that the Phase 4 inspection occurred in August 2019. And at that time, the licensee was in the process of excavating the area in order to replace the affected piping.

Also at that time, several CRs, condition reports, had been written. But the root cause and extent of condition of the issue had yet to be determined.

Subsequently, the licensee determined that longstanding exposure to moist or wet soil had resulted in the reduction in the wall thickness at several locations due to graphitic corrosion.

To determine which areas of the fire protection loop had been exposed to groundwater, the licensee dug several initial exploratory holes approximately 300 feet apart and found that the water level in some of the holes was much higher than the elevation of the buried piping.

The findings indicate that there is a higher potential for additional sections of buried piping to be degraded. But until additional areas can be explored, the soil characteristics and condition of the piping cannot be determined.

On October 18, 2019, the entire fire protection loop was declared non-functional because the licensee's evaluation could not determine that the loop had reasonable assurance of safety.

With no fire suppression system functional, the Surry technical requirements manual requires that a backup suppression system be established within 24 hours.

Compensatory actions were put in place

within that timeframe, which include, as the licensee had previously described, the use of backup fire pumps and hoses connected to the hydrants in the current system.

In an October 31st letter response to NRC comments on Dominion's annual subsequent license renewal update letter, the licensee committed to drill a minimum of 25 exploratory holes along the piping to determine if additional corrective actions are necessary, including excavation and evaluation of any piping in the presence of groundwater.

The letter states in part that this activity will be performed once prior to the subsequent period of extended operation and during each ten-year inspection interval in the subsequent period of extended operation to identify suspected system leakage and elevated groundwater.

Compensatory measures are still in place at the site. And the current path forward for the region is to perform a focused PI&R inspection. The inspection will focus on reviewing the licensee's corrective actions, including if and how this recent operating experience will be incorporated into the Surry buried piping program.

We have also been in communication with

our counterparts in the Office of Nuclear Reactor Regulation to ensure that the latest information from the site is available to them for their consideration in the subsequent license renewal application review. Next slide, please.

So, overall, for a plant that is in its first or initial period of extended operation, the material condition is generally acceptable.

As mentioned earlier, the licensee has been successful at completing large capital improvement projects that maintain or improve the material condition of its structures, systems, and components.

Furthermore, all NRC performance indicators are green. And having no greater-than-green inspection findings indicate that the material condition of SSCs has been maintained to sustain adequate protection.

Finally, the license renewal program inspections did not identify any substantial weaknesses in the station's performance in managing the effects of aging at the site.

The resident inspectors continue to inspect and assess the licensee's ability to manage the effects of aging through our baseline inspection program.

So, if there are no further questions, I'll yield the floor back to Angela Wu to conclude the presentation.

MEMBER RICCARDELLA: I have a couple of questions.

MR. DOWNEY: Sure.

MEMBER RICCARDELLA: The first would be, Steven, so we had in your summary table on your inspections for Phases 1 through 4 no findings and just eight observations in that Phase 2.

Could you calibrate us? And for the record, how does that compare to other plants, without naming other plants? Is this typical or is this exemplary or is it average? You used the word acceptable.

MR. DOWNEY: Generally acceptable, the most objective term that I could think of --

MEMBER RICCARDELLA: Yes, so, okay. I understand the guarded word. But can you just calibrate us versus other plants where you've done these kinds of inspections --

MR. DOWNEY: So --

MEMBER RICCARDELLA: -- as an Agency?

MR. DOWNEY: And I can -- in general, we

don't have a lot of, a lot of the aging management issues tend to not reach the level of being determined as more than minor, meaning significant, you know, if left uncorrected would lead to a significant safety issue --

MEMBER RICCARDELLA: Right.

MR. DOWNEY: -- precursor to a significant event, et cetera.

So you'll see at a high level that typically this is in line with what we see in terms of no findings of significance, because that's what determines getting to the area of significance being more than minor.

Observations are, I can't really attest to in number. But we typically have observations during these inspections. We haven't any, none that I have seen have had any findings of significance, more than maybe one or two.

MEMBER BROWN: Do these become suggestions? Does the plant ever do anything with the observations which are not --

MR. DOWNEY: So --

MEMBER BROWN: They're not requirements to do something. They're just --

MR. DOWNEY: So that's --

MEMBER BROWN: We saw this, whatever, right?

MR. DOWNEY: So that's, that falls into the timing of the inspection. So, for the Phase 2, these, they're observations because if we were, if this inspection had occurred during the period of extended operation, they would have been in violation of their license condition.

So that's why we come back during the PEO and do that follow up to make sure that they have corrected those issues prior to when that requirement kind of comes in force for us.

MEMBER BROWN: Thank you.

MR. DOWNEY: If that makes sense, yeah.

MEMBER KIRCHNER: My other question was I was thinking, you know, a lot of what you cover is also covered by the Boiler and Pressure Vessel Code, you know, Section 11.

So do you leave it to the applicant in general to fold that into their AMP programs, or do those things because they're code cases or governed by the code, I didn't say that correctly, those are independent of your AMP programs?

I mean, is there -- do you kind of bring them together when Section 11 would require an inspection of the steam generator or whatever?

MR. DOWNEY: So, typically, your longstanding programs like ISI, for example --

MEMBER KIRCHNER: Yeah, that's what I was thinking.

MR. DOWNEY: -- also aging management programs --

MEMBER KIRCHNER: I was thinking of your chart of ISI in particular.

MR. DOWNEY: Yeah, also aging management programs. But what I've seen is, for example, if a licensee augments their program, like there was some discussion earlier about small bore piping, that those would typically be outside of the scope of ASME Section 11. But it would be as an augment to their ASME Section 11 program. So it all does fold together.

MEMBER KIRCHNER: All right. Thank you.

MR. SCHULTZ: Steven, the --

MR. DOWNEY: Yes.

MR. SCHULTZ: The inspection that's related to, that's upcoming on the buried piping program and the corrective actions that have come from that, could you expand on what you see as the scope of that inspection?

MR. DOWNEY: So that --

MR. SCHULTZ: Late February, it's coming up. And what will it entail in terms of inspection personnel --

MR. DOWNEY: So I'll --

MR. SCHULTZ: -- duration? What, is there a plan for it yet or is that --

MR. DOWNEY: Yes. So I'll be on site the week of February 24th, myself in support of the residents, to perform this focused PI&R sample.

One week is what the length of the inspection will be. And the scope will be as typical for inspections performed under Inspection Procedure 71152, which is our problem identification and resolution inspection.

So just a deep dive into making sure that we understand the issue and understand the licensee's corrective action related to the issue and how it ties to their different programmatic requirements that they have in place at the site.

MR. SCHULTZ: I'm expecting that corrective action has many tentacles depending on how you define those. But --

MR. DOWNEY: It does.

MR. SCHULTZ: And it certainly is

interwoven with all of the, many of the activities in this particular area --

MR. DOWNEY: Yeah.

MR. SCHULTZ: -- technical area that took place.

MR. DOWNEY: Yeah, so one thing --

MR. SCHULTZ: September, October, November, December, and right on up to the draft SCR. So are you going to be looking at that --

MR. DOWNEY: So that --

MR. SCHULTZ: -- as well?

MR. DOWNEY: And we've been in communication with our counterparts at NRR in that the portion of this that involves updates to programs proposed for subsequent license renewal is beyond our scope in the region to look at.

We are dealing with oversight on the plant during the initial period of extended operation. And --

MR. SCHULTZ: Right.

MR. DOWNEY: -- the programs that they are -- like even the programs are different that they are proposing versus what's on the site right now. So there's a, there's pieces that we can handle --

MR. SCHULTZ: Yeah.

MR. DOWNEY: -- and pieces that are handled by --

MR. SCHULTZ: But there's not a direct -- I overstated the connection between what was done in preparing the draft SCR and so forth.

At the same time, one would expect that that corrective action does, in fact, identify all those types of things that we've been talking about here in terms of things that they would have determined, should have determined, would be done, should be done in order to correct the problem as well as identify --

MR. DOWNEY: Agreed.

MR. SCHULTZ: -- programs to assure that similar events don't happen again. Thank you. I just -- it looks like you're getting to close here. But just to follow up on my comments about the activities in the August --

MR. DOWNEY: Yes.

MR. SCHULTZ: -- August through the January timeframe, and this refers really to the program that was developed in the aging for the reviews.

MR. DOWNEY: Yeah. So are --

MR. SCHULTZ: Matt, Member Sunseri

mentioned the quality of the staff review associated with it.

The other area that is remarkable is the interactions that has gone on between the staff and the licensee associated with the request for additional information and the responses.

In reviewing what has been done, it is certainly remarkable that the quality, content, and thoroughness of the request for additional information and the responses from the licensee has been of very high quality and a lot of information that's been exchanged and a lot of changes that have come from the requests from the staff on, for additional information and for clarification and development of the final safety evaluation. So I appreciate that.

MEMBER KIRCHNER: Angela, do we go back to you to conclude?

MS. WU: Thank you, Steven. In conclusion, for the Surry SLRA safety review, the staff finds that the requirements of 10 CFR 54.29(a) have been met for the subsequent license renewal of Surry Power Station Units 1 and 2.

At this time, you will hear from two members of the NRC staff on differing views, starting with Brian Allik, Materials Engineer, Division of New and Renewed Licenses, and then James Gavula, Mechanical Engineer, Division of New and Renewed Licenses. So, first, with Brian and then we'll give him some room, yeah. Thank you.

(Off mic comments.)

MR. ALLIK: Okay. So my name is Brian Allik. And I'm a materials engineer in the Division of New and Renewed Licenses. And I'll go through my differing view related to the SCR for Surry's subsequent license renewal application.

In response to the fire water system ruptures discussed previously, the applicant modified a selective leaching program to include a requirement to dig exploratory holes to confirm the presence of groundwater around buried fire water system piping.

The applicant is, therefore, relying on a singular criterion, in other words, the presence of groundwater, to detect adverse soil conditions that may lead to graphitic corrosion.

From my perspective, it is unclear why relying on a singular criterion is technically adequate. In addition to the presence of standing water, it is well established that several soil parameters, including soil resistivity and pH play an important role in the corrosion of cast iron in soil environments.

A few literature examples supporting this statement are provided on this slide for reference. Next slide, please.

In addition, by a letter dated October 31, 2019, the applicant provided a summary of the soil analysis in the vicinity of the ruptured piping. The soil analysis documents low pH and low soil resistivity in one of the two samples, which would indicate that soil parameters other than standing water may have contributed to the ruptures.

During a call with the applicant on November 7, 2019, I questioned why relying on a singular criterion is technically adequate. However, the NRC subsequently determined that no action was required on behalf of the applicant to address this concern.

I, therefore, elected to engage in a formal process for differing views because the concern I described during the November 7th call was not addressed.

In conclusion, without a basis for relying on a singular criterion, or a specific commitment to conduct soil corrosivity testing in the vicinity of buried gray cast iron fire water system piping if a basis cannot be provided, it is unclear how the NRC staff can conclude that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the current licensing basis for the subsequent period of extended operation as required by 10 CFR Part 54.21(a)(3).

I will now turn the presentation over to Jim Gavula.

MEMBER KIRCHNER: Brian, maybe stop and --

MR. ALLIK: Sure.

MEMBER KIRCHNER: -- just ask you -- thank you, first of all. Member Ballinger I think was the first to ask along the lines of when they do their test holes, that they would also be looking at other parameters. So I just wanted to understand --

MR. ALLIK: That's if they find standing water in the exploratory hole. And then if they find water in the hole, that would drive them through excavations and soil sampling.

MEMBER KIRCHNER: Yes. But my understanding, the commitment to do the 25 additional test holes, do you not feel that that would give enough coverage of the site to look for problems, not just standing water, but if they also do the soil sampling for pH and sulfides, those things that are on your list.

MR. ALLIK: That testing is --

MEMBER KIRCHNER: Would that be adequate to address the concern that you've put before us?

MR. ALLIK: That testing is if there's water in the hole to look at that water. So, basically if they don't find standing water in the hole, then they're not driven to do any type of soil testing. So my contention is basically it's just relying on --

MEMBER KIRCHNER: Right.

MR. ALLIK: -- the concept of standing, or, you know, the presence of standing water. Whereas, I feel having a specific commitment to do soil testing, in addition to those, would be more appropriate.

MEMBER KIRCHNER: Well, perhaps, it's just one member. Perhaps I misunderstood the presentations. I had the impression once they dig these 25 test holes that they would go through and actually do the sampling.

So your contention, if I understand it correctly, is only if they find water will they then go and look at these other --

MR. ALLIK: That's my understanding.

MEMBER KIRCHNER: -- parameters. Okay.

MEMBER RICCARDELLA: Could maybe somebody clarify that, please?

MEMBER KIRCHNER: Can we clarify that? Well, maybe this isn't the place to do it. But, anyway, but, okay, Brian. That was perhaps my misunderstanding from the presentations. But I assumed once you dig a hole --

(Simultaneous speaking.)

MEMBER RICCARDELLA: Either they're going to do the soil sampling or they're not. And the contention is that if there's no standing water they're not going to do any soil testing.

It would seem that the licensee could clarify that. Are they going to do soil testing or not?

MR. MOORE: It's fair to ask the staff to have the licensee clarify it, or if the licensee is here, they can clarify it.

MEMBER KIRCHNER: All right. I'm just sharing my, perhaps, misunderstanding of what was presented earlier.

MR. MOORE: I think somebody was going to stand up.

MEMBER KIRCHNER: Okay. If we could proceed to James.

CHAIR SUNSERI: I think somebody wants to --

MEMBER KIRCHNER: Yeah, okay. Someone --

MEMBER BROWN: If somebody's got an answer, we ought to hear it.

MR. MOORE: Yeah, right.

MR. SCARBOROUGH: Good morning. Troy Scarborough, Surry Power Station.

So, when we do excavations, we do take a soil sample. As Brian mentioned, you know, when we excavate this fire protection piping based on our initial look for water present, we will do a soil sample at, you know, at that time.

MEMBER BROWN: But whether there's water present or not? Or will you only do the soil sample if there's water present?

MR. SCARBOROUGH: If there's water present, that's when we'll take the sample.

MEMBER BROWN: So, if you dig the hole and it's dry, there's no soil sample. I want to put this in straightforward language.

MR. SCARBOROUGH: Well, if we dig a hole, we will take a soil sample.

MEMBER BROWN: So you take it regardless, but whether you test it or not --

MEMBER KIRCHNER: That was my impression, yeah.

MEMBER BROWN: But whether you test it or not is dependent upon whether there was groundwater in the hole. Is that --

MR. SCARBOROUGH: No, we'll --

MEMBER BROWN: Would that be corollary to that?

MR. SCARBOROUGH: We'll send every soil sample out for testing.

MEMBER BROWN: Okay. Let me restate this again, because I'm now lost. You dig a hole. No water. However far down you have to dig it, if there's no water, do you take a soil sample? You said yes.

MR. SCARBOROUGH: Not on an exploratory hole. But --

MEMBER BROWN: Okay. So, if there's no water in it, you don't take a soil sample.

MR. SCARBOROUGH: That's correct. We --

MEMBER BROWN: Okay. I think that's what you were --

MR. ALLIK: I think there's probably,

there's -- exploratory hole is different from excavation. But your understanding is my understanding, that if it's a dry hole --

MEMBER BROWN: Well, the way I read and the way -- I was late. So I -- but I did catch the inspector's discussion of the issue. And I guess the 25 holes, those were just exploratory holes but not excavations. That's my understanding of the way that the words went.

MR. ALLIK: That's correct.

MEMBER BROWN: And so that's all that would be done, period, no excavations of any kind. It would be just the holes, no water, no sample. If there's water, you take sample. If you get a sample, you test it.

MR. ALLIK: Right.

MEMBER BROWN: Okay. That's my understanding.

I had one other question, because I'm not a big fire person. I'm an electrical. So these, the fire systems are tested periodically also I presume. And I missed probably some earlier discussion of that.

So, even if you have some small leakage due to some small corrosive thing, it may not be a complete rupture. So there is some periodic testing, not every ten years, of the fire system to ensure you really get water --

MR. ALLIK: Um-hmm, yes.

MEMBER BROWN: -- in a volume suitable enough to deal with whatever the requirements are. And so --

MR. ALLIK: I would just say it's a brittle material, though. And especially once it's undergone graphitic corrosion, it's very susceptible to more than just a leak type failure --

MEMBER BROWN: Well, I understand that. And that's why I'm trying to clarify. I'm not a soil mechanics guy. But once you have a --

MEMBER RICCARDELLA: But the failures that did occur were leak type failures, right, not ruptures?

MR. ALLIK: They were ruptures.

MEMBER RICCARDELLA: The licensee said that they could have maintained pressure in the system and delivered fire water. That's --

MR. GAVULA: 4,500 gpm leak.

MEMBER RICCARDELLA: Pardon me?

MR. GAVULA: It was a 4,500 gpm leak was the documentation I read from the licensee. So the overall capacity of the fire water system is 5,000 gpm. At that point, you're going to be at run-out on the pumps. It's all going out the hole.

MEMBER RICCARDELLA: Okay.

MEMBER BROWN: My last question was, is there any other functional testing that -- how often are the fire systems tested, or did that come out in the other discussions? I mean, is it annually or is it every six months or is it every five years or what? Does anybody got an answer to that for capacity tests?

CHAIR SUNSERI: The leak was determined during a fire suppression surveillance test which --

MEMBER BROWN: Yeah, my point is how often are those done.

CHAIR SUNSERI: I think the applicant can answer that.

MR. HARROW: This is Allen Harrow. So we do fire protection surveillance tests monthly.

MEMBER BROWN: Monthly? Okay.

CHAIR SUNSERI: Yeah.

MR. GAVULA: But that's just start the pump, make sure it runs, if there is no flow, verification at that point, because don't have a demand on the system.

MEMBER BROWN: So there's no capacity testing done at all ever?

MR. GAVULA: There may be some flow test during the outages is my understanding if --

MEMBER BROWN: Can the licensee address that? That was the question I was really answering. I mean, obviously, if they test it with no, just to see if the pump runs, that doesn't --

MEMBER RICCARDELLA: Well, unless it pressurizes the system.

MEMBER BROWN: Well, if it pressurizes the system, then that should indicate there's no leaks, right?

MEMBER RICCARDELLA: Well, yeah.

MEMBER BROWN: Or no significant leaks.

CHAIR SUNSERI: Yeah, Charlie, so I don't know the licensee's, in this particular case, specific program.

But my experience from other nuclear plants is that the fire protection system pumps do undergo period capacity testing to ensure that they can deliver the required amount. Okay. They also undergo more frequent testing to verify that they can start. They go on recert. The system pressurizes --

MEMBER BROWN: Yeah, yeah, that's good also.

CHAIR SUNSERI: -- just to make sure that they're going to start on demand. But, you know --

MEMBER BROWN: I was just familiar with the commercial plants. The Navy plants I was familiar with. We always worry about fires in ships, particularly in submarines.

So those systems were tested to make sure they deliver what they were supposed to deliver when you have the opportunity. You can't do it when you're way down under water. It doesn't work very well. But there are other systems that you can test.

So that's why I was asking. I'm trying to get some familiarity with the fire system in this circumstance. You were going to say something.

MR. RICKERT: This is Bret Rickert. I'm an engineering supervisor at Surry. We perform a capacity test every 18 months.

MEMBER BROWN: Okay. That's -- okay. That's an answer. All right.

CHAIR SUNSERI: And start-up pressure monthly.

MEMBER BALLINGER: I have a little bit more detailed question. When these plants are -- it's on. When these plants are initially constructed, there's a groundwater migration model and everything that gets constructed for these plants. And so you'd pretty much know where the water table is. You should know where the water table is.

For this particular failure, did anybody compare where the water table actually was compared to what they thought it would be to see if this is a one-off thing?

And when you decide to drill 25 holes, what's the basis for where you drill those holes? Is it based on what you think the water table looks like, or what's the criteria for where you drill the holes?

CHAIR SUNSERI: I think they said they're exploring in places near where the pipe is and they're checking for water. They go down seven feet. The pipe is six feet. And that's what their criteria is.

MEMBER BALLINGER: But then the presumption is that the water table is below seven feet.

CHAIR SUNSERI: No, they're only going down to the bottom of the pipe because that's all they care about.

MEMBER BALLINGER: Oh, okay. So they're assuming that if they find water, the water table is higher than that.

CHAIR SUNSERI: Okay. I think we have some statement from the applicant.

MR. HARROW: Okay. So this is Allen Harrow again.

The water table is greater than seven feet deep. So it's greater than the depth of the center line of the pipe, which is six feet.

In the case of the two sections of failed pipe, the water table at that location was identified less than six feet. Okay. So we feel that the water table in this particular case was a result of some type of parched aquifer where water was sitting on top of soil that was not similar to where we have seen previous water table levels.

So, in regard to this question about, well, how are we going to treat this in terms of a water table, our goal is to, as we replace pipe, to replace pipe that is not susceptible to graphitic corrosion. So we're thinking about such pipes such as high density polyethylene and that thing.

And in that case, the actual water table question in itself becomes moot.

MEMBER BROWN: Okay. Thank you.

MEMBER RICCARDELLA: I have a question relative to how this concern interfaces with the ongoing corrective action program and the, you know, the fire protection yard loop project that the applicant described.

Is it true that this commitment for the 25 holes and the holes just based on the, just, that would only be further investigated if there is water found in the holes is what's currently in the application?

But before we get into the period of subsequent license renewal operation, won't the, any effect, any results from the corrective action program come into play and they would modify the AMP based on the results of that program, won't they?

MR. GAVULA: My name is Jim Gavula with the staff.

The answer is it could. But the corrective action aspect for license renewal for the corrective action portion of the current license, the current Part 50, all of those corrective actions are not part of our review for license renewal. That's a Part 50 issue.

And our reviews are looking at the Part 54, will they establish, will the program that they have established adequately manage the effects of aging during the 60 to 80 timeframe. So that's the portion that we're reviewing.

MEMBER RICCARDELLA: But isn't there a

commitment to modify that program based on the results of the corrective action program and this ongoing project?

MR. GAVULA: If that commitment -- it's not a current commitment in their subsequent license renewal application. There is no commitment for that aspect.

MEMBER KIRCHNER: I think I'm with Pete in the sense that let's put the immediate matter just to the side for a moment.

If we find issues, and you are going to find new issues as the plants age, then it suggests, where I think you were going, is that the process that the Agency use and should allow for, well, some interaction with the applicant and modification of an AMP program to address problems that are identified going out, because one isn't all knowing for -- what, this license renewal will not start until 2030.

MR. GAVULA: And in that regard, I don't have a problem. But --

MEMBER KIRCHNER: Yeah.

MR. GAVULA: -- knowing what I know today, with respect to the aging management program that would provide reasonable assurance with Brian Allik's issue of the expectation that they do some soil sampling while they do exploratory holes seems like that would be what would be expected in the 60 to 80-year timeframe.

Now, whether that actually happens as part of the corrective action program I don't know and I don't have any --

MEMBER KIRCHNER: Okay.

MR. GAVULA: -- anything put to it.

MEMBER KIRCHNER: And, James, we didn't give you a fair chance to state your differing view. And we are running up against a timeline. So may I turn to you and --

MR. GAVULA: Good morning. My name is James Gavula. I'm a mechanical engineer in the Division of New and Renewed Licenses.

I've worked for the NRC since 1986. I was a senior reactor inspector in the Region III office near Chicago for 23 years, the last 6 years of which were spent with the NRC's Office of Investigations and the U.S. Department of Justice on the criminal prosecution and conviction of the individuals at Davis Besse associated with the hole in the head event.

Since 2009 I've worked for the NRR as a mechanical engineer performing license renewal reviews. Prior to the NRC, I had eight years of industry experience working with Combustion Engineering and Nutech Engineering, which is a consulting firm.

I am here today to briefly discuss my differing views with some of the conclusions stated in Surry's SLRA.

For the selective leaching program, SCR Section 3.0.3.1.6, the FSAR supplement does not describe critical aspects of the revised program, such as drilling 25 exploratory holes during each ten-year interval, corrective actions that will be taken in the presence of groundwater, and sample expansion if groundwater is found in the exploratory holes.

In my opinion, the SLRA does not meet the requirements of 10 CFR 54.21 Delta.

The next issue is the number of periodic visual and mechanical inspections per unit were reduced from the GALL AMP recommended ten down to eight based on similarly, sufficiently similar conditions between units.

However, recently identified soil chemistry variations between two fire piping rupture sites demonstrates that soil conditions vary across the site, questioning the justification for the reduced inspections.

In my opinion, the SLRA doesn't contain information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed.

Piping will be excavated and inspected at each exploratory hole where groundwater, and the emphasis is on groundwater, has been confirmed. However, water caused by system leakage results in different corrective actions.

Corrective action documents from the fire water system rupture noted that corrosion was greater near a leaking valve such that long-term external system leakage may have kept soil moist, the soil moist and was responsible for much of the corrosion damage.

Since piping will not be excavated and inspected if water in the exploratory holes is caused by system leakage, in my opinion, the SLRA does not contain information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed. Next slide, please.

For the open cycle cooling water system, there are no aging management review items for the essential service water pump diesel engine heat exchangers or gear drive coolers. Dominion consider these passive components as part of a, quote, active skid-mounted assembly, unquote, and excluded them from the scope of license renewal.

Dominion's lack of an AMR item was dispositioned by use of a staff-identified difference in SCR Section 3.0.3.2.7 where the staff credited Dominion's generic letter 8913 inspection and maintenance activities as providing sufficient assurance that the effects of aging would be adequately managed.

The staff's approach is inconsistent with SECY Paper 1999-148 for crediting existing programs for license renewal where the applicant provides the information in order for the staff to have reasonable assurance.

Comparable guidance from the Office of General Counsel regarding staff attempts to use statements in an NRC audit report as being considered docketed information states, quote, under NRC case law and regulations, the applicant has the burden for demonstrating the adequacy of its license application.

The staff, in contrast, is an objective reviewer of the application, not a proponent of the application information or a consultant on the scope for license ability of the proposed activities.

The precedent being set in the SCR can be used in future submittals where excluding passive components that are inconsistent with the guidance in the SRP SLR for complex assemblies.

In my opinion, the SLRA does not contain the information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed.

For the buried and underground piping and tanks program, pictures from the ruptured fire water system showed significant corrosion of the carbon steel tie rods. Although current corrective actions to replace gray cast iron with ductile cast iron will potentially resolve the selective leaching issue, it will not address the noted corrosion of the tie rods.

In my opinion, the SLRA did not contain the information required by 10 CFR 54.21(a)(3) for demonstrating that the effects of aging will be adequately managed.

Next issue, the response to RAI B2127-3 led the staff to accept the coatings on the buried fire system piping as meeting the preventive actions portion of the GALL buried pipe program.

Corrective action documents from the fire system rupture noted that the coating was not consistent with a normal coating thickness and was too thin for long-term protection in high moisture soil.

Based on this operating experience, credit cannot be given to the buried fire piping coating and adjustments to the buried pipe program are needed.

In my opinion, the SLRA does not contain the information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed. Next slide, please.

As discussed in SCR Section 6, in accordance with 10 CFR 54.29 Alpha, the Commission may issue a renewed license if it finds that actions have been identified, and put the emphasis on actions have been identified, with respect to managing the effects of aging during the period of extended operation.

For the issues that I've briefly discussed, the staff was informed that no further aging management program information would be provided until the applicant's corrective actions were completed and that no further action would be provided.

10 CFR 54.30 specifically excludes from the scope of license renewal review a licensee's obligation to take corrective actions under its current license to ensure that the intended functions

will be maintained throughout the term of the current license.

The current license does not include any obligation to ensure that the effects of aging are adequately managed during the subsequent period of extended operation.

Based on the issues with the aging management programs, I do not concur with the SCR's conclusion in Section 6 that the applicant has met the requirements of 10 CFR 54.29 Alpha relative to, quote, actions have been identified with respect to managing the effects of aging during the subsequent period of extended operation.

That concludes my remarks. Thank you for your time.

MEMBER KIRCHNER: Thank you, Brian and James, for being with us and presenting your views.

We are running a little bit over. We need to turn to public comment before closing our meeting.

(Off mic comments.)

MEMBER KIRCHNER: Oh, there's one more slide. I'm sorry. Eric, this is you?

(Off mic comments.)

CHAIR SUNSERI: I can remove the time constraint if I go ahead and leave. We can move the meeting to the other room over there. So I'll excuse myself.

MEMBER KIRCHNER: Okay. Well, I'll join you.

CHAIR SUNSERI: You still have a quorum.

(Off mic comments.)

MR. OESTERLE: I promise to be brief.

MEMBER KIRCHNER: Okay, Eric.

MR. OESTERLE: Well, good morning. My name is Eric Oesterle. And I'm Chief of the License Renewal Projects Branch in the Division of New and Renewed Licenses.

NRR's management appreciates and supports the opportunity for the staff to present their differing views. Consideration of how to address these views is still in process. And, therefore, management perspectives on these views are preliminary.

We believe that the technical positions are accurately characterized and that all these positions or views are manageable through our existing process using the NRC's regulatory framework.

As noted, the applicant entered the condition regarding the degraded fire protection loop piping into its corrective action program. And completion of that process is still underway.

Our understanding is that selective leaching has been determined to be the root cause. However, the extent of condition and final determination of corrective actions remain to be completed by the applicant.

Without knowing this final resolution, concluding that there is any impact on the augmented selective leaching AMP that may be proposed by the applicant is premature.

The applicant has included an aging management program for selective leaching, and in response to this operating experience and NRC questions, has augmented that program to include additional measures to monitor and evaluate the conditions as discussed earlier in the presentation.

Currently, this plant condition and its resolution is being monitored by appropriate NRC personnel. And we are confident that through continued oversight and communication with the region, that any impact on the selective leaching AMP will be addressed as part of the corrective actions program.

Given the totality of the NRC's regulatory framework, we have reasonable assurance of adequate protection of public health and safety.

And I would like to note that the Commission had contemplated situations just like this during the development of the 1995 license renewal rule, that is situations such as when an operational issue arises during the review of a license renewal application that may have an impact on aging management of plant structures and components.

For background, I'll provide a quote from the statements of consideration from the 1995 license renewal rule.

I quote, if aging issues are identified during the license renewal review that applied to the current operating term, licensees are required to take measures under their current license to ensure that the intended function of systems, structures, and components will be maintained in accordance with their current licensing basis throughout the term of the current license.

In addition, if aging issues are identified during a license renewal review that applied to the current operating term, the NRC will evaluate these issues for generic applicability as part of the regulatory process.

This concludes my remarks.

MEMBER KIRCHNER: Thank you, Eric. In

lieu of the time, I think we need to now ask for any public comment. I'll turn first to the room. If there is anyone in the room who wishes to make a comment, please come up to the microphone, state your name, and make your comment.

Kent, do we have the bridge line open? Okay. On the bridge line to the public, if there is anyone out there who wishes to make a comment, please state your name and make your comment.

I'm using the five-second rule. So hearing none, at this point, we can close the bridge line. And I'll turn to members. Starting with Pete, did you wish to make any other further comments?

MEMBER RICCARDELLA: No, I don't think so at this time.

MEMBER KIRCHNER: Charlie?

MEMBER BROWN: Only that you mentioned that staff had not -- I'm sorry. In your opening remarks, you commented that you had not completed your overall assessment of how the differing views would be addressed as part of the final resolution and determination. Is that correct?

MR. OESTERLE: That's correct.

MEMBER BROWN: Okay. So there's more to come.

MR. OESTERLE: More to come.

MEMBER KIRCHNER: Yeah, and there's a formal process for that.

MEMBER BROWN: No, I understand that. So we will hear more at some other circumstance --

MEMBER KIRCHNER: Yeah.

MEMBER BROWN: -- relative to its resolution.

MR. OESTERLE: Yes, sir.

MEMBER BROWN: Okay. Thank you very much. That's the only question I had.

MEMBER RICCARDELLA: We will hear more?

MEMBER BROWN: Yes.

MEMBER RICCARDELLA: I mean, there will be more. But it is not clear --

(Simultaneous speaking.)

MEMBER BROWN: We've got a full committee meeting.

MEMBER RICCARDELLA: Okay.

MEMBER BROWN: Yeah, that's where we will address this.

MEMBER RICCARDELLA: And that will be resolved before the full committee meeting?

MEMBER BROWN: Hopefully.

MR. OESTERLE: That's the intent.

MEMBER RICCARDELLA: Huh?

MR. OESTERLE: That's the intent. Yes, sir.

MEMBER RICCARDELLA: Okay. Thank you.

MEMBER KIRCHNER: Eric, have you any comments?

MR. SCHULTZ: I have one question for Eric.

MR. OESTERLE: Yes.

MR. SCHULTZ: Just for my understanding, that your preliminary review is that the technical, there are technical merits which have been presented by the differing views to be considered through the overall process for resolution.

And your timeframe is that by the time we reach the full committee meeting a couple things will happen. The corrective action inspection will have been done. There may be some results from that activity --

MR. OESTERLE: Could be.

MR. SCHULTZ: -- as well as your evaluations that are going to be moving forward here.

MR. OESTERLE: So, yes, our view is that the, we have, the NRC has adequate processes in place to address these technical issues. They may be outside of license renewal space and in corrective action space as part of the current operating term. And we would expect that the outcome of the corrective actions may impact the selective leaching AMP.

MR. SCHULTZ: Okay.

MR. OESTERLE: But we have yet to see what the final resolution is.

(Simultaneous speaking.)

MEMBER BROWN: Well, that was interesting choices of words as you went through. That was a good question. I didn't follow up with it the same way.

I presume you will be able to say at the full committee meeting how you've addressed or not addressed based on any subsequent corrective action, other type changes that might be made. But that would be addressed at the full committee meeting.

MR. OESTERLE: Yes. So, if we do a thought experiment --

MEMBER BROWN: But let me interrupt for a second. You said the existing programs are adequate to address this issue.

MR. OESTERLE: Yes.

MEMBER BROWN: Processes rather.

MR. OESTERLE: Right.

MEMBER BROWN: So we would --

MEMBER KIRCHNER: Framework.

MEMBER BROWN: We will hear about how those processes are going to address this issue.

MR. OESTERLE: Right. So, if you carry this forward, there may be several different outcomes of the corrective actions program.

MEMBER BROWN: That's fine.

MR. OESTERLE: Right? One which may impact the aging management program and others which may not.

MEMBER BROWN: I'm not asking for a judgment as to what's what, just that we will know what the differentials are on that when we get here at the next time.

MR. OESTERLE: Yes.

MEMBER BROWN: Well, actually, I will request that.

MR. OESTERLE: Okay.

MR. SCHULTZ: I have no further questions or comments except to --

MEMBER KIRCHNER: Okay. Good. All right. I --

MR. SCHULTZ: -- remark that the presentations were very helpful today --

MEMBER BROWN: Yeah.

MEMBER KIRCHNER: Yeah.

MR. SCHULTZ: -- as well as the, as we've commented on, the work and quality of the application and the -- I don't want to rank order. But the review has been substantial and very effective in my view.

MEMBER KIRCHNER: Okay. I want to close by thanking the applicant and the staff for their presentations and also single out Brian Allik and James Gavula for coming before us and presenting their differing views.

And with that, we are, let me get this, adjourned. Thank you.

(Whereupon, the above-entitled matter went off the record at 12:08 p.m.)

Surry Power Station

Units 1 and 2

Subsequent License Renewal Application

ACRS Sub-Committee Meeting

February 5, 2020

Dominion Energy

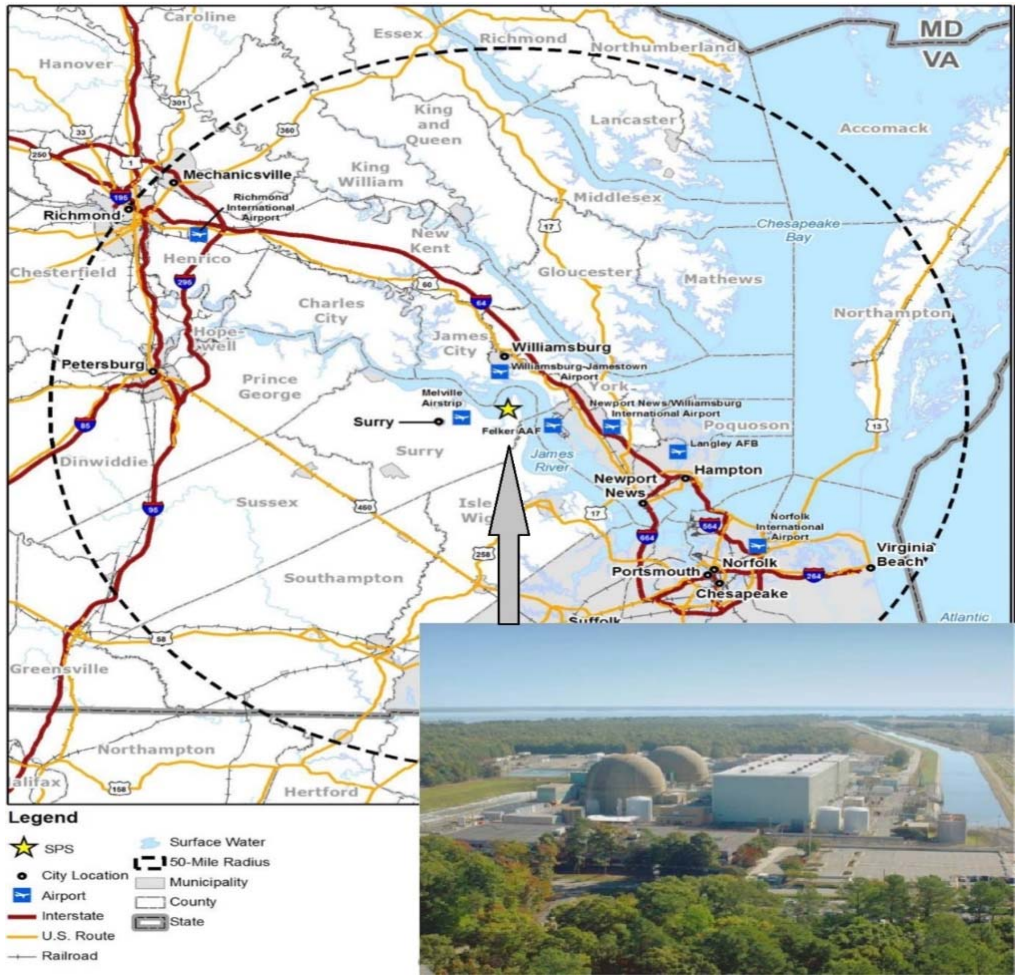
Introductions

➢ Paul Phelps	SLR Director
➢ Paul Aitken	SLR Manager
➢ Eric Blocher	SLR Technical Lead
➢ Chuck Tomes	TLAA Principal Engineer
➢ Allen Harrow	Surry Engineering Manager
➢ Craig Heah	SLR Technical Lead

Agenda

- Station Overview/Performance
- SLR Application Development
- GALL SLR Consistency
- SLR Aging Management Programs
- Technical Topics
- Closing Remarks

Surry Power Station



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Station Overview

	Unit 1	Unit 2
Full Power License – 2,441 MW_t	May 25, 1972 (Operating License Issued)	January 29, 1973 (Operating License Issued)
Independent Spent Fuel Storage Installation (ISFSI), Pads 1 & 2	1986	
4.3% Power Uprate to 2,546 MW_t	1995	
First License Renewal Approval	2003	
1.6% MUR to 2,587 MW_t	2010	
Entered Period of Extended Operation	May 25, 2012	January 29, 2013
Current License Expiration	May 25, 2032	January 29, 2033

Dominion Energy®

Station Overview

Dominion Energy

Surry Performance

- Surry operates on an 18-month refueling frequency

- Plant Capacity Factor:

  - 2017: U1 - 102.35% U2 - 94.18%
  - 2018: U1 - 89.39% U2 - 90.69%
  - 2019: U1 - 90.48% U2 – 102.59%

- Regulatory Status

  - ROP Actions Matrix Column 1
  - All ROP Indicators are Green

Significant Plant Modifications

Surry	Unit 1	Unit 2
Flux Thimble Replacement	2001	2011
Reactor Vessel Head Replacement	2003	2003
FAC Pipe Replacement	N/A	2005
Ultrasonic Feedwater Flow Installation	2009	2011
Reactor Coolant Pump Main Flange Bolt Replacement	2009	2009
Steam Generator Feed Ring Replacement	2010	2011
Isolated Phase Bus Duct Replacement	2010	2011
Fire Detection System Replacement	2012	2012
Main and Station Service Transformer Replacement	2015	2005
Carbon Fiber Reinforced Polymer (CFRP) Installation	2016	2016
Reserve Station Service Transformers (RSST) Replacement	2019	2020

Carbon Fiber Reinforced Piping

SLR Application Development

SLR Application Development

- Regulatory and Industry Guidance
    - Dominion Energy staff integrally involved in the development of the GALL SLR/SRP
    - Followed NUREG-2191 (GALL-SLR) and NUREG-2192 (GALL-SRP) to the greatest extent possible (discussed later)
    - Followed NEI 17-01 guidance (updated for SLR)
    - Reviewed previous RAIs from several previous licensees during application development
    - Conducted Industry Peer Reviews
    - Conducted a Safety pre-application meeting with the NRC Staff in April 2018 to discuss SLRA content and obtain insights

Integrated Plant Assessment

Deltas between First License Renewal (FLR) and SLR

- Scoping & Screening
  - Minimal Differences from FLR (pre-GALL)
  - Some updates required to address 10 CFR 54.4(a)(2)
  - Followed NUREG-2191 (GALL-SLR) and NUREG-2192 (GALL-SRP)
- Aging Management Reviews
  - Surry FLR was pre-GALL, additional aging effects required disposition based on NUREG-2191 (GALL-SLR)
- Aging Management Programs
  - FLR – 25 AMPs
  - SLR – 47 AMPs
- Time Limited Aging Analysis
  - Existing TLAAs Re-assessed
  - One new TLAA identified – S/G AVB Tube Wear
  - TLAAs analysis dispositioned as acceptable for 80 years per GALL-SLR Guidance

GALL Consistency

- Submittal consistent with GALL-SLR
- High AMR Consistency (99.6% Notes A thru E)
- License Renewal Commitments
  - 47 Aging Management Programs
  - UFSAR Supplement (Appendix A)
  - Managed by the Dominion Commitment Tracking System
- Implementation activities have begun and will continue following issuance of renewed license

SLR Aging Management Programs

Surry SLR AMP Considerations

- NEI involvement, collaboration with EPRI, and PWROG participation informed AMPs with New Industry Guidance and R&D products

- Incorporation of operating experience (OE):
  - Industry and plant specific OE reviewed for a 10 year period
  - Reviewed Industry RAIs for AMP insights
  - Participation in Industry Peer Reviews
  - SLR Lead Plant Alignment

- AMP Effectiveness Reviews performed on all first license renewal AMPs using elements of NEI 14-12

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First License Renewal AMPs

All First License Renewal (FLR) AMPs will be continued and incorporated into SLR AMPs:

- No FLR AMPs discontinued
- Some FLR AMPs are consistent with NUREG-2191 (GALL-SLR) AMPs
- Several FLR AMPs required enhancement for consistency with GALL-SLR AMPs
- Several FLR AMPs subdivided into other GALL-SLR AMPs

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Mechanical		Structural
XI.M1 ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	XI.M30 Fuel Oil Chemistry	XI.S1 ASME Section XI, Subsection IWE
XI.M2 Water Chemistry	XI.M31 Reactor Vessel Material Surveillance	XI.S2 ASME, Section XI, Subsection IWL
XI.M3 Reactor Head Closure Stud Bolting	XI.M32 One-Time Inspection	XI.S3 ASME Section XI, Subsection IWF
XI.M10 Boric Acid Corrosion	XI.M33 Selective Leaching	XI.S4 10 CFR Part 50, Appendix J
XI.M11b Cracking of Nickel-alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in Reactor Coolant Pressure Boundary Components	XI.M35 ASME Code Class 1 Small-Bore Piping	XI.S5 Masonry Walls
XI.M.12 Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)	XI.M36 External Surfaces Monitoring of Mechanical Components	XI.S6 Structures Monitoring
XI.M16A PWR Vessel Internals	XI.M37 Flux Thimble Tube Inspection	XI.S7 Inspection of Water-Control Structures Associated with Nuclear Power Plants
XI.M17 Flow-Accelerated Corrosion	XI.M38 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	XI.S8 Protective Coating Monitoring and Maintenance
XI.M18 Bolting Integrity	XI.M39 Lubricating Oil Analysis	**Electrical**
XI.M19 Steam Generators	XI.M41 Buried and Underground Piping and Tanks	XI.E1 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
XI.M20 Open-Cycle Cooling Water System	XI.M42 Internal Coatings/Linings for in scope Piping, Piping Components, Heat Exchangers, and Tanks	XI.E2 Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits
XI.M21A Closed Treated Water Systems	**TLAA**	XI.E3A Electrical Insulation for Inaccessible Medium Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
XI.M23 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	X.M1 Fatigue Monitoring	XI.E3B Electrical Insulation for Inaccessible Instrumentation and Control Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
XI.M24 Compressed Air Monitoring	X.M2 Neutron Fluence Monitoring	XI.E3C Electrical Insulation for Inaccessible Low Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
XI.M26 Fire Protection	X.E1 Environmental Qualification of Electric Components	XI.E4 Metal Enclosed Bus
XI.M27 Fire Water System		XI.E6 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements
XI.M29 Outdoor and Large Atmospheric Metallic Tanks		XI.E7 High Voltage Insulators

Surry SLR – 47 GALL-AMPs

	Consistent with GALL-SLR	With Enhancement	With Exception	Exception and Enhancement	Plant Specific
Existing 40	6	24	1	9	0
New 7	5	0	2	0	0
Total 47					

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New SLR AMPs

- XI.M32 - One-Time Inspection
- XI.M33 - Selective Leaching
- XI.M35 - ASME Code Class 1 Small Bore Piping
- XI.E3B - Inaccessible Instrument and Control Cables Not Subject to 10 CFR 50.49
- XI.E3C - Inaccessible Low-Voltage Power Cables Not Subject to 10 CFR 50.49
- XI.E6 - Electrical Cable Connections Not Subject to 10 CFR 50.49
- XI.E7 - High Voltage Insulators

AMPs with Exceptions

- XI.M2 Water Chemistry
- XI.M3 Reactor Head Closure Stud Bolting
- XI.M20 Open-Cycle Cooling Water System
- XI.M21A Closed Treated Water Systems
- XI.M27 Fire Water System
- XI.M29 Atmospheric Metallic Storage Tanks
- XI.M30 Fuel Oil Chemistry
- XI.M35 ASME Code Class 1 Small Bore Piping
- XI.M42 Internal Coatings/Linings
- X1.S1 ASME Section X1, Subsection IWE
- XI.E4 Metal Enclosed Bus
- XI.E7 High Voltage Insulators

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Types of AMP Exceptions

- 6 AMP Exceptions – Test frequency and/or inspection technique alternatives proposed
- 5 AMP Exceptions – Plant-specific configurations
- 2 AMP Exceptions – EPRI Chemistry guideline revision
- 1 AMP Exception – Management of a different component type

First License AMP Effectiveness

- FLR AMPs have been evaluated for AMP effectiveness:
  - AMP reviews conducted in 2015, 2016, and 2017
  - AMP review conducted in 2018 using NEI 14-12 guidance
  - FLR commitments have been implemented
  - Assessment of inspection schedules, results and data have been conducted
- Identified gaps have been included in the CAP system as described in Appendix B
- Periodic AMP effectiveness reviews are required to be completed by the program owners every 5 years
- OE is systematically reviewed on an on-going basis
- Training is conducted periodically for program owners
- IP 71003 Phase 4 inspection identified no findings or concerns in 3Q19

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Technical Topics

Concrete and Containment Degradation

	SLRA Sections Addressing GALL-SLR Recommendations
Concrete and containment degradation	3.5.2.2.1 Pressurized Water Reactor and Boiling Water Reactor Containments 3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due To Irradiation 4.6 Containment Liner Plate, Metal Containments, and Penetrations Fatigue Analysis A1.29 ASME Section XI, Subsection IWE A1.30 ASME Section XI, Subsection IWL A1.32 10CFR Part 50, Appendix J A1.34 Structures Monitoring A1.35 Inspection of Water-Control Structures Associated with Nuclear Power Plants

- Concrete overall is in good condition
  - No effects of ASR have been identified for SPS concrete structures
  - SPS concrete structures are managed consistent with GALL-SLR AMPs XI.S2, ASME Section XI, Subsection IWL, XI.S6, Structures Monitoring, and XI.S7, Inspection of Water-Control Structures Associated with Nuclear Power Plants
- The SPS reinforced concrete Containments are in good condition
  - Recent containment liner - slab interface region examinations did not identify degradation
  - Containment concrete biological shield wall gamma and neutron irradiation remains within conservative radiation exposure levels, through SPEO, consistent with GALL-SLR
  - SPS will manage each Containment consistent with GALL-SLR AMPs XI.S1, ASME Section XI, Subsection IWE, XI.S2, ASME Section XI, Subsection IWL, and XI.S4, 10CFR Part 50, Appendix J

Reactor Vessel Internals (RVI)

	SLRA Sections Addressing GALL-SLR Recommendations
Aging management of reactor vessel internals	3.1.2.2.9 Aging Management of PWR Vessel Internals (GAP Analysis) 3.1.2.2.10(2) Loss of Material Due to Wear A1.7 PWR Vessel Internals A2.2 Neutron Fluence Monitoring Appendix C MRP-227-A GAP Analysis for PWR Vessel Internals Aging Management

- SPS will manage RVI Primary (P), Expansion (E), and Existing (X) examinations consistent with MRP-227, Rev. 1-A and associated NRC Safety Evaluation dated April 25, 2019
- In addition, the following SLR RVI component examinations are also incorporated into the PWR Vessel Internals program:
  - MRP-2018-022:
    Primary: Lower Girth Welds, Clevis Insert Bolts, Thermal Sleeves, Radial Support Keys, Clevis Stellite Surfaces
    Expansion: Upper Core Plate (VT3 exam)
    Existing: Fuel Alignment Pins (malcomized)
  - MRP 2019-009: Lower Girth Welds (Primary-OTI)
  - WCAP-17451: CRGT Sheaths and C-Tubes (Expansion)
- SPS will manage RVI fluence projections consistent with GALL-SLR AMP X.M2, Neutron Fluence Monitoring Program
- SPS will manage RVI examinations consistent with GALL-SLR AMP XI.M16A, PWR Vessel Internals

Other Aging Management Enhancements

	SLRA Sections Addressing GALL-SLR Recommendations
Other Aging Management Considerations	A1.8 Flow-Accelerated Corrosion A1.11 Open-Cycle Cooling Water System A1.27 Buried and Underground Piping and Tanks A3.7.1 Reactor Coolant Pump Fatigue Crack Growth Analysis A3.7.6 Reactor Coolant Pump Code Case N-481 A3.7.7 Cracking Associated With Weld Deposited Cracking

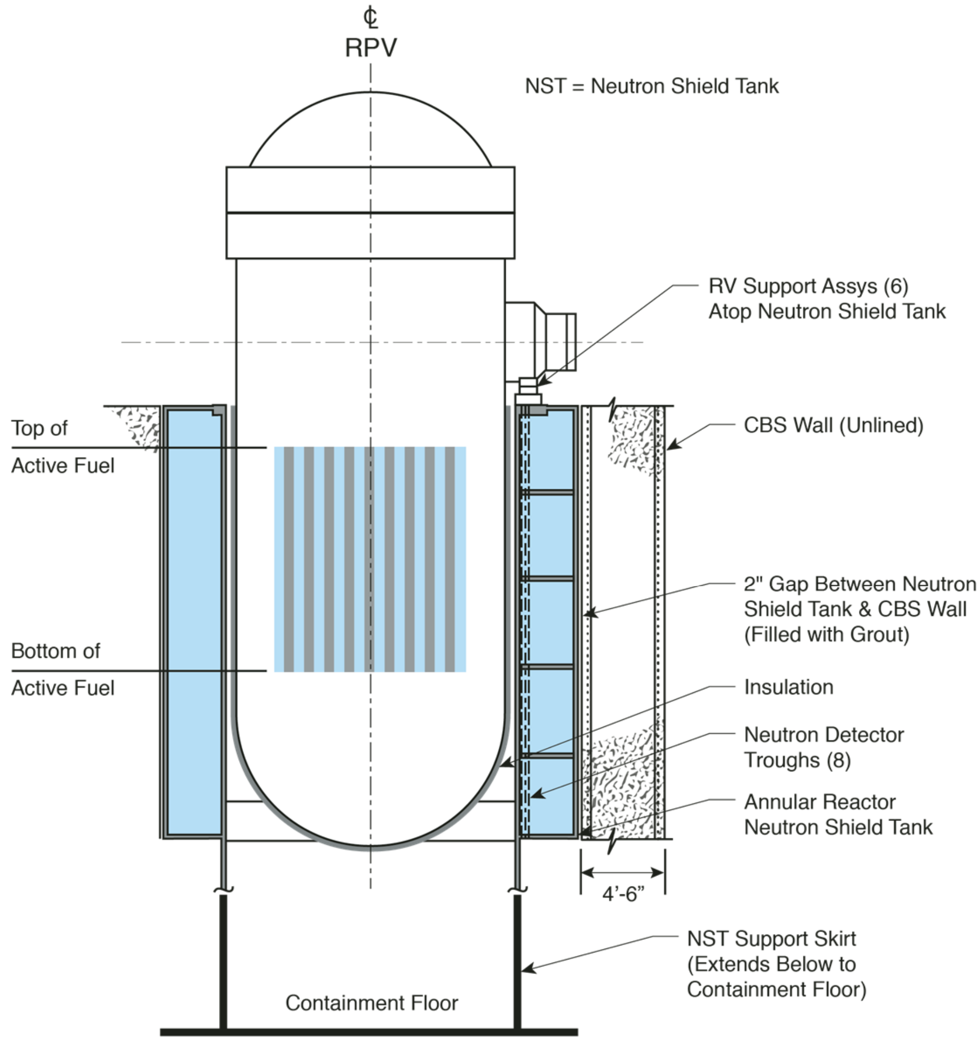
- Draft ASME Code Case N-871 examinations will manage the aging of the pressure boundary of the newly installed carbon fiber reinforced polymer pipe lining consistent with GALL-SLR AMP XI.M20, Open-Cycle Cooling Water System Program.
- Erosion monitoring manages wall thinning due to cavitation, liquid droplet impingement, flashing, and solid particle erosion consistent with GALL-SLR AMP XI.M17, Flow-Accelerated Corrosion.
- Soil surveys and analysis consistent with EPRI 3002005294 that confirms soil environment corrosivity now supplements AMP XI.M41, Buried and Underground Piping and Tanks Program.
- The following TLAA topical reports updated for 80 years were recently approved by NRC SE:
  - Reactor coolant pump (RCP) fatigue crack growth analysis (PWROG-17011-NP-A Rev 2-A)
  - Fracture mechanics integrity assessment for RCP Code Case N-481 (PWROG-17033-P-A Rev 1-A)
  - Reactor vessel underclad cracking associated weld deposited cracking (PWROG-17031-NP-A Rev 1 – draft NRC Safety Evaluation in progress)

Reactor Vessel Embrittlement

	SLRA Sections Addressing GALL-SLR Recommendations
Reactor Pressure Vessel Neutron Embrittlement at High Fluence	3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement 3.1.2.2.13 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement or Thermal Embrittlement 4.2 Reactor Vessel Neutron Embrittlement Analysis A1.9 Reactor Vessel Material Surveillance A2.2 Neutron Fluence Monitoring

- Fluence projections through SPEO (68 EFPY) were performed for neutron embrittlement analyses
- Analyses for USE, ART, and P-T Limits for beltline materials have been satisfactorily evaluated using the 68 EFPY fluence projections
- USE analysis with less than 50 ft-lb Charpy USE was projected to the end of the SPEO with Equivalent Margin Analysis
- The applicability of the existing P-T limit curves has been extended to 68 EFPY with the use of updated initial material properties used to calculate ART values and K_{IC} methodology
- SPS will manage fluence projections consistent with GALL-SLR AMP X.M2, Neutron Fluence Monitoring Program
- SPS will manage embrittlement consistent with GALL-SLR AMP XI.M31, Reactor Vessel Material Surveillance Program
  - One capsule will be withdrawn from each unit during SPEO at 60-63 EFPY

Reactor Vessel (RV) Support Steel Configuration



Reactor Vessel Support Configuration

Irradiation of RV Support Steel

	SLRA Sections Addressing GALL-SLR Recommendations
Irradiation of RV Support Steel	3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due To Irradiation A1.12 Closed Treated Water Systems A1.31 ASME Section XI, subsection IWF A1.34 Structures Monitoring

- Originally assessed in preparation of future license renewal activities by Stone & Webster under contract from DOE, WOG, EPRI, and Virginia Power
- Westinghouse DORT fluence model through 100 years (76.8 EFPY)
- New analysis was performed by Dominion for SPS SLR
  - Fracture mechanic evaluation (ASME Code formulas for PT Curves)
  - Loads for dead weight, LOCA, and seismic
  - Based on use of lower bound K_{IR} value of 26.7 ksi $\sqrt{in}$ to represent infinite amount of fluence
  - Critical stress (based on the K_{IR} curve) using the lower bound toughness of 26.7 ksi $\sqrt{in}$ is greater than the stress on NST
  - Therefore, brittle fracture will not occur
- SPS will manage aging consistent with:
  - B2.1.12 Closed Treated Water Systems
  - B2.1.31 ASME Section XI, subsection IWF
  - B2.1.34 Structures Monitoring

Fire Protection Yard Loop Operating Experience

Fire Protection Loop Piping Break

- In July 2019, leakage was experienced from two adjacent 18 foot to 20-foot-long sections of 12" diameter fire protection loop piping

Dominion Energy

Analysis of Piping Failure

- The FP pipe failure was entered into the Corrective Action Program to determine the cause of the failure and the extent of condition
- Graphitic corrosion was identified as the cause of the piping failure
  - Elevated levels of corrosion are confined to a limited area near the identified failure between the 5 o' clock and 7 o' clock positions
  - Bituminous coating was observed to have been degraded in these locations. Other locations on the pipe above the areas of water contact were not affected.
  - Hydraulic pressure surge caused by the start of the motor-driven pump contributed to the initial failure, which led to bending stresses and an overload condition affecting adjacent FP piping
- Failures due to extended exposure of the susceptible gray cast iron material to moist/wet soil in the area of failures

Analysis of Piping Failure

- Additional inspections were conducted to identify the extent of condition to identify other FP piping locations in the main loop that were exposed to groundwater
  - Reviewed OE from previous excavations around the plant site to map location to vacuum exploratory holes
  - Exploratory holes were vacuumed to depths below the buried FP Piping to confirm the absence of groundwater
  - Identified locations with groundwater were sampled and determined not to include chloride levels indicative of leakage from the intake canal
  - Soil samples were taken at the excavation location during the repairs of the ruptured FP piping and the corrosivity levels were determined to be low
- Fire suppression capabilities have been maintained through compensatory measures

Fire Protection Yard Loop Project

- Funding approved for the project includes piping as well as hydrants/valves
- Prioritized four phased approach
  - Susceptibility to graphitic corrosion
  - Location with respect to fire pumps
- On site project manager is actively working
  - Conceptual design in progress considering best technical solutions using outside expertise
- Vacuum excavation of Phase 1 in progress

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Improved Aging Management Methods

- Operating Experience is being shared with the industry
  - Program owner presented to the Selective Leaching Task Force in January 2020 and is scheduled to present to the Buried Pipe Integrity Group in February 2020 to inform the industry
  - Sections of pipe transported to EPRI to conduct selective leaching research on methods of detection
- Aging management programs will be informed with information that is learned through our experiences and as new information related to materials and examination methods
- Dominion Energy is committed to improving the integrity of the Fire Protection system

Dominion Energy SLR Summary

- NRC coordination on GALL SLR and SRP was transparent to all stakeholders
- Surry SLR met the expected norms established with the most recent industry LR/SLR applications
- Surry had a high degree of consistency with GALL-SLR, which resulted in a high quality SLR Application
- AMPs will effectively manage the effects of aging to provide reasonable assurance for the SLR period
- Dominion Energy has committed future investments in people, program enhancements and equipment modifications for the SPEO

United States Nuclear Regulatory Commission

Protecting People and the Environment

Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee

Surry Power Station, Units 1 and 2 Subsequent License Renewal Application (SLRA) Safety Evaluation Report (SER)

February 5, 2020

Angela Wu, Project Manager

Lauren Gibson, Project Manager

Office of Nuclear Reactor Regulation

Presentation Outline

- Overview of Safety Review of Surry SLRA
- SER:
  - Section 2: Scoping and Screening Review
  - Section 3: Aging Management Review
  - Section 4: Time-Limited Aging Analyses
  - Specific Areas of Review
- Region II: Inspections and Plant Material Conditions
- Conclusion
- Discussion on Differing Views

Surry, Units 1 & 2: License Renewal

Initial License Renewal

Unit	Initial License	Initial License Renewal Application	Renewed License	Expiration Date
1	5/25/1972	5/29/2001	3/20/2003	5/25/2032
2	1/29/1973	5/29/2001	3/20/2003	1/29/2033

Subsequent License Renewal

Application Submitted	10/15/2018
Acceptance Determination	12/10/2018
Draft Safety Evaluation Report with No Open or Confirmatory Items	12/27/2019

Audits

Audits	Dates	Location
Operating Experience	December 6 - 19, 2018	Rockville, MD
In-Office	February 4 - 28, 2019	Rockville, MD
On-Site	April 22 - 25, 2019	Surry Power Station, Units 1 and 2 (Surry County, VA) Dominion HQ (Innsbrook, VA)

SER Overview

- Draft SER with No Open or Confirmatory Items: December 27, 2019

- Requests for Additional Information (RAIs): 71

SER Section 2

Structures and Components Subject to Aging Management Review (AMR)

- Section 2.1 – Scoping and Screening Methodology
- Section 2.2 – Plant Level Scoping Results
- Sections 2.3, 2.4, 2.5 – Scoping and Screening Results

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SER Section 3

Aging Management Review (AMR)

- 3.0 – Use of the Generic Aging Lessons Learned Report
- 3.1 – Reactor Vessel, Internals, and Reactor Coolant System
- 3.2 – Engineered Safety Features
- 3.3 – Auxiliary Systems
- 3.4 – Steam and Power Conversion Systems
- 3.5 – Containment, Structures and Component Supports
- 3.6 – Electrical and Instrumentation and Control Commodities

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SER Section 3

3.0.3 - Aging Management Programs (AMPs)

SLRA - Original Disposition of AMPs	SER - Final Disposition of AMPs
○ 7 new programs • 5 consistent • 2 consistent with exceptions ○ 40 existing programs • 7 consistent • 33 consistent with enhancements/exceptions	○ 7 new programs • 5 consistent • 2 consistent with exceptions ○ 40 existing programs • 6 consistent • 34 consistent with enhancements/exceptions

SER Section 4

Time-Limited Aging Analyses (TLAAs)

- 4.1 – Identification of TLAAs
- 4.2 – Reactor Vessel and Internals Neutron Embrittlement Analyses
- 4.3 – Metal Fatigue Analyses
- 4.4 – Environmental Qualification of Electric Equipment
- 4.5 – Concrete Containment Tendon Prestress Analysis
- 4.6 – Primary Containment Fatigue Analysis
- 4.7 – Other Plant-Specific TLAAs

Specific Areas of Review

- Irradiation Effects on the Concrete Biological Shield Wall + Reactor Vessel Steel Supports
- Buried Cementitious Piping
- Selective Leaching
- Neutron Fluence Monitoring
- Electrical Cable Qualification and Condition Assessment

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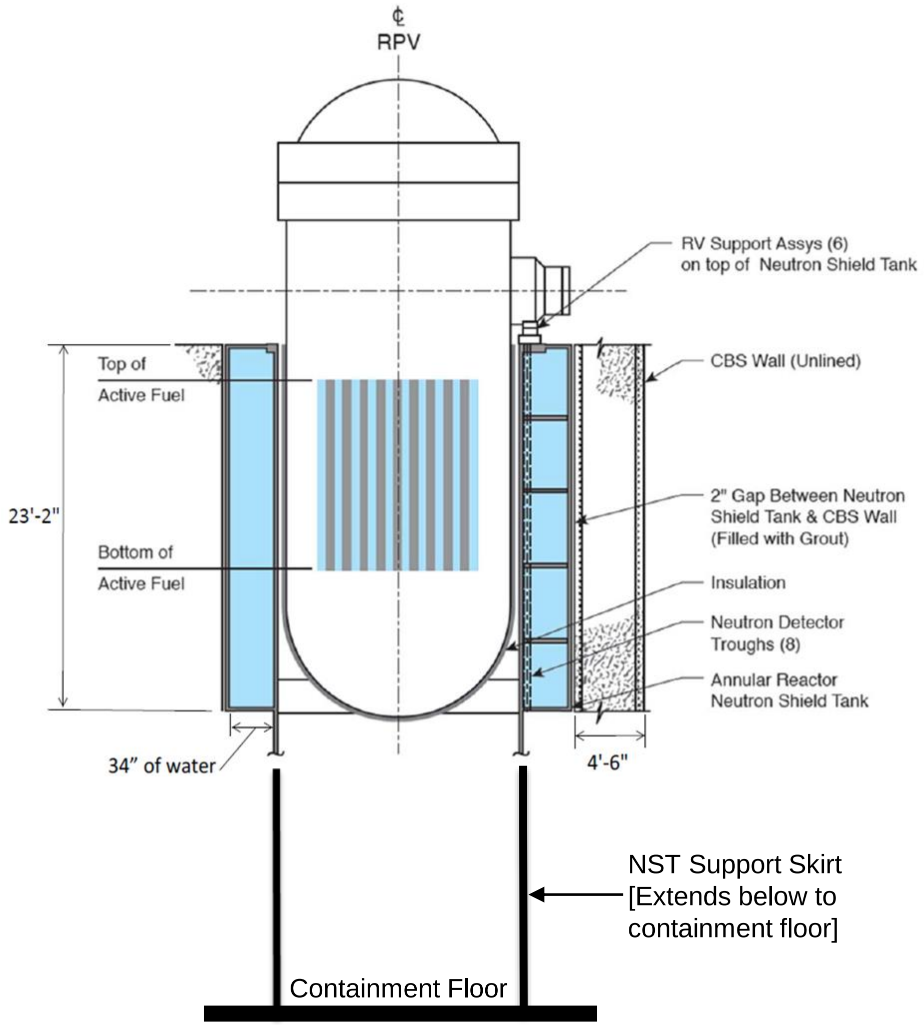
Irradiation Effects on Concrete Biological Shield Wall



Reactor Vessel Support Configuration

NST = Neutron Shield Tank

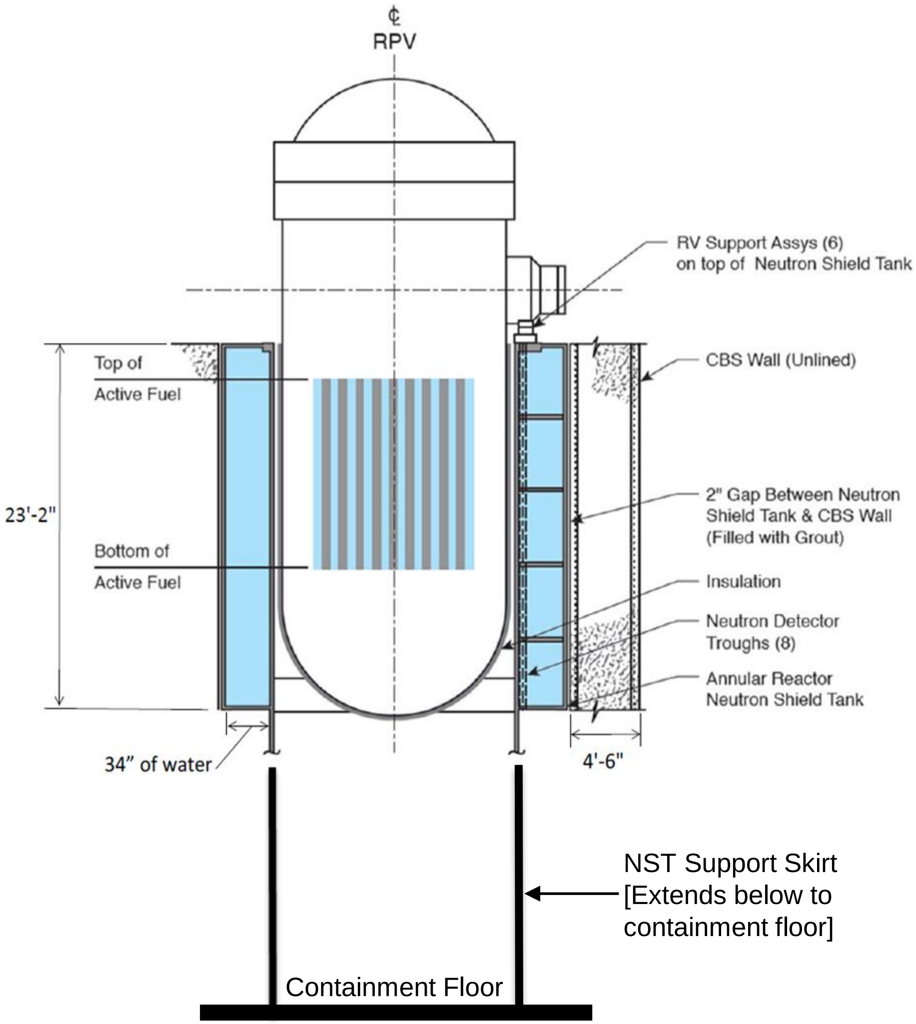
SRP-SLR 3.5.2.2.2.6 criteria for concrete is met and Dominion's determination that a plant-specific AMP is not required is acceptable:

- Calculated neutron fluence (3.17×10^{18} n/cm^2) and gamma dose (2.97×10^8 rad) at limiting locations for 72 Effective Full Power Years [EFPY] are below respective SRP-SLR thresholds (1×10^{19} n/cm^2 and 1×10^{10} rad) for potential degradation

- No plant-specific operating experience of irradiation degradation noted to date

- Accessible portions of wall will continue to be visually inspected by the Structures Monitoring Program

Irradiation Effects on Reactor Vessel (RV) Steel Supports



Reactor Vessel Support Configuration

NST = Neutron Shield Tank

The loss of fracture toughness due to irradiation embrittlement is an aging effect that does not require management:

- NST fluence and fracture mechanics evaluation demonstrated the aging effect will not occur and structural integrity will be maintained during subsequent period of extended operation
- No plant-specific operating experience of the aging effect identified to date
- Susceptible aging effects (loss of material / mechanical function) of RV Support Sliding Feet Assemblies (above NST) managed by *ASME Section XI, Subsection IWF* AMP
- Susceptible aging effects (loss of material / support function) of NST managed by *Structures Monitoring, and Closed Treated Water Systems* AMPs

Buried Cementitious Piping

- Issue: Dominion proposed an alternative approach to manage the effects of aging on the external surfaces of uncoated buried cementitious circulating water (CW) piping:
  - A one-time inspection of one of the following:
    - Below-grade turbine building concrete (i.e., surrogate structure); or
    - Buried cementitious CW piping if the surrogate structure is coated
  - Groundwater + soil testing

- GALL-SLR: GALL-SLR Table XI.M41-2, “Inspection of Buried and Underground Piping and Tanks,” recommends periodic inspections (i.e., two inspections in each ten-year period for a two-unit site)

- Reasonable Assurance: Combined approach of a one-time inspection, coupled with groundwater and soil testing

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Selective Leaching

- Issue: Identified in October 14, 2019 Annual SLRA Update
  - Two ruptures of cast iron buried fire protection system piping (July 2019)
  - Failure due to external graphitic corrosion from groundwater exposure

- Resolution: AMP Augmented to Include Exploratory Holes
  - Excavate + inspect fire protection loop piping where groundwater is identified
  - Additional holes to confirm extent of identified elevated groundwater, water from fire protection system leakage or other plant system leakage
  - Completion of corrective actions for 2019 pipe ruptures may result in additional changes to AMPs

- Reasonable Assurance: Identified activities (exploratory holes to confirm the presence of groundwater, excavating and inspecting fire protection loop piping) are capable of detecting adverse conditions due to groundwater immersion that may lead to graphitic corrosion

Neutron Fluence Monitoring

- Issue: Staff could not verify if 80-year neutron fluence values for the reactor vessel internals (RVI) fall within the ranges in the generic fluence screening criteria of the MRP-227-Revision 1 gap analysis

- Resolution: Proprietary report included the neutron fluence values projected to 80 years specific to the Surry RVI

- Reasonable Assurance: 80-year neutron fluence values for the RVI are within the ranges specified in the generic screening criteria in the MRP-227-Revision 1 gap analysis

Electrical Cable Qualification and Condition Assessment

- Issues:
  - No test matrix for inaccessible medium voltage cables in AMP B2.1.39
  - Exclusion of mechanical components in the Environmental Qualification (EQ) program. Maintaining qualification of interface between mechanical + electrical equipment in the EQ program was unclear

- Resolution:
  - AMP was revised to include a test matrix
  - Staff's onsite audit confirmed that mechanical interfaces are included in the EQ program

- Reasonable Assurance: EQ program is adequate to satisfy the TLAA consistent with 10 CFR 54.21(c)(1)(iii)

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Region II AMP Inspections

License Renewal Inspection Program for Initial Period of Extended Operations

Inspection	Dates	Results
U1 & U2 IP 71003 Phase 1	April 25 – 29, 2011 ML111460331	No Findings
U1 & U2 IP 71003 Phase 2	July 11 – July 29, 2011 ML112560062	No Findings 8 Observations
U1 & U2 IP 71003 Phase 3	June 18 – June 22, 2012 ML12220A541	No Findings
U1 & U2 IP71003 Phase 4	August 12 – 16, 2019 ML19311C688	No Findings

Region II
AMP Inspections

AMPs Reviewed During 71003 Phase 4 Inspection

- Augmented Inspection Program (Existing)
- Buried Piping and Valve Inspection Program (New)
- Chemistry Control Programs for Primary Systems (Existing)
- Chemistry Control Program for Secondary Systems (Existing)
- Civil Engineering Structural Inspection Program (Existing)
- General Condition Monitoring Program (Existing)
- Non-EQ Cable Monitoring Program (Existing)
- Tank Inspection Program (New)
- Work Control Process (Existing)

Region II: AMP Inspections
ROP Baseline Inspections

Inspection	Date	Aging Management Program
IP71111.08 ISI	Annually alternate units	Augmented Inspection Activities Boric Acid Corrosion Surveillance ISI Program – Component and Component Support Inspections ISI Program – Containment Inspections ISI Program – Reactor Vessel Reactor Vessel Internals Inspection Steam Generator Inspections
IP71111.07T Heat Sink	2011, 2014, 2017	Service Water System Inspections
IP71111.21M DBAI	3Q 2018	Ensure the selected SSCs that are subject (operating in the post-40-year licensing period) to aging management review pursuant to 10 CFR Part 54 are being managed for aging in accordance with appropriate aging management programs.
IP71111.12 Maintenance Effectiveness “B” Emergency Service Water Pump Cracked Discharge Flange	4Q 2016	Maintenance Rule Structural Monitoring Program
IP71152 PI&R Sample Emergency Bus Degraded Voltage and Undervoltage Relay Failures	3Q 2018	Non-EQ Cable Monitoring Program
IP71152 PI&R Sample 2019 Fire Loop Piping Rupture reveals unexpected corrosive soil conditions	1Q 2020	Buried Piping Program

Region II
AMP Inspections

Resident Inspector Insight and Inspection Results

- No findings from License Renewal Program inspections
- 2016: Green NCV for failing to identify degraded supports associated with the emergency service water pumps (NCV 05000280, 281/2016003-01)
- 2018: Green NCV for inadequate preventative maintenance and multiple beyond service life relay failures (05000281/2018002-01)
- 2019: Fire Loop Piping Rupture

Region II AMP Inspections

July 2019 Fire Loop Piping Rupture

- External corrosion from long-standing exposure to moist or wet soil resulted in wall thickness reductions at several locations via graphitic corrosion (i.e., selective leaching)
- Dominion committed to dig 25 exploratory holes along the piping to determine if additional corrective actions are necessary, including excavation and evaluation of any piping in the presence of groundwater.

Region II Conclusion

- Regional Inspections:
  - In general, the inspectors found that aging management programs were being implemented in accordance with the license condition.
  - The region will continue to monitor AMPs using the baseline Reactor Oversight Process.
  - A focused PIR inspection using insights from the revised IP71111.12 is scheduled for late February 2020 to review licensee corrective actions and incorporation of new operating experience into the Buried Piping Program.

SLRA Review Conclusion

On the basis of its review of the SLRA, the staff determined that the requirements of 10 CFR 54.29(a) have been met for the subsequent license renewal of Surry Power Station, Units 1 and 2.

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Differing View – Person #1: Selective Leaching Program

- Issue: A singular criterion (i.e., presence of groundwater) is used to detect adverse conditions that may lead to graphitic corrosion of buried gray cast iron fire protection loop piping.
- Other soil parameters besides standing water (e.g., soil resistivity, pH, redox potential, sulfides) play an important role in the corrosion of cast iron in soil.
    - Elayaperumal, K. Raja, V. S.. (2015). Corrosion Failures - Theory, Case Studies, and Solutions.
    - EPRI Report 3002005294, “Soil Sampling and Testing Methods to Evaluate the Corrosivity of the Environment for Buried Piping and Tanks at Nuclear Power Plants,” Table 9-4, “Soil Corrosivity Index from BPWORKS.”
    - AWWA C105, “Polyethylene Encasement for Ductile-Iron Pipe Systems,” Table A.1, “Soil-Test Evaluation.”

Differing View – Person #1: Selective Leaching Program (Continued)

- October 31, 2019 (ADAMS Accession No. ML19310E716) Submittal:
  - Limited soil corrosivity testing documents low pH and low soil resistivity, indicating that soil parameters other than standing water may have contributed to the ruptures.
- <u>No Reasonable Assurance</u>: No basis for relying on a singular criterion makes it unclear how reasonable assurance can be achieved

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Differing View – Person #2:
SER Sections 3.0.3.1.6, 3.0.3.2.7, and 3.0.3.2.20

- **Selective Leaching (SER Section 3.0.3.1.6)**
  - Issue: Final Safety Analysis Report supplement lacks critical details of currently revised program
    - Requirements of 10 CFR 54.21(d) for a summary description of the program were not met.
  - Issue: Bases for inspection reduction crediting common conditions for two-unit site do not address soil chemistry variation
    - SLRA did not contain information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed for the reduced component inspections.
  - Issue: Excavation limited to confirmed groundwater but not system leakage
    - SLRA did not contain information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed for components exposed to system leakage.
  - Issue: Operating conditions at the plant are not bounded by those for which the GALL-SLR Report program was evaluated
    - Future submittals can cite precedent from Surry SLRA SER.
    - The staff's inaccurate statements in the SER should be corrected.

Differing View – Person #2

- **Open-Cycle Cooling Water System (SER Section 3.0.3.2.7)**
  - Issue: No aging management review of passive components for essential service water pump diesel engines or drives
    - Future submittals can cite precedent from Surry SLRA SER.
    - SLRA did not contain information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed for diesel engine heat exchanger and right angle gear oil cooler.

- **Buried and Underground Piping and Tanks (SER Section 3.0.3.2.20)**
  - Issue: Bell and spigot fire water system tie rod corrosion not addressed
    - SLRA did not contain information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed for fire water system tie rods.
  - Issue: Buried fire water piping external coating found to be inadequate
    - SLRA did not contain information required by 10 CFR 54.21(a)(3) to demonstrate that the effects of aging will be adequately managed for thinly coated fire water system piping.

Differing View – Person #2:
SER Section 6, Conclusion

- Issue: For above SER sections, the applicant did not identify actions for managing the effects of aging during the subsequent period of extended operation
  - Actions to establish adequate aging management programs are pending corrective actions under current license or were not provided.
  - Without identifying actions, the applicant did not meet the requirements of 10 CFR 54.29(a) as stated in the SER.

NRR Preliminary Perspective on Differing Views

- Technical issues accurately characterized
- AMP updated based on operating experience and NRC RAIs
- Manageable by existing process
  - Entered into Corrective Action Program
  - Final corrective actions are pending
- Established regulatory framework ensures reasonable assurance