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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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672ND MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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OPEN SESSION

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WEDNESDAY

APRIL 8, 2020

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TELECONFERENCE

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The Advisory Committee met via teleconference at 8:30 a.m., Matthew Sunseri, Chairman, presiding.

COMMITTEE MEMBERS:

MATTHEW W. SUNSERI, Chairman

JOY L. REMPE, Vice Chairman

WALTER L. KIRCHNER, Member-at-Large

RONALD G. BALLINGER, Member

DENNIS BLEY, Member

CHARLES H. BROWN, JR. Member

VESNA B. DIMITRIJEVIC, Member

JOSE MARCH-LEUBA, Member

DAVID A. PETTI, Member

PETER RICCARDELLA, Member

DESIGNATED FEDERAL OFFICIAL:

MIKE SNODDERLY

LARRY BURKHART

ALSO PRESENT:

PAUL AITKEN, Dominion

BRUCE BAVOL, NRR

ERIC BLOCHER, Dominion

ANNA BRADFORD, NRR

BEN BRISTOL, NuScale

SARAH BRISTOL, NuScale

SARAH FIELDS, Public Participant

LAUREN GIBSON, NRR

ANNE-MARIE GRADY, NRR

ALLEN HARROW, Dominion

ALLEN HISER, NRR

MARY JOHNSON, NRR

MEGHAN McCLOSKEY, NuScale

LOUIS McKOWN, Region II

FRED MLADEN, Dominion

SCOTT MOORE, Executive Director, ACRS
TONY NAKANISHI, NRR
MICHAEL NELSON, NuScale
QUYNH NGUYEN, ACRS
REBECCA NORRIS, NuScale
ERIC OESTERLE, NRR
JIM OSBORN, NuScale
PAUL PHELPS, Dominion
MARIE POHIDA, NRR
MATTHEW PRESSON, NuScale
JEFF SCHMIDT, NRR
DINESH TANEJA, NRR
GETACHEW TESFAYE, NRR
CARL THURSTON, NRR
CHARLES TOMES, Dominion
ANGELA WU, NRR

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

P R O C E E D I N G S

8:38 a.m.

CHAIRMAN SUNSERI: The meeting will now come to order. This is the first day of the 672nd Meeting of the Advisory Committee on Reactor Safeguards.

I am Matthew Sunseri, Chair of the meeting. And at this time, I'm going to take a roll call of the members to confirm their attendance. Members, please acknowledge when I call your name.

Ron Ballinger?

MEMBER BALLINGER: I'm here.

CHAIRMAN SUNSERI: Dennis Bley?

MEMBER BLEY: Here.

CHAIRMAN SUNSERI: Charles Brown?

MEMBER BROWN: I'm here.

CHAIRMAN SUNSERI: Vesna Dimitrijevic?

MEMBER DIMITRIJEVIC: I'm here.

CHAIRMAN SUNSERI: Walt Kirchner?

MEMBER KIRCHNER: Here.

CHAIRMAN SUNSERI: Jose March-Leuba?

MEMBER MARCH-LEUBA: Present.

CHAIRMAN SUNSERI: Dave Petti?

MEMBER PETTI: Here.

CHAIRMAN SUNSERI: Joy Rempe?

VICE CHAIR REMPE: I'm here.

CHAIRMAN SUNSERI: Pete Riccardella?

MEMBER RICCARDELLA: Present.

CHAIRMAN SUNSERI: And Matt Sunseri. I note that we have a quorum.

The ACRS was established by Atomic Energy Act and is governed by the Federal Advisory Committee Act. The ACRS section of the U.S. NRC public website provides information about the history of the ACRS and provides documents such as our bylaws, charter, Federal Register notice for meetings, letter reports and transcripts of all full and subcommittee meetings, including all slides presented at the meeting. The Committee provides its advice on safety matters to the Commission through its publicly available letter reports.

The Federal Register notice announcing this meeting was published on March 30th, 2020, and provides and agenda and instructions for interested parties to provided written documents or request the opportunity to address the Committee.

The Designated Federal Official for this meeting is Mr. Mike Snodderly.

During today's meeting, the Committee will consider the following: Item No. 1, Surry Power

Station Subsequent License Renewal.

Item No. 2, NuScale: Chapter 15, Boron Dilution, Return to Criticality, Probabilistic Risk Analysis, and Hydrogen and Oxygen Monitoring.

And Item No. 3, Preparation of ACRS Reports.

As reflected in the agenda, portions of the NuScale session may be closed in order to discuss and protect information designated as sensitive or proprietary information.

A bridge line has been opened up to allow members of the public to listen in on the presentations and Committee discussion. We have received no written comments or requests to make oral statements from members of the public regarding today's session. There will be an opportunity for public comment and we have set aside time in the agenda for comments from members of the public attending or listening to our meeting. Written comments may be forwarded to Mr. Mike Snodderly, the Designated Federal Official.

A transcript of the open portion of the meeting is being kept and it is requested that the speakers use your microphones, identify yourself, and speak with sufficient clarity and volume so that we

can be readily heard. Otherwise, speakers and all participants should be muting their microphones when not speaking.

So, before we begin the first presentation, I want to acknowledge the support that we've gotten from our staff, the applicants, and the NRC staff to conduct this meeting via a virtual meeting process.

Due to the actions necessary to protect the public health from the coronavirus, we are following the federally promulgated guidance to avoid in-person social interactions. By my review, this will be our first such meeting, out of 671 prior meetings where we have met face-to-face.

We are well-prepared. Nonetheless, I am sure that there may be unanticipated challenges. So I ask in advance for your understanding, patience, and support as we through this process.

There are two key behavior that I want to emphasize for the participants today. First and foremost, if you are not talking or engaging in the conversation, mute your microphone.

Number two, for the presenters. Please take frequent pauses in your presentation to allow members to ask questions or provide input. When you

run for long periods of time without stopping to take a breath, it makes it hard to break in. So we will not be successful if we don't get the member participation that has been a hallmark of the effectiveness of this Committee.

So, that concludes my opening remarks. Our first agenda item is the Surry Subsequent License Renewal. And at this point, I'd like to turn to Anna Bradford for any opening remarks.

MS. BRADFORD: Thank you, Chairman Sunseri. Can you please confirm that you can hear me?

CHAIRMAN SUNSERI: Yes, you're loud and clear.

MS. BRADFORD: Great. Thank you. As you mentioned, my name is Anna Bradford. I'm the Director of the Division of New and Renewed Licenses in NRR.

We sincerely appreciate the opportunity today to present to ACRS the results of the staff's review of the third application for subsequent license renewal. We especially appreciate the ACRS' flexibility in doing business in a new way during these unusual times.

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

By way of background, Surry Units 1 and 2 received approval for their initial renewed licenses from the NRC on March 20th, 2003. The NRC review at that time was performed using guidance developed prior to the issuance of a Generic Aging Lessons-Learned Report, or the GALL Report.

The NRC guidance for license renewal over the years has evolved through enhancements and improvements based on lessons learned from NRC reviews of 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 contained in GALL SLR built upon the previous guidance and included additional focus and enhancements where necessary on aging management and time limited aging analyses for operation in the 60- to 80-year period.

In the staff presentation today, you will hear about some of these specific SLR issues as applied to the Surry review. The NRC project manager for the Surry subsequent license renewal application review are Ms. Angela Wu and Ms. Lauren Gibson. Angela will introduce the staff who will be presenting

or addressing questions regarding the staff's review of the Surry subsequent license renewal application.

Part of the management team on the phone today are Mr. Eric Oesterle, Chief of the License Renewal Project Branch. And in the audience are members of the division and other NRR technical review branches. We also have with us a representative from Region II, Mr. Louis McKown, Senior Resident Inspector at the Surry Power Station.

The staff will provide an overview of its safety review as documented in the Final Safety Evaluation Report which was provided to the ACRS on March 9, 2020.

Following the staff's presentation, Dr. Allen Hiser, Senior Technical Advisor, Division of New and Renewed Licenses, will discuss the disposition of different views from technical staff who submitted non-concurrences on the SLR.

Finally, we will address any questions you may have on the staff's presentation. We look forward to a productive discussion today with the ACRS.

At this time, I'd like to turn the presentation over to Mr. Paul Phelps, Dominion director for subsequent license renewal, to introduce his team and commence our presentation. Thank you.

MR. PHELPS: Can everyone hear me?

CHAIRMAN SUNSERI: Yes, Paul.

MR. PHELPS: Thank you, Anna, and good morning. My name is Paul Phelps and I am the engineering director responsible for the Surry Power Station subsequent license renewal, or SLR, project.

We appreciate the opportunity to speak with the Advisory Committee on Reactor Safeguards, ACRS, Full Committee 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 Committee.

By 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 relicensing 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 want to take the time to introduce the team assembled on the call present to present the

Surry SLR application. Paul Aitken, who is the 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.

Next is Eric Blocher. Eric has been involved in various first license renewal applications in the industry. He brings an extensive knowledge to the team and has been deeply involved in the development of the General Aging Lessons-Learned, GALL, SLR, not only on behalf of Dominion Energy but for the nuclear industry.

Lastly, I would like to recognize Fred Mladen who is also on the call. Fred, is the site vice president at Surry Power Station.

Next slide, please. I am on Slide 2.

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. I am on Slide 3.

Surry Power Station is located in Surry County, Virginia, 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 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. I am on Slide 4.

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 spent fuel 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 percent stretch power uprate was implemented in 1995 prior to the initial license renewal.

The renewed licenses for Surry and North Anna 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. I'm on Slide 5.

Here's an aerial view of the station. I will highlight some of the more significant features. Again, the orientation of the site and the river flow are from west to east, or upstream James River around Hog 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 from the intake. A unique feature of Surry is that the water from the James River is pumped into the 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 2 reinforced concrete containment structures in 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's staff work.

Next slide, please. I'm on Slide 6.

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. I am on Slide 7.

There has been nearly one billion dollars 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.

Here is a partial list of some of the major projects that have been completed at Surry since the first license renewal. I would like to highlight a few.

Dominion Energy was very proactive replace the reactor vessel heads at both North Anna and Surry Power Station. In addition, Surry has replaced or scheduled to replace all of the high voltage transformers.

I will note the carbon fiber reinforced

polymer installation is one of the first projects that the SLR team implemented at Surry to address longstanding aging management of large bore circulating water and service water piping.

Let me pause and ask if there are any questions before I turn over the presentation to Paul Aitken.

(Pause.)

MR. AITKEN: Okay. Thanks, and good morning. Again, my name is Paul Aitken and I am the engineering manager responsible for the development of the Surry Subsequent License Renewal Application. We are now on Slide 8.

I'll be providing an overview of the SLR application development process and other considerations for the ACRS Committee today. The Dominion Energy team has worked closely with various research organizations and utility-sponsored groups to collectively represent the industry when working with the NRC during the development of the GALL-SLR. We supported several public meetings over the last couple of years to finalize the GALL-SLR, as well as spearheading the industry guidance for SLR, as reflected in NEI Guide 17-01.

This involvement allowed Dominion Energy

the benefit from the industry engagement and used those insights in the development of the Surry application. We also reviewed previously issued RAIs to incorporate additional lessons learned from the more recent first license renewal applicants and SLR applicants.

Dominion Energy participated in the peer reviews for Turkey Point and Peach Bottom. We were able to provide feedback on their respective applications while also incorporating insights that we learned during the interactions. We also conducted an industry peer review using the NEI license renewal civil, mechanical, and electric working groups and other SLR applicants.

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 beneficial during the development of the application.

In the end, Dominion Energy submitted a high quality application, as reflected by fewer RAIs as compared to Dominion Energy's first license renewal applications, and a Safety Evaluation Report with no

open items or confirmatory items.

Next slide, please. Now I'm on Slide 9.

I wanted to provide a brief summary of the differences between first license renewal and subsequent license renewal with respect to the integrated plant assessment. With scoping and screening there were no changes in the overall process approach. This is primarily because the established industry criteria hasn't changed very much from first license renewal.

We needed to address any physical modifications for the facility since the last license renewal. Another area that we expected to have adjustments was related to scoping and screening by altitude. That's not safety-related, but it can affect safety-related equipment. This was due to the criteria and guidance evolving since first license renewal.

Surry is a plant like the previous two SLR applicants, so we are in the same situation of the methodology and scoping in additional systems. In the area of aging management reviews, the expansion and the number of aging effects we have to address significantly increase through the events of the previous application and the 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 47 going to be aging management programs.

Activities from first license renewal have been addressed in subsequent license renewal. Eric Blocher will provide some additional information on the aging management program. The Surry subsequent license renewal application has reassessed the existing licensing basis TLAAs. There was only one new TLAA identified since this license renewal, and that was dispositioned as acceptable for 80 years.

Next slide, please.

CHAIRMAN SUNSERI: Before you move on, I have a question. This is Matt Sunseri. Can you hear me?

MR. AITKEN: Yeah, I can.

CHAIRMAN SUNSERI: On the differences between your first license renewal and your subsequent license renewal, are there any aging management activities from the first license renewal that didn't carry over into the subsequent renewal?

(Off-microphone comments.)

(Simultaneous speaking.)

MR. AITKEN: There's a little feedback there. Can you repeat that? Are there any first license renewal activities that are not being addressed in subsequent license renewal?

CHAIRMAN SUNSERI: That's correct, yeah. I hear the feedback. Somebody is not muting their microphone. So, all participants that aren't engaged in the conversation, please mute your microphone unless you're trying to talk.

MR. AITKEN: So, yeah, to answer that question, all first license renewal activities are going to carry forward into subsequent license renewals. Eric is going to talk to that very point as he gets into his slides.

CHAIRMAN SUNSERI: Okay. Thank you.

MR. AITKEN: Okay. So, now we are on Slide 10. Our alignment with GALL-SLR was over 99 percent. As discussed at the ACRS subcommittee meeting in February, the high degree of alignment to the GALL-SLR is the result of the efforts by the NRC staff and the industry to broaden the GALL, to capture the additional materials, environment, and aging combinations that were identified during the first license renewal applications.

In terms of commitments, we have a total of 47. These are primarily on an AMP-by-AMP basis and are reflected in Appendix A of the Final Safety Evaluation Report. These commitments will be captured in the Surry FSEAR qualifications issued for the renewed license. These commitments will also be managed within the Dominion Energy commitment tracking system, which is based on NRC-endorsed NEI 99-04 guidelines for managing NRC commitments.

I will leave you with a sense that these commitments were discussed with the station team and agreed upon current limitation. 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 is all I have for my portion of the presentation. Are there any further questions for me before I hand it over to Eric Blocher?

CHAIRMAN SUNSERI: Members, any questions?

MEMBER MARCH-LEUBA: No questions from me.

CHAIRMAN SUNSERI: Go ahead, Eric.

MR. BLOCHER: Can you confirm that you hear me?

CHAIRMAN SUNSERI: Yeah, I got you, Eric.

MR. BLOCHER: Thank you. 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 have been in the nuclear industry for 43 years. As Paul Phelps noted earlier, I was previously involved in numerous industry license renewal projects. I will be providing an overview of the aging management programs described in the SLR application for the full Committee today.

As part of our engagement with industry, several Surry SLR project team members have held leadership roles on NEI task forces and working groups. Other members collaborated with EPRI on activities such as guidance for aging management of alkali-silica reaction, concrete irradiation evaluations, and reactor internals inspections. And others have participated in PWR Owners Groups reactor vessel integrity and time-limited aging analysis generic 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

incorporations of operating experience was performed for a ten-year period to inform the aging management programs.

As Paul Aitken just mentioned, the Surry team also reviewed recent license renewal applications RAIs associated with the Turkey Point and Peach Bottom applications, as well as more recent first license renewal projects. Our project team also participated in the Turkey Point and Peach Bottom industry peer reviews to provided insights and share constructive comments.

Prior to submittal of the application, the effectiveness of the aging management activities was addressed using the evaluation elements identified in NEI 14-12 Aging Management Program Effectiveness guidance document.

Next slide, please. Slide 12 provides a breakdown of the aging management programs that were developed in support of subsequent license renewal. Just to close the loop with Matt Sunseri's question, all first license renewal aging management activities were carried forward from first license renewal into subsequent license renewal. None were deleted.

If you look at the left column, there are 40 existing AMPs that resulted from the combination

and some subdivision process of the first license renewal AMPs. The SLR existing AMPs are 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 enhancements. Approximately half of the 47 AMPs are consistent with enhancement. Approximately one-quarter of the SLR AMPs are consistent with one or more exceptions.

Next slide, please. We're now on Slide 13. First license renewal AMPs have been, and will continue to be, assessed for AMP effectiveness. The Surry effectiveness reviews assessed first license renewal activities and included a detailed review of inspection schedules, results, and data, as well as a review of relevant operating experience within the corrective action program.

All first license renewal programs were determined to be effectively implemented. A summary of each review is found is in Appendix Bravo of the subsequent license renewal application for each aging management activity.

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 AMP 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 of 2019.

That 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 technical topics?

(No response.)

MR. BLOCHER: Next slide, please. We're now on Slide 14. On Slide 14, in the subcommittee meeting, we presented in some detail how Dominion addressed the four technical topics reflected on the slide related to concrete and containment degradation, reactor vessel internals, reactor vessel support steel, and reactor vessel embrittlement.

To summarize, we have developed our various aging management programs to be consistent with GALL-SLR guidance. There has been no loss of license renewal intended functions due to concrete aging since entering the period of the extended operation.

As we are all aware, an industry concern related to alkali-silica reaction was identified in the GALL-SLR. Dominion Energy has proactively addressed this concern by implementing the EPRI alkali-silica reaction inspection guides. This guidance 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, and detection of water ingress, as well as identification of structural misalignment. No effects of alkali-silica reaction have been identified at Surry based on inspections, to date.

Next, the concrete biological shield wall gamma and neutron radiation remains conservatively below GALL-SLR radiation exposure levels throughout the subsequent period of extended operation. Also, recent examinations of the containment liner to concrete slab interface in October 2016 for Unit 1 and May 17 for Unit 2 have not identified any degradation.

(Simultaneous speaking.)

MR. BLOCHER: Can somebody mute the --

(Telephonic interference.)

CHAIRMAN SUNSERI: Okay. Eric, you're muted.

MR. BLOCHER: What was the last subject I was talking to? The concrete?

CHAIRMAN SUNSERI: I believe that's right.

MR. BLOCHER: Okay. I'll pick up with reactor vessel internals. Surry will manage the reactor vessel internals consistent with MRP 227, Rev. 1A inspection and evaluation guidance that was issued in December 2019. We have worked closely with the various industry groups and the NRC staff to identify the requisite inspections for the subsequent period of operation.

For reactor vessel support steel, Dominion Energy determined that peak stresses for design basis loads associated with the Unit 1 and Unit 2 reactor vessel support assemblies are below the critical stress limits calculated through wall and/or surface flaws based on projected fracture toughness through the subsequent period, satisfying evaluated reactor pressure vessel material properties for 80 years. And we'll remove and test surveillance capsule for each unit during the subsequent period of extended operation.

The applicability of the existing heatup and cooldown curves can be extended to expected full-power years based upon using our updated material

property data and application of the K1c methodology which is currently included in the ASME code.

I'll pause to see if there are any questions on these topics.

MEMBER BALLINGER: Yes, this is Ron Ballinger. I wanted to confirm what I think I heard during the Subcommittee meeting with regard to the pressure vessel embrittlement issue. You folks, I assume, are aware of the sort of impending changes that may happen to Reg Guide 1.99. Do those changes, if you were to look at those, affect the extrapolation out to 80 years for embrittlement?

MR. BLOCHER: Chuck Tomes, would you like to provide some details to Mr. Ballinger?

MR. TOMES: Yes, this is Chuck Tomes from Dominion Energy. We've looked at the projections going forward for Surry Nuclear Plant. And we're confident that, while the projects will change, we will be able to maintain all of the safety margins for heatup and cooldown curves, LTOP, PTS, for the Surry subsequent licensing period for Unit 1 and Unit 2.

MEMBER BALLINGER: Thanks.

MR. TOMES: You're welcome.

MR. BLOCHER: Are there any additional questions?

(No response.)

MR. BLOCHER: That's fine. I will now turn the presentation back to Paul Aitken for closing remarks.

MR. AITKEN: Okay. Thank you, Eric. So it's around 9:15. So, on behalf of Dominion Energy, I'd like to recognize the NRC staff for the thoroughness of the safety review performed on the Surry application. I want to reiterate that Dominion Energy has been engaged in many ways with regards to moving on our SLR issuance. We have been heavily invested with a lot of others in the industry over the last couple of years to ensure we have the appropriate guidance and have explored avenues for optimization with the NRC staff based on the vast experiences during the first license renewals.

Dominion Energy has developed a high quality SLR application that benefitted from the GALL-SLR and SRP as well as various industry support. Dominion Energy will continue to invest in site optimization, as Paul noted, now and into the future to ensure the continued safety and reliable operation during the subsequent period of operation.

Mr. Chairman, this ends our presentation. Are there any further questions?

VICE CHAIR REMPE: Matt, this is Joy. I have a question for Dominion.

CHAIRMAN SUNSERI: Go ahead, Joy.

VICE CHAIR REMPE: I know the staff is going to talk about the fire protection piping issue. But I had a question for Dominion on the status of their efforts regarding updating the AMP. Is this just a project that's been authorized? Is it underway now? Where are they with respect to the status of these efforts?

MR. AITKEN: Okay. Joy, I'm going to turn to Allen Harrow, who's our site engineering manager, to give you an update on where we are.

MR. HARROW: Okay. Can everyone hear me?

VICE CHAIR REMPE: Yes.

MR. HARROW: Okay. My name is Allen Harrow. I work for Dominion Energy. I'm the site engineering manager at Surry Power Station. Currently, we are continuing with Phase 1 of our fire protection project to excavate and remove piping based on the priorities that we identified when we originally had an issue in July of 2019 with the fire protection guard loop.

We are continuing to work through Phase 1. We have dug up approximately 89 feet of additional

piping and removed the piping. As we have identified previously, in order to evaluate if corrosion concerns exist with the piping, the piping has to be sandblasted.

We have partially sandblasted 89 feet that has been dug up. We have identified that, so far, we have not seen additional through-wall corrosion through the piping that has been dug up. The piping itself is roughly a half-inch in thickness. And the most significant depth of the corrosion we've seen so far is about one-half of the thickness of the pipe.

We have also taken samples of that pipe and we've sent them off for lithoscopic examination. That was just done yesterday, so we don't have the results for that. And we've also taken soil samples that we have sent off for analysis. We don't have the analysis of that yet.

However, the fact that the piping that we have dug up that was done after the original piping repairs, the fact that it is -- is a positive indication. But we're continuing with Phase 1 of the project.

Are there any other questions?

MEMBER BALLINGER: Yes, this is Ron.

VICE CHAIR REMPE: If I were

characterizing that, I'd say you're in the initial phases of this effort. Is that how you would characterize it?

MR. HARROW: I would. We originally identified four phases of the project. This is Phase 1. We do have a project manager onsite. And the project manager reports out weekly to the station management team and provides updates.

VICE CHAIR REMPE: Thank you.

MEMBER BALLINGER: This is Ron Ballinger. There are a number of selective leeching models out there that purport to predict the amount of penetration as a function of the various chemistry parameters. And I believe there's an EPRI task force -- if that's how you want to call it -- that's addressing selective leeching going forward.

Have you folks -- do you folks have enough data on the pipes that you've dug up so that you can actually compare what you see with what these models might predict given your chemistry?

MR. HARROW: So, I do not believe I can answer that question fully at this time. I will say that Surry did send off samples of piping from the original pipes that were excavated after the original July 2019 break. And we sent those to EPRI to help

them with part of the study that I believe you're referring to. At this point, I'm not able to fully answer that question.

MEMBER BALLINGER: Thanks. I mean, I just think that you're going to have some data going forward, and there are maybe some issues with folks saying that you need to dig up more pipe or not, that having comparison and alignment with various -- with a model might allow you to project a little bit forward on where the issues might be before they happen.

MR. HARROW: I do appreciate that input, and we will be working hand-in-hand with EPRI to determine what additional analysis will help us as we move forward with the project.

MEMBER BALLINGER: Thank you.

CHAIRMAN SUNSERI: Any other questions from the members?

(No response.)

CHAIRMAN SUNSERI: I have one kind of follow-up from the Subcommittee meeting that we had back in February. I was reading back through the transcript, and I thought I understood the soil sampling program. But maybe I'm confused on that.

So, you dig a hole for excavation and you

sample the soil. You dig some exploratory wells. I think you sample the soil. But could you just re-summarize what your soil sampling program is? Or maybe not program, but your approach to the soil sampling to pinpoint the corrosion mechanism?

MR. BLOCHER: This is Eric Blocher. Can everybody hear me?

CHAIRMAN SUNSERI: Yes, we can hear you.

MR. BLOCHER: Thank you. The soil survey program used is consistent with GALL. Specifically, it's consistent with soil sampling requirements in ASTM 41. The soil characteristics that we look for in each of the samples are resistivity, pH, redox potential, sulfites, chlorides, and soil consortia, which is a measure of bacteria activity in the soil.

We use the EPRI reports 300, 200, 5294 scaling evaluations to determine the corrosivity of the soil. So, there's four levels of corrosivity. A level that scores between 0 and 10 is considered mild to moderate corrosive. Above 10 to 15 is appreciatively corrosive. Greater than 15, it's severely corrosive.

The piping within the scope of license renewal, based on our 2018 soil survey results at the site, were in areas that scored 10 or less. So it's

mildly to moderately corrosive at the station.

Did that answer your question, Chairman Sunseri?

CHAIRMAN SUNSERI: In part, it did. So, what is the sampling -- I'll call it frequency, or what drives you to sample a soil? What's your criteria?

MR. BLOCHER: The way our program is structured, there's a soil survey performed on a frequency of approximately ten years. We're actually sampling more frequent than that. The original baseline was conducted in 2012. The last follow-up survey was done in 2018.

In addition, whenever a pipe is excavated, soil survey samples are taken to assess that in comparison with the baseline and most recent results.

CHAIRMAN SUNSERI: And when you excavate a portion of pipe, and you see or you don't see water at the pipe level, what is your action?

MR. BLOCHER: Well, I believe you're referring to part of the corrective actions that are put in place from a result of our recent fire water event, fire water piping event, that Mr. Harrow spoke to. Normally, there's some moisture in the soil. But we typically do not see groundwater. As a result of

that event, that was one of the corrective actions to be sensitive to groundwater presence in that area. Groundwater monitoring is an altogether different program, and there's a series of groundwater wells that are sampled throughout the site.

Most of the fire water piping that we're doing with in the event, I believe, is buried six to eight feet below the soil surface level.

Allen, can you confirm that for me?

MR. HARROW: That is correct, Eric.

MR. BLOCHER: Thank you.

CHAIRMAN SUNSERI: And one last question. Of the 89 feet that you recently removed, was there any -- was the groundwater at the pipe or was it dry?

MR. BLOCHER: Allen, could you assist with that response?

MR. HARROW: Yeah. So, this is Allen Harrow again. So, when we removed the 89 feet of piping that we've removed since the July event, we did identify a couple of areas where there was some stormwater leakage that was essentially coming into the area where we were excavating piping. We entered that into our corrective action process to repair those leaks. I would say, other than that, we did not see signs of groundwater intrusion.

CHAIRMAN SUNSERI: Okay. I appreciate your patience with my questions. Thank you. I have no more questions. Any other members?

MEMBER KIRCHNER: Matt, this is Walt. This is for Paul or Allen. As you replace the 12-inch piping, are you going back to the same cast iron bituminous coating? Or have you new piping that you're using for the replacement?

MR. HARROW: This is Allen Harrow. We are currently replacing the piping with ductile iron piping and not cast iron piping. We are also considering, as we move forward, the use of high density polyethylene material as a consideration.

CHAIRMAN SUNSERI: Thank you. Any other questions?

Okay. Well, we appreciate the presentation from the Dominion folks. Thank you for that information. At this point, we can turn to the staff presentation. And I believe Angela Wu will be leading that.

MS. WU: Hi, yes, I am. This is Angela.

MEMBER MARCH-LEUBA: This is Jose. May I suggest a five-minute break for everybody to go get a cup of coffee or something?

CHAIRMAN SUNSERI: I was going to ask

Angela if she's going to need any transition time here. But let's go ahead and take a five-minute break while the staff brings up their presentation. So, we will resume this. We will reconvene at 25 before the hour. Thank you.

(Whereupon, the above-entitled matter went off the record at 9:27 a.m. and resumed at 9:35 a.m.)

CHAIRMAN SUNSERI: All right. Well, it's 25 to the hour, so we are reconvening here. I wonder if I need to do a roll call just to make sure all the members are back? Let me do that real quick.

So, just to make sure we have all the members back on the server that dropped out, I'm going to do a quick roll call. So, members, please acknowledge when I call your name. Ron Ballinger?

(No response.)

CHAIRMAN SUNSERI: Dennis Bley?

MEMBER BLEY: I'm here. It took about three times to get back on.

CHAIRMAN SUNSERI: Yeah. Charles Brown?

(No response.)

CHAIRMAN SUNSERI: Vesna Dimitrijevic?

(No response.)

CHAIRMAN SUNSERI: Walt Kirchner?

MEMBER KIRCHNER: Present.

CHAIRMAN SUNSERI: Jose March-Leuba?

(No response.)

CHAIRMAN SUNSERI: Dave Petti?

(No response.)

CHAIRMAN SUNSERI: Joy Rempe?

VICE CHAIR REMPE: I'm here.

CHAIRMAN SUNSERI: Pete Riccardella?

(No response.)

CHAIRMAN SUNSERI: Well, we only have four. So we need to try to get some others back. Okay. It looks like Pete is -- Pete, you there?

MEMBER RICCARDELLA: Yes, we can hear you.

CHAIRMAN SUNSERI: Pete, can you hear?

MR. NGUYEN: Yeah, it doesn't look like his mic is working. So, yeah, I'll help troubleshoot.

VICE CHAIR REMPE: Chairman, can we go through again and see some of them have joined?

CHAIRMAN SUNSERI: Yeah. So, Jose March-Leuba, are you there?

MR. NGUYEN: Court Reporter, if you're there, could you please acknowledge you're on the line?

COURT REPORTER: I'm here. I don't know if anyone can hear me. I've been trying to answer.

MR. NGUYEN: We can hear you loud and

clear.

COURT REPORTER: Okay.

MR. NGUYEN: And Member Petti needs to reboot the Skype meeting.

MEMBER MARCH-LEUBA: The all is on hold and you have to unhold it. Somebody has that somewhere. So they probably having the same problem I was having.

(Whereupon, the above-entitled matter went off the record at 9:38 a.m. and resumed at 9:41 a.m.)

CHAIRMAN SUNSERI: So, members, please acknowledge when I call your name. Charles Brown?

MEMBER BROWN: I'm here.

CHAIRMAN SUNSERI: Vesna Dimitrijevic?

MEMBER DIMITRIJEVIC: I am here.

CHAIRMAN SUNSERI: Walt Kirchner?

MEMBER KIRCHNER: Present.

CHAIRMAN SUNSERI: Jose March-Leuba?

MEMBER MARCH-LEUBA: Up and running.

CHAIRMAN SUNSERI: Dave Petti?

MEMBER PETTI: I'm only on the phone. Skype isn't working.

CHAIRMAN SUNSERI: Are you trying to get your Skype reconnected?

MEMBER PETTI: Yeah, but it's not doing

anything.

CHAIRMAN SUNSERI: Okay. You might have to reboot everything. Joy Rempe?

Say again, Joy. You broke up.

VICE CHAIR REMPE: I am here, and I'll talk a bit longer to make sure that it's working.

CHAIRMAN SUNSERI: Yeah. No, you're loud and clear now. Pete Riccardella?

MEMBER RICCARDELLA: Present.

CHAIRMAN SUNSERI: And Matt Sunseri. So we have all members attending, with the exception of Petti who does not have the Skype connection, but he's got audio. So we'll reconvene at this point in time and we are ready for Angela to provide the staff presentation. Angela, it's all yours.

MS. WU: Hi, this is Angela. Can everyone hear me?

CHAIRMAN SUNSERI: Yeah, you're loud and clear.

MS. WU: Great. Can everyone see my presentation?

CHAIRMAN SUNSERI: Presentation is on the screen.

MS. WU: Okay. Great. I'll go ahead and get started, then. Good morning, Chairman Sunseri and

members of the ACRS. My name is Angela Wu, and I am one of the project managers for the review of the Surry Power Station Units 1 and 2 Subsequent License Renewal Application, or SLRA.

As you heard from Anna Bradford, we are here today to discuss the NRC staff safety review of the Surry SLRA as documented in the Safety Evaluation Report, or SER, that was issued on March 9th, 2020.

Joining me at the virtual table today are Lauren Gibson, the second safety project manager for the Surry SLRA; Louis McKown, Senior Resident Inspector at Surry Power Station Region II; and Dr. Allen Hiser, Senior Technical Advisor for License Renewal Aging Management, Division of Materials and Renewed Licensing. Also joining on the phone are members of the technical and regional staff who participated the review and conducted on it.

So, during the presentation I will be pausing momentarily after each slide to see if there are any questions from the members. But since this is just the title slide, we'll move on to Slide 2, the presentation outline.

We will begin today's presentation with an overview of the safety review of the Surry SLRA before moving on to the SER. Section 2, scoping and

screening review. Section 3, the aging management review. And Section 4, the time-limited aging analyses. Then you'll hear from Region II on inspections and plant material conditions before sharing the conclusions of the differing views as related to the Surry SLRA review.

Okay. We're ready to move on to Slide 3.

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

On October 15, 2018, Dominion submitted an SLRA for Surry Units 1 and 2. The application was accepted for review on December 10, 2018. And the Draft Safety Evaluation Report was issued on December 27, 2019 with no open or confirmatory items. On March 9, 2020, the NRC issued the Final Safety Evaluation Report.

Moving on to Slide 4. The Surry review is the third safety review performed by the staff using the GALL-SLR and SRP-SLR guidance to their issuance in 2017. For the review, we conducted a total of three

audits as identified on the 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 in the applicant's corrective action program database.

During the interoffice 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; and time-limited aging analyses, or TLAAs.

And onsite audit limited to those technical areas that needed further review following the interoffice audit was conducted at the Surry Power Station Units 1 and 2 in Surry County, Virginia and Dominion headquarters in Innsbrook, Virginia.

Okay. Moving on to Slide 5, the SER overview. So, Surry Draft SER was issued no open or confirmatory items on December 27th, 2019. On March 9th, 2020, the Dinal SER was issued. During the staff's in-depth review, a total of 71 requests for additional information were issued.

Okay. We're moving on to Slide 6. In the next few slides, I will present the results of the

staff's safety review as described in the SER. SER Section 2 describes the scoping and screening of 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 SSC; nonsafety-related SSCs affecting safety functions; and SSCs 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 from the audit, and additional information provided by the applicant, 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.

Okay. We're moving on to Slide 7. SER Section 3 and it's subsections cover the staff's review of the applicant's programs for managing the effects of aging in accordance with 10 CFR 54.21(a)(3).

Section 3.1 to 3.6 includes the AMR items in each of the general system areas within the scope of subsequent license renewal, as shown on the slide. For a given AMR item, the staff reviewed the item in accordance with the criteria in the SRP-SLR to determine whether it is consistent with the GALL-SLR.

For items not consistent with the GALL-SLR, the staff reviewed the applicant's evaluation to determine whether the applicant had demonstrated that there is reasonable assurance that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the current licensing basis for the subsequent period of extended operation.

Based on the audits and additional information 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 the requirements of 10 CFR Part 54.

Okay. We're moving on to Slide 8 now. The SLRA described a total of 47 AMPs: 7 new and 40 existing. This slide identifies the applicant's written disposition of these AMPs as stated in the SLRA in the left column and final disposition as

documented in the SER on 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 audit, and additional information provided by the applicant, the staff concluded the applicant's aging management program activities and results were consistent with the criteria of the SRP --

(Whereupon, the above-entitled matter went off the record at 9:52 a.m. and resumed at 10:01 a.m.)

MS. WU: Okay, great, I'll go ahead and get started again. All right, so Paragraph 1, Slide 9, which is the SER Section 4, hopefully those who cannot see the actual type can follow along the presentation I shared in advance

(Telephonic interference) -- Section 4 identifies five independent analyses or TLAA. Section 4.1 documents the fast evaluation of the applicant's identification of applicable TLAA.

The Staff evaluated the Applicant's cases for identifying those plant specific or generic analyses that need to be identified as TLAAs and determine that the applicant has provided an accurate list of TLAAs, as required 10 CFR 54.10.

Section 4.2 through 4.7 document the Staff's review of the applicable TLAAs to 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) and either I, the analysis remains valid in the subsequent period of expanded operations, II, the analysis has been projected to the end of the subsequent period of extended operations, or III, the effects of aging on the (telephonic interference) will be adequate managed (telephonic interference) here.

From a literate view, the results from the audit and additional information provided by the applicant has included that the Applicant's TLAA activities and results were consistent with the criteria of SRP/SLR and the requirements of 10 CFR 54.

I will -- Louis, are you on?

MR. MCKOWN: Yes, I am on.

MS. WU: Great, thank you.

MR. MCKOWN: Good day all. I am Louis McKown, I am the senior resident inspector at the Surry Power Station, Region IV.

Thanks for your time. I am on Slide 10, titled, Aging Management Program Inspections.

In accordance with the Inspection Procedure 71003, the regions conduct a (telephonic interference) sort of a face forward section, five to ten years into the initial period of expanded operation.

During August of 2019, for the Surry inspection, the nine aging management programs, shown on this slide, were selected for a review using the criteria provided within the inspection procedure.

For each program the inspectors reviewed the licenses implementation by selecting the sample of systems, structures and components within the scope of the new program and finding the agent of the selected items was being managed.

Based upon this inspection, the team identified no findings. This provided reasonable assurance that the list was appropriately admitting the selected agent management programs.

Any questions? Next slide please. I'm on Slide 11 titled July 2019 Fire Loop Pipe Rupture.

In July 2019 two failures occurred in the varied fire protection piping at the west end of the power block below the road leading to the turbine building track bay. The installed Surry fire protection water suppression loops (telephonic

interference) six feet below the grade throughout the site.

As seen in the picture in the lower pipe here, the first structure was a ten foot long longitudinal crack along the bottom surface of the pipe. The second failure was a circumferential crack on an adjacent piping section. Which cannot be seen here.

As the last year's Phase 4 license renewal inspection was in progress at the same time that the meeting was in the process of casual analysis and immediate corrective actions to excavate and replace the effected piping, a focused problem identification resolution inspection was scheduled to fall off in the first quarter of 2020.

In the meantime, Dominion completed casual analyses and engineering evaluations which identified that longstanding exposure to moist or wetted soil had resulted in a reduction in wall thickness at several locations due to acidic corrosion or selected leaching. Which in turn led to pipe failure during pumps test.

Two out of three soil samples taken at other locations along the firewater piping identified similar type conditions. All fire assessment of soil

conditions at Surry identified that the soil was homogeneous while draining throughout the site.

As to the information in October, Dominion documented that the loss of reasonable assurance of continued reliability of the installed firewater suppression system and established a number of compensatory actions to restore compliance.

Next slide. I'm on Slide 12, Focused PIR inspection.

Region II inspectors performed the focus (telephonic interference) solutions during the week of February 24th, 2020 in accordance with inspection procedure 71152 (telephonic interference), resolution, Section 03.03 annual follow-up and selected issues.

This inspection included development of a sequence of events that led to the installed fire suppression water system being declared not functional, the determination of the current SAFDL and corrective actions (telephonic interference) help installed pressure water system, their view of (telephonic interference) and documented, and associated documents related to the Surry corrective action program, fire protection program and underground piping and integrity program and determine the programmatic requirements that were from the

actions taken by the licensee since the prior protection loop piping failures.

And it also included a verification that the Agency were in accordance with the associated regulatory requirements were acceptable and mattered. As a result of this inspection, no findings were identified.

However, the inspectors have (telephonic interference) captured observation on the status of (telephonic interference) This is fire protection loop piping failures.

In order to provide a point of reference for future NRC oversight and inspections the inspectors will be continuing these observations in the 2020 corrective (telephonic interference) for the baseline inspection report.

Next slide please. I'm on Slide 13, Focused PIR Inspection, Timeline of Status of Corrective Actions.

This diagram provides a timeline of events from the initial loop piping ruptures last July to the firewater suppression system being declared nonfunctional in October.

To date, the primary administrative actions take place in the replacement of the ductile,

the failed ductile iron casting, sorry, failed cast iron piping ductile iron and equivalent. And the use of compensatory measures, including the establishment of a backup firewater suppression system using the staged diesel driven pump at the discharge canal routed back to the main firewater header.

These compensatory actions remain in place until reasonable assurance of functionality can be restored to the installed fire suppression water piping. Dominion believes that restoring a system to a functional status will be accomplished through a combination of equipment repair and/or replacement, in addition to completion to a broader extensive condition evaluation, which includes invasive piping inspections throughout the site.

During the PIR inspection, Dominion identified that while the ultimate completion of their extensive condition investigation is scheduled for the end of December of 2021, their success path continues to be informed by the data gained in the field, as well as industry operator experience.

They believe that in the long run this will help them pull up their decision making and in turn, establish a more definitive long-term action plan for restoring the firewater suppression system

health.

With respect to the issue and the Surry aging management programs, the event was too recent of the time of the license renewal Phase 4 inspection to observe the licensee's integration of this new information into the buried piping and valve inspection program.

During the PIR inspection, the inspectors have noted that while a great deal of action had been taken with respect to the event, the action to incorporate this information into Dominion's buried piping and valve inspection program were extended from February till late April, nine months after the initiating event.

As a number of aspects are discreetly identified under a current licensing basis, and the action was established and extended in accordance with Dominion's corrective action program. The delays and incorporation do not represent a specific performance deficiency.

However, I would like to note that we were informed by the site engineering, via email late last night, that the associated corrective action to incorporate this information in Dominion's buried piping and valve inspection program, was closed

yesterday late afternoon.

That said, the scope of this condition and the breadth of regulatory oversight and programmatic impact afforded the Agency the opportunity to exercise a wide-variety of tools, at least once, if not multiple times, during the baseline inspection process over the next few years.

Including, but not limited to, equipment alignment (telephonic interference) fire protection triennial team inspection, maintenance effectiveness reviews for our new passive long lived system structure and component aging management inspections tools reside, maintenance risk assessment and a merchant work control assessments, functionality assessments, plant modification, surveillance testing reviews, as well as additional prominent identification of resolution of annual samples and follow-up by the biennial team inspection.

In short, the plant impact and broad inspection opportunities ensure that the Region will maintain appropriate oversight of the corrective actions associated with the firewater buried piping aging management challenges.

If the Committee wishes, we can provide more detail than what is listed here, otherwise we can

move onto the Region's final thoughts on Surry's aging management programs.

Okay, next slide please. And I'm on Slide 14, Region II Plant Material Condition and Conclusions.

Overall, for a plant that's in its first period of extended operation the material condition is generally acceptable. Licensee has been successful at completing large capital improvement projects that maintain or improve material of its SSCs.

And the license renewal program inspections did identify any substantial weaknesses in the stations performance in managing the effects of aging at the site. The inspectors will continue to inspect and assess the alleged ability to manage the effects of aging through the NRC's baseline inspection program.

Are there any questions?

MEMBER KIRCHNER: Louis, I had one.

MR. MCKOWN: Yes.

MEMBER KIRCHNER: This is Walt Kirchner. I'm just looking at the phraseology chosen in the first bullet. What does generally -- just acceptable?

MR. MCKOWN: I don't believe we distinguish anything between generally acceptable.

MEMBER KIRCHNER: Okay. I'm sure there wasn't some subtle (telephonic interference) that we might miss. (Telephonic interference) just word choice.

MEMBER BROWN: Is that, this is Charlie Brown. I'm done now.

MR. MCKOWN: If there are no additional questions, I'll hand the presentation back to Angela. Thank you so much.

MS. WU: Thank you, Louis. We're moving on to Slide 15, the SLRA.

In conclusion, for the SLRA safety review, the Staff finds the requirements of 10 CFR 54.29 (telephonic interference) substantive license renewal for Units 1 and 2. We'll hear from Dr. Allen Hiser (telephonic interference) the evaluation of the differing views. Slide 16.

MR. HISER: Thank you, Angela. And good morning. My name is Allen Hiser, I'm with the division of new and renewed licensee (telephonic interference) NRC.

Differing views focused on the treatment in the subsequent license renewal application of the July 2019 fire pipe rupture. Along with several other issues.

The evaluation of the differing views concluded that reliance on the Applicant's corrective action program is consistent with placing renewal safety principles. Specifically that the ongoing regulatory process is adequate to ensure plant safety.

In addition, other issues cited in the differing views were adequately addressed in the subsequent license renewal application. As a result, the evaluation of the differing views, it was concluded that no additional actions are necessary to the aging management programs at this time, beyond what the Applicant has supplemented as part of the SLRA.

However, pending the outcome of the Licensee's complete evaluation, the aging management programs may or may not be revised in the future. Further, this site safety evaluation report adequately reflects the basis for a reasonable assurance finding if the Applicant's program is adequate for the subsequent period of extended operation and no changes to the safety evaluation report are necessary based on the evaluation of the differing views.

Thus, the subsequent renewed license can be issued consistent with 10 CFR Part 54. And with that, Angela, I'll turn it back to you.

MEMBER BALLINGER: This is Ron Ballinger, I have a question about this. After reading the two versions of the DPO, is it my understanding that there still exists the difference of opinion?

MR. MOORE: This is Scott Moore, may I come in for a minute?

This slide on use of the term, differing views, does that indicate that with regard to any formal agency processes that the agency, any agency processes are not yet completed?

MS. BRADFORD: So this is Anna Bradford, I'm the director of the division of new and renewed licenses. Let me explain a little bit.

So, we do have two different (telephonic interference) process. And this was the nonconcurrence process (telephonic interference) DPO process (telephonic interference).

So, these were post, run through the nonconcurrence process. They are currently closed in terms of nonconcurrences were filed, the process was followed (telephonic interference) nonconcurrence, which is all included in the paper, and no changes were made to the SE as a result. So that's kind of how the nonconcurrence was closed.

So as of right now, there is no, I'll call

them open differing views, in terms of the process. Now, if the staff was not satisfied with where we ended up they could go to the next process, which is the DPO.

So, for right now this is, process-wise, this is considered closed.

MEMBER BALLINGER: Now, I apologize for using the word DPO, I should have used the word nonconcurrence. Thank you.

MS. BRADFORD: Sure.

CHAIRMAN SUNSERI: Any other comments, or questions I should say, from the Members?

MEMBER KIRCHNER: Yes. This is Walt Kirchner. Matt, I'm looking at my notes from the February presentations and I note one of the issues that came up during the discussion of the differing views was corrosion of tie rods.

So, I just wanted to ask how that particular item was being addressed. Much like I asked about the replacement piping.

MR. HISER: This is Allen Hiser, the Staff again. Let's see. A corrective action assessment that supports piping replacement should also ensure that the necessary associated elements, such as the tie rods, will continue to serve their necessary

design function to support the piping.

That was the conclusion in the nonconcurrence evaluation. My understanding is that that would be subject to the oversight process as well. They (telephonic interference) implemented appropriately.

MEMBER KIRCHNER: Thank you.

MS. WU: Do we have any additional questions at this time? Hearing none, I turn the presentation back to you, Chairman Sunseri.

CHAIRMAN SUNSERI: Thank you, Angela, and thanks to your staff for a nice presentation.

At this point I'd like to, this is a little awkward but we would normally ask for public comments from members in the room, or of the public in the room, so I will break this up into two parts.

I'll break it up for members of the public participating in the on the phone line. So, at this point are there any, is there anybody on the Skype session that would like to make a comment?

And while we're waiting, if I can ask Thomas to open the public phone line too.

PARTICIPANT: Copy that.

CHAIRMAN SUNSERI: Okay, there is no comments coming in from Skype. So Thomas, just

confirm when you have the public line open. Can you hear me, Thomas?

PARTICIPANT: Yes, loud and clear.

CHAIRMAN SUNSERI: Do we have the public line open? Bridge line. Let me try it this way.

PARTICIPANT: We are unmuted.

CHAIRMAN SUNSERI: You are unmuted now?

PARTICIPANT: That is correct.

CHAIRMAN SUNSERI: Okay. If there are any members of the public on the public bridge line and you wish to make a statement or provide a comment, please do so now.

Could anyone on the public line at least acknowledge by saying something that the line is open?

PARTICIPANT: The line is open.

(Simultaneous speaking.)

PARTICIPANT: -- public line.

CHAIRMAN SUNSERI: Okay. So one more opportunity for members on the public line to make a comment. Okay, Thomas, we can close the public line. At this point on our agenda I would like to go into report preparation. (Telephonic interference) report.

We will need some transition time to do that so I'm going to call for a ten minute break at this time to allow us to transition to the report

preparation phase. And we will resume, let's call it about, let's call it 25 before the hour. So, 25 before the hour we will resume with report preparation. We are recessed until then.

(Whereupon, the above-entitled matter went off the record at 10:23 a.m. and resumed at 1:02 p.m.)

CHAIRMAN SUNSERI: All right. 1302, we are reconvening the full committee meeting. I will begin with a roll call of the members. Members, please acknowledge when I call your name. Ron Ballinger?

MEMBER BALLINGER: I'm here.

CHAIRMAN SUNSERI: Dennis Bley?

MEMBER BLEY: Here.

CHAIRMAN SUNSERI: Charles Brown has acknowledged already. Vesna Dimitrijevic?

MEMBER DIMITRIJEVIC: I'm here.

CHAIRMAN SUNSERI: Walt Kirchner?

MEMBER KIRCHNER: Here, Matt.

CHAIRMAN SUNSERI: Jose March-Leuba?

MEMBER MARCH-LEUBA: Present.

CHAIRMAN SUNSERI: Dave Petti?

MEMBER PETTI: Present.

CHAIRMAN SUNSERI: Joy Rempe?

VICE CHAIR REMPE: Present.

CHAIRMAN SUNSERI: Pete Riccardella? Pete Riccardella? I see he's on but muted his mic. Can you unmute your mic? Are you there? All right, Quinn, can you try to reach out to Pete?

I'm Matt Sunseri, I'm here. We have a forum. We have one member who looks like might be stuck.

At this point we will proceed with the meeting. The item for this afternoon is NuScale Chapter 15, Boron Dilution, Return to Criticality, Probabilistic Risk Analysis and Hydrogen Oxygen Monitoring.

Walt Kirchner will lead this session. And at this point, I will turn it over to Walt for any remarks and get this session moving. Thank you.

MEMBER KIRCHNER: Thank you, Chairman. I have no further remarks to make so I think --

AUTOMATED MESSAGE: You've been muted. To unmute yourself press *6.

MEMBER KIRCHNER: -- and I'll turn to Matthew Presson.

MR. PRESSON: Thank you, Walt, I appreciate it. And I appreciate everyone's time this afternoon.

I'm Matthew Presson with NuScale and today

we'll be talking about, we'll have a couple presentations, but this first presentation is on Chapter 15 and its related topics.

Moving to Slide 2. Our presenters for today are myself, Matthew Presson, licensing project manager. We also have Ben Bristol, supervisor of system thermal hydraulics. Meghan McCloskey, thermal hydraulic analyst. And Paul Infanger, licensing specialist.

I'll be the primary presenter to keep this tele-presentation simple, but if there are any questions this will be our primary discussees.

Slide 3 covers our agenda. We will be discussing our principle design criteria, 27, boron transport. As well as changes from the FSAR Revision 2 to FSAR Revision 4.

Which incorporates a couple of items. Our NRELAP5 updates, minor module model updates, DHRS actuation logic changes, as well as overall changes in Chapter 15 analysis results.

All right. Moving to Slide 4. Kind of a background on our PDC 27. Principle Design Criteria 27.

So, the NuScale DCBA includes an exemption request from GDC 27, the NuScale power modes goal

design aligns with precedent based compliance, or GDC 27, due to the lack of a second safety related reactivity control system.

So, to cover that we follow a principle design criteria 27. It is our passive equivalent for GDC 27. It ensures that safety related reactivity control system is designed to achieve and maintain a sub-critical core and ensures fuel integrity for an extended overcooling in combination with a partial failure of a reactivity system. Such as a stuck rod.

CHAIRMAN SUNSERI: Hey, Matt, let me interrupt you for just a second.

MR. PRESSON: Yes.

CHAIRMAN SUNSERI: Will all participants that are not speaking please mute your mic. There is background noise that come over these very sensitive microphones, so disrupt, please mute your lines if you're not talking.

Thanks, Matt, you can continue.

MR. PRESSON: All right, I appreciate it. Moving on to Slide 5. We discuss a little bit of our compliance with this principle design criteria.

Before that, our immediate shutdown is sufficient to protect the reactor coolant pressure boundary as well as SAFDLs with March included for the

worst rod stuck out of the core.

Cold shutdown is achieved with all control rods fully inserted. And if there were to be an issue with that, for example, having that worst rod stuck out.

So, also shutdown marching consequences are fairly benign. They were evaluated with the single-highest worst control rod, fully worst control rod and the critical power level does not challenge either our DHRS or ECCS heat removal systems or SAFDLs.

In addition to that, the probability of the accommodation of commissions which would result in this loss of shutdown, return to power with a single rod stuck out of the core is very small.

Slide 6.

MEMBER KIRCHNER: Matthew? This is Walt.

MR. PRESSON: Yes.

MEMBER KIRCHNER: When you say very small, had you quantified that number in any, or at least can you provide an order of magnitude estimate of what you call very small in your sense?

MR. PRESSON: Yes. Ben Bristol, would you be about to speak to that number precisely? I do not have it off the top of my head.

Or we can get back to that. It is described in the FSAR Chapter 15. So once we, someone has the time to grab that, I can get back to you with that number.

MEMBER KIRCHNER: Thank you.

MR. PRESSON: Yes.

MEMBER KIRCHNER: Matthew, I was just more interested in you entering that into the transcript on the public record.

MR. PRESSON: Yes, absolutely. And once we have the time to get that exact number for you I'm more than happy to get that on the record.

All right, Slide 6 covers the results for that return to power analysis. Our ECCS tooling is most limiting when, sorry, we are most challenged with ECCS cooling with an equilibrium power limited to around one to two percent of reactor power. So that is the highest that we would expect to see.

Our core temperatures must be less than 200 degrees Fahrenheit for re-criticality. So you have to be fairly cold.

And with increasing cold temperatures we see a decrease in the magnitude of that return to power with a 140 degree Fahrenheit pool precluding a re-criticality. Even in the Chapter 15 scenarios.

For NuScale calculations the earliest re-criticality determined, could occur approximately 40 hours post-scram. Our minimum CHFR for the most limiting results are not limiting relative to our other FSAR events. Our other Chapter 15 events.

All other AOO acceptance criteria are met and our other SAFDLs are demonstrated with the overcooling return to power conditions. And they are bounded by existing analyses developed for the DCA.

And to get back to that value, FSAR 1506 cites that probability of this occurring as being less than 1e to the negative 6 per reactor year.

MEMBER KIRCHNER: Thank you.

MR. PRESSON: Yes. All right, and that is, that wraps up our summary on GDC 27. Are there any questions before we move onto boron transportation?

All right.

MR. SNODDERLY: I'm sorry, Matthew. This is Mike Snodderly. If I could just interrupt for one second.

I understand from members of the public that the public bridge line is not working. So, if Thomas can confirm that we're hooked up to that and we could troubleshoot that. Thank you.

MR. PRESSON: Got you. Yes, that's a good point to pause for that.

MR. SNODDERLY: Perhaps if I could ask, Thomas, could you please open the public bridge line and let's ask if there is anyone from the public on there and see if that's working?

MS. FIELDS: Oh hi. That was probably my error. This is Sarah Fields calling in. When I put in the wrong connection number, so yes, the bridge line does work.

MR. SNODDERLY: Okay, thank you. Thank you, Sarah, we just wanted to make sure. So, Thomas, if you could please mute the public bridge line. And, Matthew Presson, please continue. Thank you.

MR. NGUYEN: Done.

MR. PRESSON: Sounds good. And I appreciate it.

All right. So, starting on Slide 7. Our ECCS boron transportation. A little bit of context for our boron transport analysis.

So, as boron accumulates within the core and rides a region, the boron concentration in containment and downcomer decreases. This is based on a scenario where ECCS is already actuated, so you have water in the containment, downcomer and core riser

areas.

Boron precipitation analysis was performed as part of the ECCS long-term cooling analysis and determined that it was not a concern for the MBM.

Boron dilution analysis was performed to evaluate a potential for a lower boron concentration fluid in core or near the core inlet. So basically we're looking to ensure that for the, for any of the analyses that we're performing that boron concentration does not decrease within the core or riser region.

We are also looking to confirm the appropriate step, return to power analysis, by demonstrating that this core region concentration remains above that initial concentration. And the full details on that analysis are provided in the NuScale response to RAI-8930. With the bulk of that being in supplement to that response.

Boron transport is governed by boiling in the core. And condensation within the containment vessel.

All right, Slide 8 goes into a little bit of our method. So, our summary for dilution analysis, our long-term cooling PERT had a higher ranked phenomena of a second boron transport as evaluated.

We used a control volume approach to analyze the transport between those regions. That core, downcomer and containment region.

NRELAP5 is used to provide logging fluid masses and flow rates. Which we use as input for our boron transport calculation. Volatility and entrainment are calculated separately.

And this calculation is performed separate from NRELAP5. And as part of that we conservatively model the transport between those regions. We use those factors to minimize the boron transport into the core and maximize boron transport out of that core hot region so that we show as little boron flowing into the core as we can.

And we demonstrate that, that RCS hot region concentration remains above the initial concentration.

Heat areas for NRC review are looking into the treatment of boron volatility. As well as mixing within the core, downcomer and containment. So we have some additional discussion of that provided for in our closed session slides.

The results for our CCA analyses focus on boron transport evaluation during ECCS cooling. Those results are summarized in RAI-8930. And they show

that our core boron concentration does remain above that initial concentration. So no net core boron dilution is expected, even with those biased transport assumptions.

So, a more realistic analysis of that boron transport indicates that our concentrations in the core region are two to three times above the initial concentration at 72 hours and that they can see turning above initial concentrations for at least seven days.

So, realistically, long-term high boron concentration is expected to be seen within that RCS hot region with a low concentration in the RCS cold region and containment as that boron transports into the core.

To address some concerns that were brought up. When we do look to recover posts in ECCS actuation or DHRS actuation, when we move back to, towards node 3 or some other defined node, it does take multiple deliberate operator actions following the appropriate procedures.

Part of that is shown, it would be a deliberate choice with a lot of steps along the way to make sure that no errors were made. And procedures are developed on a site-specific basis for that

recovery time period. Which are laid out in the NRC law commitments, 13.5-2 and 13.5-7.

MEMBER MARCH-LEUBA: Yes, this is Jose.

MEMBER KIRCHNER: Matthew? Jose, you want to go, go first, Jose.

MEMBER MARCH-LEUBA: It's okay, you can. I can wait. Go for it.

MEMBER KIRCHNER: I am curious, Matthew, why you say site specific basis. Why wouldn't these be generic?

MR. PRESSON: So, they are not generic because the DOL controls and procedures for that applicant would be the one who --

MEMBER KIRCHNER: No, I understand that, but what I don't understand is why, at this juncture, you can't define a path to recovery that has nothing to do with the site.

MR. PRESSON: Yes. So we can do that. And we have looked at that to make sure that we understand what kind of reactions you would be looking at and would be taking. It's just that we would not be forcing that specific procedure.

We would definitely include guidance on that for RCOL applications who were developing procedures so that would be included as a thing to pay

attention to during recovery.

MEMBER KIRCHNER: So this feels more to me like a tech spec issue than it does a procedure issue. I mean, and then the procedure to implement makes sure you don't violate tech specs, but.

I mean, this is something that's more within the reactor vendor, NuScale's purview than necessarily just site developed operating procedures.

MR. PRESSON: Yes.

MR. BRISTOL: This is Ben Bristol, can you hear me?

MEMBER KIRCHNER: Yes.

MR. BRISTOL: This is Ben Bristol with NuScale. I think what we were trying to allude to there is the specifics about numbering schemes are real plant specific processes that would go into writing that procedure.

In general, the recovery action I think could be written generically. And certainly, the acknowledgments of demonstrating that shutdown margin is reached would be part of exiting any LP into, back into normal operation modes.

And I think what we're trying to do address there is the specific system designs and latent schemes that may be plant specific.

MEMBER KIRCHNER: And that I understand, but I think the general approach to successfully recovering and establishing Mode 3 would, in my mind, be a generic one given the MBM design.

MR. BRISTOL: Understood.

VICE CHAIR REMPE: Well, wasn't it Matthew you said, guidance will be provided? Where is that guidance? Is it part of the DCA submittal?

MR. PRESSON: It is not part of the DCA submittal. It would likely be captured in GTGs or some other guidance. Again, assuming an applicant came to NuScale. That is the other fun little nuance there. Assuming that they --

MEMBER MARCH-LEUBA: This is Jose. You mentioned the GTGs, generic technical guidelines. Are those not part of the submittal?

MR. PRESSON: They were provided as part of the submittal to, and I was not part of that so I'm not one to speak --

MEMBER MARCH-LEUBA: Yes, I --

MR. PRESSON: -- but, yes, they were looked at. They were provided to show that we understood what the format of those would look like and what we would want to provide at the fuel up stage, but they were not reviewed and approved as part

of DCA.

MEMBER MARCH-LEUBA: Yes. I guess what we're trying to say is even the really bad consequences of doing it wrong, which is also why this is not covered on the GTGs, or whatever you want to cover it.

But it is kind of assumed that the field applicant will do it right. It really, as I say in the Subcommittee, the cat is out of the bag, or however the expression goes, and nobody is going to forget to do this right. Okay.

But you really should (telephonic interference) saying, hey, go into Mode 3 requirement, making sure you don't, I mean, you know what they mean, it used to do that.

MR. PRESSON: Yes, I understand that point. And again, as if not a reviewed and approved document that is, even if we did add them it would not necessarily provide anything more at the DCA stage. But your point on providing that guidance, making sure that that is out there for people to use is taken and understood.

MEMBER MARCH-LEUBA: Yes.

MEMBER KIRCHNER: Matthew, another aspect of this is that it opens up the door on human factors,

engineering, about errors of co-mission. And clearly this is something you want to prevent. And so, you were, as Jose is saying and the GTGs are, wherever is the appropriate vehicle, this is something that should be clearly spelled out.

MR. PRESSON: Yes. And let me move to the next slide. Slide 10. Which covers a bit of an update regarding our commission report that we were looking at.

I will say that figuring out the best way to describe that need for an action is being considered within this overall response. So figuring out how to place that meaningfully within the DCA space we are looking into that. And we are working with the NRC to make sure that that fits and is captured and does still work within that DCA space.

MEMBER MARCH-LEUBA: Okay. I have to be careful --

MR. PRESSON: So, it's a little bit of ongoing work, but -- Yes.

MEMBER MARCH-LEUBA: I have to be careful, Matt, because I have read the proprietary presentation, but here you do mention the design change in the last bullet.

MR. PRESSON: Yes.

MEMBER MARCH-LEUBA: Is there something that you can put on the record, on the open session, about what the design change is and what is the schedule?

Because it's likely it won't affect, and this is what ACRS has done in potential letters. I mean, the dates I'm seeing there may affect our timeline.

But is there something you can put on the record, on the open session, about this?

MR. PRESSON: Yes. I can say that we are, we are implementing a design change for the DPA, FSAR in regards to ECCS actuation.

So we are working through that. That is an in-process design change that is looking to actuate ECCS earlier in order to preclude the conditions that we identified back in March.

In terms of schedule, I am not sure what is in-prop and what is a non-prop space, but we are looking at a schedule sometime in May, to get that back to you. I can at least say that much.

MEMBER MARCH-LEUBA: Okay, thank you. I just wanted you to say something in the record.

MR. PRESSON: Yes.

MR. NELSON: Yes, let me add, this is Mike

Nelson, manager of license with NuScale. So we did have a scheduling commission in closed session, and I think Matthew characterized it correctly.

As the work with the DCA changes we will work with the staff and the ACRS regarding downstream schedule. So we'll be getting back to you fully on that so you can make an effort by case. That's all, thanks.

MR. PRESSON: Yes. But we did want to include this in the open session to discuss because it is, you know, it is an update to the design that we are working on so we wanted to make sure that was available for public discussion.

MEMBER MARCH-LEUBA: So, let me put also something on the open record. I have looked at the proprietary record, which I cannot tell you about, but I like the changes and I think it speaks, very likely, to fix the problem.

But we're eagerly waiting all those calculations to assure that it did address, okay. But in principle I like the modification. It makes sense.

MR. NELSON: So, to confirm that you will be talking about it in the closed session? The design changes.

MR. PRESSON: Correct.

MEMBER MARCH-LEUBA: Yes.

MR. PRESSON: We will discuss those.

MR. NELSON: Okay, got you.

MEMBER MARCH-LEUBA: Yes. But I wanted to put in the record for the public that we have reviewed it. We have access to the proprietary information. In my opinion, it fixes the problem.

MR. PRESSON: Yes. And all that information will be going into the public record once it is finalized and approved. And all that is simply in process at this point in time.

MEMBER BLEY: Excuse me, this is Dennis Bley. I lost my line for the middle of that discussion. This is the design change, it will be incorporated before the design cert application is approved, is that right?

MR. PRESSON: Correct. We did feel that it was important to include this within the DCA.

MEMBER BLEY: Okay.

MR. PRESSON: So I wanted to get that in. Yes. All right, any other questions for Slide 10. Okay.

Okay. Moving on to Slide 11. Our conclusions for boron transport is that a lot of the inherent design characteristics within the MPM

provides ample safety.

We have low core power, we have a large RCS inventory. We have a small high-pressure containment and a large ultimate heat sink.

Compliance with in sent of GDC is demonstrated for reactivity control systems. We provide conservative analysis of low probability of return to power condition. And that analysis demonstrates some of that safety margin.

MEMBER MARCH-LEUBA: My, sorry to interrupt. Can you move the slide to Slide 11? Because we don't turn them.

MR. PRESSON: Got you. It is --

MEMBER MARCH-LEUBA: You're talking about 11.

MR. PRESSON: Yes.

MEMBER MARCH-LEUBA: My scale is frozen then, sorry.

MR. PRESSON: Yes. Let me re-present that. See if that fixes it. I've seen several other people who have that. All right, it should be presenting Slide 11 now.

MEMBER MARCH-LEUBA: I can see my Slide 11.

MR. PRESSON: Okay, excellent. So we were

on the second bullet. Our compliance with the intent of GTCs is demonstrated for reactivity control systems by showing that the conservative analyses are low probability, return to power conditions filled in the safety margin.

And for that last bullet, boron redistribution is reevaluated and demonstrated to not be a safety topic. We naturally accumulate boron within the core. It adds to shutdown margin for design basis events as well as severe accidents.

Moving on to Slide 12. This kind of begins our section discussing Chapter 15 changes from FSAR Revision 2 to Revision 4.

Revision 2 was the FSAR revision that the NRC right there, Chapter 15 Phase 2, I see against. And Revision 4 is the revision that we submitted in December.

And kind of following along with that, the results from FSAR Revision 2 were presented to ACRS in June and July of 2019 in subcommittee and full committee meetings.

Changes from that to FSAR Revision 3 included an update from NRELAP Version 1.3 to Version 1.4. It also updated the NRLEP5 base model input.

More considered core designed inputs were

placed in some cases. Our THRS actuation signal saw not a large effect of change but the details of how it actuated were changed via the addition of a secondary side isolation signal. And ECCS actuation signals were changed.

And changes in Rev 4 were primarily focused on ECCS IAB threshold and release pressure changes.

Slide 13 covers our NRELP5 Version 1.4. As we went from 1.3 to 1.4 a lot of those changes were made due to routine code maintenance.

We had 26 specific code fixes, which are documented with the three most notable being a condensation correlation error correction, a correction to the choking model quality factor as well as updating the executable to 64-bit.

We also added five new features, none of which impact DCA calculations. Including proprietary classifications, expand a number of elements allowed on the water property file and circulation update for CHF correlation.

Adding a warning message to users. If the math error stop one percent is disabled and removal of developmental options from user access.

The changes to the NRELAP5 base model

included, well, Jeff says that overall Revision 0 was released in December of 2015, Revision 1 was released in August of 2017 and Revision 2 was released in January of 2019. So that Revision 2 was associated with the FSAR Revision 3 submittal.

It removed the ECCS actuation on the RCS riser level signal as well as minor RCS flow loss updates. And a couple of minor geometry error connections.

For Revision 3, the DHRS actuation changes probably drove most of the changes we saw in Chapter 15. A summary of that change is that we added a secondary side isolation actuation for a range of signals that indicate upset and normal secondary side cooling conditions.

And then we took the DHRS signal and had that actuation limited to a subset of those signals, which indicated insufficient secondary site cooling. So DHRS now actuates the following secondary side isolation.

The purpose of that change was to support expected plant startup progressions. And the effect of that change on the transient analyses was that heat up events, no change was expected to DHRS, actuations on high pressure, pressurizer pressure or high RCS hot

temperature.

For cool down events our secondary side isolation may be actuated first with the ACRS then actuating afterwards on high steam pressure. And for reactivity events, inventory increase and inventory decrease events, we did not see them significantly impacted.

So, conclusions overall from our summary presentation today, our revised return to power analyses shows the ECCS cooling conditions result in the equilibrium power, at most, around one to two percent.

ECCS boron transport analysis demonstrates that core boron concentration remains higher than initial concentration. And that will be maintained with the new design change.

Changes incorporated into FSAR Revision 3 included minor changes to NRELAP5 code. And the MPM plant base model as well as DHRS and ECCS actuation changes.

IAB changes were incorporated into FSAR Revision 4, which opened up the range of the IAB. And the Chapter 15 limiting transient events were consistent between Revision 2 and Revision 4.

And the overall summary is that Chapter 15

for our DCA shows that we demonstrate margin to all of our acceptance criteria.

Slide 17 is an acronyms page. And Slide 18 is just a little closing. Any questions for Chapter 15?

MR. NELSON: This is Mike Nelson with NuScale. Just one clarifying note.

We did present scheduling information in public slides, in a public meeting with the NRC. So it is on the record back on April 1st, which wasn't that long ago.

So we do have scheduling information there. I added a follow-up transient (telephonic interference) DCA for (telephonic interference). So I wanted to make sure I clarified that. Thanks.

MR. PRESSON: Okay, thanks, Mike.

MEMBER KIRCHNER: Is there any further questions from Members?

Matthew, I'm not hearing any further questions from Members so we can transition to the next NuScale presentation.

MR. PRESSON: All right, that it sounds good. All right, I believe that is Jim Osborn. Feel free to correct me if I'm wrong?

MEMBER KIRCHNER: I believe that's

correct, Matthew.

MR. PRESSON: Okay, let me stop presenting and you should be able to press the presentation.

MR. OSBORN: All right, let me know if you can see the presentation?

VICE CHAIR REMPE: It's on.

MR. OSBORN: I'm sorry?

VICE CHAIR REMPE: We can see it.

MEMBER KIRCHNER: Jim, this is Walt Kirchner, it's showing.

MR. OSBORN: Okay, good. Good.

MEMBER KIRCHNER: Please proceed.

MR. OSBORN: All right, so, this is the full committee presentation having to do with the hydrogen and oxygen monitoring topic. The presenters are listed as Matthew and myself, Jim Osborn.

So this will be a very brief presentation. We're just providing a summary of what we presented in the subcommittee.

So, this is my summary and conclusion slide from the subcommittee meeting. You might recognize it a lot.

But it's, you know, NuScale has not changed any of its positions since the subcommittee meeting. So, as a recap of the presentation in the

subcommittee we first discussed the overall paradigm of actual amounts as it relates to differences between design basis and beyond design accidents.

And the rules that the industry applies as it relates to accident mitigation. So, and we talked about how non-safety SSCs can be used and credited for mitigation of beyond design basis accidents, but not for design basis accidents in general.

We also explained that the low frequency of the NuScale core damage accident is due to the fact that it requires multiple failures of safety and non-safety related equipment. For example, some sequences involve multiple failures involving highly reliable DC power system in conjunction with multiple failures of the safety related ECCS, EPCS system.

So, second, we discussed the timing aspects of combustible gases inside containment. And then a bounding analysis shows that there is a minimum of 72 hours before detrimental combustible gas mixture, remember, detrimental means a gas mixture that could result in containment failure.

And then third, we discussed the risk-informed decision process in which operators would utilize in taking the hydrogen monitoring system into service.

We discussed that there is sufficient time for the operators to inspect and verify that the hydrogen monitoring system is indeed intact and available for use. And if the system does develop a leak, the operator must isolate the system and repair as needed.

Regarding the radiation protection, the NRC stated there is insufficient design information to perform a offsite dose analysis or operator dose analysis from the leaking monitoring system and therefore created a card valve so that this topic can be resolved in a future date.

And then we discussed the hydrogen monitoring pathway is capable of withstanding a combustion event, like the containment is.

And then lastly we talked about containment mixing and ensuring that we have representative monitoring. And that NuScale and the Staff agree that we accounted for this.

MEMBER MARCH-LEUBA: You just mentioned that the piping can withstand an explosion, the same as a containment. Is that the requirement? Is that specified in the DCA?

MR. OSBORN: So yes. The monitoring pathway, the valve side containment, the pressure

boundary is required to, and this is stated in the DCA, that it has to withstand a combustion event just like containment does.

MEMBER MARCH-LEUBA: Okay. And you can specify in DCA?

MR. OSBORN: It is specified in Table, DCA Table 3.2-1.

MEMBER MARCH-LEUBA: Perfect. That's what I was looking for. Thank you.

MR. OSBORN: Yes, sir.

MEMBER MARCH-LEUBA: Now while I have, I have the microphone on, I'm primary concern with the way we are doing it is being able to obtain a representative something, this is your last bullet, on that piping.

To do that you will have to establish flow on that pipe. A non-tribute flow. And just something not liking to establish sufficient flow.

So, you something that has to be able to withstand the coordination, it has to work.

MR. OSBORN: Sure.

MEMBER MARCH-LEUBA: I don't see anywhere, any requirement that says it must work. That would be my complaint for months now.

MR. OSBORN: Yes, so, I did present at the

subcommittee that we do committee to, what was it, ANSI 13.1. That number may not be right, but there is an ANSI standard that we are committee to that requires that the monitoring and sampling that we do be representative. And so, that will, that is required.

And if, you know, so the system will have to do that. I mean, that's just a, that's a requirement that we have stated in the FSAR.

MEMBER MARCH-LEUBA: I can design one that works. It will require an addition pump to start this flow through the pipe.

And the (telephonic interference) that you are going to be, that's only opening in containment, but you're circulating the containment atmosphere through the extent of a pipe (telephonic interference). That's my complaint, okay.

To make it work, you have to circulate the containment atmosphere through all this piping. You just, it doesn't look like a optimal solution. And I'll stop there.

MEMBER KIRCHNER: Okay. And the other concern, I think one of the other concerns we had, Jim, was -- this is Walt Kirchner -- that the standard reference is, really, isn't that for large bore stacks

sampling out of the, like in a fossil plant, from the significant diameter chimney?

MEMBER BALLINGER: Yes.

MEMBER KIRCHNER: I don't know how, quote/unquote, representative that is of the kind of unique system and design that NuScale has.

MEMBER BALLINGER: Yes. This is Ron Ballinger. Again, a number of us went out and got the standard and read it. It's quite a stretch, quite a stretch.

MR. OSBORN: So, this external hydrogen monitoring system is not, I mean, that's -- we're not the first to have that kind of system.

There are other plants in the country that have a hydrogen -- either a recombiner or a hydrogen monitoring system that is outside of containment and takes (telephonic interference) and then, returns it back to containment.

So, I'm not sure why this would be different from any other similar design. And we've employed, I can't remember the name of the company, but we've employed or consulted with a company that has done this kind of design for these systems across the country.

And so, it's, I mean, that's -- so, I

think if we've designed a system that doesn't work, then we couldn't move forward, right? It has to be representative, in my understanding.

MEMBER KIRCHNER: Members, any further questions of Jim?

MR. OSBORN: So, I have one more slide.

MEMBER KIRCHNER: Go ahead, Jim.

MR. OSBORN: All right. So, relative to the risk, NuScale has looked at various containment bypass scenarios in Chapter 19.

And while we did not look specifically at the risk of performing hydrogen monitoring, there is an evaluation in Chapter 19 that looks at a containment bypass event that involves a potential failure, for example, of a containment evacuation system isolation valve, the potential failure of that that leads to a release.

So, this evaluation in Chapter 19 will include the fuel coolant interaction event, which is assumed to lead to a containment failure. In reality, it does not actually lead to a containment failure, but we looked at the consequences as if it did.

So, in this evaluation, the earliest possible time that this event would occur and the containment failure is assumed is at 6.8 hours post-

accident.

So, the analysis shows that during this 6.8-hour period, there is sufficient deposition of the airborne aerosols in the containment atmosphere that the containment release through the bypass does not amount to a large release.

So, to reiterate, the actual Chapter 19 analysis does not result in containment failure, but we looked at the release as if it did.

And so, therefore, if the hydrogen monitoring system breaks off completely, with a containment isolation valve open, it is reasonable to conclude that this release would not result in a large release or threaten public safety. This is further evidence, this is a scenario that is (telephonic interference).

MEMBER MARCH-LEUBA: This is Jose again.

MEMBER KIRCHNER: The pressure in the containment, what would the pressure be in the containment at 6.8 hours?

MR. OSBORN: So, well, again, so, they wouldn't open the containment isolation unless the pressure was below, I think it's 250 pounds. So --

MEMBER KIRCHNER: I think the concern would be, if you have significant pressure and you

unisolate, then this fraction of volatile fission product aerosols that could be swept out with the blowdown of the containment.

MR. OSBORN: Well, so, I think that's the point, that at 6.8 hours, there's enough deposition of that material that what is swept out does not constitute a large release.

MEMBER KIRCHNER: So, the timing of a release isn't a fuel coolant interaction? I'm a little confused on what the scenario is there that you're talking about.

MR. OSBORN: Yes. So, it's a fuel coolant interaction, so you get a pressure pulse from steam expansion, right? So, it's a large pressure event, but -- and it doesn't result in containment failure. However, we looked at it as if it did and at 6.8 hours, there was enough aerosol deposition that the release did not constitute a large release from a risk standpoint.

MEMBER KIRCHNER: Okay. So, a fuel coolant interaction is really a mechanism of (telephonic interference)?

COURT REPORTER: Hello, this is the court reporter, I'm having difficulty understanding the person who just spoke.

CHAIRMAN SUNSERI: Yes, I'm having a hard time hearing as well.

MEMBER KIRCHNER: The fuel coolant interaction is just the means by which you transport material from the reactor coil to the containment?

MR. OSBORN: Yes. It -- yes. Like I said, we did not look at hydrogen monitoring failures, per se, right?

So, we've drawn an analogy using this even in Chapter 19 that shows that even if, in this coolant interaction event, that it does not, the bypass would not result in a large release. This is all intended to address the -- we didn't look at the risk of hydrogen monitoring failures.

MEMBER MARCH-LEUBA: This Chapter 19 event that you described, the containment failure, typically we would see take credit for the pool, that it will release into the pool. Whereas, if the CES is the one that fails, you would be releasing on the floor upstairs. This analysis assumes that the proper discharge path --

MR. OSBORN: Yes.

MEMBER MARCH-LEUBA: (Telephonic interference.)

MR. OSBORN: Yes, no, I don't think the

discharge from this containment bypass was released under water, I think it was released above water.

MEMBER MARCH-LEUBA: Okay.

MR. OSBORN: Because that's where all the containment isolation valves are. So that's all I had, if there's any other questions?

MEMBER KIRCHNER: Members, any further questions of Jim?

CHAIRMAN SUNSERI: Walt, this is Matt, I don't have any questions.

MEMBER KIRCHNER: Any other members? Hearing none, then, I think we can transition to the next NuScale presentation. I think that will be PRA, if I have that correct.

MS. NORRIS: This is Rebecca Norris. Yes, that was the -- we are the next scheduled presentation, PRA.

MEMBER KIRCHNER: Okay. Rebecca, as soon as we have the slides up, then we can turn it over to you.

CHAIRMAN SUNSERI: Okay. Walt, we've been at this almost an hour, why don't we take a five-minute break here and reconvene at 14:00 Eastern Daylight Time, if that's okay with you?

MEMBER KIRCHNER: Yes. Okay.

CHAIRMAN SUNSERI: All right. We'll take a short recess here, five-minute bio break, and we'll resume at 14:00. Thank you.

(Whereupon, the above-entitled matter went off the record at 1:55 p.m. and resumed at 2:00 p.m.)

MEMBER KIRCHNER: So, we're turning now to Rebecca Norris and the topic is PRA.

MS. NORRIS: Yes, this is Rebecca Norris, would you like me to begin?

MEMBER KIRCHNER: Yes, go ahead, Rebecca.

MS. NORRIS: All right, perfect. Good afternoon. As he said, I am Rebecca Norris. I would like to start by sincerely thanking everyone for still giving us the opportunity to make these presentations. I know this is a very complicated time and I hope everyone is safe and healthy.

My presentation today is for the ACRS full committee on the Phase 5 focus area, Probabilistic Risk Assessment, or PRA. The PRA is integrated into all concerns in a nuclear design and NuScale has interacted with ACRS in numerous aspects as part of the design certification process.

The primary topic remaining for ACRS discussion is related to ECCS valve operation, as indicated in our most recent ACRS interaction on the

March subcommittee meeting. From that meeting, NuScale identified two questions from the members that we wish to follow up with additional information.

The PRA's perspective on the other topics discussed today were discussed within those presentations, but obviously, we have the support personnel online, so if you need to ask questions, then we are here to support them.

I am Rebecca Norris, Licensing Project Manager for both PRA and for FSAR Chapter 6, which covers the mechanical design of ECCS, or the emergency core cooling system. Our expert on PRA to answer technical questions is Sarah Bristol, NuScale's PRA Supervisor.

We thought -- this is Slide 3, for those who do not have access to the Skype video. We thought we would begin this presentation with a history of ACRS interactions in PRA to give context to our meetings on ECCS valves and the risk assessment models that we used on them. Note that a reference for the presentation is used in those discussions is provided in the parentheses.

This is not an all-inclusive list of meetings. For example, ACRS interactions regarding the risk-significant topical report are not included

on this slide.

So, in 2018, we had a overview of the NuScale PRA for selected members. This included methods, quality processes, process feature, modeling, human error, and multi-module risk.

In May through June of 2019, we had the official DPA FSAR Chapter 19 subcommittee and full committee. This covered multiple topics, including the passive system reliability.

In July of last year, we also had a special meeting in Corvallis with select ACRS members that included multiple topics. And it was during our testing of the ECCS valves, so we still owed some followup on the final products in the ECCS valve testing.

Between July 2019 and March of this year, NuScale completed the intermediate round of testing, and thus, the NRC staff was able to issue a Phase 4 Safety Evaluation Report with no open items.

And then, as mentioned before, in March of this year, we had the subcommittee meeting on this topic. This focused on ECCS operations.

The March subcommittee meeting covered the following topics, ECCS mechanical configuration, the valve and the inadvertent actuation block, or IAB,

operation, the testing that had been completed so far on the valve, the valve failure modes and probability, the logic, including a sample of fault trees, and also, a new sensitivity study completed to address questions specific to these valves brought up by the committee. This new sensitivity study evaluated the impact of valve reliability on selected support systems.

There were two outstanding questions from the committee in the March meeting. One was an inquiry on units in the sample fault tree, whether it was per year, day, et cetera. This was per year, to answer that question.

The other was a request for NuScale to provide specific values for the auxiliary sensitivity study listed in the last slide. The insights from our sensitivity study are provided here.

If the committee would like additional detailed discussion, NuScale is prepared to address both of these questions in the closed session, because much of the data is proprietary.

And that is all I have to present today. Thank you for your time and please let us know if you have any questions.

MEMBER KIRCHNER: I'll turn first to Vesna.

Vesna, have you any questions of Rebecca?

MEMBER DIMITRIJEVIC: No, I'm good.

MEMBER KIRCHNER: Thank you. Any other members?

CHAIRMAN SUNSERI: This is Matt. I don't have any specific, but in the same interest of getting, seeking our expert, does Dennis have any specific comments or questions?

MEMBER BLEY: No, I don't, thanks.

MEMBER KIRCHNER: Well, then, Matthew, at this point, then, I think we're ready to transition to the staff presentations.

MR. SNODDERLY: Could we ask that Bruce Bavol ask for control of the -- or share his desk screen? Thank you.

MR. BAVOL: Yes, this is Bruce. I'll be taking control here in a second. Mike, can you see the slides?

MR. SNODDERLY: Yes, I can.

MR. BAVOL: Okay. If Jeff and Carl are standing by, I'd like to begin?

MEMBER KIRCHNER: Go ahead. Go ahead, Bruce.

MR. BAVOL: Thank you. Okay. My name is Bruce Bavol, I'm a Project Manager for the Nuclear

Regulatory Commission. I'm currently reviewing, in the process of reviewing, design certification for the NuScale design.

On Slide 2, the agenda was reused from the subcommittee, but what you're going to find out is we've significantly condensed a lot of the discussion and brung out the key points for the ACRS full committee members.

Moving to Slide 3, the NRC staff team, review team, there's a significant list of people who were involved with the development and review of Chapter 15. And today, though, the presenters will be Jeff Schmidt, followed by Carl Thurston.

And I'd also like to mention the Branch Chief overseeing this particular review, Becky Patton, who is the Branch Chief for the Nuclear Method, Systems, and New Reactors.

So, with that, I'd like to turn it over to Jeff.

MR. SCHMIDT: All right, thank you, Bruce. This is Jeff Schmidt, NRR Reactor Systems.

As Bruce mentioned, these are really just condensed slides from the subcommittee. There are some new slides and new material that we'll discuss and I'll try to highlight those when I get to those

slides.

This is pretty much the subcommittee slide, which was on the closure of unclear open items. So, on July 10, 2019, the Phase 3 Chapter 15 ACRS meeting discussed the status of the Chapter 15 review.

Out of that, we listed 11 unclear open items. The following presentation kind of walks through those open items. You'll see that usually in parentheses as we go through. Some of the selected Phase 2 OIs, or open items, are also included in this presentation.

Some were not necessarily in the Chapter 15 subcommittee meeting, some were brought out in the ACRS February 19, 2020, LOCA topical report meeting, and that was the NRELAP Version 1.4, and also, Open Item 1502-4, which was a open item related to the steam generator heat transfer uncertainty. That was discussed at the February 19, 2020 ACRS subcommittee meeting on the non-LOCA topical report. Next slide, Bruce.

So, this is Slide Number 5. Again, this is from the subcommittee meeting, the return to power and the exemption from GDC-27.

The staff took a position in the pre-application that reliably controlling reactivity in

GDC-27 means shutdown is the final end state, when considering the totality of the NRC regulations regarding reactivity control.

Following an initial shutdown, the NuScale reactor can return to power and maintain criticality during a cooldown on safety-related passive heat removal systems, the decay heat removal system, and the ECCS system, under certain conditions.

Staff drafted SECY-18-0099, which established three return to power criteria, to ensure public health and safety. And these are summarized below.

SAFDLs are met upon a return to power. Return to power is not expected to occur in the lifetime of the module. And the incremental risk from the multi-module of the site does not impact Commission's goals related to frequencies of core damage or large releases.

So, those are the three criteria that we're using to judge the exemption to GDC-27. NuScale submitted an exemption and requested approval of a principal design criteria, PDC-27. Next slide, Bruce.

So, NuScale revised, this is the revised PDC-27, this was an open item, in DCD Section 3.1.3.a. It's basically, the first part of that sentence is the

same as GDC-27, about reliably controlling reactivity during postulated accidents with appropriate margin for stuck rods, that the core capability, the capability to cool a core is maintained.

The second sentence, following a postulated accident, the control rods shall be capable of holding the reactor core subcritical under cold conditions with all rods fully inserted, is the addition to the GDC-27 that composes this PDC-27.

We moved the discussion of maintaining the SAFDLs under AOO and postulated accidents into the DCD. So, NuScale revised DCA Chapter 15 Tables 15.0-2, 15.0-3, and 15.0-4 acceptance criterion to ensure that the capability to cool a core is maintained.

And that refers to meeting the specific acceptable fuel design limits, or SAFDLs, including margin for stuck rod for all design-basis events. Next slide.

So, we are on Slide 7 now. And I just wanted to recap the return to power scenarios, we're going to be talking about those in a little more depth coming up. Three scenarios can potentially lead to return to power.

Decay heat removal cool down with DC power available. Here, RPV level remains above the riser or

it could drop below the riser, depending on conditions.

And then, the decay heat removal cool down without DC power. ECCS would actuate at the IAB setpoint, going on ECCS cooling mode.

And then, just a -- actual actuation of the ECCS signal and a ECCS cooldown. These can occur as a result of most Chapter 15 AOOs and postulated accidents.

The key assumptions in the return to power scenarios and analysis was no operator action, only safety-related equipment is used to mitigate, and the worst stuck rods is assumed out, consistent with the GDCs.

Return to power is possible at EOC conditions, but not when significant RCS boron exists, such as at BOC or MOC conditions. Next slide, please, Bruce.

EOC return to power analysis results for the decay heat removal system cooldown, assuming riser remains covered and ECCS cooldown, a return to power is possible. Return to power is less than two percent rated thermal power, significant critical heat flux margin exists, and General Design Criteria 10 is met. In other words, fuel remains intact.

The decay heat removal system cooldown with water level dropping below the riser or riser uncovered remains subcritical due to sufficient decay heat, at least to 72 hours.

Staff's independent confirmatory analysis yielded similar results to the applicant's and the staff recommended approving the exemption to GDC-27. Next slide, Bruce.

So, there are -- as the previous slides described, there's certainly a condition at EOC where a return to power is possible. Since excess reactivity is greater early in the cycle, we wanted to make sure that the EOC was truly the bounding case, so we looked at return to power potentials at what I call non-EOC conditions.

The loss of soluble boron in the core during cooldown could cause a criticality similar to the EOC, ECCS cooldown scenario, obviously depends on the distribution of boron throughout the RPV and CNV.

Core boron can be reduced by flashing or liquid discharge, entrainment, boron volatility, core and riser boron gradient, and diluted CNV water entering the core. So, this is what NuScale evaluated and the staff reviewed as the mechanisms for a potential redistribution of boron. Next slide, Bruce.

Staff reviewed, documented in SER Section 15.6, staff conducted a detailed audit and numerous public meetings on the topic.

A control volume method was used in NRELAP to calculate the fluid transport. Boron transport is effectively informed by the fluid transport that is derived from the NRELAP code.

Methodology uses conservative assumptions to minimize boron concentration in the core. Boron mass is removed by conservative treatment of certain physical phenomenon. And boron mass is artificially removed to ensure overall method conservatism.

Determination of boron loss using NRELAP 5 information included flashing, liquid discharge, entrainment, boron volatized and redeposited outside the core, and CNV level.

Riser and boron gradient was evaluated based on NIST test data and VEERA test data. Next slide, Bruce.

So, the staff's findings regarding potential return to power during non-EOC conditions. Staff agrees that boron will concentrate in the core riser region due to boiling. Staff concluded that boron loss terms informed by NRELAP are conservative.

Staff concluded that assuming the

elimination of the downcomer and lower plenum boron mass is conservative with regard to the core boron concentration.

Boron volatility correlation was reasonable, based on NuScale's operating conditions and conservative by not including any boron that could be rewet and returned to the core.

VEERA test data demonstrates that the core boron is uniform once saturated boiling conditions are reached. The applicant also performed an evaluation with a fully diluted water mass entering the core below the saturated boiling core elevation to demonstrate that the core remained subcritical.

NIST-1 test data from their long-term cooling test, we examined the core exit flow data to demonstrate that two-phase mixing would occur, which would promote riser and core mixing, so we wouldn't have too adverse a gradient between the core and the riser.

Staff concluded that the final boron concentration at 72 hours is greater than the initial core RCS boron concentration, thereby maintaining subcriticality.

And then, as NuScale talked earlier, the staff is aware of a condition report, written by

NuScale, dealing with steam space LOCAs.

VICE CHAIR REMPE: Jeff, this slide talks about things being conservative --

MR. SCHMIDT: Yes.

VICE CHAIR REMPE: -- in several places. How much are things conservative? Are you ten percent, 50 percent, 80 percent?

VICE CHAIR REMPE: Yes, they're pretty conservative. I think we can go into details in the prop discussion, where I can give specific numbers.

But I think as you walk through those numbers, you will see that -- for example, one of the modeling assumptions is not to include the boron mass that exists in the downcomer, in this analysis. That mass of boron effectively just goes away, doesn't exist in the problem. And that's a large mass that is conservative assumption in this analysis.

So, we can walk through the specific numbers and I think I could give you a better feel, but that's just one of the areas that the overall methodology shows significant conservatism. But there are a number of conservatisms I think we can talk in the proprietary section.

VICE CHAIR REMPE: That sounds good, I just want to have a good feel for how much margin there

will be.

MR. SCHMIDT: Yes, there was conservatisms taken in many aspects of this modeling, whether it be a boron loss below certain elevations and containment, some of that never recirculates back in. So, there are a number of conservatisms here.

VICE CHAIR REMPE: Thank you.

MR. SCHMIDT: Okay. Slide 12, please, Bruce. So, this is a new slide relative to the subcommittee meeting. NuScale kind of alluded to this.

There's a condition report for steam space LOCA, with DC power available. The current CNV level setpoint may cause a diluted water slug to quickly enter the core upon ECCS actuation due to a RPV and CNV water level difference. And that's what their revised setpoints are attempting to correct.

An additional source of diluted water in the downcomer beyond that from the CNV could be created if a water level drops below the riser due to the break inventory loss.

The decay heat removal system, which is expected to be operating, could condense that diluted steam into the RPV downcomer.

A diluted water slug from either the CNV

or a combination of the CNV or downcomer could lead to a potential reactivity event.

NuScale is examining new CNV level setpoints and additional ECCS actuation logics to minimize a large RPV and CNV level difference, precluding a rapid diluted water slug from entering the core.

Right now, we're under an audit plan is in place for the staff to review the revised ECCS actuation setpoints. Staff will engage NuScale to ensure impacted FSAR sections and analyses are updated as necessary.

MEMBER MARCH-LEUBA: Jeff, can I ask you? So, I understand from this that the condition report has been finalized, meaning that it has been closed?

MR. SCHMIDT: It has been issued, I don't think it's right to characterize it as closed.

MEMBER MARCH-LEUBA: Yes, issued. So, I mean, all of the analyses have been finalized and --

MR. SCHMIDT: Yes.

MEMBER MARCH-LEUBA: -- they have concluded and I do have it here, the organization, that they're going to change some setpoints to minimize. What is the plan, I mean, you plan to audit this as they do the -- because this is going to affect a number of the

event calculations. You're going to have to update some FSAR sections.

MR. SCHMIDT: That's correct.

MEMBER MARCH-LEUBA: So, you're going to be reviewing them online, I mean, in parallel as they do them?

MR. SCHMIDT: Yes. We're under an audit plan and we'll be reviewing documents as they place them in the electronic reading room.

MEMBER MARCH-LEUBA: Okay. And one thing I want you to, I'm begging you to do is, the law of unintended consequences. This looks like a great idea, it looks like the right thing to do, but let's make sure we're looking around to make sure we didn't mess something else up. So, you need to keep an eye for the law of unintended consequences.

MR. SCHMIDT: Yes, I agree with you. I mean, we are trying to look at non-LOCA events and how that changes things, and even non-LOCA events. That is certainly actively under discussions.

We are also, and I think coming up in some other slides, we're looking at some other potential dilution scenarios that maybe weren't examined as thoroughly. So, we will be looking at the setpoint change and I think we'll be looking at some other

things.

MEMBER MARCH-LEUBA: Yes. Because if I have a dollar for every time I made a change in a software line and it looked like a good idea and I see the consequences, mess up something completely different.

MR. SCHMIDT: Yes.

MEMBER MARCH-LEUBA: Let's make sure we review everything carefully.

MR. SCHMIDT: I agree with your concern. Is there any more question on this slide, since it was new? Okay. Hearing none, let's go to Slide 13.

The staff also looked at the non-EOC potential for return to power out to seven days. The staff considered the NuScale capability to cope with the boron redistribution without the need for additional non-safety-related equipment for a period of seven days, consistent with SECY-96-120.

Staff reviewed NuScale's calculations, including the initial (telephonic interference) and results. Staff agrees that there is sufficient decay heat removal and the core would remain subcritical throughout the seven-day period.

Boration from the CVCS is not required in the first seven days. Again, boron will concentrate

in the core, as long as it's not displaced from the core, you will remain shutdown. Next slide, Bruce.

So, this slide will have some new additions. This is staying on the decay heat removal system for a long period of time or long-term operation.

The decay heat removal system is a safety-related heat removal system used to mitigate non-LOCA transients.

RPV level may drop below the riser elevation following a reactor trip and subsequent cooldown from an AOO or postulated accident. Without makeup, the water level will drop below the riser within three to six hours, depending on the initial conditions and the core decay heat.

Staff asked if adequate cooling is maintained when the riser becomes uncovered and if a return to power is possible? The applicant demonstrated that adequate residual heat removal is maintained and a return to power does not occur within 72 hours.

And that was the original staff finding related to riser uncovery, but as we've discussed some of these newer issues, especially related to downcomer dilution, I think the staff has realized that the

original applicant response did not address the potential for dilution of the downcomer when the riser becomes uncovered for an extended decay heat removal system operation.

The staff was originally focused on adequate cooling and potential for return to power at these lower temperatures, but is now focusing on the dilution of the downcomer as well.

Staff requested the applicant to evaluate the potential of downcomer dilution leading a return to power during extended decay heat removal operation as part of resolving this CR.

So, this is, it's staying on the decay heat removal system for a long period of time and the potential for almost like a diluted slug entering the core under this operating condition.

MEMBER MARCH-LEUBA: Yes, Jeff, this is Jose again. What reports are you following for this? Is this, again, the audit?

MR. SCHMIDT: Yes.

MEMBER MARCH-LEUBA: Because we basically have the SER issued.

MR. SCHMIDT: Yes.

MEMBER MARCH-LEUBA: Are you issuing new RAIs or just talking to the applicant?

MR. SCHMIDT: We're addressing this under the same CR that the LOCA ECCS setpoint change.

MEMBER MARCH-LEUBA: So, the same audit plan applies to this?

MR. SCHMIDT: That is correct.

MEMBER MARCH-LEUBA: Yes. See, because my real goal is the operators in the control room are trained that whenever you uncover the riser, you have to treat the downcomer as if it was poisonous. I don't know what happened to it, let's assume the worst. And as long as that training happen, everything will work.

MR. SCHMIDT: Well, okay, let me be clear here, Jose, is that we're -- I'll have a slide coming up on the recovery aspect.

But we're actually looking at the potential for a diluted downcomer and recriticality within 72 hours, without operator action. In other words, this is of the normal scope of Chapter 15. You're referring to the recovery, where they would add mass, which is also a concern, but this is a related but separate concern.

MEMBER MARCH-LEUBA: Yes. That's because we want to take it as a full operator activation, but in real life, the operator will be in the control room

and be looking over the shoulder and they will prevent -- in real life, the operator will help.

I know we need to analyze Chapter 15 as if he was not there, but in real life, the operator will be there. And the most important, the most critical thing we can do is make sure the operator is aware of the problem. I see what you're doing, you have to analyze the reactor they send you, which is a passive one.

MR. SCHMIDT: That's right. And we have to evaluate this potential issue to 72 hours without operator action, as you said, under Chapter 15 assumptions.

MEMBER MARCH-LEUBA: Okay.

MR. SCHMIDT: Yes, I think I get to your issue, I think, maybe in the next slide. Let's go to Slide 15, Bruce. So, this is recovery after long-term decay heat removal operation. So, this is, I think, what you're referring to, is that correct, Jose?

MEMBER MARCH-LEUBA: Yes.

MR. SCHMIDT: Okay.

MEMBER MARCH-LEUBA: And in addition, you can have an actuation of things, like CVCS, that will raise the levels.

MR. SCHMIDT: Right.

MEMBER MARCH-LEUBA: Of course, that actuation has a very low probability of happening.

MR. SCHMIDT: Right, right. Yes. So, this could apply if they took actions to mitigate during the event as well.

So, and this is, again, in a riser uncovered scenario, some water vapor will condense on the steam generator tubes, the ones that are -- the surface area that's exposed.

This has the potential to dilute the downcomer over a long period of time, as water vapor is assumed to have negligible boron concentration. The rate of the downcomer dilution is limited by the fraction of the steam generator surface area uncovered.

Boron volatility entrainment and rewetting may help limit downcomer dilution, but are not quantified.

A potential exists that reestablishing single-phase natural circulation could transport diluted downcomer to the core, causing a potential recriticality.

Reestablishing RPV level above the riser after extended decay heat removal system operation requires the operator to initiate action to recover

the module through the addition of water.

Post-accident monitoring recovery is not required to be evaluated in Chapter 15 design basis. And that's kind of why I separated out the two issues, because the one of diluted downcomer does have to be evaluated under Chapter 15. So, this is -- we're kind of parsing it recovery versus no operator action in the stylistic manner of Chapter 15.

MEMBER MARCH-LEUBA: Yes, I understand what you're trying to say. We've talked about this for the last several months.

MR. SCHMIDT: Right.

MEMBER MARCH-LEUBA: So, this is all.

MR. SCHMIDT: Yes, okay, thank you. All right. Bruce, Slide 16, please. Okay. So, this is recovery, long-term decay heat removal operation recovery continued.

As indicated, the modules following extended decay heat removal system operation will be procedurally controlled. Plant procedures are not part of the DCA review. Procedures will be developed by the COL applicant or holder. Chapter 13 COL item addresses the development of operating procedures.

The staff believes procedures should be developed to adequately address recovery from this

condition. Plant design allows for the following operational strategies that could address recovery from this condition.

Mixing the core and downcomer boron concentration by simultaneous injection and letdown, preserving RCS level, where the RCS level would be below the riser.

Downcomer and core boron concentration sampled to ensure adequate mixing before single-phase natural circulation is reestablished.

Confirming adequate shutdown margin before restoring level above the riser. Okay. Bruce, Slide 17, please.

MEMBER KIRCHNER: Jeff, this is Walt.

MR. SCHMIDT: Yes?

MEMBER KIRCHNER: Going back to my line of questioning of NuScale. It seems to me that this scenario of downcomer dilution somehow should be governed by tech specs.

MR. SCHMIDT: We have had, recently have had numerous discussions with NuScale of how we're going to capture this. We have not reached conclusion in those discussions.

I think NuScale could speak to the tech spec aspect, that has been brought up. I think they

have a reasonable answer to that.

We are looking at maybe other means of capturing that and I think, in the future, I think we'll be able to speak to it more. Like I said, we haven't reached conclusions on how we're going to capture this event.

MEMBER KIRCHNER: I'm not trying to drive the answer, but I will draw an analogy for you. And the reason I'm falling back on tech specs as one way to deal with this.

Procedures aside, it's -- if you think about your operating envelop under tech specs, temperature and pressure and so on, this is similar in a sense.

In other words, once that riser is uncovered, you're in a different place, where you don't want to be, obviously, if you can avoid it, because it opens up the potential of, in your preceding slides, of a slug of diluted water going in and perhaps causing a recriticality.

So, it seems to me that somehow this is a candidate that is a little bit more stringent requirement than just, well, we'll take care of it in terms of procedural space. That's just one member's opinion.

MR. SCHMIDT: So, we are looking, I'm not sure I can speak to just anything beyond procedures, but we are looking to capture this concern and this phenomenon better documented, so either it can be addressed by potential design change and/or operating procedures at the COL stage.

Is that -- we haven't finalized anything, so I can't speak too much more to it, but we are in active discussion with NuScale.

MEMBER KIRCHNER: Thank you.

MR. SCHMIDT: I'm not sure I'm answering your question, though.

MEMBER KIRCHNER: Not really, in the sense that you're going ahead now and doing a design certification. So, you identified a potential, let me parse my words carefully, scenario with the design that could lead to a potential recriticality of some extent.

And that's, to me, not a space that you really want to be in without having -- again, I go back to my analogy. You have an operating window for pressure and temperature, and that's for good purposes, like fracture of the reactor vessel.

Well, here, you have something that my mind is an analogous issue. And so, I just -- this

idea that procedures will be developed by a COL applicant, rather -- I don't want to say kicks the can down the road, because, obviously, both you and NuScale are addressing the issue.

But it just doesn't seem strong enough, if you will, in terms of when the DCA is issued, that you really put a bound on this particular problem.

MR. SCHMIDT: So, would you be, then, suggesting it would be analyzed, the recovery worst case scenario analyzed?

MEMBER MARCH-LEUBA: I would -- definitely a yes, definitely a yes. But I'm with Walt, I would love, you know I care about this issue, I would love to see on tech specs an LCO, limited condition for operation, the moment you uncover the riser, you enter an LCO. And that tells the operator, you have problem, you have to do something.

And that would be a perfect way to do it. You uncover the riser, you are in LCO, and here are your procedures to get out of it. You don't have to develop the procedures now --

MR. SCHMIDT: Right.

MEMBER MARCH-LEUBA: -- but it's -- I don't know.

MR. SCHMIDT: Thank you. I think that

clarifies what Walt was I think alluding to. I understand now. Okay. Yeah, I think, you know, we're in active discussion with NuScale of how we're going to proceed with this issue. I think we recognize that I am certainly not in a position to commit one way or the other of how this would be resolved, but it is certainly almost a daily discussion item at this point.

MR. PRESSON: Hey, and this is Matthew Presson with NuScale, if I may jump in?

Okay, our -- we are aligned with making sure that this is captured within DCA space somehow. The main issues with tech specs being -- that that's what provides the boundary for our events leading into a Chapter 15 event. But we understand and we limit what could be considered with those deterministic assumptions. Once you are into -- you've gone and tripped, you know, you aren't technically within tech spec space anymore, so it wouldn't be very useful within that space.

And that's kind of the issue that we've been seeing with this is figuring out the proper place to document it without it like tech specs not being particularly applicable or, you know, if you did see that you'd already be out of that and into either

abnormal procedures or other procedures. So figuring out how to address the fact that you will be in this procedural space, handling it with operators, but still capturing that in DCA.

MR. MOORE: This is Scott Moore, the Executive Director, and just a note for the staff and NuScale and anybody else that's on the line, you're going to get comments and questions about any of the presentations, but I just remind everybody that's listening and presenting that the committee speaks through its letters and letter reports. And so the committee speaks as a whole, and that's what you really need to pay attention to, the full committee's presentation in its letter reports. Thank you.

MEMBER KIRCHNER: Jose, I think you were going to say something?

MEMBER MARCH-LEUBA: Basically the same thing you said. That is -- individual members wishes -- the desire to be helpful.

MEMBER KIRCHNER: Thank you.

MR. SCHMIDT: Okay, I guess can we proceed at this point?

MEMBER KIRCHNER: Go ahead, Jeff.

MR. SCHMIDT: Okay. Thank you. Slide 17. So this describes an ATWS scenario where you can

basically lose inventory through the safety relief valve and be in a situation where you would have a potentially diluted water slug inside of containment as well.

To be clear though, that ATWS is not considered a design basis event due to the design of the reactor trip system within the MPS, lowering the probability of occurrence to one times ten to the minus five per reactor year, and hence it's not evaluated in Section 15.8 of the DCA.

Let's go to the next slide.

So ATWS mitigation scenarios. You know, if the operator has recognized that an ATWS has occurred, if they control -- if they insert the control rods early in the transient, it effectively becomes like any other cool-down event. If operators delay or take no action to mitigate the ATWS, operators will probably have to be careful in how they restore or get back to a normal operating mode following the ATWS. If it's left alone, our ATWS analysis has indicated that the reactor stays in a safe, stable state, and basically water remains above the top of the active fuel.

Let's go to the next slide, Bruce?

Again, as I mentioned, if the operators

insert the control rods early in the event, CNV level reaches -- before the CNV reaches the lowest ECCS set point, recovery would be very similar, the same as a design basis decay heat removal cooldown. Staff's conservative analysis demonstrates the lowest CNV level was reached approximately within one hour.

The likelihood of operators failing to insert control rods within that one hour is highly unlikely. If the operator could not insert control rods before reaching the lowest CNV level, ECCS set point, additional analysis may be needed to determine the appropriate operator actions.

ATWS mitigation procedures are dependent obviously on the specific ATWS event and available equipment. Operator actions to recover the plant following a beyond design basis are not within the scope of the DCA review and are developed by the COL applicant are older.

Again, Chapter 13 has a COL item which addresses the development of operating procedures similar to the design basis event discussion we had earlier.

Next slide, please.

So we're switching gears here a little bit. This was one of the unclear open items regarding

rod ejection or return to power from rod -- the potential for return to power from rod ejection. DCA does not address the potential return to power following a postulated rod ejection. Rod ejection is evaluated for short term reactivity response only. This is consistent with the requirement in GDC 28 and the guidance in SRP 15.4(a) to appropriately limit the rate of reactivity increases associated with postulated reactivity accidents including ejected rods.

Primarily a check -- the rod ejection accident is primarily a check of the loading pattern and control rod design such that a coolable geometry is maintained. The staff determined that the provisions in GDC 27 for evaluating design basis accidents in the long term are met for the NuScale design because the control rod ejection accident need not be considered in the long term, due to the robust design of the control rod housing -- drive housing. The staff evaluated the control rod housing design in SER section 3.9. Can't actually see the last number there, so.

Any questions on this slide?

Okay, Bruce, next slide.

Long term cooling analysis, there's two

long term cooling situations evaluated by NuScale. One is we've talked to already, the decay heat removal system, and the other is the ECCS cooling. Staff review is documented in SER section 15.0.5 and 15.6.5.

Long term cooling methodology is documented in the technical report, incorporated by reference into DCD Chapter 1. There's long term cooling technical report addresses the ECCS cooling after recirculation is established. Long term cooling methodology assumes sub-criticality. Return to power is addressed in DCD Section 15.0.6.

Phase 2 SER included open item 15.0.5-2 as the long term cooling technical report had stated that cooling was demonstrated to 30 days. NuScale revised the statement, and staff SER documents the review to 72 hours.

A figure of merit for the long term cooling analysis include the minimum collapsed level, minimum RPV temperature to preclude boron precipitation and maximum clad temperature. All figures of merit met acceptance criteria for the long term cooling analysis.

Next slide.

Okay, I'm going to turn it over to Carl Thurston for the rest of the presentation. Thank you.

MR. THURSTON: Okay. I hope everyone can hear me. So this is Carl Thurston, Reactor Systems Branch, New Reactors. I'm going to speak about the staff's review of analysis for Chapter 6 and Chapter 15 for phase 4.

So as NuScale reviewed earlier, there were changes made from RELAP 5 Version 1.3 to 1.4. There was updates to the NPM model for I will say rather miscellaneous changes. The biggest change again was related to the condensation modeling and some other smaller changes.

Staff looked at the ECCS logic changes. There were two open items associated with that change. There were changes in IAB release set point, so initially the IAB setpoint was at 1100 plus or minus 100. I guess some of those may be proprietary. So the changes -- the IAB settings are reduced.

Additionally, as NuScale has indicated rather significant changes to DHRS logic. That change affected primarily non-LOCA analyses. So staff reviewed the updated analyses and results for impacted events in DCD Rev. 3.

So next slide, Bruce, slide 23.

Okay. So, again, NuScale -- the code changes again and the modeling changes were

incorporated into Rev. 3 of the DCD, and staff reviewed those changes. Staff presented details of the code for the local topical report that was presented on February 19th to the subcommittee.

For the ECCS changes, as we indicated, NuScale reviewed -- removed the actuation on riser level, riser low level, so now the actuation is based on loss of DC power or high CNV level or low AC voltage after 24 hours and conditions. There will be a new logic or logic added per the NuScale condition report.

Also, we'd like to highlight that initially NuScale had increased the level set point for the water level in the CNV, and now that will be changed again per the condition report.

So here is a review of the IAB logic changes. The release set points changed, and the block set point has changed. The block set point has very little impact on safety analysis events.

For the DC DHRS logic changes, NuScale split the signal into two signals, one for DHRS activation and another for secondary side isolation. The direct DHRS actuation inputs now are reduced from 13 inputs to four input signals, and those are high RCS pressure, high RCS temperature, high steam

pressure, and low AC voltage to the batteries. So the functions of the DHRS actuation is essentially all the same as the SSI except that it also opens up the DHRS valves for the heat exchangers to cool the steam generators. So this allows for better operation -- operational controls and reduces the frequency of DHRS activation.

For transient analysis, it delays DHRS activation until much later into the transient, but as far as the figure of merit for Chapter 15, it had very minimal effect on pressure and temperatures and those key values for accepting for the figure of merit margins.

Okay, next slide, Bruce, 24.

So here we look at selected LOCA analyses and Chapter 6 analyses. So for 15-65 LOCA analysis, you can see that there's a slight reduction in minimum CHFR. There is a rather large increase in minimum collapsed liquid level, and this was due to a methodology change by the applicant in the way that the minimum collapsed level was calculated.

For 15-66, inadvertent opening of reactor valve which is an AOO event. The changes were primarily related to treatment of the core. I don't have the value listed for the Rev. 2 DCD, but it's

higher so the new value for Rev. 3 is a lower value, but it still meets the acceptance criteria as indicated.

The minimum collapsed liquid level is not limiting for the IORV event, so, in general, after ECCS opens and the module transitions to long-term cooling, you will reach about ten foot of collapsed liquid level in the core above the top of active fuel. So that's consistent with what we have been seeing for many other events.

Next, we'll talk about Chapter 6.2, containment design. That pressure increased rather significantly, and this in large part is due to changes and more conservative treatment of non-condensables and a little bit related to the code change from version 1.3 to 1.4. But as you can see, they still have adequate margin to the acceptance criteria of 1,050 psia. And also for the containment temperature, they have adequate margin.

The adjectives indicate that these analyses all will need to be evaluated for impact of the ECCS set point change for the condition report. These analyses and potentially other Chapter 15 events will require re-analysis for long-term cooling for this set point change to confirm the boron

redistribution issue as it remains bounding based on the previous results for the RAI 89-30.

Okay, next slide, Bruce.

Next, we will look at non-LOCA transients, 15-15 which is steam line break transient. As you can see there, very minimal difference in the key parameters of minimum CHFR for pressure slightly more conservative results for Rev. 3 of the DCD. For steam pressure, again, similar results as being slightly more conservative. For control rods, missed operation, there's a rather significant drop in minimum CHFR, and that's primarily related to the core treatment. They used more conservative power assumptions, and so that resulted in a lower minimum CHFR, and similar for 15-47.

So here, we've highlighted that more than likely the steam line break 15-15 will need to be reviewed for the ECCS set point change.

Okay, next slide.

Next, we will review some of the committee's questions related to Chapter 6.3, ECCS design. So there were some issues related to water hammer and to make sure that the hydraulic lines and the ECCS valve set ups were functioning properly, were not impeded by water hammer or other phenomena. So

different trip valve hydraulic line lengths for each valve, so the staff wanted NuScale to consider that. And we realized that flow inside the lines can experience two-phase flashing when the trip valve opens. Staff requested a full scale high temperature and high pressure test to confirm no water hammer occurred.

NuScale stated that the temperature of the ECCS valves and their hydraulic lines will remain above the precipitation temperature for boron during the plant's operation, and NuScale plans to flush the ECCS valves and their hydraulic lines during each refueling outage to remove particulates that may accumulate during operations.

Next slide, 27.

So this is the last slide of the staff's presentation, and it involves the CNV and RPV level instrumentation. So NuScale uses this new radar technology. I understand there are four strips in the CNV and four strips in the RPV, and they are separated into three different spans. First, for the containment water level, the sensor spans from the top of the RRV to the top of the containment, to the inside of containment, and that's about 684 inches. And the span is 0 to 100 percent.

So this means that for levels below the RRV, the operators would not have an indication until the level increases above the RRV, but of course, they will know via the pressure, that the containment pressure will increase if there is a leak inside of containment.

The next span is for the pressurizer level, and so that goes from the inside of the pressurizer plate to the top of the pressurizer, and that's about 131 inches, and that span is also from 0 to 100 percent.

And lastly, the RPV riser level spans from the top of the core to the top of the pressurizer. So in fact, it's the same sensors that provide the pressurizer level reading as provided the RPV level reading. And NuScale has removed that indication from ECCS activation, so now it's only used for post-accident monitoring.

Also, we note that at the top for the pressurizer level, it indicates 264 to 300 inches to activate ECCS, and of course, that level is being revised. It's going to be reduced based on the preliminary values that NuScale has given the staff for the new ECCS settings per the condition report.

MR. NGUYEN: There has been a request to

say what slide we're on.

MR. THURSTON: Twenty-seven.

VICE CHAIR REMPE: So, Carl, can I -- okay to ask a question or is there a problem?

MR. THURSTON: Yes.

VICE CHAIR REMPE: This is Joy. The span for actuation has decreased, and is there a discussion occurring about the need to reduce the uncertainty in this radar-based sensor because it looks like you might want to have a more accuracy since you've reduced the span for actuation.

MR. THURSTON: So the span of the signals, and I don't know if we have any Chapter 7 staff on the line, but the --

MR. TANEJA: I'm here.

PARTICIPANT: Dinesh is here.

MR. TANEJA: Yes.

MR. THURSTON: So the spans haven't changed. You can chime in, Dinesh.

MR. TANEJA: Yeah, span is the same. It's just the set point is lower.

VICE CHAIR REMPE: Okay, you're right. It's the set point, that you had a broader range where you could have it actuate. What I was trying to say was the range for actuation has decreased. That's

true, right, Dinesh?

MR. TANEJA: Yeah. It's tighter.

VICE CHAIR REMPE: So wouldn't we want to have a tighter accuracy because the uncertainty of this radar-based sensor was pretty large, previously. Is that --

MR. TANEJA: Right.

VICE CHAIR REMPE: I'm not sure anymore about what's proprietary or not so I don't want to give the numbers right out unless you can verify that it's okay to say them.

MR. TANEJA: So one of the things that we are expecting in the Electronic Reading Room is the technical report on the sensors, the Advanced Sensor Technical Report. That has been identified as one of the potential documents that's been revised due to this change.

VICE CHAIR REMPE: Oh, good.

MR. TANEJA: So I'm expecting to see the calculation in the set point methodology and the technical report for the sensors to see how they're treating this uncertainty.

VICE CHAIR REMPE: Thank you. That's good to hear.

MEMBER BROWN: This is Charlie. Excuse me

for -- Joy, if you could refresh me. I had a call from the home that I had to take, and I missed part of this discussion on the sensors that you were excited about. Could you just give me a quick comment on that?

VICE CHAIR REMPE: Okay, so you are looking at slide -- help me, I don't see --

MEMBER BROWN: I'm on -- I've got Slide 27.

VICE CHAIR REMPE: Twenty-seven and you can see that the actuation range is now shown as 264 to 300 inches.

MEMBER BROWN: Yes, I see that.

VICE CHAIR REMPE: That's a much tighter range than what it used to be. And so my question pertained to the fact, and, again, I don't have in front of me what is proprietary or not, but if you will recall, there was a large amount of uncertainty allowed in the accuracy of this radar-based sensor. And my question is it seems like you would want to have tighter accuracies on the sensor now.

And I think Dinesh said yeah, they're looking at that, and they said they're going to be updating the sensor report. If you remember there's like a -- is it a technical report that's on that

topic, and we'll see something coming out soon.

MEMBER BROWN: Okay, well, one of the reasons for tightening the bands frequently is that you have a less accurate sensor that you're dealing with. Therefore, you tighten it up so that less accuracy doesn't drive you outside what you can accept one way or the other. I mean this is a pretty tight band.

VICE CHAIR REMPE: Yeah, and with that sensor, as you'll recall, it was allowing a lot of uncertainty in their measurements.

MEMBER BROWN: Yeah, and I can see why they would tighten it up as opposed to a wider band because you couldn't depend on a tight -- a better accuracy out of the sensors.

VICE CHAIR REMPE: Yeah.

MEMBER BROWN: As we discussed many times.

VICE CHAIR REMPE: You bet.

MEMBER BROWN: Okay, thank you. I'm sorry, I was -- I'm sorry I missed a few slides. I apologize for that. I had another issue I had to take care of.

VICE CHAIR REMPE: And you can call me later if you want to walk about it.

MEMBER BROWN: Yeah, I will. I've got the

picture. That's all I need right now. Thank you.

MR. THURSTON: Yes, we have one additional slide at the end but it's just a figure to illustrate the location of the various signals.

So, Bruce, if you go to slide 28 we can -- we can wrap things up. So the figure to the right, we can see the pressurizing level and we can see the RPD level, and as Joy indicated, the uncertainty for the signals are being reduced and so that will be reviewed again as a part of the Chapter 7 technical reviews.

If you look at the figure to the right, it shows the span for the containment level, again, spanning from the top of the RVV to the inside top of the containment. So that's about 904 inches for zero to 100 percent water level.

MEMBER BROWN: Are you talking about the left hand figure? You said --

MR. THURSTON: The left hand signal shows the containment level and the right hand signal --

MEMBER BROWN: Yes, you said right -- you said right hand figure.

MR. THURSTON: I am sorry. I am sorry.

MEMBER BROWN: Okay. You confused me. Thank you.

MR. THURSTON: Sorry.

MEMBER BROWN: Go ahead.

MR. THURSTON: Yeah. So I think it's very self-explanatory. So if there are any additional questions from the -- from the committee, from any of the Chapter 15 analyses.

If not, I'll turn it over to Bruce.

CHAIRMAN SUNSERI: So, Bruce, I guess you can proceed to the next topic.

MEMBER KIRCHNER: I think we are changing now from Chapter 15 to page 202 and post-accident monitoring. Okay.

PARTICIPANT: Yeah. Okay.

MR. TESFAYE: Yes. Thank you. This is Getachew. Bruce, please go to the next slide, please.

Good afternoon. My name is Getachew Tesfaye. Can you hear me, first?

PARTICIPANT: Yes, we can hear you.

MR. TESFAYE: Thank you.

Again, my name is Getachew Tesfaye. I am the NRC project manager for NuScale verification FFR Chapters 9, 11, 12, and 16 and also the topical reports for accident source damage.

The hydrogen-oxygen post-accident monitoring issue that we will be addressing this afternoon in both FSAR Chapter 9 of NRC systems and

Chapter 12, radiation protection, as well as the accident source and topical report.

The principal technical reviewers for this issue are Anne-Marie Grady and certification with Michelle Hart. Anne-Marie will be presenting staff a high level summary of the presentation we gave at the security meeting in March of this year. This is the introduction and I will ask Anne-Marie to take over from here starting with the next slide.

MS. GRADY: Thank you, Getachew. This is Anne-Marie Grady and like the earlier presenters I am going to be rereviewing what was presented to the subcommittee at a high level. There's no new material that's going to be presented and I welcome the questions.

CHAIRMAN SUNSERI: Hey, Anne-Marie. This is Matt. Could you introduce the slide number as you walk through your deck?

MS. GRADY: I'd be happy to do it but I can't see it.

CHAIRMAN SUNSERI: You're on number three right now, I believe.

MS. GRADY: Okay. So I am on slide number three. Thank you, Matt.

First of all, this slide addresses the

need for long-term post-accident hydrogen and oxygen monitoring, and the basis of the need is that it informs the timing of the following actions either to inert the containment atmosphere with nitrogen using the CDCS and the nitrogen distribution system, or venting the containment during that set of conditions routing the gas either to the plant exhaust stack and the reactor building ventilation system or to the gaseous waste -- gaseous rad waste system.

It also -- the long-term post-accident monitoring confirms the success of the above to mitigating actions. They are also used, the information, to inform the actions in EOPs and the SAMGs, and, Bruce, if you could go to slide number four.

The need for post-accident monitoring is also to have information to avoid either risking an impulse pressure to the inside of the containment vessel, which in 45 days would be approximately double the impulse pressure at 72 hours, and as I know the members have heard me say before and NuScale as well, the containment has been shown to be able to withstand an impulse pressure from a detonation event in the first 72 hours. So the entire discussion is beyond 72 hours.

And an impulse pressure beyond 72 hours could lead to -- could lead to the CRDM access flange bulk load exceeding the as used service level restrained limits.

Now, for 72 hours that was not the case. It was close to the limit, but the containment was configured to be intact. And if there were CRDM access bulk load exceeded and it were to fail, it would be risking an uncontrolled release to the public.

Please, if you'd go to slide five. Okay. The capability of the design for accurate long-term post-accident hydrogen and oxygen monitoring. The flow path, as we've described before has been established by first making sure the containment pressure was below 250 pounds, which is very different than expected to be, unisolating the containment evacuation system and the containment flooding and drain system CIVs, and creating a flow path from the containment atmosphere via the CTS through the post process sampling system sample pump and in-line gas monitors and funnel to the containment vessel atmosphere via the containment flooding and drain system. The flow path, except for the CIVs, is non-safety related and is acceptable for equipment

specifically used for mitigating a severe accident.

Bruce, if you'd go to the next slide, which I think is seven.

Okay.

CHAIRMAN SUNSERI: It's slide six.

MS. GRADY: Oh, thank you, Bruce. Or Matt, I guess.

To address comments that have been made in an ACRS December letter, that one of the comments was that there were weeks available before post-accident monitoring information was needed to inform any mitigating actions, and I would like to elaborate that that's true if you're talking about the time that the containment atmosphere, conditions that would support combustion, which is essentially oxygen being 5 percent, that would occur by about 14 days. I am sorry, 45 days. NuScale calculated that. We have a confirmatory analysis that agrees with that number. The minimum concentration of 4 percent, which on some occasions has been shown to support combustion, would occur at about 30 days.

Prior to reaching combustible mixtures when the oxygen concentration is about 3 percent would occur in about 15 days. Now, that is -- that 3 percent is a value that was taken from the GTGs, which

is when NuScale decided that that would be a prudent wait time to take action to vent a containment.

So there aren't really weeks to decide to -- what action to be taken. It's really much, much shorter. And another comment that was made in the ACRS letter was that there are other indications that would be available to follow the severe accident progression such as pressure, what temperature, and that they are not -- they do not provide the information as to the potential for the combustion of gases.

Bruce, if you'd go to the next slide. ACRS comments have also been that they were reluctant to contemplate the idea after -- in a severe accident that the containment would be unisolated, and the actions that have been described prior to this venting or the inerting absolutely require unisolating the containment.

However, either by injecting nitrogen and inerting it or venting the containment to the stack. However, there have been no alternatives provided or identified by NuScale or derived -- proposed by staff that would allow us to gain the information on combustible concentrations and containment without unisolating the containment.

Okay. If you'd go to the next slide, please. Okay. I was just summarizing the slide I discussed previously, and this was in response to the comment that a risk evaluation should be considered or was suggested to be considered, and the operator actions that are in the -- in the first column would either be to vent the containment via using the CVS and the reactor building ventilation system.

If the operator took action at 72 hours, as early as 72 hours, or as late as 15 days, the hydrogen and oxygen monitoring path could be isolable, could prevent the DDT pressure pulse, and opening -- the result would be the containment opening would not lead to the large release.

Similarly, on the second or the third row, inerting the containment using the CVCS and nitrogen distribution system in the same time frame, around 72 hours or less than 15 days, the path would still be isolable. You'd still prevent the DDT pressure pulse and the containment wouldn't lead to a large release.

However, taking no action there's no time for operator action at all because you're not going to do anything. The containment is not -- it's not applicable to isolate the containment because it hasn't been opened and it would not prevent the DDT

pressure pulse from occurring in the containment and there is a potential that there could be a CRDM access flange bolt failure after 15 days.

And the next slide, please. Okay. This is more or less the information that was provided by the Chapter 12 reviewers. I can go over it unless Mr. Tesfaye would prefer to.

Hearing not --

MR. TESFAYE: Okay, Anne-Marie. Go ahead, please.

MS. GRADY: Okay. Okay. They had -- the staff believed that the information obtained from monitoring is beneficial and would sustain the operators making decisions following an accident. The staff does not currently have enough information from NuScale on the post-accident monitoring flow path design such as flow rate, leakage rate, volumes with the specifics of the piping, the sizes, the equipment, to be able to estimate the dose to an individual performing actions to reisolate the systems and that would be -- reisolating the system would be one of the actions that would be taken if in fact this monitoring flow path were to develop leakage.

Therefore, the staff believes that at this stage of licensing the best path forward is to retain

the rulemaking carve out, and I believe that's the last slide. And if anybody has any questions I'd be glad to answer them.

MEMBER KIRCHNER: Anne-Marie, this is Walt Kirchner.

MS. GRADY: Yes, Walt?

MEMBER KIRCHNER: I don't think from the get-go we have disagreed with the logic and what you propose here. I think our problem has been one of the design and the size of the piping that would be unisolated to make this to be able to sample, and secondly, how representative the sample actually would be.

And therein lies at least this member's concerns and since we are not in the position to suggest redesign of the -- of the system, that, at least for this member, has been a concern from the get-go.

But not -- we believe with you, yes, this information is beneficial. So that has not been an issue for us. But, again, the size of the piping that's unisolated and how representative the sample would be has been of continuing concern, and as you point out, we really do not have a lot of information about what downstream of the isolation valves this

system would look like and, hence, how much -- risk is not the right word to use but how much inventory may be in play as a result of unisolating the containment.

MS. GRADY: I agree with you. We don't have that design information yet and we are not expecting it in the DC review stage. So being able to say that we have reviewed information would show that a representative sample would be provided is at this stage a design commitment. But it's not been demonstrated.

MEMBER KIRCHNER: Other members?

David, do you have any specific comments, or Jose, or Dennis or any member?

MEMBER BLEY: None from Dennis.

MEMBER MARCH-LEUBA: This is Jose. I was trying to unmute. I'll second -- I think, Walt, you and I are thinking basically in the way of independent individuals so having different opinions. But my point -- I think this is -- I agree with the staff that you need a hydrogen-oxygen monitor.

My complaint is if you need one make sure you have one that works, and I am not convinced that this one works. So but the thing I am convinced is that eventually when the COL comes with a new one there will be one that works. So I am not really

concerned about it. But if you are going to have one, have a good one.

MS. GRADY: Agreed. I agree.

MEMBER KIRCHNER: Any other questions or comments from members?

Thank you, Anne-Marie. Oh, there's David. Go ahead, David.

MEMBER PETTI: I just wanted to make sure I am remembering correctly. In terms of the assessment and the radiolysis, is that a conservative calculation in terms of how much radiolysis occurred and there's no consideration of all the hydrogen that's around that can act to push the reaction in the opposite direction? Is that true?

MS. GRADY: The amount of hydrogen that had been produced from the zirc -- the cladding of the -- deoxidation of the cladding could vary from a small amount to a large amount prior -- in the 72 hours and that would certainly change the time frame at which radiolysis would produce enough oxygen to threaten the containment.

As far as the radiolysis being generated, both NuScale and the confirmatory calc means the guidance of SRP 625 in Reg Guide 1.7. So it's -- in other words, the production radiolysis by itself is a

standard calculation.

MEMBER PETTI: Okay. I am just trying to understand what the (telephonic interference) hydrogen to make sure the radiolysis stays in check. So I am (telephonic interference) correlation have that built in.

MS. GRADY: That's correct.

MEMBER PETTI: Does the correlation that you use have that phenomena in it? Do you know?

MS. GRADY: No, the correlation -- the correlation just addressed the fact that there would be potential hydrogen in the containment initially when the radiolysis started. It wasn't -- it wasn't used to suppress it.

MEMBER PETTI: Okay. But, I mean, in the actual situation the presence of the hydrogen in the core, not in the containment, right?

MS. GRADY: The contribution from the dissolved hydrogen in the accident was credited as having been released into the containment. Is that your question?

MEMBER PETTI: No, not exactly. You know, there's a rate of formation from radiolysis in the core. But if there's a lot of hydrogen around the reaction gets pushed back in the opposite direction.

And so I am trying to understand if that effect has been considered in the rate that we are calculating because there's a lot of hydrogen around many reactors. So there should be.

MS. GRADY: Yes.

MEMBER PETTI: So I am trying to get a sense of if that was in there or not. My main question is how conservative the calculation is if that is not in there.

MS. GRADY: I don't recall if suppressing the rate of radiolysis was credited as being affected by the concentration -- the initial concentration of hydrogen in the containment atmosphere.

MR. OSBORN: Anne-Marie, this is Jim, if I could help you.

MS. GRADY: Yes?

MR. OSBORN: Yeah, this is Jim Osborn.

So I think you're correct that the large quantity of hydrogen will suppress the radiolysis of oxygen. It'll drive the reaction to the left, right, and so you will not produce as much oxygen as the model or the calculation assumes. So the suppression of the radiolysis of oxygen is suppressed by a large amount of hydrogen and that is not how we modeled it.

Like Anne-Marie said, we used the Reg.

Guidance on this and it has a standard oxygen production through radiolysis. It does not credit the suppression due to the large amount of hydrogen.

MEMBER PETTI: Okay. Great. That's what I just needed. Thanks.

MEMBER KIRCHNER: Members, any further questions on this topic?

Hearing none, were you finished, Anne-Marie, at this --

MS. GRADY: Yes. Yes, I am, Walt. Thank you.

MEMBER KIRCHNER: Thank you very much for your presentation.

Mr. Chairman, I would suggest before we transition to the next topic, which I believe will be the staff on PRA, that we take a break.

CHAIRMAN SUNSERI: I agree. We have been at this a little more than an hour and a half. Let's take a break until quarter til the hour. Is that sufficient?

MEMBER KIRCHNER: Yes. Thank you. That will work.

CHAIRMAN SUNSERI: Quarter til the hour we will all resume with the next presentation. So --

(Whereupon, the above-entitled matter went

off the record at 3:33 p.m. and resumed at 3:45 p.m.)

CHAIRMAN SUNSERI: So let me do a quick roll call of the members. Members, please acknowledge when you hear your name.

Ron Ballinger?

MEMBER BALLINGER: Here.

CHAIRMAN SUNSERI: Dennis Bley?

MEMBER BLEY: Here.

CHAIRMAN SUNSERI: Charles Brown?

Charles Brown?

Vesna Dimitrijevic?

MEMBER DIMITRIJEVIC: Here.

CHAIRMAN SUNSERI: Walt Kirchner is here.

MEMBER KIRCHNER: Here.

CHAIRMAN SUNSERI: Jose March-Leuba?

Jose March-Leuba?

MEMBER MARCH-LEUBA: I am here.

CHAIRMAN SUNSERI: Dave Petti?

MEMBER PETTI: Yeah.

CHAIRMAN SUNSERI: Joy Rempe?

VICE CHAIR REMPE: I am here.

CHAIRMAN SUNSERI: Pete Riccardella?

MEMBER RICCARDELLA: I am here.

CHAIRMAN SUNSERI: And myself. So the only one missing is Charles Brown. He's been dealing

with a number of distractions today. So we have a quorum. I suggest we move forward then.

MEMBER KIRCHNER: Okay. Thank you, Mr. Chairman.

We are now turning to the staff's presentation on probabilistic risk assessment.

MS. JOHNSON: Yeah. Good afternoon. This is Mary Ruiz Johnson. We are going to present today the probabilistic risk assessment. The presenters are Marie Pohida and Tony Nakanishi.

Next slide, please. Today we are going to present the PRA review status and a summary of the March 3rd subcommittee meeting including the DC PRA use limitations. ECCS model sensitivity and uncertainty analysis in the reactor building crane operations.

Now I am going to turn it over to Marie Pohida, please.

MS. POHIDA: Thank you, Mary Ruiz. Can you please advance to slide three, please?

Thank you. This is Marie Pohida of the PRA branch in NRR APLC and I'd like to provide a status, an updated PRE review status.

The PRA staff is engaging with NuScale on potential PRA impacts including multi-module risks

from the anticipated design changes from boron redistribution issues and events leading to riser uncovery. And the PRA staff, we will finalize our findings on the NuScale PRA after evaluation of the submitted DCA changes.

And with that, I'll break and answer any questions that anybody might have.

MEMBER MARCH-LEUBA: Yes, Marie. What type of timing are you thinking about this? Because we were supposed to finalize the ACRS review anytime now. We need to plan ahead.

MS. POHIDA: I understand. We are participating in the same audit with reactor systems and as design changes and assessments come in we are monitoring those for PRA impacts and it's -- I think I'd like to just state that it's under staff evaluation.

MEMBER MARCH-LEUBA: But to this -- for planning purposes we can assume it would be late May as to the other topic?

MS. POHIDA: Yes.

MEMBER MARCH-LEUBA: Okay. Thank you.

MEMBER BLEY: Marie, this is Dennis Bley.

Are you expecting all of the design changes that may be forthcoming in the next few weeks

to be reflected in a recalculation of the PRA?

MS. POHIDA: I think I would just like to state at this period of time that it's -- that this is under staff evaluation. We are still waiting for NuScale PRA staff to give us information that we would be looking at.

MEMBER BLEY: Okay.

MS. POHIDA: Are there any more questions, please?

With that, I would ask we advance to slide four and that Tony Nakanishi will continue the discussion. Thank you.

CHAIRMAN SUNSERI: This is Matt. Before Tony begins, I note that there are many people that have their microphone unmuted. So please, if you're not the presenter mute your microphone. There is a little bit of background noise coming through. Thank you.

MR. NAKANISHI: Okay. Good afternoon. My name is Tony Nakanishi and I am with the Division of Risk Assessment along with Marie Pohida.

What I'd like to do is to summarize the topics that were reviewed during the March subcommittee meeting and the way we structured those topics were based on feedback we received from the

ACRS members including the ECCS modeling sensitivity and uncertainty analyses and reactor building crane operations.

But before we got into the specifics, we wanted to clarify staff, you know, expectations relative to design certification PRAs. So consistent with commission policies and guidance, we -- our expectation from ECPRA is to be used to identify risk-informed insights at the design certification stage. So design and operational insights that would inform the design.

The quantification aspect is relied upon to support the consistent -- design's consistency with respect to commission goals. But, you know, the staff's focus really was to ensure that the appropriate insights were identified through the use of the PRA and that they support programs such as regulatory treatment of nonsafety systems, reliability assurance programs, operation of human factors programs, and so forth.

So some of the staff's review at the DC stage is to ensure that the PRA is adequate to support the uses. So if you could go to the next slide, Mary Ruiz, and we are on slide five now.

So we also wanted to just highlight that

at the DC stage, you know, we have information that is not available where we need to rely upon assumptions and this chart shows how the PRA would progress under the Part 52 framework.

So at the DC and COL application stages there are many, you know, detailed design information that's not -- that's not known. Procedures are not available and but certainly there's, you know, a regulatory framework that will -- that requires PRAs to be upgraded -- updated or maintained and upgraded per regulatory requirements in 50.71(h).

And so the key takeaway here is really that at the DC stage we rely upon assumptions and so we want those to be adequately documented.

Next slide, please.

MEMBER DIMITRIJEVIC: Can we question on these slides? This is Vesna Dimitrijevic.

MR. NAKANISHI: Yes?

MEMBER DIMITRIJEVIC: When we have a -- in your opinion, when will COL items be addressed?

MR. NAKANISHI: So COL items are -- by definition it's a COL applicant's action and the staff would review the COL applicant as part of the application to make sure that the COL applicant as addressed the COL item. And so --

MEMBER DIMITRIJEVIC: See, I want to really -- I would like you to differentiate for me because I get confused with exactly the difference between COL applicant and COL holder. Even COL holder in one moment with COL applicant.

So this is why I am asking you specifically do you believe that COL items will be addressed in your second column before too long? When do you think the COL items will be addressed and what type of review would you have?

MR. NAKANISHI: So the COL items -- the staff expectation is that, you know, the COL applicant -- so it's really the first column. So they would -- they would submit an application addressing the COL item and, you know, the expectation --

MEMBER DIMITRIJEVIC: So let me then ask you how would -- a lot of this -- one of the COL items in the PRAs to confirm all the assumptions that obviously in your first column you will not have any, you know, like -- you know, you would not have a completed design or anything. You would not have a procedure.

MR. NAKANISHI: That's correct. So --

MEMBER DIMITRIJEVIC: How would they address the COL items in the COL application?

MR. NAKANISHI: So the expectation is that the COL applicant would address them and evaluate them. For the PRA that's supporting the COL application. So, you know, the findings that we would be making at the COL application has to be supported by the COL application PRA.

If they -- if they elect to use the PRA in a more sophisticated manner, then we would expect a more detailed, you know, review of those assumptions and their impacts on the application.

MEMBER DIMITRIJEVIC: Then we are -- extend them because that's the procedure which was then supposed to control some of these boron dilutions, which we just discussed will not be available if the COL application is submitted. Then, obviously, you cannot address this in the first column of this table.

MR. NAKANISHI: So, again, we would have to make sure -- so the, you know, PRA findings that we make at the COL application stage is fairly similar to the DC application findings. So we could do that and --

MEMBER DIMITRIJEVIC: Then you would be -- then you work on a site and you have to perform the site inputs like a seismic and external events

enveloping. But nothing else. You don't have a design yet. You don't have the procedures. You have -- the cables have not been lie out. The equipment cannot be, you know, procured.

So therefore, everything which we discussed now when you say COL applicant we actually mean COL holder in the -- in the report. So I don't know why we even use the COL applicant. The only difference would be site information.

Why don't we say COL holder and everyone would understand we are talking, you know, before the -- long time in the future. Not an event. We are talking before the -- there is not any review scheduled.

So that's why I have to say it was very important for me to discuss this with my colleagues before this week because we have not really planned reviews after procedures are written, for example.

MR. NAKANISHI: Right. So I agree. So, you know, a lot of the assumptions -- the important aspect is to document those assumptions so that it'll carry forward.

For COL applicants, you know, we want to make sure that those assumptions are still appropriate for the COL application.

Now, if you go further to fuel load then, you know, there are some upgrade requirements and so our expectation is to, you know, have -- you know, have the appropriate acceptability for those phases. But those assumptions being documented is an important aspect.

MEMBER DIMITRIJEVIC: Well, this is because we just had today discussions about how are you going to handle these dilutions and everybody says operating procedure. Which operating procedures will we finish in your second column? There is not a new schedule for anything in that column.

MR. NAKANISHI: So what we would say to that is as Marie Pohida indicated, we are involved in these daily audit calls with the applicant and we are interested in and we have requested, you know, the applicant to address the redistribution issue for impact on PRA. And so we are waiting for that information.

MEMBER KIRCHNER: Tony? Tony, this is Walt Kirchner.

MR. NAKANISHI: Yes?

MEMBER KIRCHNER: May I interrupt a little bit and just follow up on Vesna's line of questions?

It seems to me I don't know as a result of

this condition report whether there will be, quote/unquote, additional carve outs in the rule. But we know already there are commitments with regard to the steam generator, as an example.

And so under -- and I am not an expert or a practitioner in this area. Under the COL application are you going to expect that the PRA that is currently adequate for its purposes would be updated as part of a COL application to address any issues with regard to steam generator or this post-accident monitoring system?

MR. NAKANISHI: So what we would say to that is if the -- if the risk -- so updating the PRA is something that, you know, would have to be evaluated based on -- so I guess, you know, what we would -- for boron distribution issue, for example, we are -- you know, we think that's important enough to ensure that we address the impact on PRA at this stage and the steam generator issue we might -- you know, based on the -- again, the assumptions around the steam generator, you know, there's some failure probabilities that we assume there and the applicant provided some sensitivity analyses as to the impact of potential to failures and things like that. So we think there's -- you know, we can move forward, I

think, with the steam generator issue at the DC stage.

The boron distribution issue we are currently evaluating, as Marie Pohida indicated, and the hydrogen issue, as Anne-Marie presented, you know, we don't believe that that issue will result in a large release. So from that standpoint we think -- we think we can move forward.

So I guess the question of whether the PRA needs to be updated that would actually have to come into play when we discuss what we are using the PRA for.

MEMBER KIRCHNER: And I just wanted to understand, much like Vesna pointed out, you've got on your left hand column of the slide you have the DC application and a reference to the CFR, and then the COL application, another CFR reference. But other than site information, as Vesna has pointed out, it doesn't sound like there's any difference between the PRA for the DCA or the COL. Am I missing something?

MR. NAKANISHI: No, you're correct, for the most part. There may be additional design, you know, evolution between DC and COL application. But it's probably not going to be significant. A lot of the -- a lot of the PRA information at the COL application stage is referenced -- you know, it's IDR,

if you will, was it --

MEMBER KIRCHNER: That's what I would expect. I would expect that it would reference the NuScale PRA.

MR. NAKANISHI: Right. So but I guess the point I want to make here is that, you know, that's why the assumptions are very important and that would provide a basis for further evaluation further in the licensing and operations stage.

MEMBER BLEY: This is Dennis Bley. I got knocked off Skype for a couple minutes when Walt was asking questions. So forgive me if you've already addressed this.

But all of those carve outs that exist are going to have to be completed in the review of the COL application -- your first column. If any of them affect the PRA then you ought to be looking at those.

MR. NAKANISHI: Yes.

MEMBER BLEY: And the applicant should be addressing it.

MR. NAKANISHI: Yes, the applicant should address it and, you know, the staff should question it. But, again, you know, there's some level of evaluation that we could -- we could do.

Well, yeah, I should -- I guess -- yeah,

I don't know that -- the specifics with respect to the steam generator issue. But from the standpoint of, you know, potential two failures and, you know, maybe increased transient frequency, I think for the -- for the typical uses of the PRA at the COLA stage, we are probably in a position to be able to move forward. It all depends on what the applicant -- the COL applicant decides to use the PRA for.

You know, they could -- they could try to apply the PRA for other applications. You know, risk-informed tech specs or other things, and if they do that then we will certainly have to do a more detailed review of the assumptions.

MEMBER BLEY: I am just telegraphing at least my thoughts if we should schedule a COL applicant. If there are things we learned when those carve outs are closed, change -- we could change substantively the design cert PRA results. They really have to be addressed, though, in the COL application.

MR. NAKANISHI: I agree. Thank you.

MS. POHIDA: May I add a clarification to this discussion? This is Marie Pohida. Okay.

MEMBER KIRCHNER: Yes. Go ahead, Marie.

MS. POHIDA: Thank you. The rule language

for COL applications says is that the applicant in 52.79(d)(1), it says the applicant is supposed to use the PRA developed for design certification and it's supposed to be updated for site-specific features and design departures.

MEMBER BLEY: One -- this is Dennis again. These carve outs are different. There's no finality on the design cert in those areas. So you'd have to get finality during the COL application review.

MEMBER DIMITRIJEVIC: These can be -- these can be completed in design structure. You know, maybe that's what they have in mind. I mean, if something changes from what the assumptions were.

But in addition to these carve outs, which are just one small category because there is only a couple of them and we have all of these COL items which are depending on operating procedures which were not being completed until they -- before long.

So we have different categories. We have a carve out, which is the main region supposed to be addressed during the COL application, and then we have what we just discussed about boron dilution, this -- the things which have been present for all -- the same applies to the post-accident monitoring. That system would not be designed in the COL space. That system

will be designed before the full load.

So there is a lot of things we hear -- I mean, we are just guessing. You know, we don't have a clear picture between COL applicant and the COL holder and when is this happening and what is the review status.

So in my opinion, not too much is going to happen in COL. In my opinion and in my experience, because we can report COL applications with EPR, nothing is basically happening in the COL application in relation to the PRA other than adding the site-specific information.

You know, you also have experience with AP1000. So AP1000 was reviewed in design certification phase and in the COLA phase. I don't see any review explained before the full load if AP1000 doesn't apply to some risk-informed application.

So I think in this moment, whatever the COL items related to procedure or design or layout of agreements and tables, that would not be reviewed if not -- they don't apply to risk-informed applications.

MR. NAKANISHI: Correct. We wouldn't -- we can't really verify those until the plant is built and, you know, and same with the operating experience.

We are not going to have surveillance, you know, data coming in.

So, again, what we can do, though, is to make sure those important assumptions are documented and if the PRA is going to be used in a way that's more quantitative, if you will, then those will be appropriately evaluated. The assumptions have to be -- to be valid -- well, the impact of the assumptions have to be -- impact on the decisions that you're making have to be evaluated.

MS. POHIDA: Tony, may I offer a clarification?

MR. NAKANISHI: Yes, please.

MS. POHIDA: Thank you. To address Vesna's concerns. And regarding the boron redistribution issue, we are evaluating that for potential PRA impacts at design stage. Regarding the carve outs, because they do not have finality, we will be looking at those for -- at the COL application stage. Okay.

Once the -- once you have -- you have a holder, okay, if they state design changes to tier one and tier two information that meets criterion -- that meets the change of criteria for prior staff approval in a LAR, when a COL -- I mean, a COL holder submits

a LAR there is often an assessment of the impact on the PRA and we review that.

For example, when AP 1000 submits a LAR, there is often assessment of whether there are any impacts on the PRA. Does this help?

MEMBER DIMITRIJEVIC: I mean, we are familiar with this. I just want to say that we -- it is very important for our clarification in this process that we shouldn't be expecting reviews of anything related for completing design and procedures because that's my opinion. There will not be upcoming reviews for that.

MEMBER BLEY: Vesna, this is not for discussion with the committee than for -- on interaction with the staff. But the experience with completed COL applications is pretty minimal and if we have significant concerns about specific things that aren't yet clarified even at the COL stage, there is nothing that prevents us from writing our letter to the commission asking them to suggesting that they have us follow up on some of those items later in the review. Just something they can talk about later.

MR. NAKANISHI: So, yeah, I agree with everything that's being said. I guess one thing I would add regarding these COL items and the

assumptions, what that does, I think, is it provides guidance to the applicant as well as the staff to -- you know, to make sure they look at the right things and make sure they are still appropriate for the COL phase.

Now, when you get to the holder phase, we -- unless there's an application to the PRA, there really isn't a trigger for, you know, a detailed staff review. You know, you get into how operating reactors use the PRA for risk-informed applications and that gets into, you know, Reg Guide 1-200, peer review process, and things like that.

MEMBER BLEY: I have a question here for you. This is Dennis. Because we have never had a Part 52 operating license holder coming up to the fuel load place so we have absolutely zero experience in that step of this whole process.

What is the staff's intent at this point in time? You were hinting at it. But is that really being thoroughly considered by the staff, because this would be the -- well, there is a first time coming up but we don't have one yet -- on what kind of look staff ought to do with that fuel load PRA.

It will certainly have to have met the requirements of having a full review. But what kind

of look over that peer review or what issues that you might have flagged earlier that you want to make sure are covered in that PRA you plan to look at?

MR. NAKANISHI: Right. Those are very good questions and, like you said, we really don't have experience. So we are -- I think we have to sort of, you know, create the guidance for that, you know, maintenance rule implementation as one -- you know, one potential event where we may get into looking at the PRA.

But with Vogtle, we will have -- we will have to be, you know, prepared for that. So I think there's additional homework we have to do there.

MEMBER DIMITRIJEVIC: And if I can mention, there is very clear guidance versus you have ITAAC guidance. Before they go to the logged, every ITAAC item has to be closed and reported to be submitted to the regulator.

So ITAAC items have a very clear closure part. COL items, they are not going to be closed in the COL. Most of those that I saw in the -- I mean, in PRA, so the thing is that we don't even have a similar guidance to the -- for the other things which we say COL applicant and then when we say COL applicant in a lot of cases it's not really applicant.

It's the holder almost 99 percent of the time.

MR. NAKANISHI: Correct. Correct. And ITAAC has a lot more -- a lot stronger regulatory force, if you will.

MEMBER KIRCHNER: Tony, do you have any further slides?

MR. NAKANISHI: Well, I do. But I'll go real quick. So if we could go to the next slide.

So the only point here that I'd like to make, we evaluated the ECCS model with the understanding that there's no operating experience but we -- you know, so there's modeling uncertainties associated with that. But we -- you know, we addressed this with -- through, you know, sensitivity studies and things like that, and one thing I would mention here is that, you know, the ECCS saturation logic is something that we are looking at closely for a potential impact here, particularly relative to any increase in incomplete ECCS saturation because that could potentially change that risk profile.

So next slide, please. Seven. And sensitivity and uncertainty analyses, we -- again, you know, many of the assumptions that could affect the design certification stage findings we believe the applicant provided a sufficient analysis here.

But, again, relative to the, you know, potential impacts due to the boron redistribution, we are -- I guess we are not done yet. We are just -- we are monitoring, you know, the assessment from NuScale and then we would -- we would conclude accordingly.

So and with that, I am going to turn it back over to Marie just for the reactor building crane discussion that she was the lead reviewer in that area.

MS. POHIDA: Thank you, Tony. May we proceed to slide eight, please?

Thank you. This is basically the same slide that I presented to the subcommittee regarding reactor building crane operations. The calculated drop probability is dominated by operator errors, of commission, over speed, over race, over travel, and failure of instrumentation. That's in interlocks or switches to provide a safety stop.

In revision four of the DCA key assumption was added for the shutdown PRA that movement of the reactor building crane is modeled as being operator controlled and that administrative controls will ensure that reactor building safety features such as limit switches and interlocks that prevent undesired movement are functional during module movement.

The validity of these assumptions in the DCA and crane data supporting the PRA will be confirmed by the COL applicant per COL Action Item 19.1-8.

The reactor building crane is within the scope of the human factors process during COL per the human factors engineering design implementation plan and the risk significance of the crane has resulted in additional ITAACs.

So that is the end of my slide -- I'll stop -- and the end of our presentation. So I'll stop here.

MEMBER DIMITRIJEVIC: This is a very good example of this COL Item 19.1-8 application to RFDC. There will not be any changes. RDC will not be -- you know, have the design in the COL application. That will happen really before they are logged.

So why don't we say here the COL applicant -- it's not applicant. It's COL holder. Happens much later in the -- in the life and that, similarly, the entrance to the -- you know, that there is nothing else right now on this in the process. So --

MEMBER BLEY: Is that true? I was under the impression from our subcommittee meeting that this would be addressed in the COL application. So --

MEMBER DIMITRIJEVIC: Well, that is implementation-based -- implementation plan.

MEMBER BLEY: That was really for the staff.

MS. POHIDA: Oh, excuse me. When we reviewed the reactor building crane notebook, we understood from NuScale that the reactor building crane is evolving and that we understood that COL application that we would have more design details.

MEMBER BLEY: That's what I understood and I understood it to mean both -- I thought it was in your SER but also I thought that the applicant had talked about that as well and that their crane vendor would have completed that design and the human factors analysis to support it by the time of the COL application.

MEMBER DIMITRIJEVIC: Yeah, but the only difference is site so I don't know what is obligating the -- what the COL applicant -- how is the COL applicant obligated to do that. It's not.

MEMBER BLEY: It's obligated in the SER and I thought it was, and two, I thought I heard NuScale say they -- that would be in place and they were moving ahead with that line. NuScale and the staff ought to speak to that.

MS. POHIDA: Yes. For details I would like to defer to NuScale on this -- on this issue, please.

MS. NORRIS: This is Rebecca Norris with NuScale. I am sorry. We are having some connectivity issues on our end and we are collecting our thoughts. Can we get back to this in a few minutes?

MEMBER BLEY: Okay by me. This is Dennis.

MEMBER DIMITRIJEVIC: Okay by me, too.

MS. BRISTOL: The is Sarah Bristol. Can you hear me?

MS. POHIDA: Yes. Yes, Sarah. You're a little quiet but we can hear you.

MS. BRISTOL: Yes. It's NuScale's expectation that the -- as you have mentioned, the crane is being -- is continuing to be designed, and we believe that at the COL stage there will be additional information and that will be part of the additional design information that will be included in the COL PRA as we reevaluated consistent with COL Item 19-1-8 risk assumption.

Since we do have the assumption associated with crane operation and operator action, we believe that the crane tech will be addressed at the COL application stage.

MEMBER BLEY: Thanks. That was my expectation. You --

MEMBER KIRCHNER: Members, any further questions?

Hearing none, I think this is -- I believe we are at the end of our open presentations. So we need to ask for public comment. But before we do that, any further comments by members?

CHAIRMAN SUNSERI: Walt, this is Matt. I have no other questions or comments.

MEMBER KIRCHNER: Anyone else?

Hearing none -- Mike Snodderly, can we turn to the opening of the public line?

MR. SNODDERLY: Yes, Thomas can assist us with that, and if someone from the public could let us know.

MS. FIELDS: This is Sarah Fields. I do not have any comments at this time. Thank you.

MEMBER KIRCHNER: Thank you, Sarah. Is there -- are there any other members of the public who wish to make a comment? If so, identify yourself and please make your comments.

Mike, hearing none, I think we can close that public bridge line and then I'll pass back to the chairman. I think the intent is for us to go into

closed session with NuScale through a bridge line. I recommend that you just mute your Skype control panel and leave it connected, and then when we finish with the closed session we can come back to consideration of letter writing.

MR. SNODDERLY: Thank you, Walt, and I had two other things to add. One is that this would be a good time for a break because Thomas -- now that we couldn't initiate the bridge line so we ended the public bridge line.

So we need about five minutes to get that up and running and let people call in. But once we -- once the chairman ends this open session, yes, we will proceed with the NuScale bridge line to conduct the closed session.

I remind all members to look at the email I sent you yesterday evening at 6:29 p.m. That has the slides that we will be -- that we will be discussing.

And then the only other thing I had to add was for everyone to be aware that all four commission TAs requested the closed bridge line and I expect them to be on. So just as a heads up.

That's all I have.

MEMBER BROWN: Mike? Mike?

MR. SNODDERLY: Yes?

MEMBER BROWN: I thought your email said that we were supposed to exit Skype and then go to the bridge line whereas Walt just commented we should just minimize --

MR. SNODDERLY: I was -- yes, Charlie, if I could speak to that. That was my direction yesterday evening but after talking to the members and I think Chairman Sunseri was exactly right. Just leave Skype up and running. Just put it on mute and that way we don't have to go through the hassle of rephoning back in.

MEMBER KIRCHNER: We need to be sure everybody puts it on mute so that we don't have public access to it.

MR. NGUYEN: So I am going to interrupt. So what we are doing is we are making most of the individuals except the Skype team and the ACRS leadership as presenters. Once everyone is on attendee and once the chairman gives the go ahead, we will mute the entire attendees.

MEMBER BROWN: Do we go -- are we supposed to mute or not?

MR. NGUYEN: You should. But as an extra safeguard, we will mute all attendees, which means you

cannot unmute yourself until we -- until we hear from the chairman to release it.

MEMBER BROWN: Okay.

MEMBER BLEY: Quynh, this is Dennis Bley. Even the presenters we ought to mute because if anybody slips up and leaves it open we have got a public connection.

MR. NGUYEN: I understand. But it's -- yeah. Yeah. We are going to mute, too. But we can't put a lock on presenters because we need the authority rights to do what we do.

MEMBER BLEY: Okay. As long as you keep watching.

MR. NGUYEN: Right. If we -- if we hear something, we are just going to interrupt right away so you can stop talking.

MEMBER MARCH-LEUBA: Just so you know, I am going to hang up the phone call because it only takes a key join to go back in. So you won't see me there.

MR. NGUYEN: Okay. So the closed bridge line is now open. I am going to lock all the attendees now so you can't unmute yourselves.

(Whereupon, the above-entitled matter went off the record at 4:32 p.m. and resumed at 4:33 p.m.)

CHAIRMAN SUNSERI: At this time, we are going into the closed session.

(Whereupon, the above-entitled matter concluded at 4:33 p.m.)

Surry Power Station

Units 1 and 2

Subsequent License Renewal Application

ACRS Full-Committee Meeting

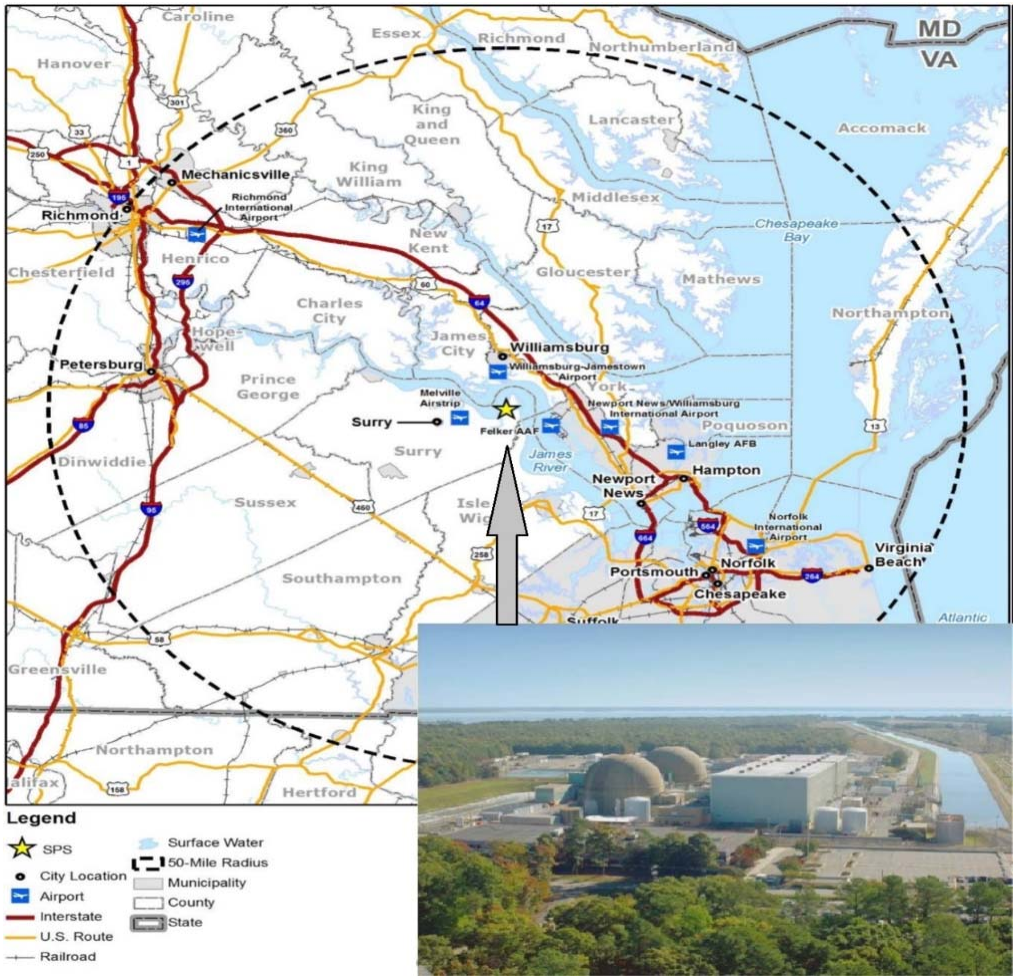
April 8, 2020

Dominion Energy

Agenda

- Station Overview/Performance
- SLR Application Development
- GALL SLR Consistency
- SLR Aging Management Programs
- Technical Topics
- Closing Remarks

Surry Power Station



Dominion Energy

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

SLR Application Development

- Dominion Energy staff integrally involved in the development of the GALL SLR/SRP
- Followed NUREG-2191 (GALL-SLR) and NUREG-2192 (SRP-SLR) to the greatest extent possible
- Followed SLR industry guidance in NEI 17-01
- Reviewed RAIs from the most recent first license renewal applications
- Conducted Industry Peer Reviews
- Conducted a Safety pre-application meeting with the NRC Staff in April 2018 to discuss SLRA content and obtain insights

SLR Application Development

Deltas between First License Renewal (FLR) and SLR

- Scoping & Screening
  - Updated for plant modifications
  - Updated to NEI 17-01 guidance
  - Some updates required to address 10 CFR 54.4(a)(2)
- 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

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 based on NEI 99-04, "Guidelines for Managing NRC Commitment Changes
- Implementation activities have begun and will continue following anticipated issuance of renewed license

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

Surry SLR – 47 GALL-AMPs

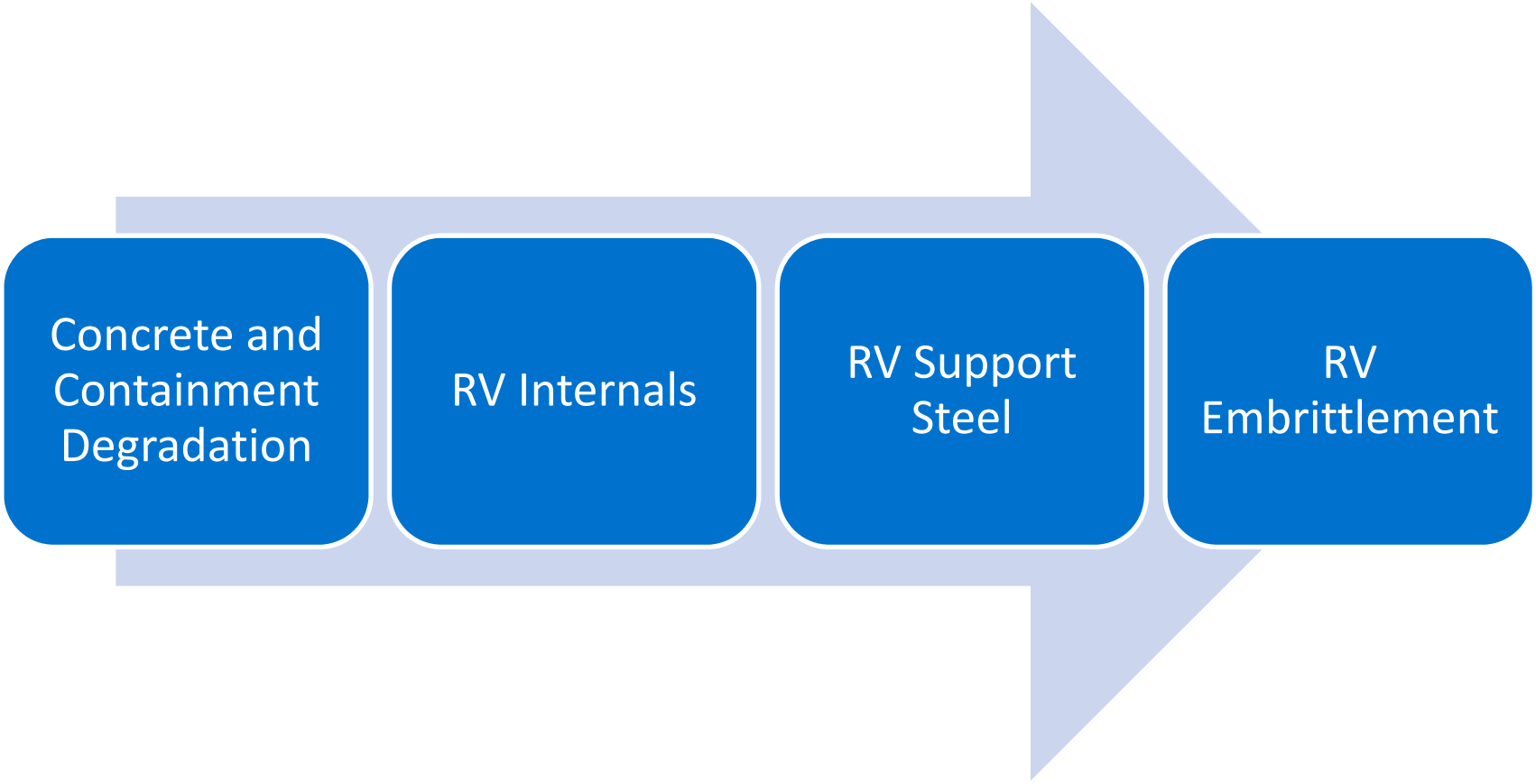
	Consistent with GALL-SLR	With Enhancement	With Exception	Exception and Enhancement	Plant Specific
Existing 40	6	24	1	9	0
New 7	5	0	2	0	0
Total 47					

Dominion Energy

FLR AMPs are Effective in Managing Aging

- 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

Technical Topics



Dominion Energy

Dominion Energy SLR Summary

- 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

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Advisory Committee on Reactor Safeguards

Surry Power Station, Units 1 and 2 Subsequent License Renewal Application (SLRA) Safety Evaluation Report (SER)

April 8, 2020

Angela Wu, Project Manager
Lauren Gibson, Project Manager
Office of Nuclear Reactor Regulation

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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
- Inspections and Plant Material Conditions
- Conclusion on Surry SLRA Review
- Conclusion on Differing Views on Surry SLRA Review

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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
Final Safety Evaluation Report	3/9/2020

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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
- Final SER: March 9, 2020
- Requests for Additional Information (RAIs): 71

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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

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 and/or exceptions	○ 7 new programs • 5 consistent • 2 consistent with exceptions ○ 40 existing programs • 6 consistent • 34 consistent with enhancements and/or 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

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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)

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July 2019 Fire Loop Piping Rupture

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Focused PI&R Inspection

- Inspector: Steven Downey
- Dates: February 24 – 28, 2020
- Procedure: IP 71152, “Problem Identification and Resolution”
- Activities:
  - Developed timeline of events that lead to fire suppression water system nonfunctional declaration
  - Determined the current status and path forward for corrective actions intended to restore the health of the fire water suppression system
  - Determined the programmatic requirements that govern the actions taken by the licensee since the fire protection loop piping failures occurred
  - Verified that actions taken by the licensee were in accordance with the applicable regulatory requirements and self-imposed programmatic requirements
- Result: No Findings Identified
- Observation on status of corrective actions included in IR 2020-001

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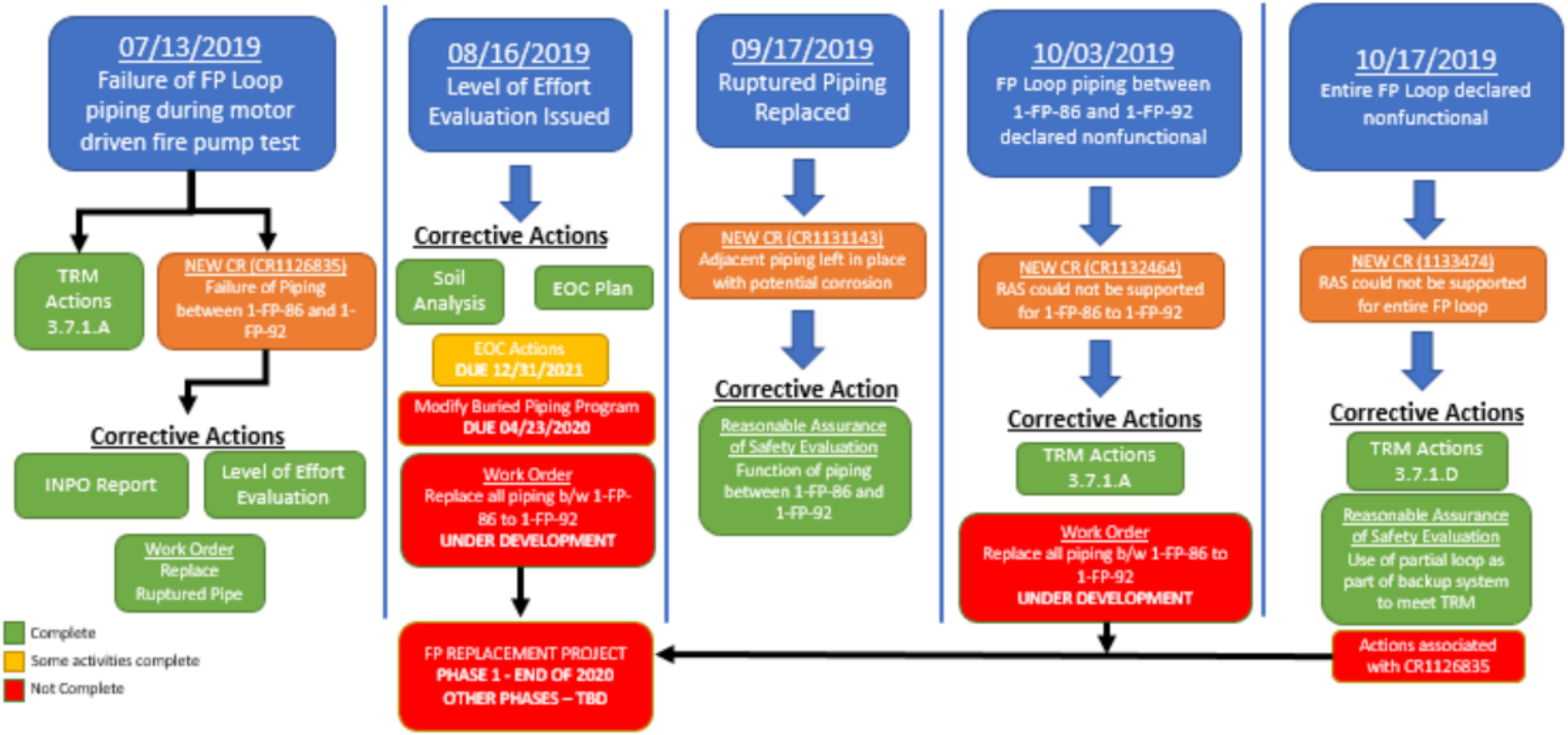
Focused PI&R Inspection: Timeline + Status of Corrective Actions



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Region II: Plant Material Condition + Conclusion

- Plant material condition is generally acceptable and meets regulatory requirements for systems, structures, and components.
- The inspectors found that the AMPs were being implemented in accordance with the license condition.
- The NRC will continue to monitor AMPs using the baseline Reactor Oversight Process.

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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Conclusion on Differing Views

- Focused on the July 2019 fire pipe rupture
- Evaluation concluded:
  - Reliance on applicant's correct action program is consistent with license renewal safety principles
  - Other issues adequately addressed in application
- No changes needed to the SER
- The renewed license can be issued consistent with 10 CFR Part 54

April 6, 2020 Docket No. 52-048

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SUBJECT: NuScale Power, LLC Submittal of Presentation Materials Entitled "ACRS Full Committee Presentation – NuScale FSAR Topic: Chapter 15," PM-0420-69573, Revision 0

The purpose of this submittal is to provide presentation materials to the NRC for use during the upcoming Advisory Committee on reactor Safeguards (ACRS) NuScale Full Committee Meeting on April 8, 2020. The materials support NuScale's presentation of NuScale Chapter 15.

The enclosure to this letter is the nonproprietary presentation entitled "ACRS Full Committee Presentation – NuScale FSAR Topic: Chapter 15," PM-0420-69573, Revision 0.

This letter makes no regulatory commitments and no revisions to any existing regulatory commitments.

If you have any questions, please contact Matthew Presson at 541-452-7531 or at mpresson@nuscalepower.com.

Sincerely,

Zackary W. Rad
Director, Regulatory Affairs
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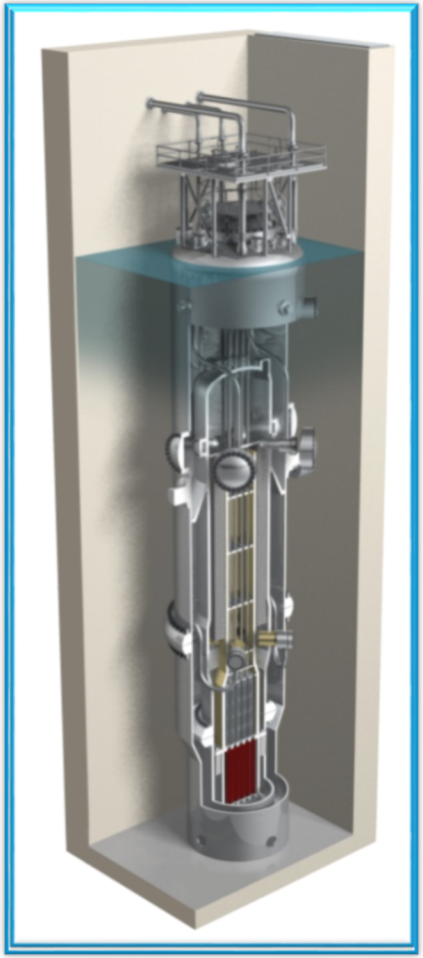
Enclosure: "ACRS Full Committee Presentation – NuScale FSAR Topic: Chapter 15," PM-0420-69573, Revision 0

Enclosure:

"ACRS Full Committee Presentation – NuScale FSAR Topic: Chapter 15," PM-0420-69573, Revision 0

ACRS Full Committee Presentation



NuScale FSAR Topic: Chapter 15

April 8, 2020

PM-0420-69573
Revision: 0

Template #: 0000-21727-F01 R6

Presenters

Matthew Presson
Licensing Project Manager

Ben Bristol
Supervisor, System Thermal-Hydraulics

Meghan McCloskey
Thermal-Hydraulic Analyst

Paul Infanger
Licensing Specialist

Agenda

- Principle Design Criteria 27
- Boron Transport
- Changes from FSAR Rev. 2 to FSAR Rev. 4
  - Incorporates NRELAP5 v1.4
  - Minor module model update
  - DHRS actuation logic changes
- Overall changes in Chapter 15 analysis results FSAR Rev. 2 to FSAR Rev. 4

Principle Design Criteria 27

- DCA includes an exemption request from GDC-27
  - NPM design aligns with precedent based compliance for GDC-27 due to lack of second safety reactivity control system
- Principle Design Criteria 27
  - Passive reactor GDC-27 equivalent
  - Ensures the safety related reactivity control system is designed to achieve and maintain subcritical core
  - Ensures fuel integrity for an extended overcooling in combination with a partial failure of reactivity system (stuck rod)

Compliance with PDC-27

- Immediate shutdown is sufficient to protect RCPB and SAFDLs with margin for the worst rod stuck out of the core
- Cold shutdown is achieved with all control rods fully inserted
- Loss of Shutdown Margin Consequences Benign
  - Evaluated with single highest worth control rod fully withdrawn
  - Critical power level does not challenge DHRS or ECCS heat removal or SAFDLs
- Probability of the combination of conditions that results in a loss of shutdown return to power with a single rod stuck out of the core is small

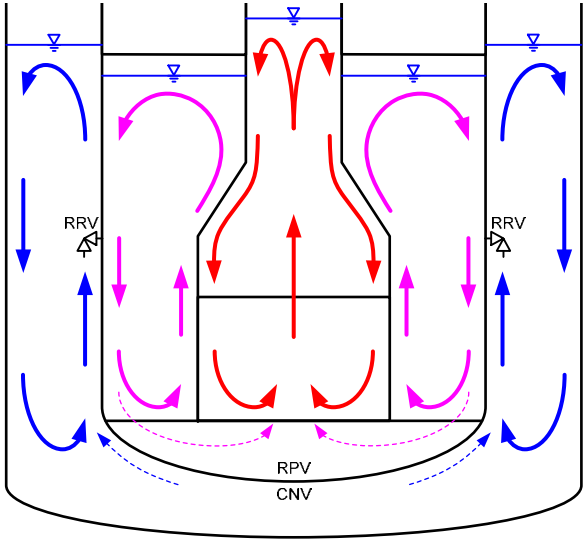
Results – Return to Power Analysis

- ECCS cooling most limiting with equilibrium power limited to 1-2% RTP.
- Core temperature must be <200°F for recriticality
- Increased pool temperature decreases the magnitude of the return to power, with 140°F precluding a recriticality
- Earliest recriticality determined to occur approximately 40 hours post-scram
- MCHFR for most limiting results non-limiting relative to other events
- Other AOO acceptance criteria met
- Other SAFDLs demonstrated with OCRP conditions bounded by existing analyses developed for the DCA

ECCS Boron Transport – Context

Context for ECCS boron transport analysis:

- As boron accumulates in the core/riser region, boron concentration in the CNV and DC decreases
  - Boron precipitation analysis performed as part of ECCS long term cooling analysis
- Boron dilution analysis performed to:
  - Evaluate potential for lower boron concentration fluid in core or near core inlet
  - Confirm appropriate scope of return to power analysis by demonstrating that core region concentration remains above initial concentration
  - Response to RAI 8930



Boron transport governed by:

- boiling in the core
- condensation in the containment vessel

ECCS Boron Transport – Method

- Method summary for dilution analysis:
  - LTC PIRT high ranked phenomena affecting boron transport evaluated
  - Control volume approach to analyze transport between regions
  - NRELAP5 used to provide volume fluid masses, flow rates as input for boron transport calculation
    - Volatility, entrainment calculated separately
  - Boron transport calculation performed separate from NRELAP5
  - Conservatively model transport between regions:
    Boron distribution factors applied to minimize boron transport in, maximize boron transport out of RCS hot region
  - Demonstrate that RCS hot region concentration remains above initial concentration
- Key areas of NRC review:
  - Treatment of boron volatility
  - Mixing
- Additional discussion in closed session

ECCS Boron Transport – Results

- Boron transport evaluated during ECCS cooling
  - Results summarized in RAI 8930 show core boron concentration remains above initial concentration
    - No net core boron dilution is expected even with biased transport assumptions
    - More realistic analysis of boron transport indicates boron concentration in RCS core region is 2-3 times the initial concentration at 72 hours. Core boron concentration remains above initial concentration for at least 7 days.
- Realistically, long term, high boron concentration expected in RCS hot region, with low concentration in RCS cold region, containment
- Recovering the riser and establishing Mode 3 conditions will take multiple deliberate operator actions following appropriate procedures
- Procedures are developed on a site-specific basis (COL commitments 13.5-2 and 13.5-7.)

ECCS Boron Transport – Update

- Status Update:
- In March 2020, NuScale determined under certain conditions, ECCS actuated later than expected, which could result in a higher containment water level accumulation than is considered in the RAI 8930 response basis.

- Resolution and Design Change to ECCS Actuation:
- NuScale is implementing a design change to ECCS actuation, which will be modified to actuate earlier and eliminate this potential for containment water level accumulation and downcomer dilution.

Conclusions

- Inherent design characteristics provide ample safety
  - Low core power, large RCS inventory, small high pressure containment, and large ultimate heat sink
- Compliance with intent of GDCs is demonstrated for reactivity control systems
  - Conservative analysis of the low probability return to power condition demonstrates safety margin
- Boron redistribution is evaluated and demonstrated to not be a safety topic
  - Naturally accumulating boron in the core adds to shutdown margin for design basis event and severe accidents.

Ch 15 Changes FSAR Rev. 2 to Rev. 4

- Results from FSAR Rev. 2 presented to ACRS in June, July 2019 in subcommittee and full committee meetings for Chapter 15
- Changes in FSAR Rev. 3 include
  - Update from NRELAP5 v1.3 to v1.4
  - Updated NRELAP5 base model input
  - More conservative core design input in some cases
  - DHRS actuation signal changes, addition of secondary side isolation signal
  - ECCS actuation signal changes
- Changes in FSAR Rev. 4 include
  - ECCS IAB threshold/release pressure changes

NRELAP5 v1.4

- Modifications made from v1.3 to v1.4 were due to routine code maintenance
- 26 specific code Fixes (documented in error reports) with most notable being:
  - Condensation correlation error corrections (< 2 psi increase in CNV pressure calculations)
  - Correction to choking model quality factor (little to no impact)
  - Updated Windows executable to 64-bit version (not used for production calculations)
- 5 new Features – None of which impact DCA calculations
  - Added proprietary classifications marking to source files
  - Expanded number of elements allowed in water property file (no water property file update)
  - Interpolation update for CHF correlation not used in DCA calculations
  - Added warning message to users if mass error stop (1%) is disabled
  - Removal of Developmental Options from user access

NRELAP5 Base Model

- Revision 0 released 12/2015 (DCA submittal 12/2016)
- Revision 1 released 8/2017
  - Updates for design consistency
    - Minor geometry changes based on drawing updates
    - Minor RCS flow loss updates (changes in best estimate values)
  - Updates for analysis consistency and ease of downstream use
    - Minor nodalization changes to match LOCA model
    - Added passive heat structures defined in LOCA model
  - Other changes
    - Change from elevation based to volume based calculation of collapsed liquid level
    - Error correction when specifying lower CNV material (had been previously corrected in impacted analysis calculations)
- Revision 2 released 01/2019 (FSAR Rev. 3 submittal 8/2019)
  - Removed ECCS actuation on RCS riser level signal
  - Minor RCS flow loss updates
  - Minor geometry error corrections

DHRS Actuation Changes

- Summary of change:
  - Add secondary side isolation actuation for range of signals that indicate upset in normal secondary side cooling conditions
  - DHRS actuation limited to subset of signals indicating insufficient secondary side cooling
  - DHRS actuated following secondary side isolation
- Purpose of change: Support expected plant startup progressions
- Effect of change on transient analyses:
  - Heatup events – No change to expected DHRS actuations on high pressurizer pressure or high RCS hot temperature
  - Cooldown events – Secondary side isolation may be actuated first; DHRS actuated afterwards on high steam pressure
  - Reactivity events, inventory increase, inventory decrease events not significantly impacted

Conclusions

- Revised return to power analysis shows ECCS cooling conditions result in equilibrium power at 1-2% RTP
- ECCS boron transport analysis demonstrates that core boron concentration remains higher than initial concentration
- Changes incorporated into FSAR Revision 3:
  - Several minor changes in NRELAP5 code, NPM plant base model
  - DHRS, ECCS actuation changes
- ECCS IAB changes incorporated into FSAR Revision 4
- FSAR Ch 15 limiting transient results consistent between FSAR Rev. 2 and Rev. 4
- FSAR Ch 15 analysis results demonstrate margin to acceptance criteria

Acronyms

AOO – Anticipated Operational Occurrences

CHF – Critical Heat Flux

CNV – Containment Vessel

COL – Combined License

COLR – Core Operating Limits Report

CRDM – Control Rod Drive Mechanism

CVCS – Chemical and Volume Control System

DC – Downcomer

DHRS – Decay Heat Removal System

DTC – Doppler Temperature Coefficient

ECCS – Emergency Core Cooling System

EOC – End of Cycle

GDC – General Design Criteria

IAB – Inadvertent Actuation Block

LCO – Limiting Condition for Operation

LOCA – Loss of Coolant Accident

LTC- Long Term Cooling

MCHFR – Minimum Critical Heat Flux Ratio

MTC – Moderator Temperature Coefficient

NPM – NuScale Power Module

OCRP – Overcooling Return to Power

PDC – Principal Design Criteria

PIRT – Phenomena Identification and Ranking Table

RCPB – Reactor Coolant Pressure Boundary

RCS – Reactor Coolant System

REA – Rod Ejection Accident

SAFDL – Specified Acceptable Fuel Design Limits

SDM – Shutdown Margin

WRSO – Worst Rod Stuck Out

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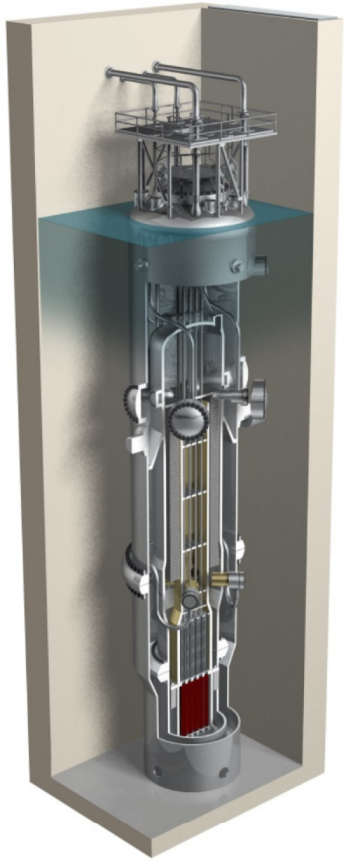

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April 6, 2020 Docket No. 52-048

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SUBJECT: NuScale Power, LLC Submittal of Presentation Materials Entitled "ACRS Full Committee Presentation: NuScale Topic – Hydrogen/Oxygen Monitoring," PM-0420-69518, Revision 0

The purpose of this submittal is to provide presentation materials to the NRC for use during the upcoming Advisory Committee on Reactor Safeguards (ACRS) NuScale Full Committee Meeting on April 8, 2020. The materials support NuScale's presentation of hydrogen/oxygen monitoring.

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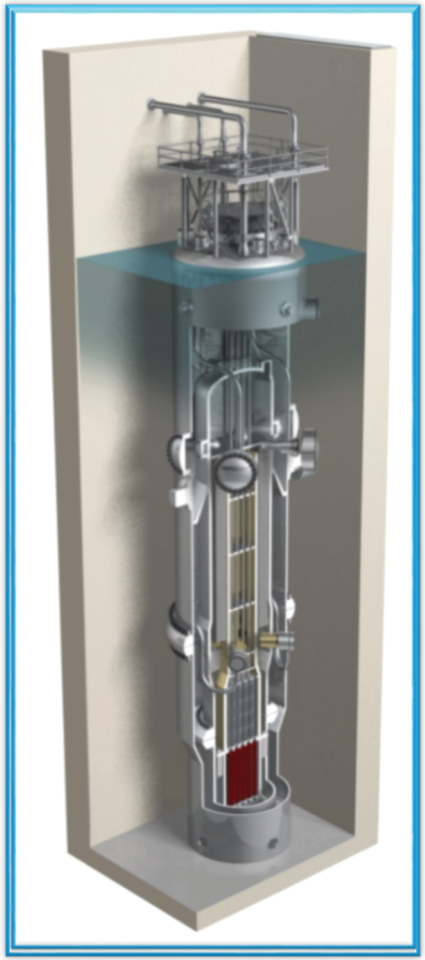
ACRS Full Committee Presentation



NuScale Topic
Hydrogen/Oxygen Monitoring

April 8, 2020

PM-0420-69518
Revision: 0

Template #: 0000-21727-F01 R6

Presenters

Matthew Presson
Licensing Project Manager

Jim Osborn
Licensing Engineer

Summary and Conclusions

- Core damage accident is a beyond design basis accident
  - Consistent with industry practice, allows nonsafety-related SSCs
  - A NuScale core damage accident is low frequency
- Bounding analyses shows there is a minimum of 72 hours before containment can be threatened
- Decision to place system into service would include precautions and follow RG 1.7 risk-informed process
  - There is sufficient time to inspect and evaluate system condition
  - If leaks develop, can isolate and repair
- Monitoring path can withstand combustion events
- Containment is well-mixed and representative sampling is required

Containment Isolation Failure

- Chapter 19 documents an assessment of whether a severe core damage event with a containment failure could lead to a large release
- The conclusion is that “at the earliest possible time of fuel-coolant interaction (FCI), the airborne fraction of volatile fission product aerosols is less than the calculated threshold for a large release.”
  - 6.8 hours is the earliest possible time of FCI for intact containment accidents
- Under the bounding assumption that the containment evacuation system (CES) piping were to be completely sheared at the time of unisolation, it is reasonable to conclude this event would not result in a large release or threaten public safety

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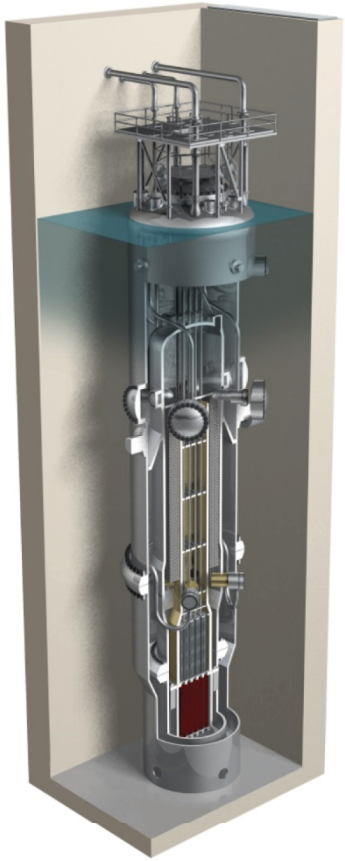

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April 3, 2020 Docket No. 52-048

U.S. Nuclear Regulatory Commission
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SUBJECT: NuScale Power, LLC Submittal of Presentation Materials Entitled "ACRS Full Committee Presentation: NuScale Topic – Probabilistic Risk Assessment, with a Focus on Emergency Core Cooling System Analysis," PM-0420-69559, Revision 0

The purpose of this submittal is to provide presentation materials to the NRC for use during the upcoming Advisory Committee on reactor Safeguards (ACRS) NuScale Full Committee Meeting on April 8, 2020. The materials support NuScale's presentation of the probabilistic risk assessment.

The enclosure to this letter is the nonproprietary presentation entitled "ACRS Full Committee Presentation: NuScale Topic – Probabilistic Risk Assessment, with a Focus on Emergency Core Cooling System Analysis," PM-0420-69559, Revision 0.

This letter makes no regulatory commitments and no revisions to any existing regulatory commitments.

If you have any questions, please contact Rebecca Norris at 541-602-1260 or at RNorris@nuscalepower.com.

Sincerely,

Zackary W. Rad
Director, Regulatory Affairs
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Enclosure: "ACRS Full Committee Presentation: NuScale Topic – Probabilistic Risk Assessment, with a Focus on Emergency Core Cooling System Analysis," PM-0420-69559, Revision 0

Enclosure:

"ACRS Full Committee Presentation: NuScale Topic – Probabilistic Risk Assessment, with a Focus on Emergency Core Cooling System Analysis," PM-0420-69559, Revision 0

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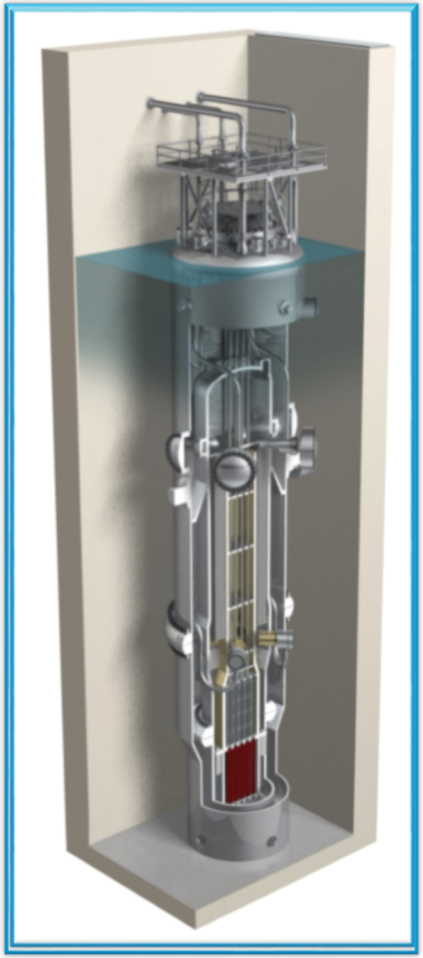
ACRS Full Committee Presentation



NuScale Topic

Probabilistic Risk Assessment, with a Focus on Emergency Core Cooling System Analysis

April 8, 2020

PM-0420-69559
Revision: 0

Template #: 0000-21727-F01 R6

Presenters

Rebecca Norris
Licensing Project Manager

Sarah Bristol
Probabilistic Risk Assessment Supervisor

ACRS Interactions

- March and October 2018 – Overview of NuScale PRA for selected members (Ref. LO-1018-62248, 10/30/18)
  - PRA methods, quality process, passive features modeling, human error, multi-module risk
- May-June 2019 –FSAR Chapter 19 Subcommittee and Full Committee (Ref. LO-0519- 65373, 5/09/19; LO-0519-65769, 5/31/19)
  - Multiple topics including full committee discussion of passive system reliability
- July 2019 –NuScale site (Corvallis, OR) meeting.
  - Multiple topics including results of intermediate ECCS valve testing
- March, 2020 – Phase 5 focus area Subcommittee (Ref. LO-0220-69047, 2/28/20)
  - Discussion of ECCS operation

Focus Area Review Topics

- ECCS mechanical configuration
- ECCS valve and inadvertent actuation block (IAB) operation
- ECCS valve testing
- ECCS valve failure modes and probability
- ECCS logic
- ECCS valve generic data sensitivity
  - Evaluated the impact of ECCS reliability on select support systems

Outstanding Subcommittee Questions

- Units in sample fault trees (Ref. slide *ECCS Valve Logic (Spurious Opening)*) are per year

- Fussell-Vesely values (Ref. slide *Generic Data Sensitivity*): In a sensitivity study including generic data for ECCS valves, there were no new support system risk insights, including consideration for human action risk significance (i.e., FV importance measures)

Reference slides are contained in the presentations submitted as LO-0220-69047, 2/28/20

Acronyms

ACRS	Advisory Committee on Reactor Safeguards
DCA	Design Certification Application
ECCS	emergency core cooling system
FSAR	Final Safety Analysis Report
FV	Fussell-Vesely
IAB	inadvertent actuation block
NRC	Nuclear Regulatory Commission
PRA	probabilistic risk assessment

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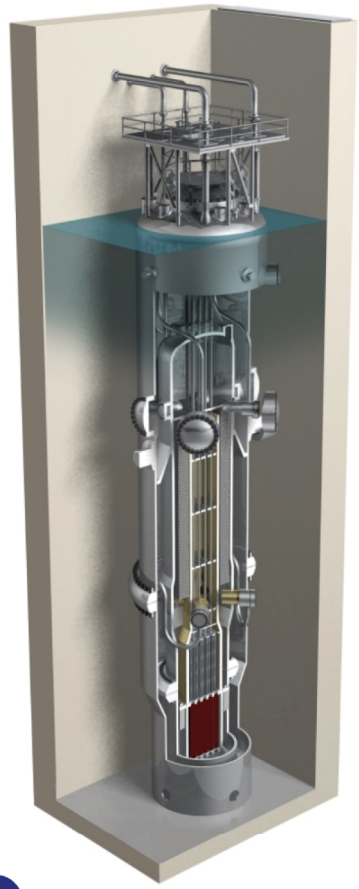

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Power for all humankind

From: mshd.resource@nrc.gov
To: Gurr, Amee
Subject: General Form Submission (30346) Received
Date: Friday, April 3, 2020 9:25:15 AM

The NRC received your General Form submission on: 04/03/2020 at 12.25 PM. It is being tracked as submission ID# 30346.

If it is a 'Publicly Available' submission after 6 work days from today the submission's attached document(s) will be available for viewing and download from the Agency's Public Web Based ADAMS website (https://adams.nrc.gov/wba) by searching for the following document accession number(s): [ML20094H674]. If this is a 'Non-Public Available' submission the submission's attachment(s) will be retained in NRC's document management system (ADAMS) and will not be published to the public website.

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United States Nuclear Regulatory Commission

Protecting People and the Environment

Chapter 15, “Transient and Accident Analyses"

Focus Areas on: Boron Redistribution/Return to Power and ECCS

NuScale Design Certification Application

ACRS Full Committee Meeting
April 8, 2020

Agenda

- NRC Staff Review Team
- Closure of Unclear Open Items
- Return to Power
- Boron Redistribution
- Recovery from certain DHRS and ATWS scenarios
- Changes to Design in Phase 4
  - NRELAP5 v1.4
  - ECCS Actuation Logic
  - IAB block/release pressure
  - DHRS Logic
- LOCA
- Long-Term Cooling
- Changes to Selected Analyses in Phase 4
  - IORV Analysis
  - Peak Containment Pressure
  - Steam System Piping Failure Inside/Outside Containment
  - Control Rod Misalignment
  - Inadvertent Loading of an Assembly
- ECCS Design
- CNV and RPV Level Instruments

NRC Staff Review Team

- Chapter 15 Technical Reviewers:
  - Antonio Barrett, NRR/DANU
  - Andrew Bielen, RES/DSA
  - Tim Drzewiecki, NRR/DANU
  - Michelle Hart, NRR/DANU
  - Andrew Ireland, RES/DSA
  - Shanlai Lu, NRR/DSS
  - Ryan Nolan, NRR/DSS
  - Jeff Schmidt, NRR/DANU
  - Alex Siwy, NRR/DSS
  - Ray Skarda, RES/DSA
  - Jason Thompson, RES/DSA
  - Boyce Travis, NRR/DANU
  - Carl Thurston, NRR/DSS
  - Chris Van Wert, NRR/DANU
- Additional Technical Reviewers for Boron Redistribution/Re-criticality and ECCS Focus Areas:
  - Syed Haider, NRR/DSS (containment peak pressure)
  - Peter Yarsky, RES/DSA (ATWS)
  - Tom Scarbrough, NRR/DEX (ECCS valves)
  - Dinesh Taneja, NRR/DEX (I&C)

Closure of Unclear Open Items

- July 10, 2019, Phase 3 Chapter 15 ACRS meeting discussed status of Chapter 15 review
- Listing of 11 Unclear Open Items provided
- The following presentation notes these OI numbers as each is discussed
  - Selected additional Phase 2 OIs are also included
- OI 15.0.2-2: unclear portion of OI related to staff review of NRELAP5 v1.4
  - Discussed in February 19, 2020, ACRS SC on LOCA topical report
- OI 15.0.2-4, unclear portion of OI related to staff review of the steam generator heat transfer uncertainty
  - Discussed in February 19, 2020, ACRS SC on Non-LOCA topical report

Return to Power: GDC 27 Exemption

- Staff took the position in the pre-application Gap 27 letter (ML16116A083) that "reliably controlling reactivity" in GDC 27 means shutdown as the final state when considering the totality of NRC regulations regarding reactivity control
- Following an initial shutdown, the NuScale reactor can return and maintain criticality during a cool down on the safety-related, passive heat removal systems (DHRS and ECCS) under certain conditions
- Staff drafted SECY-18-0099 which established three return to power criteria to ensure public health and safety
  - SAFDLs are met upon a return to power
  - Not expected to occur in the lifetime of the module
  - The incremental risk to public health and safety from the hypothesized return to criticality at a NuScale facility with multiple reactor modules does not impact Commission goals related to frequencies of core damage or large releases
- NuScale submitted an exemption to GDC 27 and requested approval of a principle design criteria, PDC 27

Proposed PDC 27 (OI 15.0.6-1)

- NuScale revised PDC 27 in DCD Section 3.1.3.8 to state:
  - "The reactivity control systems shall be designed to have a combined capability of reliably controlling reactivity changes to assure that under postulated accident conditions and with appropriate margin for stuck rods the capability to cool the core is maintained. Following a postulated accident, the control rods shall be capable of holding the reactor core subcritical under cold conditions with all rods fully inserted"
  - NuScale revised DCA Chapter 15, Tables 15.0-2, 15.0-3 and 15.0-4 acceptance criterion to ensure that "capability to cool the core is maintained" refers to meeting the specific acceptable fuel design limits (SAFDLs), including margin for a stuck rod, for all design basis events (DBEs)

Return to Power Scenarios

- Three scenarios can potentially lead to a return to power
  - DHRS cooldown with dc power (EDSS)
    - RPV water level remains above the riser
    - RPV water level drops below the riser
  - DHRS cooldown without dc power (EDSS)
    - ECCS actuation at IAB setpoint
  - ECCS cooldown
- Can occur as a result of most Chapter 15 AOOs or PAs
- Key assumptions in the return to power scenarios
  - No operator action
  - Only safety-related equipment is used to mitigate the event
  - The worst stuck rod is assumed stuck out consistent with GDCs
- A return to power is possible at EOC conditions, but not when significant RCS boron exists (e.g., BOC and MOC conditions)

EOC Return to Power Analysis Results

- DHRS cooldown, assuming riser remains covered, and ECCS cooldown return to power
  - Return to power is less than 2% rated thermal power
  - Significate MCFHR margin exists
  - General Design Criterion 10 met
- DHRS cooldown with water level dropping below the riser (riser uncovered) remains subcritical due to sufficient decay heat at 72 hours (UOI: OI 15.0.5-1)
- Staff's independent confirmatory analysis yielded similar results
- Staff recommended approving the Exemption to GDC 27

Potential Non-EOC Return to Power (UOI: OI 15.0.6-5)

- Excess reactivity controlled by soluble boron
- Loss of soluble boron in the core during a cooldown could cause a recriticality similar to the EOC ECCS cooldown scenario
- Core boron can be reduced by:
  - Flashing/Liquid Discharge
  - Entrainment
  - Boron volatility
  - Core and riser boron gradient
  - Diluted CNV water entering the core

Return to Power at Non-EOC Analysis Methodology

- Staff review documented in SER Section 15.0.6
  - Staff conducted detailed audit and numerous public meetings on topic
- Control volume method using NRELAP5 to calculate fluid transport
  - Boron transport informed by NRELAP5 fluid transport
- Methodology uses conservative assumptions to minimize core boron concentration
  - Boron mass is removed by conservative treatment of physical phenomenon
  - Boron mass is artificially removed to ensure overall methodology conservatism
- Determination of boron loss using NRELAP5 information include:
  - Flashing/Liquid discharge
  - Entrainment
  - Boron volatized and redeposited outside the core
  - CNV level
- Riser and core boron gradient evaluated based on NIST-1 and VEERA test data

Staff Findings Non-EOC Analysis Methodology

- Staff agrees that boron will concentrate in the core/riser region due to boiling
- Staff concluded that boron loss terms informed by NRELAP5 are conservative
- Staff concluded that assuming the elimination of the downcomer and lower plenum boron mass is conservative with regard to core boron concentration
- Boron volatility correlation was reasonable based on the NuScale operating conditions and conservative by not including boron rewetting and return to core
- VEERA test data demonstrates that core boron is uniform once saturated boiling conditions are reached
  - Evaluation of a fully diluted water mass (0 ppm) below the saturated boiling core elevation demonstrated the core remained subcritical
- NIST-1 long-term cooling core exit void test data demonstrated that enough two-phase mixing would occur to promote riser and core mixing
- Staff concluded that final core boron concentration at 72 hours is greater than the initial core RCS boron concentration, maintaining subcriticality
- Staff is aware of a Condition Report written by NuScale dealing with steam space LOCAs

NuScale Condition Report

- For a steam space LOCA, with DC power available, the current CNV level setpoint may cause a diluted water slug to quickly enter the core upon ECCS actuation due to RPV and CNV water level differences
- An additional source of diluted water in the downcomer, beyond that from the CNV, could be created if the water level drops below the riser due to break inventory loss
  - The DHRS, which is expected to be operating, would condense diluted steam into the downcomer
- A diluted water slug from either the CNV, or some combination of CNV and downcomer, could lead to a potential reactivity event
- NuScale is examining new CNV level setpoints and additional ECCS actuation logic to minimize a large RPV and CNV level difference precluding a rapid diluted water slug from entering the core
- An audit plan is currently in place for the staff to review the revised ECCS actuation setpoints
- Staff will engage NuScale to ensure any impacted FSAR sections and analyses are updated as necessary

Return to Power at Non-EOC 72 hours ➡ 7 days

- Staff considered NuScale capability to cope with potential boron redistribution without the need for additional nonsafety-related equipment for a period of 7 days consistent with SECY-96-128 (RTNSS ‘B’).
- Staff reviewed NuScale calculation initial conditions, assumptions, and results.
- Staff agrees there is sufficient decay heat removal and the core would remain subcritical throughout the 7-day period.
- Boration from the CVCS is not required in the first 7 days.

Long Term DHRS Operation

- The DHRS is a safety-related heat removal system used to mitigate non-LOCA transient events
- RPV water level may drop below riser elevation following a reactor trip and subsequent cooldown from an AOO or postulated accident
  - Without makeup, water level will drop below the riser within 3-6 hours depending on initial conditions and core decay heat
- Staff asked if adequate cooling is maintained when the riser becomes uncovered and if a return to power is possible
- The applicant demonstrated that adequate residual heat removal is maintained and a return to power does not occur within 72 hours
- The original applicant response did not address the potential for dilution of the downcomer when the riser becomes uncovered during extended DHRS operation
- Staff has requested the applicant to evaluate the potential of downcomer dilution leading to a return to power during extended DHRS operation while resolving its CR

Long Term DHRS Operation Recovery

- In a riser uncovered scenario, some water vapor will condense on the exposed steam generator tubes
- This has the potential to dilute the downcomer over a long period of time as water vapor is assumed to have a negligible boron concentration
  - The rate of downcomer dilution is limited by the fraction of steam generator surface area uncovered
  - Boron volatility, entrainment and rewetting may help limit downcomer dilution but are not quantified
- Potential exists that reestablishing single-phase natural circulation could transport the diluted downcomer to the core causing a potential re-criticality
- Reestablishing RPV water level above the riser after extended DHRS operation requires the operator to initiate action to recover the module through the addition of water
- Post-accident module recovery is not required to be evaluated in Chapter 15 design basis review

Long Term DHRS Operation Recovery (cont)

- NuScale has indicated the recovery of an NPM following extended DHRS operation will be procedurally controlled
  - Plant procedures are not part of the DCA review
  - Procedures would be developed by the COL applicant or holder
  - Chapter 13 COL item addresses the development of operating procedures
- Staff believes procedures could be developed to adequately address recovery from this condition
- Plant design allows for the following operational strategies that could address recovery from this condition:
  - Mixing core and downcomer boron concentration by simultaneous injection and letdown preserving RCS level
  - Downcomer boron concentration sampled to ensure adequate mixing before single-phase natural circulation is reestablished
  - Confirming adequate shutdown margin before restoring level

ATWS Scenario

- The limiting RPV pressure ATWS event is initiated by a loss of A/C power.
- Loss of A/C causes the feedwater pump and turbine to trip.
- Control rods are assumed to fail to insert.
- RPV pressure increases due to loss of heat sink.
- High RPV pressure trips the DHRS to activate
- RPV inventory is lost by lifting the RSVs and discharging into containment
- ATWS is not considered a design basis event (DBE) due to the design of the reactor trip system within the MPS lowering the probably of occurrence below 1.0E-5 per reactor year (see SER Section 15.8)

ATWS Mitigation

- Two ATWS scenarios are possible:
  - Operators insert control rods early in the event
  - Operators delay or take no action to mitigate the ATWS
- In both cases, the RSVs relieve pressure and discharge into containment
- If operators insert the control rods early in the transient as expected, the ATWS event progression resembles the long term DHRS cooldown scenario with the riser potentially becoming uncovered
- If operators delay or take no actions to insert the control rods, enough RPV inventory is lost, the level drops below the riser - breaking natural circulation and establishing a new equilibrium power.
  - A safe state is reached and collapsed liquid level remains above the top of the active fuel

ATWS Mitigation and Recovery

- If operator acts to insert rods before CNV inventory reaches the lowest CNV level ECCS setpoint, the event recovery would be the same as a DBE DHRS cooldown
  - Staff's conservative analysis demonstrates the lowest CNV level is reached in approximately 1 hour
  - The likelihood of operators failing to insert the control rods within 1 hour is highly unlikely
- If the operator could not insert control rods after reaching the lowest CNV level ECCS setpoint additional analysis maybe needed to determine the appropriate operator actions
- ATWS mitigating procedures are dependent on the specific ATWS event and available equipment
- Operator actions to recover the plant following a beyond design event are not within the scope of the DCA review and are developed by the COL applicant or holder
- Chapter 13 COL item addresses the development of operating procedures

Return to Power with Ejected Rod (UOI: OI 15.0.6-6)

- DCA does not address the potential return to power following a postulated rod ejection
- Rod Ejection is evaluated for the short term reactivity response only
  - Consistent with the requirement in GDC 28 and the guidance in SRP 15.4.8 to appropriately limit the rate of reactivity increases associated with certain postulated reactivity accidents, including rod ejection
  - Primarily a check of loading pattern and control rod design such that a coolable geometry is maintained
- The staff determined that the provisions in GDC 27 for evaluating DBAs in the long term are met for the NuScale design because:
  - Control rod ejection accident need not be considered in the long term due to the robust design of the control rod drive housings
  - The staff evaluated the control rod housing design in SER Section 3.9.4

Long-Term Cooling Analysis

- Two LTC situations evaluated by NuScale
  - DHRS and ECCS cooling
- Staff review documented in SER Section 15.0.5 and 15.6.5
- LTC methodology documented in technical report incorporated by reference into DCD Chapter 1
  - LTC technical report methodology addresses the ECCS cooling after recirculation is established
  - LTC methodology assumes subcriticality; return to power addressed in DCD Section 15.0.6
- Phase 2 SER included OI (UOI:15.0.5-2) as LTC technical report had stated cooling was demonstrated to 30 days
  - NuScale revised statement and staff SER documents review to 72 hours
- FOM include minimum collapsed level, minimum RPV temperature, to preclude boron precipitation, and maximum cladding temperature
- All FOM met acceptance criteria

Changes to Design in Phase 4

- Staff reviewed impact of design/method changes on Chapters 6 & 15 during Phase 4
  - NRELAP5 v1.4 & NPM Model Rev. 2 (UOI: OI 15.0.2-1)
  - ECCS Actuation Logic (UOI: OIs 15.0.0.4-1, 15.6.5-1)
  - IAB block/release pressure
  - DHRS Logic (UOI: OIs 15.0.0.4-1, 15.6.5-1)
- Updated analysis results provided for impacted events in DCD Rev. 3
  - Staff audited revised calculations

Changes to Design in Phase 4

NRELAP5 and NPM Base Model changes (NRELAP5 v1.4, Base Model Rev. 2)

- Reviewed by staff in LOCA topical report during Feb. 19, 2020 ACRS subcommittee meeting

ECCS Logic changes

- Removed actuation on riser low level
  - Actuation only on either loss of DC power, high CNV water level, or low AC voltage after 24 hrs, or “new added logic per NS cond. Report”
- CNV water level ECCS trip increased by 24” but now decreased per “cond. Report”

IAB Block/Release Pressure changes

- IAB release 950 psid (±50 psi), IAB blocks ≥ 1300 psid

DHRS Logic changes

- DHRS signal split into two signals (DHRS actuation and Secondary isolation (SSI))
- Direct DHRS actuation inputs reduced from 13 to 4 signals, high (1) RCS press, (2) temp, (3) steam press, and (4) low AC voltage to batteries, function opens DHRS valves and closes primary and secondary MSIV and bypass, MFIVs and MFRVs
- Allows better operator control at startup, reduce frequency of actuation
- Delays DHRS actuation until much later in transient; min change to Chapter 15 FOM margins

Changes to Selected LOCA Analyses

Chapter Event	Figure of Merit	DCA Rev. 2 Value	DCA Rev. 3 Value	Acceptance Criteria Limit
15.6.5 (LOCA-DBE)**	MCHFR	1.80	1.72	1.29
	Min CLL (ft)	0.14	1.7	>TAF
15.6.6 (IORV-AOO)**	MCHFR	-	1.32	1.13
	Min CLL (ft)	-	10.2	>TAF
6.2 (Cont. Design)**	Peak Pressure (RRV) (psia)	951	994	1050
	Peak Temperature (Inj line brk) (°F)	-	526	550

** To be evaluated for impact of ECCS setpoint change

Note: some Chapter 15 events will require re-analysis for LTC related to ECCS setpoint change and boron redistribution

Changes to Selected Non-LOCA Analyses

Chapter Event	Figure of Merit	DCA Rev. 2 Value	DCA Rev. 3 Value	Acceptance Criteria Limit
15.1.5 - Steam Line Break (PA)**	MCHFR	1.861	1.866	AOO: 1.284*
	Maximum RCS Pressure (psia)	2156	2081	AOO: 2310* PA: 2520
	Maximum SG Pressure (psia)	1346	1495	AOO: 2310* PA: 2520
15.4.3 - Control Rod Misoperation (Misalignment) (AOO)	MCHFR	2.509	1.437	1.284
15.4.7 - Inadvertent Loading and Operation of a Fuel Assembly in an Improper Position (AOO)	MCHFR	1.916	1.437	1.284

* Although a steam line break is a postulated accident, it meets the AOO acceptance criteria.

** To be evaluated for impact of ECCS setpoint change

ECCS Design: Water Hammer & follow-up testing

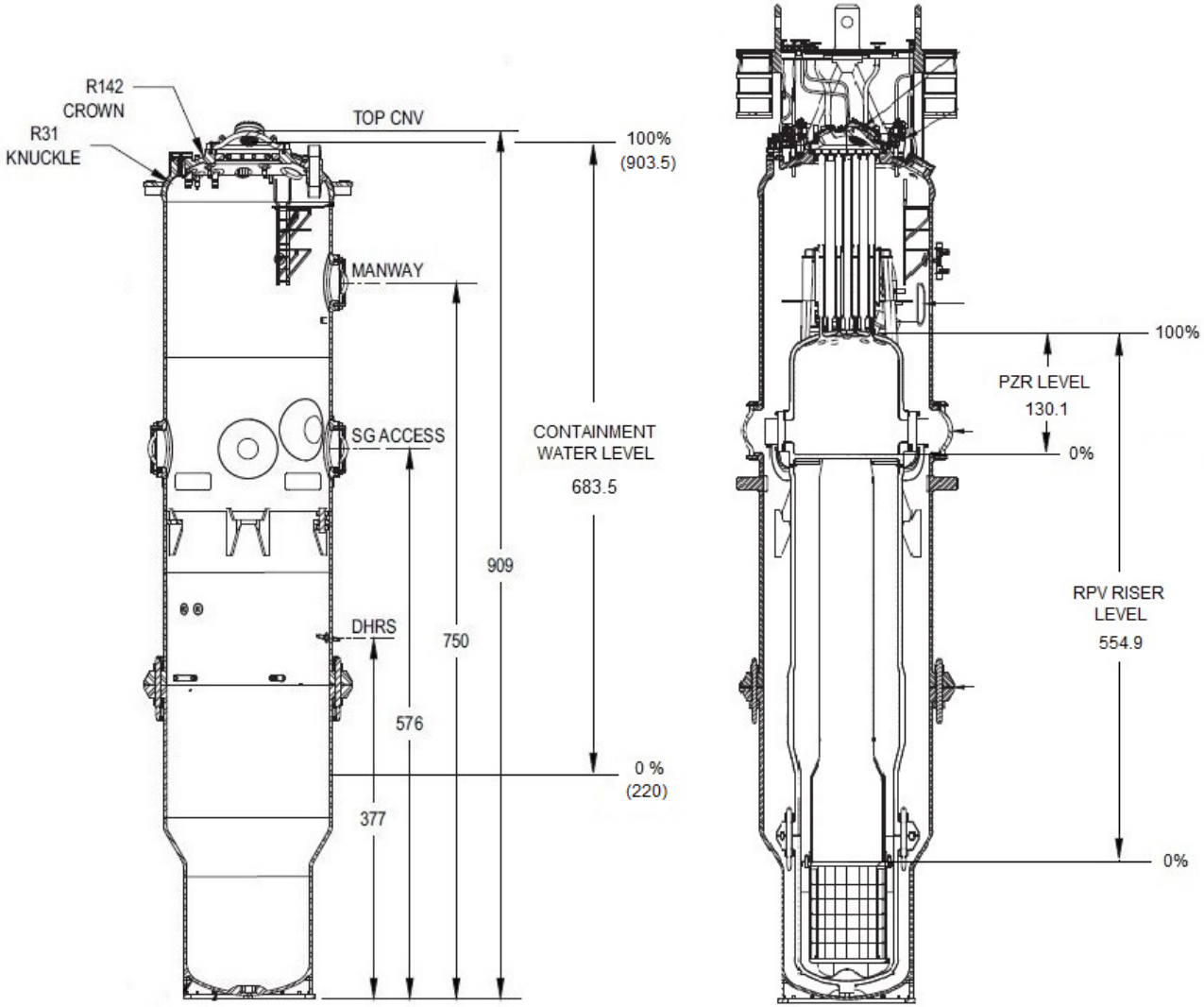
- ECCS Valves Trip Valve Hydraulic Line
  1. Different trip valve hydraulic line length for each valve
  2. Fluid inside the lines experiences two-phase flashing
  3. Staff requested full scale, high temperature and high pressure tests to confirm no water hammer effects
- NuScale has stated that the temperature of the ECCS valves and their hydraulic lines will remain above the precipitation temperature of boron during plant operation.
- NuScale plans to flush the ECCS valves and their hydraulic lines during each refueling outage to remove any particulates that might unexpectedly accumulate during plant operations.

CNV and RPV Level Instruments

Level Transmitter	Indicated Range (Span) [Process Range]	Nominal (100% RTP)	Function	Safety & Risk Classification
Containment Water Level	0 to 100% (683.5 Inches) [approx. 220 to 903.5 Inches[1]]	0%	ECCS Actuation 264" to 300"[2] High Level L-1 Interlock >540" & RT-1 active (Reactor Trip Breakers Open) PAM Variable Type B, C, D	A1
Pressurizer Level[3]	0 to 100% (130.1 Inches) [Full height of PZR]	50%	Reactor Trip 80% High Level 35% Low Level Secondary Sys Isolation 20% Low-Low Level Containment Sys Isolation 20% Low-Low Level Demin Water Sys Isolation 80% High Level 35% Low Level CVCS Isolation 80% High Level 20% Low-Low Level Pressurizer Heater Trip 35% Low Level L-2 Interlock >20% & T-3 active (RCS T_{hot} <350°F)	A1
RPV Riser Level	0 to 100% (554.9 Inches) [Top of upper core plate to top of PZR]	100%	PAM Variable Type B, C, D	B2[4]

[1] Levels are reported in terms of module elevation with the global zero elevation at the bottom of the reactor pool.
[2] The ranges allow ±18" from the nominal ECCS level setpoint of 282" **TBD based on cond. report**
[3] Common Level Transmitter is used for Pressurizer Level and RPV Riser Level
[4] Common Level Transmitter is used for Pressurizer Level and RPV Riser Level. However, function of RPV Riser Level is classified as B2

CNV and RPV Level



Acronyms

- AC alternating current
- ACRS Advisory Committee on Reactor Safeguards
- AOO anticipated operational occurrence
- ATWS anticipated transient without scram
- BOC beginning of cycle
- CLL collapsed liquid level
- COL combined license
- CNV containment vessel
- CVCS chemical and volume control system
- DBA design basis accident
- DBE design basis event
- DCA design certification application
- DHRS decay heat removal system
- ECCS emergency core cooling system
- EDSS highly reliable dc power system
- EOC end of cycle
- FOM figure of merit
- FSAR final safety analysis report
- GDC general design criteria
- IAB inadvertent actuation block
- IORV inadvertent opening of a RPV valve
- LOCA loss of coolant accident
- LTC long term cooling
- MCHFR minimum critical heat flux ratio
- MOC middle of cycle
- MPS module protection system
- MFIV main feedwater isolation valve
- MFRV main feedwater regulating valve
- MSIV main steamline isolation valve
- NPM NuScale Power Module
- OI open item
- PA Postulated Accident
- PDC principal design criteria
- PZR pressurizer
- RCS reactor coolant system
- RPV reactor pressure vessel
- RSV reactor safety valve
- RTP rated thermal power
- RTNSS regulatory treatment of non-safety systems
- SAFDL specified acceptable fuel design limits
- SER safety evaluation report
- SG steam generator
- SRP standard review plan
- TAF top of active fuel
- UOI unclear open item

United States Nuclear Regulatory Commission

Protecting People and the Environment

Presentation to the ACRS Committee

NuScale Power, LLC (NuScale)

Design Certification Application Review

Safety Evaluation with No Open Items:
H_2 and O_2 Post-accident Monitoring

8 April 2020

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Technical Reviewers:

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Michelle Hart, NRR/DANU/UART

Project Managers:

Greg Cranston – Lead Project Manager
Getachew Tesfaye – Chapter Project Manager

Focus Area - ACRS AST letter

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Need for long-term post-accident H_2 and O_2 monitoring.

Informs the timing of the following actions:

- Inert the containment atmosphere with nitrogen via CVCS and DNS
  or
- Vent the containment during accident conditions (i.e., routing the gas either to the plant exhaust stack (RBVS) or to the gaseous radwaste system (GRWS).

Confirms success of above mitigating actions

Inform the actions in the EOP and the severe accident management guidelines (SAMG)

ACRS AST letter and related topics

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Need for long-term post-accident H_2 and O_2 monitoring.

Informs the timing of operator action **to avoid**:

Risking an impulse pressure to the inside of the CNV, which, at 45 days:

- would be approximately double the impulse pressure at 72 hrs, and
- could lead to CRDM access flange (CNV25) bolt load exceeding the ASME Service Level D strain limits

Risking an uncontrolled release to the public.

Focus Area - ACRS AST letter

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Capability of the design for accurate long-term post-accident H_2 and O_2 monitoring.

The H_2 and O_2 monitoring closed loop flowpath is established by:

- Confirming CNV pressure is < 250 psig (design pressure of CES, PSS, and CFDS)
- Unisolating the CES and the CFDS CIVs
- Creating a flow path from the CNV via CES through the PSS sample pump and in-line gas monitors, and returning to the CNV via CFDS.

This flowpath, except for the CIVs, is non-safety related, as is acceptable for equipment specifically used for mitigating a severe accident, per SECY-90-016, Equipment survivability.

Focus Area - ACRS AST letter

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Comments about the rationale for long-term post-accident H_2 and O_2 monitoring in 20 December 2019 ACRS letter

(Item b):

- Weeks are available before monitoring information is needed to inform mitigating actions.

Staff elaboration:

- Combustible mixtures (5% O_2) would occur by 45 days post-accident
- The minimum concentration (4% O_2) would occur by 30 days
- Prior to reaching combustible mixtures (O_2 > 3%) would occur in 15 da

(Item d):

- other pressure, temperature and radiation sensors available to follow severe accident progression

None of these components indicates potential for combustion of gases.

Focus Area - ACRS AST letter

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ACRS comments about alternatives to long-term post-accident H_2 and O_2 monitoring that don't unisolate the containment

The options for actions which prevent combustible/detonable conditions in containment all include reopening isolation valves:

- Inerting by injecting N_2 into the containment via the CVCS

  or
- Venting the containment by using the CES system and directing the gas to the RBVS stack or the GRWS

No alternatives have been provided or identified by NuScale to obtain the concentration in containment of the combustibles, H_2 and O_2 without unisolating the CNV.

Focus Area Topics

U.S.NRC
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Post-accident monitoring of O_2 and H_2 risk evaluation

Operator action to prevent H_2 combustion →DDT	Time for operator action	H_2O_2 monitoring path isolable?	Prevent DDT pressure pulse	Result
vent CNV via CES+RBVS	3days< t <15 days	yes	yes	Opening CNV will not lead to large release
inert CNV via CVCS+DNS	3days< t <15 days	yes	yes	Opening CNV will not lead to large release
take no action	N/A	N/A	no	potential failure of CRDM access flange bolts after 15 days

Focus Area - ACRS AST letter

- The staff believes that the information obtained from monitoring is beneficial in assisting operators in making decisions following an accident.
- The staff does not currently have enough information from NuScale such as system flow rate, system leakage rate, ventilation flow rate, room volumes, the specifics of the piping and equipment, etc., to be able to estimate the dose to an individual performing actions to re-isolate the systems.
- Therefore, the staff believes that at this stage of licensing the best path forward is to retain the rulemaking carveout.

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Probabilistic Risk Assessment

NuScale Design Certification Application

ACRS Full Committee Meeting
April 8, 2020

Topics

- PRA review status
- Summary of March 3, 2020 Meeting
  - DC PRA uses and limitations
  - ECCS model
  - Sensitivity and uncertainty analyses
  - Reactor building crane operations

PRA Review Status

- PRA Staff is engaging with NuScale on potential PRA impacts (including multi-module risk) from:

  (1) anticipated design changes for boron redistribution issues

  (2) events leading to riser uncovery

- PRA Staff will finalize its findings on the NuScale PRA after evaluation of the submitted DCA changes.

DC PRA Uses

- Verify applicant documented risk-informed insights
  - The design's robustness, levels of defense-in-depth, and tolerance of severe accidents initiated by either internal or external events
  - The risk significance of potential human errors associated with the design
- Determine how risk compares against Commission's goals of less than 1x10-4 per year for CDF and less than 1×10-6 per year for LRF.
- Use results and insights to support programs such as RTNSS, ITAAC, RAP, TS, COL action items, and interface requirements.
- Staff findings are made to support Commission's objectives for use of PRA in design.

Availability of Information at Various Licensing Stages

Information Availability	Licensing Stage: DC Applications 52.47(27) COL Applications 52.79(46)	Licensing Stage: COL Holders 50.71(h)(1) "fuel load PRA"	Licensing Stage: COL Holders 50.71(h)(2) 1st four-year update
• Site-specific information	Unknown for DCs/Known for COLs	Known	Known
• Layout, cable routing, equipment capacities	Not fully known	Known	Known
• Plant-specific operating guidance	None	Available	Available
• Plant operating experience	None	None	Available
• Trainers or operations staff with plant-specific experience	None	None	Available
• Walkdowns	Not possible	Possible	Possible
PRA acceptability guidance	• RG 1.200, as modified by DC/COL-ISG-028	• RG 1.200 • Portions of DC/COL-ISG-028 are still relevant	• RG 1.200 • DC/COL-ISG-028 not applicable

ECCS Model

- Assumptions are used to address issues associated with level of detail, completeness, and data
- System/component reliability data is uncertain due to unavailability of design-specific operating experiences
- Staff evaluated assumptions for impact on safety findings made for the DCA
- Staff is evaluating potential PRA impacts of ECCS actuation logic change

Sensitivity and Uncertainty Analyses

- Sensitivity and uncertainty analyses have been performed to support regulatory findings
- NuScale identified important SSCs, operator actions, and risk insights to support programs such as DRAP and human factors engineering
- Focused PRA showed Commission goals met without credit for SSCs that are not safety-related
- Additional analyses will consider additional risk insights and inputs to operational programs expected at DC stage, if any

Reactor Building Crane Operations

Calculated drop probability dominated by:

Operator errors (over speed, over raise, etc.)

AND

Failure of instrumentation (interlocks/switches) for safety stop

Key Assumptions for the LPSD PRA added to DCA, Rev 4, Table 19.1-71

1. Movement of the RBC is modeled as being operator controlled
2. Administrative controls will ensure that RBC safety features (e.g., limit switches, interlocks to prevent undesired movement) are functional during module movement

Validity of RBC assumptions in DCA and crane data supporting the PRA will be confirmed by COL applicant per COL item 19.1-8

RBC is within scope of human factors process during COL per “Human Factors Engineering Design Implementation Plan” (Report RP-0914-8544)

Risk significance of RBC resulted in additional ITAACs

Abbreviations

- **ASME** – American Society of Mechanical Engineers
- **CDF** – core damage frequency
- **CIV** – containment isolation valve
- **COL** – combined license
- **CVCS** – chemical and volume control system
- **DC** – design certification
- **DCA** – design certification application
- **DHRS** – decay heat removal system
- **DRAP** – Design Reliability Assurance Program
- **ECCS** – emergency core cooling system
- **EPZ** – emergency planning zone
- **ITAAC** – Inspection, Test, Analysis, and Acceptance Criteria
- **ISG** – Interim Staff Guidance
- **LPSD** – low power and shutdown
- **LRF** – large release frequency
- **PRA** – probabilistic risk assessment
- **RAP** – Reliability Assurance Program
- **RBC** – reactor building crane
- **RG** – Regulatory Guide
- **RSV** – reactor safety valve
- **SER** – safety evaluation report
- **SRP** – standard review plan
- **TS** – Technical Specification