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NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
566th Meeting

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Thursday, October 8, 2009

Work Order No.: NRC-3134 Pages 1-322

NEAL R. GROSS AND CO., INC.
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1323 Rhode Island Avenue, N.W.
Washington, D.C. 20005
(202) 234-4433

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARD

(ACRS)

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566th MEETING

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THURSDAY, OCTOBER 8, 2009

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ROCKVILLE, MARYLAND

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The Committee convened at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Dr. Mario Bonaca, Chairman, presiding.

COMMITTEE MEMBERS PRESENT:

MARIO V. BONACA, Chair

SAID ABDEL-KHALIK, Vice Chair

J. SAM ARMIJO, Member-at-Large

GEORGE E. APOSTOLAKIS

SANJOY BANERJEE

DENNIS C. BLEY

CHARLES H. BROWN, JR.

MICHAEL CORRADINI

COMMITTEE MEMBERS PRESENT: (cont)

OTTO L. MAYNARD

DANA A. POWERS

HAROLD B. RAY

MICHAEL T. RYAN

WILLIAM J. SHACK

JOHN D. SIEBER

JOHN W. STETKAR

NRC STAFF PRESENT:

SAM DURAISWAMY, Designated Federal Official

TOM KEVERN

AMY CUBBAGE

MARK McBRIDE

WEIJUN WANG

TOM SCARBROUGH

LARRY WHEELER

NEIL RAY

GEORGE GEORGIEV

JERRY WILSON

SAMSON LEE

GLENN MEYER

DAVE PELTON

EMMA WONG

DAVID BEAULIEU

NRC STAFF PRESENT: (cont)

TIM McGINTY

CHRISTOPHER BOYD

TIM LUPOLD

LOUISE LUND

HANS ASHER

TIM O'HARA

KAMAL MANOLY

ALSO PRESENT:

MARVIN SMITH

GINA BORSH

GEOFF QUINN

DOUG KEMP

JOHN KRAIS

DAVE FLYTE

DALE ROTH

DAN MILLER

CHRIS HOFFMAN

MIKE GALLAGHER

JOHN O'ROURKE

CLARENCE MILLER

PETE TAMBURRO

STAN TANG

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8:28 a.m.

CHAIR BONACA: Good morning. The meeting will now come to order. This is the first day of the 566th Meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the committee will consider the following: Combined License Application for North Anna, Unit 3, Economic Simplified Boiling Water Reactor (ESBWR) and the Draft Safety Evaluation Report with Open Items; License Renewal Application and Final Safety Evaluation Report for the Susquehanna Steam Electric Station, Units 1 and 2; Steam Generator Action Plan Task 3.5, A Risk Assessment of Consequential Steam Generator Tube Ruptures, and other SGAP items; Oyster Creek 3-dimensional structural analysis of the drywell shell; Preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Sam Duraiswamy is the designated federal official for the initial portion of the meeting. We have received no written comments or requests for time to make oral statements from members of the public regarding

today's session. There will be several people on the phone bridge line to listen to the discussion regarding the North Anna COL application and the Susquehanna new license renewal application. To preclude interruption of the meeting the phone will be placed in a listening mode during the presentations and committee discussions. A transcript of portions of the meeting is being kept and it is requested of the speakers, use one of the microphones, identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

I will begin with the items of current interest. On behalf of the committee I would like to thank everyone involved in the completed construction-related work in the conference room in a timely manner so as to hold our meeting in this very comfortable room. There was - up to the last minute we didn't know if we could have the meeting here rather than in the commissioner's room. So I would like to introduce John Lai. Okay. A risk analyst who's on rotation to the ACRS staff from the Office of New Reactors. In New Reactor he was reviewing the ESBWR, the CPRA and COL application for North Anna, Fermi and

South Texas bridge project. Prior to joining NRC in May 2006 he worked at Public Service Electric & Gas Company as a probabilistic assessment engineer since 1995. His other employment includes working at PSEG Nuclear as a nuclear fuel engineer, Solumbra Company as a lead engineer and Brookhaven National Laboratory as a research associate. He has 30 years of experience working in the nuclear area. He holds a BS in Nuclear Engineering from Tsing Hua University in Taiwan, an MS in Nuclear Engineering from the University of Cincinnati, and a Ph.D. from Drexel University in Mechanical Engineering. Welcome aboard.

(Applause)

CHAIR BONACA: With that we are done for the introductions and I think we should move to the next item on the agenda which is the combined license application for North Anna, Unit 3, Economic Simplified Boiling Water Reactor and the Draft Safety Evaluation Report with Open Items. And I turn to Dr. Corradini.

MEMBER CORRADINI: Thank you, Mr. Chairman. So today we have a presentation by the staff and the applicant for the first COL of I assume a few others coming down the road. This

references the ESBWR. Many of you have - either are part of the subcommittee for the ESBWR or have attended in a rotating fashion. I guess I want to frame this. Tom Kevern will lead us off, but before I turn to Tom let me just frame this. The one thing that I want to put kind of as an undertone here is that we're running essentially two parallel efforts. One is to essentially finish the design certification. We now have issued a number of interim letters and the staff is coming back to close out open items with General Electric Hitachi. Simultaneously we have started the COL. So what we're going to hear today from the staff and the applicant, that is Dominion, is the COL application and open items and issues relative to the site at North Anna, rather than generic issues relative to the ESBWR. So I welcome your questions, but I will be - since we have limited time I will be fairly quick to point out when something's generic, and we'll log it, and we'll see you in middle October or middle November for our fun subcommittee meetings for ESBWR. But I think we ought to stay on track relative to things related to North Anna. So with that I'll turn it to Tom.

MR. KEVERN: Thank you. Good morning. My name is Tom Kevern. I'm the lead project manager for North Anna. With me is Janelle Jessie, another North Anna project manager. On behalf of the staff we appreciate the opportunity to meet with the full committee this morning. We have a rather full agenda you see on the slide. We're going to have presentations by several of the members of the staff as well as representatives from Dominion. So in the interest of time, rather than going through introductions now I'll defer that until we're doing the respective presentations and just start right in with the first presentation and that is the overview by Dominion. And I'd like to introduce Marvin Smith who's the project director for Dominion North Anna.

MR. SMITH: Good morning. I'm Marvin Smith as Tom indicated and I'd like to - next slide please, thank you. This is certainly not the first time that we've been here. North Anna 3, our process started some time ago with the filing of an early site permit application in 2003 as indicated here. Our ESP was issued and our COL application filed on the same day in November of

2007. So as indicated earlier, the focus here today is on the North Anna site and the interface with ESBWR and not on the generic issues associated with that. And the North Anna COL is also interesting in that it is, as indicated here, one that referenced an approved early site permit when it was filed. So many of the siting issues associated with North Anna were considered previously as part of that early site permit process. The draft actual supplemental EIS was issued in 2008 and we submitted COLA Revision 1 in December of 2008 as well. So this application has been under consideration now for some time.

We've had several subcommittee meetings and we've I think been here for four different days, three different meetings with the subcommittee and we certainly appreciate the thorough review that you've given. So as you can see this shows where we covered various chapters of the COL application during those meetings. North Anna Power Station currently has two operating units, Units 1 and 2. Those are both Westinghouse-designed PWR units. The site is located in central Virginia. It's approximately 35 miles northwest of the city of Richmond and as

I say, it has been the subject of the early site permit investigation that was already completed. The North Anna Units 1 and 2 and the proposed Unit 3 are located on the North Anna Power Station site. And Lake Anna, that's the cooling water for source for Units 1 and 2. Unit 3, however, will not use the lake for cooling other than as - the only use of the lake for Unit 3 would be as makeup water to the cooling circulating water system. North Anna - Lake Anna is also not used for Unit 3 in any safety-related manner.

As shown on this slide, the proposed Unit 3 is located to the west and slightly south of where the Units 1 and 2 are. As you can see, it's oriented in such a way that the rotating turbine is not in the direction that would potentially send anything towards Units 1 and 2. We have a proposed cooling system that's shown in the figure here. It's actually a hybrid circulating water cooling system that's partially wet, partially dry and we did that in order to minimize the water consumption associated with the operation of Unit 3. So we've been through quite a lot of environmental work to look at this site, again, beginning with the early site permit and

then continuing through the COL application. So if there are any general questions I'd be happy to address them. Thank you.

MR. KEVERN: Okay, thank you Marv. Next I'll be doing an overview from the staff's perspective. As you can see on this slide, we completed the Safety Evaluation Report with open items. That consists of the standard 19 chapters plus the applicable appendices. That was transmitted to ACRS by a memorandum from the Office of New Reactors early August and it is publicly available. And the ADAMS accession number you see there in the slide provides access to that through ADAMS on the public availability.

The application as Marv mentioned not only incorporates by reference the DCD Revision 5 and also the early site permit, but also it included acceptable responses to most of the staff's requests for additional information that were issued up to November of last year. So on the schedule we had, what we call Phase I, our initial review and issuance of requests for additional information. That occurred from the November 2007 to roughly November 2008 timeframe. The Revision 1 of the application came in in

December. That incorporated - or I'm sorry, acceptable responses to the majority of those RAIs. So then after that timeframe we had another 10 months of additional review, follow-up from the original RAIs as well as the content of that Revision 1 of the application.

The meetings that Marv mentioned, I'd like to emphasize that those subcommittee meetings in June, July and August were focused solely on the North Anna review as just emphasis of what Dr. Corradini said earlier. There are separate subcommittee meetings that have been and are being and will be conducted associated with the design certification review, but those meetings and the content of those meetings has focused solely on the North Anna COL application, our evaluation, the staff's evaluation of that application.

Significant point here at the bottom of the slide. There were no significant issues identified in those four days of meetings. There were of course a number of questions and comments from all members of the subcommittee I guess I'd say, and those questions and comments were addressed either during a meeting by the staff or by Dominion as appropriate. In several cases we

had written responses the staff provided to clarify information and then some of the issues, as Dr. Corradini alluded to, were determined to be more appropriate for actual design certification issues and part of the generic design rather than specifically applicable to the North Anna COL application. So that gives us a history and that brings us up to today and today's presentation.

So then around to subcommittee meetings and today we're going to focus on three different - actually four different topics: an update of the open items that the staff has at this point in time. It'll be a snapshot as of today. We're going to be discussing several selected site characteristics that will illustrate the relationship between the COL application and the design certification document and the early site permit. We'll discuss several selected site-specific systems that will illustrate again the relationship between the COL application and the DCD. And then we're going to provide clarifying and updated information to address several of the inquiries that the subcommittee members identified during the meetings in June, July and August.

For the technical presentation today

we're going to follow the format of first it'll be Dominion speaking and addressing the content of the FSAR, and then the staff speaking and addressing our evaluation of that part of the FSAR. And then last and not least I want to reiterate what Dr. Corradini said. We appreciate the opportunity to be first. So far it's been a challenging experience that I hope it continues this morning with no pitfalls or miscommunications among us and that we're having a good meeting as we move on. So that concludes the overview from the staff's perspective. Any questions, comments before we start the more meat of the presentations?

All right, so moving on. I'll continue to talk. The first topic we have is an update of the open items. First bullet on the page identifies the one significant open item we have relative to the North Anna review and that is the staff's evaluation of the ESBWR design certification. That evaluation is not yet complete, again reiterating what Dr. Corradini said in his opening comments. And as we all know when we are implementing the Part 52 process the staff cannot finalize the North Anna safety

evaluation until the staff has finalized the evaluation for design certification. So for administrative convenience - we acknowledge that of course, but then for administrative convenience we identify that as Open item 1-1 in Chapter 1 of our Safety Evaluation Report and then cross-referenced throughout the remaining 19 chapters to that single open item. So that one open item is the meat if you will, it's the big-ticket item and you'll see it just listed once rather than numerous times. And I believe that's the protocol that all of the rest of the design centers are going to follow. So it makes it more administratively convenient than getting bogged down with a multitude of open items and RAIs.

Moving on to the specific RAIs. The staff documents and tracks our requests for additional information in our electronic RAI database. And what you see on the next slide is a download from that database. It identifies the open items, open RAIs for North Anna up to this point in time. And on the slide it looks - the font's a little small, but that is the best I could do to get all of the RAIs listed. The ACRS members have a full-size page in your handout and

the rest of the attendees, if you go to the back page of your handout you'll see a full-size page there listing that puts it in a more legible or a more readable format.

I'll make a couple points. These open RAIs are a snapshot at this point in time. They do not reflect significant challenges and actually from the staff's point of view, our perspective is that all of the open RAIs are on a path toward resolution. Several of the RAIs are going to be addressed in the respective technical presentations this morning, those associated with Section 2.4 Hydrology, 2.5, 3.9, 3.11 and 9.2 Plant Service Water are all going to be addressed in technical presentations and I want to just comment on a few of the others. In SAR Section 5.3.2 dealing with pressure temperature limits. We currently have seven open RAIs and those - the sum in there is a little bit disproportionate considering the total number of RAIs that are open. I want to tell you why. That's because we just had a recent submittal back in mid-June from the applicant on this topic that is a supplement to their application. Staff reviewed that just recently and issued RAIs. Seven is the sum total

you can see on that subject from the staff and that pressure temperature report was something that was discussed in a subcommittee meeting with either Kurt or - and Kurt's copy to ACRS and that's why I wanted to bring that up as a current status.

In 13.3 Emergency Planning, FEMA, external to the review that the staff does for offsite emergency planning, FEMA has identified multiple RAIs as part of their review that are currently being addressed by the applicable offsite entities with support from Dominion as a result of those RAIs.

MEMBER CORRADINI: Are we going to get back to those later today? I was looking.

MR. KEVERN: No, sir.

MEMBER CORRADINI: Okay. So let me ask a question here. So, how does - what's the process there? Are you guys - is the staff working as kind of - I'm trying to find the right word here - facilitators between FEMA and the applicant to identify significance of these issues, or is it basically the applicant and FEMA are working this out and you're observers to the process? How does that work with these?

MR. KEVERN: Short answer is the latter.

MEMBER CORRADINI: Okay.

MR. KEVERN: We're observing. You recognize as -

MEMBER CORRADINI: So in that role, are you seeing any issues there that are going to be a problem, or is it a matter of clarification of what - matter of clarification of what the applicant is presenting and FEMA is asking?

MR. KEVERN: It's closer to the latter, but I would not say they're insignificant. I mean, it requires some work for updating, clarifying content of the plans and procedures that FEMA thinks appropriate for implementing their emergency planning requirement. But it is - in fact, I'll give Dominion an opportunity to speak. As far as we know it's on schedule, they're on schedule to be completed and resolved by the end of this month.

MEMBER CORRADINI: So there's a path to resolution I guess is maybe the way to ask this?

MR. SMITH: Yes, there is.

MS. BORSH: Right, they're - I'm Gina

Borsh from Dominion. There are - we've had meetings with FEMA and the Commonwealth and Dominion because of the RAIs obviously are really associated with the Commonwealth's work and their plans. So we have a path forward to answer all of them and we are on schedule for completing the work in October.

MEMBER CORRADINI: Okay, thank you.

MEMBER MAYNARD: Are you having to do things differently from emergency planning-wise for the ESBWR than you are for the other plants there?

MS. BORSH: Generally, no. Most of the questions that we got were clarification - from FEMA were clarifications. Are you talking about the FEMA RAIs or are you talking about Dominion's plan?

MEMBER MAYNARD: Well yes, with FEMA, yes.

MS. BORSH: Yes. Most of them were clarifications and resolving some inconsistencies between the high-level plan and the procedures. But let me just check and see if our subject matter expert is on the line.

MR. KEVERN: Let me clarify part of

that. From the staff's perspective, the way the technical staff has explained it to me, let me see if this answers the question, sir. As part of the - the answer is no, nothing additional, but as part of FEMA's looking at the new COL application, they did an in-depth review of everything associated with emergency planning around the site. And in the process of that review they found - trying to be tactful on this - they found some items that were not meeting their expectations that and that were not identified previously during exercises or during other evaluations. Because this is the first time FEMA had done that level of an in-depth review of everything related to offsite planning in the last several decades.

MEMBER MAYNARD: Okay. So it's not just unique to the ESBWR design. Okay.

MEMBER CORRADINI: Thank you. Go ahead, sir.

MR. KEVERN: Then in 13.6 related to security the staff is just in the middle of their ongoing review in the security area and there are multiple RAIs that have been and are being generated by the staff in that security area, and

just - it lists all of those.

VICE CHAIR ABDEL-KHALIK: Back to the FEMA interface. At the end of the day NRC is the agency that approves this application.

MR. KEVERN: Correct.

VICE CHAIR ABDEL-KHALIK: So, in your role as an observer of the interaction between FEMA and the applicant, at the end of the day are you just going to take their word that whatever has been done and agreed to is acceptable to you?

MR. KEVERN: FEMA is the lead for offsite planning from a federal oversight perspective. They - FEMA provides a detailed report to the NRC. NRC takes that report and that information provided by FEMA as input for the staff's determination of the adequacy of emergency planning, and then as part of -

VICE CHAIR ABDEL-KHALIK: Let's go to the heart of my question.

MR. KEVERN: What is it?

VICE CHAIR ABDEL-KHALIK: What level of detail in terms of review does the staff add to this process after FEMA issues its report?

MR. KEVERN: We do not re-evaluate FEMA. What we do have, though, are an extensive

number of inspection tests analysis and acceptance criteria, ITAAC, that occur after a license is issued and before the plan is authorized to do power operation that involve exercises with extensive objectives, both onsite and offsite activities. Is that sufficient or do you want more detail? I have a member of the staff here, but I was not -

VICE CHAIR ABDEL-KHALIK: I think that's sufficient for the moment. Thank you.

MR. KEVERN: Okay. Then moving down, the second to the last bullet on the previous slide there, talking about Chapter 16. This is the technical specifications. The staff issued one multifaceted RAI that pertained to finalizing the completed plant-specific detail specifications and parts of that RAI are yet to be completed. And this also ties back into the information and the updated design certification document for ESBWR. And then the last item, again, it's a note, a follow-on to a previous subcommittee meeting on turbine missile probability analysis. The applicant recently provided a submittal, late July. We provided a courtesy copy to the ACRS members at their request and there were a number

of inquiries back in the last subcommittee meeting. The staff is just starting its review of that topic and the, I won't say likely, maybe, whatever term you want to use, RAIs pertaining to that. And we'll have that process completed over the next several months.

MEMBER STETKAR: Tom, for clarification, will those RAIs be issued under the COL, or is that - I thought that we were told that that turbine missile analysis was folding over into the DCD? Is that true, or is it actually the COL applicant's responsibility now?

MR. KEVERN: It is the - let's see if I can clarify this. It is a little confusing. It is a document that was prepared by GEH. It was submitted as part of a COL item in the North Anna COL application and so we are reviewing it as part of the COL application.

MEMBER CORRADINI: And the reason is because of the geometrical arrangement? I guess I - is it that? Because I know it was partly a material - an estimation of the jet missile generation and also the effect. So is it just because the history of how it came to here that it's not generic and back with the DCD? That's

what I'm - I think John's -

MEMBER STETKAR: Well, the reason I ask is when we brought up the question in the subcommittee meeting, several of the questions that we had related to their treatment of the turbine protection and control system reliability. There are also materials issues and at that time it was my understanding we were told, well, that's going to be resolved, it's a generic design issue, it's not part of the COL applicant. So we sort of dropped the line of questioning at that time.

MR. KEVERN: Well, that may be true, but it is a GEH turbine. But there is a COL item identified in the COL application that this - the submittal of this document addresses that COL - meets that, satisfies that COL commitment. So we are currently reviewing it under North Anna application.

MEMBER STETKAR: I guess the question is is GEH going to - I mean, is every COL applicant going to submit precisely the same document? No one responds to their commitment.

MEMBER CORRADINI: I guess that's a process question that maybe we can address later. But I mean, my thinking would be if they take it

on now and get it cleared up I would R-COLA it, go back to the DCD and get cleared up generically so no other applicant has to deal with it.

MS. CUBBAGE: This is Amy Cubbage, the design cert project manager with NRL. It's not planned to come into the design certification. If a subsequent COL applicant chose to follow the same approach as the reference COLA, then we've done one review and we've completed that review. If they chose to deviate from what the reference COLA did then we would have to review that applicant's report. And it just happens that this report that's being provided by Dominion was prepared by GE Hitachi, but it's not part of the design certification review.

MEMBER CORRADINI: Amy, just for our clarification. And that's because it's part of the secondary system that could be different with every - is that the point I guess I'm trying - I think we're still trying to understand how it fell where it did.

MS. CUBBAGE: I think we'd have to ask the applicants why they chose to do this on a COL-specific basis, but it was identified as a COL action item in the DCD, therefore it's the

responsibility of the COL applicant.

MEMBER CORRADINI: Okay. Is that enough for now, John?

MEMBER STETKAR: I guess that's enough for now, yes.

MEMBER CORRADINI: All right, thank you.

MR. KEVERN: All right. Sorry I couldn't make that more clear. I hate to ask are there other questions? That's the end of the discussion I was planning on presenting on requests for additional information.

MS. CUBBAGE: I guess what I will offer, Tom, is that if there was confusion at the time of the subcommittee on the scope and where this review is going to take place, so the ACRS didn't get to fully vet your questions on this report that had recently been submitted. So you know, those questions could come at the next phase. You haven't seen an evaluation yet of this report. And you will.

MEMBER STETKAR: That's correct. Okay, thank you.

MR. KEVERN: Let me just follow on to what Amy said. The next - it moves into the last

slide, but the next phase of our review, Phase IV, is after we finish the ACRS discussions then we move into the next part which is our review in the final safety evaluation report with no open items. So as part of that review process then we come back to ACRS. So if we come back and say we have no open items, you say oh wait a minute, why then we're back into the second round of meetings.

MEMBER CORRADINI: Okay.

MR. KEVERN: All right, so moving along, that ends the discussion on open items and the next topic is Section 2.4 Hydrology. Starting the technical topics. And we will have first Dominion and Gina Borsh with Dominion.

MS. BORSH: Okay. Thanks Tom. Good morning. Before we get started on 2.4 I just wanted to give you a little bit of an overview of how we prepared our COLA. As Tom and Marvin said, we incorporated the ESBWR DCD and the ESP applications SSAR by reference, so those are actually part of our FSAR content. Then we supplemented the information in the DCD and the SSAR from the ESP application to address the remaining requirements and guidance that are information that's required to be in our FSAR. So

most of the time the supplemental information that we added was added to either address a COL item that was in the DCD, a COL action item that was in our ESP or an ESP permit condition. And then we also added some actual design information for the site-specific portions of systems that are going to be included in the North Anna plant. And that replaced the conceptual design information that is in the DCD. And then finally we had supplemental information that we added for various other reasons. For example, Reg Guide 1.206 may have had some additional guidance on what should be in our FSAR and so we added information to address that guidance.

Chapter 2 in the FSAR is about our site characteristics. And as Tom said, we've selected two topics from Chapter 2 to present to you today to show you what kind of site-specific information is in our FSAR. 2.4 is on hydrology, 2.5 is geology, seismology and geotechnical engineering. Then we're going to talk about specific inquiries that came up from the ACRS members, the subcommittee members on makeup water systems, circulating water and plant service water.

In Chapter 2, just to give you a little background, we provided a summary of the comparisons that are related to the site features. We compared Unit 3 FSAR site characteristics and facility design values with the corresponding DCD, ESP or ESP Application SSAR values to determine if, one, the Unit 3 site characteristics fall within the DCD's site parameters; two, if Unit 3 site characteristics or facility design fall within the ESP site characteristics or design parameters; and three, do the Unit 3 site characteristics and design values fall within the SSAR site characteristics and design parameter values. That's all summarized up in 2.0 of the FSAR. Then we go into detail in the different sections to explain further what we summarized in 2.0 of the FSAR.

So for 2.4 I'm going to give you a brief overview of what is in that section of our FSAR. We incorporate the SSAR Section 2.4 by reference and then we supplement it with a lot of information. We added to address the DCD COL item. We state that the layout of Unit 3 will affect a few small wetlands and the upstream portions of two intermittent streams that flow

into Lake Anna. No other natural drainage features require changes to accommodate Unit 3. We also specify the design plant grade for safety-related structure systems and components which is at elevation 290 feet. This provides over 22 feet of freeboard above the design basis flooding level. Local intense precipitation is discharged to Lake Anna and we've located the safety-related structures systems and components at elevations that are above the maximum water surface elevation that would be produced by local intense precipitation.

The water supply to the alternate heat sink is above the design plant grade elevation and therefore it's capable of withstanding the probable maximum flood on streams and rivers without loss of the ultimate heat sink safety functions. To address two ESP COL items, we explain that the UHS for the passive design does not use safety-related underground reservoirs or storage basins. The UHS is in the reactor building. So even if Lake Anna were to be drained due to a dam failure, no safety-related structures or systems for Unit 3 would be adversely affected. We state that the emergency cooling water for

Unit 3 is provided from the UHS which isn't affected by ice conditions. We also go on in Section 2.4 to discuss ice impacts beyond the UHS.

To address an ESP COL item regarding whether Lake Anna is used for safety-related water withdrawals, we've included an explanation in the FSAR that the UHS for Unit 3 has water in place during Unit 3 operation for safety-related cooling in the event that use of the UHS is required. So as Marvin said, Lake Anna is not used for safety-related water withdrawals for Unit 3.

Another ESP COL item in Section 2.4 requires us to address slope embankment protection for the Unit 3 intake structure. We describe the location of the intake structure, including the fact that the embankment for the structure is protected by rip-rap to prevent local runoff from eroding the structure. We also note for the ESBWR design the intake structure is not safety-related. To address the DCD COL item, we performed a local PMP flood analysis. The maximum PMP water level in the power block area is 2.8 feet below the design plant grade elevation for safety-related facilities. Therefore, no safety-related

structure is subject to static or dynamic loading due to flooding as a result of design basis flood events or local PMP events.

To address another ESP COL item which deals with low water conditions in Lake Anna we added information to the FSAR to describe the two operating modes for the circulating water system, either energy conservation mode without the dry cooling tower or maximum water conservation with the dry cooling tower and hybrid cooling tower operating in series.

In Section 2.4 we also provided supplemental information based on additional borings, groundwater level measurements and hydraulic conductivity testing that was performed. Specifically, we identified one variance from the SSAR which we discussed in our last ACRS subcommittee meeting. In Section 2.4 we also provided supplemental information about groundwater supply wells, groundwater use and the groundwater level monitoring program. We identified a variance involving the North Anna water supply well information which is also discussed with the ACRS subcommittee members.

The estimated maximum groundwater

level that can occur in the power block area is 7 feet below the design plant grade elevation of 290 feet. Therefore, we determined that a permanent de-watering system is not required for safe operation of Unit 3 because this more than satisfies the DCD requirement that the maximum groundwater elevation is at least two feet below the design plant grade elevation.

MEMBER STETKAR: You know, we've had some discussion about that at the subcommittee meeting. I just, again, want to make sure that I've got it straight in my mind. At that time I understood that the lack of a need for a de-watering system was now being considered as a DCD item. Is that correct? That's part of the DCD review now? The reason for concern for the benefit of the other members of the committee who weren't there is that although the maximum groundwater level is 7 feet below plant grade, it's about 40 feet above the basement of several of the buildings. So it's not clear why a de-watering system is not required. And when we asked that, we were told that - that is a DCD item?

MEMBER CORRADINI: The only other

thing that I guess I remember from the subcommittee, I have it written down somewhere, but - was that safety grade equipment was not - everything you said I think is correct except safety equipment was not in those lower levels. At least that was the implication I heard.

MEMBER STETKAR: It's the implication, but there may be RTNSS equipment in these lower levels. I'm not sure. We're just not sure.

MR. KEVERN: Right, and that is something that's going to be addressed. The question is going to be addressed in a subcommittee meeting associated with the design certifications. Amy?

MS. CUBBAGE: Right. That review was part of the design certification and after the subcommittee meeting we confirmed with GE and with the DCD that the RTNSS equipment is also protected and is not in these locations.

MEMBER STETKAR: Okay, thanks.

MS. BORSH: Okay? Going on to Slide 17. To address a DCD COL item and an ESP permit condition we describe mitigating design features that have been incorporated into the ESBWR designed to preclude an accidental release of

liquid effluents. To address a DCD COL item we analyzed a postulated accidental release of radioactive liquid effluents to the groundwater or surface water at the Unit 3 site. We demonstrated that the release complies with the 10 C.F.R. 20 limits for release to the unrestricted areas. Finally, for Section 2.4 we state that Unit 3 will shut down when the water level in Lake Anna drops below elevation 242 feet mean sea level.

MEMBER CORRADINI: That's when we're in an environment - just, again, to put my memory straight - that's more environmental on the Lake Anna side because you use it for makeup, is that correct?

MS. BORSH: Yes, it has nothing to do with safety. That's correct.

MEMBER CORRADINI: That's what I thought. Okay.

MS. BORSH: And that's it for 2.4 so I'll turn it over to Don.

MR. KEVERN: Thanks, Gina. Mark, come on up. Okay, next we will have the staff's perspective on Section 2.4 and Mark McBride with the staff. Mark?

MR. MCBRIDE: Thank you. I'm again

Mark McBride from the Hydrologic Engineering Branch. Does not seem to be working. Good morning again. I'm Mark McBride from the Hydrologic Engineering Branch and I'm going to be presenting an overview of our Safety Evaluation Report Section 2.4, Hydrologic Engineering for North Anna. Now Section 2.4 covers a wide range of issues related to water and is relatively large. I'm not going to talk about every topic that we reviewed partly because Regina Borsh has already touched on some of these topics, and also because many are already resolved. Instead, I'm going to primarily highlight areas where we're now moving forward toward resolution. The staff comprehensively reviewed the early site permit with regard to Section 2.4. Aside from the open items I'll discuss in a moment, a few significant issues were identified. The six variances noted here covered minor matters such as for example a correction to the coordinate system that was used in the drawings.

Two permit conditions are relevant to Section 2.4. One permit condition, 3.E(2) was determined to be inapplicable to Unit 3. This condition had required dry cooling rather than

water cooling for Unit 4, but Unit 4 will not be built. The other condition, 3.E(3) required special engineering features to preclude accidental releases of radioactive liquid waste. The staff concluded that the features proposed by the applicant satisfied this permit condition.

The NCR addresses two different kinds of flooding. The first is large-scale flooding resulting from watershed-scale events, and second, local flooding from locally intense precipitation. Watershed-scale flooding was not found to be problematic. There are, however, two open items associated with locally intense precipitation. I'll illustrate some of the features here that bear on locally intense precipitation flooding. A ditch called the South Ditch drains surface runoff from the steep slope located on the south and southeast sides of the new plant area. On the map this ditch is emphasized in orange. There's also a North Ditch on the opposite side of the plant. The open items are associated with two particular features of the South Ditch. First, the South Ditch makes an abrupt bend to the northwest just before it enters the storm water management basin. That'll be on the right side of the figure.

Second, an access road parallels the ditch and this road also acts as a dyke that separates the South Ditch from the existing Unit 2 area. Some minor features affecting drainage are also included in this review such as for example the newly added ancillary diesel building off to the left.

The issue of most immediate interest is potential flooding near the Unit 3 nuclear island. HEC-RAS modeling of the runoff indicated that this is unlikely to be a problem.

MEMBER CORRADINI: What's that?

MR. MCBRIDE: Pardon?

MEMBER CORRADINI: Whatever you just said, that's a computer model?

MR. MCBRIDE: HEC-RAS is a computer model of surface runoff.

MEMBER CORRADINI: Okay, thank you.

MR. MCBRIDE: The two open items address refinements to the HEC-RAS modeling of runoff elsewhere in the site and related channel maintenance. The first concerns updating the modeling to show that the effects of minor changes such as for example the newly added ancillary diesel building and also ensuring that the South

Ditch will function as described. Three RAIs now under review concern the need to maintain the channels in the same condition as they are represented in the modeling. The second open item addresses uncertainty that modeling will overtop the access road and protecting the existing units. One RAI requested further information on control measures proposed to prevent overtopping.

Open Item 2.4.12-2 pertains to groundwater. The underlying concern here is that the DCD requires that groundwater must be more than 2 feet below plant grade. The drainage ditches described previously are also expected to help maintain this condition by acting as drains for groundwater and the open item concerns evaluating their effectiveness for that function. One RAI requested further information to support the conclusion that groundwater levels will be below the DCD design level in the power block area.

Open Item 2.4.13-4 concerns accidental releases of radioactive liquid effluents and the transport of radionuclides in groundwater. Staff wants to verify that the transport analysis is a bounding analysis. However, the applicant's

analysis did not use site-specific values for all parameters and did not always use the maximum or minimum value measured. An RAI has been issued requesting a bounding transport analysis using the maximum hydraulic activity and minimum K_d values observed onsite in the analysis. Now I'd like to invite any questions about hydraulic engineering issues that we've presented here.

MEMBER CORRADINI: Questions?

MR. KEVERN: All right, thank you very much. And the next topic moving along on the agenda is Section 2.5 Geology, Seismology and Geotechnical Engineering. Follow the same format. We'll start with a presentation by Dominion followed by the staff's perspective on that topic. Gina?

MS. BORSH: All right. In Section 2.4 - I mean, I'm sorry 2.5, like in 2.4, we incorporated SSAR Section 2.5 and we added supplemental information. The first bullet on this side explains that we collected additional borings for Unit 3 beyond those obtained for the ESP to further describe the site's stratigraphy. To address an ESP permit condition we commit to excavating weathered or fractured rock at the

foundation level for safety-related structures and replacing it with lean concrete before constructing the foundation. To address another ESP permit condition we commit to geologically mapping future excavations for safety-related structures and evaluating any other perceived geological features that we may encounter.

We go on to state that the Unit 3 operating basis earthquake ground motion is one-third of the foundation input response vector, or FIRS, and is bounded by the DCD's operating basis earthquake. In the excavation backfill subsection of Section 2.5.4 we describe the seismic category once excavation fills and slopes. We discuss the excavation methods in relation to the stability of the excavation and we identify the sources and quantities of the backfill that we plan to use. We provide the compaction criteria for backfill and we describe the QC requirements that will be applied to backfill. To respond to a DCD COL item and an ESP COL item we provide the sheer wave velocity profiles for the soil which we use to perform the liquefaction analysis and the slope stability analysis. So right here we just want to note that the sheer wave velocity profiles that we

developed for Unit 3 are used in the slope stability analysis and the liquefaction analysis which are coming up in later slides. Also, the only seismic Category 1 structure that will be founded on compacted structural fill is the firewater storage complex. The primary source of the fill is the bedrock that we're going to be excavating to construct the Unit 3 power block because the fill will be obtained from the new plant excavation. We weren't able to use measured sheer wave velocities for this fill so we used estimates to obtain the sheer wave velocity profile for the analyses.

Section 2.5.4 includes a discussion of the potential for liquefaction. We looked at the material at North Anna and we determined that the only material that requires analysis is the Zone IIA saprolitic soil. The analysis determined that the chances of liquefaction occurring in the Zone IIA saprolite are extremely low. We also determined that if any liquefaction were to occur it would not impact the stability of any seismic Category 1 structure or any seismic Category 2 structure.

In Section 2.5 we cover foundation and

slope stability. This includes an analysis of bearing capacity. We determined that the reliable bearing capacity values are adequate for seismic Category 1 and 2 structures and for the rad waste building. We also performed a settlement analysis and determined that the total and differential settlement values are well within the DCD limits for seismic Category 1 structures. Information about the static and seismic lateral earth pressures is also provided.

MEMBER BROWN: Let me ask a question. You made a statement on the previous page relative to you made estimates because you didn't have any other data.

MS. BORSH: Yes. For the soil that will be under the -

MEMBER BROWN: I'm an electrical guy so you're going to have to talk way down to me. It was something, was it the SWV profiles?

MS. BORSH: Sheer wave velocity.

MEMBER BROWN: Is that where you made the estimates?

MS. BORSH: Yes.

MEMBER BROWN: Okay. You used a term that I - if you made estimate where do you -

because there wasn't any data, where do you get them? Is there a standard set of stuff that everybody agrees to? It may be an ignorant question, but.

MS. BORSH: No and actually we did describe it in the FSAR about how we created that profile. And if you'd like we can ask our subject matter expert to -

MEMBER BROWN: I just wanted to know that there was some basis for getting there.

MS. BORSH: It is described in detail in the FSAR.

MEMBER BROWN: Okay.

MS. BORSH: In 2.5.4.

MEMBER BROWN: That's all I need.

MS. BORSH: You're welcome. All right. And then finally on Section 2.5 we provided the slope stability analysis. We describe the Unit 3 slopes, we discuss the impact of slope instability, we provide slope characteristics, we summarize the design criteria and analysis and provide the boring logs. And that's all I have for 2.5. Very high-level summary. Yes?

MEMBER RYAN: Just a question that may

tie a little bit of geotechnical engineering back to hydrology. After it's all said and done, do you have an idea at this point how you're going to be able to identify any sources of contamination with regard to, say, the first two units versus the third? Have you factored, you know, the factor co-located into your groundwater monitoring plant.

MS. BORSH: Well, we've done two different analyses. One analysis is just for releases from Unit 3 and then we've also done an analysis that - for releases from all three units to make sure that we're meeting the regulatory limits.

MEMBER RYAN: That's the compliance part, but my question's not that. My question is how do you know that you're monitoring in the right place so that you know where stuff's coming from.

MS. BORSH: Oh I would have to leave that with the subject matter expert.

MR. SMITH: Units 1 and 2 are down-slope, if you will, from Unit 3.

MEMBER RYAN: Are you going to verify that after construction, that it stays the same?

I don't know your site well enough to know whether it will or won't, but that's always a question to put through.

MR. SMITH: We can get one of our subject matter experts to answer that question in detail, but the elevation of Unit 3 is considerably higher than the elevation of Units 1 and 2 and it's further away from the lake. So the flow of water is basically away from Unit 3 towards Units 1 and 2 so.

MEMBER RYAN: How much is that elevation difference? In terms of feet?

MR. SMITH: It's approximately 20 feet.

MEMBER RYAN: Twenty feet? That helps a lot. Okay, thanks. Actually, if you could get a more complete answer that'd be helpful.

MEMBER CORRADINI: Why don't you log that and lets get back to it.

MEMBER RYAN: Absolutely.

MEMBER CORRADINI: I'm not even sure if the bridge line is allowable to talk in. I guess we're having problems. They can hear but they can't speak for the moment, so if you just log it in we'll get back to it. Jack?

MEMBER SIEBER: Does the construction of Unit 3 and the features that you've added have any negative impact on Units 1 and 2?

MR. SMITH: That's certainly something we evaluated to be sure that it would not and Unit 3 is located relatively far away from Units 1 and 2 as well. They're not that close together.

MEMBER SIEBER: Could you tell me briefly what kinds of things you evaluated to be able to assure yourself that Units 1 and 2 will not be affected by hydrology, for example?

MR. SMITH: The concern with a local intense precipitation was evaluated for potential impacts on Units 1 and 2. We just generally looked at for example the orientation of the turbine so that it would not potentially impact Units 1 and 2.

MEMBER SIEBER: All right.

MEMBER CORRADINI: Other questions?

MEMBER ARMIJO: A quick one. I'm not familiar with saprolite, I don't know what that is, but you conclude that it will not contribute to liquefaction or be a source of liquefaction. What is that soil and why is - what's the basis for your conclusion? Some property that you

measure, or is that commonly known?

MS. BORSH: Jeff, we're going to have to ask John about that. Or if he can't -

MEMBER CORRADINI: We'll try. I was told that they can hear but they can't speak back in. Try it.

MS. BORSH: John Davy?

MEMBER CORRADINI: Yes, I don't think we - we've lost that.

MR. QUINN: Let me just say that for the safety-related structures the saprolite will all be removed. We're going down to the bedrock.

MEMBER ARMIJO: So what's the problem. Liquefaction is not there.

MEMBER SIEBER: It measures liquefaction capability in soils, right?

MR. QUINN: Yes, sir.

MR. SMITH: None of the saprolite will be allowed to remain under any safety-related structure.

MEMBER CORRADINI: All right. Let's move on then to the staff's review.

MR. WANG: Good morning. My name is Weijun Wang. I'm a geotechnical engineer at the NRC. I'm going to present about safety evaluation

Section 2.5. The Section 2.5 about geology, seismology and geotechnical engineering. Because Gina Borsh from Dominion already described how the applicants address all the COL items and the ESP permit conditions and the variations. So I just give a brief summary of staff's review. There are five subsections in 2.5. Among those, the 2.5.1, 2.5.3 and 2.5.5 related to basic geologic and seismic information, surface faulting and stability of slopes. The applicant provided additional site geologic and seismic information and they also performed new slope stability analysis using updated site data. There are no outstanding issues for those three subsections. Next slide, please.

Subsection 2.5.2 is about laboratory ground motion. The applicant addressed the related COL items and the ESP permit conditions. They revised ground motion is above spectra based on updated site subsurface profile and also there are no outstanding issues. Next slide.

MEMBER SHACK: Just on that, wasn't the original ESP done with a uniform hazard ground motion response spectra? Have they now changed to the performance-based?

MR. WANG: Yes. They too seem related to why they revised the TMRS and one is because we have new Regulatory Guide 1.2.8. In that regulatory guide the NRC gave a guideline to moderate the site sediments with bounds using the - we call it the TMRS which is the ground motion with response spectra other than ICDE probably you are familiar with that term. And another issue is because - based on the new site investigation data the site soil profile changed a little bit -

MEMBER SHACK: From ESP?

MR. WANG: From the ESP. Because during the COL siting investigation, the applicant overturned a lot of more detailed information about the subsurface soils. Based on the new updated information, the soil layer elevation changes a little bit. So because of that they conducted a new site analysis. That's why they revised the TMRS. Next slide, please.

The subject in 2.5.4 is stability of subsurface materials in the foundations. Most staff RAIs and open items are related to these subsections. The applicant addressed the COL items by providing additional boring data. The site's soil profiles subsurface materials

properties and stability analysis. They also resolved the RAIs or open items, related the two static and dynamic property of backfill soils. Foundation stability analysis, coefficient of fraction of the foundation interface and dynamic settlement calculation of soil slopes. Next slide.

But there are two remaining open items. The first one is the applicant needed to clearly describe acceptance criteria in backfill soil data and needed to clearly define shield density test frequency during backfill soil placement. The second one is the applicant needed to clearly define concrete fill properties in the COL FSAR. I would like to point out those two open items are minor ones because for the first one the applicant needed to make some wording in ITAAC for backfill more clear. There's no significant issue there, just some wording about acceptance criteria. The second open item, the applicant provided the detailed information about the concrete fill in the response to staff's RAI. But we would like to see those, the specification about the concrete fill property in the documentation of the COL application. Because the

concrete fill will be placed directly underneath the safety-related structure foundations. So that's the two open items, and as I said, both are minor ones. So that's the end of my presentation. Any questions?

MEMBER CORRADINI: Questions? Thank you very much. Thank you.

MR. WANG: Thank you.

MR. KEVERN: Moving along on the agenda. Next topic, we've got two topics out of Chapter 3 dealing with in-service testing of pumps and valves, and also environmental qualification of equipment. We're going to have just a staff presentation on this topic, or these two topics rather, and Tom Scarbrough from the staff.

MR. SCARBROUGH: Good morning. My name's Tom Scarbrough. I'm with the Component Integrity Branch and I'll walk you through Section 3.9.6 and 3.11 this morning. Section 3.9.6 is the functional design qualification in-service testing for pumps, valves and dynamic restraints. And the COL application for North Anna relies on the ESBWR, DCD and the FSAR to fully describe the function design, qualification and IST programs for pumps, valves and dynamic restraints of

certification items in SECY Paper 05-0197. In response to a number of RAIs, Dominion and GEH revised the FSAR and the DCD to be able to come up with a fully integrated description of the functional design and qualification and IST programs for these components. And on the next page I'll mention some of the changes that were made.

We did perform an audit of the GEH design and procurement specifications in July 2009 at Wilmington. And that was to evaluate the implementation of the DCD provisions into the specifications. So next slide. This is a summary of some of the important aspects from my perspective in Section 3.9.6 for the 3.9.6 review. First, the DCD specifies that the ASME Standard QME-1-2007 for functional design and qualification will be used for new valves and for previously qualified valves the key QME-1 aspects will be implemented. So there's an oversight. Even if the valves have been qualified previously they have to go through the key aspects of QME-1 which incorporates the lessons learned from many years of motor-operated valve experience and testing programs that we have. And then QME-1 was

recently accepted in Reg Guide 1.100 Revision 3. Also, the DCD specifies the valve IST program. It's based on 2001 edition and up to the 2003 addenda of the ASME OM code. That's incorporated by reference in the NRC regulations. Now the North Anna FSAR supplements the DCD in several areas. For example, in IST provisions it incorporates and expands the discussion to be consistent with OM code and describes the periodic verification of design basis capability of power-operated valves. There are no safety-related pumps or safety-related motor-operated valves in the ESBWR design. But the description in the FSAR incorporates the attributes for Regulatory Issue Summary 2000-03 which incorporates those lessons learned that we talked about in terms of motor-operated valves in terms of the importance of properly qualifying those valves. Also, the FSAR provides a description of the snubber IST program consistent with the ASME OM code Section ISTD. So that's a summary of what's in the spectrum 2.9.6.

Now, where we are right now with the resolving, closing out the section review. We had one open item which we talked about with the subcommittee. It involves the implementation of

the DCD qualification and IST provisions and the NRC audit results were being used to address those. And we summarize those results in a memorandum dated September 1. And overall we found the specifications to be properly incorporating the DCD provisions. We do have some follow-up items such as clarifying some specifications in the IST table which I'll talk about in a minute. Now, GEH provided a response on September 21 which resolves most of those items. They indicate that the specifications will be updated primarily by the end of this year. The IST table clarifications are already apparent in Revision 6. They've already included those. And they will provide us with a schedule for the qualification testing for valves and the different components as they get them. From a Section 3.9.6 perspective, the only remaining item from the audit to close out this open item was the reference in the response that once the QME-1-2007 and second Reg Guide 1.100, that that would be reviewed to determine how that would be folded into the specifications. So we'll be talking to Dominion about that since the reg guide is now issued. Other than that, that's all we have left

on Section 3.9.6.

Now for 3.11 it also is an operational program. So we have the FSAR incorporates by reference the DCD description of the EQ program for mechanical and electrical equipment. Now, the DCD description of the EQ process was accepted based on NUREG-1503 which is the ABWR SER. And there's also, in addition to DCD, includes ITAAC which are more operational program ITAAC. There are specific component ITAAC which relate to qualification, but there actually is a section in the Tier 1 which is an operational program ITAAC for the EQ program and goes through discussing the variation qualification-type testing and such for this process. So that's another level that's added.

During the audit in July we also looked at EQ specifications while we were in Wilmington and I'll talk with you about what we found there. So we had two open items and they were interlinked. The first Open Item 1 had to do with the general implementation of the DCD EQ provisions. The second item had more specifically referencing the safety-related mechanical equipment which is my area in particular. So as

we noted we summarized the results in the memorandum and they resolved most of those items. There were a couple of EQ items left over from the audit. One of them was that the specification that we reviewed was a final draft after the audit. It was close to being finalized but it wasn't finalized yet. So we understand that GEH will be finalizing that in the near future and there was one item there in the response. We wanted to make sure we had the right number of specs that was referenced. That would be closed out and we need to work with GEH and find out, make sure that's clear, but that's probably just a loose end we need to deal with.

The other item from EQ audit was the transition from the initial EQ program to the fully operational EQ program. And that transition phase is something that we'll be discussing with Dominion, GEH, we discussed it with them. They consider it to be outside their scope. They focus really on the initial EQ and they expect the COL applicants to pick up the transition. So with that, now that we understand that transition point and where it is, we'll be working with Dominion to be able to make sure that's fully ascribed so we

can close out that portion of the SER. So with that, that's where we are with 3.9.6 and 3.11, and I'll be happy to answer any questions.

MEMBER CORRADINI: Questions by the committee? All right, I guess not.

MR. KEVERN: All right, thank you Tom. The reason we chose 3.9.6 and 3.11 to talk about today briefly was to represent the complexity of this interaction between the design certification review and the COL application review. IST and the equipment qualification complex combination of technical design issues as well as what the staff calls and what the Commission calls operational programs. And this was rather a quick discussion by Tom, but I hope that represents the depth of the staff's review and the idea of it's not just simply incorporated by reference, it's an in-depth review requiring interface, even audits of GEH as well as Dominion, trying to ascertain if some combination of both the DCD and the FSAR information is adequate to meet the regulations as well as the staff's expectations and our regulatory guidance. So that was the purpose of 3.9.6 and 3.11. I hope that at least met part of your expectations in that area.

Next topic is a combination of follow-up to inquiries from ACRS members at subcommittee meetings as well as an update to status of RAIs in the area of plant service water. So in this case we're going to start off with discussion by Dominion addressing all three topics and then we'll have a presentation by the staff on one of those topics. Gina?

MS. BORSH: Thanks, Tom. As Tom said, one of the inquiries relates to the makeup water system. Just as a background, the system is designed to supply demineralized water to the equipment that's listed in the DCD. It's non-safety related and it consists of a demineralization subsystem and the storage and transfer subsystem. A question was raised regarding a statement in the COL about the potential for using a temporary demineralization subsystem during the shutdown/refueling/startup mode. Per the DCD, the makeup water system pumps and demineralization subsystem are designed for normal power generation capacity water requirements only. It's been determined that it's not cost-effective to design a permanent system to handle the potential outage loads or the potential

to handle simultaneous demands that may be occurring during that mode. So during the shutdown/refueling/startup mode there may be an increase of plant water consumption due to draining that occurred of non-contaminated systems that can't be refilled with condensate-quality water. The capability to use a temporary condensate-quality - I'm sorry. The capability to use a subsystem that's temporary will allow us to assure that there's an adequate supply to supplement the condensate storage tank volume and also we'll be using and implementing an outage makeup water usage plan that will minimize the need for a temporary subsystem.

The next item that was an inquiry from ACRS subcommittee was about the assumptions that the PRA made regarding the plant-specific portion of the circulating water system. The PRA model for the system is described in the DCD PRA. The plant-specific design of the system, for example, the cooling towers, is enveloped by the DCD PRA analysis.

MEMBER STETKAR: Can I interrupt you because I can read the words here.

MS. BORSH: Sure.

MEMBER STETKAR: I'm curious why it's enveloped by the DCD PRA because the DCD PRA does not include the cooling towers at all. So it's curious how the DCD PRA envelopes the design by not including it.

MS. BORSH: Now I'll have to look at my technical notes here, John. Hold on one second. Rick and Gary, you probably can't speak, can you? I mean, you can speak but we probably can't hear you.

(Laughter)

MS. BORSH: All right.

MS. CUBBAGE: We may have to that to the takeaway. Just a wild guess, I mean they may have made some bounding assumptions.

MEMBER STETKAR: They are just not in there at all. The cooling - the pumps are modeled in excruciating detail, trash racks, screens, all of that, but the cooling towers are not there. In effect, the PRA assumes that the cooling towers are absolutely perfect. There is no failure contribution from that.

MS. BORSH: And what Gary said in his notes to me, Gary Miller from GE, was that the other - you're absolutely right John, just what

you said. He said the other failures have been determined to be insignificant and that's why they haven't been modeled in the PRA. He said when the circulating water fault tree is quantified, failure of the circulating water top event, the probability is $9E^{-6}$. So it's not a significant contributor to PRA. In fact -

MEMBER STETKAR: That might be true, but including the cooling towers might increase that from $9E^{-6}$ to something larger than $9E^{-6}$ and in fact it would. Now, whether that new number is significant or not is something that the PRA sorts out internally, but the fact of the matter is the cooling towers are not modeled and they would be an incremental contribution to whatever that current number is. I guess the question is -

MEMBER CORRADINI: The concern you have differently, if I say it differently is not that it might turn out to be incrementally small. It's not modeled at all and you want to know what the -

MEMBER STETKAR: It is not modeled at all and the question is does the PRA need to be updated specifically for the North Anna site because the North Anna site includes this

difference in that heat removal function as compared to the DCD which does not include credit for any mechanical draft cooling towers. So that's the real crux of the question.

MS. CUBBAGE: And I guess to pursue that a little further. So you're satisfied on the DCD?

MEMBER STETKAR: I'm satisfied on the DCD because the DCD does not include any mechanical draft cooling towers in the circulating water system. That's strictly a change for the North Anna site.

MS. CUBBAGE: Well, it would appear we don't have anyone that would be able to provide any more information than what Gina did.

MR. KEVERN: Unfortunately we have provisions to deal with, but the - whoever is -

MEMBER CORRADINI: We're trying to see if we can get them back online to talk to us. It's on the table. What did you say, Dana? I'm sorry, I didn't hear you.

MEMBER BLEY: I am not sure an oral response is adequate.

MEMBER CORRADINI: Keep on going.

MS. BORSH: Okay. Gary and Rick,

thank you for trying. Okay. All right. The last two items - so we don't need to talk about PRA anymore?

MEMBER CORRADINI: We have our own open item. Keep on going.

MS. BORSH: Yes. Last two topics that ACRS members asked about were related to the plant service water system. The function of this system is to reject heat from the non-safety related reactor component cooling water subsystem and the turbine component cooling system. It has no safety-related function. It is categorized as a RTNSS Level C system in the DCD. The first item of interest related to the plant service water system involves the cross-connect between this system and the normal plant heat sink which is our circulating water system. The DCD identifies the PSWS and normal plant heat sink cross-connect as part of the conceptual design for the system. At North Anna we didn't include this cross-connect in our design. The decision not to incorporate the cross-connect was based on the following disadvantages associated with interconnecting the two systems. First, the operating conditions at North Anna might have required design changes for

other systems such as the RCCW and TCCW. Also, during loss of offsite power the system would have had to have been realigned to maintain PSWS cooling capability. The cross-connect arrangement would have increased capital costs, for example, significant additional underground piping would have been required for the cross-connect and it would have increased operating costs during certain periods without any offsetting benefits. Although our system design at North Anna doesn't include the cross-connect that was described in the DCD, the system as designed does meet the performance requirement specified in the DCD for cooling RCCW and TCCW.

MEMBER STETKAR: Gina?

MS. BORSH: Yes, John.

MEMBER STETKAR: I just wanted to make sure because in the ITAAC I believe there's a requirement to show the PSWS basin has enough inventory to provide cooling of RCCWS. It doesn't mention TCCW. Does the basin actually have enough capacity to provide cooling for both RCCW and TCCW? Because recognizing that TCCW is certainly a non-safety related system, however, some of its cooling loads will indeed remain connected after a

normal plant trip and would indeed take heat away and require flow. So I was curious whether that ITAAC commitment should include both the RCCW and the TCCW cooling loads, or whether it already does and I missed it.

MS. BORSH: Yes, I'm trying to pull it up now John, but Jeff, do you know offhand? Or Doug, do you know the answer to that? We have Doug Kemp from Bechtel here with us. I was going to pull up the wording.

MEMBER CORRADINI: You will have to come to a microphone and identify yourself, please.

MR. KEMP: Doug Kemp. I believe as far as the defined heat load for the coping period of the seven days it was not specifically identified. It was the RCCW heat loads for the coping period as well as the diesel generator cooling loads, but not specifically - again, as was mentioned, you know, your TCCW loads would probably be very minimal because your plant has shut down.

MEMBER STETKAR: There's a table in the DCD. It's Table 9 - if I can pull it up here - Table 9.2-1 in the DCD that says during a normal

post-trip condition RCCW has about 91 megawatts and TCCW has about 21 megawatts heat loads. So TCCW accounts for something on the order of about 20 percent of the total PSWS heat load. So it's not insignificant. I don't particularly know exactly what those heat loads are because they're not elaborated in this table, but TCCW is not an insignificant fraction of the total PSWS post-trip, normal post-trip heat load.

MS. BORSH: But I think John what we did was the interface requirement in the DCD specifies the heat that has to be removed and we meet that requirement. So if you have a question about the heat removal that's really a DCD question.

MEMBER STETKAR: No. In, I believe, and I don't have all of my notes in front of me here so I'm struggling a bit. I did make a note that there was a commitment to contain enough inventory of cooling water sufficient to remove heat from RCCWS for the 7-day coping period. And it doesn't mention TCCWS so that - the question was if the heat loads are indeed correct, does the 7-day coping period inventory in the basin also account for the additional TCCWS heat loads. And

if not do you -

MS. BORSH: But that's really a DCD -

MEMBER STETKAR: That's right. And there's no provision, as far as I can tell, I can't find any automatic isolation or any provision to shut off those heat loads under certain conditions. So it seems it would require a manual action if -

MR. KEMP: I think we're getting -

MS. BORSH: Mike Arcaro was saying -

MR. KEMP: - was just here from GEH and I think the response from Mike Arcaro from GEH is that no, TCCW is not included.

MS. BORSH: It is not included. And the removal capability requirements are specified in the DCD. And I'm sure that if Mike were on the phone he could explain in more detail why that is.

MEMBER BLEY: I think the other side of what John's saying is those heat loads are there and unless you have provision to kill TCCW the water's going to go away.

MR. SMITH: I guess the point would be from our perspective, we're meeting the DCD requirement. So I think it is more in our view a question for the DCD as to what the heat load

requirement is that would have to be met. And it's more of a generic issue.

MS. CUBBAGE: Okay, so we'll take that over to the DC and straighten that out. I don't think we're going to solve it here.

MEMBER STETKAR: No, I don't think we are either, but you understand it though. You understand -

MS. CUBBAGE: Yes, I understand. And I do have some follow-up. We've been able to relay phone messages back and forth on the PRA question and that question was considered by Dominion and they asked GE to consider the impact of the tower and the answer is that the fan was an insignificant contributor, the fan component itself, and what drives the risk is the support systems, and it's the same support systems for the pump as it is for the fans. So if you have a loss of power it's going to affect both so there's not an increased risk of a loss of power to the fan versus a loss of power to the whole system.

MEMBER CORRADINI: The support system being -

MS. CUBBAGE: The system as far as power supplies, et cetera, are driving the risk so

it was determined that there was no significant - it would not have changed the PRA results to include the fan components.

MS. BORSH: That was the last bullet that Gary had given us on that slide. And you can ponder that.

MEMBER CORRADINI: I'll still have to ponder that, especially -

MS. CUBBAGE: Power supply was mentioned.

MEMBER CORRADINI: Okay, fine. We're still trying to get your people back online. They're lost somewhere, I'm not sure.

MS. CUBBAGE: They were able to hear, but now I'm afraid they're not even able to hear because it doesn't sound like - they're dialing in and out.

MEMBER STETKAR: That may be less frustrating.

MS. BORSH: Thank you Amy though, that was really helpful.

MS. CUBBAGE: Welcome.

MS. BORSH: So John, you still have a question?

MEMBER STETKAR: I still have a

question only because the PRA includes extensive analyses of things like common cause failures of pumps and fans and valves and things like that, and the conclusion may be true. I guess I'd just like to see it.

MEMBER CORRADINI: Okay. So let's save it. We'll get back to it.

MEMBER STETKAR: That's right.

MEMBER CORRADINI: Okay. Gina, you're up.

MS. BORSH: So, we don't have a cross-connect and we meet the performance requirements of the DCD. All right? Are we?

MEMBER CORRADINI: Yes, keep on going.

MS. BORSH: Okay. All right. The last item that we had related to specific ACRS members' questions involves our use of fiberglass reinforced piping for the underground portion of the plant service water system. We evaluated the different piping material options that we had before us and we determined that FRP piping is the best option for several reasons including the following. First, the material meets the design requirements that are specified in the DCD. Second, the material has certain advantages over

other materials such as its long-term resistance to internal and external corrosion and biological attack. The NRC - I'm sure they'll be talking about this in a couple of minutes - has issued RAIs to Dominion regarding our use of FRP for the application and as a result of several discussions that we've had on the topic with NRC we've decided for the non-safety related FRP piping that we have we're going to use an ASME code case as a starting point and as guidance to develop the requirements that will apply to the FRP in the plant service water system.

MEMBER CORRADINI: I don't - I guess you have to help me. What does that mean?

MR. KEVERN: Perhaps we could clarify that with the staff?

MEMBER CORRADINI: That's fine. Okay.

MS. BORSH: Any questions before I turn it over to Tom?

MEMBER CORRADINI: No.

MS. BORSH: Okay.

MR. KEVERN: All right. So as a great segue-way provided by Dr. Corradini we have staff presentation now, an update on the plant service

water situation, both regarding the RAIs as well as specifically on the fiberglass issue. So Larry?

MR. WHEELER: Good morning. Larry Wheeler from balance of plan plants. A recap from the July subcommittee meeting. As Dominion stated, service bar system is non-safety related, categorized as RTNSS. Since the service bar system is categorized as RTNSS, staff asked questions to ensure the service bar system is reliable. Since the staff used to the SERs with open items we have had meetings and phone calls with Dominion and Dominion has submitted revised RAI responses. The staff reviewed these responses and identified six open items, Items 8 through 13. Open Items 8 through 12 are now resolved and now considered confirmatory items. Open Item No. 8, GEH revised Revision 6 of their DCD addressing the Tier 1 interface requirements related to the service water system. Removing the requirements, BTUs appeared at seven days without active makeup in addressing sufficient MPSH from the service water coolers. North Anna has provided an FSAR markup to be consistent with the DCD.

Open Item No. 9 addresses COL items

for piping material. Aboveground service water materials will be carbon steel. Materials will be noted in the North Anna FSAR. The underground materials are addressed in Open Item No. 13.

Open Item No. 10. The staff asked the RAI related to the service water treatment in accordance with the Maintenance Rule program. The response, the service water system as initially classified as highly safety significant.

Open Item No. 11. North Anna application for the Section 9.2.1 mixed together the text of the ESBWR DCD and the North Anna conceptual design information and COL items. In response, the application will only address the CDI and COL items in the North Anna FSAR.

Open Item No. 12, address conceptual design information related to the aux heat sink. The initial plant test program that has design features will minimize water hammer events are tested. North Anna will revise the FSAR addressing the ultimate heat sink testing, including the water hammer mitigating design features. Open Item No. 13 will be discussed by Neil Ray.

MR. RAY: Good morning. My name is

Neil Ray, Acting Branch Chief of Component Integrity, Performance and Testing Branch. And as you heard from Larry Wheeler, I'm going to specifically talk about the issue of fiberglass usage in the PSWS system. Let's keep in mind that we are talking about this subject because this is RTNSS which is special category for the passive characters. And in this case ESBWR so this is RTNSS Class C.

When we looked into fiberglass we looked into of course its environment and the material compatibility of that environment and under the function that it will press forward. And in doing so we look back the history of fiberglass in terms of usage in the nuclear power plant and we found out that there are quite a few operating nuclear power plants use fiberglass. And some of them already gone through licensed in one process, namely Palo Verde. And so that is some basis for us to even consider fiberglass in the RTNSS system. The applicant originally suggested to use B-31/1 and non-mandatory Appendix 3 for usage of fiberglass. In our opinion that was not enough because B-31/1 doesn't talk about all the design aspects, material aspect,

installation, all those things. So we searched around and we found that back in `80s, ASME code case 155-2 has been gone through NRC review, extensive review, and in Reg Guide 1.84 NRC staff approved that document. So here we have fiberglass as RTNSS Class C which does not carry any radioactive material, which is a low temperature, low pressure environment and we have the basis that current plants using fiberglass, we have the basis that we have a code case which we can depend on. So, we talk with the applicant over the phone twice and tell them that under the situation we would strongly suggest to you to consider using the code case N-155-2.

MEMBER CORRADINI: So let me just - since I'm not enough of a good mechanical engineer on this -

MR. RAY: Yes.

MEMBER CORRADINI: What that means is the code case is an enveloping protocol for the use of FRP in these situations, is that really what it comes down to?

MR. RAY: You can say that, yes.

MEMBER CORRADINI: Okay, fine.

MR. RAY: We are not and nobody is

really asking - let me make it very clear to all committee members. We are not asking the applicant to completely accept code case 155-2 with the stamping, all those things. No. We are asking in terms of materials fabrication, in terms of installation, inspection, to follow the guidance of code case N-155-2. And in our judgment, based on the response we get from the applicant we will decide what to do here. So at this point we have not decided that we accepted this material for this usage. That will be decided sometime in the future within very short time. We ask the applicant to provide us how far they can use this code case. And based on that audit process we will decide what to do about it.

MEMBER SHACK: What was the intent of use that the code case was considering?

MR. RAY: Well, as I said, because B-31/1 does not talk all the details, and N-155-2, it's a about 50-page document. It tells all the details what to do, what not to do, how to make sure the installation is good as far as not said. All those information are there, so this is a good starting point of using code case N-155-2.

MS. CUBBAGE: Neil, I think he was

asking what application was the code case -

MR. RAY: Is that your question? Why they are using fiberglass?

MEMBER SHACK: What was it intended to be used for, yes.

MS. CUBBAGE: The code case in the `80s when it was -

MR. RAY: Oh, okay. That was for the current reactors.

MS. CUBBAGE: Right, but for what application.

MR. RAY: No. Essentially for spray pumps, yes, but it does talk about other buried piping as well, it does. And it refers to other codes when it comes to the installation, like ASTM document also. So it is a pretty comprehensive document I would say. As I said, it is about 50-page document which tells what to do, what not to do. And that's basically our starting point for this consideration.

MEMBER ARMIJO: Does it address joints between let's say pipes?

MR. RAY: Yes, it does.

MEMBER ARMIJO: Does it? And joints between the fiberglass pipe and the metal pipe?

MR. RAY: I believe it does. George, you want to add something?

MEMBER CORRADINI: Go to the mic, identify yourself please.

MR. GEORGIEV: I'm George Georgiev -

MEMBER CORRADINI: That mic is dead. We have power loss everywhere.

MR. GEORGIEV: Yes, my name is George Georgiev. I am senior materials engineer with the Component Integrity Branch. And the answer is yes. Adequate guidance is provided within the code case to use flange connection between the metallic and non-metallic portion of the piping.

MEMBER SHACK: Has Dominion used this in flush plant applications? Do you have experience with the FRP piping? The similar applications?

MS. BORSH: Yes. We're actually using it in nuclear applications today at our existing plants and we like it. I mean, we are not choosing - we've chosen it because we do believe it's a superior material to our other options.

MEMBER SIEBER: Well, Dominion's had problems in the past with steel piping in service water systems.

MS. BORSH: That's right.

MEMBER SIEBER: And there is some experience with fiberglass pipes in the same application because it's more flexible and so when you backfill overtop of it it becomes oval-shaped and creates some stresses inside. I don't think the code case deals with that issue.

MS. BORSH: However, there are other codes that we - and standards that we plan to commit to regarding installation and construction and maintenance that will prevent the problems that occurred previously in the `70s regarding construction.

MEMBER SIEBER: Yes, this is in a bio-plant.

MS. BORSH: Right, Perry. Oh, I'm sorry.

MEMBER SIEBER: So you know all about it.

MS. BORSH: We've looked, yes, and we've spoken directly with the Perry people that have been involved.

MEMBER SIEBER: I feel much better. Thank you.

MS. BORSH: You're welcome. Yes. Did

that answer your question?

MR. RAY: Any further questions?

MEMBER CORRADINI: Thank you.

MR. KEVERN: All right, we have finished with water systems. I expected that fiberglass was going to take a little longer than what we had scheduled for, so the next topic we have are inspections tests and analysis acceptance - I'm sorry, special tests analysis and acceptance criteria for specific to North Anna. I'm going to provide a summary of the ITAAC for North Anna. Specific to North Anna there are four categories of ITAAC, the ITAAC associated with certified design, with emergency planning, security and then of course the site-specific structure systems and components. Taking these one at a time as you see here on the slide, as far as the certified design is concerned in Tier 1 of the DCD for the ESBWR we have all of the ITAAC applicable to the certified design identified and discussed, and North Anna - Dominion makes these applicable to North Anna by incorporating by reference the Tier 1 in its entirety. So all of these ITAAC applicable to certified design now become North Anna-specific ITAAC.

In the area of emergency planning, the COL application included a number - well, all of the expected by the staff site-specific ITAAC. We have rather specific guidance in that area for ITAAC emergency planning area. Staff reviewed and evaluated the ITAAC that were provided in the application and we currently have two open RAIs in that area, both of which are concerned with a specific criteria for - in two areas. Again, not significant. We're talking about specific wording for criteria, but those are currently two open items associated with 13.3. In the area of physical security, as I said earlier, the staff's review is currently ongoing and there may be RAIs related to ITAAC, but it's premature to say whether we will or will not have it at this point in time.

Site-specific structure systems and components. To determine the ITAAC appropriate for those SSCs specific to North Anna Dominion applied the same selection criteria and methodology as GEH did in the certified design application. Staff found that that approach and criteria methodology to be acceptable and so therefore we found that approach by Dominion to be

acceptable for the site-specific SSCs. As a result of the applicant applying that criteria methodology, they ended up with ITAAC and then the three areas you see identified on the slide here, the backfill under Category 1 structures, ITAAC and we currently have an open RAI as Weijun talked about a little while ago. For plant service water we had an open RAI that has now become confirmatory, just mentioned previously in the plant service water presentation. And pertaining to offsite power system, we went through a series of discussions. We had a couple of RAIs, multi-part RAIs both with the design certification applicant as well as Dominion for the North Anna application. Identified the need for ITAAC and the offsite power area. And this is relative to equipment that's in the switchyard. It serves as an interface between the onsite power system and the transmission grid. I've had multi-part RAI in that area that has been addressed by Dominion and that has now moved in the confirmatory status.

And last and definitely not least, by applying this criteria methodology the applicant identified and the staff agrees that there are no ITAAC for any other site-specific systems. So the

way we're going to close out to address ITAAC for North Anna is going to be the same as all of the other COL applications. To ensure completion of ITAAC we're going to have a license condition that specifically identifies that the ITAAC will be satisfied before fuel load. And in addition to that, the actual closure process for North Anna has been a work in progress by the staff now for awhile. We currently have guidance identified in Reg Guide 1.2.15 and that will be applicable to North Anna as well as to all of the other COL holders for the closure process. Yes, sir.

MEMBER CORRADINI: This is the reg guide that we had reviewed -

MR. KEVERN: That is correct, right. And that's why I put it on the slide here. I know ACRS has - the entire ACRS has been interested in the ITAAC closure process. It's been evolving and you've had interactions with the staff and in fact there's a presentation tomorrow on this topic. So the point I want to make here is there's nothing unique about ITAAC closure for North Anna. It's going to follow the generic process the staff concludes here, with some help from ACRS as far as the reg guide is concerned. And that's a summary

of ITAAC specific to North Anna. Any questions?

MEMBER STETKAR: Yes, Tom. I almost hesitate to ask this, but in the -

(Laughter)

MEMBER STETKAR: And you know what's coming, don't you? In the subcommittee meeting there was mention made by Dominion that they were going to request the staff issue an SER on closeout of the DAC. Has that discussion progressed?

MR. KEVERN: I'd like to defer the answer to that to the subject matter expert from the staff, Jerry Wilson, who's going to be giving the presentation tomorrow to the full committee.

MEMBER STETKAR: Okay, so -

MR. KEVERN: Maybe he'll answer that now, maybe he'll answer it tomorrow.

MEMBER STETKAR: Okay. Well, I know we're going to have a presentation tomorrow, I was just curious within this specific context.

MR. KEVERN: What we'll try for here is a short answer to that question.

MR. WILSON: Jerry Wilson, Office of New Reactors. The short answer is on this subject matter of how we're going to expose design

acceptance criteria we sent a letter to the committee and in there we stated that we're developing guidance and we're going to be getting back and have a meeting with the committee to go over that guidance in the future. And I'll just alert the committee that in the future is tomorrow.

MEMBER STETKAR: Okay, thanks.

MR. KEVERN: All right, no other questions? Then the last slide we'll hear from the staff's perspective is a quick review of the schedule. North Anna is the reference COL for the ESBWR design and therefore we follow the - what the staff considers a standard 6-phase review process. At this point in time we've completed Phase I which was the initial round of all of the RAIs reviewing the initial application as well as Phase II, the safety evaluation report with the initial open items. And now we're nearing the end of Phase III which is our interaction with you folks. And that'll be - we expect that to end on schedule the first of the month with the issuance of the interim letter for - from ACRS. And then following that the next step is Phase IV where we end up with the deliverable being the safety

evaluation report with no open items. Then to address the staff's perspective on that we come back to ACRS. We currently have meetings for both the subcommittee and full committee scheduled for October of next year. That's in the master plan schedule there for North Anna. And then we finish the issuance of the license scheduled on the slide. And with that that concludes the staff's presentation today. We have brief concluding remarks from North Anna before we turn it back to Dr. Corradini.

MS. BORSH: We just want to say thank you very much for having us today. I'm sorry that our subject matter experts couldn't answer your questions. I know they would have been right on top of it and had answers for you, so we'll follow up on that as we need to. And just in conclusion, we continue to work on our R-COLA. We're addressing the remaining RAIs, the ones we have, the ones we'll receive, and we look forward to seeing you all later in the process. So thank you very much.

MR. SMITH: That's all.

MEMBER CORRADINI: Questions by the committee for anyone from either Dominion or

staff?

MEMBER MAYNARD: I've got just a quick question. Back to the decision to eliminate the cross-connect for the water systems. And that's for Dominion and the staff. What kind of review was done to make sure that there wasn't some other credit taken for that. Sometimes when you have something like that in the design, other designers take a look at that and they say oh well a cross-connect is there so - what kind of review was done to ensure it wasn't something else credited for that?

MS. BORSH: Internally for Dominion as we prepared our packages we had GEH, the technical people that had written the DCD review the packages and approve it for us to agree that we did not miss something that would have been buried in the DCD, for example. So we got GEH concurrence on doing the review. and then of course we had our internal Dominion engineers reviewing the package too.

MR. KEVERN: From the staff's perspective then we look at to Dominion's application to ensure it meets the design specifications from the DCD as well as whatever

the interface requirements are. For more detail I've got the subject matter expert on that specifically for how the cross-connect was looked at or not looked at.

MEMBER MAYNARD: I guess my question is as much a caution as anything. Sometimes somebody else has taken a look at that and said well that cross-connect is there so I'm going to do this a little different or something like that. For some of these involved there.

MEMBER STETKAR: It was one of the reasons I focused on TCCW and RCCW and the amount of water. I was a little bit less concerned when there was an additional water supply out there.

MEMBER CORRADINI: When there was a cross-connect.

MEMBER STETKAR: When there was a cross-connect. And not seeing TCCW listed as a specific heat load sort of raised that flag now that the amount of water that's available is strictly limited to what's in the basin.

MS. BORSH: Well, and the interface requirement, John, does specifically say that the interface requirement is necessary for supporting the post 72-hour cooling function of the PSWS so -

MEMBER STETKAR: This is the 7-day coping inventory in the PSWS basin. So it's the full 7-day heat removal capability without makeup.

MS. BORSH: Yes. I mean, it goes on, right. And that's our interface requirement, you're absolutely right. So it does go on. But also in the DCD GEH for us specifies the performance requirements for those systems that are conceptually described, this conceptual design is described in the DCD. So to answer your question we - GEH has determined what's the minimum requirement for a particular system and then we of course make sure that we meet those as we implement and develop our actual design.

MR. KEVERN: And specific on the ITAAC, that was a subject of an RAI where the staff - what initially was proposed was thought to be too vague. We wanted more detail to ensure that that interface was met. And that was a subject that Larry Wheeler had talked about earlier. I've lost him so I cannot give you the details of his background and his review related to that ITAAC.

MEMBER MAYNARD: Just review emergency procedures and stuff thoroughly because that might

have got buried in something that you guys get, you know, what comes from GE then you could miss something like that easily in part of the emergency procedures and stuff.

MS. BORSH: Thank you.

MEMBER CORRADINI: Other questions? Hearing none, let me thank Dominion and the staff. And at this point I guess I'd invite any comments by the committee. We're going to get back to this where we're going to have to draft an - well, we are planning to draft an interim letter tomorrow so that if I can get some comments from you now verbally or in writing or after you see the first draft I'd welcome it. But other than that, thank you all and I'll turn it back to you, Mr. Chairman.

VICE CHAIR ABDEL-KHALIK: I guess according to the schedule we will recess till 10:45.

(Whereupon, the foregoing matter went off the record at 10:23 a.m. and went back on the record at 10:43 a.m.)

VICE CHAIR ABDEL-KHALIK: We will come back into session. At this time we're scheduled to look at the license renewal application final

SER for the Susquehanna Steam Electric Station Units 1 and 2. And Dr. Shack will lead us through that discussion.

MEMBER SHACK: Okay. Our subcommittee reviewed the license renewal of the Susquehanna Steam Electric Station on April 1. There were no open items in the SER at that time. However, the subcommittee asked for some additional information on our favorite topics, medium-voltage cables, the containment liner condition and SBO recovery scope. The staff has also been pursuing some additional information on Boral and the fatigue-monitoring program and the factors used to calculate environmental effects on fatigue life. We'll be hearing follow-up on these issues from both the licensee and the staff, and I'll now turn to Sam Lee of the staff to open the discussion.

MR. LEE: Okay, good morning. My name is Samson Lee. I'm the deputy division director for Division License Renewal, NRL. Brian Holohan the division director would normally be here. However, he's away at an international conference. And as Dr. Shack said, today the staff is going to talk about two items from the subcommittee meeting. One was Boral, one was metal fatigue.

And actually, the metal fatigue issue was added to address some of the ACRS questions. So those are the questions and we address them. And to my left is Dave Pelton the branch chief in License Renewal and to his left is Evelyn Gettys. She is the department manager for Susquehanna for License Renewal. And also I have Glenn Meyer. He is the Region 1 team leader for the inspection and he will be here from then till when it's time for the presentation. But before that I'm going to turn over the presentation to the applicant and John Krais, the manager for Special Projects PPL is going to lead the discussion.

MR. KRAIS: Thank you. Good morning. My name is John Krais. I'm the manager of Special Projects for PPL Susquehanna. I want to thank you for the opportunity to discuss the Susquehanna license renewal request. With me here today are Rick Pagodin, general manager of engineering for Susquehanna, Dale Roth, supervisor of programs and testing, Dave Flyte, our license renewal lead engineer, both of whom will be speaking to later. And we also have with us our subject matter experts, license renewal project team including representatives from AREVA and

Structural Integrity who assisted us in our license renewal application preparation. The agenda for today's meeting starts with a brief description of the site. Following that, Dave Flyte will discuss the operating experience review, the commitment process, underground medium-voltage cables and station blackout recovery scoping. Dave Roth will provide an overview of the condition of containment and Dave will conclude with the discussion on main steamline flow restrictor aging management evaluation.

Susquehanna is located in northeast Pennsylvania approximately 20 miles southwest of Wilkes-Barre. The plant is owned by PPL Susquehanna who has a 90 percent share and the Allegheny Electric cooperative with a 10 percent share. The licensee and operator is PPL Susquehanna, LLC. We have two BWR-4 units licensed up to 3952 megawatts thermal and a generator limit rating of 1300 megawatts electric. General Electric was our - supplier and Bechtel was our architect engineer. The ultimate heat sink is provided by a spray pond. Turbine cycle cooling is provided by natural gas cooling towers,

and the makeup water is pumped up from the Susquehanna River.

A little bit of history. Our operating license was issued for Unit 1 in July of 1982 and Unit 2 in March of 1984 for 3293 megawatts thermal. Our license renewal application was submitted in September of 2006. Our extended power uprate of 14 percent to 3952 megawatts thermal was approved in January of 2008 and our current license expires July 17, 2022 for Unit 1, and March 23, 2024 for Unit 2. At this time Dave Flyte will continue with the discussion of our operating experience.

MR. FLYTE: Thank you, John. The Susquehanna operating experience review was performed in accordance with the guidance that's in the industry guideline document NEI 95-10. As recommended in that guidance we started with industry information that's been pulled together over the years and the EPRI tools was one of those documents that we used. It's a good compilation of aging effects from various industry experience over a number of years. So we used that as a starting point to identify potential aging effects for evaluation for Susquehanna. In addition, as

recommended by the guidance we didn't rely solely on the industry information that had been accumulated. We did a plant-specific operating experience review. We started out with at the time the application was submitted we had done a 5-year review plant-specific operating experience. While the application was in review we continued with updates to the operating experience and we effectively have very close to eight and a half years of operating experience reviewed plant-specific. We also looked at industry operating experience during that time period to make sure that we had reviewed all the pertinent industry operating experience since the industry guidance documents had been issued, the GALL and the tools and everything like that. So with that we've been able to identify all potential aging effects. I would just note that the plant-specific review didn't turn up anything new and different than what was included in the industry guidance documents which I think has been pretty typical.

MEMBER SHACK: Can you refresh me? You haven't replaced your piping. You rely on mechanical - or on stress improvement and the hydrogen water chemistry, that's correct, isn't

it?

MR. FLYTE: I believe that's correct. Which piping would you be referring to?

MEMBER SHACK: Recirc piping.

MR. FLYTE: Recirc piping, yes. That's mechanical.

MEMBER SHACK: Is that mechanical stress improvement or is that induction heating?

MEMBER ARMIJO: I think I read both.

MR. SWOYER: I'm Bruce Swoyer, design engineering, Susquehanna. We use both. We use IHSI when the units were young and then we went in and did MSIP in the early `90s.

MEMBER SHACK: Okay. And what's the level of your hydrogen addition, or is that proprietary information?

MR. KRAIS: We currently inject about 95. Dan Miller will -

MR. MILLER: Yes, Dan Miller, site chemistry. Yes, we're running 1.97 PPM feedwater hydrogen. We're a moderate hydrogen injection plant.

MEMBER SHACK: Now has that been increased since you did your power up-rate or that's the level you've been?

MR. MILLER: That's the level we've been able to maintain since up-rate. We've done evaluations to increase it if needed.

MEMBER SHACK: Okay. And can you do that without shine. I mean, what's the limit for you? Is it just an economic limit, or?

MR. MILLER: Right now we're limited to 2 PPM feedwater hydrogen with the increased feedwater flow. So we can increase our injection rate to 98 for the first level of EPU and 106 FCSM for the second phase of EPU.

MEMBER SHACK: Okay, thank you.

MR. FLYTE: The next topic on our agenda is the commitment process. The license renewal application as amended during the regulatory review process includes 60 commitments. Each of these commitments has already been entered into the station commitment tracking process and is scheduled for completion prior to the period of extended operation. Commitments are assigned to individual station personnel and there's also oversight on the commitment process by a nuclear regulatory affairs group to ensure that implementation goes as planned. And of course there's an NRC inspection prior to entering

the period of extended operation to validate that that implementation has occurred.

Moving into the subcommittee follow-up items. At the subcommittee meeting we did discuss the underground medium-voltage cables. At Susquehanna we have both 5kV and 15kV cables. They're routed underground within the scope of license renewal. The 5kV are the safety-related cables and portions of those cables are routed underground in duct bank. And from pass inspections of manholes in those duct bank runs we've never observed any submerged medium-voltage cables that are safety-related. We also have 15kV non-safety- related cables that are within the scope of license renewal and they're included in scope for the offsite power supplies and station blackout recovery. Past inspections of manholes in those duct banks, we have observed submerged medium-voltage cables in two of the manholes. And we knew that information going into license renewal application, so based on that plant-specific OE we did include in our original submittal a commitment to implement a program that was consistent with the GALL recommendations for cables that could have an opportunity to be

submerged, and that would be to periodically test the underground medium-voltage cables and also to inspect the manholes and pump them as needed to keep the cables from exposure to standing water. Although that's a license renewal commitment, we have been keeping up with industry developments on that and that's - those activities have already been put in place so we've started those already.

MEMBER STETKAR: Dave, can I ask just to make sure I understand the commitment. And recognizing that this is a plant licensing issue so it isn't necessarily unique to the license renewal commitment. As far as the license renewal commitment, you're only committing to the testing of the cables and inspection of the manholes that include - that contain the 13.8kV cables, is that correct? You're not -

MR. FLYTE: That's correct.

MEMBER STETKAR: - going to be doing any inspections of the manholes that contain the 5kV cables?

MR. FLYTE: For license renewal that's a correct statement. However -

MEMBER STETKAR: What's the basis for excluding the 5kV cable, 4.16kV cable?

MR. FLYTE: The 5kV cables are not energized more than 25 percent of the time. They're standby. They're ESWR chart service water kind of service so they don't meet the criteria for water treating that's cited in GALL so they don't meet the threshold of continuously - or I shouldn't say continuously, but energized more than 25 percent of the time and submerged.

MEMBER STETKAR: So the basis for exclusion is not that they might not be submerged, it's that they're not energized more than 25 percent of the time, is that correct?

MR. FLYTE: That is correct.

MEMBER STETKAR: Okay.

MR. FLYTE: In addition, we've never seen them submerged so -

MEMBER STETKAR: But that doesn't say in the future they might be submerged. But it's basically they're not energized more than 25 percent of the time.

MR. FLYTE: Right.

MEMBER STETKAR: Okay, thanks.

MEMBER MAYNARD: Can you just describe briefly what your inspection pumping program is? How often do you look or what criteria do you use

for when you look?

MR. FLYTE: What we did is, I think it was in 2005 we monitored four manholes that we called at that time low points in these duct bank runs for both the 5kV and the 15kV cables. So we picked up all the duct bank runs and over a period of six months we monthly looked at the water accumulation in those manholes and from that we established, you know, a rough infiltration rate if you will of water, an inches per month type of thing. Based on that we set a frequency for inspection and pumping. So depending on the particular manhole it varies, the frequency varies.

MEMBER MAYNARD: Have you found that it's fairly predictable, or does it vary quite a bit?

MR. FLYTE: From manhole to manhole or in general? I'm not sure I understand the question.

MEMBER MAYNARD: Well, I'm saying you based your frequency on what you'd been finding and I guess my real question is based on that frequency have you had to make any adjustments to that frequency, or is that?

MR. FLYTE: We're actually in the beginnings of this. The most frequent pumping cycle we have is a 3-month frequency, so we've had the opportunity to complete one - a second round on the 3-month pumping and it was right on the mark. So I have one data point that I can offer you and say the first one was good news. However, our PM activities have a threshold that say if you're above this level it gets into the corrective action process and we adjust the pump down frequency and the inspection frequency.

MEMBER RYAN: Just a quick follow-up question. Do you know if it's groundwater coming up in all cases, or is it surface water coming down or both?

MR. FLYTE: We do not have a definitive answer on that.

MEMBER SHACK: Now are you continuing to inspect those manholes associated with the 5kV cables even if it's not a license renewal?

MR. FLYTE: Yes, yes we are. We have established the PM activities for those as well and those are in place too.

MEMBER RYAN: Again, just one follow-up. Are you working toward trying to figure that

out?

MR. FLYTE: We'll gain experience as we go. I can't say there's any specific plan to try to figure out the exact source. Right now we have what's a success path to keep the cables dry. If we pump it frequently enough they will stay dry so we're relying on that. We're consistent with recommendations in GALL and we're just following that path at this point.

Next topic is station blackout recovery scoping. Right in front of us is a conceptual overview of the plant site. And you'll see in kind of the center, upper center there's an area that's enclosing a dotted line which is laid at the fence so that's the plant site. We have the - the power block is the rectangle on the right hand of that fenced area called Susquehanna CS. And of course we have the cooling towers to the left. So just to continue with the general lay of the land here.

Well first I'll say that the equipment is built for license renewal. The transmission level or high-voltage equipment is highlighted in red. But to continue with the layout, on the upper left we have a switchyard which is the T-10

230 kV switchyard. Lower left is another switchyard which is a 500 kV switchyard. On the far right is the Susquehanna 230 kV switchyard which is located physically across the Susquehanna River from the plant. To review, as you go out from the plant from the power block I'll start with going down the left side of the power block if you will there. We go through startup transformer T-20 and move toward the grid. And you'll see we go into that T-10 230 kV switchyard and include two circuit breakers at the T-30 kV level within scope. As we look for our other offsite power supply source it comes out of the bottom of that power block box there. We move out from transformer T-20, the other startup transformer. That's tapped into a tie line between the two switchyards, the 500 and the 230 kV switchyard. And as you can see, we go out and pick up circuit breakers at the 230 kV level in both of those switchyards. So we have established the scoping boundary at the 230 kV breaker level in the switchyards surrounding the plant.

MEMBER STETKAR: Dave, just out of curiosity, is the breaker in the lower left corner, the 221 water transformer, is that an

active breaker or is it a disconnect?

MR. FLYTE: It's an active breaker.

MEMBER STETKAR: It's an active breaker? Thanks.

MEMBER BROWN: The cable that goes across the river, is that overhead?

MR. FLYTE: Yes, that's transmission towers. Yes.

MEMBER BROWN: Okay.

MR. FLYTE: At this point Dale Roth will continue with a discussion of the condition of the containment.

MR. ROTH: Good morning. My name is Dale Roth. I'm the supervisor of programs and testing at Susquehanna. As noted earlier, the nuclear steam supply system for each unit at Susquehanna consists of a GE BWR-4 boiling water reactor. The containment is a Mark II pressure suppression design. A cross-section of the containment is shown in the slide. The upper chamber is the drywell, steel-lined concrete cone. The lower chamber is the expression chamber. It's a steel-lined concrete cylinder. The drywell expression chamber is separated by a steel-lined concrete diaphragm slab. During normal operation

the atmosphere is inerted with nitrogen. The reinforced concrete walls of the drywell expression chamber are nominally 6 feet thick. They are designed as the containment's pressure-retaining structure. The liner plate is one-quarter inch carbon steel. It acts as a leak-tight membrane.

Visual inspections to the liner plate and concrete structure are performed in accordance with the requirements of ASME Section 11. Pressure testing is performed in accordance with 10 C.F.R. 50 Appendix J. Neither inspections nor pressure testing at the station have identified any significant degradation on either unit. As a result, our programs are effectively managing the aging of the containment.

MEMBER SHACK: And do you see problems at all with any of your coatings? Does that require continual maintenance?

MR. ROTH: We've seen some white corrosion, surface corrosion, minor discolorations, minor pitting. That's it.

MEMBER SIEBER: The suppression pool is part of the containment boundary?

MR. ROTH: Yes.

MEMBER SIEBER: What have you done to inspect the condition of the liner underneath the surface of water level?

MR. ROTH: Every 10 years it's inspected visually. We bring in divers who are qualified to perform visual inspections of that liner plate.

MEMBER SIEBER: And the conditions in the suppression pool, are they - do you consider them mild or aggressive with respect to corrosion?

MR. ROTH: We have seen some corrosion, but I don't consider it aggressive.

MEMBER SIEBER: Well, what have you seen?

MR. ROTH: Again, minor degrees of corrosion and some minor pitting. That's all that's been reported.

MEMBER SIEBER: Pitting of the coating or the liner itself?

MR. ROTH: Into the coating and a little bit into the liner.

MEMBER SIEBER: Okay, and have you done any repairs?

MR. ROTH: We have not been required to do any repairs.

MEMBER SIEBER: Have you done anything other than visual examinations?

MR. ROTH: Other than pressure testing. Pressure testing and visual inspections.

MEMBER SHACK: In the submerged case, are those coatings - you just repair them as needed?

MR. ROTH: As needed, that's right.

MEMBER SIEBER: How do you repair a submerged coating?

MR. ROTH: There are materials that can be deployed underwater. I don't have the details, but there are materials that can be applied.

MEMBER SHACK: The diver does the repair?

MR. ROTH: Yes, the diver does it.

MEMBER BROWN: Waterproof paintbrush.

(Laughter)

MEMBER SIEBER: Okay.

MEMBER BROWN: Can I ask one question? Back on the steel liner underwater. I'm not a corrosion expert, but guys down there with goggles on. I mean, it's just this nice clear water or is there a -

MEMBER POWERS: This is the clearest water you've ever seen.

MEMBER BROWN: Well, it just seems a little bit beyond me that you can go down and do an inspection for corrosion. I mean, how do you even get a corrosion thickness value if you're underwater? I mean, that's -

MR. ROTH: We do it as part of our clean-out of the inspection pool. So we bring in filtering equipment. We run all the water through a filter medium. We do vacuuming of all the material off the bottom of the expression pool so the water is quite clean when they get done, and then they do the inspections after they're done.

MEMBER POWERS: You cannot judge the depth of the water by looking from the top because it is so clear.

MEMBER MAYNARD: Do you also use cameras?

MR. ROTH: I believe we use cameras. I'm not - I know we've done visual inspections using the divers.

MEMBER SIEBER: Relatively calm in that you can - in the pressure pool?

MEMBER BROWN: Well, the diver's got

to sit there and wiggle his fins.

MEMBER SIEBER: Well yes. My question is to what - some debris also comes from the operation. Any other debris that's there has to come from corrosion at the surface. Do you look at the debris that you retrieved to try to figure out where it came from?

MR. ROTH: We -

MEMBER SIEBER: If you get a lot of rust.

MR. ROTH: We do characterize the debris that we do pull out, the sludge. Some of it is - it may be dropped in from above. Some of it may be corrosion particles.

MEMBER SIEBER: Okay. I have to think about that a little bit.

MEMBER ARMIJO: When you inert the containment, do you sparge the suppression pool in that, or do you just let the nitrogen just -

MR. ROTH: No, we just let the nitrogen fill the volume.

MEMBER ARMIJO: Okay. So whatever oxygen that would be available to cause corrosion is still in the water, but there's no air.

MR. ROTH: Right.

MEMBER BROWN: Is the oxygen content of the water monitored?

MR. MILLER: Dan Miller, chemistry. We do not monitor the dissolved oxygen level in the suppression pool water.

MEMBER BROWN: I missed it.

MR. MILLER: We do not.

MEMBER BROWN: You don't, okay. All right. That answers it.

MEMBER POWERS: Why would you?

MEMBER BROWN: If there's no oxygen, you can't corrode. If you have oxygen, you can. I'm not a chemist, but that's -

MEMBER SIEBER: Adequate oxygen, potential to corrode.

MEMBER ARMIJO: Right, that's what I asked about the sparging. That could be pretty effective to strip oxygen. They don't do that.

MR. PELTON: This is Dave Pelton. I've just got a request from the back of the room. If we could move a little closer to the microphones. We're having a little trouble hearing. So thank you so much. This is all good conversation, they want to make sure they're all hearing it all.

MR. FLYTE: The last of the subcommittee follow-up items on our agenda today is the aging evaluation that was performed for the main steamline flow restrictors. The aging evaluation that we performed identified two possible aging concerns. One is corrosion, loss of material due to corrosion and the second is loss of material due to erosion. Flow restrictors are formed of cast austenitic stainless steel and carbon steel. And in the environment of - the reactor cooling environment, corrosion is an applicable aging effect. So consistent with GALL - and that's an aging effect for both materials, the cast and the carbon steel. Consistent with GALL we've credited the BWR water chemistry program supplemented by a one-time inspection to verify effectiveness as the aging management program. Even though it is a dry steam environment and not conducive to corrosion, GALL would recommend that you have an aging management program. The one-time inspection scope will be determined by engineering evaluation. And they'll ensure that all the components that are inspected are most susceptible to corrosion and bound all the components that are in the population being

managed by the BWR water chemistry program.

The aging management evaluation for erosion concluded that this is not an aging effect that requires management. And it was evaluated as a time-limited aging analysis and dispositioned per 10 C.F.R. 54.21(c)(1)(ii) which is the option for projecting for 60 years. The real bottom line on the erosion is that it's in a dry steam environment and the material is resistant to erosion so that's the bottom line why it's not an aging concern.

MEMBER SIEBER: Yes, the steam condition is saturated and not super-heated, right?

MR. KRAIS: Correct.

MEMBER SIEBER: So it's really not dry. What you're really saying is it's very high-quality. Content on the order of typically is less than 1 percent. But to say it's dry is not correct, right?

MR. KRAIS: Moisture content -

MEMBER SIEBER: Yes. Okay, thank you.

MEMBER SHACK: What was the design decision on whether the flow restrictor is cast stainless or carbon steel?

MR. KRAIS: I am sorry, what was the question?

MEMBER SHACK: You said the flow restrictors are austenitic cast - or I mean, are cast stainless steel or carbon steel?

MR. FLYTE: I'm sorry, the clarification on that is the leading edge in the venturi is cast and the -

MEMBER SHACK: Okay. That makes a whole lot more sense. Okay.

VICE CHAIR ABDEL-KHALIK: And what is the velocity in the flow restrictor compared to the velocity in the steam line?

MR. FLYTE: The velocity in the steam line is about 150 feet per second and in the venturi it's about 600 feet per second.

VICE CHAIR ABDEL-KHALIK: Six hundred feet per second. And at 600 feet per second you had no erosion concerns?

MR. FLYTE: Again, going back to the dry steam, it's no concern with erosion. I'm sorry, I continue to call it dry steam here.

In summary, the Susquehanna license renewal application was developed by an experienced project team that was actively

involved extensively with the industry throughout the preparation and review. And to help ensure that we submit an application that complied with the regulatory requirements, followed the industry guidance and met current expectations. The application had a thorough review by the staff and the PPL project team worked aggressively with the staff to understand and resolve issues as they came up which resulted in an SER with no open items. The bottom line for Susquehanna is that we will manage aging of equipment and structures in a period of extended operation.

MEMBER SHACK: Just looking ahead to the staff's. You had 59 commitments, now you've picked up one more, right?

MR. FLYTE: That's correct.

MEMBER SHACK: What's the sixtieth commitment?

MR. FLYTE: The sixtieth is for Boral, for coupon testing.

MEMBER ARMIJO: Just going back to the containment. When you did your industry experience review, did you check with other Mark II - plants that had Mark II containments to see if they had the same favorable experience as far

as liner corrosion?

MR. FLYTE: We did not actively contact individual plants. However, we looked at their operating experience with everybody else's and saw the absence of operating experience so in that way we did.

MEMBER ARMIJO: I'll ask the same question of the staff.

MEMBER SHACK: This liner, it's directly on the concrete.

MR. ROTH: Yes, the concrete was poured right up against it.

MEMBER SHACK: Right up against it. There's no spacer or anything that was used as a construction aid as we say?

MR. ROTH: No.

MEMBER MAYNARD: And the liner is more of a diaphragm. It's not intended to be a standalone if the concrete wasn't there?

MR. ROTH: That's correct. The concrete is the pressure-retaining structure of the liner's membrane.

VICE CHAIR ABDEL-KHALIK: Are there studs that hold the liner to the concrete?

MR. ROTH: Yes, there's studs on the

back of the liner plate that are used to bond it to the concrete essentially when it's poured.

MEMBER SIEBER: Same as a PWR large dry containment.

MR. FLYTE: That concludes our presentation for today.

MEMBER SHACK: Committee? Thank you very much, gentlemen.

MS. GETTYS: Good morning. My name is Evelyn Gettys and I am the safety project manager for the Susquehanna Steam Electric Station Units 1 and 2. Today I will be discussing the staff's review of Susquehanna's license renewal application. Can you hear me? Okay. This is the overview of the review. Section 2 is the scoping and screening review. Region 1 performed the license renewal Region 1 inspection. Section 3 is the aging management program and review. Section 4 is the time-limited aging analysis, or TLAs, and then the conclusion.

This is some background information that was mostly covered by the applicant. Just go on to the next slide. This slide is a recap of the April 1, 2009, ACRS subcommittee meeting. The Safety Evaluation Report which I will refer to as

the SER throughout the rest of the presentation was issued in March 2009. The staff issued 278 requests for additional information with the applicant making 59 commitments. There were no open items and there were no confirmatory items. As previously mentioned, the staff issued the SER in March 2009 and at that time two plants under review for license renewal had issues with Boral and metal fatigue. It was decided that the staff would issue RAIs on these emerging issues. However, they were not able to do so until after the SER meeting. Therefore, subsequent to the subcommittee meeting there were additional RAIs issued, five on Boral and three on metal fatigue. As a result of the RAIs issued, the applicant amended the LRA and included one additional commitment on Boral which I will talk about in more detail later in the presentation.

Since issuing the March 2009 SER there have been no changes to Section 2 and the staff concluded that the applicant scoping and screening methodology is consistent with the requirements of 10 C.F.R. 54.4 and 10 C.F.R. 52.21(a)(1) and that there were no emissions from the scope of license renewal. There were no emissions from the aging

review in accordance. Since issuing the March 2009 SER, there have been no changes to the regional inspection and the conclusions remain as the scoping of non-safety structure system components and the aging management programs are acceptable. Inspection results support a conclusion of reasonable assurance that aging effects will be managed and that the intended functions will be maintained. Section 3 of the SER consists of the following subsections. I do not plan to cover the subsections, but we'll touch on those which are of interest.

After the subcommittee meeting, the staff requested additional information on the emerging issues regarding neutron-absorbing material in the spent fuel pool. In Susquehanna's case it's Boral. In response to the RAIs, the applicant made an additional commitment regarding Boral, that in the spent fuel pool, the Boral coupon testing program will be continued into the period of extended operation and that the aging effects will be managed through the water chemistry program and the Boral coupon testing program. The staff found the responses to the RAIs acceptable and revised the SER. Next.

This was the staff's conclusion for Section 3. Based on its review of the LRA and additional information submitted as a result of RAIs, the staff concluded that the effects of aging will be managed so that the intended function swill be maintained during the period of extended operations per 10 C.F.R. 54.21(a)(3). This is the list of the time-limiting aging analysis. Changes were made to 4.3 which covers metal fatigue. In 4.3.1 which is the reactor pressure vessel fatigue analysis, the staff asked the applicant to address transience event, design specifications and the recording of transient data. The applicant responded and indicated that all monitoring transient events are bounded by the design specifications and that the cycle tracking activities cover the entire operating history of the plant. The staff found the applicant's response acceptable and revised the SER. The staff asked the applicant to justify the large reduction in the projected 60-year cumulative usage factor, or CUF values seen for some locations. With relatively minor reduction in cycle projections, even though some transients had projected cycles higher than design cycles. The

applicant provided justification for the 60-year CUF by stating that the 40-year design CUF values had incorporated extra conservatism, including contributions from fault condition loads directly using results of bounding locations and conservative design cycles. Unnecessary conservatism was removed in the 60-year fatigue analysis. The staff found the applicant's response acceptable and revised the SER.

In 4.3.3 which covers the effect of reactor coolant environment on fatigue life of components and piping, the staff requests that the applicant provide pre-1994 data to supplement the data previously provided and also the justification for the dissolved oxygen data applicable to all NRC - excuse me, NUREG/CR/6260 components. The applicant provided the dissolved oxygen data, described the water samples, schedule schemes and the water flow routes and demonstrated the applicability of the sample data to all the NUREG/CR/6260 locations. The staff found the applicant's response acceptable and revised the SER.

The conclusions for Section 4 on the TLAs is that based on its review of the LRA and

additional information submitted as a result of the RAIs, the staff concluded that the applicant provided an adequate list of TLAs for 10 C.F.R. 54.3 and that the TLAs will remain valid for the period of extended operation, the TLAs have been projected to the end of the period of extended operation, or the aging effects will be managed for the period of extended operation. The staff's overall conclusion for Susquehanna is that it is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current license bases and any changes made to Susquehanna's current license basis, in order to comply with 10 C.F.R. 59.29(a) are in accordance with the Act and the Commission's regulations. That's the end. Any questions?

MEMBER ARMIJO: Yes, I have a couple of questions, one related to the Boral. You say the applicant is going to - has a coupon testing program. How does the staff relate that coupon to the actual condition of the Boral in the racks themselves? Is there a supplementary inspection of the condition of the Boral in the fuel storage racks themselves? That says okay, these coupons

are truly representative of what's going on in the racks.

MS. GETTYS: I think Emma wants to address that.

MEMBER ARMIJO: Or the applicant, either.

MS. WONG: This is Emma Wong of the staff. Could you repeat the question?

MEMBER ARMIJO: Yes. I don't fully understand the coupon testing program, but I'm assuming that you have some samples that are periodically tested in one way or another and examined or tested to see how much attenuation - neutron absorption there is. But how do you know that that is representative of what's actually in the racks themselves? Are the - is the Boral in those racks inspected as well?

MS. WONG: As far as I know at Susquehanna they don't actually inspect the Boral in the racks, they just rely on their coupon testing program until they find some sort of indication that there would be start of degradation. Then they would put that into the corrective action program and then they might look into the Boral on the racks.

MEMBER ARMIJO: And how have they demonstrated that that's okay, that those coupons are truly representative of what's going on in the racks?

MS. WONG: So their coupons have been placed in areas of the highest neutron flux. So they always put them near freshly discharged fuel every time which is not usually what the racks see. They shuffle around the fuel in the racks. So they don't actually see the highest neutron flux every time. So the coupons actually receive more flux than the racks would ever actually see. So that would be an indication before degradation in the racks actually would happen.

MEMBER ARMIJO: Maybe the applicant would like to comment. I'm still a little confused.

MR. HOFFMAN: Chris Hoffman, Nuclear Fuels, PPL Susquehanna. The coupons are basically double-chambered. They have one dry chamber and one wetted chamber. The dry chamber is representative of the Boral can in its manufactured condition. The wetted chamber would be representative of Boral can if you add water infiltration. Coupons are taken out of the fuel

pool and analyzed on a periodic basis. So they are representative of the performance of the Boral in the actual pupil.

MEMBER ARMIJO: Just to put it to bed, have you actually inspected the Boral in the racks at any point? Just to make sure everything's okay.

MS. GETTYS: I believe they've had camera inspections also.

MR. HOFFMAN: We have not inspected the Boral in the racks. We use the coupon testing program as a representative sample of what is in the racks.

MEMBER ARMIJO: Okay. That's all I have for that. My second question had to do with the dissolved oxygen in order to justify the environmental correction factor. Is there any requirement - the data that's used to - the historical data, was that data required by tech specs in the plant operation? Does Susquehanna have to take that data even today by tech spec, or is that just something they record as a routine operational matter?

MS. GETTYS: I'm not sure if it's part of the tech specs or not.

MEMBER ARMIJO: Does Susquehanna know?

MS. GETTYS: I believe they're coming to the mic right now.

MR. MILLER: If I understand the question, are you asking do we take dissolved oxygen measurements as part of our tech specs or some -

MEMBER ARMIJO: Yes.

MR. MILLER: Okay. We measure dissolved oxygen in reactor water and feedwater to comply with the EPRI BWR water chemistry guidelines. They are not technical specification-related.

MEMBER ARMIJO: And your historical data actually was before some of those guidelines, so you were taking them for your own purposes I guess?

MR. MILLER: Yes. The guidelines were issued circa 1982 so yes, I suppose a few of those could have been before the guidelines. Yes.

MEMBER ARMIJO: Okay. So in the future you're just going to take it to be in compliance with the EPRI guidelines on water chemistry?

MR. MILLER: We are also putting in an

administrative limit for feedwater dissolved oxygen not to exceed 50 parts per billion. Now that is more conservative than the current guidelines.

MEMBER ARMIJO: Okay, thank you.

MEMBER SIEBER: Could you state your name?

MR. MILLER: I'm sorry. My name is Dan Miller, Station Chemistry, Susquehanna.

MEMBER SHACK: Do you have a minimum on the oxygen content for the feedwater?

MR. MILLER: Yes, we have a minimum of 30 parts per billion.

MEMBER SHACK: Any further questions from the committee? Thank you very much.

MS. GETTYS: Thank you.

MEMBER SHACK: We are ahead of schedule, Mr. Chairman, but I'll turn it back to you.

CHAIR BONACA: This has been a very efficient presentation. Looking at the agenda we have for today I think we will have to simply adjourn now - I mean, recess now for lunch and start again at 1:15. Okay. Let's recess until 1:15.

(Whereupon, the foregoing matter went off the record at 11:32 a.m. and went back on the record at 1:15 p.m.)

CHAIR BONACA: So, let's get back into session. The next item on the agenda is Steam Generator Action Plan, Task 3.5, A Risk Assessment of Consequential Steam Generator Tube Ruptures, and other SGAP items. And Dr. Powers will take us through the presentation.

MEMBER POWERS: This is actually under the purview of our Materials, and Metallurgy, and Fuels Subcommittee headed by up by Mr. Meagle, at his behest in this process.

MEMBER SHACK: And I should point out that I have a conflict of interest in this, since Argonne did a substantial amount of work on some elements of the steam generator program.

MEMBER SIEBER: Say that again.

MEMBER SHACK: I have a conflict of interest because Argonne was involved in work on the steam generator -

MEMBER POWERS: Understand, of course, that the steam generator tubes are part of the primary system pressure boundary, and rupture of those steam generator tubes has been recognized

since PWRs came into existence as a failure of the primary pressure boundary. And they are subject to a great deal of scrutiny during plant operation.

Over the years, a mechanism by which steam generator tubes degrade in time has evolved. I hasten to comment that rupture of a steam generator tube is a design-basis accident. Plants are designed to cope with such an accident. And, indeed, we have such events, and the plants have coped well.

Over the years, the mechanism that leads to a steam generator rupture through corrosion has evolved from a corrosion process that resulted in tube wastage, to one that involves cracking. Wastage, of course, is the removal of material, and is relatively easily detected. And the regulations were originally configured to account for that wastage. Whereas, the mechanism that leads to cracking would have alternate ways of detection and interpretation.

The industry evolved, and an alternative repair criterion was established based on voltage of the turbine. But there was a probability of detection. And, of course, that

means that there's a probability of non-detection. And, consequently, tubes that have flaws in them are -- generally exist in steam generators, and plants are allowed to operate.

This raises the question of can you have accidents initiated by other means that evolve into a steam generator tube rupture accident? Why would we care, if that evolution took place, of course, is that where the activity that gets released would pass directly into either auxiliary buildings, or, in some cases, directly to the environment without having benefit of mitigation by systems within the containment in cold bypass accidents. And, typically, though rare, they certainly can dominate the risk at pressurized water reactors.

At any rate, the Staff has been addressing steam generator tubes for some time through an action plan. And ACRS, in a review of the alternative criteria for evaluating flaws in tubes, made a variety of recommendations that the Staff added to their action plan, and have pursued. And they pursued them sufficiently far that they think that it's time to bring this action plan to a close.

The closure here is different than completing the research. Closure here does not mean topics all come to an end, and we never look at them again. And we have a report to write up, and it is the definitive word on the subject, and will stand for decades to come.

Closure, here, is a general thing, which means that the research moves into the regular research program, and becomes directed more toward the needs of the line agency, line organizations in the agency, NRO or NRR, one or the other, what they need for their particular activities, as opposed to a more generic research looking to make sure we understand the width and the breadth of this subject.

Staff has come to us and said gee, we'd like to close this research, close this action plan. Not really close the research, but close the action plan. Staff came to us to discuss this because based on our report some time ago, the Commission actually asked us to watch the action plan. And, episodically, we have over the time. So, the purpose of today's discussion is for the staff to describe both parts of the action plan that they have not previously closed out,

usually with our -- coming to us and discussing their closure on. And, in the main, what they're going to discuss is the work done on the problem of induced steam generator tube rupture; that is, something causes a plant to enter into an accident. And that accident evolves in a direction that involved ruptures in generator tube, and venting of radionuclides to the outside.

And, again, what they're asking to do, they will articulate, I'm sure, but, in general, what they're asking us to do is to close these items in the action plan. And where additional research will be needed to support the line organizations, that research will be initiated based on a user need letter.

Okay. Are there any questions on that introductory part? With that, I will ask David Beaulieu to begin the presentation.

MR. BEAULIEU: My boss, Tim McGinty, is going to be -

MEMBER POWERS: Oh, I'm sorry. Tim. Tim is going to start. Sorry about that, Tim.

MR. McGINTY: Just a couple of opening remarks. First off, thank you very much, Dr. Powers. Good afternoon, Mr. Chairman, and members

of the Committee. I'm Tim McGinty, Director of the Division of Policy and Rulemaking in NRR. It's the division responsible for the project management of the Steam Generator Action Plan.

First off, I'd like to thank the Committee, and the Subcommittee for taking the time to review the staff's work, in light of the large amount of supporting documentation, and the history associated with the Action Plan.

Today, Dave Beaulieu is the lead Project Manager for the Action Plan, and he'll be providing the opening staff presentation. Others that we have here are Bob Palla from NRR, and from Research we have Chris Boyd, and Tim Lupold, and Selim Sancaktar. And, also, in the audience we have various staff members who contributed to the Action Plan close-out effort, particularly, Ken Kowalski and Evan Murphy, that I would call to your attention.

As I mentioned, Dave will begin with the presentation providing an overview of the Steam Generator Action Plan, the desired outcome of this meeting, and future plans regarding steam generator research activities. The staff has completed all of its work on all steam generator

action items, and has provide the close-out documentation to ACRS.

And, as Mr. Beaulieu will explain further, the desired outcome of the ACRS review is a letter from ACRS that finds acceptable the staff's close-out of each action plan item that ACRS has not previously reviewed, and closed.

Following the ACRS review, the staff would like to close the Steam Generator Action Plan. So, with that said, I apologize also in advance, because I have another commitment at 2:00 that I'll need to depart for, and I appreciate your understanding in that regard.

MEMBER POWERS: Oh, no understanding at all.

(Laughter.)

MR. McGINTY: It's on pandemic. So, Dave.

MR. BEAULIEU: Thanks, Tim. We'll keep to our schedule here. I'm Dave Beaulieu, Project Manager. And I'm going to start out with Steam Generator Action Plan history.

During the NUREG-1150 severe accident risk studies from 1985 to 1990, the issue of consequential steam generator tube rupture was

evaluated. What we mean by consequential tube rupture, is that we mean that instead of the steam generator tube rupture itself being the initiating event, consequential tube ruptures refer to those ruptures that may be caused as a result of another initiating event, such as a very large main steam line break that leads to a high differential pressure across the steam generators, or severe accident condition that leads to the failure of steam generator tubes.

For severe accident-induced steam generator tube ruptures, the concern was that high temperature gases created during core damage sequences could cause steam generator tubes to be the first component in the reactor coolant pressure boundary to fail, resulting in a potential containment bypass, and the release of large amounts of radioactive material outside containment.

NUREG-1150 quantified the frequency of this occurrence in the low ten to the minus six per reactor year on the basis of expert elicitation.

MEMBER APOSTOLAKIS: This was the frequency, the initiating event, plus the -

MR. BEAULIEU: Of?

MEMBER APOSTOLAKIS: The whole thing.

MR. BEAULIEU: Of an actual bypass.

MEMBER APOSTOLAKIS: A bypass, okay. Yes. But did they say anything about the condition or probability of the consequential failure?

MEMBER POWERS: In fact, it's about ten to the minus two.

MEMBER APOSTOLAKIS: Ten to the minus two.

MEMBER POWERS: This is a product of expert elicitation, so it's actually a distribution.

MEMBER APOSTOLAKIS: You really liked Dr. Powers jumping in, didn't you?

MR. BEAULIEU: Yes, I like that.

In the early 1990s, the industry made several requests for relaxation of regulatory requirements regarding steam generator tube integrity. A differential -- a differing professional opinion was filed involving concerns with these industry relaxation requests, given that eddy current methods could accurately measure uniform tube wall thinning as a result of general corrosion, they were less reliable in detecting

and sizing cracks that occurred in Alloy 600 tubes, as a result of stress corrosion cracking.

The staff review of these requests identified that granting them might substantially increase a conditional probability of containment bypass during core damage accidents.

At approximately the same time, in the early 1990s, NRR, with the assistance of Research, began a study of the effects of severe accident conditions on tube integrity, as background information on a proposed new rulemaking on tube integrity. The results of this study published as NUREG-1570 indicated that the risk is controlled by the current tube integrity requirements to a value that is low enough that no new rulemaking was needed. The NUREG was not intended to address DPO, necessarily, and DPO is still open at this time.

In 2000, following the rupture of the steam generator tube at Indian Point, Unit 2, there was additional focus on the resolution of several longstanding issues, including the DPO. The DPO was referred to ACRS by the EDO for resolution.

After extensive public meetings, and

review of the issues raised in the DPO, the ACRS published NUREG-1740, to present its conclusions and recommendation. In particular, ACRS concluded that the methodology being used to quantify the risk of containment bypass under high temperature challenges to steam generator tubes was not technically defensible.

The technical staff in NRR and Research jointly reviewed the text of the ACRS NUREG-1740 to extract a list of issues that required additional work. These tasks were incorporated into a new section of the steam generator action plan, which identified specific staff members with lead responsibilities for each task, and schedules for completing each task.

Most, but not all, of the steam generator action plan tasks are directly related to work that defined the risk associated with severe accident-induced steam generator tube ruptures leading to containment bypass.

Section 3 of the action plan also included work, such as that performed under Items 3.1 and 3.11 of the action plan, that involve design-basis events, which address the potential for damage progression of multiple steam generator

tubes due to steam generator depressurization events, such as a main steam line break, or other type of secondary side design-basis accident.

The staff's work to address steam generator action plan items involving design-basis events is complete, and ACRS has reviewed and endorsed the closure of these items. This was based on the overall conclusion of the work, which is that the dynamic loads from such design-basis events are low, and do not affect the structural integrity of the tubes, or lead to additional leakage or ruptures beyond what will be determined using differential pressure loads across the tubes alone.

MEMBER POWERS: It is fair to say, isn't it, David, that that's a generic endorsement, that you still have to validate for each plant that, in fact, they fit the constraints that existed on that conclusion. That is, the plates have to be locked, and not left easily, and things like that.

MR. BEAULIEU: That's true.

MEMBER POWERS: Yes, you answered -

(Laughter.)

MR. BEAULIEU: Where does the action

plan stand today? The staff has completed its work to close all the steam generator action plan items, and a close-out document has been provided to ACRS. The purpose of this meeting is for ACRS to review all action plan items that ACRS has not previously reviewed and closed.

The desired outcome. The staff requests a letter from ACRS that finds acceptable the staff's close-out of each steam generator action plan item that ACRS has not previously reviewed and closed. These items are 3.1.k, 3.4, 3.5, 3.10, 3.11, and 3.12.

So, what can you expect to hear from us today? Essentially, all the items are directly related to the work to define the risk associated with severe accident-induced steam generator tube rupture leak on containment bypass. This work involved the following technical areas of research, including thermal hydraulics, steam generator tube material failures, reactor coolant system material failures, component behavioral studies, and probabilistic risk assessment.

The way these work together is the thermal hydraulics work takes the PRA sequence being evaluated and determines the fluid

temperatures, and pressures as a function of time. These conditions are then used as inputs into the reactor coolant system material failure and component behavior models.

Finally, all the thermal hydraulic information, and the material failure information are logically combined into a PRA model to determine the risk associated with a consequential steam generator tube rupture.

Future activities. While the close-out documents for each steam generator action plan item provides a solid basis for closing the item, NRR User NEED to Research is in concurrence that requests specific research products to facilitate the development, and review of future risk assessments involving consequential steam generator tube rupture events. These products will build upon the analysis methods, tools, and expertise developed as part of the steam generator action plan.

The research work to address the NRC User Need no longer requires the level of coordination and agency focus that's required to implement an action plan.

MEMBER APOSTOLAKIS: What does that

mean?

MR. BEAULIEU: It's that the level of review, the action plan process is a higher level review. It's something that can't go away. It has to be done, and it's not -- in my next few -

MEMBER APOSTOLAKIS: Why did you think it was important for you to tell us this?

MR. BEAULIEU: Okay. In my next statement, I'll explain that. Consequently, the closure of the action plan does not preclude future research activities, but we'd simply like the future activities associated with a topic to be coordinated with other agency tools, such as User Needs. In the planning and budget process means that the work going forward goes into all of Research's work, and based on risk, it's budgeted and prioritized consistent with all the work that's on Research's plate. And we'd like to do that in the future versus adding new additional steam generator action plan items. We've completed the work on the current items.

MEMBER APOSTOLAKIS: Well, I think what you're saying is that the basic work has been done.

MR. BEAULIEU: Basic work has been

done.

MEMBER APOSTOLAKIS: It's just guidance how to do it on a plant-specific basis.

MEMBER POWERS: You can certainly agree to disagree with me, but my perception is that an action plan was formulated here because there was a question on whether the existing regulatory structure provided adequate protection or not. And, therefore, reach a high priority. I think that when we close this out, we're essentially saying the staff has done enough work now to say well, the issue of adequate protection as a generic undertaking has been addressed.

Now, that does not mean that in specific things, there will not need to be additional research done in order to look at a specific question that came up. But the generic question of are we providing adequate protection is a satisfactory answer. Is that a fair -

MR. McGINTY: I don't disagree with that. And we just wanted to be careful not to have any kind of a misunderstanding, either with the Committee, or the public, that this represents, or precludes additional research, as necessary.

MEMBER SIEBER: Well, I'm curious about one thing. One of the items you want to close, the basis for your closure is that you intend to do additional work. Plus, it says it's okay to close that item, but what prompts you to track the tactic you're actually going to do that additional work, when you don't really have the funding or the approval to do it?

MR. BEAULIEU: We have User Need that is one particular topic that Bob Palla will be discussing with you today that covers the User Need that's currently in concurrence. And pretty thorough research has concurred on it so far, and it's in the final throws of NRR management.

MR. McGINTY: Right. So, I can't, necessarily, say it's agreed upon and approved yet, but I would also say -

MEMBER SIEBER: Yes. On the other hand, to the legitimate sense, since these action plan items came from our NUREG, the ACRS' NUREG, why would we close an item when the work really isn't done? What you're telling us, the work isn't done, in that one item.

MR. BEAULIEU: I'm not sure which one. We think the work is done -

MEMBER SIEBER: By the time you're done, I'll find it.

MR. BEAULIEU: Okay.

MEMBER SIEBER: Okay.

MR. BEAULIEU: Yes. We think we've provided sufficient basis for closing all the items.

MEMBER SIEBER: Why don't we listen to that.

MR. McGINTY: All right. Fair enough.

MR. BEAULIEU: With that, we'll go to the easiest item. This will take just a minute. This is just simply an administrative item, steam generator action plan item 3.11, was GSI-163. ACRS has reviewed, and found acceptable, and closed GSI-163. But in the staff's presentation, we never mentioned that, by the way, this is also Item 3.11 of the action plan. So, this proposed document that Item 3.11 is closed.

MEMBER POWERS: We have to do that, because the Commission sent us a letter to track these items. So, consequentially, we've got a little mechanics here, anyway.

MR. BEAULIEU: Okay. With that, our next presenter is Chris Boyd.

MR. BOYD: My name is Christopher Boyd. I'm from the Office of Research. And I'm going to talk to you about Action Plan Items 3.4A-G. I don't list them. I believe you guys have a record of what they are. But, basically, it's the thermal hydraulics calculations, the system, number of predictions, and then some of the detailed 3-D predictions that go in behind that. So, what I have is the unenviable job of trying to explain how, after four, or maybe up to 18 hours after a severe accident, we're going to predict that hot leg failure occurs five or six minutes prior to steam generator tube failure. And how is that possible.

MEMBER CORRADINI: And the uncertainty in that.

MR. BOYD: And the uncertainty. It's, obviously, something we're concerned about. So, this is the gist of the topic.

We have four NUREGs out that summarize. Two of them are draft, two of them are final. We have identified the action plan items, and addressed them one-by-one, with specific memos, that I assume you have copies of.

The NUREGs do a different job. They

look at the whole picture, and try to answer the action plan items. But, in addition, they answer many other questions that were uncovered, and try to put a full coverage of the issue. So, we have a large report on the system analysis, that tries to give an idea, and maps out where the problems are, where we might expect there to be a probability of containment bypass, and where we don't have that. And then we have some supporting CFD analysis that is needed to augment some of the three-dimensional details in those calculations.

So, I want to go over, quickly, what a typical scenario is. This is something we consider a fast scenario. This is where we did our sensitivity studies, and I'll explain why. We start with a station blackout, and we also need to assume that diesel generators are going to fail. And then, if we're going to challenge the tubes, we also have to assume that the auxiliary feedwater systems will fail. In addition to this, I don't have it on the slide, we'll also have to assume that the secondary side depressurizes. Without all -- you need to have high dry low conditions to challenge the tubes.

MEMBER BANERJEE: What's the

probability of all these things happening together?

MR. BOYD: That I don't -- I won't speak to that, because I may make mistake.

MEMBER APOSTOLAKIS: This is in thermal hydraulics system.

MEMBER BANERJEE: I know, but we must be informed by PRA viewpoint here.

MR. BOYD: I don't have it off the top of my head.

MEMBER APOSTOLAKIS: It's pretty low.

MR. BOYD: I've asked these questions, and was told that it's a very, very low probability. But because of the potential consequences, it's something we look at.

MEMBER BANERJEE: Is that sort of -

MR. BOYD: This would be a question for our PRA group.

MEMBER APOSTOLAKIS: So, we are still in adequate protection space, Dana. Right?

MEMBER POWERS: No, this is -- you are automatically into severe accident space, because you've had a dual failure here.

MEMBER CORRADINI: Then you original comment, Dana, I didn't appreciate. Then why was

adequate protection not deemed appropriate at the beginning, not because of -

MEMBER POWERS: The action plan was set up with questions of adequate protection. Most of those design-basis considerations we previously dealt with.

MEMBER CORRADINI: Oh.

MEMBER POWERS: The new steam generator issue arose -- I think it really came up full force during the course of NUREG-1150.

MEMBER CORRADINI: That's what I thought.

MEMBER POWERS: And it was triggered, because we know that we're looking at tubes now with eddy-current technology that have cracks in them. So, there's some probability that the eddy-current device simply won't detect a crack which is sufficiently large, that will grow over the course of between inspections. And the severe accident issue becomes since the steam generator is now, in some sense, degraded unbeknownst to us from the full-force, we raise those questions in the form of recommendations in the review of this overage criterion for using eddy-current. So, they just folded them into the action plan.

MEMBER CORRADINI: Okay. All right.

MEMBER POWERS: I mean, that's the distinction.

MEMBER BANERJEE: But if the -- I guess I'm still trying to understand, Dana, that if this is a very, very low probability event, does it need to be considered?

MEMBER POWERS: No, this is probably a frequency-dominant event for many PWR units, station blackout, failure of diesels. And then something else happens, so I would -- I mean, it's going to vary from plant to plant, but a number around one times ten to the minus fifth is not -

MEMBER BANERJEE: One times ten to what?

(Off mic comments.)

MEMBER BANERJEE: Okay.

MEMBER POWERS: Ten to the minus five, ten to the minus six ball park is the right ball park.

MEMBER BANERJEE: That is the right ball park. Okay. In that case, I withdraw. I got an answer.

MEMBER CORRADINI: Oh, that's high enough for you?

MEMBER BANERJEE: Yes.

MEMBER CORRADINI: Okay.

MEMBER BANERJEE: I mean, if it was ten to the minus fifteen or something -

MEMBER POWERS: Only in the metallurgical fields do we countenance numbers on the order of ten to the minus sixteen.

MEMBER BANERJEE: Okay.

MEMBER POWERS: Only when you do probabilistic fracture mechanics.

MEMBER POWERS: That's right. That's right.

MEMBER APOSTOLAKIS: This is a necessary condition.

MEMBER POWERS: The unit of time in probabilistic fraction mechanics is ten to the minus forty-fifth.

MEMBER CORRADINI: I guess, I -

MEMBER APOSTOLAKIS: I think so, yes.

MEMBER CORRADINI: Not to get to the number, but I guess I wanted to make sure, just to follow-up with what Sanjoy was asking, so I understand it properly. So, it's not a matter of adequate protection at this point. This was folded into the action plan, and this is what's

now being assessed.

MEMBER POWERS: That's right.

MEMBER CORRADINI: Okay.

MR. BOYD: Thank you. That saved me from guessing at exponents. So, we start out, and because we don't have auxiliary feed, of course, we start losing inventory on the secondary side. We also have a small reactor coolant pump seal, loss of coolant accident. At some point, around 100 minutes, we would dry out the steam generators. At this point, the primary system would pressurize. We'd start cycling the pressurizer relief valves. Losing inventory in the primary side, at some point the inventory will drop low enough that we'll lose full loop circulation. We'll continue to boil off -

MEMBER BANERJEE: This is a question. When you cycle the pressurizer relief valves, would there be any significant loss of inventory through that, or is it always through the loop seals?

MR. BOYD: No, we do see significant inventory going up through that at certain points in the transient, yes. You're boiling off. You've got some -

MEMBER BANERJEE: Yes, but you're not getting any liquid. It's all -

MR. BOYD: Well, obviously, at some point, there's some liquid. But as the level goes down, it actually goes liquid-solid at some point.

MEMBER BANERJEE: So, the TMI scenario.

MR. BOYD: Yes, so we do lose -- I don't have the numbers, though, the fractions of what we lose.

As the primary inventory continues to drop, at some point, it will drop below the hot leg, and we'll start getting superheated steam coming off the core. At this point, there's a three-dimensional natural circulation flow pattern that will set up to carry energy from the core out into the loop. This flow pattern has been observed experimentally at one-seventh scale.

With continued inventory loss, we'll get collapsed liquid levels down near the bottom of the core. At some point, we'll start to get oxidation, additional energy being dumped into the system from that reaction. At some point, the system oxidation power becomes an order of magnitude higher than the decay power. At that

time, we'll get a significant system heat-up, and temperatures now are well beyond what the structures can take. And when these temperatures become absorbed in the structures, they will fail.

Again, I'll point out you need the high-dry-low conditions to challenge the steam generator tube, so we had to dry the steam generator, remain at high pressure on the primary side, and then also drop the pressure on the secondary side, through either a leak, or a stuck-open valve.

MEMBER CORRADINI: So, just hold right there for a second. So, that's why I don't think the -- I'm looking at Mr. Stetkar, where he said ballpark. Somehow, I don't believe we're in the five to ten to minus six ballpark with that many things happening coincidentally. That is, I have low-dry, I haven't depressurized the primary side. I seem to remember it was a much lower probability estimate to get to this point.

MEMBER POWERS: They're not independent events.

MEMBER STETKAR: They're not independent events. The seals are going away because you have a station blackout. And

auxiliary feedwater has -

MEMBER CORRADINI: And I have no way to open the pressurizer relief valves to depressurize.

MEMBER POWERS: Even if you try, it takes forever to depressurize that system.

MR. BOYD: Well, we do transients, where we do open that. But, at some point, we lose battery power, and then it fails closed. That delays things, but it does not, ultimately, get us out of the scenario.

MEMBER BANERJEE: How long does it take to lose the battery power?

MR. BOYD: We've done four and eight-hour battery life.

MEMBER STETKAR: The key for the numbers, as Dana said, the keys for the numbers is it depends on the plant. And the key is it's in the minus five, minus six ballpark, as opposed to the minus two ballpark, or the minus ten ballpark.

MEMBER CORRADINI: But, I'm sorry to keep on dwelling on this, because I'm just -- historically, I've just forgotten. This is, essentially, a subset of TMLB prime. Right? Of that accident sequence. Okay.

MEMBER POWERS: And, remember, the secondary depressurization is also a consequential event.

MEMBER CORRADINI: Is a?

MEMBER POWERS: Consequential event. It's going to happen because the relief valves go, and they fail open the whole time.

MEMBER SHACK: You can look on page 250 of NUREG-1570 to get a plot. And you will find they're between ten to the minus five, and ten to the minus six.

MEMBER BANERJEE: All right. We trust you guys.

MEMBER SHACK: Wow, my credibility has been enforced.

(Simultaneous speakers.)

MEMBER BANERJEE: I guess, intuitively, it feels like a far-out event, but all right.

MEMBER APOSTOLAKIS: It's not just any NUREG.

MEMBER SHACK: 1570.

MEMBER APOSTOLAKIS: Oh, okay.

MEMBER SHACK: 1570 was the early -

MEMBER ARMIJO: The action plan.

MR. BOYD: I'll also point out that this particular -- this is our most typical scenario. Once we've piled on all of these other assumptions, we get this three-dimensional natural circulation flow pattern. There's also another scenario that can evolve from this, and that is a scenario of clearing the loop seals. And on that scenario, this three-dimensional natural circulation flow pattern in that particular loop would be disrupted, and we would have full loop circulation. And then, at that point, we don't benefit from the mixing, which I'm going to discuss in a minute. And the tubes are presented with a much more significant challenge. And we do predict tube rupture.

MEMBER APOSTOLAKIS: You know, you have this real good picture there. Not once do you tell us what's going on here. Can you use a cursor maybe in the future?

MEMBER POWERS: You're going to have to excuse the speaker. We assumed the Committee was so familiar with this picture, it was unnecessary to explain it.

MEMBER BANERJEE: It is thermal hydraulics, obscure at any level.

MEMBER POWERS: As we all know, thermal hydraulics is such a fundamental and essential, we just assumed the familiarity.

MR. BOYD: But what we want to get from this, though, is that we've had a boil-off on the secondary side. And sticking on the secondary side, we've also either stuck-open a valve, or it has leaked down to a low pressure. On the primary side, we've also now lost all the inventory through a boil-off. We've gotten water level down very low in the core, and the key here is that we're now going to oxidize the core. The core is damaged. The power coming off the core due to this oxidation reaction is very high. Temperatures are going to skyrocket at this point. And, basically, the system is going to fail at some point. And the next slide will help us a little bit with that.

MEMBER BANERJEE: Maybe you should show them the flow patterns. Go back to the previous slide. Show them the refluxing more, and just explain those arrows.

MR. BOYD: Okay. That's a good point. This is -- it's not, necessarily, like reflux condensation. This is all superheated steam.

What we have is superheated steam coming off the core. And it quickly finds its way into the upper part of the 30-inch hot leg, runs along the upper hot leg like smoke across a ceiling, and then rises vigorously into the steam generator tube bundle, which forms almost a chimney effect, and really draws. It actually draws twice the flow into the generator as what comes across the hot leg, so it's very vigorous. The heat exchange in the steam generator is very good, as we would expect.

And then, because the loop seal is filled, this flow that goes up through the generator gets to the outlet plenum, and must turn around and come back. So, it's pushed back by the chimney effect of this heated flow going into the generator. So, we've got flow going around the steam generator, getting to the outlet plenum, and then being forced back through the tubes, mixing in the inlet plenum.

Now, this mixing is key. This what we're going to look at on the next slide. This is why the tubes are a cooler temperature. And then that flow is going to flow along the bottom of the hot leg, and waterfall back into the vessel,

stirring up the vessel, keeping the vessel fairly well mixed, keeping circulation patterns in the vessel going. So you've got that pattern going on, with the addition of some steam being generated in the vessel.

MEMBER BANERJEE: Can you also explain why you consider the loop with the surge tank rather than the -

MR. BOYD: Okay. We -- that was a question I saw. We consider all the loops. In the base case highest pressure case, which we consider our worst case, the tubes and the hot leg fail earlier in the loop with the pressurizer. And that's because the pressurizer is cycling, for one. That pulls an enormous amount of steam out to that loop, and actually pulls it away from the other loops a little bit. That's going to heat up the hot leg much more significantly than the other hot legs. And then it turns out with the hot leg hotter, and the pressurizer always drawing a little bit of additional hot steam, because it's pressurizing, and then releasing, that makes the flow down the hot leg hotter. Even though it's the same mass flow, it's hotter, and that challenges the tubes more. So, our first failures

are in this loop on our worst high pressure case.

Now, actually, when we go to a lower pressure case, this loop is no longer the first failure, but we're monitoring all the loops, the hottest tubes in each loop, the hot leg in each loop. So, we talk about the pressurizing loop because in what we consider the worst case, it fails first. But when I say fails first, it's not much difference, really.

MEMBER CORRADINI: So, just to make sure I understand. The heat exchange in the bundle is more just heating up the steel, or you're getting significant heat transfer to what is now a low pressure dry system on the other side?

MR. BOYD: No, there's not much on the secondary side. We are heating up the steel.

MEMBER CORRADINI: Okay.

MR. BOYD: And the next plots will help us with that. Here's the steam temperatures in the system. At the very top of this plot, I don't know if you have both of these plots. They're on top of each other on the slide. The top plot here is a core exit temperature. This is a trick of PowerPoint, they're laid on top of each

other.

MEMBER APOSTOLAKIS: Where is your cursor?

MR. BOYD: The top is the vessel, I'm sorry, the core exit temperatures. And then significantly below that, you'll have the hot leg entrance temperatures. And significant below that, you'll have the hottest tube temperature. So, this becomes the issue, how come the hottest tube is so much cooler than the hot leg? And then below that, we'll have the average tube, and then the steam generator tube return temperature. So, we'll talk in a minute about why these temperatures can drop like this. But let's look at structure temperatures next. And this has failure times imposed on it. And this becomes sort of the gist of the problem.

So, the upper curve is the hot leg inner wall temperature, structure temperature. The average temperature of the hot leg is obviously much cooler than this. I just picked the inner wall temperatures to plot. And let's -- I apologize, I have to go back one minute.

These are -- this plot has some inflection points on it that we talked about in

the earlier slides. If we look here where all the curves diverge, up until that point, they were sitting around the saturation temperature. Once the core starts to dump out superheated steam, things start to diverge at that point. You'll see the core exit temperatures going up very fast. You'll see the hot leg following, and everything else trailing in behind.

This is a key point. And that's where we reach peak oxidation. At that point, the power coming off the core due to the oxidation reaction has increased by an order of magnitude. That's what you see on this plot, they look nearly vertical. This is on the order of 25 degrees per second.

VICE CHAIR ABDEL-KHALIK: Now, these plots assume no operator actions.

MR. BOYD: I'm sorry. That's right.

VICE CHAIR ABDEL-KHALIK: These plots assume no operator actions.

MR. BOYD: This particular plot. Now, I would like to mention, though, that when we looked at a bunch of operator actions, that, ultimately, if -- let's say they stick open a PORV, and then they lose battery power, and the

thing sticks closed again, or there's some other operator actions that we looked at. Assuming no heroic activities to put water on the steam generator, or things like that, we end up getting to a temperature signature that looks very similar to this.

It might be 18 hours out, instead of four hours in this case, but it looks very similar. Once you lose the water in the core, and that oxidation reaction kicks off, and dumps all that power into the system, the loop temperatures look very similar to this.

VICE CHAIR ABDEL-KHALIK: But at these core exit temperatures, the emergency operating procedures would put the operation in, I guess, FRC-2, and then FRC-1. And the operators will find a way to get water to the primary system by somehow initiating safety injection.

MR. BOYD: I wouldn't argue with you, but these calculations are done to show what happens if they don't.

VICE CHAIR ABDEL-KHALIK: If that's the purpose.

MR. BOYD: Well, these -- my purpose isn't to explain the risk.

MEMBER CORRADINI: But you're assuming that it happens, and you're looking at the consequences.

MR. BOYD: I don't run many calculations where they keep water in the steam generator tubes, because they're boring. Nothing happens. That's going to weigh itself out in integrated risk assessment, but at the end of a PRA event tree, where all of this stuff that has happened, we know what happens, and that's what the purpose of these calculations are.

MEMBER BANERJEE: Chris, you keep some water in, because if you don't, then again, we go back one more slide. If the water is not there in that loop seal, the game is over.

MR. BOYD: That's right. There's water in the loop seal. There's also water in the lower downcomer. We predict this heat-up to occur before the water in the lower downcomer even totally evaporates. The top of the core is oxidizing, starting to relocate, things along these nature. So, we -- this is our best estimate prediction of what happens.

MEMBER POWERS: Then you start to get substantial steam oxidation to cladding starting

when the water level is about a third of the core height. Once it drops below the core support plate, you just don't get any heat -- massive amounts of heat transfer to the water. So, it takes forever to steam out the lower plenum.

MEMBER CORRADINI: You don't lose it. It's always there.

MEMBER POWERS: You have to really relocate fuel in order to boil that dry, typically.

MEMBER BANERJEE: It depends on how much is leaking out of the pump seal, whether you suck out the loop seal, I suppose.

MR. BOYD: Okay.

MEMBER ARMIJO: Just a quick question. You have a leak at the pump, something -- steam is coming out of that pump, but no water is coming out, because the pressure is the same on both sides. Is that what we're looking at?

MR. BOYD: The reactor coolant pump seal is going to be vapor. The loop seals, themselves, are eight or nine feet deep, which is going to be up higher than that. The suction point on the pump is not down that low, so we're going to be leaking steam.

MEMBER ARMIJO: No significant depressurization in the system with that leak? It's too small?

MR. BOYD: No, that leak is relatively small. Even at the highest reactor coolant pump seal leakage of 480 gpm equivalent, it's about a .6 inch hole, and we have a larger bypass between the upper plenum and the downcomer, just from the relief nozzles in the upper downcomer. That's about a two or three inch hole at the smallest, and that can be up to a 10 or 15 inch hole equivalent.

MEMBER POWERS: We're going to have to move on. We're getting kind of off schedule here.

MR. BOYD: I'll breeze through the last two slides. I only had six. This slide took two hours in the Subcommittee meeting, so I expect those guys -

So, the reactor coolant system temperatures are here. Now, just say, when we do the SCDAP-RELAP calculations, all we consider ourselves doing is a screening calculation. We're looking at the scenarios given to us, and we want to see if there's a possibility that the tube fails first.

We feel that we're a little bit on the conservative side, because of the way we do these calculations. Our hot leg failure model is a one-dimensional model. We've looked at three-dimensional models that show the hot leg fails actually earlier than what we predict. In our tube model, we use the hottest tube, and we assume flaws in it right above the tube sheet at the hottest location. And we also feel that we're a little conservative on our hottest tube estimate. So, we feel like -

MEMBER CORRADINI: So, you purposely degrade the strength of the hottest tube.

MR. BOYD: That's right. We degrade it to the point -- I'll show you on this plot what we do. Here's a hot tube in pristine condition, and it would fail at this point in time. If we multiply the stress on that tube by 1-1/2, it will fail up here much closer to the hot leg. If we multiply that stress by two, it will fail before the hot leg. Our screening criteria is to multiply the stress by three. In this particular plot, that puts the failure time at about just under 220 minutes, so we're failing that way out in front of the hot leg. And that is our

screening criteria. That will flag that scenario as a potential bypass, and will throw it off to the materials guys to do a more detailed study.

Now, I'll just go over this quickly, I hope. But the question is, how can we get all of that mixing, and how can the tube temperatures drop so low? And I'll just say that we have some three-dimensional CFD predictions. And they've been checked, or at least we looked at the one-seventh scale testing, and then we've extrapolated from that. This approach did very well at one-seventh scale. And we believe that we're doing an adequate job at these full-scale conditions.

I did not show a grid sensitivity study. I know we had a question, but we use a million cells. They're perfect cubes in the inlet plenum, which was much better than we did earlier, and we got the same answer. And then we also cut each of those down, and we made 8 million perfect cubes in the inner plenum, except right around the edges. And we got to within three significant -- the third digit is all that changed in that calculation. So, as far as the code goes, we're using the best available mesh with a Reynolds stress turbulence model, which has buoyancy

effects in it, so it's not isotropic turbulence. We're doing a kind of a state-of-the-art computation of fluid dynamic simulation. It's not largely -

MEMBER BANERJEE: How are you modeling the tubes, again? Remind me, Chris.

MR. BOYD: The tubes are -- we model the tubes as groups of three-by-three. Each tube is -- so, we have one-ninth of the total number of tubes. And we do a side study, where we model the tubes in great detail with millions of cells per tube. And then we use this larger tube, and we verify that our larger tube gives us the same pressure drop, and heat transfer characteristics as the smaller tube. Of course, to get that we have to boost the heat transfer and the friction.

MEMBER BANERJEE: Okay.

MR. BOYD: The key to RCFD calculations is this histogram. It gives us the temperature distribution. And, again, we have high confidence that at least with the tools we're using, we're not grid-dependent. We're using best practices on the mesh and the turbulence models. And this is where we pull off, on the right side of this histogram, we pull off what we consider

the hottest tube, and then we monitor that in our calculations.

MEMBER BANERJEE: So, coming back to that, the mitigation of the hottest temperature due to the movement of the plume non-steady nature is by how many percent? If you just took the hot part, not -- without taking into account the averaging effect of the plume meandering.

MR. BOYD: Okay. What Sanjoy is talking about is that this histogram that I'm showing here is actually just the hottest temperatures, irregardless of location. We looked at this in another way, where we focused on each tube individually. And what happens is, the hot plume moves off of the tube. So we looked at mass average temperatures into specific tubes. And what that did, that dropped the peak temperatures -- on this plot we have about .625 is the peak temperature, where we have a tube area that stays in that range; although, it's moving. We dropped that to .425 on this normalized scale.

Now, we've run the sensitivity studies, if we look in the code, we use .5 for our screening calculation. We're run the .625 in our code, and that makes about a three-minute

difference in the failure times.

MEMBER BANERJEE: Does it mean that you get a lot of tube failures before the hot leg? I mean, to the extent that these -

MR. BOYD: At .625?

MEMBER BANERJEE: Yes.

MR. BOYD: No, we still -- instead of having six minutes of margin between a pristine tube, we now have three minutes of margin. And instead of having to maximize the stress by about 1.6 to get failure with the hot leg, we only have to do it by about 1.25. So, it does reduce the margin, if you assume that higher temperature.

MEMBER CORRADINI: The higher temperature occurs, though, when you pen the plume, instead of letting the plume move around.

MR. BOYD: Yes.

MEMBER BANERJEE: Sucked and stuck.

MR. BOYD: What we did is, at each instant in time, we just looked at the peak temperatures, irregardless of where they were. But that's not a best estimate, so they dropped off a little bit on that.

So, in summary, the thermal hydraulic issues have been looked at in great detail. We

have a large NUREG that summarizes the system code analysis. We have maps of different parameters, and how they affect whether or not we have the potential for bypass. And then we have supporting CFD studies in NUREG-1781, 88, and NUREG-1922, which further support the system code analysis.

We're looking into future work, as needed, with the User Need that's coming over from NRR. And we haven't identified the details of that work, yet, but we may be studying the CE plant, and maybe looking into a little bit more of our uncertainties.

MEMBER CORRADINI: The User Need is exactly what?

MR. BOYD: I believe the User Need is going to be spoken about, Bob is going to talk about it.

MEMBER CORRADINI: Sorry. Okay.

MR. BOYD: At the end here.

MEMBER CORRADINI: Okay.

MR. BOYD: I was just making the point that we will continue to support the agency with this work, as needed. But we have answered the action plan items.

MEMBER BANERJEE: I guess, Chris, to

explain what Mike is questioning, it depends very much on the shape in the plenum, and its depth. So, if you have a plant with a shallower inlet plenum, you can get a different answer, because you get less mixing, and the plume can move easier.

But going back to the uncertainty work that you're talking about, this accident is ten to the minus five, ten to the minus six, so there's a broad range, factor of ten, I guess, or more, maybe. What would be sort of interesting to know is what is the probability that you would get a lot of steam generator tubes failing before the hot leg, in which case, you might get a bypass path. Is it 10 percent, is it 5 percent, is it 1 percent, ten to the minus one percent?

MEMBER POWERS: Sanjoy, one tube failing in a severe accident is a disaster.

MEMBER BANERJEE: Is it?

MEMBER POWERS: Yes.

MEMBER BANERJEE: Even one?

MEMBER POWERS: Yes.

MEMBER BANERJEE: All right.

MEMBER CORRADINI: You use -

MEMBER POWERS: No, you're venting

radionuclides directly to the outside. You go through the 25 rem at the site boundary with one tube.

MEMBER BANERJEE: Okay. But from a point of view of the hot -- even if you blow one tube, Dana, eventually, the hot leg is going to go, too. Right? In that case. If you blow say a fairly large number of tubes, I don't know what that number is, the system will depressurize, and the hot leg will not blow. Right? I mean, there is some point at which -

MEMBER POWERS: You're rating bad versus really bad.

MEMBER STETKAR: As I understand it, some of the risk assessment arguments have been made that even if one, or let's say a small number of tubes go first, that the hot leg will shortly thereafter fail, and the off-site consequences of these small number of tube failures are relatively small. That's what I understood from some of the -

MEMBER POWERS: And all that's true, and the question is, you're debating the prompt fatalities, or not. That's all that we're debating, is the prompt fatality issue.

MEMBER BLEY: It is not insignificant.

MEMBER BANERJEE: So, the sort of thing that would interest me, if I was -- well, you guys have asked the question, what is the probability, taking into account uncertainties, that we would get fairly large number of tubes failing, and the hot leg wouldn't fail? Did you ask that question?

MEMBER ARMIJO: Chris, just a question of clarification. The hottest tube moves around. Right? I mean, this isn't a stable -

MR. BOYD: The location of the hottest tube at any one time moves around, but we have identified which tube, on average, is the hottest tube. And that's been fairly consistent. It's the location, obviously, right above the nozzle.

MEMBER ARMIJO: Okay. So, it's going to be in that general region.

MR. BOYD: That's right. I've got one plot where I show the -

MEMBER ARMIJO: Move around so much that the temperature of the hottest tube could change a lot.

MR. BOYD: The temperature of the hottest tube can change a lot.

MEMBER ARMIJO: It can.

MR. BOYD: I does. The plume moves completely away from it. It actually sees some pretty cool temperatures at some point in time. And it continues to draw in that cooler fluid because of the chimney effect, so it's not just only drawing fluid when it's hot.

MR. LUPOLD: Hello. I'm Tim Lupold from the Office of Research. And I have one of the Corrosion Metallurgy Branches over there. And I'm going to talk to you about 3.4H, which was the task looking at the locations outside of the -- outside of the steam generator tubes in the RCS. What we needed to do was to evaluate three failures of these primary system components, things like the surge line, the hot leg. We had to evaluate other active component failures, but also included under that -- when I think active, I think a thousand problems, but also this included bolting and manways. And we had to determine the feasibility of the RCP seals leakage failure. And, if necessary, conduct large-scale tests.

This was taken and worked in three phases. Our first phase, we reviewed the methods and models, identified information needed. And

the key here is scoped the RCS components that needed to be looked at closer.

In Phase II, there was 3-D model developed on those selected components, utilized specific detailed drawings in that phase, and included operating experience.

Under Phase III, then we took -- we calculated the RCS component failure sequence, again. We did that under Phase II, but then did it again in Phase III, with some improved codes and modeling that was done, the RELAP and the CFD that was done. And, also, expanded the database for material properties.

Okay. Phase I workshop was held, and concluded it was possible to predict some of the behavior of these certain components, specifically, like the manway bolts. And then following the workshop, the building connections were modeled to predict failure times. And then we selected -- components were selected to undergo additional evaluation in the Phase II analysis.

In Phase II, the analysis was based on the Zion station. We looked at the hot legs of loop 4. As Chris explained, why loop 4 was selected, because of the pressurizer attached to

that, and the continual feeding of fluid into that loop. Okay?

We had results from RELAP5 from a hydraulic analysis that was used as inputs into the component evaluations. Failure times due to tensile and creep rupture were calculated using literature, where data was available, and if it wasn't available, we used extrapolated data, at times. Okay?

Sensitivity analyses were conducted to determine the variability of the predicted times. And various things, like the surface heat flux on the component, the conductivity, the creep rate, and yield strength of the components. And, also, we analyzed the stress/strain response due to the impact on the PORV, power-operated relief valve. MEMBER RAY: A comment was made earlier about power-operated relief valves, and I let it go, because you said well, the batteries wouldn't last. Now not all points are power-operated relief valves on the primary side, so I guess I'm wondering what effect that has on your analysis.

MR. LUPOLD: Well, under our analysis, it -- the power-operated relief valve operation

would be more of an impact on the thermal hydraulics calculations, and determine what the temperatures of the components were. We took the input from the thermal hydraulics calculations, and used that for the analysis.

MEMBER RAY: Well, I'm not sure what to take away from that.

MR. LUPOLD: If the PORV did not operate, then you would only be controlling your pressure via your safety valves.

MEMBER RAY: Correct.

MR. LUPOLD: Okay? So, you would probably end up having higher pressure in your system.

MEMBER RAY: Yes.

MR. LUPOLD: All right. Because you're operating at that level for the safety valves.

MEMBER RAY: It appears that way, so what's the result? What impact does that have on the result here, I guess is what I'm trying to figure out.

MR. LUPOLD: It, actually, does not have a major impact on the results. What really drove the results in our calculations was the

temperature spike that proceeded, and how rapid that temperature spike was.

MEMBER RAY: Okay. I'm just -- I'm trying to intuit what the effect is.

MEMBER SHACK: You can change absolute numbers, as Chris said. Things go back and forth, but, again, it's the relative failure times that's always of concern here. Everything is going to fail sometime, and the only question is which fails first.

MEMBER RAY: Well, all that being said, I don't want to take people's time. It's just not obvious to me that -- it's obvious to me that there would be a difference, like we said. What effect that would have on the answers we're talking about is what's harder for me to imagine.

MEMBER BANERJEE: Are you saying that for different types of plants, there would be sort of different outcomes?

MEMBER RAY: We don't have -

MR. LUPOLD: On some, yes.

MEMBER RAY: Yes.

MEMBER POWERS: Some of them don't have loop seals, either.

MEMBER RAY: Well, that's a different

question.

MEMBER BANERJEE: Well, the depth of the loop seals are very different for different plants. I assume you used Zion here. Right?

MEMBER RAY: That's what they use in the Zion. Yes. I understand. I've got to pick something. I just made a simple question, I'm just not clear what the implications of not having -

MR. BOYD: I can try to answer that. This is Chris Boyd from Research. If we're operating at the safeties, we would be at a slightly higher pressure. That pressure percentage-wise is not a real big deal, but you would have slightly higher stress in the tubes and the hot leg. This is kind of a materials issue, where we're heating things up, and we're bringing down the magnitude of the flow stress of the materials, is a simple way that I look at it, as a thermal hydraulics guy. So, as the thing heats up, it continues to get weaker and weaker. At some point, it will have a stress-strength ability that will equal the stress that's on it. And it's not much difference between the set points of the power-operated relief valves, and the safeties

from a percentage point of view. What is it, 4 or 5 percent, maybe, so the stress is going to go up by 4 or 5 percent. So, things are going to fail at a slightly lower temperature, but it's not a big deal time-wise.

MR. LUPOLD: And that pressure, actually, is through the entire RCS. It's not just in the tubes, like you said. So, you have that increased pressure on all your other components.

MEMBER RAY: I mean, I should have come to the Subcommittee meeting. I couldn't do that, so -

MR. LUPOLD: Let's go on.

MEMBER BANERJEE: Well, one of the questions which sort of arose was, when you do the CFD calculations, you're actually calculating the temperature field in the walls, aren't you?

MR. BOYD: No, we're not, not in the CFD calculations.

MEMBER BANERJEE: Oh, you're not. So, it's not coupled to the walls.

MR. BOYD: No. We looked at that as a sensitivity, but we're doing a quasi-steady calculation. And in that type of calculation, the

walls would all reach the fluid temperature. We do a three-dimensional finite element analysis of the temperature walls, of the walls, temperatures in the walls.

MEMBER BANERJEE: I'm sorry. Then, I didn't understand. I thought you had coupled the walls. So, what you have is the wall temperature sort of as a lumped parameter. Is that the way -- when you show metal temperature rising -

MR. BOYD: Those metal temperature rises came from the system level code, SCDAP/RELAP5. That was the one-dimensional heat structure inner wall temperature on the upper hot leg. We did some CFD analysis. I don't know if you saw it, where we did have the walls in place. And we believe there's mixed convection all the way down the hot leg. We don't account for that. That would put us on the conservative side. We have looked at that. But, in general -

MEMBER BANERJEE: There will be radial conduction from the -

MR. BOYD: There is radial conduction. That's right. And the cold boundary layer falls off the wall and causes mixed convection. We have all of that going on. We've looked at that, but

we don't use that in our calculations.

MEMBER BANERJEE: So, you're just taking -- so, it's quite conservative. So, you're just taking the top tube, if you wish, the top heat structure in the SCDAP/RELAP calculation in the -

MR. BOYD: That's right. We only moved it -- it's a screening calculation. We just look at the one cell closest to the vessel where it's the hottest. Right.

MEMBER BANERJEE: Okay.

MR. LUPOLD: Okay. To get back on track, to really answer your question, I guess, we didn't look at the situation where a --

MEMBER RAY: I mean, you ought to think about it, but if it's a material difference, that's fine. I was more thinking about whether operator action played any role in here, to open the PORVs at a lower pressure, or something of the kind, that would affect the analysis.

MR. LUPOLD: Well, obviously, that would affect it. But the analysis that we were doing, we were not assuming any operator actions.

MEMBER RAY: Okay.

MR. LUPOLD: Okay. So, the results of

Phase II are what you see on the screen right now. And these were the -- kind of a timeline, where relative, I don't have absolute times here, but you have core uncovery, and then you would have the RTD hot leg weld would fail first. Then the instrument line, then the instrument line weld, socket weld, and the surge line in the hot leg nozzle weld, the hot leg near the reactor pressure vessel, generator tube failure, and then you would have the surge line bend near the hot leg. These were the results from Phase II.

MEMBER BANERJEE: When does the metal-water reaction start in the core, or metal-steam react. Is that steam reaction?

MR. LUPOLD: Well, that would be some time after the core uncovery, before you actually had a failure of the RTD hot leg weld. It's that reaction that's necessary in order to drive that spike in temperature, in order to drive these into the creep range, and then have failure.

MEMBER BLEY: Some of the things you showed us in the Subcommittee meeting made that a lot clearer, that it really does -- if the timing until you get to that point is much different, it really doesn't matter much, because things happen

so fast. And then the timing is pretty constant, no matter how you -

MR. LUPOLD: Phase III, we made some improvements in the thermal hydraulic modeling. Refinements were made in the surge line, the hot leg connections in the RELAP model, thermal hydraulic calculations using RELAP were improved, high-temperature materials database was expanded. The enhancements actually did change the calculated failure sequence. And after the enhancements were made, it results in hot leg failing first, as opposed to the surge line.

And, also, there's still suggestions that the RCP seals could possibly fail prior to steam generator tubes failing. And we didn't go into that a lot here, but there are scenarios where if you have leakage of those components, they can reduce the pressure, and change the failure consequence.

MEMBER BANERJEE: Well, what sort of seals of these pumps -- the pump seals, but you say they could fail. How would they fail? I mean, isn't there a labyrinth in -

MEMBER CORRADINI: It's heat. They start leaking at higher temperatures.

MEMBER BANERJEE: They leak, but when you say fail, what does that mean?

MEMBER CORRADINI: They leak more.

MEMBER BANERJEE: Oh, but how much more?

MR. LUPOLD: That's a really difficult thing to answer. There was not a lot of work done to try and measure this leakage on the seals. This is just a possibility that, if we thought necessary, there could be added work done there.

MEMBER CORRADINI: If memory serves me, Westinghouse about 20 years ago at Triden had analyzed this, and they came up with two or three times the leak flow through, something on that order. It's a controlled leakage letdown system, so it's about three times the normal leakage letdown through those. That was a guess. That was an engineering guess at the time, I remember.

MR. LUPOLD: I had seen estimates on seal leakage, 25 gallons per minute per pump, up to a much, much higher value, depending on the damage that progressed, and the way the temperatures changed at the seals.

MEMBER BANERJEE: This is a steam leak we're talking about. Right?

MR. LUPOLD: Well, your fluid would flash to steam as its dropping pressure across the seal faces. So, you'd be flashing, you'd be flashing the steam immediately. And it would be a liquid flashing of steam until sometime in the evolution that you had steam in your cold leg at the reactor coolant pump seals.

Okay. So, then after this work was done, an expert workshop was held to evaluate these findings. And the general consensus there was that yes, seal failure could possibly occur sooner than previously estimated. There were no changes on the challenges to the failure sequence of the components. And we're not saying this will happen. They're just saying there's a possibility that it could happen. And if you had to make anything definitive on it, you would have to do some additional work.

So, overall conclusions, we felt we accomplished the intent of what the steam generator action plan item was, looked at the differences in times between components outside of the RCS. Again, seals could fail. And there is a -- there is some follow-on work on research that's being done. You've heard the User Need request

mentioned here a couple of times.

VICE CHAIR ABDEL-KHALIK: What would you do, and what is it that you're trying to prove by doing that work, the last bullet?

MR. LUPOLD: The additional work?

VICE CHAIR ABDEL-KHALIK: Right.

MR. LUPOLD: Actually, what they've asked us to do in the materials area was to come up with some flaw distribution in the steam generator tubes right now. And, also, look at -- and I'm not sure exactly what we need to do yet for the components outside the RCS, but there's talk about developing a flaw distribution which could be in some of those welds. There's a lot of negotiation that has to go on there yet, so I can make sure I can meet what their need is.

But, as you know, in the steam generator tubes these days, there's been a lot of steam generator replacements. They're now using 690. The current degradation mechanism in the generator is 690, is different than what it is in the steam generators that have 600 mill-annealed, or 600 thermally treated tubes in it. So, we are basically trying to rebaseline what the flaw distribution is.

VICE CHAIR ABDEL-KHALIK: I'm still trying to put my arms around the big picture, and I can't figure out what is it that you -- what additional information you would get with this follow-on research.

MEMBER CORRADINI: Asking it differently, are you trying to determine margin, a lack thereof, or an improvement of margin with the change in material? I guess -- that's what I assume.

MR. PALLA: I could talk about that.

MR. LUPOLD: Good, because I was going to have to defer that, because I'm just giving inputs into the other calculations that are going to be done.

MEMBER CORRADINI: He's helping -

(Simultaneous speakers.)

MR. PALLA: I'll just cover it a little bit later.

MEMBER ARMIJO: All right. In the future -- well, first of all, in your analysis, let's say at the RPV nozzle, it seems to me that's going to be the hottest part. Yet, you're failing -- at least at the Subcommittee, it seemed like you were failing in the straight tube part. How

detailed is your RPV nozzle analysis? Because we've got the carbon steel, which is very weak.

MEMBER SHACK: It's very detailed.

MEMBER ARMIJO: It is?

MEMBER SHACK: It's so mass -- I mean, I went back and I checked with Shurin after the Subcommittee meeting to ask. It doesn't fail very far down the hot leg, but you're down there in the stainless steel because the nozzle, although it's a weaker material, there's just an awful lot of it connected to a very large vessel.

MEMBER ARMIJO: And with the detail of that, it's machined down quite a bit.

MEMBER SHACK: Right. All that is in -- this is a detail finite element model that includes that from, essentially, the vessel down to the nozzle, down to the hot leg.

The other question that came up at the Subcommittee meeting was, when you say "fail", is this kind of -- you know. And what we did was, we based the failure on, essentially, the average stress thruster, so when this baby goes, it's going big time.

MEMBER CORRADINI: You mean it's not leak-before-break. I'm sorry.

MEMBER SHACK: It's going bang. And it will depressurize rapidly, at that point. But contrary to what you might expect if you only looked at the materials property, it really does seem to be the hot leg that goes first.

MEMBER CORRADINI: And nothing on the vessel head?

MEMBER ARMIJO: Yes. That's the other question. You've got all those jay-welds and all that stuff up there. Why doesn't that get hot?

MEMBER SIEBER: The things that fail before that are just not big enough to bring the pressure down.

MEMBER ARMIJO: That's the right answer.

MEMBER SIEBER: That's right.

MEMBER BANERJEE: It's a real doomsday scenario.

MEMBER STETKAR: Even on this slide that's up there, that slide that was up there -

MR. LUPOLD: Do you want to go back to it? Yes, the graph?

MEMBER STETKAR: No. The slide that -

(Simultaneous speakers.)

MEMBER STETKAR: The third bullet down there that says the RCP seals could fail prior to the tubes. They have to fail in a way that's big enough, also, to achieve that. It's got to be the kind of worst possible failure for that -

MEMBER SIEBER: It's got to be more than the sealed materials.

MEMBER STETKAR: That's right.

MEMBER SIEBER: I mean, that structure.

MEMBER ARMIJO: That doesn't look very likely.

MEMBER BANERJEE: If it fails, you might clear the loop seal, in which case, it would be a horror scenario.

MR. BOYD: We don't find that you have to fail them where there's more than the seals failing. There are some failure mechanisms, and I don't know the basis of them, but they have some different failure mechanisms for their reactor coolant pumps, and we find that we need the equivalent of about maybe 100 gpm per pump, which is within their failure modes. In fact, the most probably failure mode is 180 gpm per pump. And I'm not sure exactly -

MEMBER STETKAR: I thought they said 180 wasn't enough, that you had to be -

MR. BOYD: 180 is enough to depressurize the system. It's not enough to clear the loop seal.

MEMBER STETKAR: For the loop seal, okay.

MR. BOYD: It's enough to depressurize the system. And we could call it saving the tubes, but you take the pressure off the tubes.

MEMBER SIEBER: The pump seals are going to be one of the last things to go, because it's in the tube, so it's all -

MEMBER BANERJEE: If it has liquid, then it will get two-phased flow through it.

MEMBER BLEY: In this scenario -

(Simultaneous speakers.)

MEMBER BLEY: -- to go long before we get to these really bad things that are going on, because you've lost all power, you've lost all seal -

(Simultaneous speakers.)

MEMBER BLEY: So, they start leaking pretty soon, and they -

MEMBER SIEBER: Within an hour, I

would think.

MEMBER BLEY: Yes.

(Simultaneous speakers.)

MEMBER POWERS: I'm going to have to intercede a little bit. The question that the Committee is really addressing here is, have they done enough to close out the steam generator action plan. And they don't presume to have solved all of the research problems here. So, in order to keep us on schedule, I'd like to intercede and let them go ahead, unless you have questions that may strike to the heart of whether they have done enough to close out the steam generator action plan.

MEMBER CORRADINI: No.

MEMBER POWERS: Please continue.

MR. LUPOLD: Now I'll talk real briefly about Action Item 3.10, to address some concerns that the ACRS reported regarding our understanding of stress corrosion cracking, limitations of laboratory data and application of those to real field situations, and issues with the voltage and eddy current testing. Okay.

Actually, this particular item was not based on a specific ACRS recommendation that came

out of the NUREG, and operating experience we have on the plants indicates that plant practices for predicting flaw initiation and growth have been effective in assuring tube integrity consistent with the assumptions that were used in the risk analysis. And that the NRC staff, particularly NRR, monitors plant operating experience through the inspection process. And that there is really no additional work that needed to be done for the program, for the steam generator action plan on this item. So, we're asking that that be closed, since it actually was not part of the action plan recommendation from the NUREG. Questions?

All right. I'm going to turn it over to Bob Palla.

MR. PALLA: Okay. I'm Bob Palla. In the interest of time, I can ask the Committee if they want to hear all four of these items. I was going to run through four items, three of which are really covered by other actions, other items in the plan.

MEMBER POWERS: I think, Bob, it's useful for you to go through this, address some things, understanding that this is stuff that's coming.

MR. PALLA: Okay. The items that I'm going to discuss are -- that really is more administrative than technical. The tasks that we're looking at involve taking the results from the thermal hydraulic and structural analyses, and packaging that information for use in PRAs.

As I'll describe these tasks were deferred, not actively worked as originally intended. As part of the action plan close-out, we reassessed the original intent of this work to determine what additional work might be needed. We believe that the work completed to-date under the action plan tasks, combined with the work that we intend to include in the User Need request addresses the intent of the action plans, and that the tasks can be closed.

So, the first task is 3.1.k. It's called for using information developed in tasks 3.1.a through 3.1.j to evaluate the conditional probabilities of multiple tube failures for appropriate scenarios in risk assessments for steam generator tube alternate repair criteria. And these prior tasks involve the impact of dynamic loads on tube integrity.

The objective of task 3.1.k was to

calculate the leakage from existing steam generator flaws under differential pressure loads alone for the design-basis main steam line break, and the result would be expressed in the form of a probability distribution for total steam generator leak rate from the population of flawed tubes.

The planned approach was to develop the leakage distribution based on the RES developed flaw distribution for flaws in the free span. And this distribution is quite dated, at this point, but that was the plan, is to basically take that flaw distribution, combine it with formulas for predicting the occurrence of bursts and leaks in the associated leak areas, and then run RELAP5 calculations that would provide realistic flow rates through the leak areas associated with the bursts and leakage.

This information was to be used to support the resolution of GSI-163, which dealt with multiple steam generator tube leakage in design-basis accidents. This was Action Plan Item 3.11. We could also use that result in PRA.

The need for the calculation was diminished for several reasons. First, in Tasks 3.1.a through 3.1.j, dealing with the dynamic

loads from a steam line break, the conclusion was that these loads on the tubes were low, and did not lead to additional leakage or ruptures beyond what would be determined using differential pressure loads alone.

In addition, these performance-based technical specifications that have been put in place at all U.S. PWRs in the last several years as part of the industry initiative on steam generator tube integrity, this is the NEI Initiative 97-06. These measures will provide reasonable assurance that the potential for one or more tube ruptures, or the equivalent leakage from multiple tubes under normal operating conditions, or under DBAs, would be well within that which was assumed in previous risk studies. And the leakage from one or multiple tubes would also be limited to small amounts. So, we have that confidence coming from the way that these tubes are being maintained now under the performance-based tech spec. And, finally, most plants have installed replacement steam generators with more corrosion-resistant materials. And this has led to lower number of flawed tubes being left in service, and fewer proposals to increase the amount of leakage

that would be allowed under design-basis events. So, accordingly, we concluded that the calculations that were planned under 3.1.k are not needed, weren't needed to close GSI-163, and that this task can be closed.

Next task I'll be discussing is 3.4.j. The task called for putting information developed in Task 3.4.i into a probability distribution for the rate of tube leakage during severe accident sequences based on measured and regulated parameters for alternate repair criteria applied to flaws located in restricted places.

As background, Task 3.4.i provided analytical predictions of flaw opening areas and leak rates from axial and circumferential cracks under the tube support plate during a steam line break in severe accidents. And that work was performed at Argonne.

Although, under Task 3.4.j we had intended to put that information into a probability distribution, that work was actually done as part of Action Plan Item 3.5 that you'll hear about shortly.

Under 3.5, the Office of Research tasked Sandia and SAIC with developing a

methodology for integrating the results of PRA with results from supporting thermal hydraulic and materials engineering analyses. This will be discussed momentarily. SAIC developed an Excel spreadsheet to compute the probability of tube failure during an accident, and using the flaw distribution and a pressure temperature history for the accident.

Flaw distributions that were used provided for six defect types, including circumferential and axial outer diameter stress corrosion cracking at the tube support plates. And the Argonne models were used in this code to calculate the growth of each crack during the transient. So, what we conclude from this is that the SAIC model can be used to assess the impact of alternate assumptions, or models regarding leak rates from flaws in restricted places, which was the intent of this item. So, accordingly, the effort performed under Task 3.5 has achieved the intent of 3.4.j, and 3.4.j can be closed.

Next task is Task 3.4.k. This task called for integrating information provided by Tasks 3.4.a through 3.4.j, as well as Task 3.5 to address ACRS criticisms of risk assessments for

alternate repair criteria that go beyond the scope and criteria of Generic Letter 95-05, as well as criticisms dealing with other steam generator tube rupture, integrity and licensing issues in the way that they are dealt with.

ACRS concerns in this area included a specific concern, as well as a broader concern regarding the capability to perform defensible calculations in the area of severe accident-induced ruptures. The specific concern involved alternate repair criteria that credit indications restricted against burst.

The concern was specific to the South Texas project, that had stainless steel drilled tube support plates. And this is the only plant that this design in the U.S., and, subsequently, these generators were replaced. But the concern was that because the tube support plates, they're stainless instead of carbon, they didn't corrode. The tubes were not clamped in place, or dented; however, the crevices did accumulate debris, which was causing the steam generator tube cracking.

There was a concern that in a rapid depressurization event, the tube support plates could move and expose the cracks. And a measure

that was taken to limit the displacement of the tube support plates at that plant, several tubes were expanded at various tube support plate locations, which essentially locked the TSPs in place.

Now, getting back to the concern. When a flaw in this area, in the burst -- when the flaw is in that area, and the burst pressure is exceeded, the tube will not burst because of the physical restriction of the tube support plate, but the flaw will result in increased leakage.

The staff had calculated about a 5 gpm leakage per flawed tube in that region. Now, that result could have been used in a severe accident assessment calculation, but there was no action taken to actually do that, because these steam generators were removed from service. So, that addressed the specific Committee's concerns.

Now, the broader concerns involve other steam generator tube integrity and licensing issues related to flaws in the free span of the tubes, and the ability to perform severe accident calculations in a technically defensible manner.

Steam Generator Action Plan Item 3.5 that you'll hear about in a few minutes, was

specifically intended to address that concern. Based on results from the example applications performed under Task 3.5, Office of Research concluded that the contribution of induced SGTR events to overall containment bypass frequency is lower than, or about the same order of magnitude as containment bypass frequency due to other internal events. So, in light of that, RES recommended that plant PRAs should continue to evaluate consequential tube ruptures in the plant-specific PRAs, in accordance with the ASME PRA standards for PRA quality.

The methods and the results obtained through the research activities provide insights into the risk-significance of the consequential steam generator tube rupture, as well as a foundation from which risk implications of future steam generator tube integrity and licensing issues might be assessed. So, they've given us some basic tools.

As I'm going to tell you in a few minutes, we still think additional work is needed, but even though more is needed, the work completed under 3.5 has, effectively, achieved the result of what that action plan item was intending to

address. So, we think that 3.5.k can be closed, for that reason.

MEMBER POWERS: You mean 3.4.k.

MR. PALLA: 3.4. Yes, sorry. I'm going to move to 3.12.

MEMBER SIEBER: Now, before you start, this is the item that I first complained about -

MR. PALLA: I figured it was.

MEMBER SIEBER: And what you're posing is Steam Generator Action Plan Item to a future not yet approved User Need to research.

MR. PALLA: Well, this -

MEMBER SIEBER: So go through -

MR. PALLA: I'll introduce it very carefully, and explain how this action plan item was actually phrased, because what the task called for was reviewing the risk insights developed under Task 3.5, and assessing the need to complete a draft Reg Guide that was -- it was called DG-1073. It was called, "Plant Specific Risk-Informed Decision Making for Induced Tube Rupture." So, it was basically asking us, do we or don't we need additional guidance?

MEMBER SIEBER: That's correct.

MR. PALLA: Okay.

MEMBER SIEBER: And you haven't answered that question.

MR. PALLA: Well, I'm going to say yes, we do need additional guidance. And that's what we're going to be -- that's what the User Need is going to cover.

MEMBER SIEBER: I gathered the User Need, and this may be a mistake on my part, was to have Research decide extra guidance or not.

MR. PALLA: Well, they've given us guidance that they think is -- well, they've given us the method, they applied the method on an example application, a number of plants. They've drawn conclusions, and they think that their tools are sufficient to close 3.5.

MEMBER SIEBER: Right.

MR. PALLA: Now, we look at those tools and say well, will these tools be sufficient for us to use in the future should we get additional license amendment requests dealing with alternate tube repair criteria. Can we pick them up and use them, or do we need additional guidance? The answer is, we think we need additional guidance to make user assessments.

MEMBER SIEBER: And that's written

down.

MR. PALLA: That's written down. Yes, absolutely.

MEMBER SIEBER: Okay. I withdraw my comment.

MR. PALLA: Okay. At the time -- this original Action Item 3.12 was, I guess -- and the need for that guidance was identified COM-SECY-97-013. At the time, the NRC staff had concluded that the regulatory approach for assessing, or addressing steam generator tube integrity should be revised from issuing a new rule, to issuing a compliance-based Generic Letter, with supporting regulatory guidance. And that regulatory guidance was expected to include this DG-1073. And the idea was that 1073 would address how to make changes to the steam generator licensing basis consistent with Reg Guide 1.174.

Now, we didn't end up going in that direction. Instead, we had a decision to endorse the industry initiative, in lieu of the Generic Letter. And that Reg Guide was never developed. Now, when we came to looking at this action plan item, and saying well, what do we do now? Do we, or don't we need this guidance document that was

never developed? We did what the action plan item said, is look at the insights coming out of Task 3.5, and determine what you need.

Based on that assessment, we concluded that additional guidance and tools are still needed to support future risk assessments of induced steam generator tube rupture.

MEMBER SIEBER: Okay.

MR. PALLA: And the criteria, or kind of the logic, is summarized on the sub-items there. I'll just say briefly, Task 3.5, as well as numerous studies performed by NRC and industry over the last decade have not generically dispositioned the issue of steam generator tube rupture, induced steam generator tube rupture, or substantially reduced the inherent uncertainties in the analysis of these events.

Also, the work to-date, while sufficient to resolve the technical concerns regarding 3.5, there are certain limitations to that work that restrict its usefulness in supporting future risk assessments. For example, the risk analyses do not account for updated flaw distributions, or the results from the most recent thermal hydraulic analyses. So, the flaw

distributions in there are probably 20 years, based on generators as they were operated 20 years ago. And the thermal hydraulic analyses that Chris Boyd described, significant advances in thermal hydraulic modeling, both CFD and systems modeling at both levels, those results, the most recent, at least, have not -- were not really rolled into the work that you'll hear about on Task 3.5. So, you've got, potentially, much different flaw distributions, and flaw -- thermal hydraulic forcing functions, basically, that maybe not radically different, but maybe different enough that actually, if you kind of put that information together and turn the crank, again, you might see a substantial reduction in the conditional probability of tube failure.

Another thing that was not in there was the work that Tim Lupold had mentioned about the finite element analysis of the different structural components in the RCS. The calls that you'll hear about didn't have full advantage of those times. And, if you did, you'd have somewhat earlier times for some of these other RCS components failing.

The third sub-item underneath there is

that there's a PRA standard that identifies the need to address induced steam generator tube ruptures. This is one of the supporting requirements for quality PRA. That item -- in the standard, it references NUREG-1570 as one acceptable approach. And we noticed in our dealings with the industry that there's at least two other methodologies that are out there, and being used. Westinghouse has a simplified methodology. It's part of their methodology for simplified Level II modeling, but they've re-looked at steam generator -- consequential steam generator tube rupture, and have a simplified approach with their own conditional probability values for tube rupture. EPRI has a document that they've submitted. It's several years old now, but it's still -- it's newer than 1570.

We've not -- we know about this, but we've not reviewed these methods. And one of the things I'll mention with regard to the User Need, is the desire to look at those methods, and to do some comparisons with them.

And, finally, just based on anecdotal information, licensees are using these models. We've not really looked at them, and we're not

really sure what the peer review process, how that would work with these methods. It may well be that everyone looks at each other's PRAs and thinks everything is rosy. And, in reality, if we generated our own numbers today, maybe there would be some significant differences. So, the conclusions here are that we think that additional guidance is needed.

The guidance would address acceptable approaches for modeling and quantifying conditional probability events, consequential steam generator tube rupture events in future NRC and/or licensee risk models. It would also support staff assessments of the risk implications of new licensee proposed alternate repair criteria, if they should arise. The development of the guidance is part of a User Need, and it's very much far along. It's, basically, at our office level for signature now. We have some reformatting to do. There are no issues with regard to the desire to ask for the information, or the scope of the information that we've been asking for. There's been a lot of back and forth with our compatriots in Research, and general agreements on the nature of what would be done.

So, the conclusion that additional guidance and tools is needed, and the decision to proceed with the development of these tools meets the intent of the action plan. This gets to, I think, your concern. We're not trying to pull a fast one, but we look at the way the item was phrased, and asking for a decision, we say yes. And we think we know what we want to include in that User Need.

I didn't really plan to talk about it much, so maybe I'll just say the User Need letter, it covers four broad areas. CFE and system code calculations for CE plants, a lot has been done for Westinghouse. We think that some additional calcs for Westinghouse are still needed. For example, replacement generators have different geometries in the lower plenum of the generator that could affect the mixing in the hottest tube, and some of these conditional probabilities, so we may need to look at some additional Westinghouse plants, or at least look at what we've assessed so far, and determine if it covers the rest of the Westinghouse plants. But, clearly, CE plants is an area that not that much has been done. So, one of the key items in that first bullet is let's expand

the scope of what we look at to go from Westinghouse to now include some of the CE things.

One of the things that you may have heard about in the context of the SOARCA code, and I don't think Chris Boyd had the time to bring it up, but under SOARCA they've run calculations that have shown that even if you failed multiple tubes, initially, if the first point of failure in this consequential rupture scenario is actually tubes, you can fail multiple tubes. You mentioned eight tubes at the Subcommittee meeting, and even then, you would have a hot leg failure shortly thereafter that would basically pull the plug on the pressure loads, and knock the fission product inventories down to a percent, a couple of percent of the Cesium and Iodine. And like Dr. Powers had said, you'd exceed your 25 rem at the boundary, but this wouldn't be a LERF, if you're looking at the criteria for when do you have early fatality. So, the subsequent failures that look to be pretty robust finding for Westinghouse plants, may or may not pan out for CE, so that's one of the things we want to look at.

Also, the impact of in-core instrument tube failure on consequential tube ruptures, some

studies have been done by industry, Fauske & Associates have done some looks at TMI scenario. They like to study that.

MEMBER BLEY: Bob, at the Subcommittee meeting we did hear a comment about the tubes.

MR. PALLA: Right.

MEMBER BLEY: Although, I have to say, we have never seen that analysis yet.

MR. PALLA: Okay.

MEMBER BLEY: We haven't heard from those folks.

MR. PALLA: Yes. And I knew they said it there, but at this Committee today they didn't mention it. But this whole idea, that even if you fail the tubes first, it doesn't necessarily mean that's the only failure location.

MEMBER SIEBER: What about B&W plants?

MR. PALLA: We did not have any plan to look at that, thinking that there wasn't a concern in that area.

MEMBER SIEBER: Why is there not a concern?

MR. PALLA: I'd have to talk to somebody smarter than me to find out why that has never really been on the plate.

MEMBER SIEBER: Well, you're smarter than me, so that person is -

MR. PALLA: I think it's been looked at before, but it was never flagged as a concern. I don't know if it has to do with the basic structure of the generators.

MEMBER SIEBER: There's nothing that pops out to me that's obviously different, so I would -- I'm curious to know why that's the case.

MR. PALLA: Well, maybe we ought to reconsider whether we're complete enough. But, at this point, there's no plan, there's no mention of B&W. It's not on our radar. And I'll make a note to make sure that it shouldn't be.

Okay. The second item, second major bullet was updated flaw distributions, and structural -- RCS structural analyses. Now, the point of the second bullet, and the idea of updating the distributions is that the flaw distributions that are in the analyses done to-date are quite old. A lot of generators have been replaced. You have, perhaps -- you don't have the same types of flaws. You may have different flaws. You may have flaws induced by foreign objects bouncing around in the system. But you

would expect that the situation with replacement generators is quite a bit better. And if you looked at those generators, you'd probably have a different result than using the old distribution.

Similarly, the new performance-based tech spec, the population of tubes that are left in service with flaws is probably more favorable, so our expectation is if we can develop a reasonable updated flaw distribution, that's what we would like to use in these updated calculations.

Finite element analyses of RCS components. This just refers to relooking at the same kind of things that we looked at before, but with the latest thermal hydraulic analyses, and there were some, I think, weaknesses in the analyses. The TH work that was provided to our colleagues in Research that they used in the prior analyses of the different structural components, we think, for example, if you looked at the hot leg, that the heat transfer coefficients in the hot leg area are understated in those calcs. So, if we go back and come up with -- properly account for the heat transfer, it would probably increase some of the margin in the time. It would

probably result in earlier hot leg failures.

There was also some concern about the material properties not being properly fully accounted for in that area. So, the focus, I think, is going to be really on the hot leg, and maybe the surge line, but not the RCP seals. The seals are understood to be highly uncertain. There's actually a Westinghouse topical report in that deals with -- it's a seal mod, they call the shutdown seal that would be -- if implemented, would probably drive the likelihood of a RCP seal load, quite small, so the need to look at RCP seals, probably not too high on the list.

The third major item is guidance and tools for future risk assessments. And, in that regard, what we're looking for is something that is a bit more user-friendly, that we can use in future risk assessments. We're thinking along the lines of generalized event trees, improved guidance on the treatment of critical operator actions, things like B.5.B strategies, and how they might be able to be accounted for. And guidance on the probabilistic computer code that was developed. The guidance that exists, so far, is not in the form that somebody could actually

pick it up and use it, if they wanted to use it.

MEMBER BLEY: Bob, a couple of things came up at the Subcommittee on this, I'd like to mention for those that weren't there. One is, this is a personal opinion. I think the worry about how difficult the PRA was, what Sandia did for you folks is a little overstated, because they had to learn the plant. The PRA team that knows their PRA, and knows their plant would not have done -- would have saved well over half the effort that went into that, because they were doing an awful lot of coming up to speed.

The other thing is, we did ask the question -

MR. PALLA: So, it may not be as big a deal as we think, as we -

MEMBER BLEY: I think it might not be as big a deal for them to do it.

MR. PALLA: Yes.

MEMBER BLEY: And your people who own the models here, know those pretty well, too, now, because we had a separate team come in and do this from scratch.

The other point that came up was the little code you mentioned, that puts together all the thermal hydraulics and the structural stuff.

It's a little disturbing to learn that your experts in thermal hydraulics and fraction didn't review how that was actually done inside of the PRA. So, there was interaction for the PRA people to learn what they had done, and what the results meant, but there was never the opposite review back of how it was actually implemented in the PRA, and in that little CRYSTALBALL program to see if everybody agreed that those results were telling the right story.

MR. PALLA: I think that project -- that task never really went to completion, as it was intended to go. That Sandia/SAIC activity, basically, was brought to a screeching halt, and never -- we never really had documentation until very recently.

MEMBER BLEY: Okay.

MR. PALLA: Well, I mean, it existed, but we didn't have it in-house. And had to actually, after-the-fact, go and try to reconstruct, and so the tool as a tool would not be usable yet. So, we've made some major strides towards doing that. But, yes, the QA has never been done, so it's kind of like a black box. And we think we know what it's doing, but we're not

sure yet, having gone through the QA process. We want to make sure that the equations in there are the right ones, and that you're actually doing the thinking when you run that calculation. Which, it's heavy on uncertainty, that's what -

MEMBER BANERJEE: I'm sorry. I was out talking to Chris Boyd about the thermal hydraulics.

MR. PALLA: So, we made up some time.

MEMBER BANERJEE: Yes, you made up some time. But one of the -- so, you're not going to ask them to aggregate, and put together at least a first estimate of uncertainties and predictions?

MR. PALLA: You mean the TH area?

MEMBER BANERJEE: Well, really the impact on what is first. In some sense, if it's pretty resilient, that the hot leg goes before the steam generator tubes, then you've got a particular outcome, which is lower in terms of consequences, than if the -- a lot of steam generator tubes go, and the hot leg doesn't go at all. And I think there's been a fair amount of assessment done of this already looking at uncertainties.

MR. PALLA: Well, I think maybe Selim is probably the best person to address that.

MEMBER BANERJEE: I was looking at your User Need for that.

MR. PALLA: The basic -- the uncertainties really come together in that probabilistic code that marries the TH results with the tube flaw distributions. And in input to that, also, is timing estimates for the difference RCS components.

MEMBER BANERJEE: That was done somewhere.

MR. PALLA: It's all done in that probabilistic code, and the uncertainties are ascribed to the TH, to the time of -

MEMBER BANERJEE: But in order to do this ascribing of the uncertainties, you have to have something which tells you what the uncertainties are. Right? I mean, you just can't pull the uncertainties out of the air.

MR. PALLA: Well, we've done that before.

MEMBER BANERJEE: Yes, so -

(Simultaneous speakers.)

MEMBER BANERJEE: This is thermal

hydraulics. I would rather we did it in -

(Simultaneous speakers.)

MR. PALLA: Well, if you have the TH results, you can pass the TH pressure temperature histories to the people that are doing the finite element analysis for let's say the hot leg.

MEMBER BANERJEE: Yes.

MR. PALLA: They go off and they run -

(Simultaneous speakers.)

MR. PALLA: They tell you here's the flaw -- the timing distribution for when this component would fail given this TH profile. And, I guess, ideally, you'd have a distribution for the TH, so they'd have a time and a distribution of the time. That gets fed into the probabilistic code, which is taking that same TH history and convoluting it with the flaw distribution.

MEMBER BANERJEE: I understand the process.

MR. PALLA: Okay.

MEMBER BANERJEE: It's generating this distribution -

MEMBER POWERS: I'm going to, again, assert myself -

MEMBER SIEBER: Okay.

MEMBER POWERS: I was kind of enjoying watching you squirm, Bob. In order to keep on schedule, I do caution you -- I think there's going to be a great deal of interest in this User Need once it gets completed. It might be useful to send it over to us, and -

MR. PALLA: Actually, I think that Dave had given you an ML number for it, so -

MEMBER POWERS: Giving me an ML number is the same as hiding it in the recesses of your desk.

MEMBER MAYNARD: Dana, we're not being asked to approve all the ideas at this point. Just connected to the -

MEMBER POWERS: Well, we simply -- this is more for interest and things like that.

MR. PALLA: Yes, but if you got curious, I think you have the ML number, among many other ML numbers.

MEMBER POWERS: Like I say, giving me an ML number is the same as hiding it in the recesses of a dark closet.

MR. PALLA: Well, then the key points are on the slides.

MEMBER POWERS: I'd like to go ahead and move on.

MR. PALLA: The last item is that we think that a little better documentation should be done, because there's a lot of work that's been finished and documented in many different places. And we envision a summary document that didn't reiterate all of it, but at least provided a coherent roadmap, a summary document, but, yet, something more than a two-pager.

MEMBER POWERS: Well, I think one of the items that we certainly discussed at the Subcommittee was exactly that. I'd like to move on, and I'd like to finish up by 3:30, so we'll have to move summarily.

MR. SANCAKTAR: My name is Selim Sancaktar, and I work for the Office of Research in PRA. I have minus four minutes to give this presentation.

MEMBER POWERS: And that's an upper bound, by the way.

MEMBER MAYNARD: The uncertainty of you making it that has us worried.

(Laughter.)

MEMBER SHACK: No uncertainty.

MR. SANCAKTAR: Well, I'll start by saying that when I inherited this project about less than two years ago, my understanding of the objectives were the following. A lot of work was done, and the project was, basically, in a sense, wrapping up. The main objectives, in my understanding, were develop a method to assess the risk of consequential steam generator tube rupture, apply -- extend and apply to CE plants, external events, low-power and shutdown, and main steam line breaks. And make sure that we demonstrate the methods with illustrative examples to more than one plant.

I looked at the existing pieces available at that time, and that was, of course, the 1570, which appeared, to me, to have consumed a lot of effort, and it was a valiant effort, really, if you look at the scope of it. There was the EPRI study in two volumes that looked at certain plants, and made some calculations, actually, numerical results for PRA. There was the Sandia report that Research has commissioned, and it was pretty much done, at that time. So, those were the main pieces that were available to me. And what I'm trying to explain here is my

attempt to bring them together in a report that you should theoretically have access to. It's a 145-page report, and it says, "A Risk Assessment of Consequential Steam Generator Tube Ruptures", not the, not the final, it says A. So, please notice that it's on purpose and the title is not accidental. I tried to bring things together here with the available information.

The methods that were used previously in the documents I mentioned were very detailed. They tried to a detailed job, and it's a very commendable task. When I was looking at it also from the NRC's point of view as how we would review things independently, how we would look at things and try to quickly assess results, not in a trivial sense, but more than just a trivial, asking some RAIs or something.

So, is it possible to have a less intrusive way of estimating the risk? Of course, it has its own price. I mean, there's a price for everything. The method that I suggest cannot be a final method. It has to be repeated every time you repeat your --as you change your PRA updates, however, it's done very quickly. If you do an intrusive modeling, then whenever you update your

PRA, your results pop out, so you don't have to change -- you don't have to reassess things from scratch. So, there's a price for everything, depends on what the main objective is.

We tried to reflect the current understanding of the factors that lead to consequential steam generator tube rupture. As far as I could tell, this subject was studied over like a decade, closer to 15 years, both in materials aspects of it, thermal hydraulics aspects of it, and the sequences that can lead to it. They were really well studied, and understood. It's not like people are still trying to figure out what's going on.

The work done by materials and thermal hydraulics fields were incorporated. The steam generator tube flaws were studied, although, as mentioned before, they were dated. However, I caution you that I don't think the new steam generators data, if we today we go and get new flaw distributions, I don't think it will happen, these things will go down, for simple reasons like, I was told that the new steam generators, the lowest point of the tubes is closer to the bottom, so that the Westinghouse steam generators,

newer ones, are closer to today's CE steam generators. So, they suffer from the things that we attribute to the CE plants, and CE steam generators today. So, I don't -- I think that people might be expecting too much, that somehow things will be much better if we do new flaw distributions. I wouldn't count on it.

Also, although many of the steam generators are replaced, as times goes on, the flaws will accumulate. So, this is not a time frozen issue. You can't just say okay, I look at this, I calculate some generic numbers, put them aside, I'm done. It can't be done, and it's obvious to me. I don't know, maybe I'm being too simplistic.

Another point that I want to make sure is, we in the NRC, we have SPAR models, which underwent considerable review against the plant models reviews. And they are also undergoing peer reviews, as we speak. And they can certainly be utilized to make our independent check against any submittal that might, however complicated it is, you can check independently, the essence, so we can see if it passes the common sense tests.

I'm worried about complicated models,

while people somehow pile up a lot of mitigative operator action credits here and there. And it won't be easily scrutinizable to a reviewer, because it's buried in the complexity of the model.

So, the method I tried to outline in this report, and show also extensively with tables and appendices is identify those sequences from the existing PRAs that can challenge the steam generator tubes, apply mitigation credit sequence-by-sequence, just focus on the sequences, and go down the list of sequences, starting with the ones that have the highest core damage frequency initially. So that as you go down, potentially, the frequency of the starting point comes down, so you can start wherever you want, basically, and see if it's worth going any further, or not. And then concentrate on each sequence, and apply mitigation credit. What that means is you can see the core damage, but then say okay, what else can we do in a sense of B.5.B, et cetera, and what kind of operator actions are feasible, and so on. And then, another factor is the -- even if the mitigation fails, still the tubes may not fail. So, you can see there is a three-factor formula,

the sequence frequency times total mitigation probability, times the conditional consequential steam generator tube rupture probability. So, if you multiply these three numbers -

MEMBER APOSTOLAKIS: I'm a bit confused by your use of the word "mitigation."

MR. SANCAKTAR: Yes.

MEMBER APOSTOLAKIS: Probability that the operators mitigate the conditions leading, you mean?

MR. SANCAKTAR: What -

MEMBER APOSTOLAKIS: So, you don't have a tube rupture yet.

MR. SANCAKTAR: Right. Right.

MEMBER APOSTOLAKIS: And you're doing something to prevent it.

MR. SANCAKTAR: Yes. Absolutely.

MEMBER APOSTOLAKIS: And what gives you that probability?

MR. SANCAKTAR: HRA people and the PRA.

MEMBER APOSTOLAKIS: And do you know how they do that?

MR. SANCAKTAR: They can do that with any method of their choice that is acceptable at

this point.

MEMBER APOSTOLAKIS: Come now into territorial -- I don't know what -

MR. SANCAKTAR: You name me a territory, and spend the next few hours discussing the fine points of HRA.

MEMBER APOSTOLAKIS: So, it's not mitigation. I mean, I'm confused. It's not mitigation. It's prevention.

MR. SANCAKTAR: Okay.

MEMBER APOSTOLAKIS: That was easy.

MR. SANCAKTAR: Okay. The scope of the method, does that include LERF analysis, the measure of steam generator -- consequential steam generator tube rupture importance in my context is containment bypass frequency. Okay? That doesn't mean that it's LERF. It may -- a percentage of it will be LERF, but we're staying out of it at this point.

MEMBER APOSTOLAKIS: So, Selim, what you're saying is that you created the structure, other people are giving you input. Is that what you're saying with all this? If you need this probability, you go some place and you get it.

MR. SANCAKTAR: Right.

MEMBER APOSTOLAKIS: Okay.

MR. SANCAKTAR: So, this is intended to provide a method for NRR to assess the risk, and can be incorporated into a formal guidance document.

So, again, first, we identify the sequences by looking at the details of the sequence, what happened in the primary, what happens in the secondary, initially. And, typically, as the TH analysis indicated, we are worried about high-dry-low conditions. Also, identify sequences by the initiating events that can challenge the tubes, by just the nature of the initiating events. And then, also, the method should consider external events, and shutdown initiators, as appropriate, because they are in the scope.

There were mitigation credits. Given that the core damage occurred, what's the probability that the recovery actions to mitigate the various conditions in the primary, or secondary, or both. Restoration of secondary cooling, RCS depressurization. Usually, lately, they've been collected under B.5.B-type of actions; although, many of them existed

historically in the PRAs. If you go back in PRAs in the past, you will see many situations where in severe accident domain credit, whether it's appropriate or not, was taken for various actions, which in knowledge-based arguments now, B.5.B makes it more proceduralized, and, also, dedicates some improvement. So, there might be more credibility to these.

Recovery may not be feasible in certain situations. The ones that I'll really call attention to are the high PGA, peak ground acceleration seismic events, or maybe may control in fires where loop, loss of on-site power, and station blackout may occur. You have to be careful about how much credit is justifiable. I believe that this is one of the areas where most uncertainty exists. You can easily move the answers down orders of magnitude, effectively, by giving a lot of credit to operator actions.

MEMBER APOSTOLAKIS: I must say, I'm a bit confused. Are you proposing this method, or somebody has already done it?

MR. SANCAKTAR: No, I'm proposing.

MEMBER APOSTOLAKIS: So, if I wanted to find out how people handle this mitigation

action in terms of time available, is there a place where I can go and find out, or you are saying this is what I'm advising people to do in the future?

MR. SANCAKTAR: I'm giving a potential list of actions that are applicable to many plants, although, specific plants might have other ones. And then you can take credit, as much as you can justify, for those actions.

MEMBER APOSTOLAKIS: But right now, has anybody done this?

MR. SANCAKTAR: The numbers that I use are screening values.

MEMBER APOSTOLAKIS: But it's only you, not the -

MR. SANCAKTAR: Right. And the values that were calculated in the past, like in the Sandia report, they were basically calculated by using standard techniques. So, there are tables that says if you see this action, assign this value. However, this is really both plant-specific, and sequence-specific. Not only plant-specific, but sequence-specific. So, if somebody picks up that number, and just sprinkles it to different sequences, it's possible to misuse it.

And I'm just indicating that, as a point that I think is important to consideration.

The -- we have CRYSTALBALL, which is a Excel add-on that does, basically, simulations, as we want to call it. CRYSTALBALL-based calculation that takes flaw distributions, pressure and temperature history, materials properties, common failure types 3:32:11) RCS locations, generated originally with the Sandia report. We are in the process of taking it to the next level, where it will be much more scrutinizable, and suitable for various purposes that we see need for it.

I basically used four types of consequential -- conditional consequential steam generator tube rupture probabilities. I used high-probability for sequences that are seriously challenging the steam generator tubes, .4. That number is basically calculated by -- in the Sandia report, Table 4. Low-probability, .02, negligible, .01, effectively zero unrealized .5.

The illustrative examples are applied to a four-loop Westinghouse plant, Plant One is the report on a site by itself. There is no second unit to help it. Another one is two-loop Westinghouse plant on a site by itself, again.

There is no second unit to help it. And the two-loop Combustion Engineering plant with multiple units on the same site. Included are sequences from so-called external events, such as seismic, fire, internal fire, actually, and so on.

The calculations, or illustration includes sequences not only caused by the core damage, but, also initiating events, such at ATWS, and loss of main feedwater. Examples of three dominant sequences are given in the backup slides. I don't -- I'm not going to go into it, but they are contained in the slides. Here is a typical output, just to give you a taste of it. This is for Plant One, four-loop Westinghouse single unit. The number at the lower right-hand corner - again, don't take these numbers as the final proof of anything. It's just an illustrative number. Okay?

The number at the bottom on the right-hand side is the percentage, if you take this number and divide by this number --

(Simultaneous speakers.)

MR. SANCAKTAR: Okay. The 2.8 is 1.6 ten to the minus six divided by 5.8 ten to the minus five, just to make sure. So, one shouldn't

really focus on the magnitude of what is bypassed. I mean, in this case, it's ten to the minus six, it's approximately two times ten to the minus six, but you have to see that in context of the total number that we started with. So, that number could have been ten to the minus seven, but if you started with ten minus seven -- the core damage goes to bypass, which is not terribly comforting.

The key insights to mention are, first of all -- unfortunately, I'm not in a position to say that here's a silver bullet. This issue is so insignificant for all plants, we can just forget about it. I cannot say that. Nor, I can say it is such a big deal that we should be doing something about it immediately. So, it is very plant-specific. It should be considered, and monitored in the plant risk assessments, and the current standards already force the PRAs to address this one way or the other from a LERF point of view.

MEMBER APOSTOLAKIS: Let me understand this, again, because I'm -- you're going too fast. Go to the previous slide.

MR. SANCAKTAR: Okay.

MEMBER APOSTOLAKIS: This 2.8 percent,

isn't this the conditional probability of bypassing the containment given core damage?

MR. SANCAKTAR: Yes.

MEMBER APOSTOLAKIS: How is that related to LERF?

MR. SANCAKTAR: This is an absolute bound of LERF. That's to say LERF from -- LERF will be a fraction of this. And, especially, for steam generator tube ruptures, it's probably a smaller fraction. It's probably not 50 percent, but is much less than that. But I wouldn't hazard a guess for it at this point.

MEMBER APOSTOLAKIS: So, when we're bypassing the containment through the steam generator tubes, you say that we have a full spectrum of releases. So, if large is really a smart part of it.

MR. SANCAKTAR: Another point to make is the sequences that really dominate the bypass are core damage sequences that cause thermally induced steam generator, not necessarily ATWS, or main steam lines as an initiating event, that also the -- steam generator tube rupture.

Recommendation, plant PRAs should address this issue in their evaluation of plant

LERF on Level II analyses, whatever they have on a plant-specific basis, referring to the existing PRA standard. As I mentioned before, results are, I think, it's my opinion, it's kind of obvious from the numbers that results are very sensitive to the degree of credit allowed for preventing and mitigating the conditions, very, very sensitive. So, based on that, care must be taken not to take excessive credit for same actions, or other recovery actions non-safety equipment, especially for external events.

From a programmatic point of view, the Task 3.5, which is a PRA task of the steam generator action plan has been completed, and should be closed. Thank you.

MEMBER STETKAR: I'd like to make just one comment, briefly. I completely agree that the what question has been answered here; that, indeed, the work that's been done has concluded that the issue of induced tube rupture needs to be included in any plant-specific PRA. The second sentence in the first bullet on the slide that's up there now regarding how that's done, whether that's done by actually integrating a model for induced tube rupture within the plant-specific PRA

that more comprehensively searches for the types of conditions that could cause an induced tube rupture, rather than kind of post-processing a selected set of pre-quantified accident sequences. That's the how. And we had quite a bit of discussion in the Subcommittee meeting regarding whether or not, indeed, this simplified approach that's been used to examine whether or not this issue is important enough to consider in the risk assessment process, whether that method, indeed, would be appropriate for the actual evaluation. I think that question needs some more consideration in the follow-on work. Just for the benefit of the members that weren't at the Subcommittee meeting. I view this as a question of what needs to be considered. Does it need to be considered? Yes, it does. How it's actually considered, the implementation of the models, and the methods, is something I still think needs a little bit of examination. That doesn't alter the conclusion regarding closeout of the action plan item.

MEMBER APOSTOLAKIS: So, if they include it in the PRA, so what?

MR. PALLA: If you include it in the PRA, and it's a dominant contributor, you may need

to scrutinize what you can do, let's say -

MEMBER APOSTOLAKIS: I think Selim concluded it's not, didn't you? Is it a dominant -

MR. PALLA: It's not a throw-away. It's significant -- it's probably among the dominant contributors to LERF. Now, if you looked at the subsequent piping failures, it may say that it's not a LERF contributor.

MEMBER STETKAR: George, what they concluded was that as a fraction of the containment bypass probability, if you allow me to use probability, frequency, this issue could be as large as everything else that has been previously quantified. So, in other words, this could be a factor of two-ish, perhaps less. But the fact of the matter is, it hasn't been previously quantified. So, it isn't necessarily dominant, but it's big enough that you could be underestimating containment bypass frequencies by factors of two, perhaps. It might even be a little bit larger than that. It's not a factor of ten. It's not one-one-hundredth, either.

MEMBER APOSTOLAKIS: But, still, it's within the realm of analysis in terms of actually

doing something, but would you -- suppose a licensee comes in here, does everything that Selim says, and finds that this is a dominant sequence within the ten to the minus six domain. Now what? You're not going to ask them to do anything, are you?

MR. PALLA: Well, I think -- well, what you're probably talking about is just operator actions, accident management-type actions that you might be able to, perhaps, do a little better, more guidance.

MEMBER BANERJEE: Does operator actions make a big difference?

MEMBER APOSTOLAKIS: These operator actions here -- this is the weak part of the analysis, is it not?

MR. PALLA: I don't think you're going to change it that much, but you can, at least, focus it.

MEMBER APOSTOLAKIS: My conclusion is that in terms of real action, there is very little that will result, but maybe I'm wrong. Maybe I'm not with it. I'm sorry. I'm asking in terms of real action on the part of the agency. It's one thing to improve analysis. I'm all for it, but in

terms of real action I don't see much happening here.

MEMBER BLEY: I that that's why they feel we can close these items.

MEMBER APOSTOLAKIS: No, I think he's closing it because he believes that, from a programmatic point of view, they've done enough. That's fine.

MEMBER BLEY: This is a -

MEMBER APOSTOLAKIS: Yes, I have no problem with that. Okay.

MR. BEAULIEU: The fact that it's part of the PRA standard, I think is key. And the industry is already required by the PRA standard to account for this risk.

MEMBER APOSTOLAKIS: But, again, that -- one thing is to account for it -

(Simultaneous speakers.)

MEMBER APOSTOLAKIS: And if you do -- if you find this, then what -

(Simultaneous speakers.)

MEMBER POWERS: I think they're in violent agreement here. Are you done?

MR. BEAULIEU: We're complete.

MEMBER POWERS: We're complete,

believe it or not.

MEMBER APOSTOLAKIS: Wow.

CHAIR BONACA: Okay. So, well said. Let's take a break until 4:00.

(Whereupon, the proceedings went off the record at 3:45 p.m., and resumed at 3:58 p.m.)

CHAIR BONACA: Okay. Let's get back into session. The next item on the agenda is the Oyster Creek 3-Dimensional Drywell Analysis. Before I turn over the meeting to Dr. Shack, I think Dr. Armijo has a statement.

MEMBER ARMIJO: Yes. Mr. Chairman, I have a conflict of interest on this matter, so I will just listen and learn.

CHAIR BONACA: Okay. With that.

MEMBER SHACK: During our considerations of the license renewal for Oyster Creek, we reviewed analyses presented by the licensee, and by the Staff's contractor, Sandia National Laboratory, that assessed whether the drywell shell met the structural requirements for the current licensing base of Oyster Creek.

The most challenging requirements were against buckling during refueling with the dead

weight in the reactor cavity blotter, in the post-accident case with seismic load and flooding. Both the licensee's analysis, and the Sandia analysis, found that the shell did meet the CLB structural requirements. However, these analyses did not provide a defensible estimate of the actual structural margins.

Exelon committed to perform a 3-D finite element analysis of the Oyster Creek drywell showing the as-found degraded condition to obtain a more realistic analysis of the actual margins.

Exelon will be presenting the results of that analysis today. We do note that the licensing basis analysis remains the analysis by GE that we would use during the license renewal. Exelon, as I understand it, is not proposing to replace that analysis. This analysis is being presented for information and insight on the actual capability of the shell. And I'll turn to Sam Lee to open the discussion.

MR. LEE: Yes. My name is Samson Lee. I'm the Deputy Division Director of Licensing Renewal, NRR. And, to my left is Louise Lund. She's the Senior Project Manager, and to her left

is Tim O'Hara. He's the Senior Inspector from Region 1. And he, actually, was fortunate enough to actually physically inspect the sandbed region. To his left is Allen Hiser, who is the Senior Level Advisor in division license renewal. And to his left is Hans Asher. He's a Senior Structural Engineer. And to his left is Kamal Manoly. He's the Senior Level Advisor, Division of Engineering. And the staff will be making a presentation after the utility's presentation.

Like Dr. Shack said, this is the -- meeting is on the 3-D analysis of the drywell shell. And this is long history. Oyster Creek found corrosion in the center region of the drywell back in the 1980s, and they are taking corrective action. And these have been one of the sensitive items in the license renewal review. And it draw a lot of public interest, including public citizen group this day in New Jersey, and other elected officials. And we find the drywell acceptable. We know the ASME code, but it's a commitment to perform the confirmatory analysis.

The utility did a 3-D finite element realistic analysis, and they will talk about that today. And with that, I'll turn it over to Mike

Gallagher. He is the Senior -- he's the VP of utility.

MR. GALLAGHER: Okay. Good afternoon. I'm Mike Gallagher, and I'm the Vice President of License Renewal for Exelon.

Our presentation is going to be a summary to the Subcommittee -- that we gave to the Subcommittee, so the Full Committee Members have a little bit of that background. And then there's some specific areas of feedback that we got from your questions that we are presenting our responses to.

But before we get into today's presentation, I would like to introduce the presenters to you. We have John O'Rourke, and John is our Exelon Senior Project Manager in license renewal, and he provided oversight for the development of the Oyster Creek 3-D drywell analysis. John has over 36 years of nuclear power plant experience, primarily in engineering. And John is also a registered Professional Engineer in Pennsylvania.

Structural Integrity Associates is our engineering contractor, that developed the Oyster Creek 3-D drywell analysis. SIA are experts in

the field of structural analysis. And with us today, we have Stan Tang. He also presented at the Subcommittee. And Stan has over 30 years experience in the areas of fatigue, fracture mechanics, thermal mechanical stress analysis, structural dynamics, finite element methods, and software development. Stan's work covers areas in the Defense and Nuclear industries. And Stan is also a registered Professional Engineer in the State of California.

Then, at the far end of the table we have Dr. Clarence Miller. Dr. Miller has an extensive career in the area of research and design related to the strength and stability of shell structures. Dr. Miller is currently an independent consultant after retiring from Chicago Bridge and Iron following 44 years of service. Dr. Miller is also a registered Professional Engineer in Illinois.

Dr. Miller has written over 90 papers, publications, and test reports related to shell stability. And Dr. Miller was the primary author of ASME Code Case N-284 in 1979, and N-284-1. And that's the metal containment shell buckling design methods.

We used Code Case N-284-1 in the Oyster Creek 3-D drywell analysis. Go to slide 2.

So, as I mentioned, today we'll be presenting a summary of what we presented to the Subcommittee on the 3-D drywell analysis. We also have included our response to the feedback areas we heard from you, from the Subcommittee from the September 23rd meeting. And, our presentation is framed -- this feedback is questions that we thought we heard, and followed by our responses, so we know that they're not, perhaps, the exact questions that individual members had, but we tried to frame it as such.

I will just go over background a little bit, for the Full Committee Members' benefit. So, if we go to slide 3. So, on January 18th, 2007, we met with the ACRS Subcommittee for the Oyster Creek drywell license renewal - excuse me - the Oyster Creek license renewal review. We gave a detailed presentation on the drywell corrosion issue.

In this presentation, we discussed how the issue of water entered the sandbed, and caused corrosion of the drywell shell, and how it was identified in the early 1980s; how in 1992

extensive corrective actions were completed resulting in the gaining of the access to the sandbed region, removal of the sand in the sandbed, and applying a three-layer epoxy coating system on the drywell shell.

UT thickness measurements were performed to verify adequate thickness, and we continue taking these measurements today. We do these every other refueling outage as part of our ongoing aging management program. These UT measurements have verified that the corrective actions have been effective, and there are no ongoing corrosion.

One of the items we presented was the GE analysis of drywell thickness that we use as our acceptance criteria for our ongoing UT measurements. We showed the calculated thickness margins, and why these calculated thickness margins are conservative.

On February 1st, 2007, we met with the ACRS Full Committee for the Oyster Creek license renewal, and we presented some information as a follow-up to the Subcommittee. One item was a comment from the Subcommittee that said thickness margins may be better understood with a modern 3-D

finite element model where various thickness, and thickness configurations could be evaluated.

We agreed with the Subcommittee, and committed to perform a 3-D finite element analysis of the Oyster Creek drywell shell prior to the period of extended operation. We completed the analysis, and submitted it to the Staff on January 22nd, 2009.

It's important to note that this analysis matches our commitment. The idea was to quantify the margin that is currently available. So, it is based on a realistic, but conservative thickness input based on the data that we've taken. This is in contrast to the GE analysis, which was a conservative uniform thickness in the sandbed region, that is the licensing basis, and used as our acceptance criteria.

Also, on April 8th, 2009, the staff issued the renewed license for Oyster Creek. So, why we are here today is that in the February 8th, 2007 ACRS letter, you asked us for a briefing on the results of the 3-D drywell analysis when they became available. And that's why we're here today.

If we go to the next slide, I'll just

do an overview of the results, and we'll get into the presentation. This table shows the safety factors for the base case, and two sensitivities that we studied. It shows that the required safety factors of 2.0 for the refueling case, and 1.60 for the post-accident flooding case. The base case results show that there's margin above the required, and the sensitivity show that for rather large changes in thicknesses, or bay-wide or locally, there's relatively small change in safety factors.

So, with that, I'll turn it over to John O'Rourke, and we'll get into the details of our presentation.

MR. O'ROURKE: Thanks, Mike. This is John O'Rourke from Exelon. And on Slide 5 I show, which is also Figure 1.1 in the base case summary report, illustrates a typical Mark-I containment configuration representative of the Oyster Creek drywell.

As I did at the Subcommittee meeting, I want to point out the sandbed region, this small region here, labeled as sandbed, which was part of the original Oyster Creek design. This area was originally filled with sand. The corrosion on the

exterior of the drywell shell was caused by water that got into this area, and was held against the shell by the sand. The sand was permanently removed from this area in the early 1990s, following analysis that justified such removal. The exterior of the shell was cleaned and coated with a three-layer epoxy coating to arrest the corrosion. And, although there is no longer any sand in this area, we continue to refer to this area as the sandbed region.

This is the area in which we performed the external ultrasonic thickness measurements. This area is five foot four inches, and 15 inches wide, and is divided into 10 bays equally space around the circumference. Next slide.

MEMBER SIEBER: Before you leave that -

MR. O'ROURKE: Sure.

MEMBER SIEBER: -- I do have a question. The connection between the torus and the drywell, you have a number of those around, are 81 inch pipes. There is an expansion bellows in there. Did you take into account in the analysis any forces due to the mounting of the torus with respect to the drywell in a seismic

event? As I read your drawings from our last meeting, you considered the structure of those 81-inch pipes but I did not see any interactive forces between that and the torus. Is that correct?

MR. O'ROURKE: We modeled the six foot six drywell vent pipes that go down to the vent header, we modeled the entire 360 degree vent header with vertical restraints at the point where it's anchored to the structure.

MEMBER SIEBER: Okay. Thank you.

MR. GALLAGHER: Yes. And, Mr. Sieber, on page -- slide 25, we'll be getting this when Stan talks about the one follow-up question. It shows all the areas, basically the constraint points that are modeled. So, you have like the star trusses, you have the -

MEMBER SIEBER: Thank you.

MR. O'ROURKE: Slide 6. I'd like to provide a brief overall summary of the detailed presentation of our 3-Dimensional Finite Element Analysis provided to the Subcommittee, after which I will go over several areas in detail based on the Subcommittee's questions.

The model was developed using design

drawings and documents. Shell thicknesses were developed based on the ultrasonic thickness data taken during the 2006 refueling outage. And I will discuss this in more detail in the following slides.

Current licensing basis inputs were used, including the Code of record loads, and load combinations. The Oyster Creek drywell vessel was designed, fabricated, and erected in accordance with the 1962 edition of ASME Section 8, with the Code Cases shown in this slide. We did utilize guidance from the 1980 edition of Section 3, and Standard Review Plan 3.8.2 for certain areas not covered by the 1962 edition of Section 8.

The buckling analysis was performed per Section NE-3222 of the `89 edition of Section 3. We used a modified capacity reduction factor in accordance with Code Case N-284-1, whose primary author was Dr. Clarence Miller. As Mike mentioned earlier, code minimum safety factors have been met with margin. We performed a stress evaluation, and the stresses are within code allowables.

I will now discuss in some detail the sandbed region shell thickness data that was used

as input to the analysis, starting with our aging management monitoring program. Then I'll address one of the Subcommittee questions, which will provide the basis for the sandbed region thicknesses, including two representative bays as examples of how we developed the general bay thicknesses, and the locally thinned area thicknesses.

The Subcommittee members will recall that I discussed all 10 bays in the Subcommittee meeting. I'll conclude this section of the presentation by addressing a second question raised by the Subcommittee.

This slide illustrates the various areas in the sandbed region that we monitor every other year with ultrasonic thickness measurements as part of our aging management program. It's important to note, and I'll emphasize this in the appropriate slides, that the general bay-wide thicknesses are based on the internal grid measurements, and external measurements are only used to define the locally thinned area thicknesses.

MEMBER SHACK: Why is that? Why don't you use all the information?

MR. O'ROURKE: I'll be explaining that as we go through the presentation.

MR. GALLAGHER: Yes. And, basically, the short answer, Dr. Shack, is that these external points were visually identified to be thin areas, and then further ground down to -- so we could interrogate them with UT. So, they are very thin, and biased. So, we use them for like local acceptance criteria, but not for determining average, or any acceptance criteria based on average.

MEMBER SHACK: Yes, but the statement is made that you ground off 100 to 200 mils. I mean, if it my drywell showing, somebody came up to a thin area and wanted to grind off another 200 mils, I'd -- do you really believe that you've ground off that much material?

MR. GALLAGHER: Yes. Well, we have -- the records show based on micrometer readings that were taken that that was done.

MR. O'ROURKE: It was actually about 100 mils that was ground off. It sounds like a lot, but in order to get proper UT measurements, you need a good surface to get the probe on.

MR. GALLAGHER: And, of course, the

UTs were done and verified that adequate thickness was still there, so it was still confirmed to be adequate. But I agree -

MEMBER SHACK: So, you actually have micrometer measurements. This is not somebody's eyeball estimate on the 100 mils.

MR. GALLAGHER: That's correct. And as John said, we have a slide on that, and how those points were developed.

MR. O'ROURKE: And recalling that the purpose of the analysis was to try to model the drywell in as realistic, but still conservative manner as possible. The external points become very conservatively thin, and I'll discuss why that was not appropriate to use those.

VICE CHAIR ABDEL-KHALIK: How do you do micrometer measurements? Just the outside surface?

MR. GALLAGHER: Yes. It was basically the delta between a reference point and -

VICE CHAIR ABDEL-KHALIK: This is like a depth micrometer?

MR. GALLAGHER: Yes. Sure. Depth gauge.

VICE CHAIR ABDEL-KHALIK: Okay.

MR. GALLAGHER: You're getting a delta change between a reference point and where you went to. But the UT measurements are the actual -- confirmation of what the actual thickness is after the area is prepared. And we continue to monitor those points.

MEMBER SIEBER: But the thickness was scaled since the volume was higher in the oxidized region, gives a bias toward a greater amount of grounding than probably actually occurred.

MR. GALLAGHER: But, I believe this was done after the surfaces were prepared. So, in other words, the corrosion products were removed, and then there was some more -

MEMBER SIEBER: Additional grinding to get you to a flat surface.

MR. GALLAGHER: Right.

MEMBER SIEBER: Okay.

MR. GALLAGHER: And, when you see some pictures - we have a couple of pictures, you'll see the -- they look like divots, almost, and prepared areas.

MEMBER SIEBER: That's the picture I have in my mind.

MR. GALLAGHER: Yes.

MR. O'ROURKE: And we have those, as part of the presentation.

MR. GALLAGHER: Yes. If you want to do a quick look ahead, Mr. Sieber, there's a -

MEMBER SIEBER: No, that's okay.

MR. GALLAGHER: All right.

MEMBER SIEBER: Thank you.

MR. O'ROURKE: On Slide 8, I show the aging management program points that we monitor. The green squares and small vertical rectangles represent the 19 internal grid measurements.

When the sandbed problem was first discovered, and before the sand was removed from the sandbed region, a number of grid measurements were taken around the drywell at elevation 11 foot three. Nineteen of these grid locations representing the lowest readings in each bay were selected for continuing monitoring and trending, and those are the locations that we show on this chart. The large vertical rectangles in Bays 5 and 7 represent the trench grid readings.

MR. GALLAGHER: It's 17, John.

MR. O'ROURKE: 17, 5 and 17. And they were created by removing concrete from the floor inside the drywell to allow access to the interior

drywell shell in those bays.

The triangles represent the external point readings taken in the sandbed reading after the sand was removed. The thinness points is determined by visual inspection, were ground for the ultrasonic thickness measurements, as we just discussed. And I'll talk about that in more detail in a few slides. These monitor points are also trended.

Slide 9. Our understanding of the question that came up during the September 23rd meeting is about the appropriateness of using the UT grid averages as the model thickness for large areas within the sandbeds.

The 19 internal grids that we continue to monitor were selected based on a series of grid data taken to locate the thinnest general area. The thinnest areas were then selected for ongoing monitoring; therefore, the averages we used in the 3-D analysis are representative of the bay-wide thicknesses, and are biased thin. Also, the buckling wavelength of the drywell shell is large, on the order of five to eight feet, which indicates a bay-wide effect. Based on this, the use of the average thickness over a bay, or a

large portion of the bay is acceptable, and Dr. Miller will speak on this further in just a few slides.

On Slide 10, the original series of internal grid measurements, over 500 measurements were taken before the sand was removed from the sandbed region. Where the thin locations were identified, the areas around the location were horizontally and vertically interrogated to locate the thinnest locations.

Out of all locations measured, 19 locations were selected for ongoing monitoring, making sure that there was at least one grid in each of the 10 bays. These locations are monitored every other refueling outage, as part of the ongoing aging management program. And since 1992, these monitoring locations have indicated no ongoing corrosion.

Based on this, we concluded that the UT internal grid locations are representative of the average thicknesses biased on the thin side, and that they are appropriate to use as inputs to the 3-D analysis to conservatively model the general bay thicknesses.

MEMBER SHACK: Yes, but there's an

exception. You go to the Bay 1 thickness from your presentation last time, and it said the internal grid readings for Bay 1 indicate near-nominal shell readings. And, yet, that was -- you conservatively estimated to be the same as Bay 19, which is the thinnest, so is that just additional conservatism that you've put in, or there really is more corrosion above that 11 foot 3 level than you're seeing on the internal grid?

MR. O'ROURKE: Well, the corrosion in that bay doesn't go the whole length of the bay. We did conservatively use the same thickness for the whole bay, but the -- we used Bay 1 and 19, and that is based on internal grid readings. And, also, based on the fact that -- and the pictures will show you this, that the bays looks very similar in terms of their corrosion. So, some engineering judgment was applied, but all of the thicknesses that we used for the general bay thicknesses were based on internal grid readings.

MEMBER SIEBER: I presume Dr. Miller will tell us why average biased on the thin side is just as good as, or usually as good as taking the thinnest reading.

MR. GALLAGHER: We have a slide.

MR. O'ROURKE: We have a slide right after I finish talking about trench -

MEMBER SIEBER: Okay.

MR. O'ROURKE: On Slide 11, in addition to the internal grid measurements, trenches were excavated to characterize the extent of corrosion at elevations below the drywell interior floor. Two bays were selected for excavations, representing bays having the least and the most corrosion.

The trenches extend to about the bottom of the sandbed region, and the UT measurements taken in the trenches below Elevation 11 foot 3, confirm that the measurements are bounded by the monitoring at 11 foot 3, which supports our conclusion that the internal grid measurements are appropriate to use as input to conservatively model the general bay thicknesses.

At this point, I'll turn the presentation over to Dr. Miller, to discuss the use of average thickness.

MR. MILLER: Thank you, John. I'm Clarence Miller. I'm going to discuss the use of average thicknesses in the drywell analysis. A circle shell subjected to compressive loads will

buckle in local areas with highest stresses. Local buckling stresses depend on the applied stress over a half-buckle wavelength, L sub C. L sub C equals 3.72 square root of RT, where R is the radius of the shell, and T is the thickness of the shell.

For the Oyster Creek drywell shell, the half-buckle wavelength varies between 62 inches, and 89 inches. For shells with variable thickness, where thickness can be averaged over a distance of at least this half-buckle wavelength, L sub C.

The second point, where the drywell shell is not sensitive to small thinned areas, tests have been conducted on actually compressed shells with unreinforced openings, which show little reduction in the buckling strength. In the diameter of the whole, D is less than 8/10ths squared of RT. For the Oyster Creek drywell shell, D varies between 13 inches, and 18 inches. A hole less than 13 inches will have little effect on the buckling strength. Therefore, thinned areas, less than 13 inches, will have little effect on the buckling strength.

Conclusion. The use of average

thicknesses for a bay as input to the 3-D analysis is acceptable.

VICE CHAIR ABDEL-KHALIK: Is the implication here that all the thinned areas are less than 18 inches in diameter?

MR. GALLAGHER: No. I think what we're trying to say here, the areas we have are actually -- that we modeled are actually a 51-inch circle, or an 18-inch circle. Okay? So, they're bigger than these areas. And we chose big areas so you could see some changes.

What Dr. Miller is saying is, basically, you could have a hole 13-inches, and that will change -- that won't change the buckling strength much, at all. So, having thinned areas, small thinned areas really doesn't have an effect.

VICE CHAIR ABDEL-KHALIK: I guess we're -- okay. I understand that you have large thinned areas that you modeled as thinned areas.

MR. GALLAGHER: Right.

VICE CHAIR ABDEL-KHALIK: And all the discussion here pertains to the use of average thickness throughout. So, the question is, the areas that you sort of smeared within the rest of the uniform thickness, are all those areas less

than 18-inches in diameter? They're not necessarily holes.

MR. GALLAGHER: The bays are greater than 18 inches.

VICE CHAIR ABDEL-KHALIK: I understand that the bays are -- the locally thinned areas that were not specifically modeled in the finite element analysis as thinned areas.

MR. GALLAGHER: Yes.

VICE CHAIR ABDEL-KHALIK: Do you understand my question?

MR. GALLAGHER: Yes. Maybe this would help. We could just jump to Slide 20.

MR. MILLER: Yes. I was going to say, things outside the 51-inch are actually modeled with a thicker shell.

MR. GALLAGHER: Right. Just to make sure we all have the same mental image, if you look at Slide 20, and we're jumping ahead a little bit, but I think this is important. We had shown you before how we developed these local areas. We think -- locally thinned areas. We think they're very conservative. Basically, what we did was, say in this particular case, in the inset in the bottom there, we have how we modeled Bay 1. It's

basically, there's four red points. We just simply averaged them, and assigned that value to an entire 51-inch circle. And what we're trying to show you here is, this particular picture is the -- a corner of this circle. And those points, we pointed out what -- the points are the blue points. Okay? And we pointed out what the actual thicknesses are. So, if you can imagine, we have that entire circle at 696 mils thick, but you can see that that's not the way it is. Okay? We conservatively modeled that way. So, if you look at that first point, that 783, I mean, it's much thinner than that. So, what we did was, where we had some areas where we had some external points that were kind of an area, we called that a thin area, and conservatively modeled it to a very thin value.

So, we did that in five bays, and they're either 51-inch circles, or 18-inch circles. And in he other five bays, there's none, because if you look at those values, there's hardly any thin points. All the points are valuated based on local thickness criteria, so everything is covered, as far as evaluation.

MR. O'ROURKE: That brings us back to

Slide 13. And I mentioned I would discuss two representative bays as examples of how we developed the UT thickness measurements to develop both the general thickness, and the locally thinned areas. Again, the general bay-wide thicknesses being based on the internal grid UT measurements, and the locally thinned areas being based on the external point measurements.

This slide shows a picture of the external surface of the drywell shell in Bay 19 taken in 2006. Bay 19 is one of the bays that had experienced historical corrosion throughout most of the bay, and we used -- to Dr. Shack's point, even though there might be some area of nominal thickness above -- at the top of the bay, we modeled the whole bay as the same thickness. And that thickness is based on three nominally 49-point grids that we measure in this bay. We average those points to come up with the thickness value for the whole bay.

On slide 14, this shows the locally thinned area that we've been discussing modeled by the 51-inch circle. The model thickness of this bay is the average of just the two thinnest points, two thinnest external points. Again, to

be conservative, we picked just those two points for the average of the entire 51-inch circle for modeling purposes. And recognize that the 51-inch circle is almost 20 percent of the area of the entire bay.

VICE CHAIR ABDEL-KHALIK: Now, my earlier question pertains to areas surrounding that 721 mil point. Is it possible that at a place like that, you would have a locally thinned area that's greater than 18 inches in diameter?

MR. GALLAGHER: Not based on our visual observation. That was like a point that we interrogated, ground it down, and took a UT reading. So, the area in-between all these points is thicker.

MR. O'ROURKE: And if you look at the adjacent point, page 67, very close to the 721, so it is, in fact, a localized point, localized thin point that we continue to do UT measurements and trend. So, we're watching it, but for analysis purposes, the area encompassed by the circle is an area that we had evaluated in our calculations, and wanted to model that as the 51-inch circle.

MEMBER SHACK: Okay. But you're going to give me, at last, visual assurance that there's

no groove along there that runs from the 736 to the 728, to the 721.

MR. O'ROURKE: That's correct.

MEMBER SHACK: I mean, I -- just looking at these things, I might be inclined to draw an ellipse that encompassed those. But you're telling me that, visually, if I went out there and looked, I'd see that that 721 is -

MR. O'ROURKE: You would not see a groove in the drywell.

MR. GALLAGHER: If you go back to Slide 13, Dr. Shack, I mean, that -- this doesn't show you the entire bay, but that's a visual of how that particular bay looks. Now, at some point at the top, it does stop. Right? So, you can see like a little step change, but that's where it stops. Then, basically, it's nominal thickness at that point.

MEMBER SHACK: Well, I'm just looking at this particular local area in Bay 19.

MR. GALLAGHER: Right.

MEMBER SHACK: Because the thing that we can't see is your visual judgment as you're making these decisions.

MR. GALLAGHER: Right.

MEMBER SHACK: All we see are a collection of points.

MR. GALLAGHER: Right.

MR. O'ROURKE: But the visual inspections are done along with -- I mean, the people that go in to do the UTs, also are qualified VT inspectors. And they report back, and document their findings in their reports.

Slide 15 shows a picture of the external surface of the drywell surface in Bay 1, also taken in 2006. As we discussed, this is the one where we monitor the seven-point grid. As you can see from this picture, the visual observations confirm the presence of some historical corrosion. And, therefore, we conservatively estimated this bay to be the same thickness as in Bay 19. And, again, top to bottom. So, if you go back and look at slide 13, and compare it to slide 15, you see a very similar corrosion pattern.

VICE CHAIR ABDEL-KHALIK: Just for scale, what is the size of this bead, this caulk bead?

MR. GALLAGHER: The size of the caulk bead? Pete, would you know what the size of the caulk bead is, Pete Tamburro.

MR. TAMBURRO: My name is Pete Tamburro. The size of that caulk bead is between one and two, at the out, three inches.

MR. O'ROURKE: On Slide 16, we also modeled the locally thinned area in this bay, represented, again, by a 51-inch circle. The model thickness in this area is the average of the four thinnest points encompassed within the circle, again, shown in the diagram in red.

And in Slide 17, after looking at the two examples, this pictorial of the whole drywell sandbed region summarizes the thicknesses used in the 3-D analysis, including the locally thinned areas, which are modeled in five of the ten bays.

Slide 18. Our understanding of a second question that came up during the September 23rd meeting was, why the external UT points are considered bias thin? We had purposely looked visually for the thinned points in the shell for further evaluation, and most of them were ground to permit accurate UT measurements. Therefore, the -

MEMBER SHACK: And, again, you think 100 mils is a reasonable estimate for the amount of grinding that went on.

MR. O'ROURKE: That's what the records tell us, yes. And that's on the next slide. We did identify, as we said, the thinnest locations, and were further investigated and characterized, both visually, and using UT measurements. We mapped over 100 external locations within the 10 bays.

The external surface of the drywell was rough, as you saw in the couple of previous slides, so most of the locations had to be ground in order to create the sufficient flat surface to allow a UT probe to be placed perpendicular to the drywell shell. This resulted in small one to two inch dimples, with relatively thinner local areas that were subsequently measured by UT. I mentioned the 100 mils removed. And, as you can also see from the pictures, the area between the external UT locations is thicker than the dimples that show where we take the UT measurements.

So, based on all of this, we conclude that the external UT points are bias thin, and are not appropriate to use to determine the general bay thicknesses. We did, however, use these measurements, as I said, to define the locally thinned areas thicknesses.

And, finally, going back to Slide 20, so what I discussed on the previous slide is shown visually here from the sandbed floor. We discussed the caulk, and then there are several external points that we monitor. And the inset, which we had seen previously, shows the locations that we show in the picture in blue. We've also superimposed a 51-inch circle, and we've modeled that as a thickness of 696 mils. I did mention that the 51-inch circle covers about 20 percent of the area of the entire bay. And, as I said, you can note that the thickness between the dimples shows thicker material. However, the whole area has been conservatively modeled at 696.

At this point, I'll turn the presentation over to Stan Tang of Structural Integrity, who will discuss the finite element model.

MR. TANG: Thank you, John.

MEMBER RAY: Before you get to that, have you ever had occasion to remove and replace any of the moisture seal? The moisture seal, have you ever taken any of it out and replaced it for any reason?

MR. GALLAGHER: No, we've done some

repairs, because it's kind of like a hard -- repaired cracks that could occur in the moisture seal.

MEMBER RAY: And, it's a seal against moisture going where?

MR. GALLAGHER: This is the joint where the shell and the floor is, and so a caulk -- the seal was just put there just to prevent any moisture getting into that crack.

MEMBER RAY: It would go into a crack that -

MR. GALLAGHER: It's a poured floor of like an epoxy, and poured right up to the shell. And then the -- this material was put there that just pulled that joint in. Because the shell is more like this, it's curved a lot, so it's a pretty tight joint.

MEMBER RAY: Yes. I just wondered, this moisture seal looks like it's all very good. A little surprising. I thought maybe it had been replaced, or renewed, or something.

MR. GALLAGHER: No. In these pictures here from 2006, that was installed in 1992.

MEMBER RAY: Oh, okay. It's not original.

MR. GALLAGHER: No. All these repairs were done in 1992. And just -

MEMBER RAY: And the moisture seal was part of that.

MR. GALLAGHER: And that was part of that. And just for clarity, this grinding that was done was in 1992. This isn't something we've done recently.

MEMBER RAY: Yes. No, no, no. I mistook. I thought the moisture seal was part of the original design.

MR. GALLAGHER: No. The repairs were done in 1992.

MR. O'ROURKE: And that seal is visually inspected every other outage. When we get into the sandbed regions, we inspect that seal. Stan.

MR. TANG: Thank you, John. I am presenting the finite element model. In the previous ACRS Subcommittee meeting, we have presented in details the finite element model, and the analysis results on ASME Code stress evaluations, and buckling safety factors. In this presentation, I will give a brief overview of the finite element model, and provide responses to the

questions posed by the Subcommittee in the September 23rd, 2009 meeting. Next slide, please.

The three-dimensional finite element model was generated using ANSYS Release 8.1, and analyzed using Release 11.0. ANSYS is a proven general purpose finite element code accepted by the nuclear industries. The drywell dimensions are obtained from detailed drawings, with wall thicknesses from the field measurements. The material properties are obtained from the ASME Code. The model has about four hundreds and six thousands elements, with about hundred thousand nodes.

To show that the mesh is small enough, a mesh sensitivity study was performed with a model, which has approximately one million elements. It was shown that the stresses from these two models do not have any significant differences, confirming that the four hundred thousand elements model is sufficient for analysis. Next slide.

This slide shows the overall mass of the overall mesh of the three-dimensional drywell model, including all the major components of the drywell.

The table in the upper right corner identifies the mesh sizes in some of the major components in the drywell. The local thinned areas have the smallest nominal mesh size, about three-quarter of an inch, because they are the areas of interest. The sandbed region has the next smallest nominal mesh size, about 1.5 inches. The components further away from the sandbed regions have increasing nominal mesh sizes. The larger mesh sizes are still small, compared to the overall size of the drywell.

The figure in the lower right corner shows a close up view of the mesh in Bay 19 in the sandbed region. The circle represented 51 inches diameter of the local thinned area, which has the smallest mesh. The area at the bottom of the figure is the embedded regions with the boundary conditions applied; thus, not required fine mesh.

VICE CHAIR ABDEL-KHALIK: I'm sorry. Could you go back to Slide 20? Can you explain not the low numbers, but the 1157 number?

MR. GALLAGHER: Yes. The 1157 is towards the top of the sandbed, so that would be -

VICE CHAIR ABDEL-KHALIK: I mean,

what's the nominal thickness?

MR. GALLAGHER: 1154, so that's basically nominal thickness. So, at some point, the corrosion kind of blends and either changes, because there was air, water, air-sand-water interface, and essentially stops. And we had shown pictures at the Subcommittee. I mean, I can grab one if you'd like to take a look at it, but it's from the original Subcommittee. So, up at the top, you will see nominal thicknesses.

VICE CHAIR ABDEL-KHALIK: Okay. Thank you.

(Off the record comments.)

MR. TANG: The top part of the figure represents the mesh in the vent pipe with the mesh transition from smaller mesh size to a larger mesh size. Slide 24.

Our understanding of the Subcommittee questions, or area of interest in the finite element model, is to describe specifically the modeling of the vent header boundary condition. Will the downcomer vents buckles? Is the boundary condition appropriate as to the effect on the shell?

The chosen boundary condition is

realistic as to the effect of the shell, and does not provide added benefit to the shell analysis. The vent header boundary condition modeling is appropriate. The vent pipes, and the vent header assembly will not buckle before the shell. All these will be explained in more details in the next few slides.

This slide shows all the boundary conditions at different locations in the drywell model, such as the star truss, the equipment hatch, and the drywell bottom embedded regions. In particular, the vertical constraints are used on the vent header reinforcing flanges to simulate the column supports which connected the vent headers to the torus.

I'd like to point out, as highlighted by the circle, that the vent header assembly, starting from the vent pipe inside the torus, is included for the only purpose of providing a realistic stiffness/interaction boundary condition only, as explained in the next couple of slides.

Detail modeling of the vent headers and downcomers is included only for the realistic representation of the stiffness/interaction of components attached to the drywell shell. It is

similar to the use of stiffness matrix, which is a common finite element modeling technique, to model the boundary conditions. The detail modeling is a better representation of stiffness/interaction at the end of the vent pipe outside the torus.

Modeling of the portion of vent pipe inside the torus, the vent header, and the downcomers reduces the conservatism in stress and buckling results in the drywell shell, because it accounts realistically, some of the loads, a small percentage are transmitted to the vent header assembly, as shown in the next slide. Alternate approach is to model with a conservative boundary condition at the vent pipe and torus interface location. In most cases, this would be a free end boundary condition that is allowing the end of the vent pipe to move freely. Slide 27.

This slide summarizes how the reaction forces are distributed in the flooding case. About 93 percent of the total reaction forces was at the embedded bottom head boundary conditions. The loads going through the vent pipe to the vent headers are small. About 4 percent of the total reaction forces was at the vent header support locations. About 3 percent was at the other

boundary conditions, such as the equipment hatch, and the start truss.

If the stiffness of the vent header assembly is not included in the model, the 4 percent of the reaction loads would go through the drywell shell into the embedded region. These results also confirmed that the modeling of the stiffness/interaction due to the vent headers and the downcomers assembly reduces the conservatism, even if it only 4 percent in the stress/buckling evaluation results of the drywell. The conclusion is that majority of the loads are carried by the spherical shell, that the boundary conditions are appropriate, as to the effect of the shell. Slide 28.

The question, will the downcomer vent buckle arise from the buckling mode shape results, that the first ten buckling modes are not in the drywell, but in the vent header assembly. It should be emphasized that the inclusion of the vent header assembly is only for the purpose of providing stiffness interaction with the shell, similar to the use of a stiffness matrix, as described in the previous slides. Therefore, the finite element results or the buckling modes need

to be interpreted accordingly. This slide provides a qualitative assessment to support that interpretation of the buckling mode result, and why the vent header assembly will not buckle before the drywell shell.

The vent pipe has a radius to wall thickness ratio of about 150, compared to the R over T ratio of about 300 for the drywell cylindrical shell, and about 400 to 600 for the drywell spherical cell. The vent header has a lower R over T ratio, about 110, and even a lower R over T ratio for the downcomers, about 48.

The vent pipe has a length between the stiffeners of about 85 inches. The length between the stiffeners for the vent header and the downcomers are shorter, about 48 inches and 75 inches. The drywell cylindrical shell has a length between the stiffeners, about 103 inches. For the drywell spherical shell, the length between the stiffeners is from 235 inches to 332 inches, much longer than those in the vent pipes, and the vent header assembly.

In Code Case 284-1, for cylinder, a smaller R over T ratio gives a larger capacity reduction factor. Also, a cylinder with a small R

over T ratio and a shorter length between the stiffeners would have a higher buckling strength.

Based on the comparison of R over T ratios, and the lengths between the stiffeners among different components, the vent pipes and the vent header assembly would have a larger safety factor, and a higher buckling strength than the drywell shells. Therefore, the vent pipes, or the vent header assembly, will not buckle before the drywell shells.

Now, I return the presentation to John.

MR. O'ROURKE: Thank you, Stan.

Slide 29. Up to this point, all of the discussion has been on the base case analysis. We also performed two sensitivity cases that were submitted to the NRC on January 22nd, 2009. And I will summarize the results of the two sensitivity analyses, and then address a question from the Subcommittee.

The model used for the sensitivity analysis is the same model used for the base case analysis, with two exceptions. For sensitivity case one, the thickness of the 51-inch locally thinned area in Bay 1 was reduced by 100 mils,

while keeping the general area of the bay constant. For sensitivity case two, the thickness of the general area in Bay 19 was reduced by 50 mils, while keeping the locally thinned area thickness constant.

Slide 31 compares the results of the base case with the two sensitivity cases. This is a slide Mike had shown earlier. And, as you can see, although the safety factors are reduced for the base case, they are still well above the required safety factors.

At the September 23rd meeting, we understood one of the questions to be how the selection of the 100 mil local reduction, and the 50 mil general reduction in the sensitivity cases was related to the UT data.

Our response is that we wanted to select reductions that we felt would bound data uncertainties. As you can see from this slide, the local area reduction, the 100 mil reduction reduces the locally thinned area over 15 times the observed external UT measurement difference. It is, therefore, expected to bound data uncertainties.

For the general bay-wide reduction and

with the range of standard errors for the 19 internal grids, from plus or minus 2 mils, to plus or minus 16.6 mils, the 50 mil bay-wide reduction is at least three times the standard error for the data used to determine general bay-wide thicknesses. And is, therefore, expected to bound data uncertainties.

Finally, although the drywell is not experiencing corrosion, if we hypothesized a 2 mil per year corrosion rate over the four-year measurement interval, the 100 mil local, and 50 mil general reductions would be much greater than the postulated 8 mil loss.

With that, I'll turn the presentation back to Mike.

MR. GALLAGHER: Okay. So, just to summarize, we had a license condition, and a commitment to perform a modern 3-D analysis. We believe we met that commitment to quantify the margin. We quantified that margin. And, in summary, this is the summary conclusions here, which is normal operating conditions of -- the limiting condition is refueling condition. And for this condition, the current safety factor of the limiting sandbed bays 3.54, which results in a

safety margin greater than the ASME Code specified safety factor of 2.0.

And then for the emergency conditions, the limiting condition is the post-accident flood condition. For this condition, the current safety factor for the limiting sandbed bay is 2.02, which results in a safety margin greater than the ASME Code minimum of 1.67.

And the sensitivity studies that we performed show that we could have significant thickness changes, either from uncertainty or corrosion, and that we showed that we would have rather large changes, without a significant reduction in the safety margin, as we've shown in our sensitivity cases.

That concludes our presentation, and we'd see if you have any other questions we can answer.

MEMBER SHACK: Thank you. I guess we will have the Staff presentation now.

(Off the record comments.)

MR. GALLAGHER: Okay. Thank you, Dr. Shack.

(Off the record comments.)

MEMBER SHACK: Louise, I understand

you're going to be starting us off.

MS. LUND: Yes, thank you. Am I close enough to the microphone? Okay. Is this close enough? Okay. Thanks.

MEMBER SHACK: He's the problem, not us.

MS. LUND: Who is?

MEMBER SHACK: Our reporter has to hear everything.

MS. LUND: Oh, okay. Am I all right?

COURT REPORTER: Yes.

MS. LUND: Okay. Great. As you can probably tell, on our slide up there right now we've got Allen Hiser and Hans Asher, Kamal Manoly, and Tim O'Hara. And you probably realize that I'm not Allen Hiser, but I'm substituting in for him during this presentation. And I think that probably what you remember from the Subcommittee meeting is, I was the Branch Chief for much of the Oyster Creek license renewal review. And, of course, next to me is Kamal Manoly, who is the Branch Chief in the Division of Engineering, and also participated in the review of the 3-D analysis. And to his right is Hans Asher, and he's a Senior Structural Engineer, and

he was in the Division of Engineering, now is in the Division of License Renewal. And, in fact, Kamal Manoly is now a Senior Level Staff in the Division of Engineering, and both of them are structural engineers who have been with the NRC for a long time, and sit on a number of our Standards and Codes Committee. And all the way to my right is Tim O'Hara, who joined us today from -- he's the Region 1 inspector who actually had the opportunity to go into the sandbed region, and look at the activity, the inspection activities for 2006 and 2008. So, he has quite a good perspective to bring, as far as having looked directly at the sandbed itself, and the sandbed region of the drywell shell. So, we'll be presenting that, as well.

And we're actually going to talk a little bit about some of the areas that we talked about during the Subcommittee meeting, but we're going to go on to have Tim provide his perspective, as well. And I think that the licensee had discussed where we got to as far as the drywell shell in the late `80s, the corrosion that had occurred in the sandbed region, and the reason for that. And, also, the remediation that

they did at that time. In this case, especially, I guess you've heard in their presentation, around the 1992 time frame, in which they had ground down those areas for measurements, and they also had installed this coating that you saw in the pictures.

Now, talking about -- this is, of course, one of three analyses that were actually performed. And we talked a little bit about the GE analysis, is, of course, the analysis of record, which is intended to be a conservative analysis. And it remains the licensing basis. And the acceptance criteria is derived from this analysis.

We also, during the license renewal review, had performed a confirmatory analysis by Sandia that the ACRS has also been briefed on during the license renewal review.

MEMBER SHACK: Now, what is the exact acceptance criteria for that analysis? The analysis assumes a uniform reduction in shell thickness to the 736.

MS. LUND: Actually, the GE analysis, actually, there was a uniform reduction, but there is actually a tray model. And, actually, the

bottom of the tray was .536 inches, and it transitioned up to .736. And, in some ways, it was a function of how the modeling was done back in that era, because if you remember back in the era, it was more of a pie slice instead of a 3-D, so that's why this -

MEMBER SHACK: But, I mean, how do I -- what do I measure to compare -- to get an acceptance criteria? Is this the average thickness over the worst bay, the 736? Is the 536 the thinnest minimum local UT measurement?

MS. LUND: Well, there's also a pressure criterion, which is .490, as well. Do you want to handle that, Hans, how that actually -

MR. ASHER: I can try. Otherwise, I'll ask licensee to provide more information. After they did all the modifications like putting the coating on, and everything else, the entire shell -- a very, very conservative way; that, hey, my shell is not 1.15 and 154 mils thickness. It is thickness of .736, 736 mils. So, that was one data they put in. The second data they put in was the locally thinned areas. That is where they made their made their -- that is one foot by one

square foot to three-by-three square foot on the top, and the lowest thickness was .533, which was not representative of any reading they had taken. They wanted to make a conservative assessment at that point --

MEMBER SHACK: But I've got a -- how do they know whether they're within this licensing basis or not?

MR. ASHER: I have a feeling. I'm speculating now that they did number of gyrations of calculations themselves before they came out and said 736 mils. And they decided this is the level where we can show the safety factor, and where we can provide enough confidence that the current licensing basis is good enough.

MS. LUND: But, they do do some -- what they do is -- and I see Mike Gallagher is up there to talk for the licensee, as well. But when they take the measurements, especially for the grid, they do a statistical analysis on that, because you -- this tray model is actually a 9-square foot area. Okay? So, you know what they have to do, is they have to say to themselves afterwards that none of the individual points are lower than .536, that pressure criterion .490, so

there's a first pass where they look at those readings. And then for the averaged readings, from the grids, they do a statistical analysis, and get something that is for the larger area.

Mike, do you want to contribute to that?

MR. GALLAGHER: Yes. This is Mike Gallagher from Exelon. So, Dr. Shack, it's, basically, the general acceptance criteria of 736 mils. So, we verify ever grid is greater than that. Okay? That's one step.

MEMBER SHACK: Okay.

MR. GALLAGHER: And then -- and it is. And we presented all that data to you, and I have it in my briefcase, if you'd like to look at it.

MEMBER SHACK: No, no. I just want to know what the criteria is.

MR. GALLAGHER: So, that's one. And then any point that is less than -- any individual point that is less than 736 mils is compared against two criteria. One is this tray that, basically, was a sensitivity, you're down to 536 mils -- it's a three-by-three tray down to one-by-one center. And we also verify that it's greater than the local pressure criterion.

MEMBER SHACK: Now, does that 536 point have to be within the assumed location of the tray?

MR. GALLAGHER: The trays were -- the way the trays were done was a tray could be -- one tray in each bay could be done, and it was put into the -- it was analyzed for the less stiffest part, the value of the part between the vent headers, so you can, essentially, put that tray anywhere in the back. So, basically, you just verify those three criteria, and then it's all documented in analysis.

MEMBER SHACK: Thank you.

MR. GALLAGHER: Thanks.

MEMBER BROWN: Excuse me for a second. Bill, I'm going to direct a question to you, because I'm hoping that you'll just answer it succinctly, and that's the end of it. We're spending a lot of time here on measuring these thicknesses and all in the area of the sand, what's it called, sand?

MEMBER SHACK: Sandbed.

MEMBER BROWN: Sandbed. And, again, I wasn't at the Subcommittee, so I'm a little reluctant to say anything, but we've now got this

very nice looking water seal, and it's inspected regularly. But what was done about the crack that was referred to as below this, what is now a water seal, to verify that the thickness was what it needed to be?

MEMBER SHACK: Okay. Just let me see if I can answer it quickly. They excavated those trenches, those long green lines that you saw, allowed them to make direct measurements of the material underneath there. Again, the argument also is that that material is in intimate contact with concrete.

MEMBER BROWN: Now, I'm familiar with that. I just -

MEMBER SHACK: They did that -- the trenches are there as a direct confirmation.

MEMBER BROWN: Okay. That's all. Thank you.

MS. LUND: Okay. So, I'm going to move on to -- what I wanted to point out, also, on this slide was, is that all the analyses that were performed demonstrated that the margins met the ASME Code.

Okay. All three of those analyses that were performed did receive independent

reviews, so that was another thing that I wanted to mention, as well.

The submittal that was discussed today, there was a January 22nd, 2000 submittal that had the base case, and the sensitivity cases. And that was our review as part of the license renewal inspection. And, of course, it was put into the inspection report that was issued. And we also received another submittal, September 9th, 2009, with two revised modeling approximations to add different portions. And that was discussed in the Subcommittee meeting, as well.

Both of those submittals, the calculations that supported them were audited by our staff. And to supplement our reviews, we looked at the proprietary calculations supporting the submittals. And that was to insure that the analysis was conducted according to good engineering and ASME Code practices, that the inputs were realistic, but conservatively biased, were appropriate, and that the outputs and conclusions adequately supported -- was supported by the data.

The staff reviews also whether the drywell shell factors of safety from this analysis

met Code margins. And we recognized, as did others that perform these independent reviews, that there were different approaches that could be taken to model the degradation and stresses that would be considered appropriate by the ASME Code; that with a degraded structure, such as this one that was so complex, there was not one unique way to model the structure, so the staff focused on whether the current analysis was reasonable, and consistent with good engineering and Code practices.

Now, I'm going to go ahead and turn this over to Tim O'Hara, who is going to discuss his observations during the 2006 and 2008 inspections. And I just want to note that Tim has been with the NRC for seven years. And before that, he worked for Westinghouse for 20 years, and was also with the Nuclear Navy. Thanks, Tim.

MR. O'HARA: Good afternoon. My involvement with this Oyster Creek situation actually started in February and March of 2006 during the license renewal aging management inspection. At that time, I spent maybe three to four weeks looking at all the data, looking at the entire situation here. And then we came back in, I

guess, it was November of 2006, and watched what was going on during the outage inspection of 2006.

The main things we were looking at, that Region 1 inspection staff looked at, the ultrasonic technique that was used to collect data, both internally, and externally. We watched the VT-1 inspection of the coating. We looked at the seal inspection, and what was done there. And we looked at the general condition of the drywell, and how that was all recorded.

Secondly, the other activity that was important that we were looking at is, we wanted to see if there's some way to verify a process that Exelon had laid out on page 19 of their slide, which actually said they were -- they picked the thinnest areas in the bays. And my summary of what I saw, both in 2006 and 2008 is, we noted by sample observations that external measurement locations appeared to be chosen in areas of significant relative corrosion.

Now, that's not certainty, but I don't know how else you could have done it any differently than they did. So, that's our observation of what went on. And we felt satisfied that Exelon had picked, to the best

possibility, the thinnest points.

And I would say in 2006 and 2008, I probably entered six or seven different bays while inspections were going on, while UT inspections were going on, observing that they were doing them correctly, and so on, and so forth. And I looked at different points that were marked. They were all marked, so I looked at them. And my conclusion was, I couldn't have said that there were other areas that were thinner. I couldn't say conclusively, so my conclusion is that they had done a reasonable job of picking thin spots.

Okay. The general observations -- by the way, there are inspection reports on both the 2006 and 2008, and they go into much more detail. I'm just talking about the sandbeds here. Okay? My observations on the drywell was that the exterior coating was, in general, in good condition. Okay?

The UT inspections were conducted and reported in a competent, accurate manner. And what I mean there is, they had qualified procedures, qualified technicians. They were supervised adequately, and the results were reported, and then analyzed by Level 3 UT people,

so I think they're defensible in their Code acceptable quality thickness measure, so I don't have any problem with that.

And, finally, the sandbed general conditions were good. There were some minor repairs. I was more involved in the 2006 inspection. I spent the entire outage there. In 2008, I was only there a week, or so. But the general conditions were good. There were some minor repairs. There were some seal repairs that needed to be done. And there was a coating problem that had to be fixed on the drywell shell. And all those conditions are reported in their corrective action process, and they're all adequately, or faithfully reported in their inspection records. So, I have no problem with what I saw. And that's, basically, my summary. If anybody has any other questions, I'm -

MEMBER SHACK: That's the kind of confirmation I was interested in.

MR. MANOLY: Okay. I will address the next slide. This is Kamal Manoly from NRR.

One thing we need to focus on, that even though this analysis was supposed to be realistic, there are several factors that -- of

conservatism that were included in the analysis. And these are fairly major conservative assumptions. Using the bounding spectrum, that definitely the high elevation, rather than using the different location response spectrum. One of the other things, the damping values used was lower than the Reg Guide 161 permits up to 3 percent damping.

The weight of the flood, the water from the flooding condition was all added to the drywell. And, also, the sizes of the locally thinned area was exaggerated to account for more conservative mapping. So, these are fairly sizeable areas where there are conservatisms in the analysis. They're supposed to be realistic.

The next slide, I guess when we talk about the model, and I think it's -- you all heard Exelon talk about the analysis. Personally, more than 35 or 40 years of experience, I haven't seen a model that extensive. That is a huge model with 400,000 elements.

MEMBER SHACK: A monument to the finite element art.

MR. MANOLY: Yes. And it's not really -- it's not even used for a licensing analysis.

This is for confirmatory analysis. The level of detail is very extensive. The boundary conditions which affect, usually, the analysis greatly, extended at the downcomers, all the way down to way beyond the zone of interest, so I think that's very -- beyond what I would have expected.

When they committed to this analysis, I didn't expect that it would be that extensive, but, nevertheless, that's what they did. So, we're very comfortable with the model. And we think we did a very credible job on it.

The next slide, that's a question that came up in the Subcommittee meeting. And I would like to focus on a couple of things. We found that the process used in arriving to the load factors, and the buckling loads were consistent with good engineering practice, and the ASME Section 3 requirements, Code Case 284-1, which we have endorsed in the regulation. And, also, the Code Case in Section 8 that was later included in Section 3, 754, which is similar as the Section 8 Code Case for modified capacity reduction factor.

The key point I'd like to focus on here, that question came about the displacement in the Tables A-2 and A-3 of the SIA model. These

displacements are in the bays, are not in the downcomers. So, they didn't really show any displacements for the downcomer, which is a large pipe, essentially.

As they mentioned, which is, to me, very reasonable, that the R over T ratio for downcomers is much lower than the shell, so you don't expect the downcomers to buckle before the shell.

MEMBER SHACK: I was the one who raised that, and you guys have beaten me to death.

(Laughter.)

MEMBER SHACK: As soon as I realized that capacity factor was one, and all I had to do was compute the buckling loads with the relative capacity factors, and I know the shell is buckling before the vent pipe, way before.

MR. MANOLY: Okay. I'm glad we agree on that. The other thing that also I just -- from the presentation, if you look at the weight, it's taken most by the concrete and the bottom. So, you are not going to -- these downcomers are not going to see a whole lot of load. It's mostly going to the very bottom part of the shell. So, if you don't see load, you're not going to get

buckling. I hope that's clear.

VICE CHAIR ABDEL-KHALIK: Now, the knock-down factors that I used in this analysis, assuming that the deviation from the ideal spherical or cylindrical geometry is less than the maximum allowed by Code.

MR. MANOLY: Yes.

VICE CHAIR ABDEL-KHALIK: How do we know that that's the case today?

MR. MANOLY: Well, based on the geometry. You get capacity reduction factor, you get modified capacity reduction factor. The modified accounts for the tension in the element.

VICE CHAIR ABDEL-KHALIK: I understand what it means. I'm asking you a specific question.

MR. MANOLY: Yes?

VICE CHAIR ABDEL-KHALIK: How do we know that the deviation of the geometry from the ideal spherical or cylindrical geometry today is consistent with the limits specified in the Codes for responding to those capacity reduction factors?

MR. MANOLY: Based on the measurement that they obtained.

VICE CHAIR ABDEL-KHALIK: When?

MR. MANOLY: You have certain geometries for the bays. I mean, the capacity reduction factor is a function of the geometry and the properties of a certain zone. So, you are accounting for that area.

MR. ASHER: If I may say, the capacity reduction factor are in Code Case 284-1, are based on tests, tests on the cylindrical and spherical types of shells. And they are derived from them, and I believe they are very conservatively put together here, kind of a curve, which is a parameter, M, which was explained earlier. That parameter is one that dictates as to which particular capacity reduction factor you can use. So, it is based on tests on the imperfect kind of a shell.

MR. MANOLY: It's empirical.

MR. ASHER: It's empirical in that sense, yes. But, still, it is based on tests to make sure that the capacity reduction factor really reflects the more commonly used shapes, shells, I mean, which is cylindrical shells, and spherical shells.

MEMBER SHACK: Does that answer your

question?

VICE CHAIR ABDEL-KHALIK: No, it doesn't answer my question.

MEMBER POWERS: What he's asking you is, how do you know that you've got a Russian spherical shell now, today?

VICE CHAIR ABDEL-KHALIK: Right.

MEMBER POWERS: As we speak.

MR. MANOLY: It depended on the geometry of the -- if you have a cylindrical shell, you're going to have a different capacity reduction factor than you have a spherical shell.

VICE CHAIR ABDEL-KHALIK: We all understand that. That is not the question.

MR. MANOLY: It's a derived -- it's an empirical equation that -

MEMBER MAYNARD: We're not asking about the analysis. It's just simply the Oyster Creek shell, as built, as it is right now -

MEMBER SHACK: Matches the drawings that we're using for the analysis.

MEMBER MAYNARD: How do we know the Oyster Creek shell, itself, is cylindrical right now? It has nothing to do with evaluation -

MR. MANOLY: How do we know it is

cylindrical?

MEMBER SHACK: Do I think the licensee is telling -

VICE CHAIR ABDEL-KHALIK: It's sphericity is consistent with the code limitation. How do we know that today?

MR. GALLAGHER: Yes. If I can, I think you asked the same question at the Subcommittee, and Dr. Miller, we can try that answer. I think you're referring to the E over T.

VICE CHAIR ABDEL-KHALIK: I'm asking what is the geometry now? How far off from a sphere are we today? And is that deviation consistent with the limitations imposed in the Code, corresponding to these knock-down factors?

MR. GALLAGHER: Yes. And, basically, there was criteria in the original design, and it met the E over T criteria that Dr. Miller could talk about. And then the Oyster Creek was -- the shell was installed per their specifications and drawings. So, all those design drawings, and construction installations were checked during construction. And that is, that is basically what we had.

MEMBER POWERS: But he's not asking

about the time of construction. He's asking today.

MR. GALLAGHER: Understand, but there was no changes in the fabrication, or the installation, so it was all installed per design, and we used the design drawings to build the model. Now, there are conservatisms in safety factor, and even in the capacity reduction factor that would accommodate any uncertainties. But it was designed and installed in accordance with the requirements and specifications.

MEMBER POWERS: I think the answer to your question is they don't know.

MS. LUND: Well, is the question you're asking, is it -

MR. GALLAGHER: Because it is designed and installed, and we -

VICE CHAIR ABDEL-KHALIK: Here is the rationale for my question. The capacity reduction factor -

MR. GALLAGHER: Not going to change the structure.

VICE CHAIR ABDEL-KHALIK: The capacity reduction factors depend on how far off from a perfect sphere you are.

MS. LUND: Right.

VICE CHAIR ABDEL-KHALIK: And, presumably, the values that were used were consistent with the limits imposed in the Code, which, presumably, were verified at the time of construction.

MS. LUND: Right, because they had the -

VICE CHAIR ABDEL-KHALIK: The question is, what does it look like now?

MS. LUND: Right. Because they -

VICE CHAIR ABDEL-KHALIK: How far off from a sphere are we?

MS. LUND: Basically, is the question you're asking inferring that there has been some plastic deformation, and it's changed from its as-built dimensions? Is that what the -- what's underlying?

VICE CHAIR ABDEL-KHALIK: For whatever reason, difference in ability to accurately measure deviation from perfect sphericity between then and now. The issue is how sensitive is that capacity reduction factor to -

MS. LUND: Small changes?

VICE CHAIR ABDEL-KHALIK: Deviations

from -

MS. LUND: I think that's the question.

VICE CHAIR ABDEL-KHALIK: -- what the Code limits dictate.

MS. LUND: Right. Right. Basically, they were putting in the measurements from their as-designed, and as-built shell. And what you're asking is, is that if there were small changes because of some deformation, how would that impact really what it is today? Is that what -

MEMBER ARMIJO: Could I ask -- if you take that sphere, it's a big sphere. There's a three-inch gap between the concrete and the containment vessel. If that diameter increased by six inches, stretched out by six inches, would it make any difference? That's a limit. That's as big as that sphere could get from -

MR. MANOLY: If the shell was perfectly round, and there's no defections, you would not need the capacity reduction factors.

MS. LUND: Right.

MEMBER ARMIJO: I understand that.

MR. MANOLY: You're really accounting for imperfections in the shell.

MEMBER ARMIJO: He's asking how imperfect is it today, and does that meet the criteria that you used in the analysis?

MS. LUND: And whether there could be any changes from what they actually calculated to begin with, because could there be any feasible mechanism for it to deform, or in some way not represent what it was when the initial measurements were used.

MR. MANOLY: I don't think the numbers in the capacity reduction factor are very sensitive, if the -- when the shell was constructed, it, obviously, met the construction specs. Okay? So, the Code Case was developed when we have certain potential variations in the -- from the perfect shell.

MEMBER SHACK: I think the best we could do is get an expert opinion by Dr. Miller.

VICE CHAIR ABDEL-KHALIK: Please.

MEMBER SHACK: If we've met the original configuration -

MR. MILLER: I can't positively answer, you're right.

VICE CHAIR ABDEL-KHALIK: Thank you.

MR. MILLER: Your question, what I can

say, that the initial out-of-roundness allowed by the ASME Code is one shell thickness measured over a half-buckle wavelength, which I mentioned was somewhere between 62 and 89 inches. Typically, the initial construction will be well within that one shell thickness, much less, maybe only half of the shell thickness, or less. I can't positively tell you that it's -

VICE CHAIR ABDEL-KHALIK: What it looks like now.

MR. MILLER: I would say if you go out and measure, I would be very surprised if you found there is a point of the shell where the deviation is greater than the shell thickness.

VICE CHAIR ABDEL-KHALIK: So the question then is, if I were to plot this capacity reduction factor as a function of the fractional deviation from perfect sphericity, how rapidly does this thing drop off, as this sort of imperfection size increases?

MR. MILLER: Actually, in the Code Case, I have an equation which relates the measured deviation with the allowable -- in other words, the capacity reduction factor, I have an equation, regardless of what the value -- there is

some lower bound, but in the case of this particular sphere, there's two criteria. One is local deviations in the unstiffened sphere. The second criteria is if you put ring stiffeners, you get to the point where the Alpha factor is based on the ring stiffeners, and not the local deviation. And it just happens that in this particular drywell shell, the Alpha value that we're using is based on the distance between stiffeners, as opposed to the one based on R over T. The one based on R over T is related to this E over T of one.

VICE CHAIR ABDEL-KHALIK: Thank you.

MR. MANOLY: I think another point we need to add here, that if you don't account for the modified capacity reduction factor, which improves the shell buckling capacity, if you take that out, and just calculated the factor of safety, you still meet the Code limit. So, the whole notion about modified capacity reduction factor -

VICE CHAIR ABDEL-KHALIK: But you wouldn't have a 3.5 safety factor that gets -

MR. MANOLY: It would be less, but will meet the Code limit. That's the point I'm

trying to make, that even if you know the whole argument about the tension of the shell and the whole direction that included this buckling capacity, you still will meet the Code limit at the lower number from what they show here. So, I think that's another thing that we need to keep in mind.

VICE CHAIR ABDEL-KHALIK: Thank you.

MR. MANOLY: The next slide really talks about the sensitivity analysis, and we've talked about that several times. The key here is that it was intended to capture uncertainty, potential uncertainty in the mapping of the thinned areas. And as they showed in the S-1 and S-2 analysis, in one day they reduced it by 100 mils in Bay 1, and the entire -- the thinned area was thinned by 100 mils. And Bay 19 was 50 mils in the entire bay. That's, in our opinion, very conservative. And, really, they can do the sensitivity analysis in a thousand different ways, and anybody can decide which way is right, but I think this is very conservative way of considering two pieces that are pretty extreme. And, also, if you add that to the analysis done by Sandia, analysis done by GE, they all point to the same

direction, that we still meet the Code limit. So, we think that the analysis was very adequate and reasonable for the focus that it was done.

MS. LUND: Okay. Summarizing our presentation, we say to ourselves, what were we actually aiming to do? Okay? Or what was the licensee aiming to do? And I think their intent was to do a conservatively biased realistic analysis that gave them some sense of what additional margin there was above the ASME Code limits. And in doing that, and also to look at the sensitivity of that analysis to thinning in both the thinned areas, and also in the bay. And as Kamal has said, I think that there can be other approaches towards modeling. There's going to be other approaches towards looking at realistic versus conservative inputs, but -- and, also, as Tim has said in his presentation, as well, we looked at what they had done, and it looked reasonable, and it looked like it was conservatively biased. And we had confidence that what they had done was what was asked in this particular analysis.

And another thing I wanted to mention, too, is, when Tim was -- and also the other

regional inspectors were looking at this, there's a lot of background information on the work that they did to characterize this, to put on the coating, to the inspection reports. There's piles, and piles, and piles of documentation, and probably far more than I've seen for a lot of work that I've seen done. It is very adequately documented, a lot of the work that they've done in the past. And I know that the inspections had -- the inspectors and the inspections had use of a lot of that material to prepare for that, and understand what happens. Anyway, that concludes what our presentation is.

MEMBER SHACK: Any further questions from the Committee? Again, a lively discussion. This thing always does seem to raise a number of issues. Thank you.

MEMBER POWERS: A defense-in-depth physical barrier. It should receive lots of attention.

MEMBER SHACK: Thanks very much to the Staff, and to the licensee for the very good presentations. Are there any questions from anybody in the audience? Back to you, Mr. Chairman. Sorry we're a little late.

CHAIR BONACA: Thank you very much for the presentation, and we'll take a break now until ten of six, and we'll get together, and talk about the letters.

(Whereupon, the proceedings went off the record at 5:36 p.m.)

North Anna 3

North Anna Unit 3 Presentation to Advisory Committee on Reactor Safeguards

Dominion

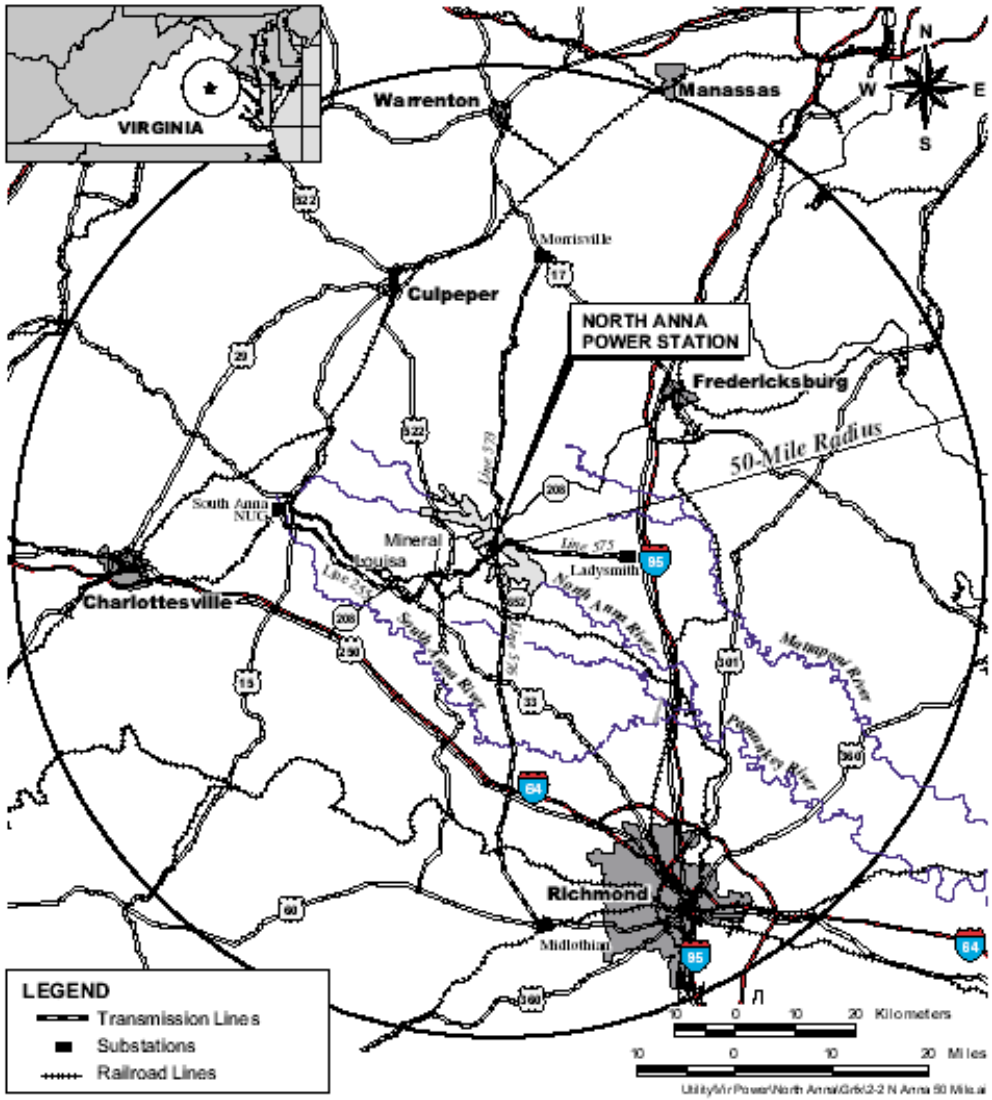
Dominion's North Anna 3 Licensing Activities

• ESP Application submitted	9/25/03
• ESP issued	11/27/07
• COLA submitted	11/27/07
• Draft EIS issued	12/17/08
• COLA Revision 1 submitted	12/20/08

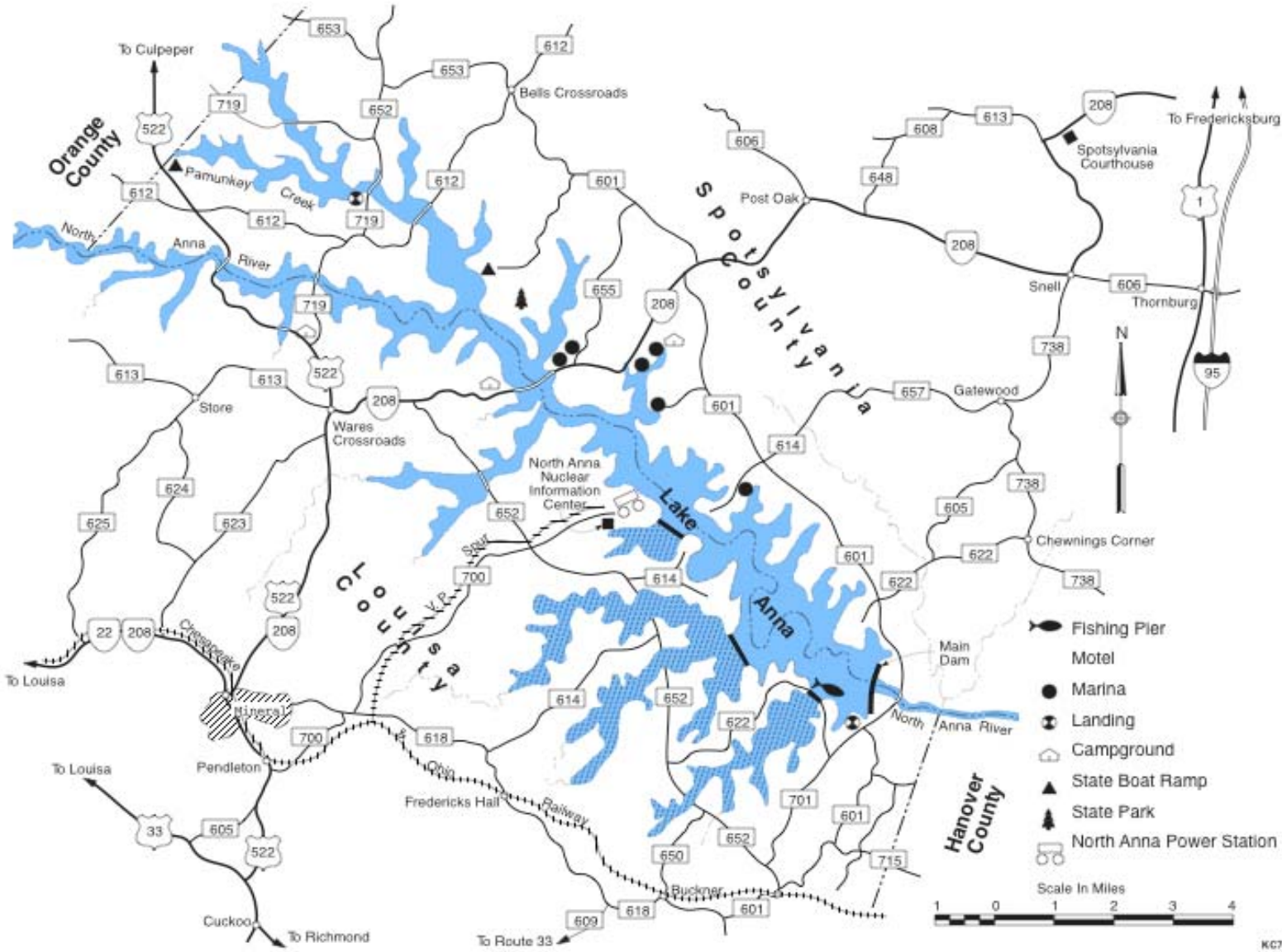
Dominion North Anna 3 Presentations to ACRS Subcommittee

- June 11, 2009
  - Chapters 1, 4, 6, 7, 8, 15, 17, 18, 19
- July 21 and 22, 2009
  - Chapter 5, 9, 10, 11, 12, 13, 16
- August 21, 2009
  - Chapters 2, 3, 14

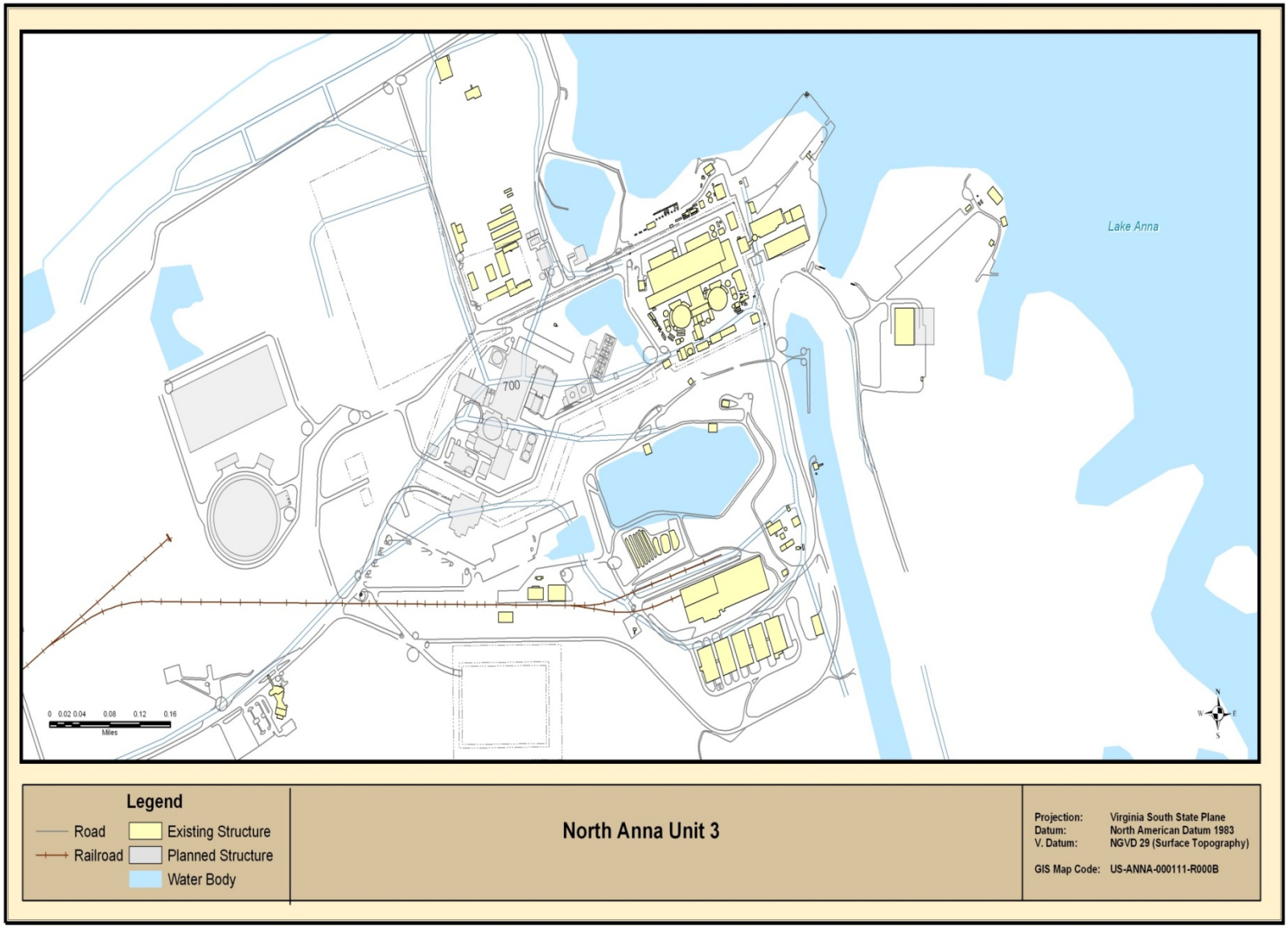
Location of North Anna Power Station



Location of North Anna Power Station



North Anna Power Station



Introduction of COLA Team's Meeting Participants

Dominion

- Joe Hegner
- Gina Borsh

GEH

- Rick Kingston
- Patricia Campbell

Bechtel

- Doug Kemp
- Geoff Quinn

Subject Matter Experts by phone

North Anna 3

ACRS COLA Presentation: Site-Specific Topics and ACRS Inquiries

Introduction

- NAPS U3 FSAR Content
  - Incorporated by reference (IBR):
    - ESBWR DCD as permitted by 10CFR52.55(c)
    - ESPA SSAR
  - Supplemental information added:
    - COL Item
    - ESP COL Action Item
    - ESP Permit Condition
    - Conceptual Design Information
    - Supplemental Information (e.g., Reg Guide 1.206)

Discussion Topics

- Chapter 2 – Site Characteristics
  - 2.4, Hydrology
  - 2.5, Geology, Seismology, and Geotechnical Engineering
- 9.2.3 Makeup Water System
- 10.4.5 Circulating Water System
- 9.2.1 Plant Service Water System

Chapter 2, Site Characteristics: Background

- Compares Unit 3 FSAR site characteristics and facility design values with corresponding DCD, ESP, or ESP Application SSAR values to determine if:
  - Unit 3 site characteristics fall within DCD's site parameters
  - Unit 3 site characteristics or facility design fall within ESP's site characteristics or design parameters [ESP used plant parameter envelope (PPE)]
  - Unit 3 site characteristics and design values fall within SSAR site characteristic and design parameter values

North Anna 3

Chapter 2:
Site Characteristics

Section 2.4, Hydrology

Chapter 2, Site Characteristics: 2.4 Hydrology

- SSAR Section 2.4 is incorporated by reference and supplemented with:
  - Impact on wetlands and two intermittent streams that flow into Lake Anna [NAPS COL]
  - Design plant grade is above design basis flooding level [NAPS COL]
  - Location of safety-related SSCs is above maximum water surface elevation produced by local intense precipitation [NAPS ESP COL]

Chapter 2, Site Characteristics: 2.4 Hydrology (cont.)

- Supplemental Information (cont):
  - Water supply to the UHS is above design plant grade elevation [NAPS COL]
  - Engineered underground reservoirs or storage basins not used for UHS [NAPS ESP COL]
  - Emergency cooling water for Unit 3 is provided from UHS, which is not affected by ice conditions [NAPS COL]
  - Lake Anna is not used for safety-related water withdrawals for Unit 3 [NAPS ESP COL]

Chapter 2, Site Characteristics: 2.4 Hydrology (cont.)

- Supplemental Information (cont):
  - Embankment for water intake structure is protected by rip-rap [NAPS ESP COL]
  - Maximum PMP water level in power block area is 2.8 ft below design plant grade elevation for safety-related facilities [NAPS COL]
  - Circulating water system operating modes [NAPS ESP COL]

Chapter 2, Site Characteristics: 2.4 Hydrology (cont.)

- Supplemental Information (cont):
  - Additional borings, groundwater level measurements, hydraulic conductivity testing [NAPS COL, NAPS ESP VAR]
  - Groundwater supply wells, groundwater use, and groundwater level monitoring program [NAPS COL, NAPS ESP VAR]
  - Estimated maximum groundwater level in power block area is 7 ft below design plant grade elevation of 290 ft; therefore, permanent dewatering system is not required for safe operation of Unit 3 [NAPS COL]

Chapter 2, Site Characteristics: 2.4 Hydrology (cont.)

- Supplemental Information (cont):
  - Mitigating design features are incorporated into design of Unit 3 to preclude an accidental release of liquid effluents [NAPS COL, NAPS ESP PC]
  - Accidental release of radioactive liquid effluent to either groundwater or surface water complies with 10 CFR 20 limits for release to unrestricted areas [NAPS COL]
  - Unit 3 will shut down when water level in Lake Anna drops below Elevation 242 ft msl [NAPS ESP COL]

North Anna 3

Chapter 2: Site Characteristics

Section 2.5, Geology, Seismology, and Geotechnical Engineering

Chapter 2, Site Characteristics: 2.5 Geology, Seismology, and Geotechnical Engineering

- SSAR Section 2.5 is incorporated by reference and supplemented with:
  - Additional Unit 3 borings to further describe the site stratigraphy [NAPS COL]
  - Weathered or fractured rock at foundation level for safety-related structures will be excavated and replaced with lean concrete before foundation construction [NAPS ESP PC]
  - Future excavations for safety-related structures will be geologically mapped and unforeseen geologic features will be evaluated [NAPS ESP PC]

Chapter 2, Site Characteristics: 2.5 Geology, Seismology, and Geotechnical Engineering

- Supplemental Information (cont):
  - Unit 3 OBE ground motion is one-third of FIRS and is bounded by DCD OBE [NAPS COL]
  - Description of excavations, fills, and slopes, including discussion of excavation and fill methods and stability [NAPS ESP COL, NAPS ESP PC]
  - SWV profiles for soil used for liquefaction analysis and slope stability analysis; backfill for FWSC [NAPS COL, NAPS ESP COL]

Chapter 2, Site Characteristics: 2.5 Geology, Seismology, and Geotechnical Engineering (cont)

- Supplemental Information (cont):
  - Liquefaction Potential [NAPS COL, NAPS ESP PC]
    - Chances of liquefaction occurring in Zone IIA saprolite are extremely low; will not impact stability of any Seismic Category I or II structure
  - Foundation and Slope Stability
    - Allowable bearing capacity values are adequate for Seismic Category I and II structures, and Radwaste Building [NAPS COL]
    - Total and differential settlement values are within limits for Seismic Category I structures [NAPS ESP COL]
    - Static and seismic lateral earth pressures are provided [NAPS ESP COL]
    - Slope stability analysis [NAPS ESP COL]

North Anna 3

Water Systems

Make-up Water System

Circulating Water System

Plant Service Water System

Chapter 9, Auxiliary Systems: Section 9.2.3 Makeup Water System

- Function: Supplies demineralized water to equipment listed in DCD
  - Nonsafety-related system
- During shutdown/refueling/startup mode, increases in plant water consumption may require use of temporary demineralization subsystem
  - Per DCD, design capacity is for normal power requirements
  - Increase is due to draining of non-contaminated systems that can't be refilled with condensate-quality water
  - Ensures adequate supply to supplement CST volume
  - Effective outage Makeup Water usage plan will minimize need for temporary subsystem

Chapter 10, Steam and Power Conversion System: Section 10.4.5: Circulating Water System

- PRA model for system is described in DCD PRA
- Plant-specific design of circulating water system (e.g., cooling towers) is enveloped by DCD PRA analysis
  - Condenser only credited in PRA for events with low significance – where offsite power is available
  - DCD PRA includes analysis of CIRC pump failures due to power loss and trash rack plugging
  - Cooling tower fans not specifically modeled in DCD PRA
    - Fan power supply is same as CIRC water pumps

Chapter 9, Auxiliary Systems: Section 9.2.1 Plant Service Water System (PSWS)

- Function: PSWS rejects heat from nonsafety-related Reactor Component Cooling Water System (RCCWS) and Turbine Component Cooling Water System (TCCWS)
  - No safety-related function
  - Categorized in DCD as RTNSS C

Chapter 9, Auxiliary Systems: Section 9.2.1 Plant Service Water System (PSWS) (cont)

- DCD conceptual design provides for connection between PSWS and normal plant heat sink (CIRC)
- NAPS U3 design does not include this connection
  - Operating conditions might require design changes for other systems (RCCW, TCCW)
  - LOOP would require re-alignment
  - Increased capital cost (e.g., larger normal power heat sink, added booster pumps or larger PSWS pumps) and operating cost (e.g., added booster pump maintenance and increased auxiliary power demand) without offsetting benefits
- NAPS U3 PSWS meets the DCD's performance requirements without cross-connect

Chapter 9, Auxiliary Systems: Section 9.2.1 Plant Service Water System (PSWS) (cont)

- Piping for underground portion of system will be fiberglass reinforced polyester (FRP) pipe
- Rationale
  - Meets design requirements
  - Advantages over other options (e.g., long-term resistance to internal and external corrosion and biological attack)
- ASME code case being used as guidance to develop applicable requirements

Conclusions

- R-COLA work continues
  - Addressing remaining RAIs
  - Advanced SER with no Open Items scheduled to be issued September 2, 2010
  - ACRS review of SER with no Open Items scheduled to be completed December 21, 2010

Presentation to the ACRS Full Committee

North Anna Unit 3 COL Application

Safety Evaluation Report (SER) with Open Items (OI)

October 8, 2009

Office of New Reactors

ACRS Full Committee Presentation
North Anna SER/OI

Agenda

- Opening Comments
- Overview – Applicant and Staff
- Open Items Update
- Hydrologic Engineering (SER Section 2.4)
- Geology, Seismology, & Geotechnical Engineering (SER 2.5)
- Functional Design, Qualification, and Inservice Testing Programs and Environmental Qualification of Equipment (SER 3.9.6, 3.11)
- Plant Water Systems – Circulating, Makeup, & Plant Service (SER 10.4.5, 9.2.3, & 9.2.1)
- ITAAC (SER 14.3)
- COL Application Review Schedule

ACRS Full Committee Presentation
North Anna SER/OI

Staff Overview

- SER/OI complete
  - 19 chapters + appendices
  - DNRL Memorandum to ACRS [ML092150277]
- North Anna COL Application, Revision 1 (12/08)
  - Incorporates by reference
    - Early Site Permit (ESP-003) – Site Safety Analysis Report
    - ESBWR Design Control Document, Revision 5
  - Includes responses to staff RAIs (Phase 1)

ACRS Full Committee Presentation
North Anna SER/OI

Staff Overview (continued)

- ACRS Subcommittee Meetings
  - Focus – North Anna COL application
  - Presentation topics
    - June 18 – Chapters 1, 4, 6, 7, 8, 15, 17, 18, & 19
    - July 21-22 – Chapters 5, 9, 10, 11, 12, 13, and 16
    - August 21 – Chapters 2, 3, and 14
  - No significant issues identified
  - Questions/comments
    - Addressed in meetings or written response
    - DCD resolution

ACRS Full Committee Presentation
North Anna SER/OI

Staff Overview (continued)

- Today's Presentations
  - Open Item update
  - Site characteristics
    - relationship with ESP & DCD
  - Site-specific systems
    - interface DCD
  - Subcommittee transcript comments
- Presentation format
  - Dominion – application (FSAR) content
  - Staff – safety evaluation
- Milestone – 1st COLA SER/OI presentation to ACRS

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BACKUP SLIDES

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North Anna SER/OI

Staff Overview (Backup)

- Lesson Learned – ACRS subcommittee feedback (June 18th) regarding evaluation of "IBR" information
  - SER: "The staff reviewed … FSAR and checked the referenced DCD to ensure that the combination of the DCD and the information in the COL application represent the complete scope of information relating to this review topic. The review confirmed that the information contained in the application and incorporated by reference addresses the relevant information related to … ."
    Staff presentations to include examples

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Open Items

- Open Item 1-1 – ESBWR DCD not finalized (IBR)
- E-RAI Report – Open RAIs
  - Staff: All open RAIs on path toward resolution
  - RAIs in Sections 2.4, 2.5, 3.9, 3.11, & 9.2 – addressed in technical presentations
  - 5.3.2 PTLR – staff review recent submittal
  - 13.3 FEMA – multiple being addressed by offsite entities;
  - 13.6 Security – on-going review with RAIs
  - Chapter 16 – finalize plant-specific technical specifications
  - Turbine Missile Probability Analysis – review commencing – possible RAIs

Open RAIs

RAI	Status	Subject
01-4	Responded	source, byproduct and special nuclear material
02.04.02-4	Responded	Local intense precipitation flood calculation
02.04.02-5	Responded	Local intense precipitation flood calculation
02.04.02-6	Responded	Local intense precipitation flood calculation
02.04.02-7	Responded	Local intense precipitation flood calculation
02.04.12-2	Responded	groundwater modeling.
02.04.13-4	Responded	radionuclide transport analysis.
02.05.04-20	Issued/Open	backfill ITAAC
02.05.04-21	Issued/Open	properties of concrete fill.
03.02.01-7	Issued/Open	SSCs necessary for continued safe operation following OBE
03.09.06-1	Responded	design and qualification of safety-related valves and dynamic restraints
03.10-1	Issued/Open	seismic qualification of equipment.
03.11-1	Responded	environmental qualification operational program
03.11-2	Responded	implementation of environmental qualification approach in DCD
05.03.02-2	Issued/Open	Pressure-temperature limits (GEH Licensing Topical Report NEDC-33441P)
05.03.02-3	Issued/Open	Pressure-temperature limits
05.03.02-4	Issued/Open	Pressure-temperature limits
05.03.02-5	Issued/Open	Pressure-temperature limits.
05.03.02-6	Issued/Open	Pressure-temperature limits.
05.03.02-7	Issued/Open	Pressure-temperature limits
05.03.02-8	Issued/Open	Pressure-temperature limits
09.02.01-13	Responded	fiberglass reinforced polyester pipe in Plant Service Water System
11.04-3	Issued/Open	storage of low-level radioactive wastes.
12.03-12.04-8	Responded	minimization of radioactive contamination and waste (10 CFR 20.1406(a))
13.03-5	Issued/Open	ITAAC for Emergency Operations Facility.
13.03-6	Responded	ITAAC for emergency exercises.
13.03 FEMA	Issued/Open	offsite emergency planning issues
13.06 Security	Issued/Open	RAIs on several topics
16-1	Responded	plant-specific technical specifications.

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Section 2.4

Hydrologic Engineering

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Section 2.4 - General Remarks

- Section 2.4 includes many different water topics, from floods and tsunamis to ice and groundwater. Emphasis is on physical rather than biological issues.
- The ESP review was comprehensive.
- Six variances exist in section 2.4, but were of minor technical consequence.

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Section 2.4 - General Remarks (Continued)

- ESP Permit Condition 3.E(2) – Single unit only. The permit condition for second unit cooling no longer applies.
- ESP Permit Condition 3.E(3) Features to Preclude Accidental Releases of Radionuclides into Potential Liquid Pathways
  - Below-grade tanks are in steel-lined compartments large enough to contain entire contents
  - Above-grade condensate storage tank is in a basin large enough to contain entire contents
  - *Staff concluded that these design features satisfy the permit condition*

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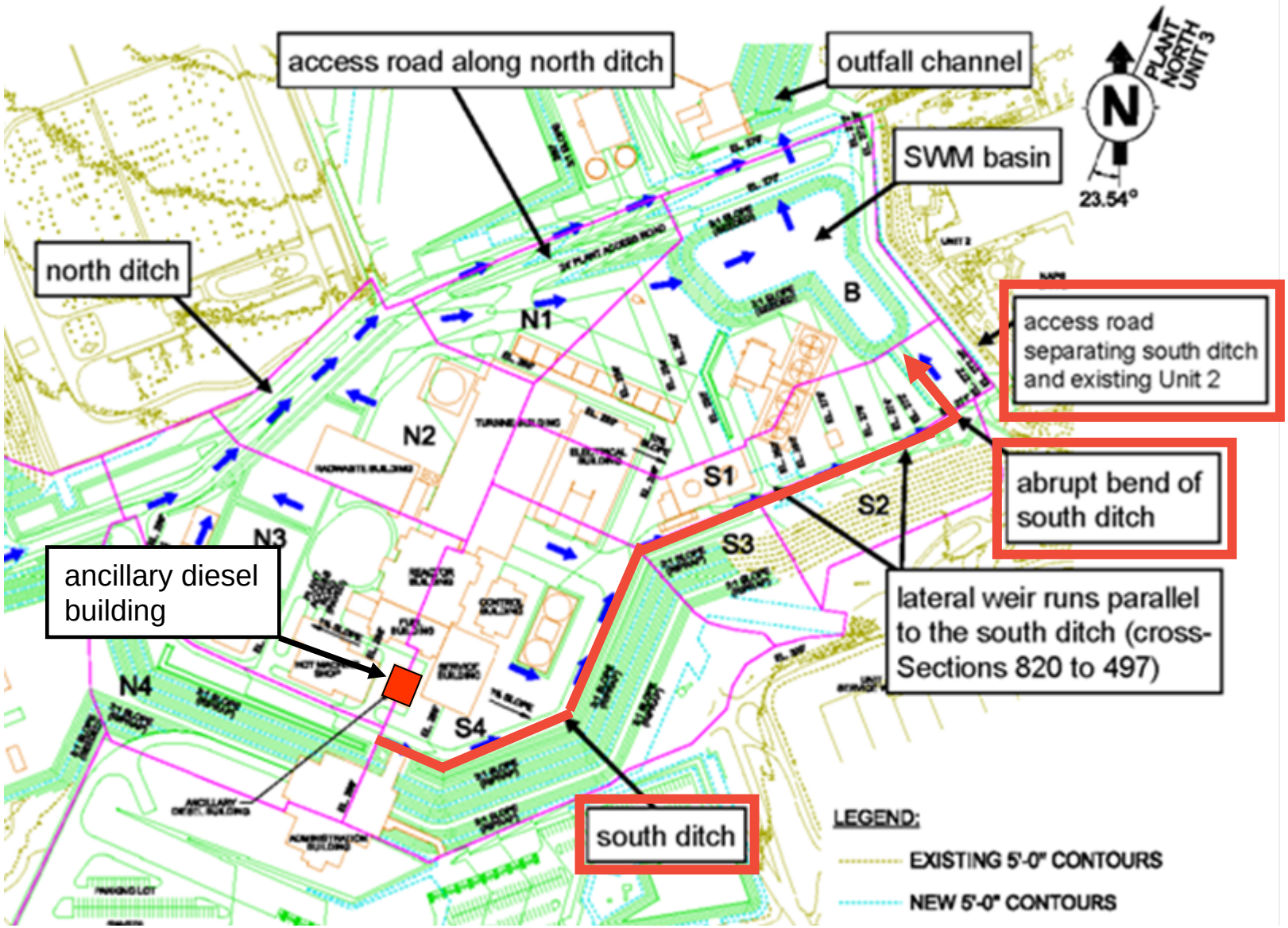
Section 2.4.2 – Floods

There are two different flooding issues:

- Watershed-Scale Flooding
  - The design plant grade elevation is above probable maximum flood (including dam breaks and wave action)
  - No Open Items
- Locally Intense Precipitation Flooding
  - Two Open Items

Section 2.4.2 – Floods (continued)



Based on FSAR Figure 2.4-201

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Section 2.4.2 – Floods (continued)

- Locally Intense Precipitation Flooding
  - Water Levels near Unit 3
    - Modeling analysis demonstrates that water elevations are not high enough near Unit 3 nuclear island to be problematic.

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Section 2.4.2 – Floods (continued)

- Locally Intense Precipitation Flooding (continued)
  - Open Item 2.4.2-2
    - Provide updated HEC-RAS input files for NRC review. Addresses DCD Rev. 5, which adds Ancillary Diesel Building.
    - Provide additional details on the South Ditch to ensure system will function as described.
    - Three RAIs under review (2.4.2-4, 2.4.2-5, 2.4.2-6)

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Section 2.4.2 – Floods (continued)

- Locally Intense Precipitation Flooding (continued)
  - Open Item 2.4.2-3
    - Uncertainty that flood will overtop access road/safety dike that protects existing units (10 CFR 52.79(a)(31))
    - One RAI under review (2.4.2-7)

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Section 2.4.12 – Groundwater

- Open Item 2.4.12-2
  - Concern: Groundwater level must be more than 2 ft below plant grade of 290 ft
  - Staff Issues:
    - Model sensitivity studies of effect of drain cell properties on groundwater elevations
    - Effectiveness of surface water drainage features as groundwater drains
  - One RAI under review (2.4.12-2)

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Section 2.4.13 Accidental Releases of Radioactive Liquid Effluents

- Open Item 2.4.13-4
  - Concern: Staff wants to confirm that the Applicant's groundwater transport analysis is a bounding analysis.
  - Staff issues:
    - Certain literature K_d values used in transport analysis were greater than minimum measured onsite K_d
    - Hydraulic conductivity used in transport analysis was less than the maximum measured onsite
  - One RAI (2.4.13-4)

QUESTIONS ?

Section 2.4
Hydrologic Engineering

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Section 2.5

Geology, Seismology, and Geotechnical Engineering

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- 2.5.1 Basic Geologic & Seismic Information
- 2.5.3 Surface Faulting
- 2.5.5 Stability of Slopes
  - Provided additional site geologic and seismic information
  - Performed new slope stability analyses using updated site data
  - No outstanding issues

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- 2.5.2 Vibratory Ground Motion
  - Addressed COL items and ESP permit conditions
  - Revised Ground Motion Response Spectra (GMRS) based on updated site subsurface profile
  - No outstanding issues

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- 2.5.4 Stability of Subsurface Materials and Foundations
  - Addressed the COL items by providing additional boring data, site soil profiles, subsurface material properties, and stability analyses
  - Resolved RAIs/OIs related to:
    - static and dynamic properties of backfill soil
    - foundation stability analysis
    - coefficient of friction at foundation interface
    - dynamic settlement calculation of soil slope

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- 2.5.4 Stability of Subsurface Materials and Foundations – Remaining Open Items
  - Clearly describe acceptance criteria in backfill soil ITAAC and define field density test frequency (02.05.04-20)
  - Clearly define concrete fill properties in COL FSAR (02.05.04-21)

QUESTIONS ?

Section 2.5
Geology, Seismology, and Geotechnical Engineering

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Back up slides

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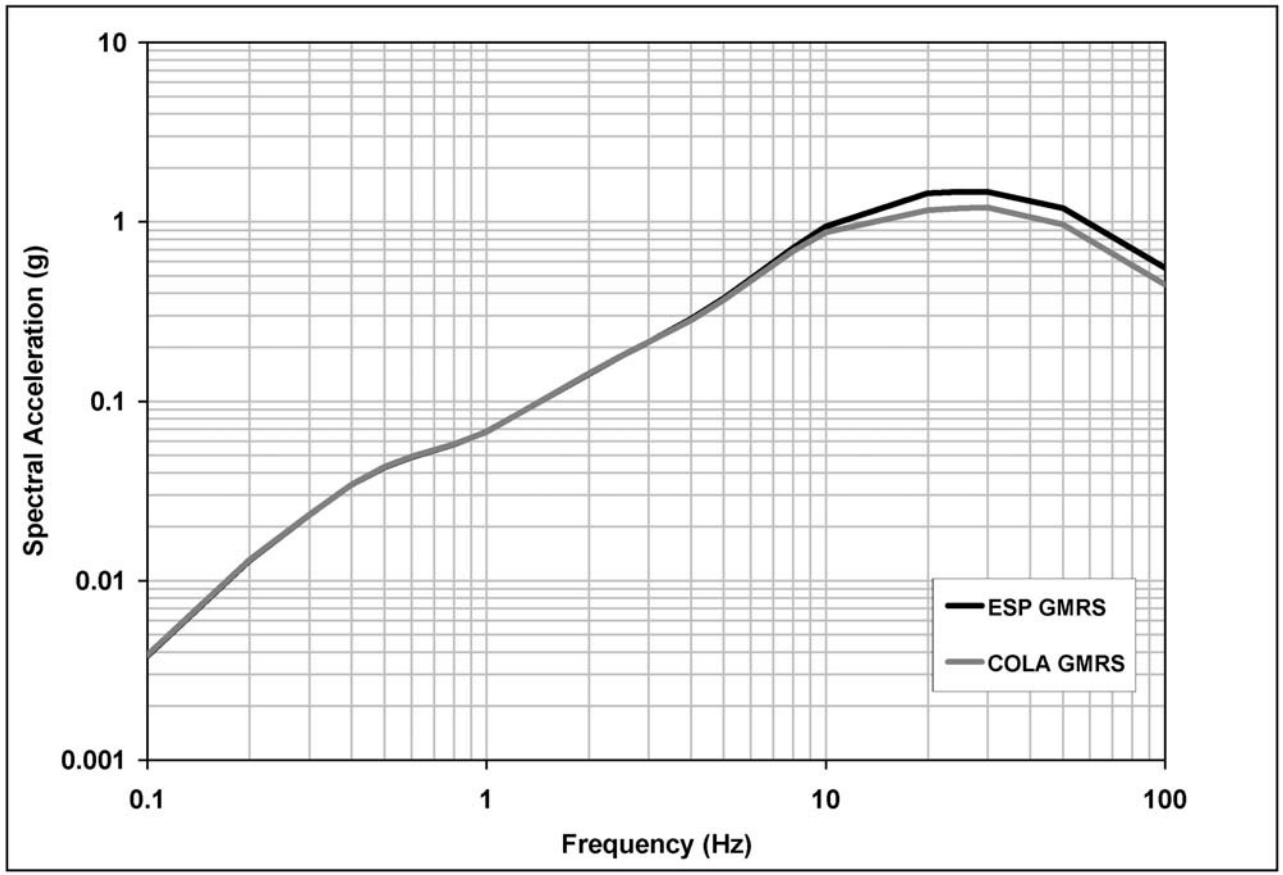

Comparison of Horizontal Ground Motion Response Spectra (GMRS)

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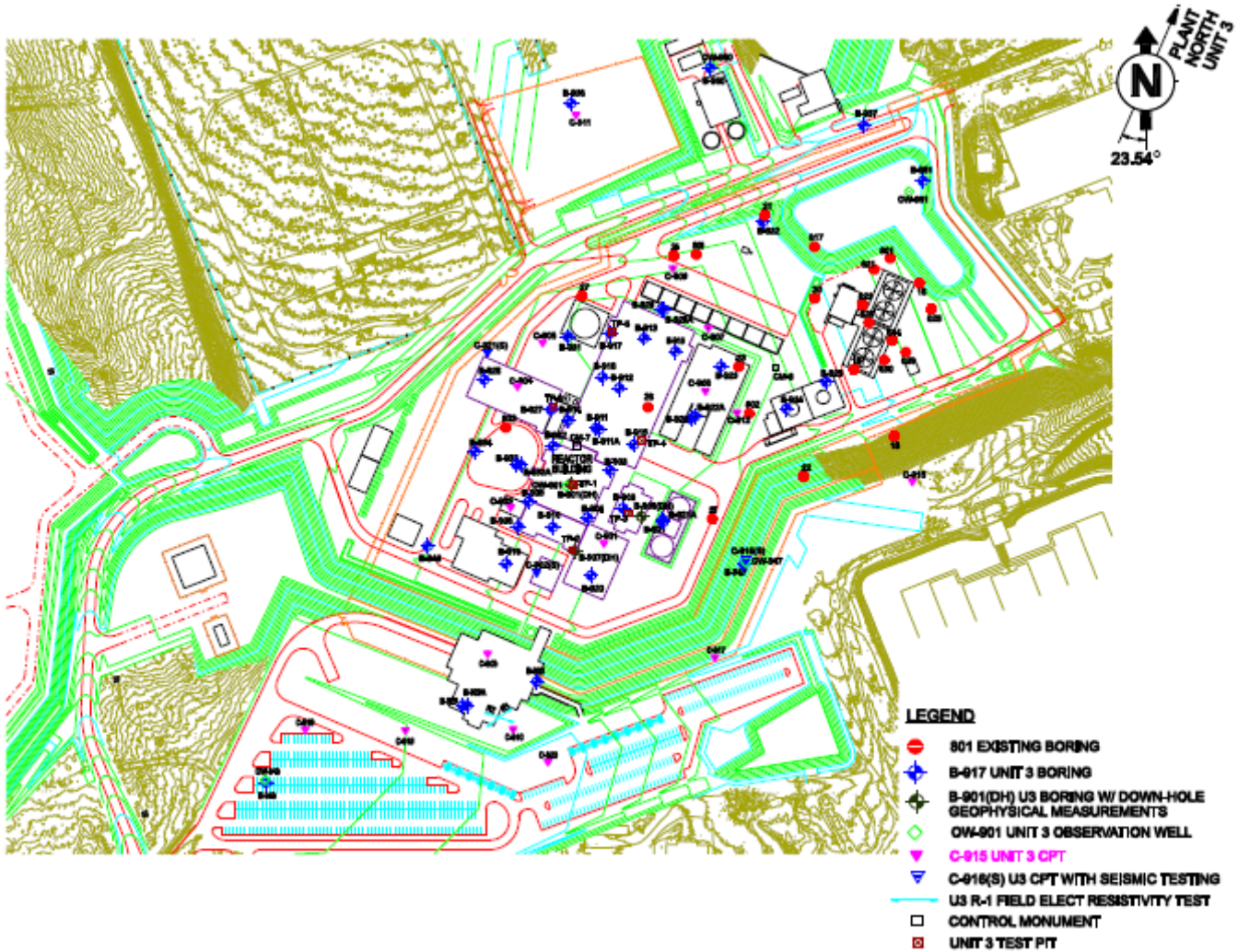

Unit 3 Boring Locations – Power Block

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

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Site Investigations	ESP	COL
Borings	7	55
Corn Penetration Test	8	23
Test Pits	0	6
Observation Wells	9	7
Velocity Test	5	6

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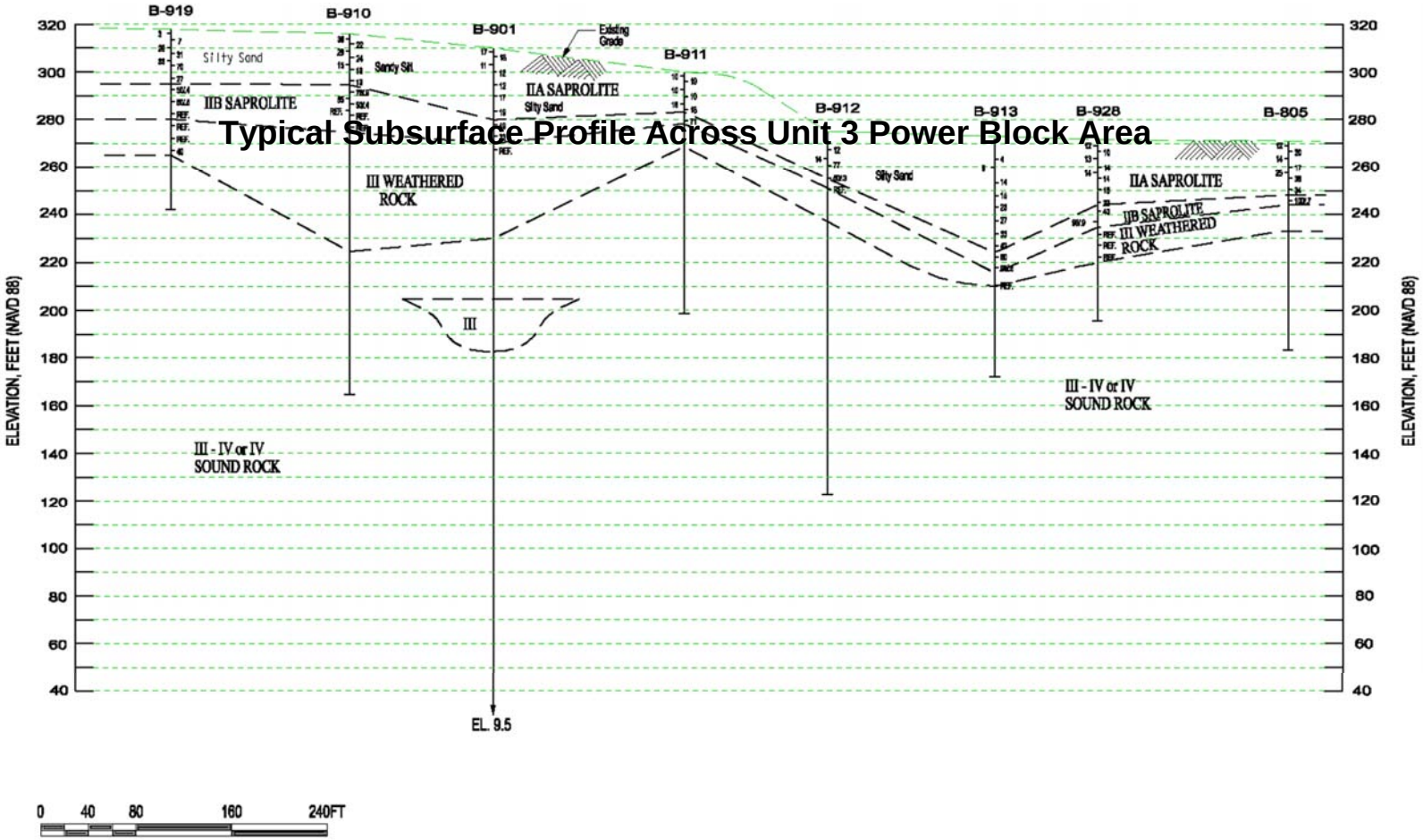

Typical Subsurface Profile Across Unit 3 Power Block Area

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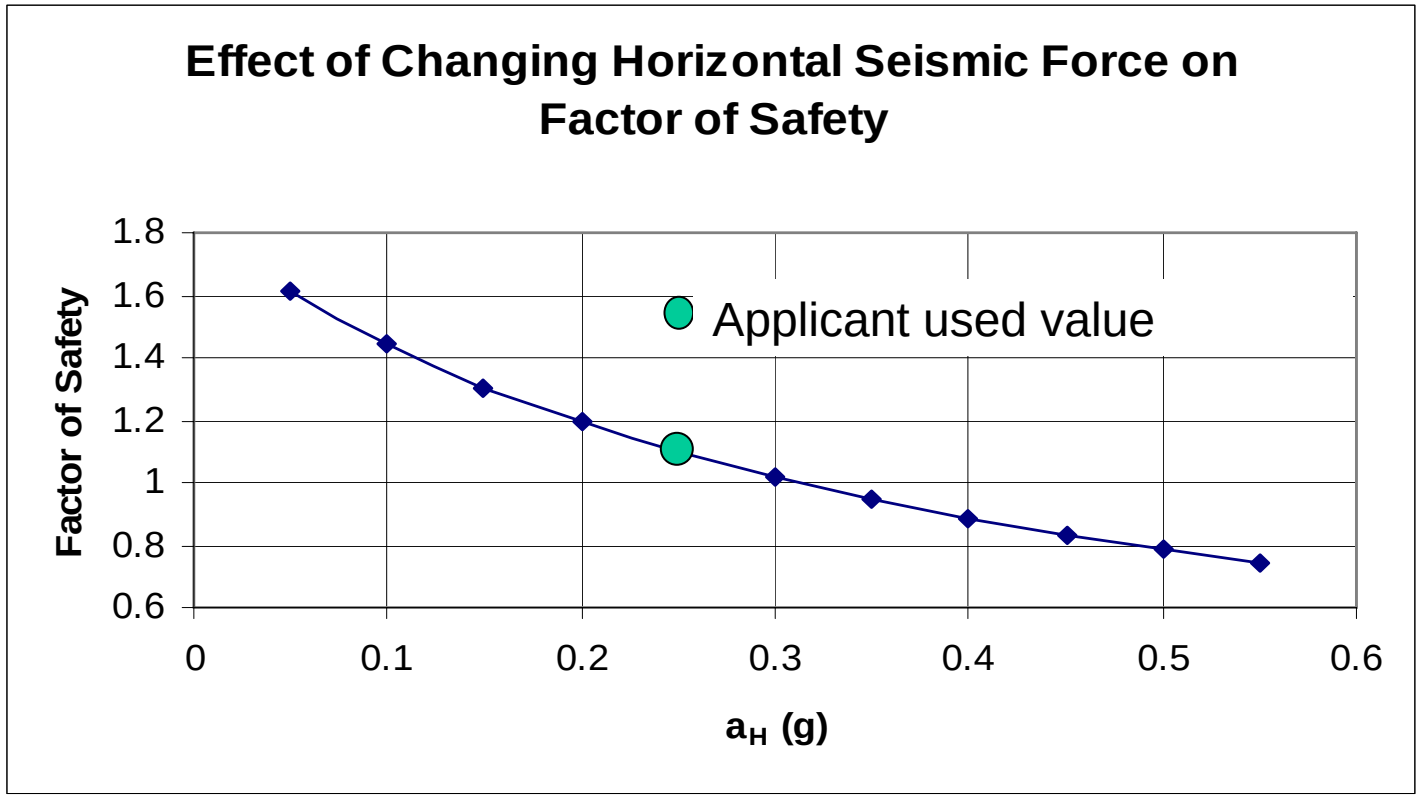
Staff Stability of Slopes Confirmatory Analysis Results



Note: The return period for 0.3g at 2.5 Hz is about 70,000 years, which corresponds to an annual frequency of exceedance of 1.4 x 10-5 per year.

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Section 3.9.6

Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints

Section 3.11

Environmental Qualification of Mechanical and Electrical Equipment

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Section 3.9.6

- COL application relies on ESBWR DCD and FSAR to fully describe functional design, qualification, and IST programs for pumps, valves, and dynamic restraints
- In response to RAIs, Dominion and GEH revised FSAR and DCD
- NRC performed audit of GEH design and procurement specifications in July 2009 to evaluate implementation of DCD provisions

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Section 3.9.6

- DCD specifies ASME Standard QME-1-2007 for functional design and qualification of new valves with key QME-1 aspects required for previously qualified valves
- DCD describes valve IST program based on 2001 Edition/2003 Addenda of ASME OM Code
- FSAR supplements DCD for IST provisions and periodic verification of design-basis capability of power-operated valves
- FSAR describes snubber IST program consistent with ASME OM Code, Section ISTD

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Section 3.9.6

- Open Item 3.9.6-01 (Implementation of DCD qualification and IST provisions)
  - NRC audit results summarized in memorandum dated September 1, 2009
  - GEH provided response to audit follow-up items in letter dated September 21, 2009
  - GEH response resolves most audit follow-up items with minor issues remaining to close open item

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Section 3.11

- FSAR incorporates by reference DCD description of EQ program for mechanical and electrical equipment
- DCD description of EQ process acceptable based on NUREG-1503 (ABWR SER)
- ITAAC will confirm electrical and mechanical EQ
- NRC performed audit of GEH design and procurement specifications in July 2009 to evaluate implementation of DCD EQ provisions

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Section 3.11

- Open Item 3.11-01 (Implement DCD EQ provisions)
  - NRC audit summarized in September 1, 2009, memorandum
  - GEH response provided in September 21, 2009, letter that resolves most audit follow-up items
- Open Item 3.11-02 (Safety-related mechanical equipment EQ)
  - NRC staff review of GEH audit response to be used to close open item

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QUESTIONS ?

Section 3.9.6
Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints

Section 3.11
Environmental Qualification of Mechanical and Electrical Equipment

Section 9.2.1

Plant Service Water System

ACRS Full Committee Presentation
North Anna SER/OI

Section 9.2.1
Plant Service Water System (PSWS)

- Open Items – Subcommittee interest (July meeting)
- Open Items Resolved (Confirmatory Items)
  - OI #8 - Revised Interface Requirement (ITAAC)
    - PSWS ability to remove necessary heat load
  - OI #9 - Above ground PSWS piping materials
  - OI #10 - PSWS treatment under Maintenance Rule
  - OI #11 - Clearly identify CDI and COL items in FSAR
  - OI #12 - Design capability of the Auxiliary Heat Sink
    - Initial plant test program
    - Water hammer design features

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Section 9.2.1
Plant Service Water System (PSWS)

- Open Item #13 – Buried Fiberglass Piping (FRP)
- Proposed Resolution
  - NRC-approved ASME Code, Section III Code Case N-155-2, provides rules for fabrication and installation of FRP
  - Procedures in Code Case provide for FRP to be properly designed and installed and thus provide for structural integrity and safety commensurate with RTNSS status of the system
  - Applicant agreed to use Code Case to design/install FRP
  - Path to resolve OI #13:
    - Staff will audit applicant's use of Code Case
    - Applicant will document use of Code Case in FSAR

QUESTIONS ?

Section 9.2.1
Plant Service Water System

Section 14.3

Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC)

ACRS Full Committee Presentation
North Anna SER/OI

Section 14.3 – ITAAC

North Anna ITAAC

- ESBWR Certified Design ITAAC
  - ESBWR DCD Tier 1
  - North Anna incorporates by reference
- Emergency Planning
  (SER 13.3 – 2 open RAIs)
- Physical Security
  (SER 13.6 – on-going review)
- Site-specific Structures, Systems, Components

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Section 14.3 – ITAAC

Site-specific Structures, Systems, Components

- Selection Criteria and Methodology
  - North Anna – same as DCD
  - Applied to systems not evaluated in DCD
- Backfill under Category I Structures
  (SER 2.5.4 – open RAI)
- Plant Service Water System
  (SER 9.2.1 – confirmatory RAI)
- Offsite Power
  (SER 8.2 – confirmatory RAI)
- Other Systems - No ITAAC

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Section 14.3 – ITAAC

Post COL Activities

- ITAAC – license condition to be satisfied before fuel load
- ITAAC closure process – Regulatory Guide 1.215

QUESTIONS ?

Section 14.3

Inspections, Tests, Analyses, and Acceptance Criteria (ITAAC)

ACRS Full Committee Presentation
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COL Application Review Schedule

Safety Review

- Phase 1 - Requests for Additional Information – Complete
- Phase 2 - SER with Open Items – Complete
- Phase 3 - ACRS Review of SER with Open Items – 11/04/09
- Phase 4 - Advanced SER with no Open Items – 09/10
- Phase 5 - ACRS Review of SER with no Open Items – 12/10
- Phase 6 – Issue Final SER – 02/11

ACRS Full Committee Presentation
North Anna SER/OI

QUESTIONS / COMMENTS

Susquehanna Steam Electric Station

License Renewal ACRS Meeting

October 8, 2009

Introductions

- Rick Pagodin, General Manager – Engineering
- John Krais, Manager – Special Projects
- Dale Roth, Supervisor Programs and Testing
- Dave Flyte, License Renewal Lead Engineer
- Subject Matter Experts and LR Project Team

Agenda

- Site Description
- Operating Experience Review
- Commitment Process
- Subcommittee Follow-Up Items
  - Underground Medium Voltage Cables
  - Station Blackout Recovery Scoping
  - Condition of Containment
  - Main Steam Line Flow Restrictors
- Summary

Site Description

- Location: Northeast Pennsylvania
- Plant Owners
  - PPL Susquehanna, LLC (90%)
  - Allegheny Electric Cooperative (10%)
- Licensee/Operator: PPL Susquehanna, LLC

Site Description

- Two Units - BWR/4
  - 3952 MWt
  - 1300 MWe
- General Electric (NSSS), Bechtel (AE)
- Ultimate Heat Sink – Spray Pond
- Turbine Cycle Cooling Provided By Natural Draft Towers
- Make-up Water – Susquehanna River

Site Description

Construction Permit	November 1973
Operating License (Unit 1/Unit 2)	July 1982/March 1984
Stretch Power Uprate ~4.5% (Unit 1/Unit 2)	February 1995/April 1994
MUR Power Uprate ~1.5%	July 2001
LRA Submitted	September 2006
Extended Power Uprate ~14%	January 2008
License Expires (Unit 1/Unit 2)	July 2022/March 2024

Operating Experience Review

- Operating Experience Review Per the Guidance in NEI 95-10
- EPRI Tools Used as Starting Point to Identify Aging Effects
- Five Years of SSES and Industry Operating Experience Reviewed to Ensure Identification of Aging Effects

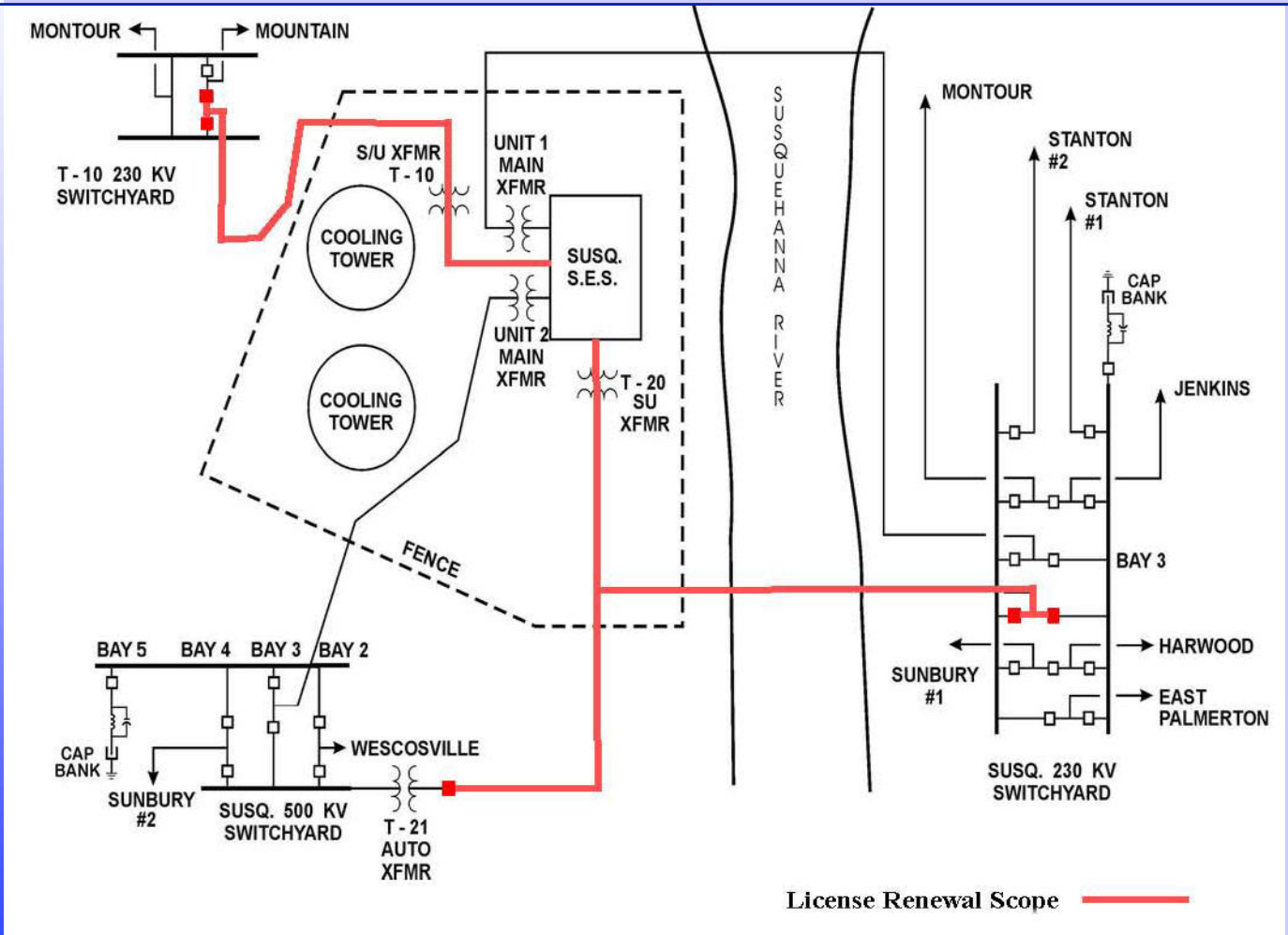
Commitment Process

- 60 Regulatory Commitments for License Renewal
- Entered into the SSES Commitment Tracking Process
- Commitments Assigned to Station Personnel for Implementation

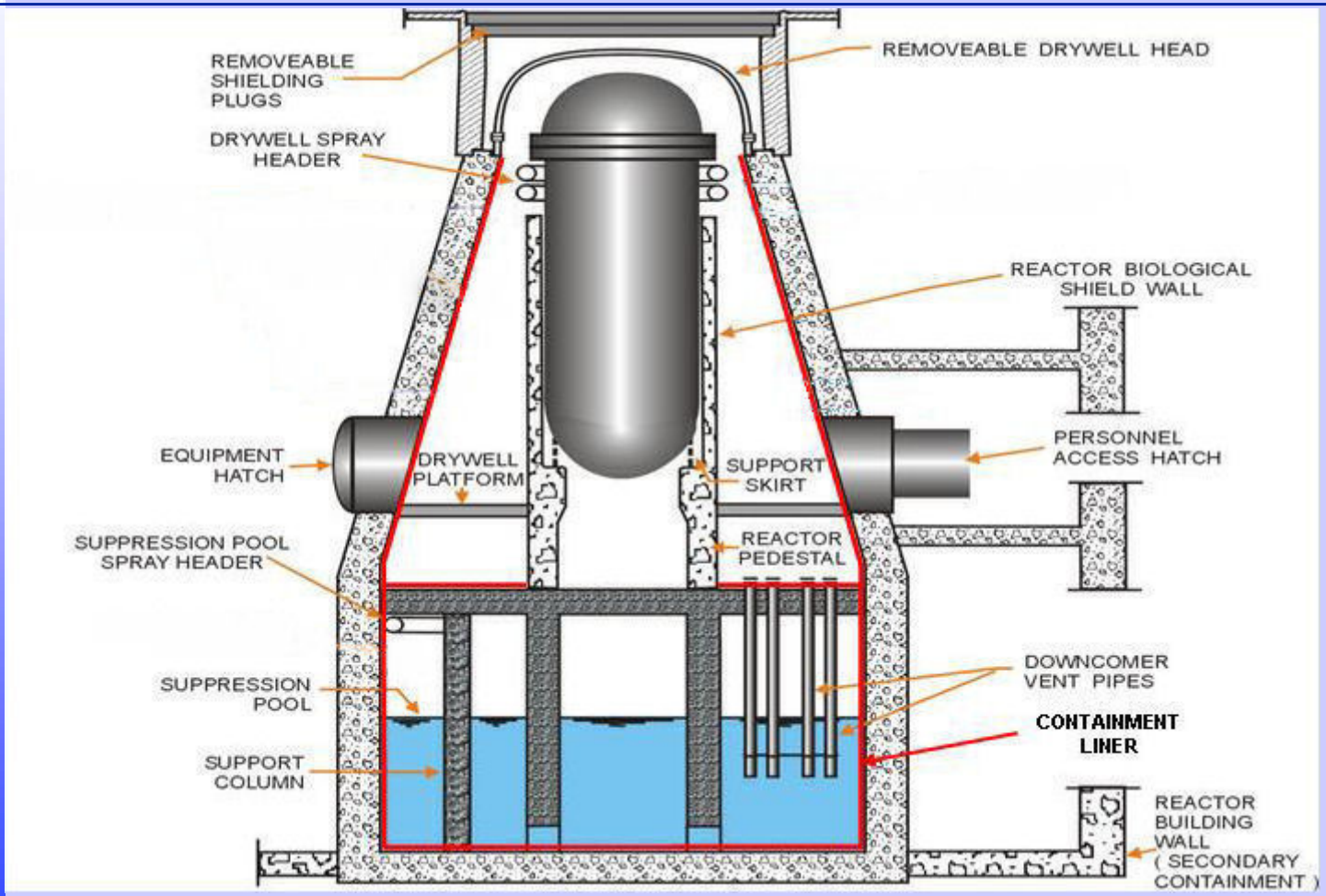
Subcommittee Follow-Up Items Underground Medium Voltage Cables

- 5 kV Safety-Related Cables – No Submerged Cables Observed
- 15 kV Non Safety-Related Cables – Submerged Cables Observed in 2 Manholes
  - License Renewal Commitment Consistent with GALL
    - Test Underground MV Cables
    - Inspect/Pump Manholes to Keep MV Cables from Exposure to Standing Water
  - Testing/Pumping Preventive Maintenance Activities In Place Today

Subcommittee Follow-Up Items
Station Blackout Recovery Scoping



Subcommittee Follow-Up Items
Condition of Containment



MARK 2 CONTAINMENT

Subcommittee Follow-Up Items Condition of Containment

- Nominal 6 Foot Reinforced Concrete – Pressure Retaining Structure
- 1/4 Inch Steel Liner – Leaktight Membrane
- Visual Inspections Under ISI Program per ASME Section XI
- Pressure Tested in Accordance with 10 CFR 50 Appendix J

Subcommittee Follow-Up Items Condition of Containment

- Inspections Have Not Identified Any Significant Degradation Over the Past 25 Years
- Pressure Testing has Not Identified Any Indication of Degradation
- Programs are Effectively Managing Aging of Containment – No Degradation of Design Function

Subcommittee Follow-Up Items Main Steam Line Flow Restrictors

- Potential Loss of Material Due to Corrosion and Erosion Evaluated
- Loss of Material Due to Corrosion Managed by BWR Water Chemistry Program
  - Dry Steam Environment Not Conducive to Corrosion
  - One-Time Inspection of Bounding Components to Verify Effectiveness of BWR Water Chemistry Program
- Erosion Evaluated as TLAA
  - Dispositioned Per 10 CFR 54.21(c)(1)(ii) – Projected for 60 Years
  - Dry Steam Environment and Resistant Material

Summary

- LRA Conforms to Regulatory Requirements and Follows Industry Guidance
- Thorough Review of the Application and Supporting Documentation
- No Open Items
- SSES Will Manage Aging in the Period of Extended Operation

Advisory Committee on Reactor Safeguards

Susquehanna Steam Electric Station Units No. 1 and 2 Safety Evaluation Report

October 8, 2009

Evelyn Gettys, Project Manager
Office of Nuclear Reactor Regulation

Introduction

- Overview of SSES license renewal review
- Section 2: Scoping and Screening Review
- License Renewal Regional Inspection
- Section 3: Aging Management Program and Review Results
- Section 4: Time-Limited Aging Analyses (TLAAs)
- Conclusion

Overview

- LRA Submitted by letter dated Sept 13, 2006
- GE Boiling Water Reactor (BWR), Mark II containment
- Jan. 30, 2008 - Extended Power Uprate (EPU) was granted to SSES to operate at
  3952 MWth, 1300 MWe for Units 1 & 2
- Operating license for Unit 1- NPR-14 expires July 17, 2022
- Operating license for Unit 2- NPR-22 expires March 23, 2024
- Located approximately 7 miles NE of Berwick, PA

Overview

Recap of the April 1, 2009 ACRS subcommittee meeting

- SER issued March 2009
- 278 RAI's
- 59 Commitments
- No Open or Confirmatory Items

Overview

Subsequent to subcommittee meeting

- 8 RAIs issued:
  - 5 Boral
  - 3 Metal Fatigue
- 1 Commitment

Section 2 – Conclusion for Scoping and Screening

- The applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1)
- The applicant adequately identified those SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a) and those SCs subject to an AMR in accordance with 10 CFR 54.21(a)(1)

Regional Inspection Conclusions

- Scoping of non-safety SSCs and aging management programs are acceptable
- Inspection results support a conclusion of reasonable assurance that aging effects will be managed and intended functions will be maintained

Section 3.0 Aging Management Review Results

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

Section 3.3.2.2.6 Reduction of Neutron-Absorbing Capacity and Loss of Material due to General Corrosion

- Commitment to continue spent fuel pool Boral coupon testing into the period of extended operation
- Water Chemistry Program & Boral Coupon Testing Program

Section 3 Conclusion

- Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the effects of aging will be managed so that intended function(s) will be maintained during the period of extended operations, per 10 CFR 54.21(a)(3).

Section 4: Time-Limited Aging Analyses

- 4.1 Identification of Time Limited Aging Analyses (TLAAs)
- 4.2 Reactor Vessel Neutron Embrittlement
- 4.3 Metal Fatigue
- 4.4 Environmental Qualification of Electrical Equipment
- 4.5 Concrete Containment Tendon Prestress (N/A)
- 4.6 Containment Liner Plate and Penetration Fatigue
- 4.7 Other Plant-Specific TLAAs

- **Section 4.3.1 – Reactor Pressure Vessel Fatigue Analyses**
  - Requested transient event design specifications and recording of transient data.
  - Applicant responded and indicated that all monitored transient events are bounded by the design specifications and that cycle tracking activities covered the entire operating history of the plant.

Section 4.3.1 – Reactor Pressure Vessel Fatigue Analyses

- Requested justification for the large reductions in projected 60-year CUF values seen for some locations, with relatively minor reduction in cycle projections, even though some transients have projected cycles higher than design cycles
- Applicant provided justification: 40-year design CUF values have incorporated extra conservatism, including contribution from faulted condition loads, directly using results of bounding location, and conservative design cycles.

Section 4.3.3 Effects of Reactor Coolant Environment on Fatigue Life of Components and Piping

- Requested pre –1994 data to supplement the data previously provided and also justification that the DO data is applicable to all NUREG/CR-6260 components
- Applicant provided the DO data, described the water sampling schedule schemes, the water flowing routes, and demonstrated applicability of the sampled data to all of the NUREG/CR-6260 locations considered

Section 4 Conclusion

Based on its review of the LRA and additional information submitted as the result of RAIs, the staff concluded that the applicant provided an adequate list of TLAAs, per 10 CFR 54.3, and that the:

- TLAAs will remain valid for the period of extended operation, per 10 CFR 54.21(c)(1)(i)
- TLAAs have been projected to the end of the period of extended operation, per 10 CFR 54.21(c)(1)(ii); or
- Aging effects will be managed for the period of extended operation, per 10 CFR 54.21(c)(1)(iii)

Conclusion

- The staff has concluded there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the SSES CLB in order to comply with 10 CFR 54.29(a) are in accordance with the Act and the Commission's regulations

STEAM GENERATOR ACTION PLAN
OPENING REMARKS

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

OCTOBER 8, 2009

TIMOTHY J. MCGINTY
Director, Division of Policy and Rulemaking
NRC Office of Nuclear Reactor Regulation

STEAM GENERATOR ACTION PLAN BACKGROUND AND OVERVIEW

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

OCTOBER 8, 2009

DAVID BEAULIEU
Project Manager, Division of Policy and Rulemaking
NRC Office of Nuclear Reactor Regulation

Steam Generator Action Plan History

- 1985-1990 NUREG 1150 severe accident risk studies evaluated the issue of “consequential” steam generator (SG) tube rupture.
- For severe accident induced consequential SG tube ruptures, concern was that the high temperature gases created during core damage sequences could cause SG tubes to be the first component of the reactor coolant pressure boundary to fail, resulting in a potential containment bypass and the release of large amounts of radioactive material outside containment.
- NUREG-1150 quantified frequency in the low 10−6/reactor-year range on the basis of expert elicitation.

SG Action Plan History (cont'd) Differing Professional Opinion

- In the early 1990s, the industry made several requests for relaxation of regulatory requirements for SG tube integrity.
- A Differing Professional Opinion (DPO) was filed involving concerns associated with this relaxation given that while eddy-current methods could accurately measure uniform tube wall thinning due to general corrosion, they were less reliable in detecting and sizing cracks that occur in Alloy 600 tubes due to stress corrosion cracking.
- Staff review of those relaxation requests identified that granting them might substantially increase the conditional probability of containment bypass during core damage accidents.

SG Action Plan History (cont'd)

- In the early 1990s, the NRC staff began a study of the effects of severe accident conditions on SG tube integrity as background information for a proposed new rulemaking on SG tube integrity.
- The results from this study, published as NUREG-1570, indicated that the risk is controlled by the current tube integrity requirements to a value that is low enough that no new rulemaking was needed.
- The DPO remained open.

SG Action Plan History (cont'd) DPO Was Referred to ACRS for Resolution

- In 2000, the DPO was referred to the ACRS for resolution.
- After extensive public meetings and review of the issues raised in the DPO, the ACRS published NUREG-1740 to present its conclusions and recommendations.
- In particular, the ACRS concluded that the methodology being used to quantify the risk of containment bypass due to high-temperature challenges to SG tubes was "not technically defensible."

SG Action Plan (Section 3) Created to Address ACRS Recommendations

- Technical staff in NRR and RES jointly reviewed the full text of NUREG-1740 to extract the list of issues that required additional work.
- Those tasks were incorporated into a new section (Section 3) of the SG Action Plan .

SG Action Plan Tasks

- Most, but not all, SG Action Plan tasks involve severe accident induced SG tube ruptures.
- SG Action Plan also includes tasks work that involved design basis events, which addressed the potential for damage progression of multiple SG tubes due to SG depressurization. (e.g., during a main steam line break (MSLB) or other type of secondary side design basis accident).

Design Basis Event Tasks Closed – ACRS Review Complete

- The staff's work to address SG action plan items involving design basis events is complete, and;
- ACRS has previously reviewed and endorsed the closure of these items.
- Basis - Dynamic loads from such design basis events are low and do not affect the structural integrity of tubes or lead to additional leakage or ruptures beyond what would be determined using differential pressure loads alone.

SG Action Plan Status

- The staff has completed its work to close all SGAP items.
- Closeout documentation has been provided to ACRS.
- The purpose of this meeting is for ACRS to review all SGAP items that ACRS has not previous reviewed and closed.

Desired Outcome of ACRS Review

- The staff requests an ACRS letter that finds acceptable the staff's closeout of each SGAP item that ACRS has not previously reviewed and closed which are:
  - SG Action Plan Items 3.1.k, 3.4, 3.5, 3.10, 3.11, and 3.12

Agenda

- Essentially all of today's items are directly related to the work to define the risk associated with severe accident induced SG tube ruptures leading to containment bypass.
- This work involved the following technical areas of research:
  - thermal-hydraulics,
  - steam generator tube material failures;
  - reactor coolant system material failures;
  - component behavior studies, and
  - probabilistic risk assessment

SG Action Plan Closeout
Future Activities Outside of Action Plan Process

- SG Action Plan work is complete and, following ACRS review, the staff would like to close the SG Action Plan.
- NRR User Need to RES is in concurrence -- Requests specific research products to facilitate the development and review of future risk assessments involving consequential SG tube rupture events. These products will build upon analysis methods, tools, and expertise developed as part of the SG Action Plan.
- The RES work to address the NRR User Need no longer requires the level of coordination and agency focus required to implement the action plan process.
- Future work activities associated with this topic will be coordinated using other agency tools such as the User Need and the Planning, Budgeting, and Performance Management processes.

Steam Generator Action Plan Item 3.11

- SGAP Item 3.11 states, "In order to resolve GSI 163, it is necessary to complete the work associated with tasks 3.1, 3.7, 3.8, and 3.9. Upon completion of this task, develop detailed milestones associated with preparing a GSI resolution document and obtaining the necessary approvals for closing the GSI, including ACRS acceptance of the resolution."

- ACRS letter dated May 20, 2009, endorsed the closure of GSI-163.

- The staff requests that ACRS document that ACRS considers the staff's closeout of SGAP Item 3.11 acceptable.

ACRS
Steam Generator Action Plan (SGAP)

October 8, 2009
Rockville, MD

SGAP Items 3.4.a-g
Thermal-Hydraulics
System Code Predictions and CFD

Christopher Boyd RES/DSA

Background

- SGAP section 3.4.a-g
  - thermal-hydraulic behavior of the system during severe accidents

- NUREG/CR-6995 (draft) summarizes the overall project and focuses on the system level predictions. This work improves our understanding of the T/H behavior of the plant during these types of scenarios and addresses criticisms of past analyses.
  - Covers 3.4.a, b, d, f

- Supporting CFD analyses improves our technical basis and helps to extend experimental results to full-scale conditions
  - Covers 3.4.c, e, g
    - NUREG-1781 and NUREG-1788
    - NUREG-1922 (draft)

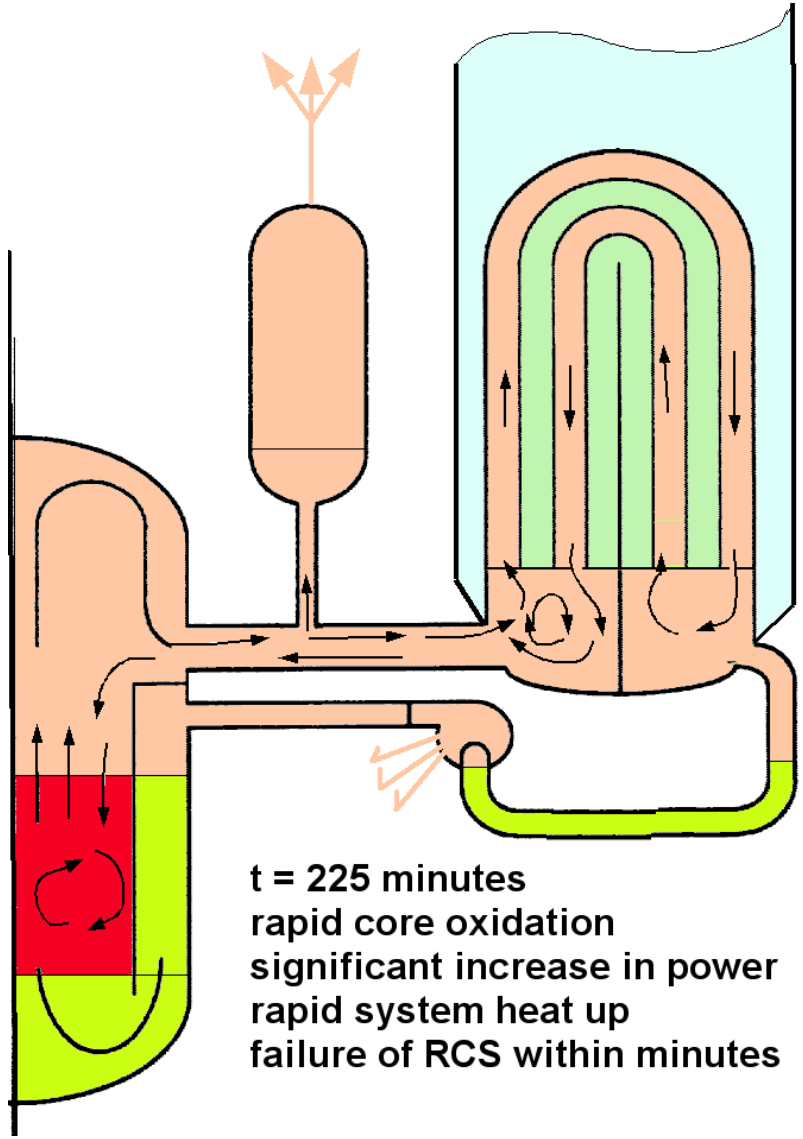
A Fast Scenario

RCS failure within 4 hours

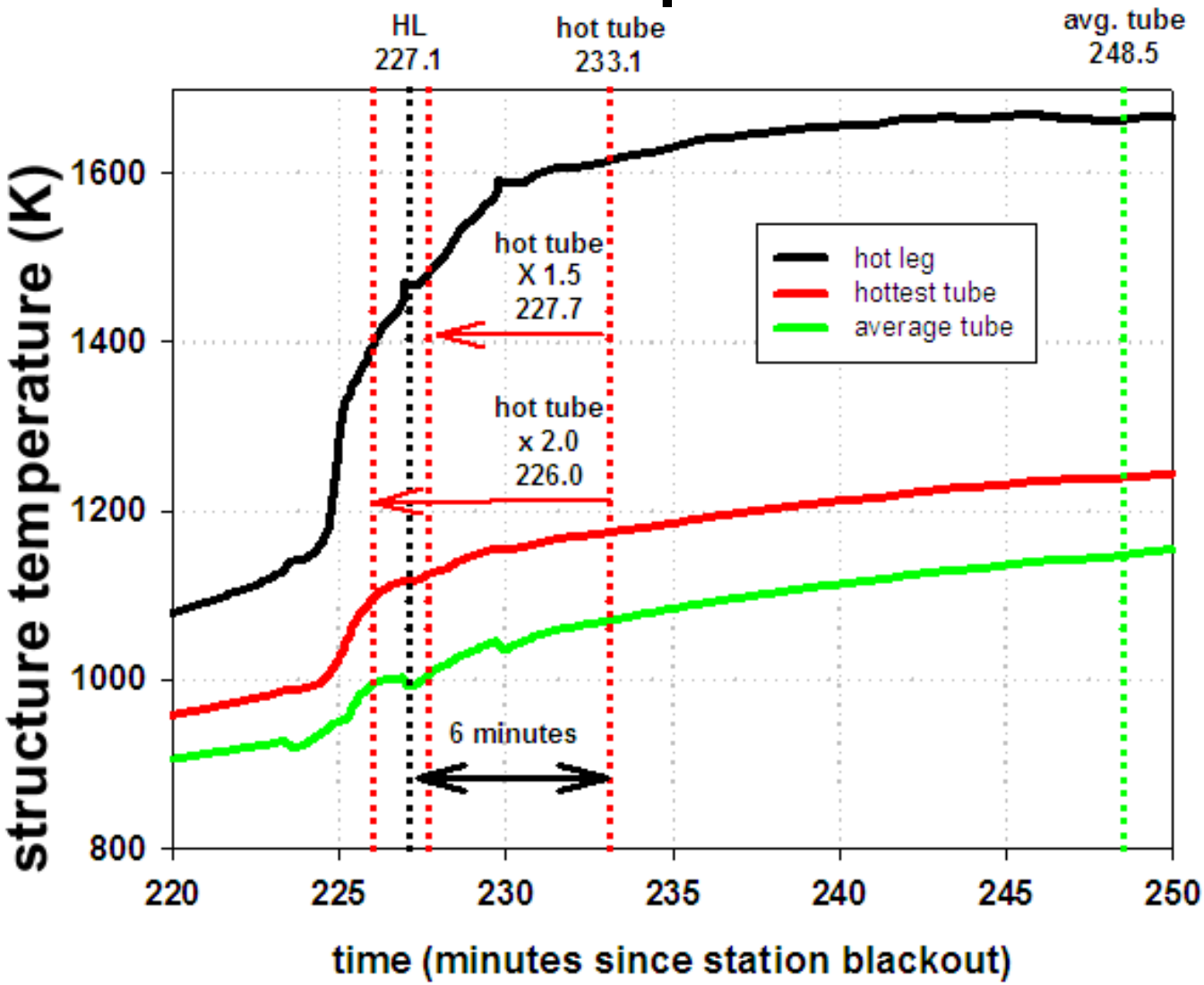
- loss of offsite power, failure of diesel generators, and failure of all auxiliary feedwater
- Reactor coolant pump seal LOCA and secondary side boil off
- secondary system dry out, safety relief valves cycling, primary inventory lost through valves and pump seal LOCA
- loop circulation stops
- Inventory falls below hot legs, natural circulation of superheated steam begins, system heats up

- Core uncovers, core oxidizes and releases significant energy, system heat up accelerates and induced failure is predicted for RCS components.
- High-Dry-Low conditions needed to challenge the SG tubes.

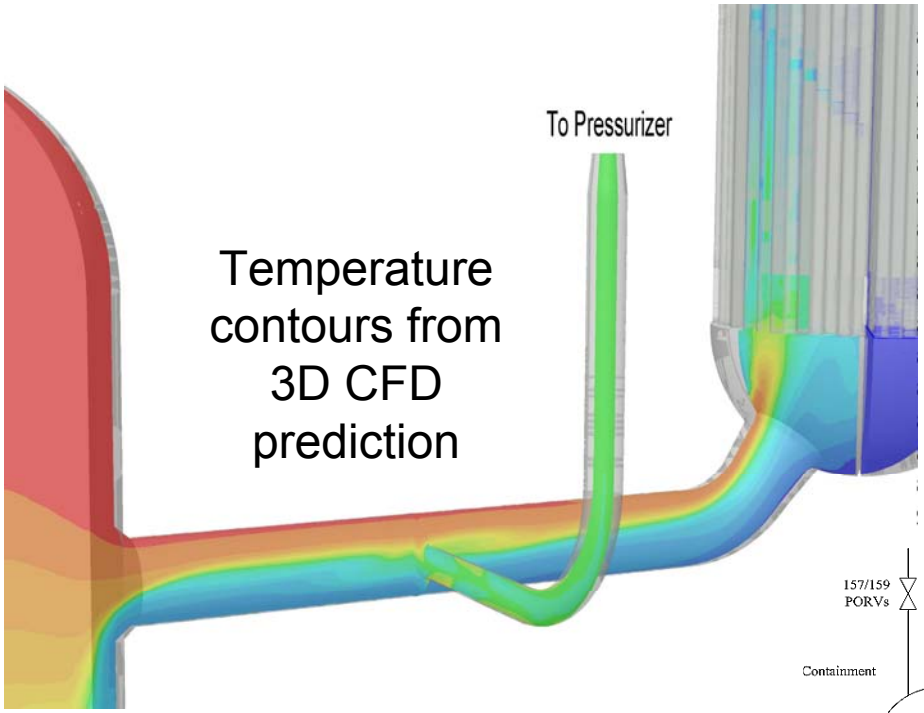
- Clearing the loop seals creates direct circulation flow path and presents a severe challenge to the SG tubes.



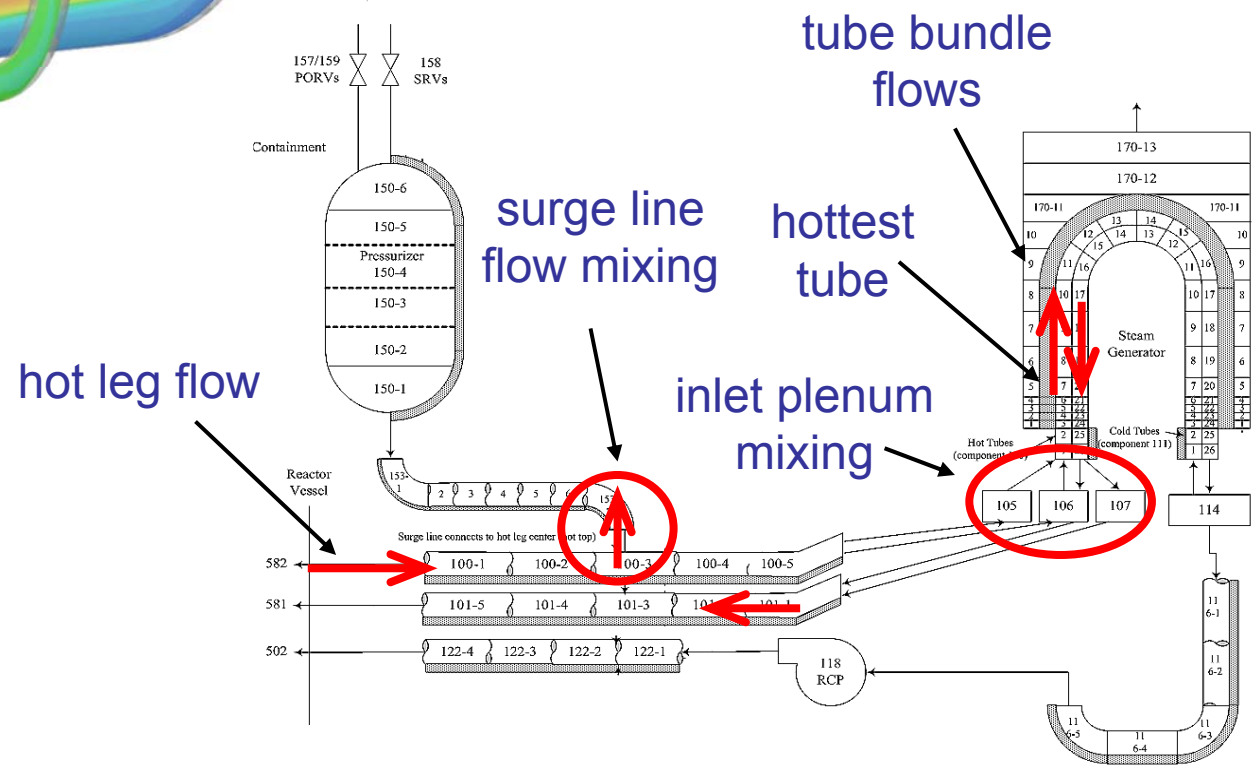
RCS Temperatures



System Model is adjusted to be consistent with 3D Computational Fluid Dynamics and Experiments



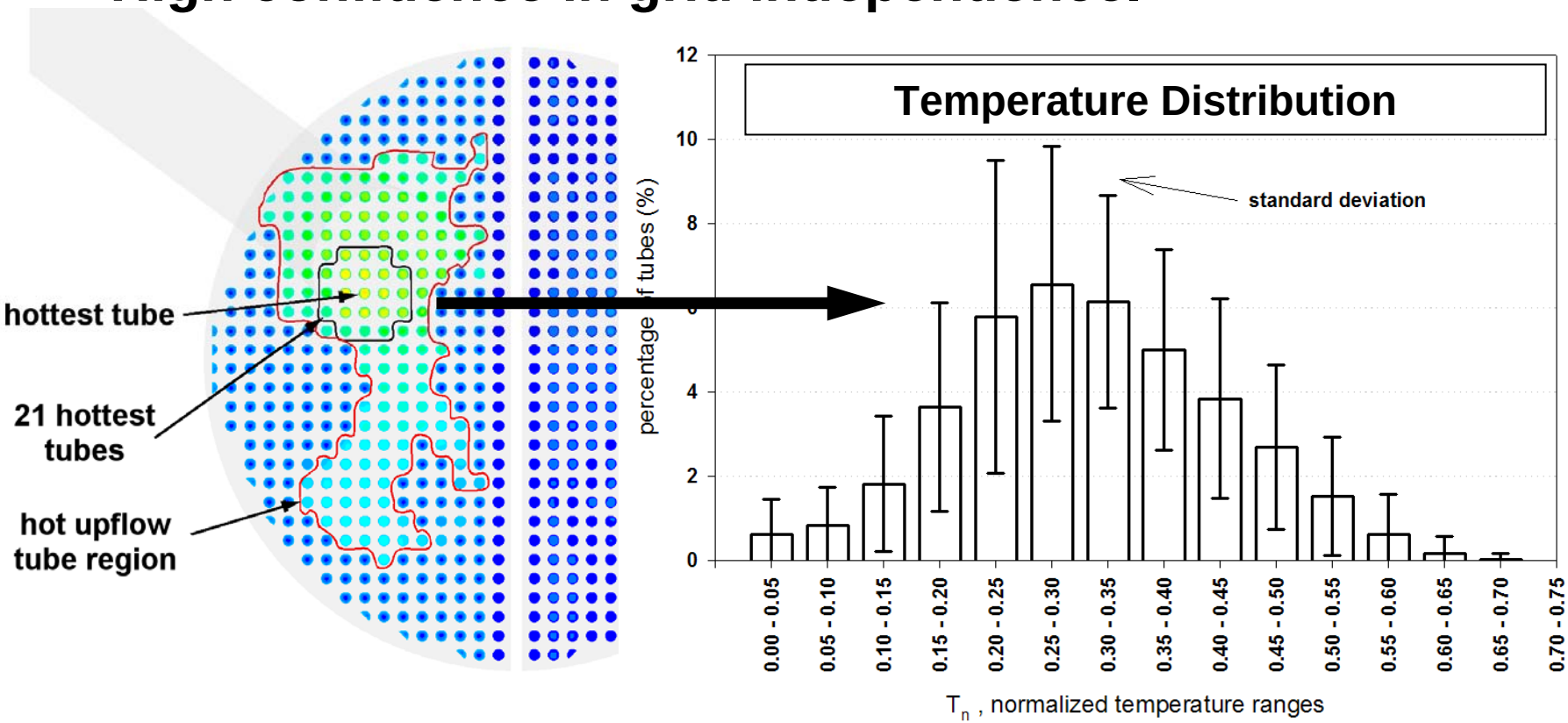
CFD modeling used to extend experimental results to full-scale SGs



CFD Predicts Peak Temperatures

- **Consistent results over 3 different models and with multiple turbulence options.**

- **High confidence in grid independence.**



Summary

- SGAP items 3.4.a, b, d, f are addressed by NUREG/CR-6995.
- SGAP items 3.4.c, e, and g are addressed by NUREG-1781 and NUREG-1788.
  - Specific ACRS concerns are further supported by the updated modeling in NUREG-1922
- Future work will be completed in support of the agencies ongoing research into steam generator tube integrity issues as needed.

STEAM GENERATOR ACTION PLAN
ITEM 3.4h POTENTIAL RCS FAILURE LOCATIONS

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

OCTOBER 8, 2009

T. R. LUPOLD
Branch Chief, Corrosion & Metallurgy Branch
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3.4h: Systematic Examination of the Alternate Vulnerable Locations in the RCS.

h.1 Evaluate Creep failure of primary system passive components.

* i.e pressurizer surge line, hot leg
* Consider material properties, residual & applied stresses pressure stress, and presence of flaws

h.2 Evaluate active component failure.

* i.e. PORVs, safety valves, and bolted seals
* Based on operability and “weakest link” considerations

h.3 Determine Feasibility of extending the Rhodes model (RCP seals leakage/failure) to severe accident conditions.

h.4 Conduct large scale tests if needed.

Three phase study:

- Phase I:
  - Reviewed methods & models (failure modes and times-to-failure)
  - Identified additional information needed,
  - Scoped RCS components that might be “weak links”
- Phase II:
  - Developed 3-D computer models of select RCS components (Westinghouse 4-Loop)
  - Utilized detailed plant drawings
  - Included analyses of component operating history
- Phase III:
  - Calculated RCS component failure sequence
  - Utilized improved codes and modeling
    - (RELAP5) Reactor Leak and Power Safety Excursion code
    - (CFD) Computational Fluid Dynamics
  - Expanded high-temperature materials database

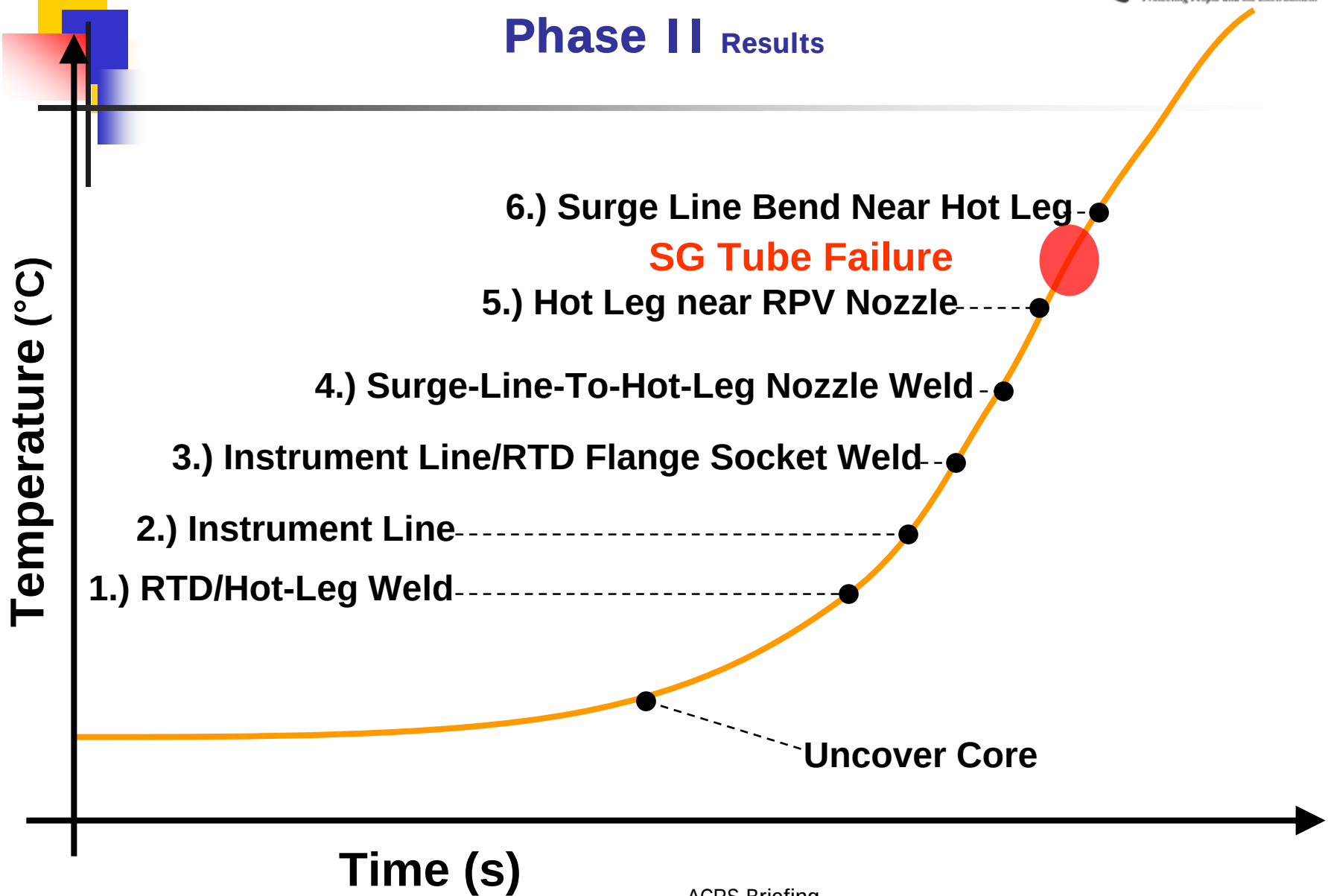
Phase I

- November 2001 Workshop held to discuss expected behavior of non-SGT RCS components and bolted connections during severe accidents in PWRs
  - Workshop concluded it would be possible to analytically predict behavior during severe accidents of certain components
- Following Workshop, non-SGT RCS components and bolted connections were modeled to predict failure times
  - In view of closeness of predicted rupture times for SGTs, surge lines and hot-leg piping reported in NUREG-1570, NRC initiated effort to develop improved models for predicting failure of non-SGT RCS components
- Selected Components for Phase II analysis

Phase II

- Analysis based on Zion Nuclear Station
  - Hot leg and nozzles of Loop 4, which include pressurizer and surge line, were analyzed for reference station blackout (SBO) severe accident transient that involved "high-dry" sequence
  - Results from RELAP5 thermal hydraulic analysis of surface heat flux were used as input for thermal-conduction and stress-strain analyses
  - Failure times due to tensile and creep rupture were calculated with data from literature when available,
    - developed or extrapolated data were only available at lower-than-severe accident temperatures
  - Sensitivity analyses were conducted to determine variability of predicted failure times
    - due to variations of surface heat flux, thermal conductivity, creep rate, and yield strength
  - Also analyzed was stress-strain response due to repeat plug-to-seat impact of typical PORV

Phase II Results



Phase III

- Improvements were made to the thermal hydraulic modeling
  - Refinements were made to surge-line-to-hot-leg connection in RELAP5 model
  - Thermal hydraulic data calculated using RELAP5 were improved to account for entrance effects and flow reversals during PORV cycling
  - High-temperature materials database was expanded by conducting high-temperature tensile and creep tests on stainless steel and carbon steel weldments.
- Enhancements changed calculated failure sequence
  - Resulted in hot leg failing first
  - Suggested that RCP seals could possibly fail prior to SGTs
- Expert Workshop was held to evaluate new findings
  - It was agreed that seal failure could occur sooner than previously estimated and could possibly avert or mitigate containment bypass
    - Based on judgment and experience with RCP seals

Conclusions

- Research accomplished overall goal of developing improved models for evaluating non-SGT PWR RCS components under severe accident conditions
- Determined that differences in times-to-failure between non-SGT (except RCP seals) RCS components were relatively close to each other for transients evaluated
  - Failure times were only nominally affected by variations in heat transfer entrance effects and other sensitivity variations
  - Analysis results for some components (e.g., RTD welds, primary manway, instrument line welds) are sufficiently generic to be applicable to other Westinghouse plants
  - Analyses related to hot leg and surge line may also be applicable to other plants provided relevant dimensions and constraints are comparable
- Determined that RCP seals could fail prior to SGTs, which could avert or mitigate containment bypass
  - Quantifying RCP seals time-to-failure with adequate confidence would require additional experimental and analytical studies
- NRR and RES looking at follow-on research

Steam Generator Action Plan Item 3.10

- 3.10 - To address concerns in the ACRS report regarding our current level of understanding of stress corrosion cracking, the limitations of current laboratory data, the difficulties with using the current laboratory data for predicting field experience (crack initiation, crack growth rates), and the notion that crack growth should not be linear with time while voltage growth is, the following tasks will be performed:

Conduct tests to evaluate crack initiation, evolution, and growth. Tests to be conducted under prototypic field conditions with respect to stresses, temperatures and environments. Some tests will be conducted using tubular specimens.

Using the extensive experience on stress corrosion cracking in operating SGs, and results from laboratory testing under prototypic conditions, develop models for predicting the cracking behavior of SG tubing in the operating environment.

Based on the knowledge accumulated on stress corrosion cracking behavior and the properties of eddy current testing, attempt to explain the observed relationship between changes in eddy current signal voltage response and crack growth.

Staff Closure of SGAP 3.10

- Not based on a specific ACRS recommended action in NUREG-1740
- Operating experience indicates that plant practices for predicting flaw initiation and growth have been effective in ensuring tube integrity consistent with our assumptions in risk analyses
- NRC staff monitors plant operating experience through the inspection process and our review of licensee reports on the results of their steam generator tube inspections. If analysis of future operating experience or research indicates the need to revisit this area, it will be considered and prioritized consistent with our budget process.

SGAP TASK 3.1K
SGAP TASKS 3.4J AND 3.4K
SGAP TASK 3.12

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
OCTOBER 8, 2009

ROBERT PALLA, NRR/DRA

Task 3.1k – Based on Tasks 3.1a – 3.1j, evaluate the probability of multiple tube failures in risk assessments for SG tube ARC

- Objective of Task 3.1k – develop probability distribution for total SG leakage under ΔP loads alone
- The need for this calculation was diminished for several reasons
  - Postulated phenomena associated with depressurization (addressed in Tasks 3.1a – 3.1j) did not prove to be realistic
  - Performance-based TS provides reasonable assurance that DBA leakage will be small and well within that assumed in risk studies
  - Replacement SGs result in fewer flawed tubes left in service and fewer proposals to increase allowable leakage
- The calculations planned under Task 3.1k are not needed to support closeout of GSI-163
- This task can be closed

Task 3.4j – Develop probability distribution for rate of tube leakage for ARC applied to flaws in restricted places

- Task 3.4i provided predicted flaw areas and leak rates from cracks under the TSP during MSLB and severe accidents
- As part of Task 3.5 SNL/SAIC developed a methodology to compute the probability of tube failure during an accident which uses the models developed in Task 3.4i
- The SNL/SAIC methodology can be used to assess the impact of alternate assumptions or models for flaws in restricted places
- This effort has achieved the intent of SGAP Task 3.4j
- This task can be closed

Task 3.4k – Integrate information provided by Tasks 3.4a – 3.4j & 3.5 to address ACRS criticisms on risk assessments for ARC

- Specific concern: ARC that credit "indications restricted against burst"
- Concern was specific to South Texas Project unit with stainless steel drilled-hole support plates (the only SGs of this type in US)
- To limit displacement, tubes were expanded at various elevations
- Staff estimated conservative leak rate of 5 gpm per burst tube within TSP region
- Result could be included in a risk calculation but was not pursued because South Texas Project SGs have been replaced

Task 3.4k (Continued)

- Broader concern: Other SG tube integrity and licensing issues related to flaws in the free-span of SG tubes, and the ability to perform severe accident calculations in a technically defensible manner
- SGAP Task 3.5, “Develop improved methods for assessing the risk associated with SG tubes under accident conditions” was specifically intended to address this concern
- Although additional research related to C-SGTR is planned, the work completed has achieved the intent of SGAP Task 3.4k
- This task can be closed

Task 3.12 – Review Insights from Task 3.5 and Assess Need for Completing Additional Regulatory Guidance

- Staff has assessed the need for guidance on SGTR, and concludes additional guidance and tools are still needed
- Decision rationale
  - Task 3.5 and other studies have not generically dispositioned the issue. Plant-specific PRAs should continue to address C-SGTR
  - Limitations of current work restrict its usefulness in supporting future risk assessments (flaw distributions, TH, documentation & tools)
  - Alternative methods have been developed by industry and are being used by licensees but have not been reviewed by NRC
  - Effectiveness of the peer review process in assuring technical adequacy of this PRA element is not clear
- Development of this guidance will be part of an RES User Need now in concurrence

User Need on C-SGTR

- Additional TH analysis
  - CFD and system code TH analyses for CE plants
  - Impact of incore instrument tube failure on C-SGTR
- Updated flaw distributions and RCS structural analyses
  - Distributions for remaining alloy 600 SGs and replacement 690 SGs
  - Finite element analyses of RCS components
- Guidance and tools for future risk assessments
  - Simplified tools and supporting documentation
  - Reassessment of $P_{C\text{-}SGTR}$ based on updated TH and flaw distributions
  - RG on RI-decisionmaking related to C-SGTR
- A document compiling/summarizing key research

A RISK ASSESSMENT OF CONSEQUENTIAL STEAM GENERATOR TUBE RUPTURES

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

OCTOBER 8, 2009

Dr. Selim Sancaktar
Probabilistic Risk Assessment Branch
NRC Office of Nuclear Regulatory Research

Task 3.5 – Main Objectives

- Develop improved methods for assessing the risk of consequential SG tube rupture (C-SGTR) (3.5.d)
  - Extend method to CE plants (3.5.e)
  - Extend method to external events and low power/ shutdown (3.5.f)
  - Extend method to include consideration of Main Steam Line Breaks (MSLBs) (3.5.g)

- Demonstrate the method with illustrative calculations of the frequency of containment bypass at example plants

General Approach

- Method should be straightforward and scrutable
  - Previous approaches to model C-SGTR have relied on intrusive changes to the PRA
- Reflect current understanding of factors leading to C-SGTR
  - The conditions and sequences that can lead to C-SGTR are well studied and understood
  - Consider plant specific features (SG tube flaw distributions, mitigative credit)
- Utilize Agency Standardized Plant Analysis risk (SPAR) Models
  - Represents as-built, as-operated plant and verified through benchmarking and review activities
- Information and data available at the time of performance of tasks is used – considered prudently conservative

Analysis Method

- A straightforward systematic method based on the sequence results from a PRA is used:
  1) Identify sequences that challenge SG tubes
  2) Apply mitigation credit (i.e. probability that the operators mitigate the conditions leading to C-SGTR)
  3) Apply conditional C-SGTR probability (i.e. probability that SG tubes do not fail given the conditions)
  4) Calculate containment bypass frequency.
- Scope of the method does not include LERF analysis; the measure of C-SGTR importance calculated is containment bypass frequency.
- Intended to provide a method for NRR to assess C-SGTR risk: can be incorporated into a formal guidance document

Analysis Method – Identify Sequences

- Identify sequences that can lead to a C-SGTR by performing the following steps:
  1) Sort core damage sequences by their contribution to CDF
     - Identify risk-significant sequences that lead to High-Dry-Low conditions
     - Typical scenarios involve failure of AFW system and RCS feed and bleed
  2) Identify sequences that represent a pressure challenge to SG tubes (including otherwise successful sequences)
     - ATWS
     - MSLB
     - LOCA

     May require some simple modeling changes to PRA model
- Method should consider external events and shutdown initiators as appropriate

Analysis Method – Apply Mitigation Credit

- Given that a core damage event has occurred, what is the probability that recovery actions to mitigate the plant conditions leading to a C-SGTR will fail?
  - Actions generally involve restoration of secondary cooling or RCS depressurization
  - Any standard HRA method may be used – screening values are used in the report
- Recovery may not be feasible in certain situations (e.g., fast developing scenarios)
- Highly plant specific evaluation
- Certain strategies may rely on security related actions
  - Credit should conform to Regulatory Issue Summary 2008-15, "NRC Staff Position on Crediting Mitigative Strategies Implemented in Response to Security Orders in Risk-Informed Licensing Actions"

Analysis Method – Apply SG Tube Failure Probability

- A C-SGTR Tube Failure Probability Calculator Integrates thermal-hydraulic and materials information
  - Flaw distributions
  - Pressure and temperature history
  - Material properties
  - Failure times for alternate RCS locations
- C-SGTR probabilities generally fall into four bins:
  - High probability (0.4)
  - Low probability (0.02)
  - Negligible probability (0.001)
  - Unanalyzed (0.5)

Illustrative Examples

- The quantitative risk assessment method and its application to multiple plants are in a technical PRA report prepared by RES.
- Method applied to
  - 4-loop Westinghouse (Plant 1)
  - 2-loop Westinghouse (Plant 2)
  - 2-loop Combustion Engineering (Plant 3)
- Includes risk from internal and other hazard categories (“external events”)
- Includes C-SGTR caused by initiating events, as well as RCS conditions after core damage sequences
- Examples of three dominant C-SGTR sequences are given in the backup slides.

Plant-1 4-Loop Westinghouse single unit on a site - Results

Event Category	CDF	Bypass frequency due to C-SGTR	Bypass Freq. as % of Total Plant CDF
Internal Events at Power	2.0E-05	9.0E-07	1.55%
Internal Flooding Events	3.9E-06	1.9E-07	0.33%
Internal Fire Events	3.4E-05	2.0E-07	0.35%
Large Steam Line Break Events	2.5E-08	1.2E-08	0.02%
Seismic Events Bin 1 (pga 0.05 to 0.3g)	2.7E-08	1.3E-09	0.00%
Seismic Events Bin 2 (pga 0.3 to 0.5g)	7.9E-08	1.3E-08	0.02%
Seismic Events Bin 3 (pga > 0.5g)	6.9E-07	3.0E-07	0.52%
Totals	**5.8E-05**	**1.6E-06**	**2.8%**

Conclusions

- Key insight - the fraction of CDF from potential C-SGTR sequences is lower or at the same order of containment bypass fraction that may exist for the currently postulated containment bypass fraction of internal events (e.g. 0.1 or less)
  - C-SGTR is not a negligible part, nor a main contributor of total plant risk. It should be considered and monitored in plant risk assessments in a manner commensurate with its expected importance for each plant.

- An otherwise “successful” accident sequence turning into a core damage sequence due to C-SGTR is not a major contributor to plant risk. However, an accident sequence initially progressing as core damage turning into a containment bypass sequence due to C-SGTR may not be negligible.

Recommendations

- Plant PRAs should address C-SGTR in their evaluation of plant LERF or level 2 analyses on a plant-specific basis, referring to the existing PRA standard. However, an in-depth and intrusive modeling of C-SGTR within the current level 1 models may not be necessary.

- Results sensitive to degree of credit allowed for mitigative actions

- Care must be taken not to take excessive credit for SAMG actions, other recovery actions, and non-safety-related equipment to avoid C-SGTR, especially for external event scenarios.

Programmatic recommendation:

- Task 3.5 of the SGAP has been completed and should be closed.

BACKUP SLIDES

An Internal Event C-SGTR Sequence for Westinghouse 4-Loop Plant

- A loss of offsite power initiating event occurs and results in station blackout; Initially AFW system is operable via the turbine-driven AFW pump; rapid secondary depressurization is successful; 21 gpm per pump RCP seal LOCA occurs; recovery off offsite and onsite power in 8 hours fail; loss of AFW pump due to battery depletion is postulated (operator action for pump control is not credited in SPAR models to avoid core damage); core damage is postulated.

- Sequence proceeds as a very Small LOCA without AFW and without feed and bleed. Sequence CDF is 3.35E-06/year; due to availability of long time window, mitigation credit for secondary cooling to avoid C-SGTR is credited as 0.1. The sequence is assigned a high conditional C-SGTR probability of 0.4.

- The estimated C-SGTR frequency is

  F = 3.35E-06 * 0.1 * 0.4 = 1.3E-07/year.

High-pga Seismic Event for W 2-Loop Plant

- Seismic events with high pga (> 0.5 g) causing failure of structures, where core damage is postulated.
  - The frequency of this seismic event for plant-2 is three times the frequency of the corresponding one for plant-1. There are large uncertainties in which equipment is failed and which equipment may be still available. Conservative assumptions may be present in the classification of this “sequence”.
- The initial sequence CDF is 3.8E-06. The large structural failures considered are reactor vessel, steam generators, RCS piping, containment building, turbine building, and auxiliary building.
- 35.4% of the sequence already has either containment bypass or vessel failure. In order to estimate the additional containment bypass risk due to C-SGTR, the original sequence CDF is multiplied by 0.646 (1.0 - 0.354).

High-pga Seismic Event (continued)

- This is a high-pga seismic event beyond design basis:
  - no mitigative strategy is credited (no recovery). No credit is given for B5b equipment.
  - the highest conditional C-SGTR probability of unanalyzed case = 0.5 is used.
    - (For those sequences that are not studied in the Sandia report, a screening value of 0.5, which is very similar to this highest reported conditional C-SGTR frequency, is selected. Use of such a screening value in PRA acknowledges that information about this parameter is not known: however it is neither deemed to occur with certainty, nor it is deemed to be insignificant.)

- The estimated C-SGTR frequency is:

$$F = 3.8E\text{-}06 * (1 - 0.354) * 0.5 = 1.2E\text{-}06/yr.$$

A Fire Event Sequence for W 2-Loop Plant

- Internal fire event that result in evacuation of the main control room and causes LOOP.
- Control of the plant at the dedicated shutdown panel and AFW fails. Both the fire scenario frequency and the equipment that can be credited to deal with the sequence have large uncertainties and possibly conservative assumptions.
- Initial sequence CDF is 3.23E-06.
- Since AFW fails and no safety injection is credited, core damage occurs relatively rapidly. Due to the short available time for the operator actions, use of B5b equipment or AFW recovery are not credited.
- High conditional C-SGTR probability of 0.4 is used. This probability applies to transient or an RCP seal leak of up to 150 gpm per pump (RCS pressurized; no relief or small leak).

- The estimated C-SGTR frequency is:

  F = 3.23E-06 * 0.4 = 1.3E-06/yr.

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Oyster Creek
3D Drywell Analysis

ACRS Full Committee
October 08, 2009

Agenda/Presenters

- ✓ Summary of 3D Drywell Analysis
- ✓ Resolution of Questions from September 23, 2009 Subcommittee Meeting
- ✓ Presenters:
  - Mike Gallagher
  - John O'Rourke
  - Stan Tang
  - Dr. Clarence Miller

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Background

- ✓ Exelon made a commitment to perform 3D Drywell Analysis at the February 01, 2007 ACRS Meeting
- ✓ The ACRS described Exelon's commitment in its February 08, 2007 letter to Chairman Klein as follows:
  - "The applicant has committed to perform a 3D finite-element analysis of the OCGS drywell to determine the margin of the shell in the as-found condition using modern methods. This analysis will provide a more accurate quantification of the margin above the Code required minimum for buckling. …. The analysis should include sensitivity studies to determine the degree to which uncertainties in the size of thinned areas affect the Code margins"
- ✓ Exelon formalized this commitment in a letter dated February 15, 2007
- ✓ The analyses were submitted to the NRC on January 22, 2009.

Overall Results (Sandbed Region)

Load Combination Case	Required Safety Factor	Base Case Safety Factor (Limiting)	Case 1 Safety Factor (Limiting)	Case 2 Safety Factor (Limiting)
		Based on 2006 data confirmed by 2008 data	100 mil local reduction in Bay 1	50 mil reduction of Bay 19
Refueling	2.0	3.54 Bay 3	3.21 Bay 3	3.46 Bay 3
Post Accident Flooding	1.67 (Service Level C)	2.02 Bay 19	2.01 Bay 19	1.98 Bay 19

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Drywell Description

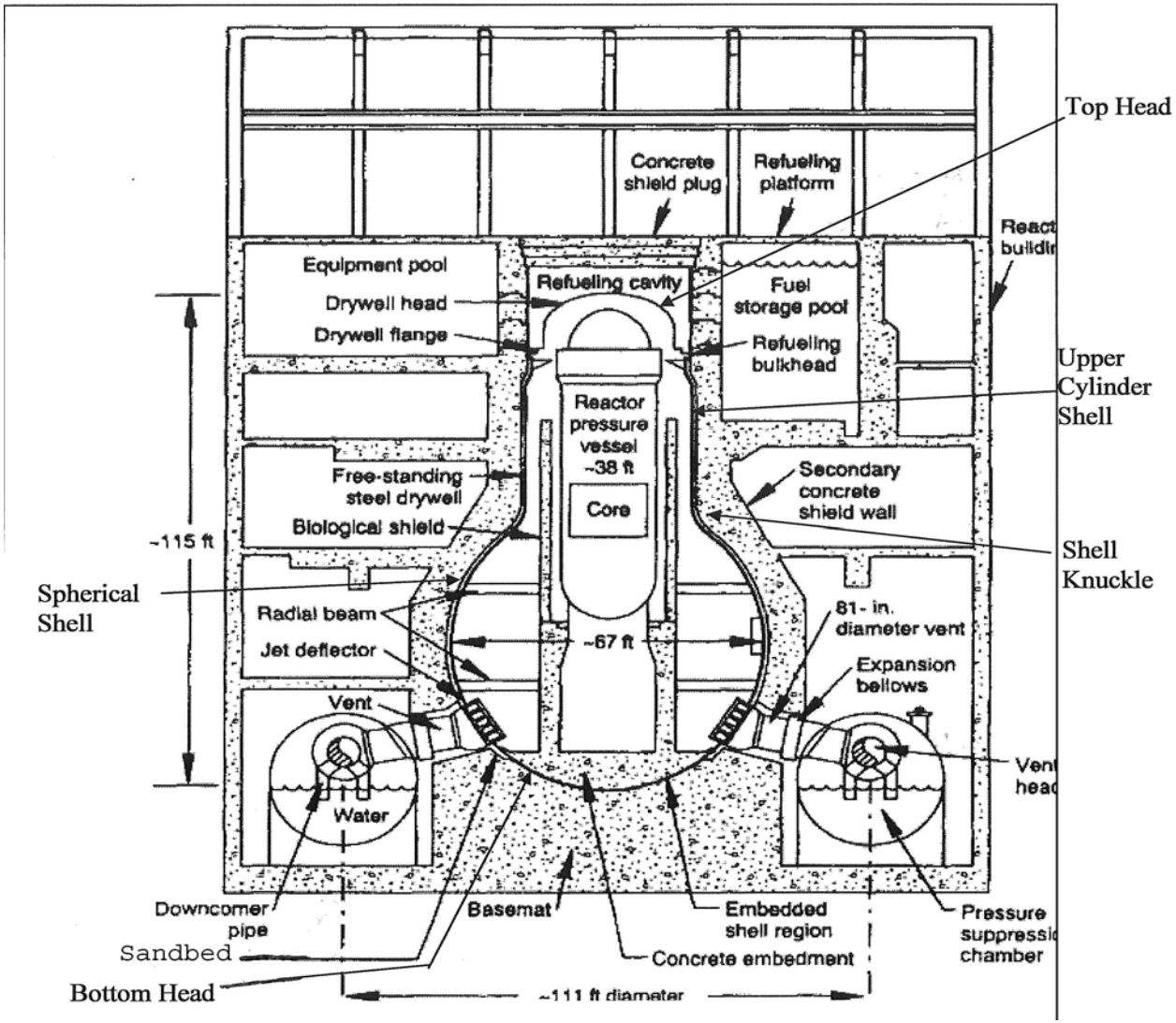

Figure 1-1: Oyster Creek Containment Schematic

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Analysis Summary

- ✓ **Detailed finite element model developed using design drawings**
- ✓ **Shell thicknesses were developed based on UT thickness data**
- ✓ **Current licensing basis inputs such as code of record, loads and load combinations were used**
  - **The Oyster Creek drywell vessel was designed, fabricated and erected in accordance with the 1962 Edition of ASME Code, Section VIII and Code Cases 1270N-5, 1271N-5 and 1272N-5**
  - **For the size of the region of increased membrane stress, guidance sought from the 1989 Edition of ASME Code (including Winter 1991 Addenda), Section III, Subsection NE, Class MC Components**
  - **For the post-accident stress limits, Standard Review Plan Section 3.8.2 was used as guidance**
- ✓ **Buckling analysis performed**
  - **Allowable Stress Values per Section NE-3222 of the 1989 Edition (with Winter 1991 Addenda) of the ASME Code, Section III, Division 1, Subsection NE, Class MC Components**
  - **Modified Capacity Reduction Factor utilized in accordance with Code Case N-284-1 whose primary author was Dr. Clarence Miller**
  - **Code minimum safety factors satisfied**
- ✓ **Stress evaluation performed**
  - **Stresses are within Code allowables**

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Drywell Thickness Description

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Sandbed Measurement Locations

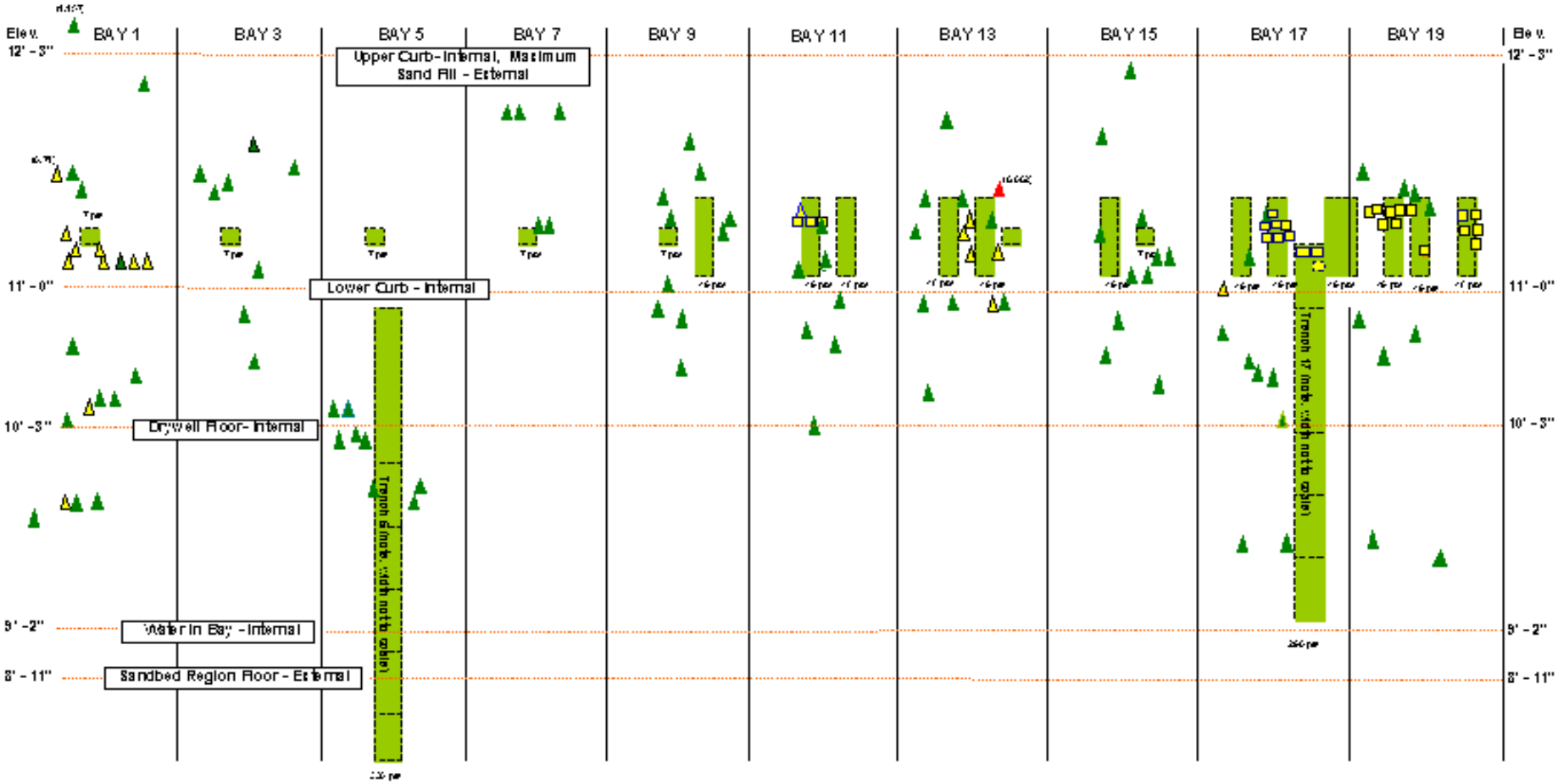
2006 Measurement Locations in the Sandbed Region

Color Code for thickness:

Green =UT Measurements > 736 Mils
Yellow = UT Measurements Between 636 and 736 Mils
Red = UT Measurements Between 536 and 636 Mils

Location / Type of UT Measurement

△ External Point UT Measurements
⛶ Internal Grid UT Measurements
□ Internal Point UT Measurements



Subcommittee Question #1

- ✓ Why is it appropriate to use the UT Internal Grid averages as the modeled thickness for large areas of the sand bed bay?
- ✓ Response:
  - The internal UT grids were located based on a series of data taken to locate the thinnest general areas for ongoing monitoring. Therefore, these grids are representative of the general area average thickness, biased on the thin side.
  - The half buckling wavelength is large, on the order of 5 to 8 feet, which indicates a bay-wide effect. Therefore, the use of average thickness over a bay is acceptable.

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Sandbed Internal UT Measurements

- ✓ From 1983 to 1986, measurements were taken around the inside of the drywell at elev. 11'3"
  - Over 500 initial data points were measured
  - When thin locations were identified, UT measurements were taken horizontally and vertically to locate the thinnest locations
  - UT grid measurements were taken at the thinnest locations
  - 19 locations were selected for ongoing corrosion monitoring with at least one grid is located in each of the 10 bays
- ✓ UT measurements are obtained at these locations every other refueling outage as part of the ongoing aging management program

The UT Internal Grid locations are representative of the general area average thickness, biased on the thin side. Therefore, the UT Internal Grids measurements are appropriate to use as inputs to conservatively model general bay thicknesses.

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Sandbed Trench UT Measurements - Background

- ✓ Trenches in Bays 5 and 17 were excavated in 1986 to characterize the extent of corrosion in sand bed at elevations below the drywell interior floor
  - Bays 5 and 17 were selected because UT measurements indicated these bays had the least and the most corrosion, respectively
  - The trenches extend to about the elevation of the bottom of the sand bed
  - UT measurements taken in the trenches confirmed that the corrosion below elev. 11’ 3” was bounded by the monitoring at elev. 11’ 3”.

This supports our conclusion that the UT Internal Grid measurements are appropriate to use as inputs to conservatively model general bay thickness.

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Use of Average Thicknesses

- ✓ Local Buckling Stresses depend on the applied stress over the half buckle wavelength L_c
  - $L_c = 3.72(Rt)^{0.5}$
  - For the Oyster Creek Drywell Shell, the half buckle wavelength varies between 62 inches and 89 inches
  - For shells with variable thickness, the thickness can be averaged over a distance of, at least, the half buckle wavelength L_c
- ✓ Tests (Miller, 1982) have been conducted on axially compressed shells with unreinforced openings which show little reduction in the buckling strength when the diameter of the hole, d, is $< 0.8(Rt)^{0.5}$. For the Oyster Creek drywell shell d = 13 in. to 18 in.
  - A hole less than 13 inches will have little effect on the buckling strength, therefore, thinned areas less than 13 in. will have little effect on the buckling strength

Conclusion: Use of average thicknesses for a bay as input to the 3D Analysis is acceptable.

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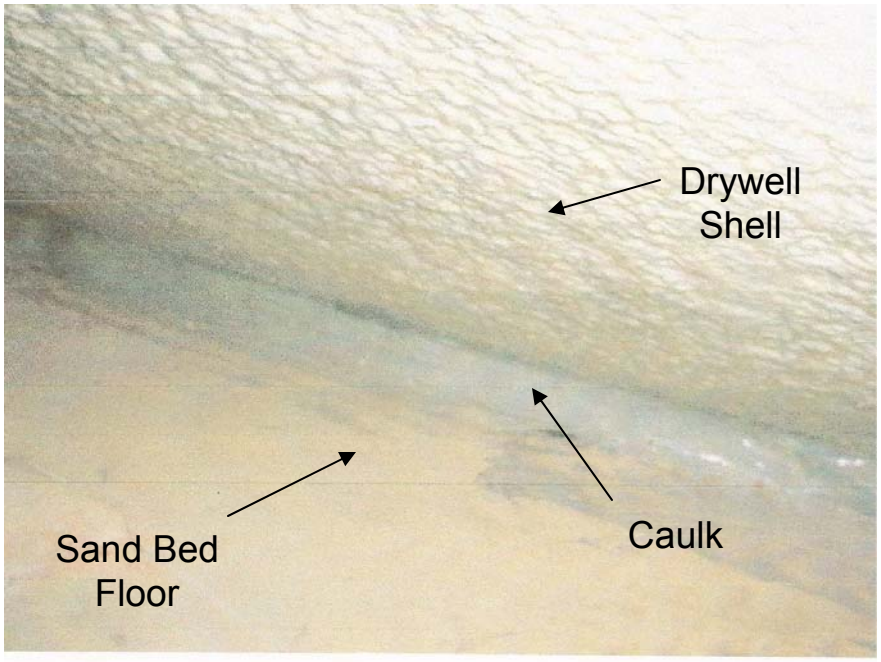
Bay 19 Thickness

- ✓ The bay exhibits historical corrosion above and below Elevation 11'-0"
- ✓ 3 internal grids (All nominally 49 points) are used to measure shell thicknesses in Bay 19
- ✓ Average of three internal grids used as general area thickness for entire bay (826 mils)



Bay 19
(2006)

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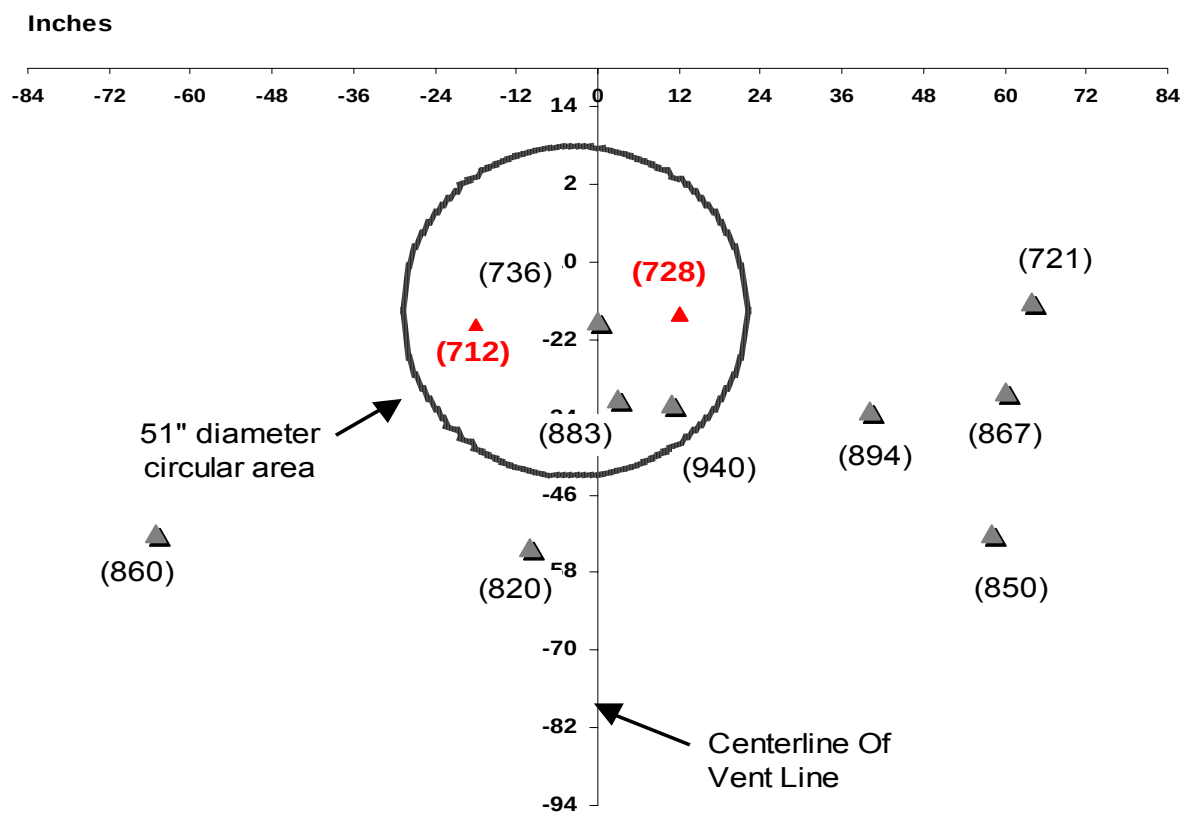
Bay 19 Locally Thinned Area

Bay 19 - Location of 2006 External Measurements
Near Modeled Locally Thin Area (Thickness in mils)



Average of Red locations (720) was input to model
Gray locations were not input to model

Reference
C-1302-187-5320-024

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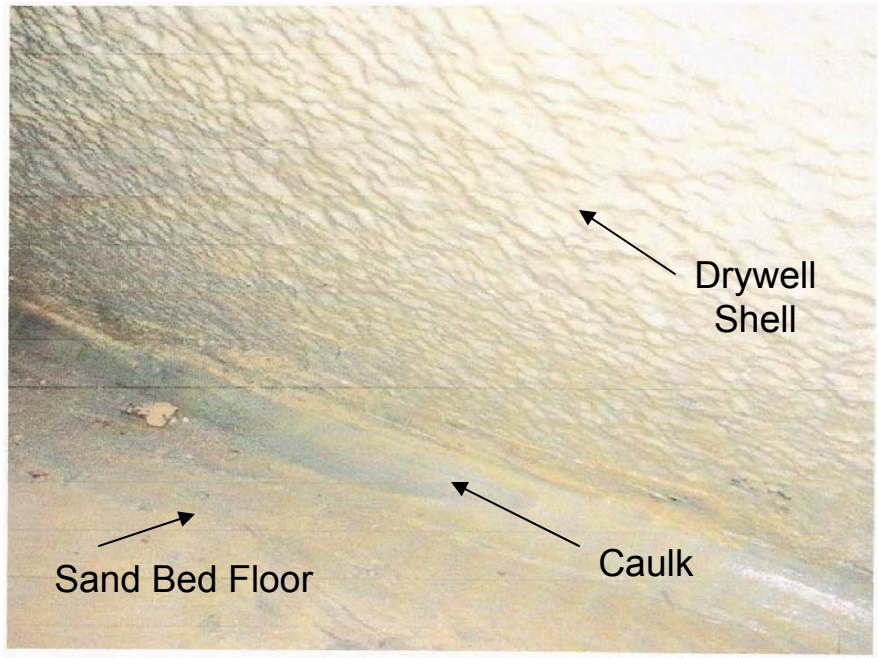
Bay 1 Thickness

- ✓ Visual observation of the external shell surface in Bay 1 indicates the presence of historical corrosion
- ✓ 1 internal grid (7 point) is used to measure shell thickness in Bay 1
- ✓ Internal near nominal grid shell readings for Bay 1 indicate that the grid location is above the former sand/water/air interface boundary
- ✓ Adjacent bay (Bay 19) is one of the most corroded bays
- ✓ Bay 1 thickness was conservatively estimated to be the same as Bay 19 thickness



Bay 1
(2006)

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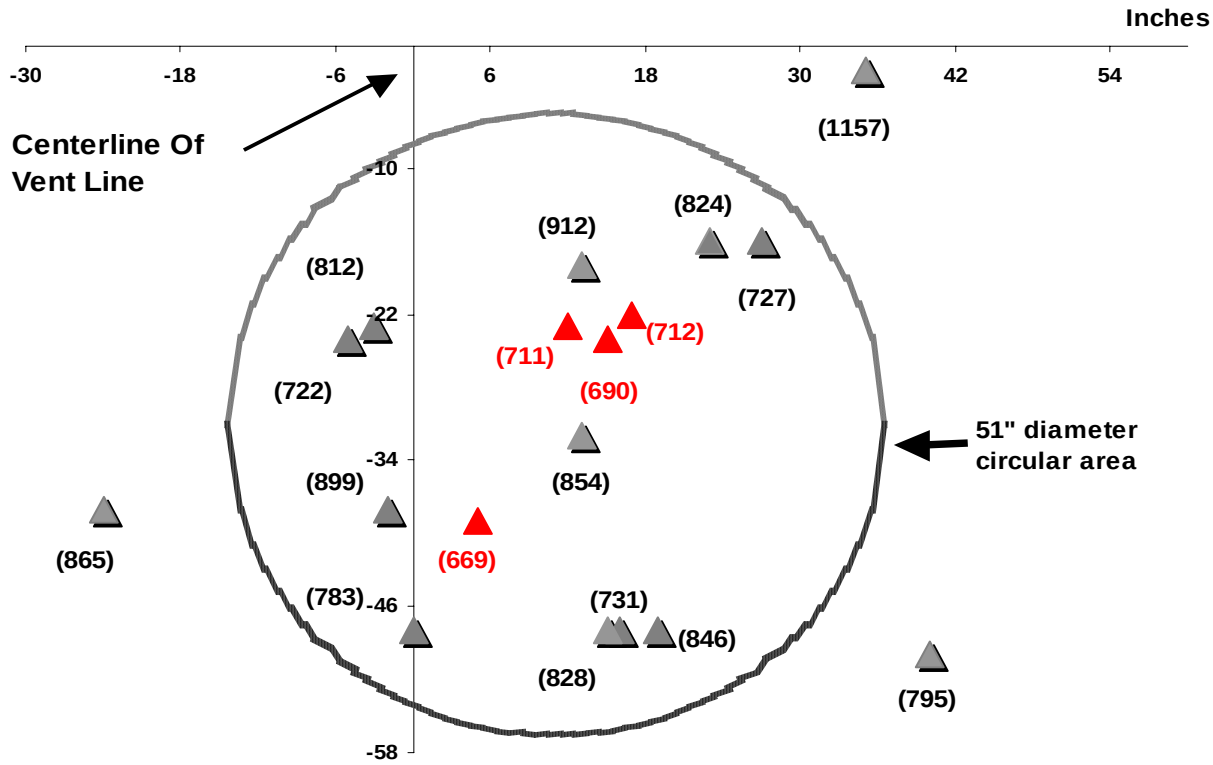
Bay 1 Locally Thinned Area

Bay 1 - Location of 2006 External Measurements
Near Modeled Locally Thin Area (Thickness in mils)



Average of Red locations (696) was input to model
Gray locations were not input to model

Reference
C-1302-187-5320-024

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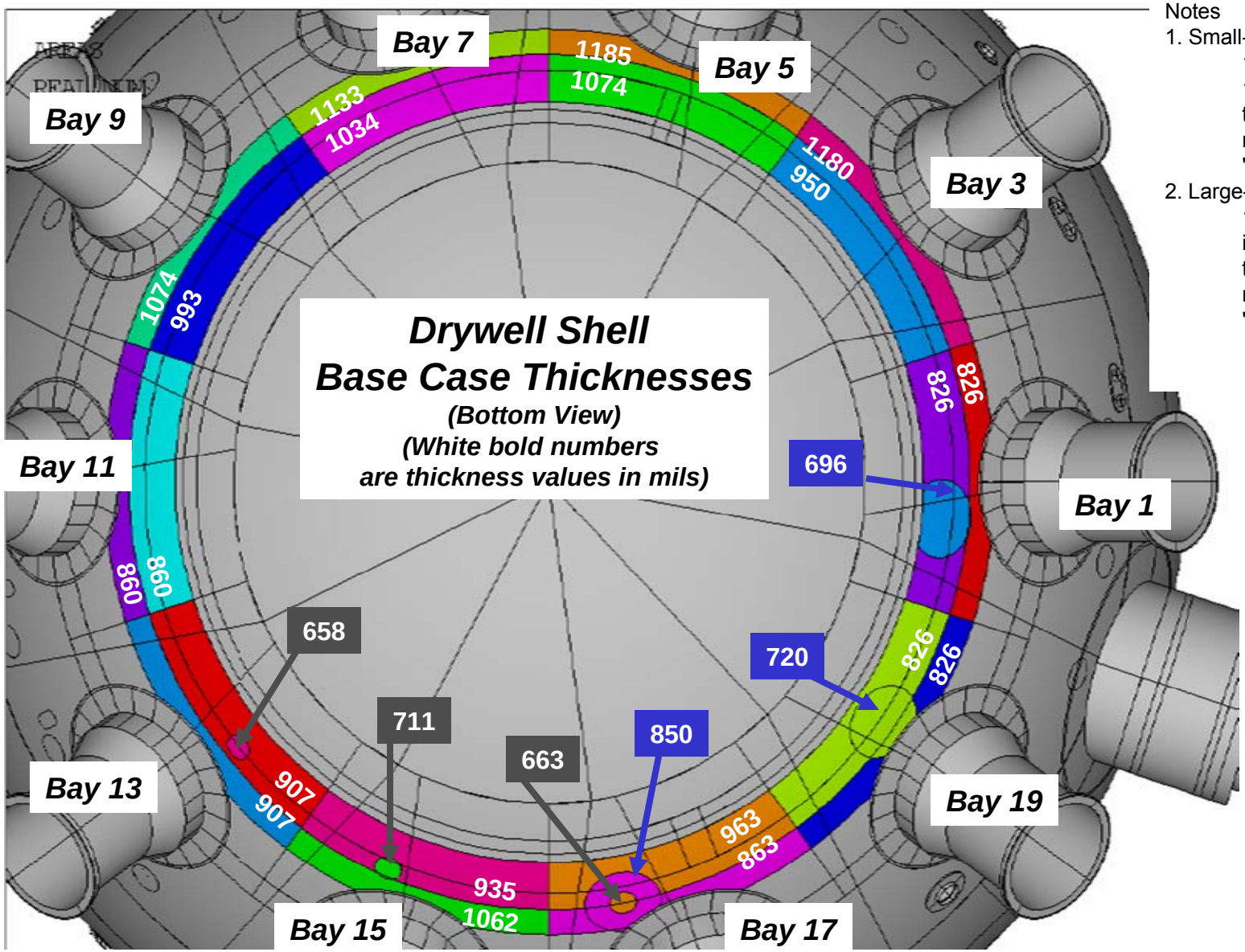

Notes

1. Small-diameter circles in Bays 13, 15, and 17 represent 18-inch diameter locally-thinned areas that were modeled as part of the "base case."
2. Large-diameter circles in Bays 1, 17 and 19 represent 51-inch diameter locally-thinned areas that were modeled as part of the "base case."

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Subcommittee Question #2

- ✓ Why are the External UT points considered biased thin?
- ✓ Response:
  - The External UT Points were identified visually as thin areas for further evaluation. The areas were also ground to permit UT measurement. Therefore, they are biased thin.

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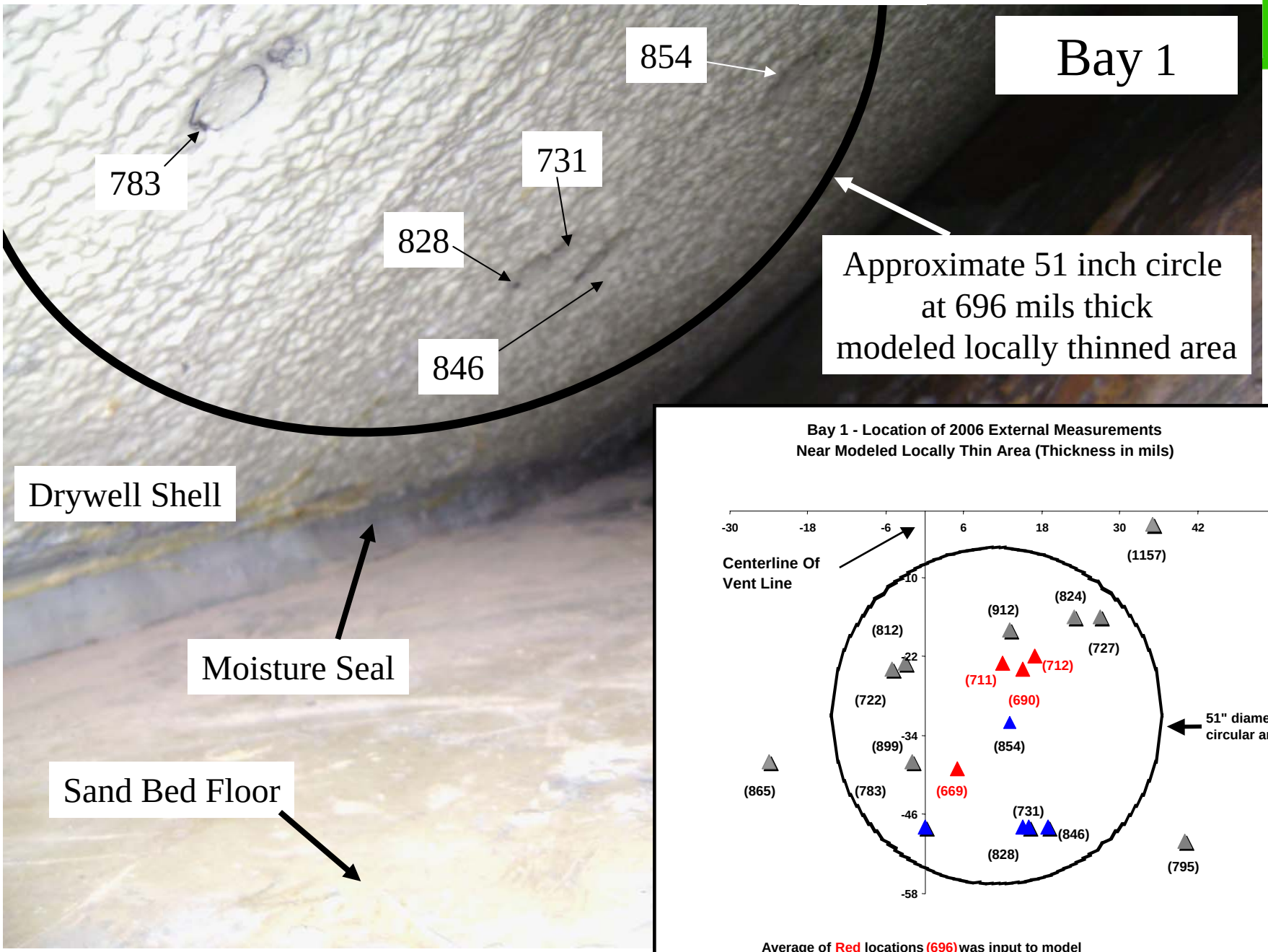
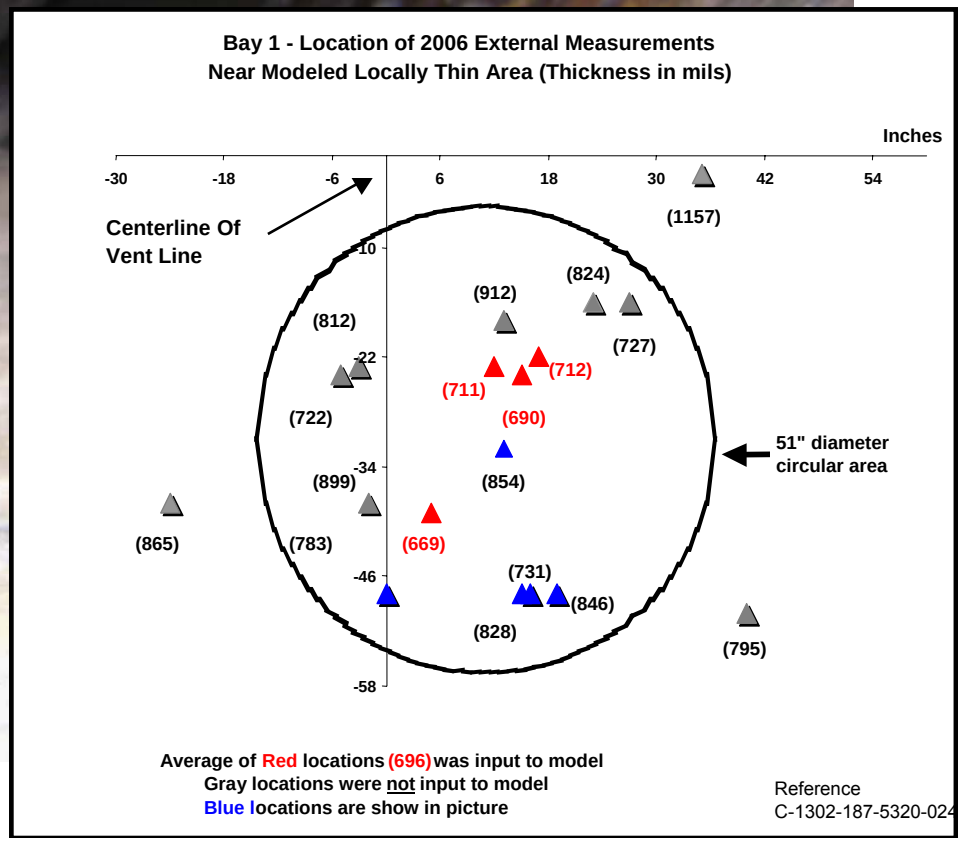
Development of External UT Locations

- ✓ After the sand and corrosion byproducts were removed from the sandbed bays, the thinnest locations in each bay were identified.
- ✓ Each bay was visually inspected and the thinnest local spots were investigated both visually and using UT measurements.
- ✓ Approximately 100 locations were identified and mapped.
- ✓ The external surface of the shell was rough, requiring most of the locations to be ground down to create small flat surfaces so the UT probe could be placed perpendicular to the shell wall.
  - This resulted in small 1 to 2 inch diameter dimples in the surface with relatively thinner local areas (biased thin) that were then measured by UT.
  - Micrometer characterization showed that the grinding process may have removed up to 100 mils.
  - Between the individual External UT points, the shell is thicker.

The External UT points are biased thin. They were used to develop the locally thinned modeled areas. It is not appropriate to use these individual measurements to determine general area thicknesses.

Bay 1


854
783
731
828
846
Approximate 51 inch circle at 696 mils thick modeled locally thinned area
Drywell Shell
Moisture Seal
Sand Bed Floor


Bay 1 - Location of 2006 External Measurements
Near Modeled Locally Thin Area (Thickness in mils)
Inches
-30
-18
-6
6
18
30
42
54
-10
-22
-34
-46
-58
Centerline Of Vent Line
51" diameter circular area
(1157)
(824)
(912)
(812)
(727)
(712)
(711)
(722)
(690)
(854)
(899)
(865)
(783)
(669)
(731)
(846)
(828)
(795)
Average of Red locations (696) was input to model
Gray locations were not input to model
Blue locations are show in picture
Reference
C-1302-187-5320-024

Finite Element Model

Finite Element Model

- ✓ ANSYS
  - Release 8.1 and ANSYS Release 11 used to generate the three dimensional model
  - Industry accepted, finite element analysis software
- ✓ Dimensions and material properties obtained from OEM drawings
- ✓ Model Size
  - Approximately 406,000 elements
  - Approximately 400,000 nodes
- ✓ Mesh Sensitivity
  - Up to approximately 1,000,000 elements

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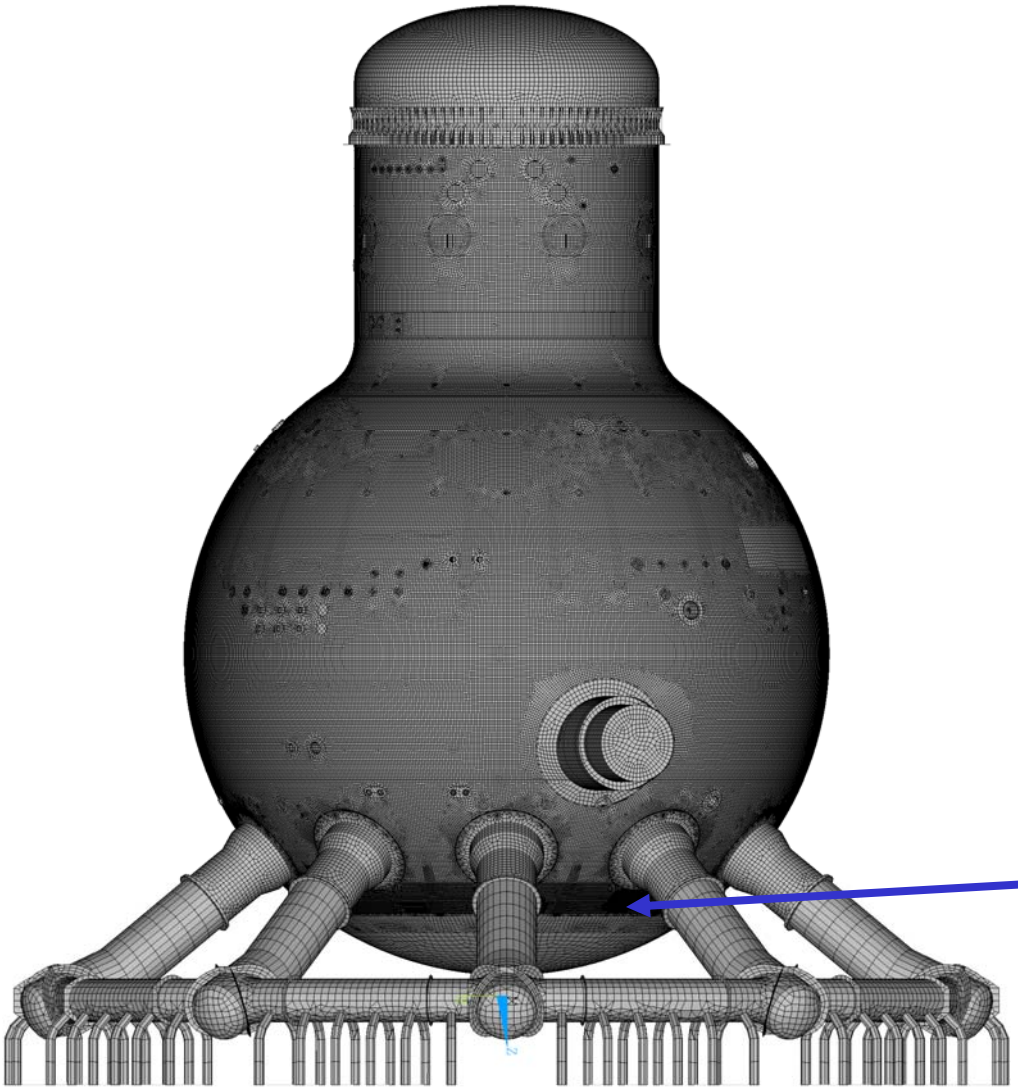
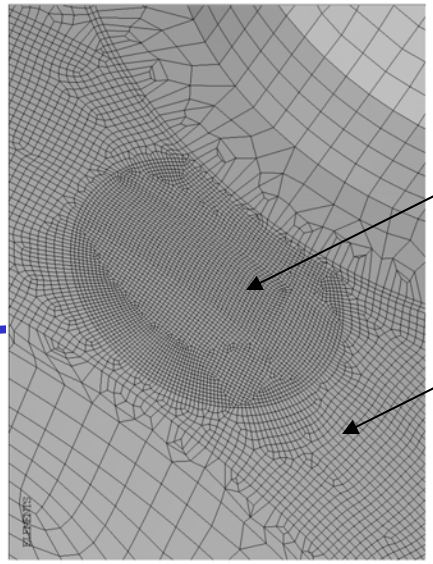
Finite Element Mesh



Elevation View of Finite Element Model

MESH SIZES	
Region	General Mesh Size (Inch)
Local Thinning Area	0.75
Sandbed Region	1.50
Mid Spherical Shell	3.00
Knuckle Region	3.00
Cylindrical Shell	3.00
Top Dome	6.00
6 inch or smaller penetrations	2.50
8 inch or larger penetrations	5.00
Vent Pipes	6.00
Vent Header	10.00
Equipment Hatch	6.00
Bottom Spherical Shell (within concrete)	12.00



Locally Thinned Area in Bay 19

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Subcommittee Question #3

- ✓ Describe specifically the modeling of the vent header boundary condition. Is this boundary condition appropriate as to the effect on the shell? Will the downcomer vents buckle?
- ✓ Response:
  - The vent header boundary condition modeling is appropriate and the boundary condition does not provided added benefit to the shell analysis
  - The vent pipes/header will not buckle before the shell

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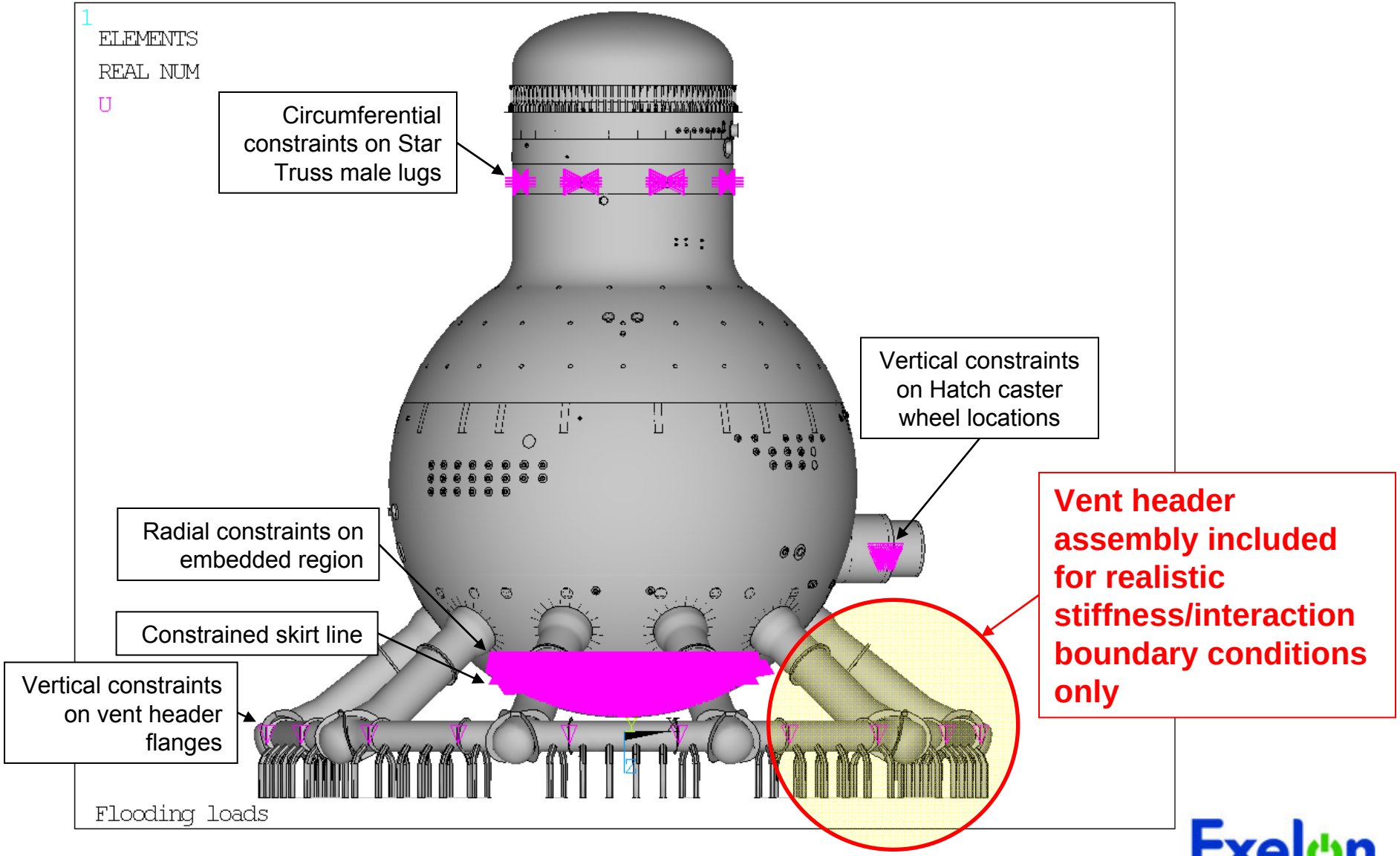
Boundary Conditions & Vent Header Interaction



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Drywell Stiffness Interface with Vent Header

- ✓ Detailed modeling of the vent headers/downcomers is included for realistic representation of stiffness/interaction of components attached to the drywell shell
  - Similar to the use of stiffness matrix as boundary conditions
- ✓ Detailed modeling reduces conservatism in stress/buckling results
  - Account for realistic load transfer
  - Alternate simplified approach is to model with estimated boundary conditions at vent pipes/vent header interface location

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Reaction Loads at Embedded Sandbed Region

- ✓ Loads going through the vent pipes are low
- ✓ Case: Flooding Loads
  - 93% of reaction force was at the embedded bottom head boundary conditions
  - 4% of reaction force was at the vent header boundary conditions
  - 3% went to other boundary conditions (equipment hatch and star truss)

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Vent Pipes will not Buckle before the Shell

- ✓ R/t: Vent pipe ≈ 150, Vent header ≈110, Downcomers ≈ 48
  - Cylindrical shell R/t ≈ 300
  - Spherical shell R/t ≈ 400 to 600
- ✓ Length between stiffeners: Vent Pipe ≈ 85”, Vent header ≈ 48”, Downcomers ≈ 75”
  - Cylindrical shell length between stiffeners = 103”
  - Spherical shell length between stiffeners = 235” to 332”
- ✓ In Code Case N-284-1, for cylinder, a smaller R/t gives a larger capacity reduction factor and higher buckling strength

Conclusion: Based on the comparison of R/t and the length between stiffeners for the vent pipes and the shell, the vent pipes would have higher buckling strength and larger safety factors than the shell.

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Sensitivity Studies

Sensitivity Studies

- ✓ Case 1: Reduce the wall thickness of the 51 inch defined locally thin area in Bay 1 by 100 mils (from 696 mils to 596 mils), keeping the general area of the thickness in Bay 1 constant (826 mils)

- ✓ Case 2: Reduce the wall thickness of the general area in Bay 19 by 50 mils (from 826 mils to 776 mils), keeping the locally thin area constant (720 mils)

Results (Sandbed Region)

Load Combination Case	Required Safety Factor	Base Case Safety Factor (Limiting)	Case 1 Safety Factor (Limiting)	Case 2 Safety Factor (Limiting)
		Based on 2006 data confirmed by 2008 data	100 mil local reduction in Bay 1	50 mil reduction of Bay 19
Refueling	2.0	3.54 Bay 3	3.21 Bay 3	3.46 Bay 3
Post Accident Flooding	1.67 (Service Level C)	2.02 Bay 19	2.01 Bay 19	1.98 Bay 19

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Subcommittee Question #4

- ✓ How is the selection of the 100 mil local reduction and 50 mil bay-wide reduction related to UT data?
- ✓ Response:
  - **Local Area Reduction**: The measurement difference between individual external UT points was -6/+1 mils. The 100 mil local reduction is over 15 times the observed external UT measurement difference and, therefore, is expected to bound data uncertainties.
  - **General Bay-Wide Reduction**: The internal UT Grid measurement standard errors range from +/- 2 to +/- 16.6 mils. The 50 mil bay-wide reduction is at least 3 times the standard error for the data used to determine the general bay-wide thickness input and, therefore, is expected to bound data uncertainties.
  - UT measurements demonstrate that the drywell shell is not experiencing corrosion; however, a hypothetical corrosion rate of 2 mils per year would yield a postulated bounding value of 8 mils over a 4 year measurement interval. The selected reductions of 100 mil local or 50 mil bay-wide are much greater.

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Overall Results/Conclusions

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Overall Results/Conclusions

- ✓ For normal operating conditions, the limiting condition is the refueling condition. For this condition, the current safety factor of the limiting sandbed bay is 3.54, which results in a safety margin greater than the ASME Code specified safety factor of 2.0.

- ✓ For emergency conditions, the limiting condition is the post-accident flooding condition. For this condition, the current safety factor of the limiting sandbed bay is 2.02, which results in a safety margin greater than the ASME Code specified safety factor for Service Level C conditions of 1.67.

- ✓ Sensitivity studies demonstrate that significant thickness changes could occur in the future, or measurement uncertainties could exist, without a significant reduction in margin to ASME Code specified safety factors.

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Questions?

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U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

NRC Staff Review of Oyster Creek Drywell Shell 3-D Finite Element Analysis

Allen Hiser, Jr.
Hans Ashar
Division of License Renewal

Kamal Manoly
Division of Engineering

Timothy O'Hara
Region I

Advisory Committee on Reactor Safeguards
October 8, 2009

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

TOPICS

- Overall Perspective
- Historical Perspective of Analyses
- NRC Inspections
- NRC Staff Review
- NRC Conclusions

OVERALL PERSPECTIVE

- Corrosion identified late 1980s
  - Narrow band of the lower spherical portion of the shell – “sandbed” region
  - Prevalent in half of bays

- Remediation
  - Removed source of corrosion (wet sand)
  - Protected with a robust coating
  - Ultrasonic test measurements indicate corrosion arrested; upper shell measurements indicate low general corrosion

OYSTER CREEK DRYWELL SHELL ANALYSES

- General Electric Analysis - 1992
  - Assumed uniform reduction in shell thickness (sandbed region) to minimum measurement (0.736 in.) and locally thinned area (0.536 in.)
  - Modified capacity reduction factor – refuel load
  - Current licensing basis analysis
- Sandia - 2007
  - Conservatively modeled degradation based on average of external UT measurements, locally thinned area set to bay lowest thickness
  - Conservative assumptions based on no access to proprietary design data
  - Unmodified capacity reduction factor – refuel load
- Structural Integrity Associates – 2009
  - Realistic analysis to compute margins in existing drywell shell above ASME Code
  - Performed base case analysis and sensitivity analyses to address measurement uncertainty
  - Access to GE proprietary design data
  - Modified capacity reduction factor – refuel load

All analyses demonstrate margins that exceed ASME Code

INDEPENDENT REVIEWS

- Brookhaven National Laboratory review of GE analysis for NRC
- ACRS review of Sandia analysis as a part of license renewal review
- Becht Nuclear Services review of SIA analysis for State of New Jersey

All three reviews point to the conclusion that the Oyster Creek drywell shell can perform its intended function without compromising the ASME Code margins

NRC STAFF REVIEWS

- January 22, 2009, submittal
  - Base case and sensitivity cases
  - Detailed rigorous review of submittal
  - Part of license renewal inspection
    - Inspection report issued (ML091380379)
  - Staff assessment issued (ML091310413)

- September 9, 2009, submittal
  - Two revised modeling approximations
  - Detailed review of submittal
  - Performed audit to supplement review
  - Audit report to be issued

NRC INSPECTIONS

ACTIVITIES

- Region I inspectors observed Exelon's drywell shell inspections in 2006 and 2008
- Noted by sample observation that external measurement locations appeared to be chosen in areas of significant relative corrosion

OBSERVATIONS

- Drywell exterior coating was, in general, in good condition
- UT inspections were conducted and reported in a competent, accurate manner
- Sandbed general conditions were good, some minor repairs to seals and coating were needed

NRC REVIEW FINDINGS

CONSERVATIVE ASSUMPTIONS

- Bounding seismic response spectra
- In post accident flooding case, all the water in included as added mass in the drywell seismic analysis
- Conservative 2% damping under OBE
- Post accident Flooding Case evaluated against ASME Service Level C limits
- Support provided at locations of Star Truss/bioshield wall conservatively neglected from the analyses, especially in buckling evaluation
- Sizes of locally thinned areas in sandbed region conservatively mapped

NRC REVIEW FINDINGS

FINITE ELEMENT MODEL

- Realistic estimate analysis of current condition of the drywell shell including realistic simulation of locally-thinned areas identified in 1992 and confirmed in 1994, 2006 & 2008
- Extensive model with general element size of 3”, refined to 0.75” in locally-thinned areas

STRESS EVALUATION

- Refueling case limiting load combination in Levels A and B service conditions, while post-accident flooding case limiting for Level C service condition

NRC REVIEW FINDINGS

BUCKLING EVALUATION

- Where applicable, CRF modified to account for benefit of hoop tensile stresses in the shell as a result of the weight of the water in the reactor cavity pool
- Refueling and post-accident flooding load cases are controlling for buckling evaluation
- In refueling load case, minimum FS 3.39 in the cylindrical region compared against a min FS of 2.0
- In flooding load case, minimum FS 2.0 in the sandbed region, compared against a min FS of 1.67

NRC REVIEW FINDINGS

SENSITIVITY ANALYSIS CASES

- Two sensitivity analysis cases considered to capture potential uncertainties in location and degradation of locally thinned areas
- Stresses in regions above the sandbed area marginally affected and remain essentially the same as in the baseline analysis … less than 8% increase in stress intensities well below allowable ASME Code limits

NRC CONCLUSIONS

- Overall, the 3-D FEA analysis performed utilizing widely accepted engineering practices consistent with ASME Code, good engineering judgment, and applied conservatively biased realistic assumptions
- All components of the drywell shell show adequate margins against instability under refueling loads and post-accident flooding loads
- In all loading cases, stresses are less than allowable ASME Code limits
- For refueling load case, margin against buckling is the lowest in the cylindrical shell region, an area that has experienced little corrosion
- Evaluations in all cases (baseline and sensitivity cases) confirm the Oyster Creek drywell shell complies with the ASME Code limits, and provide reasonable and realistic quantification of the available safety margin of the drywell shell for the postulated loading conditions