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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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580TH MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

OPEN SESSION

+ + + + +

THURSDAY

FEBRUARY 10, 2011

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ROCKVILLE, MARYLAND

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The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., Said Abdel-Khalik, Chairman, presiding.

COMMITTEE MEMBERS: SAID ABDEL-KHALIK, Chairman

J. SAM ARMIJO, Vice Chairman

SANJOY BANERJEE, Member

DENNIS C. BLEY, Member

MICHAEL L. CORRADINI, Member

DANA A. POWERS, Member

HAROLD B. RAY, Member

JOY REMPE, Member

MICHAEL T. RYAN, Member
WILLIAM J. SHACK, Member
JOHN D. SIEBER, Member

NRC STAFF PRESENT:

FRANK AKSTULEWICZ
MARISSA BAILEY
OM CHOPRA, NRO/DE/EEB
DENNIS R. DAMON, NMSS
MELANIE GALLOWAY, NRR/DLR
TONY GARDNER, NRR/DLR
DON HABIB, NRO/DNR/NWEI
CHARLES S. HINSON, NRO/DCIP/CHPB
ALLEN HISER, NRR/DLR
BRIAN HOLIAN, NRR/DLR
WILLIAM HOLSTON, NRR/DLR/RAPB
YONG LI
JAMES MEDOFF, NRR/DLR/RARB
CLIFFORD MUNSON*
SHI JENG PENG, NRO/DSRA/SPCV
LISA REGNER, NRR/DLR
STEVE SCHAFFER
JOE SEBROSKY, NRO/DNRL/NWEI
KEN SEE, NRO/OSER/RHEB
GERRY L. STIREWALL*
LARRY WHEELER, NRO/DSRA/SBP

NED WRIGHT, NSIR/DPR

DAVE WRONA, NRR/DLR

KENT L. HOWARD, SR., Designated Federal Official for Palo Verde Portion of the Meeting

WEIDONG WANG, Designated Federal Official for Summer Section

MICHAEL BENSON, Designated Federal Official for ISA/PRA Section

JOHN LAI, Designated Federal Official for NFPA 805 Section

ALSO PRESENT:

ERIC BLOCHER, STARS

TIM BONNETTE, South Carolina Electric & Gas (SCE&G)

RANDAL BOYD, Arizona Public Service Company (APS)

BIFF BRADLEY, NEI

ANGELOS FINDIKAKIS, Bechtel Power

JOHN HESSER, APS

MARK HYPSE, APS

ANGELA KRAINIK, APS

JAMES C. LaBORDE, SCE&G

SCOTT LINDVALL, WLA*

LARS LIPPARD, Shaw Group*

JOE LITEHISER, Bechtel Power*

ALSO PRESENT

JIM McGREGOR, Shaw Group*

ROBIN McGUIRE, Risk Engineering Associates*

GLENN MICHAEL, APS

AMY M. MONROE, SCE&G

AL PAGLIA, SCE&G

SHABBIR PITTALWALA, APS

MARK RADSPINNER, APS

JANET R. SCHLUETER, NEI

TIM SCHMIDT, SCE&G

MARK STELLA, Westinghouse

STEPHEN SUMMER, SCANA

DOUG TRUE, ERIN Engineering

CHARLES VAUGHAN, NEI

RICK WACHOWIAK, EPRI

BOB WHORTON, SCE&G

*Present via telephone

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

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

8:29 a.m.

CHAIRMAN ABDEL-KHALIK: The meeting will now come to order. This is the first day of the 580th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting the Committee will consider the following: (1) Final Safety Evaluation Report associated with the license renewal application for the Palo Verde Nuclear Generating Station. (2) Final Safety Evaluation Report associated with the Virgil C. Summer Units 2 and 3 combined license application. (3) Comparison of integrated safety analyses (ISAs) for fuel cycle facilities and probabilistic risk assessments (PRAs) for Reactors. (4) Current state of licensee efforts to transition to National Fire Protection Association (NFPA 805). And (5) Preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Kent Howard is the Designated Federal Official for the initial portion of the meeting.

Portions of the sessions dealing with the Final Safety Evaluation Report associated with the

Virgil C. Summer Units 2 and 3 combined license application may be closed to protect information designated as propriety by Westinghouse.

We have received written comments from Mr. Bob Leyse regarding the Palo Verde license renewal application. Mr. Charles Vaughan of the Nuclear Energy Institute will provide an oral statement regarding the comparison of ISAs for fuel cycle facilities and PRAs for reactors.

There will be a phone bridge line. To preclude interruption of the meeting, the phone will be placed in a listen-only mode during the presentations and Committee discussion.

A transcript of portions of the meeting is being kept and it is requested that the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

We will now proceed to the first item on the agenda, Final Safety Evaluation Report associated with the license renewal application for the Palo Verde Nuclear Generating Station. And Mr. Sieber will lead us through that discussion.

MEMBER SIEBER: Thank you very much, Mr. Chairman. Before we begin this morning, Member Harold

Ray would like to make a statement.

MEMBER RAY: Thank you, Jack. Due to a conflict, I will not participate in the deliberations on Palo Verde.

MEMBER SIEBER: Okay, thank you, Mr. Ray. We had a Subcommittee meeting on the Palo Verde license renewal on September 8th of last year. At that time there was one open item and five confirmatory items in the Safety Evaluation Report and I believe we will hear about how those items have been resolved this morning.

In addition to those items, the staff reviewed five additional items related to first inaccessible medium-voltage cables not subject to 10 CFR 50.49 Environmental Qualification Requirements Program; second, buried piping in tanks inspection program; third, NUREG/CR-6260 limiting locations; fourth, selective leaching; and fifth, steam generator tube denting and weld susceptible to primary water stress corrosion cracking after the September Subcommittee meeting.

I believe that both the Applicant and the staff are prepared to discuss them.

As stated by the Chairman, we have received written comments from a member of the public, Mr. Bob Leyse. Mr. Leyse's written comments have been provided to you. They're on the table before each one of you and they will be considered during Committee deliberations on this matter.

With that, I would like to turn the meeting over to Mr. Brian Holian, Division Director for the Division of License Renewal.

Brian?

MR. HOLIAN: Yes, thank you, Mr. Sieber. Thank you, Chairman, and good morning, members of the Committee. My name is Brian Holian. I am the Director of the Division of License Renewal. We're here today for the second of three STARS plants that have come in for license renewal. We had Wolf Creek several years ago, Palo Verde, and Diablo Canyon just came to the Subcommittee yesterday afternoon.

The agenda for today is to have brief introductions by myself and then right to the Applicant for the discussion of the open and confirmatory items, followed by the staff, where we'll give our assessment of closing out the Safety Evaluation Report.

Brief introductions now: to my left is Melanie Galloway, the Deputy Director of the Division of License Renewal. Behind me is the Branch Chief, Projects Branch Chief for Palo Verde. Palo Verde is one of the plants, Mr. Dave Wrona. And next to him is Lisa Regner, the Senior Project Manager. And she'll be leading the staff's presentation when we go next.

As was mentioned by Mr. Sieber, the one open item dealt with metal fatigue issues, very similar to what you saw, the Subcommittee members saw yesterday on Diablo Canyon. Some of those were repeated on that application from STARS. We had a good discussion yesterday with the Subcommittee on those and at the Subcommittee for Palo Verde a couple of months ago. We'll address how that was closed out.

The confirmatory items were very similar to some of the items that we've had on recent operating experience. The staff wants to verify that they're proper and updated aging management programs were in place. So we'll cover that as we go on.

With that I'll save any other comments we have or particular items for the beginning of the staff's presentation and with that, I'll turn it over to Mr. John Hesser, the site VP for Palo Verde.

MR. HESSER: Thank you, Brian. Mr. Chairman and honorable members of the ACRS, good morning. I'm John Hesser, the Vice President of Nuclear Engineering at Palo Verde and I am the executive sponsor for our license renewal application.

Next slide, please.

We are pleased to be here today to provide you a discussion of our license renewal application and our Draft Safety Evaluation Report. Here with me to facilitate that discussion and to answer any questions you might have are Ms. Angela Krainik, our manager for license renewal at Palo Verde; Mr. Eric Blocher, who is our project manager for our license renewal application; Mr. Glenn Michael, who is our lead licensing engineer for license renewal; and to my right is Mr. Mark Radspinner. He's the supervisor of system engineering, specifically in the mechanical and NSSS section.

Also with me today is several members of our technical and operations staff at Palo Verde. I would like to introduce one of those members, Mr. Randal Boyd.

Randal, would you stand up, please?

Randal is our lead engineer for the implementing of our living license renewal program at Palo Verde. He takes care of all aspects of that. So he'll be with us today and may enter into the conversation.

Next slide.

This is the agenda for our presentation. I will give you a very brief station description overview as a reminder from our Subcommittee meeting, along with a time line on our current license. Then Ms. Krainik will discuss the license renewal application open items and confirmatory, along with the resolution of those five additional items previously mentioned, and will facilitate any questions that you may have. And if time allows, I'll make some concluding remarks.

At Palo Verde, our mission is to safely and efficiently generate electricity for the long term. If you please note, the word "safely" is capitalized and underscored. This is done on purpose so that it remains a constant presence to the station leadership and personnel, that safety and the protection of health and safety of the public is job one at all times. And that now includes license renewal and the period of extended operations that we hope to be granted for the long term.

Next slide, please.

At Palo Verde, we have three units that are common design. They all work with a common operating procedure and we maintain the configuration at Palo Verde as close to similar as possible. As noted in our license renewal application, we do have minor differences such as field-routed conduit and piping, but they're all done to a common design criteria.

Each unit is rated at 3,990 megawatts thermal and 1346 megawatts electric. Our nuclear steam supply system is supplied by combustion engineering, is a System 80 design. The turbine generator is by General Electric and Bechtel Power Corporation was the designer of our balance of plant and the constructor of record.

Next slide, please.

Our initial construction permit was issued on May 25, 1976 and our operating license was issued in 1985, 1986, and 1987, respective of Units 1, 2, and 3. Our current license will expire in 2025, '26, and '27, again respective of Units 1, 2, and 3.

Currently at Palo Verde, all three units are in their 16th operating cycle. I would note that we're on an 18-month fuel cycle and that we have in the spring Unit 2 is scheduled for refueling outage and Unit 1 is scheduled in the fall for its refueling outage. Today, all three units are operating at 100 percent and there are no challenges leading to shutdown today.

And if you have no questions for me, I'll turn it over to Ms. Angela Krainik who will lead us through our discussion.

MS. KRAINIK: John, thanks for the introduction.

Chairman and members of the ACRS, as John stated, I've had the opportunity to lead the license renewal team at Palo Verde and have been the primary interface with the NRC staff during their review and response to their inquiries for information.

I'll be providing an overview, as John mentioned, of the SER items that were discussed earlier, mentioned earlier, I should say, and then provide an overview of our implementation status to date.

The SER was issued on January 11th with the staff's conclusion and review that addressed both the open and the confirmatory items from the SER from open items that was issued in August. We did have one open item which was a compilation of 18 RAIs or requests for additional information in the area of metal fatigue. All of these RAIs were responded to and after staff review, the open item has been closed.

As I discussed in the Subcommittee meeting, we had to change the presentation and the discussion of our metal fatigue monitoring program in our license renewal application. We added consistency and some clarity to it in response to the questions from the staff. As a result, we believe that we ended up with an improved program for fatigue monitoring under our aging management program.

We also had five confirmatory items in the SER with open items. We responded to these and/or completed actions and provided the documentation to the staff, the SER documents, the staff's review and completion or closure of those as well. For example, one of the items that we had had to do with our spray chemical addition tanks that we needed to drain. We have identified that some fluid containing a small amount of hydrazine in previously abandoned tanks and piping was left from the prior flushing operations. We had committed to drain the tanks and the piping and we did that. If you also recall, we had originally intended to have it done by August of last year. We ended up having to extend that through November, but we were able to complete the evolution at all three units in October.

In the additional items that were mentioned earlier, these are items that following the issuance of the Safety Evaluation Report with open items, we worked with the staff to address some operating experience. These are titled as additional items in the SER. I'd like to review these items, if I could.

The first one is the inaccessible medium voltage cabling. As a result of industry operating experience, we were asked to and we were going to include low-voltage cabling down to 480 volts within the scope of our aging management program. For buried piping and tanks, we addressed industry operating experience having to do with fluids contained within buried piping. We added a commitment that we would inspect our diesel fuel oil piping or a portion of that in the three inspection periods we have in front of us.

The next one has to do with the NUREG 62.60 limiting locations. The staff requested that we confirm the limiting locations for the environmentally-assisted fatigue analysis for the reactor coolant pressure boundary components. We committed to complete the review and add any additional analysis as required prior to the period of extended operation.

For the selective leaching aging management program, we included specific details about our sampling program to select locations to be inspected. And finally, we committed to address the aging of the primary side welds in our steam generators and add that to our aging management program. That's the divider bar plate welds and tube-to-tube sheet welds.

Although our primary focus for the license renewal program or the application has been taking -- has been the application, we are taking steps, as we mentioned, to ready the plant for implementation. For the 40 aging management programs identified for Palo Verde, we have 149 station procedures and programs that will be invoked to implement these.

We're pretty well along with the process of incorporating the aging management activities into those programs and procedures, but we still have a few yet to complete. Although the procedures are used to implement at the station, it's also the infrastructure that needs to be ready in order to implement the programs. To this end, we've added an implementation engineer to our staff, as John has already introduced Randal. And he's been working to develop the implementation plan.

This is, in part, based on information that we're gathering from the industry for those that are in the process of either readying for implementation or those that are in their period of extended operation now, getting operating experience from them on how best to implement the programs.

We continue to also participate with the industry in efforts coordinated by NEI for implementation. And although not all the implementation work to date has been identified, we have added a place holder in the Palo Verde long-range plan to acknowledge that there's work scope, particularly inspections during outages that we need to make sure that we're ready for.

I'd like to return the presentation back to John for his closing remarks.

MR. HESSER: Thank you. Mr. Chairman, and members of the ACRS, that concludes our presentation. I would like to on behalf of the Palo Verde owners and the station personnel recognize the hard work and rigorous reviews of the NRC staff. We truly do believe that they have positively enhanced some of our implementing programs and license renewal application at Palo Verde. As a learning organization, we do appreciate critical feedback and we'll continue to work on that application implementing programs by the review of operating experience as we go forward and I would like to thank you again and appreciate your time and consideration for Palo Verde's license renewal.

This slide here shows again that our license will expire in 2025, '26, and '27 and if we are granted license renewal, the period of extended operation will go to 2045, '46, and '47.

Next slide.

I do again want to emphasize that at Palo Verde, we are truly committed to the safe and efficient generation of electricity for the long term. And if you have any questions of us, we'll conclude.

MEMBER SIEBER: No questions. I think the Applicant can begin to consider life after 60.

MEMBER BLEY: Is there?

(Laughter.)

(Pause.)

MR. HOLIAN: This is Brian Holian again, Division Director, License Renewal. I'd like to complete staff introductions at the table. We do have additional staff, branch chiefs, in the audience here to support questioning, but at the table we have Bill Holston, the Senior Engineer in the Division of License Renewal, Mechanical Engineer, and deals with buried piping and other issues in the mechanical area. Dr. Allen Hiser, our senior level advisor in the

Division of License Renewal will be addressing the metal fatigue issues. Lisa Regner, who I mentioned earlier, the Senior Project Manager in License Renewal, she's dealt with us on both the environmental side and the safety side for the Palo Verde review, so we thank Lisa for taking on both of those projects during the time. And finally, a new person from License Renewal at the table, Tony Gardner is our new project manager. He's been assisting Lisa throughout the Palo Verde project.

With that, I'll turn it over to Lisa Regner.

MS. REGNER: Thank you, Brian. Good morning. As Brian said, my name is Lisa Regner and I'm pleased to again be sitting before you to present the staff's findings for the Palo Verde Nuclear Generating Station license renewal project.

I would like to recognize the staff. There is an extensive number of staff who worked on this and some of them are in the room. Some of them are in the overflow room, so I do want to thank them for their tireless support of this review. I didn't do it on my own.

My agenda for this presentation includes discussions of the staff's efforts involved in closing the open end confirmatory items and a brief discussion of other topics of interest. I'll try not to repeat any information that you've heard before. These were all resolved following issuance of the Safety Evaluation Report with open items.

Last September, the staff discussed with you the Safety Evaluation Report with open items which was issued in August. Since then, all outstanding concerns have been resolved. We have received the Region IV Administrator's letter recommending license renewal. That was issued in January. And the final SER was also issued in January.

The lead inspector for the Palo Verde license renewal inspection, Mr. Greg Pick, and his chief, you probably heard from them yesterday at the Diablo Canyon Subcommittee meeting. They were unable to join us today. I don't think -- I'm not sure whether they got back to Texas with the weather there, but I don't see them shouting out.

I would like to remind you though that the Region and headquarters staff did work very well together, especially on an issue associated with the structures monitoring program which I think I discussed with most of you at the Subcommittee meeting. Headquarters staff identified concerns with the frequency of inspections of external stressors during their aging management program audit and issued a request for additional information. Subsequently, and independently, the Region inspectors identified the same issue and an additional item associated with structural baseline inspections that the Applicant had not performed completely. Both Headquarters and the Region coordinated well and ensured that those concerns were resolved to everyone's satisfaction without duplication of effort.

MEMBER STETKAR: Lisa, I was looking through my notes here. Can you refresh our memory, were there concerns with specific structures or was it just the general frequency of monitoring?

MS. REGNER: There were specific structures that were more important. Obviously, the safety-related structures the staff was very concerned about making sure they were in accordance with the guidance in the American Concrete Institute 349 standards which are recognized in the GALL. And that had recommended a five-year periodicity. There were other structures where the Applicant was able to provide us some technical justification for a longer time period in between those frequencies, those inspection frequencies.

MEMBER STETKAR: Thank you.

MS. REGNER: We now would like to discuss a few main topics from the open item, the metal fatigue analysis. Again, as a reminder, the metal fatigue analysis was an extensive and complex review for Palo Verde. During the acceptance review of the license renewal application, the staff effort was postponed due to incomplete cumulative usage factor information for Class 1 valves. APS staff submitted that information by April, but subsequently staff identified additional concerns related to design basis information inconsistencies, irregularities between metal fatigue analysis subsections and dispositioning of the time limiting age analyses.

Staff issued over 70 questions, held approximately 15 conference calls and conducted a public working meeting with Arizona Public Service Company staff in May of last year. And 95 percent of these efforts were all conducted before the Safety Evaluation Report with open items was issued. So by the time we met with you in September, we were really down to a few fairly minor issues that the staff still needed to resolve. And those were identified in the 18 subcategories of the open item.

Also, the Applicant did submit an

extensive rewrite of major portion of the license renewal application on metal fatigue analysis which the staff needed to thoroughly review.

And now I would like to turn it over to Dr. Allen Hiser, so he can discuss a few of the more important concerns.

DR. HISER: The first thing that I want to describe, metal fatigue calculations, I think maybe more than almost any other calculation in reactor safety. You can do a simple analysis to demonstrate that you meet the acceptance criteria which in this case would be a cumulative usage factor, less than one, or a cumulative usage factor incorporating environmental effects that's less than one. If you find that you do not meet that criteria, you can less conservatively, more accurately, model certain portions of the analysis.

One of the issues where this is really important is the first item listed here. That's with the reactor vessel instrument nozzle. We had a lot of discussion at the Subcommittee meeting. The Applicant had calculations for one or two calculations, one for Unit 1, one for Units 2 and 3. In the case of the Unit 1 calculation, the CUF, they calculated was a 0.68. So it's less than the factor of one. This calculation had many simplifying assumptions in how vortex shedding in particular was treated. It met the acceptance criteria. The Applicant was satisfied with the result. For Units 2 and 3, using a more rigorous analysis, the CUF came out to a factor of 0.140.

There was a lot of discussion within the NRC staff had as to the differences. As part of the RAI responses, the Applicant described the differences in the calculations. Our conclusion was that both calculations were acceptable. They both met ASME code requirements. So even though there's a factor of five difference, it is simply the modeling differences between the two.

MEMBER CORRADINI: But both are less than one.

DR. HISER: Both are less than one, that's correct.

MEMBER CORRADINI: So has -- I'm sorry, I didn't mean to interrupt you, but I guess my thought is not knowing metal fatigue analysis, is this surprisingly different, noticeably different, normally different?

DR. HISER: I think given the modeling differences that were used, the simplifying assumptions that went into the Unit 1 calculation, this is what we would expect.

MEMBER CORRADINI: Okay.

DR. HISER: I wouldn't have been surprised if maybe they had more than a factor of 5, maybe a factor of 10 or 50 which is what we have seen in many cases.

MEMBER BANERJEE: Can you just briefly describe what this simplified analysis versus less simplified analysis?

DR. HISER: Partly, it relates to the way that the stresses due to vortex shedding were combined with other stresses. In the KC Unit 1 in one case, they did an arithmetic summation of the stresses as opposed to a vector-based summation. So that creates much higher stresses.

I think ultimately what was identified from the Unit 2 and 3 calculation was that the vortex shedding loads were sufficiently low that they really could be -- could have been ignored in the calculation. But in terms of completeness for Unit 1, they did include them in a very conservative manner. As I mentioned before it did meet the acceptance criteria so the plant did not do a more conservative and more realistic, more accurate calculation for Unit 1.

MEMBER BANERJEE: Just the way you sum the stresses?

DR. HISER: I think that's the most significant contributor. Okay?

MEMBER BANERJEE: And the shedding phenomena is well understood?

DR. HISER: I believe that it is. The one concern that we had and I think the Subcommittee had expressed was it appeared that vortex shedding was not treated for Units 2 and 3 and so we wanted to verify that indeed the phenomenon was considered for all three units. It's just that the way that it was treated for Unit 1 made it a much more significant factor in the CUF calculation.

MEMBER BANERJEE: So the question I had was when a flow goes past a body it becomes vortices behind it.

DR. HISER: Yes.

MEMBER BANERJEE: Depending on the situation that the vortices can form a von Karman street or they can form other types of structures, what was happening here?

DR. HISER: I don't know that we know the details on how they --

MEMBER BANERJEE: So how did you know

about the frequency and the temperature fluctuation and things that might occur due to the vortex shedding?

DR. HISER: We did not do any confirmatory thermal hydraulic calculations.

MEMBER BANERJEE: But how did they do it?

DR. HISER: I'm not familiar with the details of their analysis. Maybe they --

MEMBER BANERJEE: Do you accept it, what they did?

MEMBER CORRADINI: They followed the ASME Code.

MEMBER BANERJEE: So there's a code that's giving you the velocity past object which gives you the vortex.

DR. HISER: Well, the ASME Code provides the criteria that they have to use in the calculation.

MEMBER BANERJEE: But what are the inputs?

DR. HISER: One of the inputs would be the results from thermal hydraulic calculations.

MEMBER BANERJEE: Right, and how is that done? I don't need you to pursue this. I just want to know what depth you looked at it.

DR. HISER: We did not look at it at the thermal hydraulic calculation in detail.

MEMBER BANERJEE: So who did? Did the Applicant do this?

DR. HISER: Yes. They did the calculation.

MEMBER BANERJEE: How do you know it's right?

DR. HISER: This is consistent with what we had found for other plants. There are no unique characteristics with Palo Verde that we are aware of that --

MEMBER BANERJEE: Perhaps the Applicant would speak to this. Just tell us how you did it and perhaps that will take care of the problem.

MR. RADSPINNER: Hello, my name is Mark Radspinner, System Engineering at Palo Verde. I can attempt to address your concern. As I understand the question is a level of understanding of how that analysis was performed in terms of calculating the alternating stresses that are produced by vortex shedding. Of course, the analysis was performed back in 1979. The techniques used though are standard with respect to the hydraulic loads for vortex shedding. They're dependent on correlations that are well developed, flow rates, and the geometry of the protruding nozzle, so they calculate the lift and the drag forces and then the subsequent frequency of the eddies that are produced as the flow goes around the nozzles.

So it's a very standard methodology. The primary purpose, of course, of the calculation is to show that the natural frequency of the protruding nozzle is sufficiently away from the vortex shedding frequency so that you don't get a resonance condition and that's clearly demonstrated in the analyses.

MEMBER BANERJEE: So it's some form of a correlation that's used?

MR. RADSPINNER: Yes.

MEMBER BANERJEE: Okay. Thanks.

MR. RADSPINNER: Thanks.

MEMBER ARMIJO: Now in this analysis, you didn't have, at least for these nozzles, you didn't have a thermal cycling as a result of that vortex shedding as well? Is that correct? This is just strictly --

MEMBER BANERJEE: Mechanical.

MR. RADSPINNER: Yes. I'm sorry, I was walking away from the microphone.

MEMBER ARMIJO: Yes, did you have any kind of a thermal cycling? You know in some nozzles you can have a thermal cycling, depending on how it's designed and whether you have safe end designs.

MR. RADSPINNER: If I understand the question correctly, it's whether the vortex shedding frequencies were combined with the --

MEMBER ARMIJO: No. Was there any thermal cycling as a result of high cycle thermal cycling as a result of this vortex shedding if everything was isothermal, then there's no problem?

MR. RADSPINNER: There was no consideration of thermal effects in conjunction with the vortex shedding.

MEMBER SIEBER: I would think thermal effects have to do with frequency of vortex shedding, once frequency becomes sufficiently high, there's not a --

MEMBER ARMIJO: Yes, but if everything is isothermal there's no problem.

MEMBER SIEBER: Okay. We're clear.

MR. RADSPINNER: Yes.

MEMBER BROWN: Can I ask a question? What was the concern that led them to do a more refined analysis for Units 2 and 3 as opposed to Unit 1? I mean they passed Unit 1, so they go through a more elaborate analysis for Unit 2 and Unit 3 and that's supposedly based on the earlier comments. Identical?

DR. HISER: I don't know what their -- the geometry is identical for all three units. My guess is different analysts did the two calculations.

MS. REGNER: Correct me if I'm wrong, but I believe the same analysts did both evaluations, but they were done about a year apart and they just decided to use more advanced modeling techniques. Is that pretty accurate?

MEMBER CORRADINI: They're engineers, Charlie.

MR. RADSPINNER: Yes. Mark Radspinner. That's essentially correct. I did talk to not the analyst who did these particular calculations, but one who worked at Combustion Engineering at that time frame. The approach was the Unit 1 analyses were meant to be prototypical and the follow-on analyses were meant to be addressing any material changes, as-built dimensions and things like that. And in this particular case, there were no changes of that nature, but as Brian Holian mentioned earlier, they do have the opportunity to come back and decide that well, we did take a very conservative approach in the previous analysis and one can only conclude that they decided that a more accurate, more detailed approach was appropriate for the follow-on analysis.

MEMBER BROWN: Okay, so there wasn't some technical concern that drove it. That was the point of my question.

MR. RADSPINNER: Right. Not that we're aware of, yes.

MEMBER BROWN: Thank you.

DR. HISER: Okay, in terms of environmental effects on fatigue, the staff questioned the Applicant on assumptions that go into that calculation. For environmental fatigue, there's a factor called Fen, fatigue environmental factor that depends on the material type whether it's alloy steel, stainless steel, or nickel alloy. And involves assumptions or inputs of oxygen content, temperature during the transient and also the strain rate. The Applicant indicated that they did use conservative values of oxygen, maximum temperature and strain rate, so they confirm that the Fen factors were at a maximum.

In addition, we found that the Fen factor that was used for nickel alloy was a prior value that staff no longer believes is limiting. One of the commitments that the Applicant made was to reanalyze the nickel, pressurized nickel alloy heater penetrations using a more updated value of Fen. That

that will be completed two years before they enter the period of extended operation.

MEMBER ARMIJO: Allen, in these conservative analyses, was this -- is there a systematic approach here or Fen, let's say is 50 percent than what is believed to be the case or strain rate is higher or is each analysis kind of ad hoc, somebody decides?

DR. HISER: It's either based on parameter values that would maximize the Fen factor or it's based on assumption on the characterizations on the transients that can be verified as being reasonable.

MEMBER SHACK: Typically, the hardest thing to come up with is the strain rate, so you set that at a max. And the temperature is sort of the most next difficult thing to deal with, so you typically set that at the max if you can live with it.

The dissolved oxygen is something you can actually probably make reasonable estimates for BWRs and PWRs and so --

DR. HISER: And we do -- oxygen, in particular, is one that applicants frequently will not assume the maximum value and we do ask them to demonstrate that whatever assumption they make is appropriate for their case.

MEMBER ARMIJO: But it's some factor greater than their normal dissolved oxygen operating level.

DR. HISER: Yes.

MEMBER ARMIJO: Okay.

DR. HISER: Well, it's an oxygen level that gives a higher Fen. The stainless steel --

MEMBER ARMIJO: It goes the other way because the carbon steel --

DR. HISER: It makes it very difficult in trying to assume an oxygen level. It's easier just to assume since you generally have both stainless and carbon steels, it's easier just to assume that the perimeter maximizes for each so that you don't have to justify values that would give you a lower Fen.

Next slide.

One of the other areas that I wanted to highlight relates to transient occurrence assumptions that the Applicant did not have measured transients for the entire operating period of the plant. They did go back and assess logs, LERs, operating reports, all of the information that they had available to them to come up with transient counts for the period in which they did not have transient counting.

The assumption that they made for this

ten-year period was that for each transient, the transient count was 25 percent of their design basis number. They did go back through the items listed here and were able to demonstrate that that 25 percent assumption was valid for all of the transients. So on that basis, the staff found that that was an acceptable assumption for the Applicant to make.

MEMBER STETKAR: Allen, do you have -- we had a little bit of discussion about this one in the Subcommittee meeting. Do you have a list of the specific transients for which that 25 percent assumption was applied?

MS. REGNER: I'm sorry, we don't. I can give you general numbers.

MEMBER STETKAR: Does the Applicant have a list of the specific transients for which the 25 percent assumption was applied?

MS. REGNER: Mr. Medoff?

MR. MEDOFF: Jim Medoff of the staff. Yes, we were looking at the transients in the application versus the transients in their FSAR and what they're putting down for the values for that, I was marking up which ones we had issues with the 25 percent assumption. So the answer is yes.

MEMBER STETKAR: Do you have a list of the transients for which the 25 percent assumption --

MR. MEDOFF: It should be back in my room. I can get it.

MEMBER STETKAR: Maybe Applicant would have it.

MR. MEDOFF: They have a fairly large contingent here.

MS. REGNER: Yes. The Applicant does.

MR. RADSPINNER: Mark Radspinner, Systems Engineering at Palo Verde. I understand the question is if we have a list of the subset of transients for which the 25 percent assumption was retained?

MEMBER STETKAR: Yes.

MR. RADSPINNER: It's contained within Table LRA 4.3-3 and it's indicated in there which ones --

MEMBER STETKAR: The only thing I have is an interim response to the RAI. So I'm asking you now what are those transients.

MR. RADSPINNER: Okay, there's a list of about 12 --

MEMBER STETKAR: More than six than was available, 14.

MR. RADSPINNER: Yes, approximately 14. Approximately half of those were actually emergency and faulted conditions for which fatigue analyses are not even performed and then the remaining six or seven, most of those are, in fact, all of them are lower significant transients. They're so insignificant generally that there's no way to go back into the records because they would not necessarily be even acknowledged in control room logs.

But by comparison with the subsequent operating history, we were able to demonstrate that those were all very conservative assumptions.

MEMBER STETKAR: The reason I ask this and apparently I'm not going to get the list --

MS. REGNER: You will.

MEMBER STETKAR: -- that I asked for. Let me -- I had to try to guess when I was trying to do this for the Subcommittee meeting which specific transients because I can multiply .25 times a number. And some of those transients, the total number of events are things like 1 or 2. So I was curious how one determines that that assumption of 25 percent is certainly conservative when you're looking at numbers of 1 or 2 in 10 years.

I can understand if you're looking at numbers of 20 or 30 or something like that.

DR. HISER: I think the conclusion was

that 10 of the 14 transients had not occurred, so the 1 or 2 assumption would be conservative. For 2 of them, they were verified to have occurred at less than 5 percent of the design rate, so 25 percent assumption is again conservative. And two were known to have occurred at specific intervals because they were test conditions and that was less than 25 percent.

MEMBER STETKAR: So if I can understand, they had some other way of bounding how big it was not.

DR. HISER: Yes.

MEMBER STETKAR: Okay. Thanks, that helps a little bit. I still would like a list -- that's fine. What you just said helps me a little bit to understand why they couldn't be larger than certain amounts.

DR. HISER: Yes, these are not heat ups and cool downs and trips and things.

MEMBER BANERJEE: I'm sorry, I'm still -- have you finished?

MEMBER STETKAR: Yes.

MEMBER BANERJEE: I'm still back at this fatigue thing. Are there in this system -- the thing about vortices reminded me -- stand pipes where there are vortices that go in and out causing thermal fatigue? Not even stand pipes, but things that come off the main pipe where it dead ends which can lead to a --

MEMBER SHACK: The small diameter pipe where you get the thermally-induced mixing kind of thing I think is what Sanjoy is talking about.

MEMBER BANERJEE: I don't know what it's called, but you know the idea. Larger pipes.

DR. HISER: There are some pipes such as the pressurized surge line which is well studied.

MEMBER SIEBER: That's different than what he's talking about.

DR. HISER: I'm not aware that there's been a lot of consideration of those locations.

MEMBER SIEBER: Generally, the very small-bore things like vents and drains they fail because they're not supported properly as opposed to cycling fatigue and what's in the internals that go on.

MEMBER BANERJEE: I'm just wondering if you took a look at these and any issues related to --

DR. HISER: The calculations that we deal with under metal fatigue are those that have ASME code calculations. So they have cumulative usage factors, based on ASME code. Locations that do not have a fatigue calculation are not addressed by this TLAA on metal fatigue. They would be potentially subject to inspection which is a different management process, if you will.

MEMBER BANERJEE: And how would inspection detect this?

DR. HISER: Use of ultrasonics or things like that would be the -- they would detect cracking that would be -- it would not give you an indication of precursors to macro cracking, but it would be able to detect macro cracks. In general, we would expect with the fatigue calculation that even if you hit a cumulative usage factor of one, that you would only have micro cracks at best and you may have nothing at that point.

MEMBER BANERJEE: And these locations are usually inspectable?

DR. HISER: The instrument lines and things like that, I believe --

MEMBER BANERJEE: I think it would be fairly difficult.

DR. HISER: I'm not aware of inspections that are done at Palo Verde or elsewhere in particular looking at these locations.

MEMBER BANERJEE: So in your view, is this phenomena which is fairly well understood, I think, although Bill probably knows more about this than I do, is this something which is of any concern in the aging of plants?

DR. HISER: I do not believe so for these other locations. There is no operating experience that would indicate that we should be concerned. I believe the ASME code would have addressed those locations in a more quantitative manner if there were concerns in that area.

MEMBER SHACK: I mean you do have a small bore piping program for aging management. This is really meant to address this kind of a problem.

MEMBER BANERJEE: And it's just sort of empirical correlation of some sort?

MEMBER SHACK: They do the inspections. There's also a screening criteria that EPRI has developed to tell you which of these small bore locations might be the most susceptible to this kind of thing. But they don't try to do CFD calculations or --

MEMBER BANERJEE: No, I don't expect they would, but there would be some sort of --

MEMBER SHACK: Right, so they're handled within this program basically under the small bore piping as Allen suggested. It's not the cycle counting, cumulative usage thing you look for. There's industry programs to tell you that these are the locations that are most likely to be it and to focus your attention a little bit.

MEMBER BANERJEE: And then what do you do after that? Suppose you do locate a few of these.

MEMBER SHACK: You have a problem. You fix it.

MEMBER BANERJEE: How do you fix it?

MEMBER SIEBER: You end up with expanded --

MEMBER CORRADINI: You replace it.

MEMBER BANERJEE: So are there any locations here that needed to be addressed?

DR. HISER: None that I'm aware of.

MEMBER BANERJEE: Maybe we should ask the Applicant.

MEMBER SHACK: Small-bore piping program.

DR. HISER: They do have small-bore socket weld and piping inspections that they do.

MEMBER SIEBER: That's done on a percentage basis.

DR. HISER: Yes. I'm not aware that there's --

MEMBER SHACK: But there's a difference

between small-bore and socket welds.

DR. HISER: Yes.

MEMBER SIEBER: Yes, and the fatigue failure might not necessarily be at the socket welds.

DR. HISER: Yes.

MEMBER POWERS: The screening criteria that's developed apparently by EPRI, this is an empirical basis, that is, we've totaled up all of the incidences of unacceptable fatigue and found where they occur?

MEMBER SHACK: No, I think it looks more like where you might have temperature differences between the lines, relative diameters that you might generate, the vortices that penetrate in that give you this kind of thermal fluctuation. It's a kind of a --

MEMBER POWERS: Are there recorded incidences where the screening criteria would say we did not need to be concerned, but in fact, we found that there was?

MEMBER SHACK: I don't know. I assume when they set up the screening criteria that was obviously the thing that you would set up the criteria. Then you would look at all the known data and you fix it. Now whether subsequently you come up with something --

MEMBER POWERS: We have a -- I wouldn't say a dismal record, but we certainly have had incidences where other screening criteria have been applied and we've been surprised. Full assisted corrosion comes to mind. It's one of those areas where we've done empirical things and then subsequently been surprised and learned to augment our empirical database that we were using. I mean that's a painful way to augment that.

MEMBER SHACK: Well, you're augmenting it here because you're doing these inspections and so you will be augmenting your database.

MEMBER BANERJEE: If they're inspectable.

MEMBER SHACK: Yes. You have to inspect a certain sample.

MEMBER BANERJEE: This problem has always concerned me. It sort of goes under the radar screen. The French found this was quite a problem I remember. But you feel -- are you going to look at this, Bill, what they're doing?

MEMBER SHACK: When you brought it up to the AP1000 several years ago, I did go take a look at it at that time, but that's -- I looked at the report and it is the screening criteria. I place more faith in the inspection programs. You use the screening to try to eliminate these things when you have a design basis. You use it to focus the inspections, but basically the inspections start to build your database that gives you the comfort level eventually.

It's a very hard problem to analyze your way out of.

MEMBER BANERJEE: Yes, all right.

DR. HISER: The one point I'd like to make in addition is with the recent revision of the GALL report. We did go through LERs and all the operating experience of a failure in this area would be a reactor coolant pressure boundary breach that has a very high visibility so if there were problems in this area, corrections would have been made to programs and there probably would have been engineer communications to remedy the situation. We're not aware of any. So I think we're satisfied with where the program is at this point.

MEMBER BANERJEE: Let's move on.

DR. HISER: Now the last item here is on cycle-counting. Lisa may have mentioned some of the inconsistencies between UFSAR and tech spec requirements for cycle-counting. The Applicant is committed to update their procedure to include transients that are not currently being counted and also to ensure consistency between their UFSAR and their tech specs. And those are the four main items on metal fatigue open items that I wanted to discuss.

MS. REGNER: Thank you. Moving on, just briefly, the confirmatory items that -- there were five confirmatory items that the staff resolved and prior to the SER with open items, they had been resolved informally. The staff just needed formal closure in the form of docketed correspondence and a review.

The first one, Palo Verde staff identified in their example, so I won't go over that one. The scoping of liquid-filled tanks. The next one is aging management of elastomers. The staff had identified thermoplastics and elastomer-lined carbon steel components that the staff was concerned about erosion in those components. The Applicant submitted information identifying that these components were in the essential spray pond and well water portion of the domestic water systems, therefore, they were not subject to high velocities nor high particulate levels. So erosion was not a concern.

The third, cavitation erosion which the Generic Aging Lessons Learned Report recognizes as an aging effect, requiring management due to operating experience at Palo Verde of a through-wall leak in their infrequently used stainless steel piping and in the HPSI system. Palo Verde, they identified that as cavitation erosion and put this piping on a replacement schedule. So the staff's concern was more associated with the extent of condition review where there may have been other components also susceptible to this aging management effect and we wanted to know more about their extent of condition. And so the Applicant committed to complete their inspections of susceptible piping locations before June of 2012. And if they did note degradation, they would incorporate that into a replacement plan.

MEMBER REMPE: Seven and a half years for replacement, is that just based on well-documented experience and everybody agrees that's the appropriate time frame?

MS. REGNER: They based that -- they did do fairly significant calculation using degradation over an assumed time period, used conservative numbers to come up. And the staff did review that. They did find some nonconservativisms, but still, it was still well within the conservative range, so we did look at their calculation closely.

MEMBER ARMIJO: This was stainless steel

piping, is that correct?

MS. REGNER: Yes. For the HPSI system.

MEMBER ARMIJO: Yes, it seems like this is more of a design problem than a material problem, just replacing the same material with the same design.

MS. REGNER: It is.

MEMBER ARMIJO: Seven and a half years doesn't seem like a good solution.

MS. REGNER: And you know, they did identify it as a design problem. We somewhat disagreed that since there was the time component involved that we considered aging as well. And that's why we looked a little more closely at it. But once they come up with a replacement program, it's basically out of the scope of license renewal. That's why we turned our attention to other susceptible materials and locations that could be susceptible to this aging effect.

MEMBER ARMIJO: Maybe this is for the Palo Verde people, but are they working on a design solution?

MS. REGNER: I believe they are, but I'll let them speak.

MEMBER ARMIJO: Are they saying well, it will wear out every seven years and we'll replace it.

That doesn't sound like a very good approach.

MS. REGNER: Mr. Radspinner?

MR. RADSPINNER: Mark Radspinner, Systems Engineering at Palo Verde. We did look at other alternatives. In this particular case it would take a well-designed control valve, a drag valve that's designed specifically to take a very large pressure drop on a small piece of pipe and not produce any type of incipient cavitation. So we did look at that. But based on the simplicity of the replacement, we went in and replaced it and we were done and we've done conservative projections for what the replacement interval would be and we interjected a halfway inspection, a UT inspection halfway through that first interval and that inspection has occurred, the halfway inspection on Unit 1. And there was no detectable wall loss using ultrasonics. So we would expect that when we do make the replacement in two more operating cycles that we would expect at most, just the very beginning onset of some cavitation.

MEMBER ARMIJO: Okay, thank you.

MS. REGNER: Anything else? Four, steam generator feedring flow accelerated corrosion. Steel feedrings and supports are susceptible to this aging phenomenon and the Applicant confirmed that this steam generator feedring is P-11 steel and therefore FAC resistant. And they also do consider this aging mechanism during their secondary side steam generator degradation assessment which is performed every outage.

The last one, small bore piping which you've seen many times in the past. The Applicant did provide a commitment to inspect ten percent of its Class 1 socket welds for each unit, up to a maximum of 25. And they will use a sample selection methodology to inspect the most susceptible components for significant welds.

MEMBER SIEBER: When are these inspections, small-bore piping inspections and socket and weld inspections to be completed? Is this before the period of extended operation?

MS. REGNER: Correct. That's in the commitment.

MEMBER SIEBER: Okay. And then after that, you go back to ASME?

MS. REGNER: Right. If they identify any issues --

MEMBER SIEBER: Then that expands the sample and takes on a new life.

DR. HISER: Yes. Then it would become a

specific periodic program.

MEMBER SIEBER: Right.

DR. HISER: And generally, ASME would not require inspection of these welds.

MEMBER SIEBER: Right.

MS. REGNER: Lastly, the Applicant covered the other topics of interest identified here. I did want to point out for inaccessible cables they did mention that they increased the scope to low voltage, 480 volts and above. But they did also commit to increasing their cable inspections to yearly and their cable testing to every six years.

MEMBER SIEBER: Does Palo Verde have a history of any cable failures and if so, by what voltage category were they in?

MS. REGNER: I'll let them provide details, but most of their cable failures were connections, rather than the actual cables, but I'll let them give details.

MR. HYPSE: My name is Mark Hypse, Electrical Engineering, Palo Verde. I understand the question is have we had a history of cable failures.

MEMBER SIEBER: Yes, what is your operating experience?

MR. HYPSE: We have not had a history of

cable failures. We have had reported in Generic Letter 2007-01 that we had a couple of cables that failed acceptance criteria during Megger testing. We've also had some medium voltage splices that have failed Megger testing as well, but no actual cable failures.

MEMBER SIEBER: Okay, thank you.

MEMBER BLEY: Well, as Lisa pointed out, she said something about there being connection failures. Is that what --

MEMBER SIEBER: That's not a cable.

MEMBER BLEY: I know it's not.

(Laughter.)

MEMBER BLEY: It seemed to be related.

MR. HYPSE: I think she's referring to the spliced connections in the manholes.

MEMBER BLEY: Okay, thank you.

MS. REGNER: Sorry. And then the last topic that did want to mention, there was one late identified material discrepancy associated with the steam generators that the staff does consider minor and easily resolved. We will use appropriate channels to communicate this resolution with ACRS staff.

Any questions on the other topics of interest?

MEMBER SIEBER: I do have a question. My memory of Arizona and this area is that it's pretty dry. Have you found water in manholes for buried piping with external corrosion? I know that you have cathodic protection on almost, but not all of your piping. Is that a degradation mechanism for your plant, of any real serious importance?

MR. PITTALWALA: My name is Shabir Pittalwala, Underground Piping and Special Projects for Palo Verde. I understand the question to be the presence of water in the ground is it a significant issue for us in terms of corrosion and degradation of buried piping.

We do have a pretty extensive cathodic protection system, so the majority of our underground structures are covered by that cathodic protection system and that does act as a significant preventive measure.

Obviously, the presence of water and chlorides, electrolytes in the soil has -- we've had an operating experience on our fire protection piping where the protective coating on the piping, the wrapping had been abraded away by some sharp rocks in the backfill and that caused corrosion.

On our safety-related piping, we have

looked at that and demonstrated that the wrapping was intact. The backfill material was, of course, sand, fine-grain sand, and we showed that that is in good condition.

We have an inspection program in place now for all of that.

MEMBER SIEBER: Your fire protection piping, what material was that made of? For example, the main protection for the plant, is that a cast-iron piping or --

MR. PITTALWALA: Fire protection piping?

MEMBER SIEBER: Yes.

MR. PITTALWALA: So that was ductile iron piping, but there's about 20,000 linear feet of ductile iron piping. We have replaced 11,000 of the -- of what we considered the most susceptible portion of the piping with fiberglass ring, fiber ring plus plastic piping.

MEMBER SIEBER: Okay, fine. Thank you.

MS. REGNER: Okay, so in conclusion, staff determines that Arizona Public Service Company has met the requirements of 10 CFR 54.29A for the license renewal of Palo Verde Nuclear Generating Station.

Are there any final questions? Thank you for your time.

MEMBER SIEBER: Okay, I would ask the members if they have any questions for the staff or the Applicant at this time? If not, Mr. Chairman, I turn it back to you.

CHAIRMAN ABDEL-KHALIK: Thank you. Our schedule calls for us to reconvene at 10:15 a.m. So given that fact, I'd like for the Committee to utilize its time a little more efficiently. At this time we are in recess. We are off the record.

(Off the record.)

CHAIRMAN ABDEL-KHALIK: We're back in session.

At this time, we will consider the next item on the agenda, Final Safety Evaluation Report Associated with the Virgil C. Summer Units 2 and 3 Combined License Application. And Mr. Ray will lead us through this discussion.

MEMBER RAY: Thank you, Mr. Chairman. I believe I am correct in saying this is our first experience in what we will know increasingly as a SCOLA or subsequent combined license application. So there are some aspects to it that may be a little different.

Also in this case, we are dealing with a site unlike Vogtle's where there is no early site permit. And those of you who recall our recent review in Vogtle, which is the reference combined license for the AP1000, this will be different in that regard and will be focused. And we will begin this morning discussing the site related matters, specifically geology and seismology.

You may recall that in the case of Vogtle, we were dealing with COLA which referenced an amendment to the Design Certification for the AP1000 that had not yet been approved. Well now we will be dealing with the subsequent COLA that uses standard content in the reference COLA, which also has not yet been approved.

So we are dealing with things in parallel there. I believe we last time when through the mechanism by which these things all do get reconciled at the end of the day. But we do have in our Vogtle letter and I expect we may have in this letter as well, a reminder to the staff to let us know if anything changes as a result of the reference documents being finalized.

The subcommittee met in July 2010 and again in January of this year to review Summer and we are prepared to present it to the full committee here with the anticipation that we may be able to get a letter out from the full committee this session; if not, the next one I would expect, but we will see.

With that, let me ask Frank if the staff has any comments they would like to make.

MR. AKSTULEWICZ: This is Frank Akstulewicz from the staff. I have no opening remarks to make. Again, thanks to the committee for working with us to complete these reviews in a timely manner.

MEMBER RAY: Okay, Al, it's up to you.

MR. PAGLIA: Okay. Well, good morning Mr. Chairman and the committee members. I am Al Paglia, manager of licensing for VC Summer, their nuclear department. I certainly appreciate the opportunity to present to the committee this morning the final aspects of our COLA for the 2 AP1000 unit. Our team is ready to discuss the agenda items and answer any questions you may have.

As we mentioned before, we made significant progress in preparing the site for nuclear construction. Mr. Bob Whorton will begin today with an overview of the site and the status of the preconstruction activities.

So, if there are no further questions, I will turn it over to Mr. Whorton.

MR. WHORTON: Good morning. Before we get started, could we go and take mute off so we can get a roll call of some of our call-in attendees? I would like to know who would be on the phone. Is that acceptable?

MEMBER RAY: Okay, let's see. Let's take a minute to arrange for that.

MR. WHORTON: I think the staff also has some members that are calling in.

MR. SEBROSKY: Yes.

MEMBER RAY: From the Region?

MR. SEBROSKY: No, they are out at a conference on the West Coast. Dr. Cliff Munson and Dr. Gerry Stirewall.

MEMBER RAY: Well?

MR. LINDVALL: Can you hear us?

MEMBER RAY: We can now, yes.

MR. LINDVALL: All right. Yes, you are right. Scott Lindvall, Fugro WLA and Joe Litehiser, Bechtel are here on behalf of Summer. And I will let the rest of the folks speak for themselves.

DR. MUNSON: Cliff Munson from the staff.

DR. STIREWALL: Good morning. Gerry Stirewall from the NRC staff also.

MR. McGREGOR: This is Jim McGregor from the Shaw Group on the Summer project.

MR. LIPPARD: Lars Lippard from the Shaw Group on the VC Summer project.

MR. WHORTON: Do we have Robin McGuire on the line?

MR. LINDVALL: I don't think so yet. He is, as you know, in San Diego. He is available if we need him, you might want to give him a shout on the cell phone.

MR. WHORTON: Okay, and Dave Fenster, I believe, another Bechtel attendee?

MR. WHORTON: Okay, that's good.

MEMBER RAY: Okay now I think normally we will keep this on mute or listen only and you will have to ask us to take it off, if you need input from these folks.

So let's return to that mode and you can continue.

MR. WHORTON: Very good. Thank you.

I was involved in the original licensing, construction, engineering and operation ends of the Unit 1 project and have been part of the original team for the siting, layout, design and construction of Units 2 and 3.

The Summer site is located in the central portion of South Carolina, approximately 26 miles northwest of Columbia, the state capital. Units 2 and 3 are located approximately one mile southwest of Unit 1 in Monticello Reservoir and approximately one mile east of the Parr Reservoir Broad River drainage system.

The next view I thought would be of interest again to bring back a 2007 aerial photo of the site area. And you can see in the center where Units 2 and 3 are to be constructed. To the north is Unit 1 and also Monticello Reservoir to the north.

The terrain of the area as you can maybe make out from the photo here is gently rolling hills with local relief to the streams and the Broad River to the west.

We have a satellite view from October of 2010 and this frame captures an area of approximately two square miles; two miles by two miles. The table top for Unit 2/3 construction is shown in the center and represents the plant site at a nominal elevation of 400 feet above sea level. Unit 1 and Monticello Reservoir are again located to the north of the construction site and a substation for Units 2 and 3 is shown to the west of the table top area. Parr Reservoir is also shown to the far left, which is also a part of the Broad River drainage system.

MEMBER RAY: Bob, would you outline the rail line?

MR. WHORTON: We have got the cursor going along it. It parallels the river on the east side of the Broad River Parr Reservoir system. So that rail line is approximately one mile to the west of the construction site.

MEMBER RAY: And elevation differences?

MR. WHORTON: The site elevation will be established at 400 feet. The river, I believe, is nominally like 266,130 some-odd feet long.

MEMBER RAY: So there is a drop to the west of the site.

MR. WHORTON: Correct.

And the next photo, it is a little closer satellite view of the table top construction area. And we will just point out a few features.

The Unit 2 power block excavation is shown; the foundation installation for the heavy lift derrick, which is the main crane for lifting modular components into the construction site; the modular assembly building, which is where a fabrication of most of the large modules will take place; and then off to the left or to the west is the Chicago Bridge and Iron lay down pad area, which is where the head assemblies will be assembled.

After achieving our nominal plant grade for the site table top at elevation 400, excavation --

MEMBER RAY: I'm trying to get it on listen only but we haven't succeeded yet.

MEMBER BROWN: -- of the Unit 2 power block area commenced.

A temporary soldier power retaining wall system was installed with geologic mapping of the vertical walls and floor in approximately five to six foot increments, prior to placement of the wooden lagging for safety on the sheet piles.

This is a northeast view across the Unit 2 power block excavation showing the second and third excavation lifts which were underway at that time. The vertical piles are spaced approximately eight to ten feet apart. Each panel section of each lift is then geologically mapped using GPS survey and photographs. And then all of the recorded results are digitally stitched together to provide a panoramic view of the record of the excavation. And our purpose here is to capture all of the geological evidence of the excavation prior to reaching the foundation rock level.

Now again back to our satellite view from

October of 2010, this is the Unit 2 excavation, showing the top surface of rock as was found. We had removed all of the upper soil materials.

And the next view is a more recent January 2011 view of the Unit 2 nuclear island excavation after some of the initial blasting had taken place. And you will note that the backhoe is sitting on sound rock at a nominal elevation now of 357 feet, above which filled concrete will be placed for nuclear island. The sound rock slopes downwards in the foreground towards the rubble and blast mats as is being shown.

MEMBER SIEBER: Will there be construction in the rubble area?

MR. WHORTON: Yes. We will continue to -- we are in the process of continually tracking the rock down at that slope into the foreground. And so we are going to achieve sound rock in that area. All of that will be cleaned up.

MEMBER SIEBER: Okay. And what are you going to put in there, select fill or --

MR. WHORTON: No. For the nuclear island, it will be a concrete fill material, high strength concrete fill material.

MEMBER SIEBER: Oh, okay. There is going

to be a lot of it.

MR. WHORTON: Quite a lot for the nuclear island. And for the other associated structures, the turbine building, rad waste, and the annex building, those will be founded on an engineered backfill, which is being imported into the site. And I will cover some of those aspects a little later here.

MEMBER SIEBER: Will you use Franki piles or equivalent any place to get support from bedrock in the filled areas?

MR. WHORTON: No, the compacted fill is like a crushed rock granular fill that will have adequate bearing capacity without and it will be directly on top of rock. And it is coming from locally?

MR. WHORTON: Locally a quarry in the vicinity.

MEMBER SIEBER: Okay and you are going to process that prior to using it as fill.

MR. WHORTON: That is correct.

MEMBER SIEBER: Okay, thank you.

MR. WHORTON: Yes, we will have a gradation and all the other parameters necessary.

For Chapter 2.5 of the SAR, a team of SCE&G and Bechtel pulled together the COLA application and FSAR. And we used a number of different subcontractors; William Lettis and Associates mainly for the Geology and Seismic and Geotech Association, Risk Engineering were on the seismic side; Mactec was our local contractor that did all the geotechnic investigations; and the results and evaluations were reviewed by an expert panel which we call the Seismic Technical Advisory Group.

Now the Seismic TAG, Technical Advisory Group consisted of experts familiar to the committee members. We had Dr. Martin Chapman from Virginia Tech; the late Dr. Allin Cornell from Stanford University; Dr. Robert Kennedy, a consultant; Mr. Don Moore from Southern Company, he was very knowledgeable from the Vogtle application; and Dr. Carl Stepp, also a consultant.

Now this group provided technical oversight to ensure consistency of the evaluations meeting regulatory guidance. They worked with industry to ensure consistency among the ESP and COL applications that were ongoing at the time and provided a written endorsement of the Summer Units 2 and 3 results, which were attached also as part of our application, one of the appendices.

Briefly reviewing Sections 2.5.1 and 2.5.3

on geologic and siting information, in accordance with the regulatory guidance, geologic maps were prepared for a 200-mile radius, a 25-mile radius, 5-mile radius, and 0.6-mile radius. And using these results, along with the geologic and geotechnic evaluations, including the soil and rock borings, the Unit 2/3 site foundation was defined as sound rock, which obviously is different from the Vogtle application of being a soil site.

In addition, the Unit 1 geologic mapping and studies from 1974 were also incorporated into the current evaluations. This is a sketch of the excavation foundation map and the Unit 1 area is shown on the right side. A second unit was excavated on the left side but it was never constructed. So there is only one unit at the existing site.

Small bedrock shears were mapped in the excavation for Unit 1 and after extensive evaluations and age dating through various processes, the minor features were demonstrated to have last moved between 300 million and 45 million years ago. So therefore, it was concluded that the minor bedrock shears would exist throughout the site area but they did not represent a surface rupture hazard.

A view from 1973 of the Unit 1 excavation, this is a northeasterly view, shows one of the shear fractures running across the rock surface. The next slide is a reverse view of that same shear zone and it also crosses the Unit 1 site area. So when we are talking about shear zones, that is what they look like physically in the site area.

Consistent with results at the Unit 1 investigation, it was expected that the Unit 2 and 3 excavation would expose similar shear features and in fact a few minor ones have now been observed as part of the excavation and mapping. These shears are consistent, however, with our expectations and have not exhibited any features or concerns which would suggest movement more recent than the previously documented 45 million to 300 million year age.

The Unit 2/3 excavations are being geologically mapped with results being documented and reviewed by the NRC staff. An initial visit to the site area occurred in August of 2010 and that is when we had initially exposed the surface of the rock. And then one is planned again for March 2011, which is a time frame we are expecting to have completed the blasting of the nuclear island and cleanup to an adequate presentation for the NRC staff to be able to visually see the entire nuclear island rock surface.

The staff in Region 2 had also visited the site earlier in the '06-'07 time frame during the development of our COL to observe the initial geologic and geotechnic investigations, which were ongoing at that time.

So therefore, in summary, we have not identified any new data to change our current interpretations and, therefore, conclude that the shear features are not capable tectonic sources.

Moving on to Vibratory Ground Motion under Section 2.5.2, our seismic hazard evaluation incorporated updated seismicity catalogues. Our probabilistic seismic hazard analysis replicated the EPRI 1989 hazard results, evaluated effects of the updated seismicity, updated the Charleston, South Carolina seismic source zones, developed seismic hazard and Uniform Hazard Response Spectrum for hard rock, and then developed vertical to horizontal ratios, and finally the ground motion response spectra, which is the design spectra for the site.

As part of the evaluation, three seismic source areas where we evaluated the effects of the additional seismicity. This was standard among all the ESP and COL applications. Four geometries were used for the updated Charleston seismic source hazard model. It has a summary of the VC Summer seismic source model. No new capable tectonic sources were identified within the site region. No modifications to the eastern Tennessee seismic zone were required. The updated Charleston model replaced the EPRI sources, as was adopted in the Vogtle application. And the new Madrid, Missouri seismic source zone was added, which was adopted from the Clinton characterization.

From all of these evaluations, peak ground acceleration seismic hazard curves were developed, followed by development of uniform hazard response spectra. And finally, we developed the ground motion response spectra, horizontal and vertical, using approaches described in Regulatory Guide 1.208 and the ASCE Standard 4305.

So we are looking at a comparison of the various spectra here, which was presented back in January by the staff. And then comparing the spectra, the blue dashed line represents the Summer Units 2 and 3 ground motion response spectra, which you can see is bounded by the solid black line, which is the AP1000 generic hard rock high frequency spectra. The red line in the background is the AP1000 certified seismic design response spectra, which is basically a replication of the Reg Guide 1.60 spectra with some minor tweaks made to it.

As we had developed our GMRS, the ground motion response spectra, you can see that there are exceedances above the red line or the certified seismic design. The three sites that were currently ongoing evaluation at the time, Bellefonte, Lee and Summer all developed GMRS.

And so recognizing that each site had very similar looking spectra for their GMRS, Westinghouse enveloped three sites, Bellefonte, Lee and Summer, and then added approximately a two percent margin to that spectra to develop the HRHF, the hard rock high frequency and then pursued evaluation of the HRHF exceeding their certified design.

Over a three-year process this review occurred, many tech reports were developed by Westinghouse and the conclusions by both Westinghouse and the NRC staff are that these high frequency exceedances are non-damaging.

MEMBER RAY: This is an important point that Bob is making now.

MEMBER CORRADINI: Can you repeat it then so I am clear about it?

You said you took a few steps in the last

-- The conclusion is what I was trying to -- Can you repeat it please?

MR. WHORTON: Yes. There is an exceedance at high frequency of the certified design. And in light of the applications that were going forward, Summer, Belefonte and Lee, all three sites had a very similar looking GMRS. So there was exceedance. So Westinghouse then enveloped those three sites, added a little margin to them, two percent or so, and developed the black curve or the HRHF, that curve.

Then Westinghouse did a generic evaluation against structures, key structures, systems and components to ensure that the demand did not exceed the capacity. And that was documented through a whole series of generic tech reports, which were also put into the DCD, the AP1000 DCD.

MEMBER CORRADINI: The revised, the amended DCD.

MEMBER RAY: Yes. In other words, for a hard rock site, the certified design is the curve, --

MEMBER CORRADINI: Yes, I got it.

MEMBER RAY: -- in essence.

MR. WHORTON: Correct.

MEMBER SHACK: Or it will be.

MEMBER RAY: I used the present tense when in fact I should be saying the future tense often, but we all understand.

MEMBER BROWN: Can I ask one question? I was at the meeting but I just need you to reemphasize something.

So the black curve, Westinghouse analyzed that, even though it was outside their design spectrum of the red curve and found that the structures were adequate under the response, the ground motions.

MR. WHORTON: The additional response.

MEMBER BROWN: The black curve.

MR. WHORTON: Correct. That is correct.

MEMBER BROWN: So I mean, to put it another way, the red curve could be changed for this site, to say you meet the requirements now. I am not saying you do that. I am just saying that they evaluated the differences and the variance in sound it was satisfactory as is, without changing the design.

MR. WHORTON: That is correct. So there are actually two design curves now. And they are treated independently because they, in the analyses, high frequency is treated a little differently from the low frequency and you can't just envelope both of the two curves to do the analysis.

MEMBER BANERJEE: So it is either the red or the black?

MR. WHORTON: Yes, that is correct.

And as you can see, the Summer GMRS is bounded by either the red or the black.

MEMBER BANERJEE: Right.

MEMBER RAY: Well, the exceedance is in the high frequency area and that is the important point.

MR. WHORTON: If there are no further questions, we will move on then to the geotechnical characterization, Section 2.5.4.

The foundation site profile at Units 2 and 3 consist of five layers. The upper surface layer of soils is called residual soil in our area and it is basically a reddish clay-type material. It is the upper range of soil.

Below that is a layer of material that we call saprolite, which is a completely weathered rock but it still retains some of the structure of rock and it is mainly silty sands in composition. It is more yellow silty sand looking.

Below that is when you start encountering the partially weathered rock. Below that is the moderately weathered rock and then finally sound rock.

So for the nuclear island again, we are

going to the sound rock layer for the nuclear island. We will achieve a minimum of sound rock or moderately weathered rock below the other power block structures.

MEMBER SIEBER: That is sort of similar to the Vogtle site, at least in the upper layers.

MR. WHORTON: I believe they are considerably different from Vogtle. Vogtle is more in a sandy region there. Their overburden material is over a thousand feet.

MEMBER SIEBER: Right.

MR. WHORTON: Okay.

MEMBER SIEBER: And what is the overburden layer here for Summer?

MR. WHORTON: Summer, the residual soil is typically 20 to 30 feet. The saprolite is, again, 20 to 30 feet and then you start encountering the rock.

MEMBER SIEBER: Okay.

MR. WHORTON: The rock, nominally, is 50 or so feet below ground surface and it typically follows the rolling terrain of the area.

MEMBER SIEBER: And so the bedrock is buckled.

MR. WHORTON: Yes.

MEMBER SIEBER: Okay.

MR. WHORTON: And from the photos I showed on Unit 1, you could see that pretty clearly.

MEMBER SIEBER: Yes, I gathered that.

MR. WHORTON: Unfortunately it is not a flat, smooth surface that we encountered.

From the Geotech evaluations, as we mentioned, Unit 2 and 3 is defined as a hard rock site. And what this graph shows you here is the average shear wave velocity for Unit 2 on the left and Unit 3 on the right. And of note, the horizontal green line represents the average shear wave velocity at our foundation level, 357. If you recall from the earlier photo, I said the track hoe was sitting at 357. So at that layer, you can see that we are generally above the 8,000 feet per second shear wave velocity, which is also consistent with the AP1000 foundation design assumptions that were used from their DCD.

And finally as part of the developing Section 2.5, we needed to evaluate liquefaction potential for the site. The nuclear island, as I have mentioned, is on sound rock or on concrete.

MEMBER POWERS: Must have been a tough evaluation.

MR. WHORTON: Yes, it was. I had earlier

mentioned also the other power block structures, including the Seismic Category II Annex Building portion and the Turbine Building First Bay, which is also Seismic Category II are being founded on a compacted engineered backfill being imported to the site because we did find out that the residual and saprolite materials were not really good foundation materials. And so therefore, there is no saprolite or residual soils in the zone of influence for loading of any of the power block structures.

So our final conclusion is liquefaction cannot impact plant safety.

MEMBER SIEBER: Where are you getting the backfill from?

MR. WHORTON: A quarry exists in the area about 20 miles south of our site and they make riprap and gravel and stone and everything. So this is the byproduct of the crushing operations.

MEMBER SIEBER: Okay.

MR. WHORTON: So it is a crushed, granitic-type material.

MEMBER SIEBER: Okay.

MR. WHORTON: So therefore, I guess if there are any further comments on this --

MEMBER STETKAR: Bob, I didn't sit in on

any of the subcommittee meetings on pretty much, back when you said you did probabilistic seismic hazard analysis, you said you replicated the '89 EPRI hazard results and evaluated effects of updated seismicity. Did this updated seismicity analyses account for the, I think it is, 2008 USGS seismic hazard maps?

MR. WHORTON: The basic answer is no because our COLA went in prior to the USGS 2008 study being completed.

Now, the staff --

MEMBER RAY: The staff did it and they will speak to that.

MEMBER STETKAR: Okay, thanks.

MR. WHORTON: And staff did discuss that at the subcommittee meeting.

MEMBER STETKAR: Thanks. Sorry, I wasn't there.

MEMBER RAY: It's all right.

MR. WHORTON: Okay, that is from Summer, that is our presentation. Any further questions?

MR. SEBROSKY: Mr. Ray, we would like to take the phone off mute, if we could so that Gerry, Dr. Stirewall can do a portion of this presentation. If it doesn't work out, then we are prepared to try to do the presentation from here. But we can start the presentation while the phone is being taken off mute.

MEMBER RAY: All right, let's take it off mute then and ask everybody to try and be as quiet as they possibly can while one of the participants makes input to the meeting here.

MR. SEBROSKY: You should have them mute their phones.

MEMBER RAY: Well, if you -- Yes.

MEMBER CORRADINI: They should be able to do it on their end.

MEMBER RAY: They should be. However, that often results in people hanging up and then calling back again.

DR. STIREWALL: So are we ready for a little touch of geology then?

MEMBER RAY: That's up to Joe.

MR. SEBROSKY: My name is Joe Sebrosky. I am the lead project manager for the Summer COL Safety Review. To my right is Dr. Yong Li and on the phone is Dr. Cliff Munson and Dr. Gerry Stirewall.

The first part of this presentation, Dr. Li is going to present. The latter part of the presentation, Dr. Stirewall is going to present.

MEMBER RYAN: Joe, could you just move that microphone in front of you, please?

MR. SEBROSKY: Sorry. Gerry we are on slide three now.

DR. LI: Okay. We are taking this opportunity to present the two topics which are key issues originating from the Section 2.5 review. Actually more specifically, one is related to seismology section; one is related to the geology section.

So the first issue actually originated from concern from Dr. Hines during the subcommittee. He is concerned about the applicant did not compare the USGS model with 2008, which is updated version in relation to the 2002 version. That is a concern here.

And the second topic we are going to present here is the field observation by NRC geologists for the requirement of license condition addressed in 2.5.1, who observed during the excavation about any existence of the table tectonics beneath the Category I structure.

So as I mentioned, the applicant compared the EPRI source model with USGS 2002 version but not compare it with 2008 version at the time when they prepared the application. So let me just give you a little bit background about USGS seismic hazard mapping project.

The USGS hazard mapping is targeting at the building codes for the purpose of -- for the building codes purpose. They serve as basis for people planning their construction. For example, school building, residential building, and the government buildings. So they are targeting at the relative shorter term period, which is normally 500 years and 2,500 years ground motion level.

So normally they update the map every six years, normally. That is a basic features of the USGS mapping project.

And another feature we did not address here is that they use a different approach as NRC endorsed.

So, but NRC Regulatory 1.208 is a basic guidance document followed by applicant and also by NRC staff, of course. It specifies that the minimum ground motion level required for the critical facility as nuclear power plant in this case, has to be 1,000 years to define the sit SSE or safe shutdown earthquake ground motion.

So it also recommends in this regulatory guide that applicant use EPRI or Lawrence Livermore National Lab model as the starting point to address the seismic hazard. Of course, they have to incorporate all the updates since then.

MEMBER ARMIJO: You said one thousand years and you chart says ten thousand years.

DR. LI: Ten thousand years. Sorry.

MEMBER ARMIJO: Okay.

DR. LI: Yes, it is 10,000 years.

And also it recommends to compare with any updated model, not necessarily just USGS. Any relating model in that particular area. If there is, you know, any new development or update, you have to address those in your application process.

So such as, if there is a source, the manuals change, you have to address that, or recurrent interim period, you have to address that, too.

So next please. Yes, in this case, in the USGS 2002 seismic hazard mapping project, they use a single maximum magnitude of 7.5 to address whole background source for that particular area. So it is 7.5, was the magnitude 7.5.

And EPRI developed many specific source models. Basically we call them tectonic-specific, which have a maximum M_{max} ranging from M5 to M7, a slight difference on USGS.

And for the major source which contribute to the site significantly, that is the Charleston source, which had an earthquake in 1886 with a magnitude of seven something. So in that particular source, USGS defined as magnitude 7.2 versus applicant's or EPRI's model 7.1, which is the weighted average in this case. And in the return period, a recurrence interval of 550 years from the USGS and 630 years from the EPRI. And also EPRI source geometry is more detailed. As I mentioned before, it is tectonic-specific because they set up different groups individually, starting the source characteristics based on lots of different information, such as geology, seismology, and other geotechnical information. Next please.

This figure outlines the information for this area approximately with 200 miles radius. That radius circle there is 200 miles radius. The center of the circle is the site. The red star indicates the site.

You see the contour line on this map here, the red at the bottom there, that is the center of maybe it is energy center for the Charleston earthquake, which the earthquake that occurred in 1886. All the evidence pointing to that particular location as where the earthquake energy focused.

So the confine is the intensity of ten

around that red area and then moving away, it is decreased to around six or seven at the site. And there is also other evidence such as the liquefaction evidence on this figure, which indicated by a different diamonds and different color triangular shape there.

And other evidence indicated here is the red line in the offshore. That is some active faults which was found to correlate with recent seismicity there. So that is basic evidence.

So no matter USGS applicant they based on those basic evidence to define their seismic source.

The blue box, the big box, it is the USGS's outline for the Charleston source. And that also in parallel to the black rectangular shape, those are USGS sources defined in their 2002 seismic hazard mapping project. Next please.

MEMBER POWERS: Let me ask you one question about this slide. All your liquefaction evidence is online. How do you know that the epicenter is not in the ocean and that what you are calling on the contour of ten is in fact attenuated in the maximum of the actual earthquake?

DR. LI: That is a good question I should say. Basically you are questioning the liquefaction evidence was mostly found on the land. You are missing the offshore part. Right? How do you determine --

MEMBER POWERS: Yes, you are not going to be able to get liquefaction evidence offshore.

DR. LI: Yes, but in the paleoliquefaction stories, there is some information which can enhance your analysis with regard to the determination of the so-called energy center. Because the intensity of liquefaction, you know, for example in this case, you found a lot of recent liquefaction evidence concentrated around where the Charleston, where the intensity ten is. And also the geometry of the size of the liquefaction so-called sand blows, they decrease relative with as you move away from the energy center. So all those evidence combined together, plus the current micro-seismicity we can call them, so all those information added together to help people to decide where the 1886 epicenter or energy center is.

DR. MUNSON: If I might add something. This is Cliff Munson from the NRC staff. We are not really -- We are not sure where the earthquake occurred, which is why the USGS and both EPRI, which you will see on the next slide, draw a big large source zone boundaries around the Charleston area. That reflects our uncertainty as to where the earthquake actually occurred.

MEMBER POWERS: It seems to me that the problem, one of many problems with liquefaction evidence is that it is always an incomplete dataset. If you have three more geology students, you will three more points up there in the course of a Ph.D. thesis.

Micro-seismicity on the other hand, seems like it would be very useful data for pinpointing the center. What is the micro-seismicity database that you have to work with?

DR. LI: What years? Sorry.

MEMBER POWERS: What is? I mean, how big of a micro-seismicity database do you have and how does it get analyzed?

DR. LI: We have regional seismic network which recorded all the latest seismicity from different magnitudes. That is called micro-seismicity. Relatively those magnitudes are relatively small. That is why we call it --

MEMBER POWERS: Yes, they are tiny little things but they clearly point toward an epicenter of seismic activity. I mean, how do they get analyzed and what do they point to?

DR. LI: They are more concentrated where the intensity ten is. That is what I meant.

MR. WHORTON: This is Bob Whorton again. For Unit 1, we did extensive studies back in the '70s on the Charleston earthquake. And a couple of things --

MEMBER POWERS: You and half the world.

MR. WHORTON: Exactly. The most intense shaking actually occurred in a town called, near Summerville, South Carolina, which is about 20 miles inland. So that was the more severe shaking. And that is why the circle is drawn basically centered around the Summerville area. It is called the Charleston Earthquake.

MEMBER POWERS: I bet you I can find academic papers that have an offshore epicenter on there.

MR. WHORTON: And you are exactly right. There were many papers written that had different hypotheses. Now I am very familiar with the work that Dr. Talwani from the University of South Carolina did and he was looking at two intersecting faults that are in the region of Summerville. And he plotted the micro-seismic activity along those to help describe and define the two intersecting faults. So his theory was that there was a cause mechanism for the Charleston area.

But again, there are many hypotheses on the cause.

MEMBER POWERS: You are not the first to come and talk about the Charleston Earthquake with us, as surprising as that may be to you. And we have seen lots and lots of liquefaction evidence but we never see this micro-seismicity which seems to me to be much more likely to refine these uncertainty diagrams. I mean, these are consequential things. I mean you are lucky because of you hard rock site, if you had Vogtle site where you star is right now, we would be debating these uncertainty bounds a lot.

I am just wondering why we don't see more of the micro-seismicity.

DR. MUNSON: Dr. Powers, this Cliff Munson --

MEMBER POWERS: Yes, Cliff.

DR. MUNSON: -- from the staff. The applicants are required to develop an extensive earthquake catalogue as part of their seismic characterization. So they take all the earthquakes all the way down to magnitude three and map all those earthquakes and use those earthquakes to characterize the seismic source. So they so use the micro-seismic activity.

MEMBER POWERS: That's great, Cliff. How come you guys don't?

DR. MUNSON: Excuse me? I didn't quite get that.

MEMBER POWERS: Well, the emphasis that is placed always on the liquefaction data that I am questioning a little bit here with Charleston, that the micro-seismicity seems to me that is much more likely to point to an epicenter of seismic activity than plotting contours of liquefaction because the liquefaction database is always incomplete. It is guaranteed to be incomplete because certain liquefaction spots are going to be removed by human activity. Certain ones are never going to be discovered because they are obscured, there are a bunch of trees in the way. Get rid of those trees, we can see this stuff easier.

DR. MUNSON: If I --

MEMBER POWERS: The micro-seismicity as an ongoing thing tells you something.

DR. MUNSON: In fact, those contours that you see on that plot are not liquefaction contours.

Those are damage contours from the Charleston Earthquake in 1886. And I would say that the applicant equally uses micro-seismic activity as well as liquefaction to try to draw their source zone boundaries. In fact, if you look at the next slide, which is actually the updated EPRI source model for Charleston, you will see that the applicant has quite an extensive number of source zones to try to capture the uncertainty in where Charleston was located.

MEMBER RAY: Anything more, Dana?

MEMBER POWERS: No.

MEMBER RAY: Okay.

MEMBER POWERS: I have had my fun.

MEMBER RAY: Proceed, Joe.

MR. SEBROSKY: Slide seven.

MEMBER RAY: Go ahead.

DR. LI: Okay. This figure indicates the EPRI source calculation which also use a rectangular box defined the seismic source for this area. It is quite similar to the USGS model, I would say. Next, please.

So the 2008, in 2008 USGS update their seismic hazard map in comparison to 2002. So here are some highlights some of the updates there.

The maximum magnitude was changed. It was replaced by multiple values with respect to a single value. It was 7.5 before; now it is 7.1 to 7.7. And also they updated the ground motion attenuation models using the latest ground motion attenuation models. And the Charleston seismic source was enlarged offshore actually a little bit away from the 2002 center.

So the overall, the most important thing here is that 2008 hazard results is 10 to 15 percent lower in comparison USGS 2002 model for the CEUS. This was addressed in the USGS Open File Report 2008-1128.

And staff addressed this update issue in the next version of the SER.

MEMBER BLEY: When you say 10 to 15 percent lower, what is lower?

DR. LI: Lower means that is the ground motion, and your probability of exceedance with the --

MEMBER BLEY: But the frequency of a particular acceleration is lower by 10 to 15 percent.

DR. LI: Right. Yes, that 10 to 15 percent --

MEMBER BLEY: Applies to the frequency for a given acceleration.

DR. LI: And your probability of

exceedance level is lower. Yes, in this case 10 to 15 is for the one hertz and it actually was even lower for the PGA, which is 25 to 30 percent, if I remember correctly.

MEMBER BLEY: So this is for the one hertz.

DR. LI: Yes, only one hertz, yes.

MEMBER BLEY: Thank you.

MEMBER STETKAR: Yong, it may be lower than the 2002 but I just plotted out the 2008 USGS seismic for the coordinates of the site. And at a 10,000 year recurrent frequency, it gives me a mean peak ground acceleration of about 0.43 g. So that is notably different, regardless of what 2008 is to 2002, it is a measurable difference.

So I was curious when you say you are going to update the summary SER, when are you going to do that?

DR. LI: The updated summary SER which is what I meant here is to address this comparison issue.

MEMBER STETKAR: Okay.

DR. LI: So you say it is 0.43 g PGA?

MEMBER STETKAR: Yes, well it is roughly. Yes, it is, you know, the seismic hazard maps that you can download only give you point values that they say are supposed to be mean. And I have got to interpolate between points here and I am not doing my interpolation. But is somewhere between about 0.42 g and about 0.44 g at a 10,000 year recurrence interval.

DR. LI: Yes.

MEMBER STETKAR: You know, and you can talk about 10 or 15 percent, but that is still a measurable difference. I might be off a little bit in my plot here.

DR. LI: Yes, a general practice endorsed by NRC in 2008 1.208 is to compare the USGS sources with the source that they adopt in their application. In this case, they compared a USGS source model.

MEMBER STETKAR: I understand that.

DR. LI: Specifically, area sources or point sources but not compare the final hazard result.

MEMBER STETKAR: Why wouldn't you compare the final -- yes, okay.

DR. LI: Because as I mentioned, the USGS hazard modeling, actually I mentioned this in previous slide, is targeting at short early term period and it has served the purpose for building codes.

MEMBER STETKAR: Well does that mean you totally disregard it? I mean, it goes out to about a 2.1 g, you know, peak ground acceleration. And of course there is uncertainty out at that level. But you totally disregard it for higher return periods or lower frequencies because they don't know about geology out in those return periods? I mean, I don't understand.

DR. LI: It is not totally disregard it at all. It was totally considered but from the seismic source calculation part. Your maximum magnitude, your area source geometry and your return period. From those perspectives, you have to fully consider what the others have done in this area.

So that is the staff position addressing 1.208.

MEMBER STETKAR: Okay, thanks. You can go on.

MEMBER RAY: Well if you followed that, you are doing better than I am.

MEMBER STETKAR: No, I don't because I tend to think of seismic hazard as a frequency of occurrence, with some uncertainty, as a function of acceleration.

MEMBER RAY: The earthquake for this site has a PGA of 0.2 something horizontal. Now, it sounds like what you are saying John is in conflict with that.

MEMBER STETKAR: What I am saying is that according to the USGS seismic hazard map for these geologic coordinates, a 10,000 year recurrence period corresponds to about a 2.43 peak ground acceleration.

MEMBER RAY: Yes, which sounds inconsistent with what I said, you would think.

So the question I think you are asking is how do you --

MEMBER STETKAR: My question is how did --

MEMBER RAY: -- reconcile --

MEMBER STETKAR: -- people reconcile that.

MEMBER RAY: That's right.

MEMBER STETKAR: On a seismic --

MEMBER RAY: And I didn't understand the answer.

MEMBER STETKAR: -- hazard, not characterization of sources.

MEMBER RAY: Yes. I don't know that we have time to examine that. It seems like a good question to me but I don't know.

MEMBER STETKAR: And I will admit, I am certainly not a seismic expert but I plot out curves and I look at different pieces of information and see where the different estimates come, you know, to try to estimate uncertainties. But this seems to be a different, a large enough difference that I am not sure how it was reconciled.

MEMBER RAY: Nor am I.

MEMBER STETKAR: And I don't want to -- You know, we are relatively short on time so, Harold, keep going.

MEMBER RAY: Okay but I don't mean to slight the question, John. It is not something I can answer, though. And I am not sure I hear anybody else answering it either.

MR. SEBROSKY: Can we try taking him off mute one more time?

MEMBER RAY: Yes, please. Peter, I am sure there are people out there who are striving to communicate with us.

MEMBER STETKAR: They mentioned Robin McGuire's name was on the line.

DR. MUNSON: Hello? This is Cliff Munson. Am I on the line?

MEMBER RAY: Yes, you are. Can you answer the question, then?

DR. MUNSON: Yes. Yes, we specifically, following our regulatory guidance, we used, we recommend specified use of EPRI or Livermore as a starting point and then the applicants are required to update. We do not, applicants are not required to look at USGS hazard maps and make comparisons to their hazard curves. What we tried to show in a couple of slides preceding is that the USGS is for building codes and standards and not for critical facilities. They do not do the same PSHA that we do for citing critical facilities.

So the rigor, the expert elicitation methodology, the consideration of uncertainty, it is all different than what we require.

MEMBER RAY: Okay, that is sort of a statement of fact. Can you give us any brief, very brief rationalization of why that is okay?

DR. MUNSON: For the purposes I just stated. They look at return periods that focus from 500 to 2,500 years. We require 10,000 years at a minimum for siting for the SSE. So, there is a big difference in the focus of the two PSHAs, what they develop for their maps and what we, EPRI and other modelers develop for nuclear power plants.

MEMBER BLEY: So let me rephrase what I think I heard you say. And that would be that because of the way they focus in developing their hazard, their estimates are that the 10,000 year return period you don't have much confidence in because they didn't focus out at that kind of time frame. Is that what you are saying?

DR. MUNSON: Yes, that is what I am saying.

MEMBER RAY: Well and more specifically, the consequence is that they over-predict, apparently. At least, that is the only conclusion that I can draw, --

MEMBER BLEY: At least at this point.

MEMBER RAY: -- the peak ground acceleration.

Go head, John.

MEMBER STETKAR: There is some evidence that -- You know, USGS doesn't due a rigorous uncertainly analysis. That is certainly true. And if you talk to the people, it is not clear how they account for uncertainties. There is some evidence looking at, stuff that I have done looking at other areas that EPRI tends to under predict the uncertainties and be somewhat optimistic at the high g level of long return period, high g level is some evidence that USGS tends to over predict the peak ground acceleration and they don't do uncertainty analysis. So you have to somehow deal with that.

My only question was how extensively,

given this apparent difference on what is characterized as a mean exceedance frequency, how rigorously did the various entities examine those differences.

DR. MUNSON: Again --

MEMBER STETKAR: And I think I hear what was done. So I don't need to hear it again.

DR. MUNSON: Right. I mean, we don't require them to compare their hazardous results to the map that USGS develops. It is not for nuclear power plant siting.

They do compare their source model, maximum magnitudes, recurrence intervals, how often these earthquakes happen, the maximum magnitudes and the source geometries, where they happen. Those are all things that we have looked at with respect to not only USGS but South Carolina has their own hazard. So it is not just USGS. There are various other ones that we do look at.

But we do not look at USGS hazard maps, specifically, for comparison.

MEMBER RAY: Are you satisfied, John?

MEMBER STETKAR: Yes, we should go on here, Harold.

MEMBER POWERS: You succeeded in confusing me. You come up with a factor of two, the difference between in the peak ground acceleration at one hertz. And they say that was because they over predict.

How in the world do you explain to the public that there is a factor of two here, based on errors in mathematics?

MEMBER STETKAR: That's an excellent question, I think. But I don't think we are going to answer that question in this forum.

MEMBER RAY: It seems the generic -- Okay, that's fine with me. I just don't want to not somehow recognize it as a question and we can move on, unless somebody here want to try and answer it in the context of Summer, I would suspect we just make it an observation to be dealt with by the committee later and move on.

I thought there was going to be a simple answer emerging but obviously not.

Go ahead, Joe.

MR. SEBROSKY: Gerry, we are on slide nine now.

DR. STIREWALL: Okay. That slide should be titled "Update on Observations by NRC Geologists." Is that correct?

MR. SEBROSKY: That's correct.

DR. STIREWALL: Okay. Well let's talk a little bit about the geology of what we observed in the excavation. I appreciate Bob Whorton setting this up so smoothly. Bob actually talked about the real reason for the licensing condition 2.5.1-1, really which requires the applicant to do the mapping. Bob illustrated and spoke about the shear zones that were discovered in Unit 1. There is a date on those. There are at least 45 million. And in fact, that really was the impetus for why this particular licensing condition was formulated. So Bob, thanks for setting that up.

We did do a site visit, an initial one in August 2010. Again, as Bob said, and sort of our bottom line is in fact we believe the applicant has, in fact, that they did characterize in the FSAR what they are finding in the excavation. They are not finding features that are young. That is to say none of these structures. Well, are there tectonic features? Yes. Are they young? No. They are much older than quaternary.

What I would like to do is just sort of give you a little walk into the excavation to turn you all into field geologists for just a few minutes. So if we could look at the next illustration where the geologist is lying atop bedrock and looking at a fracture face, and I assume that we are on that slide now.

MR. SEBROSKY: That is correct.

DR. STIREWALL: Okay. What is going on here -- And by the way, I think Yong may have brought a hand sample from a piece of core from Unit 2. Is that visible?

DR. LI: Yes.

DR. STIREWALL: Okay. Well that particular rock in that core is in fact granite diorite. It is about three hundred million years old and it really does form the foundation bedrock here.

What this geologist is looking at, he is looking at a natural fracture face that was uncovered by the excavation. This fracture, it is, it was generated tectonically but looking very carefully, there are no features on this particular fracture surface in the granite diorite that indicate that it is related to slip. In other words, it is not a fault. It is simply a fracture, no displacement.

But I would like to do now passing from that slide again on top of the granite diorite, a sample of which you can see, I would like to look at just a couple of different scales of features and show you the field evidence for why these things are not in fact young.

So if we could look at the next slide that talks about or illustrates a small scale hill, shear fracture that cuts an igneous vein, that is the lower part of the title. I am assuming that we are on that slide.

MR. SEBROSKY: That's correct.

DR. STIREWALL: Okay. You can see the little, there is a vein, an igneous vein that is offset that runs sort of from the top to the bottom of the photograph vertically. That particular vein, it is called a pegmatite. And the point is that the pegmatite vein is sort of part and parcel, for the last juices of these magmatic plutonic masses, like the granite diorite. So it is directly associated with formation of these major intrusive bodies, the granite diorite in this case. So in other words, the age of those veins is also very old.

Now, that vein is offset in this one by a rather small scale fracture that crosses horizontally on this figure and clearly, clearly that is offset. But if you look at the lighter colored mineral in that fracture zone, that is in fact quartz. That is also an igneous mineral. So this particular little fracture, very small scale -- What do I mean by small scale? If you look at the rectangular scale, the arrow on that little rectangular scale is ten centimeters in length. So we are looking at a rather small scale feature. Again, it is healed by minerals that were sort of the last juices of this intrusion. So it has very, very old minerals growing in it. So this kind of feature, there is no reason from the relative ages from the field evidence, to think that it is any younger than 300 million or so.

If we could look at the next slide, please, that shows a slightly larger scale. And again, Bob illustrated from Unit 1 something that sort of looks very much like this. This particular, there is a zone that runs vertically across the slide top to bottom and it is a zone of really rather intense, closely spaced fractures that probably suggest shearing. But low and behold, that zone is crosscut by the igneous veins. And remember, the lighter colored lines that you see in the background, show no offset or those same sorts of pegmatites and again, they are in the range of 300 million. So they actually cross the shear zone and again give us relative ages that these are not young features. I mean, the field evidence just shouts it at you very,

very loudly.

So if we could just, sort of in summary then, using those kinds of field relationships, we really found from our visit in August that what the applicant said in Section 2.5 is absolutely fully consistent with the geologic features that we have observed to date in Unit 2. Tectonic features are there. They are old features. And we will do, again, as Bob alluded to, we will do a follow-up visit post-blasting, once they are down at a lower level. We will actually get a third dimensional view of any of these fractures that might crosscut. And we will do similar visits to Unit 3 sort of in the same, to accomplish the same process.

That is really all I had. Again, just our bottom line being that what the applicant expected to find is what they are finding, based on our field assessment from really good and very, very solid field relationships.

That is it, unless you have some questions.

MR. SEBROSKY: If there is no other questions, we can go on mute for the rest of them.

MEMBER RAY: All right, we will do that. Thank you.

MR. SEBROSKY: Thanks, Gerry.

DR. STIREWALL: Thank you.

MR. SEBROSKY: Thanks, Cliff.

MEMBER RAY: Fellas, are you done with this piece here?

MR. SEBROSKY: Yes.

MEMBER RAY: Okay, Amy, can you catch us up?

MS. MONROE: Yes.

MR. SEBROSKY: Just so you know, we are going to be bringing staff in and out. They will bring in more subject matter experts while Amy does her presentation.

MEMBER RAY: Okay.

MEMBER ARMIJO: So you are switching.

MS. MONROE: I get to drive the mouse the whole time. We will switch people in and out but we will try to keep the discussions moving as rapidly as we can and flowing.

Yes, my name is Amy Monroe. I am a licensing engineer with South Carolina Electric and Gas Company. Our team is here today to discuss with you the site specific portions of our COL application. I am going to address the more significant items that were in Chapter 1 and the first three sections of

Chapter 2.

As we have noted before, the Summer site is located in the central portion of South Carolina in a town called Jenkinsville. Here we are showing it in relationship to two of the other applicants for the AP1000.

As we have noted, these units will be the standard AP1000 design. The Westinghouse design incorporated by reference in our application and reutilizing the standard material found in the RCOLA, Vogtle Units 3 and 4.

We have just recently submitted an amendment to our application. It is Revision 4. And in that amendment, we address the confirmatory items that are found in the NRC's SER and incorporates Revision 18 of the DCD by reference.

You will note here that this is an artist's rendering of the AP1000 units on our site. Unit 2 is to the north of Unit 3. And over here we have the four, two per unit, mechanical draft cooling towers that we will be utilizing.

Within our application we have a total of five departures, two of which are considered standard departures and are accepted by all AP1000 units. One deals with the section numbering within the application. The other deals with testing of the voltage regulating transformer in Chapter 8. Again, both of these were discussed in more detail during the RCOLA or Vogtle presentation a month ago.

We have three site-specific departures. One again for the section numbering. This is primarily in Chapter 2. One for the relocation of our technical support center and operational support center relocation. We will be discussing that departure in a little more detail here when we talk about our emergency plan.

And we have a wet bulb temperature departure. We departed from the maximum safety non-coincident wet bulb that is contained in the DCD. And here in just a few minutes, we will go through a more detailed discussion on the acceptability of that departure.

We have a total of three exemptions, two of which again are considered standard for an AP1000 plant. One deals with the section numbering. The other is an exemption to 10 C.F.R. Part 70. This is to make consistent with the requirements for Part 70 that are required of the Part 50 applicant. We are trying to get online with the same requirements as Part 50. And again, the one site specific exemption which deals with the maximum wet bulb temperature.

As discussed in FSAR Chapter 1, the units for the project are jointly owned by South Carolina Electric and Gas with a 55 percent ownership and Santee Cooper or the South Carolina Public Service Authority with a 45 percent ownership.

Westinghouse Electric Company and Shaw Group are considered the AP1000 provider, architect engineer and constructor.

Other groups that have been utilized in support of our application in our initial efforts have been Bechtel, NuStart Energy, Mactec Engineering and Consulting, Risk Engineering, Tetra Tech and William Lettis. Several of those which Mr. Whorton discussed with you a few minutes ago.

Chapter 2 discusses the siting characteristics for the Summer site. Basically to summarize, the Summer site has what we consider fairly typical southeastern climatology; hot humid summers, milder winters. Icing is not a concern either in the lakes or the rivers in the area. However, we will talk about the exemption due to the humid conditions.

Analysis of our wind and tornado data demonstrates that the wind speeds and tornado frequencies encountered in the vicinity are bounded by the DCD requirements and also meet the necessary requirements for external missile hazard protection.

The location of the site is on a rock plateau, as you sort of remember perhaps from Mr. Whorton's discussion, and it is greater than 100 feet above the flood level of the Broad River, which again, was located about a mile to the west of the site.

The local topography essentially moves all the water from that plateau down over to the west, over to the east, it tends to encounter streams which feed into the river. Therefore again, the flooding is not an issue at our plant.

Ground water levels are also very low and in fact, they are about 18 feet below the DCD required level. And as Mr. Whorton discussed with you earlier, we are considered a hard rock site for the AP1000 design.

Regional climatology as discussed in Section 2.3 is basically characterized by four very distinct seasons: mild and short winters; long mild but sunny weather in the autumn; a little bit breezier and windier in the spring, but mild; and then very long hot summers.

For our initial COLA submittal, we took three years of data, it was collected, analyzed and submitted utilizing the Unit 1 meteorological towers, as the Units 2 and 3 tower was being constructed and the initial data was being collected.

After obtaining and analyzing the data from the Units 2 and 3 tower, it was determined that the lake effects on Monticello Reservoir had a greater impact than we had anticipated from the Unit 1 tower data. Therefore, we continued to collect two years of data from the Unit 2 and 3 tower and updated the application with that data, simply because it was more representative of the conditions right there at the Unit 2 and 3 site.

Overall however, the initial conclusions were essentially unaffected with the new data. So it was consistent with the initial data. It was just more representative to use the new data.

You keep hearing me bring up the exemption. That was kind of the biggest issue we ran across. The humid conditions did result in our maximum safety wet bulb temperature being about a degree, 1.2 degrees higher than the DCD value of 86.1. The basis for that is contained in FASAR Sections 5, 6 and 9 and it will be discussed here in just a few minutes.

Hazard sources, including site-specific

chemical, asphyxiation, and explosive hazards were evaluated with the ALOHA computer model utilizing guidelines in the applicable Reg Guide and found to be acceptable.

Siting conditions such as distance from the applicable hazard and local topography, again the rolling hills which provide for greater dispersion, were additional favorable factors for the evaluation.

Three more significant hazards that we evaluated were the Unit 1 site which is located again approximately one mile to the north and there was an ammonium hydroxide tank there that we evaluated specifically. There is the railroad line that we pointed out at the very beginning of our presentation that runs along the Broad River west of the site. And there is a gas pipeline that runs from the south towards the north that ends up at our Parr Facility, which again is located approximately just over a mile to the south of our unit. So the line never runs further north than that.

Other hazards that required evaluation by the regulatory requirements were either not applicable or probabilistically insignificant.

Does anybody have any specific questions we could try and answer for you?

MEMBER RAY: Is there going to be any further discussion of the treatment of the railroad line hazardous source?

MS. MONROE: Not specifically but if you would --

MEMBER RAY: Is there anything you wanted to say?

MR. SEBROSKY: There is going to be a discussion about those stats, toxic gas --

MEMBER BANERJEE: That is separate. There is a whole presentation. Right?

MEMBER RAY: I thought there was.

MR. SEBROSKY: So the staff will do a presentation.

MS. MONROE: Yes, there is someone from the staff that will be discussing.

MEMBER BANERJEE: Yes, I noticed that. So I thought that would be the time to take it up.

MEMBER RAY: I've been looking at too many things. I can't keep track of everything that's coming up but I thought there was. Thank you.

MS. MONROE: Okay. If there are no further questions on that, we will move to, if you keep going through your slide handouts, we have got them together, we will have a discussion by Mr. Mark

Stella of Westinghouse dealing with our specific wet bulb exemption.

MR. STELLA: Thank you, Amy.

As Amy noted, I am Mark Stella from the Westinghouse Balance Plan Engineering Group. I would like to just briefly go over the historical basis of the wet bulb temperature exemption request; describe the evaluation process that we use to determine that the exemption would be a valid exemption, it wouldn't result in any changes to the performance of the AP1000 standard systems at the VC Summer site; and then summarize the results of some of the evaluations that were impacted by the increase in wet bulb temperature.

Before I start going through this, I would like to point out, I am sure most people know there are actually two wet bulb temperatures that are defined in the AP1000 DCD which relate to the performance of various safety defense-in-depth and non-safety systems. There is the maximum safety non-coincident wet bulb temperature, which is what we are talking about here today. Then there is a lower wet bulb temperature, the maximum normal wet bulb temperature, which is used to evaluate the performance of the plant in terms of time to cool the plant down and things of that nature.

So the exemption is only for the maximum safety ambient wet bulb temperature of the non-coincident value, which in the current revision of the DCD is, as Amy pointed out, 86.1 degrees Fahrenheit.

When Summer started preparing its COLA and responding to NRC questions on the COLA review, the NRC actually asked the question what would happen if we, instead of using the zero percent exceedance wet bulb temperature as measured at the site using the Met Towers, what if we calculated the 100 year return temperature for the site? Would that number be higher or lower than the zero percent exceedance temperature, which is typically the measure that utilities use to compare with the DCD limits to make sure that their plant site is within the assumptions made for the AP1000.

Summer did the analysis and found that the 100 year return temperature was indeed higher than the zero percent exceedance temperature, which had been the previous standard for the site. And Amy did point out the number was 87.3 degrees Fahrenheit, as opposed to the 86.1 that is currently in the DCD.

The question then arises, how significant is that in terms of affecting the performance of the safety systems, defense-in-depth systems and investment protection systems that are sited in the DCD. There are a number of performance statements in the DCD based on the maximum safety wet bulb temperature.

So Westinghouse had previously done a number of analyses for increasing the maximum safety wet bulb temperature because initially the DCD wet bulb temperature maximum safety non-coincident wet bulb temperature was 80.1 degrees. That was the initial wet bulb temperature which was based on a survey of a large number of potential AP1000 sites in the continental United States.

So that temperature had been raised from 80.1 to 85.5 and finally to 86.1 in Rev 18, actually I think in Rev 15 of the DCD. It was at 86.1 degrees and it has remained there since then. To do that, Westinghouse performed a number of quantitative analyses of the performance of the various systems. And those analyses are the same ones that we use to assess the performance of the VC Summer systems at the 87.3 degrees Fahrenheit maximum safety non-coincident wet bulb temperature.

MEMBER RAY: Educate me. Non-coincident here means what?

MEMBER CORRADINI: Didn't have the same

temp.

MR. STELLA: That means it is irrespective of the local dry bulb temperature. There is another measure that is specified in the tables for the DCD, which is a combination of the maximum dry bulb and maximum coincident wet bulb temperature.

MEMBER RAY: Okay. Non-coincident refers to dry bulb.

MR. STELLA: Non-coincident is by itself. It does turn out though that the non-coincident wet bulb temperature of 86.1 and the combined dry bulb maximum wet bulb temperature, it is also 86.1 degrees. So there really is no difference. But these parameters have very tongue-tying names. So if you will excuse me, I will just use maximum wet bulb temperature from now on, rather than trying to give it its perfect name. Because we are talking about the maximum safety in non-coincident wet bulb temperature. I will just call it maximum wet bulb temperature to save time.

MEMBER RAY: Okay.

MR. STELLA: When we evaluated the impacts, as I pointed out, we used the same methods that we did to increase the DCD value of the maximum wet bulb temperature. There are number of performance areas that are affected by the change in this wet bulb temperature.

In fact, there was an earlier effort in Westinghouse to assess the impact of changing this temperature, raising it above 86.1, which was done for the Turkey Point site for Florida Power and Light. That maximum wet bulb temperature was 87.4 degrees, which of course bounds very nicely the 87.3 at the VC Summer site. We had all the calc notes available for every one of the changes that would occur if we raised that temperature. So we compared those results to the Summer and the comparison is easy.

The Summer systems and structures are exactly the same as the standard AP1000 systems and structures. The only difference is the maximum wet bulb temperature. Our conclusion for Florida Power and Light was that the performance of the systems was acceptable in all respects, that all the systems that were affected by this increase in temperature. Therefore, the same conclusion would be drawn for VC Summer.

MEMBER SIEBER: That would include containment maximum pressure?

MR. STELLA: That does. That is the major, in fact I think the only safety-related parameter that needs to be looked at.

MEMBER SIEBER: And so you are below the design pressure of containment. The depressurization in cool down will take longer.

MR. STELLA: It will.

MEMBER SIEBER: Have you reanalyzed to take into account this and --

MR. STELLA: The GOTHIC analysis was redone with this higher wet bulb temperature. In fact, we actually took the maximum safety wet bulb temperature quite a bit higher than the 87.4 to see what the impact might be.

MEMBER SIEBER: And you still fit within the parameters?

MR. STELLA: We still fit within the curves that we published initially and that apply to the 86.1 Fahrenheit maximum wet bulb temperature.

MEMBER SIEBER: Thank you.

MR. STELLA: The effect on pressure, Mr. Sieber, is very minuscule. It is a couple of hundredths of a psi caused by an increase in temp.

MEMBER SIEBER: It is there nonetheless.

MR. STELLA: So that was a good result.

We looked at the investment protection parameter, the control of potential steaming from the in-containment refueling water storage tank, RIWST. The objective is to maintain that tank fluid below saturation temperature, in the event of a PRHR actuation so that you don't steam in the containment and possibly affect very expensive and good equipment. That parameter was also maintained well below saturation temperature. It did go up by about the same amount as the wet bulb temperature went up but it is still in the 200 degree Fahrenheit range. So there is quite a bit of margin for that one.

The component fueling cooling system normal operating temperature limit is 100 degrees Fahrenheit. That is set by the design of the reactor coolant pumps. That temperature is the limiting temperature for operation of the pumps at full RPM during normal plant operation. We normally try to keep our component cooling water temperature below 95 degrees. But even with the 86.1 degree DCD maximum wet bulb temperature limit, at times it does go above 95 degrees into the 96 degree range. And for Summer, it goes a little higher because of the additional 1.2 degrees added on wet bulb. However, these are excursions of limited extent, a few hours at most and the temperature will come back down below 95. Therefore, our conclusion was that this performance requirement was also meant for Summer.

We are committed to maintain the spent fuel pool temperature below 120 degrees Fahrenheit following a normal refueling. And that goal is also met, even with the 87.3 degree Fahrenheit maximum safety wet bulb temperature.

The last item that was affected by an increase in maximum wet bulb temperature was the performance of the low capacity chilled water system, in terms of its ability to cool the main control room, I should say cool and dehumidify the main control room, the battery rooms, and the electrical equipment rooms to maintain the assumed preliminary conditions in the event of a design basis accident.

We found that the increase in the wet bulb temperature caused the coolant requirements for those rooms that go up basically because of the humidification caused by the additional wet bulb temperature increase.

And the performance of the chiller itself was not affected. These were air cooled chillers that are sensitive only to dry bulb temperature. What happened was that the load on the chiller was increased by some 20 to 30 tons but the chiller itself was not running at full output. It was quite a bit below full output. We had plenty of margin. So, the 87.3 degrees posed no problem with respect to the operation of the system.

All the other parameters and performance goals that are stated in the DCD are based on either performance against dry bulb temperature or performance against the other wet bulb, the maximum normal wet bulb temperature, which is 80.1 degrees. These are mostly performance requirements related to cool down of the plant. That did not change for VC Summer. Its maximum normal wet bulb temperature is below the 80 degrees Fahrenheit temperature that applies to the DCD. And so we didn't have to look at that because the system performance would be the same or better than for the standard design at the limiting site.

That is all I have for this topic. Any questions?

MEMBER RAY: Thank you.

MS. MONROE: Now if Mr. Steve Summer will come forward and Angelos. We will move on to a discussion on hydrology. Mr. Steve Summer will provide the presentation. Steve?

MR. SUMMER: Thank you. Good morning.

Again, my name is Steve Summer and I will be discussing FSAR Section 2.4, hydrologic engineering.

Again, this slide shows the major surface water features. The site is located about a mile to the south of Monticello Reservoir, which is the upper pool of the Fairfield Pumped Storage Facility and the source of makeup water for normal operation of Units 2 and 3. The reservoir also provides cooling and makeup water for Unit 1.

The Broad River and Parr Reservoir, which is a dammed section of the river, runs generally northwest to southeast. We note the locations of the Summer Station 1, United 2 and 3, and also Fairfield Pumped Storage Facility.

There is no risk to safety-related systems, structures, or components from flooding. The probable maximum flood level is more than 100 feet below site grade and the site is not susceptible to surges, seiches, or tsunamis. Ice effects are highly unlikely. The Broad River is adequate for non-safety uses, even during low-flow conditions.

This slide shows the site topography. And as we discussed before, Units 2 and 3 are situated on a ridge top with a designed plant grade elevation of 400 feet in a VD 88, which is the North American

Vertical Datum of 1988. And that elevation is the equivalent to the AP1000 design plant grade of 100 feet. The plant grade is about 150 feet above the Broad River Flood Plain.

As can be seen from the figure, surface water drains away from the site and eventually flows to the Broad River. Again, this topography figure illustrates why flooding is not an issue at this site.

Surface water will move to ground water. Again, located on the ridge top. This figure represents the piezometric contours, which indicate that the shallow subsurface flows away from the site. Our subsurface flow would be expected to flow from high to low levels, as shown by the red arrows.

There are no plans to use local ground water for construction or operation of Summer Station Units 2 and 3. Water for construction purposes will be obtained from the Monticello Reservoir and the Jenkinsville Water District.

Continuing with groundwater, the design plant grade elevation is 400 feet, again, equivalent to 100 feet from the AP1000 DCD. The maximum allowable groundwater level is 398 feet and the maximum expected groundwater level is 380 feet, or 20 feet below the plant grade and well below the design value of 398.

Accident release of liquid effluents. The evaluation shows that an accident liquid release of effluents in groundwater would not exceed 10 C.F.R. Part 20 limits. Three conceptual flow transport models, one saprolite and two bedrock, are presented.

The accidental release scenario assumes an instantaneous release from an effluent holding tank located in the lowest level of the AP1000 auxiliary building. The next three slides are examples of the conceptual models of the transport pathways for saprolite, shallow bedrock, and deep bedrock to the Broad River to the west or to Mayo Creek to the east and deep bedrock to a hypothetical well at the nearest point outside the SCE&G property line.

This figure represents the saprolite pathway. In this flow transport pathway, flow is through the saprolite zone and discharges to a stream. We believe that this pathway is the most probable.

The second figure here represents the bedrock pathway to the Broad River or stream, Mayo Creek. And this flow transport pathway flows through the bedrock and discharges to a stream. And thirdly, the figure represents the bedrock pathway that is not intercepted by a stream. And this flow transport pathway flows through bedrock, continues under Mayo Creek, and discharges to a hypothetical well located at the property boundary, approximately 4500 feet or three-quarters of a mile to the east/southeast.

Again, none of these pathways resulted in values exceeding 10 C.F.R. Part 20 limits.

MEMBER RYAN: Were you conservative about dilution and dispersion?

MR. SUMMER: I'm sorry.

MEMBER RYAN: How conservative were you about dilution and dispersion assumptions?

MR. SUMMER: I could get Angelos Findikakis with Bechtel to address that.

MR. FINDIKAKIS: In estimating dilutions in the streams, we considered the minimum 100 year low-flow and that was the basis for estimating the dilution factor.

MEMBER RYAN: How about dispersion in the plume as it travels down?

MR. FINDIKAKIS: We considered dispersion in only one of the pathways. For all the other pathways, it wasn't necessary to consider the dispersion because the concentrations were very low.

MEMBER RYAN: Okay, thanks.

MR. SUMMER: Any other questions? Thank

you.

MR. SEBROSKY: Again, my name is Joe Sebrosky, the lead project manager for Summer. To my right is Don Habib. He is the chapter project manager for four chapters; Chapter 6, Chapter 11, 12 and 15. And to his right is Ken See. Ken did the surface water hydrology review. And to Ken's right is Shi Jeng Peng. Peng did the toxic gas review for Chapter 6.

This first slide just gives the dates when we got the application, when the acceptance review was complete and when the advanced safety evaluation report was complete, which was December 10, 2010.

There has been two subcommittee meetings, one July 21 and 22nd, 2010 and another this past January 11th and 12th.

The Summer application consists of three things, material incorporated by reference by the AP1000 DCD, the standard content material that is applicable to all the AP1000 COLs and then Summer plant specific information.

The standard content material was not discussed in either of the two Summer ACRS subcommittee meetings because the standard content material was discussed during the Vogtle subcommittee and full committee meetings. So we did not brief the subcommittee separately on the standard content.

This slide just reemphasizes what has already been stated, that Summer is a subsequent COL. It references the Vogtle advanced safety evaluation report. The second sub-bullet, if you looked in our safety evaluation report, you know that it comes from Vogtle, based on the fact that it is double indented and italicized. If it is not doubled indented and italicized, then it is unique to Summer.

The third sub-bullet, this was discussed in subcommittee meetings with Vogtle. But there is a history with Bellefonte at one point, was the RCOL. The only safety evaluation report with open items that is going to be written on the AP1000 COLs was Bellefonte. That is the only one that we wrote. The rest of them are going to go to skip that stage and use a four-phase review schedule. So there were no plans to issue any more safety evaluation reports with open items.

Because of that, that is why you see mentioned in Vogtle and you also see mentioned in Summer going back to the Bellefonte open items.

The reason that this slide is shown is that there are 16 parts of the application. It is not just the final safety analysis report that the staff reviewed in its SER. The final safety analysis report is Part II of the application.

There are a couple other things I wanted to point out here, if you look at parts 13, 14, 15 and 16; 13 is the quality assurance program, 14 is the mitigative strategies document for loss of large area of fires, commonly referred to as LOLA, 15 is a cyber security plan, and then 16 is the material control and accounting program for special nuclear material. All four of those take advantage of the standard review approach.

So if you look in Chapter 17 of our SER, you would see mention of the quality assurance program description and it utilizes the double indent. Similarly, if you look in Appendix 19A, the LOLA evaluation there is a public version of the document and there is a nonpublic version of the document. You have to go to the nonpublic version of document and when you look at that nonpublic version of the document, the safety evaluation report, you will see the use of double indented and italicized safety evaluations by the staff, taking advantage of the design-centered review approach.

Cyber security plan, there is just a

public version of that, double indented, italicized portions in 13.8. And the same thing with the special nuclear material control and accounting program. That is in section 1.5.5.

The other thing to note on this and we will reemphasize this in a later presentation, if you look at Part 5 of the application emergency plan, Chapter 2 of the FSAR and Part 5 of the application emergency plan contain the majority of the site-specific information that we briefed the subcommittee on.

Go to the next slide and I will turn it over to Don.

MR. HABIB: This slide addresses the exemption requested by the applicant for maximum safety wet bulb temperature. It was requested in the COLA Revision 2, an increase of 1.2 degrees from 86.1 to 87.3 degrees and it was based on 100 year return temperature.

And the other two temperature specifications from the DCD, the maximum coincident normal wet bulb temperature, that did not change. And also the maximum dry bulb temperature, that did not change.

When we did the evaluation, there were

several areas that were affected. The first one in Chapter 2, site characteristics comparison and the meteorology reviews; in Chapter 5, the normal residual heat removal system; in Chapter 6 containment systems and habitability systems for the control room. And for the control room we look at two systems, the nuclear island nonradioactive ventilation system and low capacity chilled water system.

And then in the chapter on auxiliary systems, the spent fuel pool cooling system, component cooling water system, and the central chilled water system.

And the staff had audited calculations made available by the applicant. And in all of these evaluations, the conclusions were not affected.

And the next portion of our presentation is for the toxic gas.

MR. PENG: This is Shi Jeng Peng. I am the reviewer for control room habitability.

The purpose of the toxic gas review is to evaluate the impact of any potential or possible chemical release within five miles of control room on control room habitability.

Section 2, the reviewer has already identified three chemicals will impact, will potentially impact control room habitability. These three chemicals are 28 percent ammonium hydroxide from Unit 1, and cyclohexylamine from the rail, and the last one is chlorodifluoromethane from rail, too because they have a lot of --

MEMBER POWERS: Cyclohexylamine is not standard nomenclature. What is that compound?

MR. PENG: The compound is, I could find it for you but it is already heavy case and type chemical anyway. It is about three times heavier than air. But I also have idea IDLH limit is about 100 ppm.

MEMBER POWERS: Is that a CAS number?

MR. PENG: I'm sorry?

MEMBER POWERS: A CAS number?

MR. PENG: I cannot follow you.

MEMBER POWERS: Does it have a CAS number? I'm trying to figure out what it is.

MR. PENG: Oh, a CAS number, I don't know. I'm sorry.

The staff identified the concentration at the control room intake exceed IDLH limit so they asked me continue to evaluate will control room habitability impact by this high, higher than IDLH concentration.

I used a HABIT computer code, which is Reg Guide 1.78 recommend to use. And this computer code has been used by Pacific Northwest Lab for in last 1988 and 1998, has been used for a while. So I got some results. The result is the next slide, please.

MEMBER BANERJEE: Now before you go on, the HABIT code does not handle heavy gases and these are heavy gases. So you have to take what they say with a pinch of salt. Though, ALOHA does. ALHOA does but the staff doesn't.

I can give you the structure of cyclohexylamine as well. It is just a benzene ring with an NH_2 on the end.

MEMBER POWERS: Monoamine, one monoamine benzene.

MEMBER BANERJEE: One, one -- yes.

MEMBER POWERS: All right. Why don't we use standard nomenclature?

MEMBER BANERJEE: Whatever it is. That is what it is.

MR. PENG: My conclusion is I have confirmed the applicant's licensing basis analysis and found the chemicals would not pose any threat to the control room operators.

MEMBER POWERS: I mean, the significance

of finding this is a little bit lost on me, if the code can't handle heavier-than-air gases. I mean, why is significant?

MEMBER BANERJEE: This is not but ALOHA can and is a fairly well recognized industry code which is used in the chemical industry.

MEMBER POWERS: Why is the staff using a --

MEMBER BANERJEE: I don't know.

MEMBER POWERS: -- code that doesn't apply?

MEMBER BANERJEE: We raised in the question in the subcommittee.

MEMBER RAY: Yes, well I think that is what they are trying to get at with the last bullet here on the preceding slide.

MEMBER BANERJEE: Now whether this dilutes enough that the early heavy gas behavior is lost, I don't know. But you will see that the ALOHA concentrations are higher than the HABIT, which is to be expected.

And also the topography of the site is such that the site is higher than where the release points would be.

MEMBER POWERS: Four hundred feet.

MEMBER BANERJEE: Yes, so I don't think that there is any really issue with the calculations with ALOHA being acceptable. I don't think we need to say more than that at this point, unless you want to pursue it.

CHAIRMAN ABDEL-KHALIK: What is the difference in elevation?

MR. PENG: It is 150 feet.

MR. SEBROSKY: Well you have to be careful about the question. If you are asking for the difference in the elevation from the railroad line --

CHAIRMAN ABDEL-KHALIK: Correct.

MR. SEBROSKY: Okay from the railroad line --

MR. PENG: To control room impact is 150 feet. One hundred fifty feet.

CHAIRMAN ABDEL-KHALIK: Okay, thank you.

MEMBER BANERJEE: So it is going up. I don't think there is any reason --

MEMBER RAY: The issue is it came up, had to do more with applications for other --

MEMBER BANERJEE: Other plants, yes.

MEMBER RAY: -- other circumstances and that is what they are trying to say here in the last bullet is that they agree that it should be looked at.

MEMBER BANERJEE: Yes, I actually went through the report carefully. And it cannot handle heavy gases.

MEMBER RAY: Proceed.

MR. SEE: Okay, let me be the first to say good afternoon to you. My name is Ken See. I am a senior hydrologist in the Office of New Reactors. I am here to discuss the surface water hydrology issues.

In my talk I am going to be referring to just this slide. It is the only one I have. This slide shows basically the major surface water features at or near the site. One with their respective surface water elevations or floor elevations.

As part of its review, the staff reviewed the various flood mechanisms and scenarios identified by the applicant in the FSAR. Additionally, the staff postulated various other mechanisms and scenarios that may generate large floods at or near the site.

After conducting our review, the staff agrees with the applicant that the design basis flood is that caused by the local intense precipitation as described in Section 2.4.2 of the final safety analysis report.

The fact that this flood is, the design basis flood is caused by the local intense precipitation is not unusual, we are finding out at many sites. Additionally the margin that we found here at the Summer site is also typical of other sites.

Details of the Monticello Reservoir Dam Breach analysis were not included in Section 2.4.4 of the FSAR because the applicant considered this to be sensitive information. However, the applicant did provide to the staff detailed information and detailed calculations during our site audit. Based upon a review of this information, we found their analysis to be acceptable.

In addition to the breach of the Monticello Reservoir as discussed by the applicant, the staff also postulated a breach in the berm between the Mayo Creek and the Monticello Reservoir, leading to a flood down Mayo Creek, which is this bright red line to the right of the figure there.

Flow values used in this analysis were obtained from the Bureau of Reclamations Dam Safety Office Projects. These values were then increased for additional conservatism. These values were then used --

MEMBER POWERS: When you increase something arbitrarily for additional consideration, how do you know what increase to make?

MR. SEE: It is a judgment call.

MEMBER POWERS: How does one tutor one's judgment in making an arbitrary increase?

MR. SEE: Well if we increase these values and then we exceed the site flood elevation here, in this case 400 feet, then we would probably back off. But when we increase the value and yet we still don't exceed the flood elevation, in this case 400 feet, that just gives us additional confidence in the analysis.

MEMBER POWERS: Why don't you go the other way, just assume a biblical flood and keep dropping it down until you get to the site elevation and then say is that more or less?

MR. SEE: We could take the 2012 approach, I suppose, but then we wouldn't license very many of these things. I mean, the analysis that was done was very conservative. That is the main point. I can't -- that is, I think different analysts would probably come up with a different number. If you were going to increase something, I think you would come up with a different number than somebody else.

MEMBER ARMIJO: Do you use a physical model of --

MR. SEE: Yes.

MEMBER ARMIJO: -- let's say a blockage of the flow channels by flood debris?

MR. SEE: I am going to talk about that a little bit later. But in this particular case, this is different. You are talking about the site drainage.

MEMBER ARMIJO: Yes, the drainage. But let's say if you had a really severe dam break and it takes a lot of debris down your normal flow channels, is that a mechanism by which you could back up and flood the site?

MR. SEE: No, not in this case. We don't see any potentials for land slides or anything of this nature. You know, the dam breach analysis, both analysis would indicate that the site is not subject to that flooding. The design basis flood for the site is based upon what is called the local intense precipitation, which is a little over six inches of rain in five minutes.

MEMBER ARMIJO: Okay.

MR. SEE: And that is almost, I mean, that is an event not to be exceeded. I mean, it is a biblical flood, if you will.

MEMBER POWERS: I guess I don't understand it. It starts to rain and it is going to be seven inches within five minutes. What do you tell the clouds not to? They are going to be fine? There is an enforcement action against the clouds?

MR. SEE: I'm not following you.

MEMBER POWERS: I mean you say six inches over five minutes is not to be exceeded. What does that mean?

MR. SEE: Well that is, the National Weather Service puts out documents of the hydrometeorological reports and their HMR 51 and HMR 52 of the documents that cover this region of the country. And that is based upon moisture maximization.

And what they have done is they have gone through and they have observed large storm events and they have correlated available atmospheric moisture with observed rain events. And then they have gone through and said okay, now given these conditions, let's try to maximize the moisture that the atmosphere can hold and then correlate that back out to our rainfall amounts called the probable maximum precipitation. That is called the probable maximum precipitation not the absolute maximum precipitation because could it be exceeded? In theory, possibly.

But to my knowledge, in this area it has never been exceeded.

MEMBER POWERS: Now that may be more a statement of your knowledge than the facts of the situation.

MR. SEE: Well, could we have missed something? Absolutely. But it is all we can -- You know, our current state of knowledge tells us that it has yet to be exceeded in this area.

Now one critique of the HMRs is that the data is 20 or 30 years old. And our Office of Research is currently trying to update these reports, bringing the data up to the year I think 2000 or 2005. And then preliminary results of that analysis indicate that we are not seeing any large increase.

But I think I may have confused you here. There are two separate events. The design basis flood here at the site is called the local intense precipitation which is a one square mile PNP. The dam breach analysis that I was talking about is a separate issue.

MEMBER POWERS: And we have got to use judgment and decide how close to biblical. That I don't understand either.

MR. SEE: Well if we did not, let's say we did not increase those values, we just took the values out of the dam safety office documents, we would get a flood elevation less than what we got here, which is 392 feet.

Okay, --

MEMBER POWERS: Well, I mean on this intense precipitation what you are saying is based on all the information you have, you are not going to exceed six inches in five minutes.

MR. SEE: Yes, sir.

MEMBER POWERS: Okay. We are not going to fine the clouds if they should happen to give seven.

MR. SEE: Well that is what the physics tells the meteorologist.

MEMBER POWERS: I understand that.

MR. SEE: You know, that is an estimated maximum.

MEMBER POWERS: Now let me ask you about this. They have developed that information on the maximum intense precipitation based on an historical body of data and it is an empirical construction. We are told by numerous people that on the east coast of the United States we experience weather cycles. Does that experiential base cover enough time periods that we have captured that cyclical weather?

MR. SEE: Now that is a simple question. Actually it is a good question.

Based upon my reading of the research, we are seeing changes in lower magnitude events. For example, what used to be considered a 40-year event may now considered a 30-year event. But at the extreme values that we are discussing here in the PNP, no one is willing to make a statement at that level.

My own personal opinion is that as you head towards to the extreme, you know, that will level off. I mean, if the data is correct and the physics behind their estimates are correct, if there is truly indeed a maximum, the climate change and weather cycle should not exceed those values. But that is a question that gets asked frequently by me and other hydrologists at the NRC to researchers. And no one has told us yes, we are seeing changes that would cause us to change our results and increase their values.

But it is an ongoing topic. And if I could answer that question, I would be making a lot more money than I am right now.

MEMBER POWERS: I mean, it is a question because these guys are going to build a plant that is going to be here for 60 years.

MR. SEE: Yes, sir. Yes, sir, I mean as I said earlier, one of the criticisms of this method is that the data stopped, you know, the data for the study stopped in 1975, something like that. And so what happens if we now take data up to the year 2000 and redo the analysis using the same methods? We have got the bureau, our Office of Research has the Bureau of Reclamation working this area for the Carolinas because a lot of the plants that we are relicensing are in the Carolinas. So they were told to start looking at that area first. And they have gone through and they have got some preliminary results and they have not seen an increase in the PNP value, based upon that new data.

MEMBER ARMIJO: Well, you actually have more conservatism in this 399.4 foot than just the six-inch of rain in an hour.

MR. SEE: Yes, sir.

MEMBER ARMIJO: And that bothered me during the subcommittee meeting. You provided an explanation of how you treated the drainage, that it wasn't a perfect drainage during this time, that you assume some blockage of --

MR. SEE: We assumed all of the culverts were blocked for this analysis. The 399.4 assumes the culverts are not working.

MEMBER ARMIJO: So did you do a sensitivity that said hey if the culverts are partially blocked, 50 percent, what would the number be?

MR. SEE: The value would be lower. You are reducing the conveyance.

MEMBER ARMIJO: How much? Ten feet lower or an inch lower?

MR. SEE: I don't have that number. If you assume all the culverts are blocked, the depressions are going to fill up and the roadways are going to overtop. So, I mean, that is --

MEMBER ARMIJO: Okay, so that approach says no matter how bad everything is blocked, it won't go over the 400 -- up to the 400 foot.

MR. SEE: You think of it as, you know, the topography is a like a little bathtub and you block the culvert and that bathtub fills up and spills over the roadways and all the infrastructure. Okay? If that culvert is working 50 percent or working properly, then you would not --

MEMBER ARMIJO: You are nowhere close.

MR. SEE: You would not get it as high.

MEMBER ARMIJO: Okay.

MR. SEE: But I do want to point out that the applicant has provided a confirmatory item where prior to large storm events, they will do a walk-down. They will develop an inspection of their facility to ensure that these culverts are indeed not blocked. So I think the 399.4 is very conservative.

MEMBER RAY: Okay. Now are we done with this part, Joe?

MR. SEBROSKY: Yes.

MEMBER RAY: We are going to begin as series of what is shown on the agenda as discussions involving both the applicant and the staff. I guess Amy, you and Joe are going to orchestrate this, are you?

MS. MONROE: Yes, sir.

MEMBER RAY: I am not going to get in the middle of it.

MS. MONROE: Actually what we intend to do is we will take through and go through the next items six, seven, and eight together. South Carolina will do our presentations and then let the staff follow.

MEMBER RAY: All right. Well, so I don't take up time, just go ahead.

MS. MONROE: Okay. And we will need to be moving people in and out but we will find they are kind of sitting there ready and waiting.

MR. SEBROSKY: I'll just do a brief introduction for the NRC staff. This is Steve Schaffer. Steve is a health physicist that did the liquid radwaste review.

MS. MONROE: Now we are going to discuss a question. During the subcommittee, there were some questions discussing our wastewater discharge line. And so Mr. Tim Schmidt from South Carolina Electric and Gas Company is going to give you a more detailed discussion on that topic.

MR. SCHMIDT: Okay, good morning. I am Tim Schmidt with SCE&G. Today we are going to talk about those items of interest that Amy mentioned. We will be talking about the interface of our liquid radwaste system with our waste water system. We will also be talking a little bit about the design and construction of our wastewater system blow down line.

And before I get into this slide, I brought a sample high-density polyethylene material that I would like to offer to the committee to pass around and if they would like to see a representation of what this material is. I will speak to a little bit more with respect to this construction on the upcoming slides.

On this slide here, I want to point out some design considerations of our wastewater system its interface with liquid radwaste. Our wastewater system has a gravity drainage blowdown line that carries a number of effluents from Units 2 and 3. One of these is diluted liquid radwaste effluent. These wastes are gravity drained from the plant, which we were talking elevation 400 all the way down to a diffuser in Parr Reservoir, which is around elevation 235.

Our liquid radwaste effluents that enter our blowdown line come from a radwaste building and there is a mechanical joint-type interface for these lines entering the blowdown line. At this interface, we do have a high-density polyethylene manhole. It serves two purposes. One is to contain any leakage that might occur at those mechanical joints and also provides a point which we can monitor for leakage at that interface. Having this manhole is implementing guidance from NRC Reg Guide 4.21, to make sure we are compliant with 10 C.F.R. 20.1406.

The next bullet here points out some features in our wastewater system. Blowdown line design, we are using a high-density polyethylene material that is very corrosion resistant, resistant to organic growth, as opposed to carbon steel. And this material does not require mechanical joint for installation, as with ductile iron or fiberglass. I talked a little bit more about that in the upcoming slides.

Along our blowdown line, we don't have any pumps, valves, or vacuum breaker type components along this line. As folks are aware, vacuum breaker valves in particular have been sources of ground water contamination events in the industry.

MEMBER ARMIJO: Is this blowdown line at operated ambient temperatures and pressures or does it ever get up --

MR. SCHMIDT: We expect temperatures below 100 degrees. The driver there is our circulating water blowdown laces that goes through the line. We don't expect it to go above 95 degrees.

The other waste streams as mentioned on the next slide, but I will go ahead and mention them here, are effluents from our wastewater retention basins out in the yard, we would expect high temperatures there.

And there is also some treated effluents from the sanitary treatment plant on-site. Our flow again is gravity from the plant all the way down to

Parr Reservoir, essentially open channel flow to this line. We don't have pressurized flow going through this line.

Okay on this next slide here is just a little schematic of our blowdown line. it is interface with the liquid radwaste system. Our blowdown line is a 36" diameter high-density polyethylene line. As I mentioned before, it is carrying a number of effluents of circulating water blowdown wastewater retention basin effluents, sanitary treatment plant effluents at approximate elevation 380 feet.

We have an intersection here with our liquid radwaste systems here, treated release lines from our radwaste buildings dump into our blowdown line. As I mentioned before, that is a mechanical joint-type interface where we have this monitored manhole rounded.

At this point, we call this our dilution point. This is where we have sufficient dilution, primarily from circulating water blowdown to ensure we need our Part 20 release limits for the liquid radwaste. This does occur within our exclusionary boundary.

And I would like to mention just for a

point of reference the flow rates we expect going through this blowdown lines. For typical coolant tower operations, we expect about 10,000 gallons per minute for both units.

Depending on cycles of concentrations that can be upwards of 30,000 gallons per minute, the liquid radwaste releases into the line. We expect less than 100 gallons per minute per unit for those releases. And it is important to note that those are intermittent. It is a batch-type release that we only expect one to two times a week per unit. And describing the system a little bit further, the piping between the dilution point and the diffuser at the plant outfall is entirely welded HTP. We don't have any mechanical joints in this installation.

Again, there is no other type of components, mechanical joints that could leak.

MEMBER ARMIJO: Is that a straight run pipe or are you using any mitered curves or anything like that or is it just straight pipe?

MR. SCHMIDT: Right now the plan for the blowdown line is that it follows the railroad spur down to the river. Any fittings that would be used for any of those turns would be HTP welded fittings. There would not be any mechanical joints on them.

MEMBER RYAN: And what is the fall? It is elevation 380 to 235. What is the typical grade? Is it always continuous down or how does it work?

MR. SCHMIDT: With respect to the slope, I can't give you exact percentages there but I know that it follows the railroad spur down. It is such that we don't have any situations where we need vacuum breakers or anything like that. We expect to open channel flow conditions.

MEMBER ARMIJO: How long is that pipe from start to finish?

MR. SCHMIDT: A rough estimate that we talked about is about 5,000 linear feet of pipe. It is a good bit.

MR. WHORTON: Excuse me. This is Bob Whorton again. The blowdown line basically follows the railroad spur line from the table top grade down to the river. And the grade on the railroad is approximately two percent.

MEMBER RYAN: Two percent. Thanks.

MR. SCHMIDT: Thanks, Bob.

Okay, this next slide and I hope the samples made it around to most of the committee members, for information the sample that you see going around the table is from a 12-inch diameter HDPE pipe with a little under an inch and a half wall thickness to it. Our pipe again is 36-inch diameters and has approximately and inch and three-eighths inch wall thickness.

What you see here is a typical installation example for HDPE. Here you see 16-inch HDP pipe being installed in the field and actually two pipe segments being welded together. During this operation, a machine operated by a crew of persons lines both pipe ends, preps both ends for welding. There is a step where a heater element is applied to both ends to create melt for the fusion, which is achieved through pressures applied to both ends of the pipe to create a fused weld.

The sample you see going around the table is a good cross-sectional cut of the fused weld.

MEMBER ARMIJO: Could you explain how that thing works just briefly?

MR. SCHMIDT: Yes.

MEMBER ARMIJO: That big guillotine thing, is that the heater plate or what?

MR. SCHMIDT: This thing right here --

MEMBER ARMIJO: Yes.

MR. SCHMIDT: -- that looks like a big saw going down there, it has blades on it. And what that does is where you have the two sections, it goes in there and it cuts both sections, cuts them, cleans off any type of contamination that could be on there.

A separate heating element which isn't shown in the figure, essentially a big, I call it the big paddle-looking device, is then inserted in there for a period of time to melt both ends. And they measure the bead that comes out to make sure that they have sufficient melt. And then the clamps here, and I don't know if you can see there is actually that presses both ends of the pipe together.

MEMBER ARMIJO: Thank you.

MEMBER SHACK: And what kind of inspection do you do after that fusion?

MR. SCHMIDT: Yes, in the next slide, if I could, it points out some of the quality assurance that goes into these installations. For information, our installation will be per ASME B31.1 Appendix 3, which addresses plastic pipe installations.

Our operating crews are all qualified and trained, as well as their fusion equipment. There is a monthly test that these folks go under after initially being qualified for those mechanical destructive tests taken or performed on samples taken from installations they have done to verify joint integrities. They will take a sample, probably a little bit longer than that in which they bent it into almost a horseshoe shape looking for any cracks, material defects, and especially the weld quality.

The installations themselves have incorporated a lot of operating experience over the years with HDPE. In particular things that could lead to bad quality welds, such as insufficient pressure, insufficient temperatures, contaminants, where their prep is are all things controlled and documented. Each weld has a datasheet to it.

Also documented is a weld inspection. And that is a visual type inspection. What they look at is what you see on the sample going around. People call it weld beads or even a rollback, that material that oozes out during the melting fusion gives you a good indication that you have adequate melt time, was there sufficient pressure when those ends came together for you know, experience is shown with that is a good method for inspections.

MEMBER BROWN: Are you just looking -- You are just looking at the external bead, though. Isn't that correct?

MR. SCHMIDT: That's correct.

MEMBER BROWN: Okay. So effectively, I am trying to recall what you said in the subcommittee meeting and that this is effectively a process that has been qualified and you are depending on the process, not an inspection, other than the external inspection of that bead. You can't do the inside. So you are dependent upon the qualification and the procedure and the process to be performed and melt the crunch or whatever it is to come out right.

MR. SCHMIDT: The process, the quality assurance that goes into making these things, is where I believe the control --

MEMBER BROWN: Yes, I just wanted to confirm that.

MR. SCHMIDT: -- and the contractor --

MEMBER BROWN: I saw the word inspections here and I just wanted to clarify and make sure I understood it was not an internal. So you don't see the same bead on the inside just the external bead.

MR. SCHMIDT: That is correct. It is external. That is a true statement.

MEMBER SHACK: And the wall thickness is what?

MR. SCHMIDT: Approximately an inch and three-eighths. An inch thick. A little thinner than what you see going around. That is 1.47 inches thick.

It is a DR26 HDP material.

In addition to the inspections on the exterior of the pipe, hydros are done on pipe segments or the whole system, depending on the installation. These are performed at one and a half times the pressure rating of the pipe. The DR26 material that we have is rated for 80 pounds. So hydro that would be done on this line would be at 120 pounds.

MEMBER ARMIJO: Will that be sort of an end-to-end hydro of the whole line or is it done as you go along?

MR. SCHMIDT: It is permissible for long runs to do them in segments. However, at some point in time, as you keep building the segments, it is required that every weld experience that hydro. And during the hydros that extend for several hours, the line is walked down looking for any through wall material defects that could be in the pipe, as well as in the welds.

In addition, pressure is monitored during the hydro to look for any fluctuations that indicate something is wrong.

MEMBER BROWN: Since this depends on the qualifications of the welders and the hardware that you use to crunch it together, is there a periodic requalification of the welders --

MR. SCHMIDT: Yes, --

MEMBER BROWN: -- and the hardware to see and then a destructive test that you generate something like that to see if you get the same thing? Is it every five years, every six months, or --

MR. SCHMIDT: Well in addition to the initial classroom and practical, they do any type or anytime that operating crew or machine goes to a different size pipe, they go through, I think it is three days where destructive tests are done every day --

MEMBER BROWN: Okay.

MR. SCHMIDT: -- from the sample. Then in addition to that, there is a monthly destructive test, the samples they are doing.

MEMBER BROWN: Okay. You answered my question. Just something to make sure everything is still calibrated.

MR. SCHMIDT: And it is a continual type process. If there is a -- If the contractor's procedures require it, or if there is a change in machines or person on that crew, they start that protocol again.

MEMBER BROWN: Okay, thank you.

MR. SCHMIDT: High-density polyethylene material has been evolving in the industry. From what I understand, it first commercially started being available in the late '60s early 1970s. Nuclear power plants have started using it in applications a little over ten years ago.

Based on experience with the HDPE, we expect long life with this material.

MEMBER RYAN: Have you examined any in-service failures in the nuclear industry with this pipe that are on record?

MR. SCHMIDT: I know from the fossil industry that there has been weld failures. It is believed that the quality assurance into the fabrication may have been attributed to that. A sister utility also informed us with their installation of service pipe at one of their stations during the hydros, they had weld failures and that was attributed in adequate heater element temperatures not being controlled.

MEMBER RYAN: So you really, I mean, at the end of the day, you really rely on the hydrotesting to confirm that whatever run of pipe you are evaluating is intact.

MR. SCHMIDT: Yes. I mean, that is

correct. That is kind of the last step in it. I mean, I think the quality assurance --

MEMBER RYAN: That is the only proof of the system behavior that you have.

MR. SCHMIDT: Right.

MEMBER RYAN: Everything else is based on QA and qualification.

MR. SCHMIDT: Keep in mind here again, this line, even though it is being hydrated, it shouldn't see any real significant pressures. It is open channel flow the whole way.

MEMBER RYAN: Well I mean, that is a different question.

MR. SCHMIDT: Right.

MEMBER RYAN: I mean, to see if the weld is working and it is not going to leak anywhere along its run, you normally test your pipe.

And you say it is 100 and --

MR. SCHMIDT: It would be performed at 120 psi --

MEMBER RYAN: At 120 pounds and held for how long?

MR. SCHMIDT: There is an initial, they call it soak time where they pump up the system while the pipe does expand to a certain degree.

MEMBER RYAN: Right. Right.

MR. SCHMIDT: That is done for four hours. And then there is a narrow hold time.

MEMBER RYAN: One hour is all it is held for?

MR. SCHMIDT: That is what is required. And that is where inspection of the line and the welds is performed.

MEMBER RYAN: And is pressure continually added or do you look to see if it leaks over time?

MR. SCHMIDT: During that soak time, you build the system up to the pressure to allow for an expansion.

MEMBER RYAN: Yes, that is with still that pressure on it.

MR. SCHMIDT: But during that one hour hold time, no pressure is to be added.

MEMBER RYAN: Okay.

MR. SCHMIDT: You are monitoring for any fluctuation at that time.

MEMBER RYAN: Okay, great. Thanks.

MEMBER ARMIJO: Now the staff has required non-UT exam of the welds for I think Catawba and Callaway. Maybe it is -- I think those were service water lines, essential service water.

MR. SCHMIDT: Right, safety-related.

MEMBER ARMIJO: Now is that not required or you do not believe that would be required to make sure that these welds wouldn't have the same kind of flaws that had failed in other cases?

MR. SCHMIDT: For this application is it not required for B31.1.

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

MR. SCHMIDT: Okay, in summary we talked a lot about the design and construction of our wastewater system blowdown line. It is interfaced with the liquid rad waste system.

We believe the design features that we have mentioned, the gravity drainage open channel flow, lack of mechanical joints in its installation, lack of components with mechanical joints that could leak, that gives us confidence in long-term operations for this pipe, further assured through our construction and installation. Quality assurance that I spoke to earlier, we believe that this line that will have long-term leak-free operations with this installation.

MEMBER RYAN: Do you see any issues for a 20-year plant life with maybe a 20-year extension?

These materials really aren't all that experienced over many decades of in-service use.

MR. SCHMIDT: I know for the code case, I think the N755 code case for some of the safety related applications, there is testing that has been done behind that to come up with the 50-year design life.

MEMBER RYAN: Well it is not 50 years of actual in-service. It is some accelerated test protocol. Right?

MR. SCHMIDT: Yes. I can't speak to the --

MEMBER RYAN: Okay.

MR. SCHMIDT: -- testing itself but I know that a 50-year design life is what was called out there. There is other -- The Plastics Pipe Institute speaks to 50 to 100-year design life. There is a culvert design guide that has a two-year design life. You know, we are looking at 60 years with this application with the development of the material that we are using, the DE-4710 material, which is the same material that is being used or is being requested in the relief request with the service water applications.

MEMBER RYAN: I think I read somewhere

that the NRC has not endorsed the code case at this point.

MR. SCHMIDT: No, that is correct. It is currently at Rev 0 Blue Book. Rev 1 is being pursued as well as a second edition. However, I just want to note that the material that we are using is the same material that is being discussed in that code case.

MEMBER RYAN: So it is a little bit up in the air that the code case isn't done and the NRC hasn't endorsed it at this point. But you are confident that you have got 60 years of --

MR. SCHMIDT: I mean, it doesn't apply to our case but for information I think the test that went into generating that code case is part of the material properties in endurance.

MEMBER RYAN: Yes, can endure in your application.

MR. SCHMIDT: Right. Okay, that's all I have.

MR. SEBROSKY: Mr. Ray, the staff doesn't have a prepared presentation but we do have the subject matter experts in the room. Larry Wheeler reviewed the welding aspects of the pipe and Steve did the review of the health physics aspects of the liquid radwaste. So if there are any questions from the full committee, we can address those.

MEMBER RAY: Sam?

MEMBER ARMIJO: Yes, just what are the consequences if you do have failures or leakage from these welds after they have been in service? There is some slow crack growth that can occur, maybe not at these temperatures but if there is a weld defect. You know, the consequences, other than being a nuisance, is there any other? There is certainly no safety problem or is there?

MR. SCHAFFER: I guess I can address that. You know, we are talking at the lowest level of safety significance.

MEMBER ARMIJO: Contamination maybe it.

MR. SCHAFFER: Right. If you remember the DCD in Chapter 11, they have the ratio of the discharge once it is diluted by the blowdown, compared to what is in 10 C.F.R. 20 Appendix B. And that level is about ten percent of the Appendix B limits. If you drank the water in that pipe as your water supply, you would get five millirems per year. You know, it is very low.

MEMBER ARMIJO: I am convinced of that but that is not what would happen in the press if you had a local tritium get into your ground water somewhere.

That is a --

MR. SCHMIDT: I could speak to the slow --

MEMBER ARMIJO: -- public relations not safety. Go ahead.

MR. SCHMIDT: Yes, I was going to say I can speak to the slow crack growth concerns. That is one of the safety-related applications driving the request for UT-type inspections. That is driven by our higher temperatures than what we would expect as well as pressurized service.

I wouldn't expect that failure mechanism with our application.

MEMBER ARMIJO: No, I wouldn't either.

MEMBER RYAN: You talked a little bit in the subcommittee about the fact that you were going to have some kind of a secondary monitoring effort with localized groundwater wells or some other kind of measurement near the pipe or at certain locations along the pipe. Could you review that for us?

MR. SCHMIDT: Yes, in our application we commit to a groundwater monitoring program that goes beyond our radiological effluent monitoring program. That will be in accordance with NEI 08-08(a). That is for the site that would evaluate buried piping and install welds as needed.

MEMBER RYAN: I guess you are probably not at the stage where you have got specific details on distance from pipe to welds. That is all yet to be determined.

MR. SCHMIDT: That's correct. We haven't started developing that program yet.

MEMBER RYAN: And again, I appreciate, Steve, your comment that those consequences are certainly not significant but that is not from a public standpoint what it is significant. What is significant is there was a leak that wasn't expected.

MR. SCHMIDT: Right.

MEMBER RYAN: We have many cases of that. So, I take comfort as a health physicist doing those numbers but certainly not an undetected leak.

MEMBER RAY: Nothing else on this then? Emergency plan.

MR. SCHMIDT: Thank you.

MR. HINSON: Now have -- This is Charles Hinson, NRC. What is the approximate length of the piping segments that will be welded together?

MR. SCHMIDT: I think we mentioned before we are looking at about 5,000 linear feet.

MR. HINSON: No, I mean the individual segments. What is the distance between welds?

MR. SCHMIDT: That I can't speak to directly. I know they come in sticks of a certain prefabricated length to haul on a truck, that kind of thing. But I can't speak to a specific length.

MEMBER ARMIJO: They could make them as long as they want. They extrude these things.

MR. SCHMIDT: But you have got to build a transport to ship them on.

MEMBER ARMIJO: You have got to get them there.

MR. SCHMIDT: You have got to be able to transport it.

MEMBER SIEBER: For a long truck.

MR. SCHMIDT: We haven't procured this pipe.

MEMBER RAY: Okay, we are one minute from the announced time when we adjourn this session. Can we move on then, please?

MS. MONROE: The remainder of the presentations will take approximately just several more minutes from the applicant's standpoint.

Next we are going to go into emergency planning. Mr. Tim Bonnette will address that.

MR. BONNETTE: Thank you. As Amy said, I am Tim Bonnette, SCE&G Emergency Preparedness. Our presentation is going to cover, discuss our emergency plan design, the DCD departure, our emergency facilities, emergency response, our emergency panning zone, and public awareness.

Our emergency plan design is a single emergency plan for all three units. It is developed in accordance with NUREG-0654/FEMA-REP-1 Rev 1, 10 C.F.R. 5.47 and 10 C.F.R. 50, Appendix E.

Our emergency action levels are developed in accordance with NEI 07-01 Rev. 0 for Units 2 and 3 and have been developed in accordance with NEI 9901 Rev. 5 for Unit 1. And I would like to note that we have a proposed licensed condition to develop the Units 2 and 3 EALs in accordance with this NEI document.

Our DCD departure, as Amy mentioned briefly a little earlier in presentation is a departure of the locations of our Technical Support Center and our operational support center. Our Technical Support Center is being relocated to the Nuclear Operations Building which is being constructed by Unit 1 for Unit 1 site upgrades. The building will house the Unit 1 staff, support staffing, and also Unit 1 TSC until Units 2 and 3 move forward towards operation.

The TSC is designed to support staffing for Unit 1 and Units 2 and 3 in the event of an emergency. The building that Unit 1 is constructing will begin construction early this year and we are expecting construction to be done in mid to late-2012.

The second part of our departure is the departure of the Operational Support Center. The Operational Support Centers will be relocated to each of the respective units annex buildings in the area designated within DCD as the Technical Support Center or TSC. And that is on the DCD elevation 117.6.

MEMBER SIEBER: How far away is your EOF?

MR. BONNETTE: Our EOF we will discuss in a little bit but it is actually outside of our ten mile EPZ.

MEMBER SIEBER: How far outside? Less than 25 miles?

MR. BONNETTE: It is a little over ten miles. It is not 15 miles out.

MEMBER SIEBER: Oh, okay. Thanks.

MR. BONNETTE: The Technical Support Center will be a common Technical Support Center for all three units to allow us a single point for technical support of on-site evaluations, on-site development of mitigation strategies and on-site emergency response.

Again, it is located outside of both fire protected areas, which I will discuss in just a moment. In the basement, in a harden facility of the nuclear operations, I mean the new Nuclear Operations Building. Thank you.

Access is controlled by security card readers and limited ingress and egress points into that facility. The facility itself has a backup power supply, which is diesel backed and an independent ventilation system with high efficiency particulate air filters, as well as charcoal air filters.

MEMBER SIEBER: How about shielding?

MR. BONNETTE: The building design is designed just as if it would have been in adjacent to the control room. So it matches 0696.

MEMBER SIEBER: Okay, thanks.

MR. BONNETTE: Real quick, it also has the human factors engineering that will support either one-unit emergency, a two-unit emergency, or a three-unit emergency.

This is the picture I was talking about that shows the location of the Nuclear Operations Building with the Technical Support Center in the basement. It is located between Unit 1's protected area and the Unit 2 and 3 protected area of the site.

And this is just an overall picture of our site with the nuclear exclusion area boundary, which is the security patrolled area and controlled area for the site itself.

The emergency facilities for all three of our units include the three units' control rooms, the three units' Operational Support Centers, single Technical Support Center, the single Emergency Operations Facility, and a single Joint Information Center. Again, the OSC for Units 2 and 3 and the Technical Support Center were discussed earlier in the departure section.

The Emergency Operations Facility and the Joint Information Center are in a co-located facility again outside of our Emergency Planning Zone, which is outside of the ten mile radius.

MEMBER STETKAR: Tim?

MR. BONNETTE: Yes, sir.

MEMBER STETKAR: The TSC mentioned -- I'll try to make this quick. The security entrance, card readers, etcetera, etcetera, does that come from Unit 1, Unit 2, Unit 3, its own power supply?

MR. BONNETTE: That part of the design detail I don't know has been finalized yet. So, I cannot speak to that.

MEMBER STETKAR: Okay, thanks.

MR. BONNETTE: Our emergency response, if you look at our emergency plan, it discusses basically three levels of hierarchy of response. Site level, individual protected area level, and then a single unit emergency response.

In these hierarchies, if there is a site level emergency response, the unit 1 control room is the lead control room for the initial notifications and the initial declarations. If we reach an alert or higher classification, then we will be activating our entire emergency response organization and all emergency response facilities.

If we have an event that affects only a single protected area, either the Unit 2/3 protected area or the Unit 1 protected area, the Unit 1 has the lead for its protected area and Unit 2 will be the lead control room for the initial notifications and declarations of the emergency.

And then for the individual units, if they have an emergency, their respective control rooms will be the lead control room for the emergency response.

Our Emergency Planning Zone, and just to note I do have a slide picture of it following this one, will remain -- the boundaries of the Emergency Planning Zone will remain the same as the existing Unit 1 Emergency Planning Zone. And this has been reviewed and agreed upon by the State of South Carolina in a letter and by resolution by the full risk counties. These boundaries have also been reviewed and accepted for Units 2 and 3 and Unit 1 by FEMA.

This is the boundary map of our Emergency Planning Zone. You can see the sectors are outlined in color. The radiuses from Units 1 are two miles, five miles, and ten miles. And what we would like to note is boundaries were based on population demographics, the topography, and then local jurisdictional lines.

When we did these boundaries, we went ahead and took into account and the populations within these boundaries include the daycares, medical facilities, assisted living facilities that may be close to the ten mile radius but are outside of it. So those are already included.

And our public awareness annually we distribute to all residences businesses within our Emergency Planning Zone a calendar which includes a map of our Emergency Planning Zone, evacuation sector boundaries, both in description and in maps. It includes the evacuation routes and descriptions and in maps, as well as public action guidance for an emergency, the shelter welcome center locations, and also the local radio and television stations, to which the public can tune into to get emergency information.

The calendar also includes a special needs assistance card, which any resident with special needs can fill out and it can be returned to VC Summer through a postage-paid pre-addressed card. And once VC Summer collects those cards, they distribute them to the applicable counties so the county can also plan for the emergency and the public assistance.

We also make sure that we try to keep our public informed if we are doing any scheduled testing to not cause undue alert. We do press releases. We also support a community coalition meeting, currently supporting it with our chief nuclear officer. So we are trying to make sure we are staying in contact with the public as we move forward and with what is going on at the site.

In addition, we make sure that the emergency responders for fire, EMS, and local law enforcement for our risk counties are all trained in basic radiological monitoring and handling. And we also train select populations of the state emergency management divisions, state law enforcement, state highway patrol, and state department of natural resources.

That's all I have.

MR. SEBROSKY: Mr. Ray, it is the same thing. Ned Wright is our lead reviewer. The staff doesn't have a separate presentation for this.

MEMBER RAY: Any comments for either the applicant or for the staff?

All right. The last item prior to our committee discussion, Amy do you have something to present?

MS. MONROE: Yes, there was one more.

MEMBER RAY: Okay.

MS. MONROE: Actually what we are going to show you today is one of the benefits of being an RCOLA and utilizing the design-centered approach. The vast majority of our application is either the DCD, which we incorporate, or the standard RCOLA material, which we replicate exactly within our application.

We found the process to be very effective, efficient, and actually beneficial for everyone. One of the greatest benefits has been the ability to pool our resources throughout the industry. Technical expertise, we are taking advantage of everybody's technical expertise within their own company and we are able to significantly increase reviews that are performed on the material.

What we think that has done is improve the depth of the review than would be expected in a single applicant coming forward. Basically what that means is we have covered essentially everything from a true safety concern has been incorporated in our application. However, we did feel like it was worthwhile the committee's time for about three minutes to have Mr. LaBorde here discuss some of our offsite electrical power.

So, Jamie?

MR. LaBORDE: Hello, my name is Jamie LaBorde. We are a standard AP1000 plant, as Amy said. Our grid connections are site-specific as well as our interface agreements and procedures for transmission.

Each one of the overhead transmission lines can carry the maximum power required for both units simultaneously for normal, abnormal, or accident conditions. ITAAC in Table 2612-1 confirms the as-built condition meets this requirement.

A new switchyard is being built for Units 2 and 3. A breaker and a half configuration is used for the 12 line connections and the two reserve aux transformer connections. The two generator step-up transformers are connected using a double bus, double breaker configuration.

Failure analysis for the transmission system was performed with acceptable results. We have done our stability studies and we have no issues meeting the requirements from the North American Reliability Corporation, commonly known as NARC. The AP1000 interface requirement which includes the requirement to maintain voltage to the reactor coolant pumps for three seconds after a turbine trip in Reg Guide 1.206. An as-built grid stability study is also required by ITAAC contained in 2612-1.

Information on this figure can be found on COLA figure 82201. The Unit 2/3 switchyard is to the left. The Unit 1 switchyard is to the top right. Lines exit the Unit 2/3 switchyard to the west and south and one line to the north. Lines exit the Unit 1 switchyard to the east, south, and one line to the north. And there are three connections between the two switchyards. We presently have just south of the plant a par 230 kV switchyard. It is going to be retired as part of the effort for the plant.

Over 95 percent of the lines that we are adding or in existing right-of-ways, we have identified the routes and we are working toward getting the required easements for the remainder of our lines, which is about six miles.

This is a single line diagram of the Unit 2/3 switchyard. The generator connections are made to each bus by dedicated breakers, which is a double bus, double breaker configuration. Both breakers open to isolate the generator. Breaker and a half connections are used for the lines and the reserve aux transformers.

And if there are no questions, this concludes my presentation.

MEMBER SIEBER: How are you going to get to three seconds under all conditions?

MR. LaBORDE: Well it is on the turbine trip that the requirement exists there because that is the condition two event. And it is that condition.

MEMBER SIEBER: Okay. You can get it that way.

MR. LaBORDE: But actually for offsite power, the grid stability event some of the follow-ups, we don't have problems with that.

MEMBER SIEBER: How long does it take if you lose all offsite power, do you automatically get a thing in your generator trip immediately or does it run back?

MR. LaBORDE: If we disconnect the unit from the grid?

MEMBER SIEBER: If the grid is dead.

MR. LaBORDE: It can run back.

MEMBER SIEBER: It can run.

MR. LaBORDE: The unit is designed to run back.

MEMBER SIEBER: So you get to three seconds that way.

MR. LaBORDE: Well actually the requirement is on the turbine trip condition where the turbine trips.

MEMBER SIEBER: Okay. That one is easy.

MR. LaBORDE: It is a coast down issue for a condition two event.

MEMBER SIEBER: Okay, thanks.

MEMBER RAY: Yes, Joe?

MR. SEBROSKY: It is the same thing. Om Chopra is our Chapter 8 subject matter expert and reviewer, if there are any questions for him.

MEMBER RAY: Thank you for coming. Sorry you missed your lunch.

Is there any questions for either

applicant or staff on Chapter 8?

MR. SEBROSKY: And then this is the last slide.

MEMBER RAY: Okay. And you are going to speak to that?

MR. SEBROSKY: Yes. So this last slide presentation, what we are attempting to do here is just give an overview of the site-specific information in the Summer COL application.

The first bullet just goes to what I had said earlier, when we briefed the subcommittee, we spent a lot of time on Chapter 2 and 13.3. We tried to give the full committee a sense of everything that was high level discussions in Chapter and in the emergency plan.

The second bullet talks to what we did not brief the subcommittee on. There was nothing in 4, 7, or 14 that we briefed the subcommittee on because it is all standard material.

Slides 3 through 22 is for your later review. It just shows every plant-specific item that is in every one of those other chapters. And in a yellow highlight, it shows the areas that we briefed the subcommittee on. If you go through that list, you are going to see that we briefed the full committee on the majority of those issues, with the exception of there is some material in 15, 17, and 19 that we provided to the subcommittee that we did not think rose to the level that the full committee needed to be briefed on.

So if you go back to the earlier presentation and you take the standard material out of what we briefed the subcommittee and full committee on, this is what you are left with. And it just attempts to give you a sense of what we briefed the subcommittee on and how we tried to touch on that with the full committee.

The last bullet is just a note that we did have a closed session with the subcommittee where we talked about some site-specific differences associated with the LOLA review. The subcommittee is aware of that. We have not, obviously, briefed the full committee on that.

And that is all I have.

MEMBER RAY: All right. Thank you, Joe.

Said, we should ask if there is any public comments. And so I believe the line is open now and I will make that request. If there is anyone on the line who wishes to make comments to the full committee, please first identify yourself.

Hearing none, is there anyone in the audience who wishes to make comments or statements?

Okay and if there is none, we should go around the table, I think. Jack?

MEMBER SIEBER: I'm satisfied with the presentations that all the issues are correctly analyzed and documented.

MEMBER RAY: Okay, Sanjoy?

MEMBER BANERJEE: I think I am fine. I have given you some information on the off-site hazards which you have.

MEMBER RAY: Yes, and basically that is in the nature of the concern that was discussed and responded to here and we simply want to track that.

Dennis?

MEMBER BLEY: Nothing.

MEMBER RAY: Sam?

MEMBER ARMIJO: Nothing.

MEMBER RAY: Said?

CHAIRMAN ABDEL-KHALIK: No additional comments.

MEMBER RAY: John, what are we going to do with your item?

MEMBER STETKAR: I have no idea. We will discuss that later, I guess.

MEMBER RAY: Are you going to write it down?

MEMBER STETKAR: We will discuss that later.

MEMBER RAY: Okay.

MEMBER SIEBER: We will work on that during lunch.

MEMBER RYAN: All right, thanks. After the subcommittee meeting, we did get some additional information independently on the HDPE pipe and related performance questions. And I appreciate the additional information today. That was very helpful. So I will write something up and offer it to you for putting in the letter.

MEMBER RAY: Okay. Well, be sure and have it by 6:00 today.

MEMBER RYAN: No problem. I've got all that time?

MEMBER RAY: That's when we are going to need it. Bill?

MEMBER SHACK: No comment.

MEMBER RAY: Joy?

MEMBER REMPE: No comments.

MEMBER RAY: Mike?

MEMBER CORRADINI: No comment.

MEMBER RAY: Back to you.

CHAIRMAN ABDEL-KHALIK: Thank you. At this time, we will break for lunch. We will reconvene at 1:45.

(Whereupon, the foregoing matter went off the record at 1:05 p.m. and went back on the record at 1:46 p.m.)

CHAIRMAN ABDEL-KHALIK: We're back in session.

At this time, we will move to the next item on the agenda, Comparison Between ISAs for Fuel Cycle Facilities and PRAs for Reactors. And Mike Ryan will lead us through this discussion.

MEMBER RYAN: Thank you, Mr. Chairman.

On January 11th, the ACR Radiation Protection Nuclear Materials Subcommittee reviewed the staff's White Paper entitled A Comparison of Integrated Safety Analyses and Probabilistic Risk Assessments. We heard presentations from the NRC staff and representatives of the Nuclear Energy Institute then had detailed discussions with them at that time.

Today the full Committee will hear a presentation from the NRC staff, by Dennis Damon and Charles Vaughan from NEI will also make an oral statement a little bit later in the briefing.

So with that, Dennis, I'll turn it over to you please.

MR. DAMON: Good afternoon. My name is Dennis Damon. I'm the Senior Level Advisor for Risk Assessment in the Office of Nuclear Material Safety and Safeguards although I'm officially assigned to the Division of Fuel Cycle Safety and Safeguards. I've been with the NRC for 16 years, ten of which I've been actually in this division, Fuel Cycle Division.

This briefing this morning -- this afternoon rather -- should be relatively quick because most of the slides which we presented to the Subcommittee have been moved to the back of the presentation as simply background material. There's only 12 slides with contents in what I'm going to say here. I'm just going to basically quickly run through the -- what the paper does.

This slide two is the objectives of the briefing here this afternoon -- is to present this paper that was -- the Commission directed that the staff produce this paper comparing integrated safety analyses and probabilistic risk assessment. And we would like to obtain a review by the ACRS and a letter from the ACRS on this subject that, in particular, we hope that it would address what we see as being the key points that are made in the paper and to address what the Commission was really asking for.

And I'll quote what they said in the second -- the SRM to the SECY-10-0031, which was -- the subject of which was revised the Fuel Cycle Oversight Program. And in the SRM to that SECY, the Commission said, "The Commission looks forward to the staff's concise comparison to integrated safety analyses and probabilistic risk assessment along with the accompanying review and letter report of the ACRS to better inform proposed enhancements to the oversight process."

So the paper tries to address what we thing the Commissioners are interested in.

MEMBER ARMIJO: Dennis?

MR. DAMON: Yes.

MEMBER ARMIJO: I just want to make a clarification because I was confused. I had the impression that this exercise was based on fuel cycle facilities licensed under Part 70. And limited to that.

Now we know MOX facility out there. And it's not a Part 70 license, as far as I know. It's some other.

MR. DAMON: No, it is?

MEMBER ARMIJO: It's Part 70? I thought it was -- okay, so MOX falls into this category?

MR. DAMON: Yes.

MEMBER ARMIJO: Okay.

MR. DAMON: The difference --

MEMBER ARMIJO: Savannah River does?

MR. DAMON: Yes. There is in Section 70.22 and 70.23, there are some specific requirements applicable only to a plutonium -- a facility licensed to possess a large quantity of plutonium in that respect. But all the rest of Part 70 also applies to them.

MEMBER ARMIJO: Okay. So that's part of the family of fuel cycle facilities that you're addressing?

MR. DAMON: Yes.

MEMBER ARMIJO: Okay.

MR. DAMON: They did an ISA.

MEMBER ARMIJO: That clear up my question.

MR. DAMON: So here on this slide, and I will come back -- this is at the end -- is we tried -- the paper ends up making two points. One has to -- the first point has to do with discussion ISA- and PRA-type analyses in the context of the safety of the facility and in compliance with the Part 70. And the point here is the staff has concluded that ISAs are acceptable for the functions that they are required to do within that context of Part 70.

And the second point relates back to this what we think the Commission is interested in in this paper, in that it came up in the context of revising the Fuel Cycle Oversight Program, and that is how one does use either ISA results or PRA in the context of trying to -- the Fuel Cycle Oversight Program that presumably has some kind of risk significance determination. And specifically the paper has an example in Section 5 of an actual -- of a hypothetical rather inspection finding and how one would evaluate that quantity -- the risk significance of such a finding quantitatively and under two circumstances, one where an ISA had produced quantitative risk indices, which is one of the methods used, and the other way, where the ISA had actually produced quantitative frequencies of the accident sequences.

And so it makes the point that -- the second point here, which is -- the example is in there to illustrate this second point. And that is that in most cases and inspection finding will only effect a very small part of the plant and just a accident sequences. And in addition, there's another point, that based on the fact the staff actually looked at all the inspection deficiencies for the last five years and the total number of deficiencies that have some kind of risk significance is only about one or two per plant per year.

So it is a small number. And each on typically only effects a very small part of the plant. So the conclusion is this second point, namely that the efficient way to evaluate risk significance is to do it when you need to evaluate a particular deficiency. So you do it case by case, when it happens as opposed to let's do the whole plant up front, you know, in advance the way it was, in fact, done for reactors.

So this is a new slide that was put in just to familiarize people with how many and what kind of facilities we're talking about. The facility that Sam Armijo mentioned here is under fuel fabrication, the MOX Fuel Fabrication Facility is one. Then there's three commercial white water fuel manufacturing plants and two that are involved with the production of naval reactors.

Then there are four enrichment facilities. And you'll notice under the enrichment, the diffusion plants, the gaseous diffusion plants are not there because they are not licensed under Part 70. They have a separate part of the regulation. When we inherited those plants from the Department of Energy, they were regulated under a different part of the rule.

MEMBER BLEY: Do they do anything like ISA?

MR. DAMON: No, they have a completely -- they have a DOE-like analysis that they do.

MEMBER CORRADINI: You said this is --

MR. DAMON: It hasn't -- it does -- it is actually somewhat analogous to an ISA. But its under DOE's requirements.

MEMBER CORRADINI: This is for enrichment you said, right?

MR. DAMON: Yes. For diffusion enrichment that -- they're not on this list. They have a different. They focus only on public risk. And they do the -- they kind of do it in a reverse order. In ISA, you identify an accident sequence. And the first thing you do is to say well what consequence level is this at? And then you evaluate likelihood.

They do it the other way around. They have very coarse likelihood bins. And they place a sequence in a likelihood bin. Then they do a very elaborate and detailed consequence evaluation to the offsite public. So they just -- it's a little bit different than what we do but it has the same -- similar purpose.

So -- by the way, many of these facilities have never been operated yet. And some of them haven't received their licenses either. And two of them on here, as is noted, are to license under Part 40, which does not have an ISA requirement. But the intent of the staff is to have a rulemaking that will require that Part 40 plants have an ISA.

MEMBER SHACK: How many have actually done their ISAs already?

MR. DAMON: I think ten. I think -- let me think --

MEMBER SHACK: So some of the asterisked ones have actually done it?

MR. DAMON: Yes. Mostly -- almost everything on this list has actually done -- I don't thing GE, the SILEX one may not be done. I don't -- I really don't know. Honeywell did something. It's like an ISA but not exactly. And, of course, International Isotopes is a new -- is in the process, so --

MEMBER STETKAR: Dennis, are you aware of any of these facilities that have done any quantitative PRA work?

MR. DAMON: You mean for their own purposes other than an ISA?

MEMBER STETKAR: I just -- are you aware of any of them that have done any quantitative PRA?

MR. DAMON: Well, both GE and Westinghouse did at least -- well, in the case of GE, their ISA is quantitative. In other words, they've got a quantitative frequency for each accident sequence. And in the case of Westinghouse, most of their sequences do also have a quantitative frequency. And their -- in other words, if you look in their ISA summary that they sent in, they'll have tables of where they -- the basis on which they assign frequencies to the various events.

MEMBER STETKAR: Okay. Thanks.

MR. DAMON: So it's quantitative in that sense. But that's not like -- they don't add up the sequences --

MEMBER STETKAR: They don't -- okay.

MR. DAMON: -- the risks from all sequences to a --

MEMBER STETKAR: That's sort of what I was talking about.

MR. DAMON: -- a given receptor like a pickle worker, add up all the sequences that effect that worker, they don't do that.

MEMBER STETKAR: They don't do that? Okay. Thanks.

MS. BAILEY: Dennis, can I just make a clarification and answer the question about which of those facilities have done ISAs? If you go back to the slide, the enrichment and fuel fabrication facilities are licensed or are being licensed under 10 CFR Part 70. So they're all required to have an integrated safety analyses. So either they've done it or in their application they have an ISA.

MEMBER STETKAR: I understand that. I was asking --

MS. BAILEY: The conversion and deconversion facilities, Honeywell has an ISA that is incorporated as a license condition. International Isotopes, in anticipation of the Part 40 rulemaking, does have an ISA in its application.

MEMBER ARMIJO: But all the operating facilities have ISAs.

MS. BAILEY: All the operating facilities that are licensed under 10 CFR Part 70 that are subject to Subpart H has ISAs.

MEMBER STETKAR: Okay.

MR. DAMON: Yes, they were required in the rule to have them done and submitted by October of 2004. And they all did. And the staff reviewed them and approved them.

MEMBER SHACK: So the GE-Hitachi, where they had paper about PRA versus ISA, they just used those thoughts to kind of inform their ISA to a certain extent? Or that was just a paper that somebody there wrote?

MR. DAMON: Right. They did that because they -- they had initially done an ISA in which they used a risk index method.

MEMBER SHACK: Oh.

MR. DAMON: Then they changed and they did it in this quantitative way with event trees and with different people doing -- participating that were PRA people. As you may know, at a certain point in the middle of this process, GE moved their staff, which probably included some PRA people, from San Jose to Wilmington where the fuel fab is. So at that point in time, they had their PRA people right there at the facility. And so they -- that's where the paper came from.

MEMBER CORRADINI: So just one quick

question. So this is the fuel cycle. If there are isotopes, did they also -- if you're making isotopes, does that fit into this as a Part 70?

MR. DAMON: Well, it depends on how you make the isotopes. If you make it in a reactor, then they have to have a Part 50 license.

MEMBER CORRADINI: I see. Okay. But if not, I guess I was looking under International Isotopes. I assumed that was the manufacture of isotopes outside of a reactor.

MR. DAMON: No, what they're doing is deconversion. They are going to recover the fluorine from depleted uranium in order to sell it.

MEMBER CORRADINI: I see.

MR. DAMON: To sell the fluorine.

MEMBER CORRADINI: Okay.

MR. DAMON: In fact, yes, the flow -- there is a flow of material through these plants. And over the years, the licensees eventually figured out who -- somebody they could sell the material to.

(Laughter.)

MEMBER ARMIJO: You can either have it in saleable fluorine or calcium fluoride piled up in mountains.

MR. DAMON: Yes. And so actually there's

no like waste. As far as I'm aware, there's no like waste stream anymore really. It all goes and it gets sold somewhere.

MEMBER CORRADINI: There's always a waste stream. The second lost also.

(Laughter.)

MR. DAMON: There isn't like oh, yes, this big -- there used to be a gigantic pile of calcium fluoride out behind GE.

MEMBER ARMIJO: I got rid of that. We changed our whole conversion system to a process where we could sell fluorine instead of piling up calcium fluoride.

MR. DAMON: And so --

MEMBER POWERS: So you're the responsible for fluoridating water?

MEMBER ARMIJO: But your teeth are better. And it's a communist plot, I understand.

MR. DAMON: On this slide, the first part of this slide refers to the idea of ISA-PRA comparison. And it's sort of semi -- I will quote from the SRM that directed us to do this, we're directed to a do a comparison and critical evaluation. And as we started to do that, it was realized well, you have -- to evaluate something or compare using ISA or PRA, it has to be with respect to some use, some particular thing you are going to use either the ISA or PRA for.

So in the paper, it does this with respect to two specific uses. And I might mention that PRAs are used -- and ISAs also are actually used for more than just these two things. There are other things that you can do with these types of analyses.

But the first one is the actual regulator purpose of an ISA, which is for safety under 10 CFR 70 Subpart H, which requires that the ISA be done. And so we're going to evaluate what's been done with ISA and how that -- in the paper, it discusses well, what if you did it more like a PRA.

And number two, the second use is this use of ISA or PRA in doing risk significance determination for inspection findings because that's the context in which this -- we were directed to do this paper.

But this is an outline of the contents of the paper. It has five sections. The first two simply discuss what ISAs and PRAs are as sort of a background reference for -- in case -- for those who may not be familiar with one or the other of these things.

Then section three is addressing the first one of these two uses, namely for safety under Subpart H. It is an evaluation of ISA and PRA in that context.

Then sections four and five are the second thing, which is this risk significance thing. Section four just sets the background and the context because risk significance determination is not the be all and end all of an oversight program. It's just one little piece that's used in it. So it sets the context.

And then section five discusses ISA and PRA in the context of doing risk significance determination. And specifically it is a quantitative risk significance determination. It's the exact analog of what is done in the reactor oversight program for quantitative. And has a specific example to illustrate how this might be done.

We're not asserting that it should be done at this point or that or anything else. This is something that would be evaluated as part of a developmental program of trying to do something like this. But it is an illustration of what you might be able to do.

And that serves as a point of reference when you discuss and ISA and a PRA and how they might differ. And that example is evaluated using results of both a risk index method and a fully quantitative ISA result, which would be what you would have also available if you had actually done a PRA.

This slide refers to the first two sections, which simply are discussing what ISAs and PRAs are. And the point here is that ISA and a PRA -- a typical -- like I say, PRAs are used for many different applications in the NRC. But none of them are exactly what ISAs are doing. So that ISA and PRA are typically being used in the Agency for different purposes.

The functions of an ISA under the Part 70 Safety Program are primarily these two things. And there's much more to the Safety Program in Part 70 than just the ISA. The ISA does this function here -- these functions here. It identifies the hazards and accident sequences.

And this is intended to be comprehensive to the -- in other words, the scope of an ISA is completeness of all things that could result in what we are defined as intermediate consequence events or above. And that's defined in the rule what that level of consequence is both for workers and the public. As I say, we do workers whereas the DOE analyses don't.

And that's -- one of the reasons for that is that most accident sequences only do effect the worker. There are really very few that could impact the public offsite. So this is what an ISA does. It identifies the accidents and what are the items relied on for safety that are preventing or mitigating those accidents. And a list of those items and the accident sequences is required by the -- to be sent to the NRC as a thing called an ISA summary. And that summary is kept up to date. It's updated annually.

MEMBER BLEY: So the summary is required to be submitted?

MR. DAMON: Yes, a summary.

MEMBER BLEY: Okay.

MR. DAMON: Now the summary is, you know --

MEMBER BLEY: Can be very large. I've seen it large.

MR. DAMON: Whereas the ISA documentation, I mean at least is like a whole room full of stuff when it's on paper.

MEMBER BLEY: I had a question about the second part of that, the compliance with the performance requirements. When you go to the regulation, it's very clear on definition of high consequence and intermediate consequence exactly what that means.

Then it says for high consequence events, they must be very unlikely or extremely unlikely --

MR. DAMON: Highly.

MEMBER BLEY: -- highly unlikely and for intermediate consequence, they must be unlikely. Is there any guidance to people about what that means? Do people interpret it differently?

MEMBER CORRADINI: Are you asking is there a number associated with the adjective?

MEMBER BLEY: I would like to see a number associated with it. The way it's written, it seems like everyone that comes in could have their own interpretation of what those words mean.

MR. DAMON: Yes, they could. There was a Standard Review Plan that was written and it actually was forward drafted at the time the rule was promulgated. So everyone knew what was going to be in it. And it has some guidance on numbers.

MEMBER BLEY: Okay. I didn't go back and look at that.

MR. DAMON: Yes. It says if you do, that quantitatively this is one number the staff -- and it has a rationale for why that number was chosen and so on. Now licensees didn't necessarily pick that number. Some licensees picked a different number. Or they used the risk -- and then there is the risk index method. And they picked a number from that that's also equivalent to a frequency.

MEMBER BLEY: But they all picked numbers? Or did some just use adjectives to describe?

MR. DAMON: Nine out of ten --

MEMBER BLEY: Used numbers of some sort?

MR. DAMON: One did not use a number.

MEMBER BLEY: Can you give us a hint of what the ranges of those numbers might have been?

MR. DAMON: Ten to the minus four and ten to the minus five for highly unlikely. Some picked one number and some picked --

MEMBER BLEY: Okay.

MR. DAMON: -- the other one.

MEMBER BLEY: That's not too bad.

MR. DAMON: Right. So, you know --

MEMBER BLEY: And for unlikely?

MR. DAMON: And order of magnitude difference --

MEMBER BLEY: Okay.

MR. DAMON: -- is usually -- I think it's true for all of them.

So the other thing that the ISAs do is

evaluate these performance requirements that Dennis Bley mentioned. And there is one other performance requirement and it is a direct quote of a requirement -- the principle requirement in ANSI 8.1, this criticality safety standard. And it says that for all normal and credible abnormal events, the system shall be subcritical. And partly that was put in in case you had a shielded facility, we still want to prevent criticalities even if there is no, you know, shield there, shielding to protect you from the results.

And the functions of PRA are various. So I just sort of synopsized it. But typically a PRA, the quantitative results of PRA are used in many different ways. And, therefore, it requires basically that you quantify a risk metric to do most of those applications although you can get obviously qualitative insights that don't involve numbers.

But most of the applications that PRAs are used for, it differs in that you must quantify it and you must add up the accident sequences to obtain a metric that are used in the applications like, for example, regulatory analysis uses a collective risk metric and most of the other applications, the main metric used is large early release frequency which is large enough to produce substantial dose to the public offsite.

And what do ISAs exactly product? Well, they're different. Each one is different because a lot of flexibility -- not having ever done these before, at the time the rule was promulgated, there was only one licensee that had actually completed an ISA. It was B&W.

And so not knowing how these things would come out, a lot of flexibility was left to the licensees. So they -- and they don't necessarily share everything with one another. So each ISA is different.

However, the rule is quite a bit of prescription about what an ISA has to do and what you have to send in an ISA summary. Consequently, they all do this. They all have a list of accident sequences. They all have a list of the items relied on for safety that prevent those sequences.

The accident -- each accident sequence is assigned to a consequence category, like I said and as was mentioned, these are quantitative categories. They're defined in the rule and by the licensee. And high, intermediate, and low -- for example, high consequence to a worker is a, for example, a dose exceeding 100 rem. Well, for example, a criticality, if you were within a couple of meters, would be way over that and would be a high consequence event.

And then the other thing is that the likelihood of each sequence has to be evaluated. But interestingly, the rule does not require that that likelihood evaluation be submitted in the summary. So for some licensees, if you want to know what the -- how they evaluated the likelihood, you would have to go to the facility and look, okay, but for most of them they did -- like as I said, nine out of ten actually did either a risk index method or quantitative evaluation of each accident sequence.

But in some -- in at least one case that I know of, it's not in the ISA summary. So --

MEMBER BLEY: Dennis?

MR. DAMON: Yes?

MEMBER BLEY: Before you leave here, I didn't see it later so let me ask it now. In selecting IROFs, in the meetings we talked -- or the group talked often about the double contingencies. And the report cites the ANSI standard for critical safety -- criticality safety as requiring double contingency.

The report goes on to say a commitment to apply the double contingency principle is often part of a fuel license -- fuel facility license. Is it not always for criticality? And is it mostly for the others, too? Or how is that applied?

MR. DAMON: Well, strictly speaking, in the standard, the ANSI standard, it's the same one ANSI 8.1, the double contingency principle is not a requirement. It's a should.

MEMBER BLEY: Oh, that's right. You're right. Yes.

MR. DAMON: Yes, it's a recommendation. Because it's believed that there would be circumstances where strictly speaking, you couldn't do it, you couldn't really get true double contingency because it's a fairly stringent statement. It says that before a criticality is possible, the safety margins will be such that before a --

MEMBER BLEY: I have it here in front of me if you'd like.

MR. DAMON: Oh, well, you can read it if you want.

MEMBER BLEY: Two unlikely independent and concurrent changes in process must occur.

MR. DAMON: Yes. And so the independent -- fully independent, no single failure type of a requirement is a pretty tough requirement. But it can be done. When you have low enriched material, you need both a mass and you need moderator. So you can control these two things quite a bit independently so that there is no way of --

MEMBER BLEY: So for criticality, it's usually applied. How about for other consequence elements? That wasn't clear to me. In the meetings, I thought that I heard they always used double contingency for everything. But when I read the words, it doesn't quite say that.

MR. DAMON: No, it doesn't. It's not absolutely required. But there is -- for new facilities, facilities that came to us and got a license after the rule went into effect --

MEMBER BLEY: Yes.

MR. DAMON: -- there's a -- I believe it is Section 70.64 has a list of things called baseline design criteria.

MEMBER BLEY: Yes.

MR. DAMON: And one of those is double contingency. But the way it is worded, it is not absolutely requirement. It's -- basically the burden is on you to tell me why you can't do this. But it's that kind of a thing.

MEMBER BLEY: Okay. So it essentially

asks for it unless there's --

MR. DAMON: Yes.

MEMBER BLEY: -- some reason to --

MR. DAMON: Right. And so that's the way it works in practice. But even before that, some licensees had committed to being doubly contingent. And it's, like I say, for a low-enriched facility, it's relatively -- you can do that. But high enriched, it's much tougher.

MEMBER BLEY: Yes, okay.

MEMBER STETKAR: Dennis, I must admit, I couldn't the Subcommittee meeting and I haven't looked at any results from ISAs. But I was curious. One of the things that PRAs spend quite a bit of time looking at are dependencies or certain whether you want to call them initiative events or hazards that might cut across lines that otherwise might be considered independent.

So, for example, we look at fires. We look at floods. We look at seismic events. We look at common power supply dependencies that might effect several systems. Do the ISAs also do that? Do they look at, for example, a ten to the minus four per year seismic event that might effect several process streams throughout a facility and examine the consequences for that --

MR. DAMON: Yes.

MEMBER STETKAR: -- in an integrated --

MR. DAMON: Yes.

MEMBER STETKAR: They do? Okay.

MR. DAMON: The rule is explicit on that. That external events shall be considered in the ISA. And so --

MEMBER STETKAR: And are considered -- you don't have a single -- they don't parse them up so that you're led to believe that a seismic event that would effect the whole facility indeed is subdivided into a thousand independent sequences?

MR. DAMON: No, I mean it's --

MEMBER STETKAR: Okay.

MR. DAMON: But they do --

MEMBER STETKAR: Okay. That's --

MR. DAMON: -- they are required to look at these. I mean, in fact, fire was pretty strongly called out. There's a whole section, a whole chapter --

MEMBER STETKAR: Okay, that's --

MR. DAMON: -- in the standard review plan of fire, for example. It was realized that's an important one to look at. And so yes, they look at fires.

And also, there's an explicit language in the rule that says thou shalt consider process interactions.

MEMBER STETKAR: Okay. But your White Paper recognizes a difference between the two in treating dependencies. I mean the conclusion is, in principle, no difference. But risk index method does not have dependency analysis built in but must be added via double contingency or other analysis.

MR. DAMON: Right. That's a true statement. Now it turns out --

MEMBER BLEY: I mean it doesn't have to be that way. But it seems that it is.

MEMBER SHACK: Well, that's the in principle no difference.

(Laughter.)

MR. DAMON: Yes, it --

MEMBER BLEY: But in practice, it seems a very large difference.

MR. DAMON: Well, I mean it isn't just the fact that the Standard Review Plan didn't have a big section on common cause analysis or a beta factor method or anything like that because the licensees recognize this. And they adopted methods for doing such things.

I mean they have -- GE's methodology, they have an explicit factor in there for if you have like identical redundancy, you don't take full credit for the second control. Some licensees -- often what I've seen is they don't take any credit for a second control. So they all do that kind of thing.

But the more problematic thing is the fact that you have a whole lot of processes in the plant. And so it's, in principle, there would be a lot of interactions. But in practice, there aren't because the processes don't interact with one another much.

And, in addition, they don't have common support systems that are actually needed for safety. For example, electric power. To my knowledge, except for the, you know, for the few exceptions like the MOX plant ventilation system that maintains the negative pressure, except for things like that, they don't -- the power is not needed for a safety function. It's needed to allow you to continue to operate the process and shut it down in an orderly manner so that the material goes where you want it to go and so on.

And so as a result of that, you don't have as much concern about these cross-cutting events that effect multiple processes.

MEMBER STETKAR: Except for perhaps some external events like severe storms, winds --

MR. DAMON: Yes, external, the fire --

MEMBER STETKAR: -- seismic events is the one, even fires, depending on the facility, it might be difficult to get a fire large enough. But large, whatever you want to call them, I'll call then external events that despite the physical distribution of things could effect several things simultaneously.

MR. DAMON: Yes.

MEMBER STETKAR: But you said those are explicitly --

MR. DAMON: They are required.

MEMBER STETKAR: -- considered. I mean if you're talking about ten to the minus four to ten to the minus five per year as sort of the conceptual threshold for unlikely, you can get some fairly interesting phenomena occurring at those frequencies. So --

MR. DAMON: Yes.

MEMBER STETKAR: -- I was curious --

MR. DAMON: That's true.

MEMBER STETKAR: -- how people consider that.

MR. DAMON: Another aspect of that though is -- the other things about like electric power is that with a reactor, the safety functions that are done, such as coolant heat removal usually require an active system to remove the heat or something, right, so you need power for -- you have a mission to complete when you trip the plant.

But a typical fuel cycle facility safety function just stops doing whatever they're doing. And there's no power needed to do some function usually. They just have to stop. And then you're in a safe condition.

So -- I mean it's not always true. But I'm just saying --

MEMBER STETKAR: I suspect sometimes you need to get some material from point A to point B before it's kind of okay. But --

MR. DAMON: Yes, well usually the processes are designed so that movement isn't an issue. And you try to make -- either the amount of material in the process is limited to the point where you don't have a problem with criticality or the process geometry is safe by geometry no matter what you put in there. So they try to achieve that goal.

MEMBER POWERS: A problem you run into in chemical process facilities, when you leave things in line, that tends to be a very bad thing. First of all, corrosion process get up, you get this weird crevice corrosion that only Shack and Armijo understand. And they disagree.

The other thing that you run into with plutonium is that you can get the plutonium hydroxide precipitations occurring if your acidities change on you. And so leaving things in lines for protracted periods of time is really a bad idea. Nearly always.

MR. DAMON: And so, yes, like I say, they have power so that they don't -- they don't get caught in that situation. So they can, in fact, off load the material that's in the process when they need to.

So this slide was put in here as the result of some discussions that went on at the Subcommittee meeting. That the configuration of a fuel cycle facility, a typical one, in the enrichment plants this is not quite true. I mean the enrichment there is basically on process going on there although there's a process of feeding and withdrawal and enrichment. So there's at least three things there.

But the fuel fab facilities have many process -- separate process steps. And for each step there is a type of equipment used for that. And there's usually multiple process units for each of these steps. So the point of mentioning this was because of a discussion we had and that is if something goes wrong in a particular piece of equipment, typically you can just shut that equipment down. You're not shutting down the whole plant. You're just shutting down that particular piece of equipment that may be one out of five identical ones that are being used to do that particular step in the process.

And here's the sort of sequence of process steps. Conversion from a uranium oxide, U-308-type composition that you get from a uranium mill, converting that to uranium hexafluoride so that you can do the next step, which is you make that UF_6 into a gas and enrich -- and run it through an enrichment process.

Then put it back in a cylinder, a two-and-a-half ton cylinder, sent it to a fuel fabrication plant, which does the next step, which converts the UF_6 into UO_2 powder. And in one type of process, the wet chemistry type process, that's done in multiple process steps, multiple pieces of equipment. And in other ones, there's one reactor that does that conversion there.

Then there's powder blending to get

enrichment and additives just right, milling of the powder to get the powder range just right. The pressing it into pellets. The sintering -- grinding -- sintering -- there's sintering of the pellets, grinding them to precise dimensions, loading them into pins, and manufacturing assemblies.

And they typically plants also have scrap recovery processes and manufacturing of absorber elements in the facility. So a typical facility has a whole lot of processes in it.

And as the -- the fourth bullet is the main reason for this slide -- is just to emphasize that when you have a process upset or an IROFs becomes inoperable so that you are no longer sufficiently safe, then typically all you have to do is to stop the process or take some other action that renders it safe. But you don't need to perform some kind of active safety function usually. There are exceptions to that.

Control failure may not cause a parameter to exceed a safety limit. At one point in time, I looked at all the upset conditions where they were down to just one control preventing a criticality. And out of 64 events like that in a four-year period, there were only six where the parameter that was being controlled actually exceeded its safety limits.

So that's what I'm -- what I'm saying here is that most processes have big safety margins built into them. And just because you lose the control doesn't mean that the parameter goes to an unsafe condition.

MEMBER STETKAR: Do they look at the kind of things we look at in PRAs? Not only -- when people talk about control failure, they usually say well, it fails in the way that it was designed to fail. So something that is actively controlling the position of a valve, that valve goes closed, for example, if it is designed to fail closed. Do they look at what we call spurious operations? In other words, faults that would convince the control system to drive that valve full open and keep it open?

MR. DAMON: I mean all I can say is they should. I can't recall an example -- maybe there's somebody else in the audience that can remember an example of something like that.

MEMBER BLEY: If they're doing HAZOP, they have to do that. That's part of doing a HAZOP --

MEMBER STETKAR: Yes, okay.

MEMBER BLEY: -- so that in principle, again --

MEMBER STETKAR: Too much, too little.

MEMBER BLEY: -- they sure shouldn't be doing too much, too little --

MEMBER STETKAR: Well, I don't know. As I said, I haven't looked -- I know nothing about these things. I was just trying to think of possible differences.

MEMBER CORRADINI: So just so I'm clear, when you said a HAZOP, I just assumed that a HAZOP and ISA were the same. Not true?

MEMBER RAY: Not true.

MEMBER RYAN: No.

MR. DAMON: Yes, HAZOP is a specific analysis step that is used in many of the ISAs and it's very applicable to chemical and things that are handling fluids and that --

MEMBER RYAN: Anywhere there's flammable solvents, it's a big deal.

MEMBER BLEY: In the operation but you go around and you find a hunk of the plant and you said what happens if, you know, you get more flow, less flow, higher temperature, lower temperature. And so it is a way to generate the sequences that you look at.

And if any of those cause trouble --

MEMBER CORRADINI: And the ISAs are qualitative renderings of these sequences without summation of the probabilities of what -- I'm just --

MEMBER RAY: The ISAs take these sequences to a full sequence definition, not just what happens at this point. Often it's a one point thing but it could be more. So the ISA is an analysis that tries to put all these pieces together.

MEMBER SHACK: Yes, the White Paper says that ISA uses hazard ops for accident identification. And then you add the risk index for likely --

MR. DAMON: As would a PRA.

MEMBER SHACK: Yes.

MEMBER RAY: HAZOPs are really good, too, for identifying the potential problem areas in a plant.

MR. DAMON: So and then the last two points here from this is that -- is this -- because this whole subject of process interactions, as has often been mentioned, is something that you have to be very careful with in a PRA -- and you do -- you should -- also it's an issue for any kind of, you know, for an ISA within a -- but it's usually within the process.

You know, interactions between processes are restricted because these plants, as I said at the first bullet, the process steps are really separated from one another. They don't -- they're not automatically feeding the output of one process into the other. It's a manual step where the output has always been in one container and is moved to another process and fed to something else. But they're not -- it's not a continuous process. It's a batch operation. And then --

MEMBER ARMIJO: There really is no feedback either. There's no way to feed back, you know. If something goes wrong in pelletizing, it doesn't effect conversion or, you know, if they're really batch processes.

MR. DAMON: Yes. So it is different. You know a reactor is all one big integrated machine doing one thing. And these plants are all these separate pieces of things that aren't doing -- it isn't just one big thing usually. Now obviously the enrichment plants, they are, you know, connected together. But the fuel fab plants are this separate step type of thing.

And I've been told anyway that like centrifuge plants, when a centrifuge goes bad, they just reroute the flow around it and they just leave it there. That's the -- you know.

Now this is addressing the first application of this ISA PRA comparison thing. And the comparison in the materials in the paper, it goes through all the different aspects of what's done in PRAs and ISAs and discusses each aspect of them.

But I wanted to mention in this slide that ISAs are not -- they're not trying to quantify the risk accurately. What they're trying to do is make sure that you've got an adequate safety. And so frequently things are done in a conservative way. And that's perfectly acceptable for the purposes that an ISA is doing in the -- for safety under Part 70, which is what this slide is talking about.

So that's the thing is that you're not trying -- they weren't trying to do an accurate estimate of risk for some application that needs that kind of an estimate. Consequently, they aren't. The ISAs are often quite conservative. Not always, you know, but I'm just saying it is quite frequent that you'll find something that's done very conservatively.

The ISAs use the systematic methods such as the HAZOP that had actually been in practice and being used because they were required by OSHA for chemical plants that possess more than a certain amount of material, of hazardous chemicals. And so there's really vast experience with using -- doing these types of analyses.

And the chemical industry also uses fault trees and event -- some of them use fault trees and event trees. Some do, you know, fully quantitative PRA-like evaluations. But they also do these process hazard analyses that are more qualitative like was done in a HAZOP.

And the rule that was put in place wasn't really just to do -- make the licensees do ISAs. It was really -- the more general idea was to bring chemical hazards under NRC regulation. We were directed by Congress basically and told to do this.

And so the question here that I'm trying to answer with this slide is why are they acceptable. Well, it's based on systematic methods that have been, you know, where there's a large experience base. And the licensees have acquired this same experience by doing these.

The process started in the middle or early 1990s. So we're almost 20 years into this. So that's why I say that the licensees themselves have quite a bit of experience now with doing this kind of a thing.

And then, of course, the NRC staff

reviewed -- expended quite a bit of resources reviewing each ISA when they were -- the summaries were submitted. They didn't just review the summary. They went to the plant and looked at the actual ISA documentation on site.

But these plants are so extensive in terms of numbers of things and so on that the staff did not review every single thing in the plant. They made sure that the plant had been covered. But as far as doing a detailed review and questioning how each number -- where each number came from, they only did that for like a subset, a representative subset.

And ISA -- and the other thing to say about ISAs and their acceptability is they can -- they can be fully quantitative and some of them are. And they do use PRA-type events in places where it's applicable. But again, as this first bullet, they're not necessarily accurate risk assessments --

MEMBER REMPE: Before you leave that one, like with reactor safety analysis, you say that they always have conservative evaluations. There's some cases where if a relief valves goes off early, it's beneficial to the plant's safety because you've depressurized. What happens if there's a situation -- is there a situation in one of the facilities that's like that? Where something that appears maybe to be conservative may not be conservative for other situations? And how do they address something like that? Or am I thinking of an example that just won't happen?

MR. DAMON: Well, they're not -- I'm not saying everything they do in the ISA analyses are conservative.

MEMBER REMPE: Do they look at a couple of different cases when something like that could occur? Where -- and I'm not -- I don't have enough knowledge of the facilities that you're looking at to say could something like that occur or can't occur.

MR. DAMON: Yes, I'm not -- I cannot think of something that has that characteristic. They two typical things that when I use this word conservative are they will have safety controls. They'll say they have three safety controls. They'll only tell you about two of them. And they'll only take credit for two them in doing their evaluation if they put numbers on them.

And if they get below the ten to the minus whatever, they're good. And they don't take any credit for the third one. So when you go in and if you -- this will come up later when I say well, what if you want to use ISA results to do risk significance, well, you've got to know whether they got another control there. So that's a conservatisms.

The other one, the big one, is for offsite consequences -- actually the rule reads this way, if a release could cause high consequences, then the release is categorized as a high consequence sequence, okay, even if 99 percent of the time it would not because of the weather would be -- it would be blowing in the wrong direction or something.

So the offsite consequence evaluations are done like that. They just determine if you were worst case weather and the thing was blowing at the peak nearest person, would it be high consequences. So that's not a risk --

MEMBER RYAN: Joy, I think the HAZOP might catch some of these things that you've talked about in your example. If they did a HAZOPs analysis right, they would catch that difference, you know. Normally often it's on that kind of thing. It would flush out on those unit operations, HAZOP kind of evaluations. I'm not saying it would be perfect. But that's usually where that kind of thinking gets flushed out.

MEMBER REMPE: I had to ask.

MR. DAMON: Yes, it's hard to make any

kind of generalization about the plant. Each type of equipment, the way it's achieving safety are quite different from one another. They're not all like analogous to a reactor. And different kinds of reactors or something they did, they just have totally different strategies for making things safe.

And so it is very difficult to generalize about what goes on. There's just a huge collection of various different things.

This has to do with the second applications of, you know, using an ISA or a PRA. And like I say, in the first one, what I'm basically saying is you can -- if you do a good ISA, it's good enough for the purposes of safety under the rule.

The second point here, well, what if you're going to use ISA or PRA and you're going to do this risk significance determination? Well, if you're going to do it quantitatively, guess what? You need quantitative information. And it has to be a reasonable -- it doesn't have to be, you know, six decimal places accurate but it has to be roughly an accurate representation of the risk to do the significance determination because what you're trying to do is rank things.

And do it on a consistent basis because

that's kind of what the fuel cycle oversight program it's first thing it wants to achieve is consistency and to rate the significance in a rough way but in a relative way correctly. So that the high significance things are correctly categorized as such and lowest -- so if you're going to do it quantitatively, obviously you need quantitative information.

Well, it turns out most ISAs do have some quantitative information. They, like I said, two fo them did it fully quantitatively. At least they put -- not fully. They have a sequence frequency assigned to each sequence.

Seven of them use this thing called risk index method, which is a very crude way of scoring sequences. And it is intended to be used in a quantitative way. I, myself, reviewed -- looked over the evaluation reports that the staff did on all the ISAs to see if, in fact, the staff was sort of holding the licensees to interpreting it as quantitative. And, in fact, the staff did do that.

In other words, they didn't let the -- they tried to make sure that the licensees weren't doing something that didn't -- that if you understood it in a quantitative way, it was wrong, you know. They were trying to do it -- but it is very crude.

And you could call -- we actually call it qualitative it's so rough.

And so -- but they do have this information. Of course, they have -- they're telling you relatively accurate information about consequences also because the consequence criteria in the rule are quantitative or could be interpreted as such.

So you do have the -- now sometimes that's done, again, conservatively. Like I mentioned the offsite consequence, well sometimes the assumption is made if there is a release of a hazardous chemical inside a building, they will just -- some licensees just simply assume the worker would be a high consequence exposure, which is life threatening. They would just assume that, which is not -- often not true.

So they do have some information but it's not necessary accurate for these reasons that I'm mentioning. And so, therefore, if you're going to use it for a quantitative evaluation of risk significance, sometimes you're going to have to make changes or add things to it. Like I say, safety controls in some plants are not all declared IROFs. So they're not listed. And safety margins are usually not -- there is usually not credit taken for that.

And the ISAs are also -- another thing that relates to risk significance determination is the ISAs aren't standardized in any way. They're not using the same database of things necessarily.

Now that's not quite true in the sense that there really are only, I think, two types of risk index tables. One that was -- they kind of -- they are kind of using the risk index is somewhat common but what I'm saying is the licensees do these analyses separate from one another. And the full details of their analyses are not communicated. They're proprietary information so they're not available to the other licensees in detail.

Section 5 of the report is this thing about an evaluation of risk in the context of risk significance determination. And it has this example in there which is a very typical safety feature of a plant. And that is that you would have a piece of process equipment that would be safe by geometry.

Meaning that for criticality safety, no matter what the composition of what's in the vessel, it won't go critical because it's either a column that's too small in diameter or it is a flat surface that's too thin. And no matter what's in there, it won't go critical. And so that that's the example analysis.

And then typically this is to contain -- fissile material in solution, which all but one criticality -- actual criticality accident in the world have been in solution systems. That's why I used this example. It's a very typical one. The way you do things -- make things safe is you -- wherever you've got your ambient solution, it's in a safe geometry vessel.

Now what could happen is it could leak. And then it goes out of the vessel. So underneath you have a typically some way of where that the process fluid goes. And there are usually also overflow lines in case you overfill something, it goes over and into another safe geometry, which is usually -- it's usually a dike around the process equipment to contain whatever leaks out.

And that's there for multiple purposes, one of them being criticality safety that stays in a flat slab. So that's the example. And in the example, the point is it postulates some hypothetical defect, namely that the dike around there has a leak in it. And the point of the example is to show that there's only a few accident sequences effected by a typical deficiency that you would find in an inspection.

And so it supports this key point we're trying to make that these significance evaluations -- the efficient way to do this is to do them on a case-by-case basis. When you have an inspection deficiency, you will do the quantitative analysis of that process when you need that information as opposed to the way reactors did. They already had the PRAs. So they went around and sort of predigested the PRAs into these inspector notebooks where they can then do a significance analysis very quickly when something happens.

Well, it would be very inefficient for these plants because you wouldn't use most of it. All this analysis you would do, 90 percent of it would never get used because of the number -- because each deficiency would only effect one little part of the plant and you would only have one or two a year. And so the rest of it would never get looked at.

MEMBER BLEY: Dennis?

MR. DAMON: Yes.

MEMBER BLEY: I know you've warned us in the report not to look at the numbers you provided in the example -- I thought the example was interesting. I thought getting to the ISA quantification result in the end was a little difficult to work through but you get there.

But I still have to ask. And I'm wondering if this is kind of typical. You have two scenarios. And in one of them, the risk index approach through the ISA comes out in an overestimate compared to the PRA. But, you know, within a factor of six. That's pretty close.

In the other case, it's just the opposite. And it's an underestimate by almost a factor of 50. And is that what we ought to expect?

That the ISA risk index thing can have several orders of magnitude change with respect to what you might get if you did a PRA on some of these things?

MR. DAMON: I would say it's not -- it's not typical that you would get a real big difference. But it wouldn't be at all unexpected to get one order of magnitude, you know, a factor of ten or so different between what you would easily -- I mean actually it's reflected --

MEMBER BLEY: I guess what kind of got me a little -- I won't say upset but just to have one case go one way and the other case swing the other in the same analysis, I would have hoped it was biased one way and not the other. But it doesn't seem to be.

MEMBER POWERS: No such luck.

MEMBER BLEY: That's what it looks like.

MR. DAMON: No, it's no -- yes, no such luck. As I mentioned, the conservatism, not all these things are conservative. I mean, you know, some of them are -- they did whatever the lookup table told them to stick in there.

MEMBER BLEY: A factor of 36 low is not conservative I would guess.

MR. DAMON: No, so like I say, they're not -- it's not all conservative. I mentioned that because often when it's done explicitly, you know, when they think about it, they often do do it conservatively. But sometimes they're just looking it up in the table. And yes, this is a passive control so it gets this.

ut if you thought about it, oh, gee, that number is probably not an accurate -- I mean I'll give you an example of one that I found myself in the early years was plugging of a -- there was a -- you don't want fissile bearing solutions to accumulate in some certain places. And so you put a hole in the bottom so it would drain out.

And they identified that as well, that's a passive control. So that's ten to the minus three per year. Normally, it's not -- plugging of a hole, you know, is more likely than ten to the minus per year, you know? It depends -- of course, it depends on what you might have but I mean it's happened before, you know. You've have something in there in that vessel other than something solid can migrate over there and plug the hole, you know.

MEMBER BLEY: It's always seemed to me there's something nice about being quantitative in that it forces you to see if you're things are making sense when you get done.

MR. DAMON: Oh, yes. I mean AFLAC has said this in a meeting that we had with the industry once and I concur with it. And that is yes, when you try to do things quantitatively, it forces you to think more -- a little bit more carefully about really what's happening.

Like, for example, HAZOP -- HAZOP has these guide words like flow and it says well, what if the flow is too high, what if the flow is to low. And so you'll have all these different things. If it's high, then this is what -- but often there isn't any discussion of well, how would you get high flow? What is actually causing this to -- and so when you have to quantify something, you have to go that extra step of saying okay, well, really what's going on here? What's happened? And how likely is that?

So it does refine you --

MEMBER BLEY: Actually when you take the HAZOP to an ISA, I would hope you would at least do the one you just talked about to make -- turn this into a scenario. Not just this is high but what is the scenario that --

MR. DAMON: Oh, yes, they have to march through the scenario of yes, it's high. And then this happens. Then usually there is some other thing, you know, double contingency, something else has to happen. And then oh, now we get a criticality. Or like for hazardous chemicals, double piping is often used. So you have to get two leaks in order to get to the unsafe condition.

MEMBER BANERJEE: But in a HAZOP, you have to document why you think something can happen, right? It's a systematic procedure when you use a guide word.

MEMBER BLEY: And you have a good team.

MEMBER BANERJEE: Yes, you have a good team.

MEMBER BLEY: The right people.

MEMBER BANERJEE: You write it down. And

then you write down what remedial action, if any. And if the consequences are of no importance, then you just cancel that.

So there is a qualitative consequence evaluation as well as a qualitative cause evaluation. If it's incredible then you don't consider it. And if the consequences are negligible, you don't consider it. It sort of gets written off.

So I think most of you know what a HAZOP is but you go vessel by vessel, line by line, auxiliary by auxiliary. And you do a certain number. And this goes on using all the guide words. And there's a lot of software that helps you to do it.

So it's a qualitative assessment but, you know, it's probably better than most qualitative assessments because it's done by people who know what they are doing. Whereas it's not sort of just putting some numbers down, you know.

MR. DAMON: Yes, that's a good point to make is, in fact, it's in the guidance, like the Standard Review Plan, and even in the regulation it very clearly identifies that you need qualified people to do this. It's done -- the ISA analyses are done not by an individual usually. It's done by a team --

MEMBER BANERJEE: Right.

MR. DAMON: -- of people who, you know, would typically like a process engineer who is familiar with the process, the operator of the process, the criticality safety engineer, maybe a chemical safety engineer, a fire safety guy, and then an ISA expert, an ISA-PRA/expert.

MEMBER RYAN: And, Dennis, very often the vendors of various components and systems and equipment pieces are involved as well. Or at least their information is available.

MR. DAMON: So, yes, that's a very crucial thing. In fact, at the time the ISAs were done for the existing plants, of course the plants had already been operating for 25 years or something like this. And had the people there that had been operating them for 25 years. So they've got that kind of knowledge in their head. You know does this thing ever fail? You know they would know that yes, it's never failed in the life of this plant.

MEMBER BANERJEE: I happen to be a big fan of HAZOPs.

MEMBER CORRADINI: We sense that.

MEMBER BANERJEE: Yes. Because I've seen it work in a real way, identify real things.

MEMBER CORRADINI: But it is a qualitative first step that leads you to what they're doing here.

MEMBER BANERJEE: Yes, you can take it as a first step and do more.

MR. DAMON: So anyway, this is just summarizing the key -- what we, the staff, sees as the key points of the paper. That firstly, that ISAs are adequate for the safety function that they perform within the context of the rule.

But we didn't come to that conclusion just because of say the abstract -- that the technique used was good. We came to this conclusion by reviewing the ISAs and seeing that yes, they were done. Staff agrees that these were done adequate to cover what they were trying to do. And that is to identify the items for safety and make sure that the safety design is adequate.

And the point is with respect to how you would do risk significance. And the efficient way to do this, we believe, is to just do these evaluations, quantitative evaluations if you're going to do them. And that's an if.

You know if that's what is decided that the way to do this, that you would do them on a case-by-case basis. And to not just try to redo the ISAs quantitatively in order to feed this process because you're not going to be using most of that information. So it's just not efficient. So that's basically it.

MEMBER ARMIJO: Dennis, how often are the ISAs reviewed by the staff? Let's say you have annual inspection or maybe more often than that. Is the review or the ISA or parts of the ISA typically done during those inspections of the facilities?

MR. DAMON: Yes. The inspectors love to look at stuff. They go right to the ISA material to look for things. And, in fact, one of the requirements in the rule is that those items that are identified as IROFs in the ISA, if there is a failure of an IROFs, there must be a log kept on site for all IROFs failures.

So inspectors can go right to this log and look up well, what's gone wrong since I was here last.

MEMBER ARMIJO: How about the process changes? You know these facilities always have some changes going on. Just --

MEMBER CORRADINI: You mean operating changes?

MEMBER ARMIJO: Oh, people change the coolant tulip fuel pump or the additive concentration. And you can't stop changes. So how often do they have to be incorporated to see if they effect their

IROFs.

MR. DAMON: Well, of course, if they make a change, the doing of an ISA-type analysis, there is a requirement --

MEMBER ARMIJO: Prior to the change?

MR. DAMON: Within the licensee's license it says if they make a change, they have to redo the analysis. And, in fact, in like the ANSI standard on crit safety, it says of course it must be done -- and analysis is supposed to be done and reach a correct conclusion before you operate the process.

MEMBER ARMIJO: Yes, I would think so.

MR. DAMON: And so, yes, it is required to be done. And then, of course, it is required to be submitted, the summary of the ISA. And that includes the entire ISA, all the changes that occurred during the year have to be -- the ISA summary has to be updated and sent in every year annually.

So the NRC -- that was one of the primary reasons for the rule other than bringing chem safety under NRC jurisdiction was to -- that the staff felt that in the past, before this rule, we had five-year license renewals. And the staff felt that just getting a picture of what the plant was like, every five years wasn't sufficient. That there were too many changes going on in the interim. And so they wanted a more current description of what was -- the way the plant was being run. So it's an annual -- now it's an annual thing.

MEMBER RYAN: Okay. Thank you, Dennis.

I think we have Charles Vaughan from NEI up to make a statement. And then we'll have more questions, okay?

MR. VAUGHAN: Good afternoon. I'm Charles Vaughan from the Nuclear Energy Institute.

And I have about 45 years experience in the nuclear industry in various aspects. And I mention that because I, as Dennis, go back to the early '90s and the mid-'90s when the development of the Subpart H in the rule was being developed.

And, in fact, that was, in part, in response to a petition that was made by NEI at a point when the NRC and industry both felt that there were opportunities to strengthen the rule with regard to defining the basis of safety at these particular types of plants.

So there has been a lot of history, as Dennis mentioned, in terms of some ten years to develop the rule and four to five years invested by licensees to implement the ISAs and then a couple of years of effort on the NRC's part to review the initial ISAs. And so we're pretty far down that path.

NEI had transmitted to you by letter, I think, a series of points and we didn't write a big fancy paper but what we tried to do was take the results of our public interactions with the NRC as they had been working on this and our interaction with your subcommittee. And simply highlight a number of points that we felt were appropriate out of those discussions. So I'm not going to read those points here because I'm sure all of you are quite capable of reading that.

But there are some things that while they may be a little bit redundant from what you've heard from Dennis Damon because we are pretty much -- industry and the NRC are pretty much in tune on most of these points with regard to the ISA and the PRA question. There are some things that I want to highlight.

And one is as the rule, the Part 70 rule that we're licensed to follow is written, ISAs are the ways to demonstrate that we meet those performance requirements. And they seem to be effective in doing that as evidenced by what you've heard from the NRC and industry feels the same way, that they are workable for doing that.

And the ISA methodology that we use is relying on at least hazards identification tools that have been used successfully by the chemical industry for quite a number of years. And most of these fuel cycle facilities are more of a chemical process than they are anything else. So using those techniques, particularly HAZOP for the more complicated processes and then some of the other discipline techniques for identifying hazards and working with the hazards has been effective. And the ISA process then goes farther and assigns items relied on for safety principally to prohibit, not just mitigate but actually prohibit those accident sequences from taking place.

So -- and in the process of doing that, it is a semi-quantitative process in that in terms of treating these on an numeric continuum, we typically treat them by putting the consequences and the frequencies in boxes. So instead of trying to deal with a numeric continuum, we're putting them in boxes which makes them somewhat easier to use.

There's been a lot of discussion as to whether that always turns out to be conservative or not. And I'm not sure that that's really the answer. The answer there seems to be that putting them in the boxes with the definition and the discipline that goes along with that, is providing us with a reasonable characterization of the particular parameter that we're dealing with.

Most any technique you use is not perfect. It has some degree of uncertainty. And, of course, bias is what we're really worried about. And there's no indication that these techniques are biased in any undesirable direction, even though they may not necessarily be perfect.

The other thing that I wanted to point out and I think you saw that in one of Dennis' charts is there's a huge amount of diversity within these facilities, even some of the ones that are doing their own job are using different techniques and different technology for certain of the chemical processes. And there is a significant foreign influence in the different companies. And there's preferences for different types of equipment.

I bring that up because it really doesn't lend itself to developing a database such as you would need to support PRAs with a significant degree of accuracy and would take a tremendous amount of work. So using or trying to go with a PRA type of analysis in this diverse industry is somewhat of a complicated task compared to a fleet of reactors that are all, while somewhat different, are generally similar in nature.

MEMBER STETKAR: Charles, can I ask you about that?

MR. VAUGHAN: Yes.

MEMBER STETKAR: Because I read that bullet. And having worked in data for nuclear risk assessment for more than 30 years, that was always an excuse for not doing risk assessment 30 years ago. Well, we need to have precise data. And your two-and-a-half inch motor-operated globe valve is different than my three inch motor-operated gate valve so, therefore, we need precise data for each of those valves and it's different.

MR. VAUGHAN: Right.

MEMBER STETKAR: We have operating experience. We found that those two valves don't really have all that different failure rates. And we quantify the uncertainties and we sort of learned that the differences don't make a difference. And by and large, the desire to have extremely precise numbers for superficially different pieces of equipment was something that really wasn't justified as an excuse for not doing something.

So I don't -- I know nothing about these facilities. So when you say you have such vastly difference equipment that it would be, you know, virtually impossible to develop data that would characterize failures. We've been through that experience and kind of learned that that isn't always true.

Now, you know, if you have some really exotic jet pump as compared to a standard centrifugal motor-driven pump, you know, there I can understand why you might need different data to characterize.

MR. VAUGHAN: Let me respond to a few -- you've raised several points in your comment. One thing. I didn't say it was impossible. I simply said it was difficult. But there are significant differences in a number of the processes.

For example, the fuel fabricators, I think every single one of them uses a different conversion process for UF_6 to UO_2. And so, therefore, the types of equipment that are used in them are just different. It's not a question of one manufacturer or another. The equipment is just different.

MEMBER STETKAR: Yes.

MR. VAUGHAN: The other thing is this is a commercial industry that is competitive. And we don't share some of the technical details that may be are shared in some other arenas for one reason or another. And so it's possible if all of that information was shared, there would be some degree of similarity.

I mean within a particular company, you obviously have your favorite valves because you know which ones fail less frequently than others. You know which ones have the best maintenance history and things like that.

So within a particular company, within a particular process there is knowledge and, in fact, that is a lot of the knowledge that is used in the judgment when these teams do their HAZOPs and the what-ifs and different types of hazard identification and then begin to assign, you know, frequencies to failures.

So it's not like we don't use any of that. It's just that it's not shared universally across the industry.

MEMBER STETKAR: Okay.

MR. VAUGHAN: Did that help?

MEMBER STETKAR: That does a bit, yes. Thank you.

MR. VAUGHAN: Okay. So that was --

MEMBER RYAN: And we're going to have to

wrap up at 3:15.

MR. VAUGHAN: Yes, there's one --

MEMBER RYAN: And I want to have an opportunity for members to ask you questions so if you would --

MR. VAUGHAN: One other little comment --

MEMBER RYAN: Please, yes.

MR. VAUGHAN: -- I wanted to make and that is we are particularly concerned about the thought of intermixing within these facilities the use of the ISA techniques and PRA techniques within the same environment. And suggest that we should try to avoid that if at all possible.

So those are the main points that I wanted to cover. And I'd be happy to entertain questions.

MEMBER RYAN: Great. Thank you. And again I make note for the record, we do have a letter signed by Janet Schlueter, who is here in the audience as well, dated February 8th, 2011, on your presentation. So thanks very much.

Are there any questions for Mr. Vaughan? And comments from members as we finish up?

MEMBER POWERS: Well, let me ask one question.

MEMBER RYAN: All right.

MEMBER POWERS: When you look at the results of an ISA and all that's gone before it, you have typically a list of IROFs. And that list being, at least in one circumstance that I imagine is fairly extensive IROFs, a list of IROFs. And those demand regulatory attention which means they demand attention from the owner/operator of the facility.

When you use the results of the ISAs, do they tell you how to prioritize your attentions to those IROFs? And if not, should not one look for some way to prioritize this attention? Especially as the lists get very long?

MR. VAUGHAN: That's a very good point. And the way things work right this minute, basically all IROFs are treated equally in terms of attention. But yet we know from the hazards analysis that some of those IROFs are being used to prohibit things that have high consequences and some of those IROFs are being used to prohibit things that have medium consequences.

But all IROFs basically get the same level of attention. But there is information there to grade them if that was desired.

MEMBER POWERS: You could.

MR. VAUGHAN: But we have --

MEMBER BROWN: Dana?

MEMBER POWERS: But, certainly, Charlie, criticality -- IROFs, do they have anything to do with criticality in a fabrication facility, they have the top priority.

MR. VAUGHAN: Right, well critical IROFs that deal with criticality go in the high consequence category, right, wrong, or indifferent, that's where they go. But what I was saying is we know what IROFs are protecting against accident sequences that fall into the high consequence and which ones protect against medium consequence.

MEMBER BROWN: I have a question for you. No, go head, Charlie.

MR. VAUGHAN: No, I was just going to make the observation that when we did -- I'm trying to remember the ISG number -- I think it was seven in the application of digital systems to the IROFs, there was a discussion where you had redundant and non-redundant.

And whether one was you had to pay more attention and you did more of this and more of that to it. We actually made a comment in our letter that said -- it went backward in the ISG to say no, you can't -- and I've forgotten all the details -- it's been a while since we did that.

But I was saying, in that conversation, they were not all treated the same as opposed to the statement that was just made. There was a consideration that some circumstances they would have less attention than others. So I don't how extensive that is.

Mr. Vaughan's experience may be different than mine but I think there's one point that the HAZOP tends, at least in my own experience, to bias the analyst. If he seems something that has a high hazard or high operational consequence, that tends to focus more attention on it.

MEMBER POWERS: Do you see how one dimensional that all is? I mean what he just said is that when I do these things, I know which ones are protecting me against high consequence and which things are protecting me against mid consequences. In other words, he can prioritize based on consequences. And that's very one dimensional.

Because one would really like to protect against is based on risk, which means that the more vulnerable, the less reliable, times its consequences should be the metric. But you can't do that so easily this way, I think.

MEMBER RYAN: And the HAZOP part, while it is a little bit of a step toward ranking, it is biased by the observers.

MEMBER POWERS: Well, you can't get around that.

MEMBER RYAN: Let me point out also that within, if one has a facility that uses a PRA, that you will say oh, well, gee, I can do that ranking there because I can do all kinds of wonderful things. And it is also not true because in a PRA, typically there might be 1,000 components. On the Q list, there might be 30,0000 components.

And consequently, we pay attention to the 29,000 of them based on the same kinds of judgmental sorts of things he's talking about with the ISA. And only a thousand of them could get this risk. So I mean it's not cut and dried.

MEMBER POWERS: I understand. Yes, no, it's not.

MR. VAUGHAN: Yes, let me say in addition to just knowing whether they're high consequence or intermediate consequence, most of the licensees, I think, have reported their information so they also understand frequency. So, you know, instead of just consequence, you could -- you do have the information there to be able to grade these IROFs rather significantly.

MEMBER POWERS: Yes. I mean I think you're absolutely right and you benefit because of memory and experience. And we see this a lot within the DOE complex that we have extremely experienced, long-term operators of hazardous facilities. They know everything about it. They can tell you the history of every bolt that went into the plant.

Unfortunately, those guys are going away. And the preservation of that experience is a problem. And even if it is documented, the retrieval of that information is not so easy. Not so easy.

MR. VAUGHAN: It's much more easy now in the digital world. If you're using some of the good software to record your hazards analysis and the balance of the ISA, you really have a lot of information there at your fingertips that is now recorded where it wasn't always recorded in the past.

MEMBER POWERS: Well, one of the things you quickly run into is that the evolution of software and the evolution of the recording media are not parallel.

(Laughter.)

MEMBER BANERJEE: Mr. Vaughan, I have a

question for you, you know. Can I just comment on what Dana said because I think this is a very serious and interesting point. You can record where every bolt is and stuff. But you cannot record the expertise of the people. And I think that's really the problem.

Remember there was a guy called Arthur Bebbington who designed distillation columns. And DuPont sent five guys around with him, you know, to learn what he know when he retired. And they couldn't figure it out. That's the real problem.

MEMBER ARMIJO: Well, yes, I just wanted to expand a little bit on that on Dana's issue because I think it is important. And it's different than, you know, in the fact that these fuel cycle facilities, and I'm not talking about all of them because I don't know all of them but the fuel factories, during the period when there were no plant orders, you know, power plant, you know, we lost a lot of technical people from the industry.

And we wound up with this situation where we had a lot of older people retiring, new guys coming in. But that's never happened with the fuel cycle facilities. They've always had a business. They've always had products. So there is a continuity of personnel learning from the experienced people that we don't necessarily have in --

MEMBER BANERJEE: The chemical industry.

MEMBER ARMIJO: -- well, in nuclear power plants, you know new people.

MEMBER POWERS: But, Sam, we had this problem in chemical plants where the same situation exists. They have not had downturns and upturns of decade-long periods.

MEMBER ARMIJO: Yes.

MEMBER POWERS: And we still find that they experience base gets lost.

MEMBER RYAN: Said, you had a question?

CHAIRMAN ABDEL-KHALIK: You made a point that this is a highly competitive industry where a lot of things are not being shared. Does that represent an impediment to learning from operating experience at other competitor's facilities?

MR. VAUGHAN: To a degree, it does. However, in the last years where safety-significant things are involved, there has been a significant amount of sharing the fuel fabrication industry. But there is still a lot of protection of the technology and the techniques that are used within the plant. And so there is a line by which you really can't cross over even though there is a significant amount of sharing of safety-related information and concerns now.

CHAIRMAN ABDEL-KHALIK: Thank you.

MEMBER SHACK: Just a question. You made a point that you didn't like the idea of mixing PRA and ISA. Is that a veiled hint that you didn't like the idea of the using of a PRA-like to determine risk in increments of findings?

MR. VAUGHAN: It would extend into that area.

MEMBER RYAN: Very good. Any other questions for Mr. Vaughan? Or Dennis?

(No response.)

MEMBER RYAN: Mr. Chairman, back to you.

CHAIRMAN ABDEL-KHALIK: Thank you.

At this time, we will take a break until 3:35. We will reconvene at 3:35.

(Whereupon, the foregoing matter went off the record at 3:22 p.m. and went back on the record at 3:35 p.m.)

CHAIRMAN ABDEL-KHALIK: At this time, we'll move to the next item on the agenda --

MEMBER SHACK: I'm waiting for today to see -- he said he was misquoted.

CHAIRMAN ABDEL-KHALIK: -- current state of licensee efforts to transition to NFPA-805, and John Stetkar will lead us through this.

MEMBER STETKAR: Thank you, Mr. Chairman. And in light of time, I've got a couple of introductory remarks here just to orient the other Committee members on where we are and what to expect here.

By way of reference, the reason -- we all know why the reason we're here. We are -- we have been tasked by the Commission, through an SRM dated June 25, 2010, to conduct a review and report back to the Commission on the current state of licensee efforts to transition to National Fire Protection Association Standard 805.

The review should include methodological and other issues that may be impeding the transition process, lessons learned from the pilot projects, and recommendations to address any issues identified.

To help us to develop this response, what we have accomplished so far is we have had two Subcommittee meetings -- a one-day meeting on November 16th that was a -- characterized it as a fact-finding mission, and a two-day Subcommittee meeting on December 13th and 14th where we tried to drill down into some more details of specific technical issues, and a little bit of discussion of programmatic issues.

In addition to those Subcommittee meetings, we also had input from a consultant to the Committee, Mardy Kazarians, who independently went out into the industry and talked to practitioners who are actually performing a lot of these studies to develop his own information base for feed-in in a forum that isn't quite the same as the public meetings that we have here.

And the only other thing I wanted to note is a couple of pieces of information about the schedule. The original SRM requested a report from the Committee by the end of February of this year. That deadline has since been extended until -- I don't have the right -- the date in front of me, but late May essentially.

Our current plans are we will not write a letter during this meeting. We will write a letter in March, and, because of the coordinating schedules, our internal schedules, external schedules, because we had published the date for the presentations. We will hear the presentations at this meeting. We will have a month to kind of collect our thoughts, and we will write the letter next month. So the letter will be actually going in earlier than the extended SRM date, but not this --

MEMBER SHACK: That's the plan.

MEMBER STETKAR: That's the plan. I'm hoping that even if we don't -- anyway, that's the plan.

And with that, I don't know whether anyone on the staff wants to say anything.

MR. WEERAKKODY: Not at this time.

MEMBER STETKAR: We'll have a presentation from the staff. With that, I will turn it over to Biff Bradley of NEI.

MR. BRADLEY: Thank you, John. We appreciate the opportunity to brief the full Committee on this subject. I have with me Rick Wachowiak of EPRI and Doug True of ERIN, who are two of our key technical people, and they are going to be discussing the technical aspects of this presentation.

Basically, what we are going to do today is a slimmed down version of what we presented to the Subcommittee. We don't really have anything new, but for the benefit of those that weren't at the Subcommittee meeting, we wanted to go through our main points, and so I appreciate that opportunity.

It was pointed out to me today that we don't know how to spell NFPA, and I guess I have to take the hit for that.

(Laughter)

I guess a little dyslexia must have crept in somewhere, but I think -- anyway, let me move forward here and discuss -- I wanted to just give a little bit of the overall, you know, why we believe this is important, why the industry believes this is important from a regulator perspective, from the perspective of risk-informed regulation.

I know sometimes it seems like we're beating this horse beyond death on the need to get fire PRA to a more realistic level, but we do believe it's that important, and have a lot of work laid out that Rick will be talking about through EPRI. The industry has taken the initiative.

We've got the resources and the experts lined up to do a lot of work over the next several years to try to get fire PRA methods to a more realistic place. And we know it does require work, and we are willing and able to do that, and look forward to NRC staff involvement in that activity, so that we can all come out with more realistic methods to support both 805 and all of the uses of PRA.

Those of us that have been in the industry for a number of years know that fire protection is one of those things that keeps coming up, and I think there is a laudable goal of both the Commission and the industry to try to stabilize once and for all the expectations and the regulatory approach for fire protection.

So 50.48(c) is believed to be a way to do that, and we remain hopeful that ultimately it can do that. We have about -- over half the industry currently transitioning. We have had two pilot plants approved, and so it has been a pretty -- I think even the NRC would agree it has been a fairly arduous and maybe a little more challenging than we thought, but we are -- it is a major effort.

And I guess it was recently indicated it may be into 2020 to get approvals of the existing plants in the pipeline, so I think that speaks to the difficulties.

Obviously, fire PRA is a major piece of the transition to 805. There have been on the order of 50 fire PRAs developed to support 805, as well as a number of other non-805 fire PRAs under development. So it's safe to say that the vast majority of the industry is out there developing fire PRAs right now, and that is appropriate.

But we want to make sure that these PRAs are usable, not just for 805, but there are a lot of places we intend to use these models for other risk-informed applications, many of which are approved and ready for use, such as the tech spec applications for B(5)(b), 50.69, and some of these applications are actually comparing fire-initiated risk to other initiators. So we need to be careful that we are getting these things on as level a playing field as we can.

Everyone is aware that the NRC policy statement calls for realism in PRA to the extent practicable. This has been a little bit of a challenge for fire PRA -- a number of reasons for that. We don't have the 20-plus years of intensive development in regulatory use of PRA that we have had for internal events.

We have had some fire PRAs developed for the IPEEEs, but we really hadn't entered into an application where there was intensive regulatory application of a fire PRA. And I think that has been a learning experience for a lot of us.

There is an NRC-EPRI document, NUREG/CR-6850, EPRI-101-1989, that provides a fire PRA methodology and approach. And that has been used, provided basically the framework for the fire PRA standard, and has also been the basic process that has been used to develop all of the PRAs that we are developing now for fire.

Early on, back in 2008, we started seeing some initial results from application of these methods, and it became clear to us that there was additional refinement needed to some of these methods, not unlike most of the other PRA methods we have developed over time. And we made these concerns known to NRC. We outlined the specific areas where we thought work was needed and requested their collaboration to help resolve these issues.

This resulted in over a two-year effort using a frequently asked question process that is under the auspices of NFPA-805 and Reg Guide 1205, to try to reach agreement on some of these methods.

This was a difficult process. I think there was -- there were some incremental results from this that did incrementally improve the fire PRA methods, but our believe on the industry side is that we -- that this process was not effective at really getting to truly -- getting us close enough to realism to be able to use these PRAs in the way we normally have been using PRAs in applications.

And there was also issues of the timeliness and just the general difficulty of achieving consensus with the schedule pressures for 805 and other things looming over everyone involved. So it was a difficult undertaking.

Back in the latter part of 2009, we essentially stopped submitting further inquiries into this process, or FAQs into this process, just for some of the reasons I mentioned. So we are searching now for a way to achieve a better process going forward. Obviously, NRC is going to be involved in these methods, but we hope to come up with a better way to do this going forward.

In December 2009, we sent a letter to the Commission. This was after some experience with the FAQ process, and still we had some lingering concerns with the lack of realism, so we did provide that letter to the Commission and attached to that letter the initial EPRI fire PRA action plan.

Since that time, we have substantially developed and fleshed out that plan, and it is a much more comprehensive plan now that Rick and Doug can speak to.

We are committed to, you know, doing the work to get these methods right, and we support the use of fire PRA and risk-informed decisionmaking for 805 and everything else we're doing. And we are -- we hope that we can achieve that. I think our -- you know, our concern right now is that -- with the schedule we are on for 805, we don't -- we are not going to get these methods complete in the timeframe that these plants are having to submit applications. That's the --

MEMBER STETKAR: Can I interrupt you --

MR. BRADLEY: Yes, sure.

MEMBER STETKAR: -- for just a second here? I understand, you know, the timeliness of the FAQ resolutions, certainly for the two pilot plants, because in practice their efforts were the genesis of the FAQs.

And in practice, if you look at the pilot plant submittals, for the large -- for the most part, they did not take benefit of any of the FAQ resolutions or very, very limited benefit. And yet they made submittals, and the submittals indeed were approved by the staff for conversion to, you know, the risk-informed framework.

One would presume that, given at least even the nominal time delays for the in-progress submittals, you know, that are currently scheduled for end of June of this year, they have at least had the time benefits to take advantage of a larger fraction, if not all of the available information, to reduce at least some level of conservatism in their studies, and, therefore, you know, in principle have at least a more realistic assessment, however you want to characterize it, for their submittals.

Could you speak to that, I mean, you know, so --

MR. BRADLEY: Sure.

MEMBER STETKAR: -- because the way you kind of presented it was more of an absolute that the FAQs were inadequate.

MR. BRADLEY: Nothing is absolute. I -- one, I think the pilots did use the FAQs to a fair degree. There may have been a couple of facts that weren't incorporated for Harris and Oconee, but generally they did, as well as some additional methods improvements that may not have been reflected in the FAQs. But they had to be scrutinized and approved by NRC, which is something we don't necessarily want to replicate 50 more times.

MEMBER STETKAR: Sure. Sure.

MR. BRADLEY: The second part of your

question, I think, you know, the evidence we provided to the Subcommittee, which we are going to go over today, is based on PRAs that have incorporated all of the FAQs.

MEMBER STETKAR: Okay.

MR. BRADLEY: And we are still seeing the results that we are going to present post-FAQ incorporation. I agree there has been some progress there. I think the question is: how do we keep that going and get all of the way to where we need to be?

MEMBER STETKAR: Okay, good. Thanks.

MR. BRADLEY: Okay? So I'm just going to mention that Doug and Rick here are going to go over this technically in more detail. We did have the opportunity to look at a number of fire PRAs that have been developed for 805, and based on those complete models, we provided some evidence to the Subcommittee looking at some of the intermediate PRA results.

We weren't trying to look at CDF, obviously, because of the very low numbers. But looking at things such as high conditional core damage probability, number of spurious operations, number of large challenging fires, things of that nature, and comparing those to what we have seen in the 3,000 reactor-years of operating experience. So Doug will be speaking to that momentarily, and the technical basis for our belief that we still haven't achieved a reasonable level of realism.

From a regulatory perspective, there is really nothing different about fire or 805 or fire PRAs. It is really no different from any other regulatory application of PRA. We have been using PRA to make risk-informed decisions and risk-informed applications.

Generally, these involve some change from the original deterministic licensing basis. That is what we use risk-informed to do. There is guidance in 1174 that discusses how we accommodate defense-in-depth safety margins and the general concept of conservatism into this process. And we believe those elements of 1174 are appropriate to do that.

Our concern is that it -- in some cases it appears here we are trying to address the issue of conservatism directly in the PRA model versus relying on those other elements of 1174. And we are concerned that that is a little different road than we have been down in the applications we have done to date, given that we did have more experience with internal events before we started doing major applications.

But whether it's an artifact of the

schedule or the level of development or what, the fact is that we are entering into a very large risk application with some level of I believe conservatism that is in the models that is still subject to being improved through methods development.

And this could lead to inappropriate decisionmaking. You know, it's hard to predict that. But it's certainly something that concerns us.

So going forward, we believe it's really important to establish an improved process on the regulatory interaction. I expect the staff will speak to this, and I think we have seen indications of understanding and acceptance of the need to come up with a good process to work together to get these methods to a better place.

And this is just referring back to some previous letters we had a couple of years ago, and maybe things are a little different now. But NRC did state in writing that, you know, we need to have a balance of conservatism and realism in the PRA. And, to me at least, that was a new regulatory concept in light of the other things we have done.

This is now 2011. Maybe we are moving more in the direction of realism, and maybe the NRC staff can speak to that. But that's just what they stated in 2009.

Okay. So we provided a report -- a technical report to ACRS. We also provided the support to NRC staff, and Doug and Rick are going to be overviewing that report for the full Committee here today. That report was intended to point us in the direction of what areas of methods improvements are important, what our priorities should be, where our resources should go, as we seek to improve these methods.

So we wanted to use these insights, understand what the PRAs we've done to date have indicated, where they seem to be diverging from operational experience, and how do we -- what work do we need to do to address that?

So that's what Doug and Rick are going to be speaking to, and I think that's probably the area of this presentation that will be of the most interest to the Committee. So unless you have any questions for me, I want to go ahead and turn it over to our technical folks here.

VICE CHAIRMAN ARMIJO: I have a clarification. These bounding assumptions and simplifications, are those -- the staff decides what these are, and you have to apply them, and that's the problem?

MR. BRADLEY: It's not --

VICE CHAIRMAN ARMIJO: I'm trying to find out exactly what the problem is, or at least --

MR. BRADLEY: Right.

VICE CHAIRMAN ARMIJO: -- the major one. If you could expand on that, I would appreciate it.

MR. BRADLEY: Okay, yes. NUREG/CR-6850/EPRI-101-1989 provides a level of detail that goes beyond the PRA standard as endorsed in Reg Guide 1.200, Rev 2. Our expectation was that if you did fire PRA, had a peer review done, and met 1.200 through that process, that that was sufficient.

What we found in actuality in going into 805 is that, in addition to the full expectation to comply with 1.200, and have the peer review, there is an additional layering on of expectations relative to the methods that are in the NUREG, the EPRI report/NUREG.

And we have learned from experience that these methods need some improvements, and there has been, for the pilot plants at least, expectations if they explain any deviations from these methods, even though they may have met one, two, three, Rev 2. So this -- I wouldn't say this is directly imposed, but it is certainly a different level of expectation on methods than what we have seen before.

And if you use a method that is different from 6850 or the facts, there will be questions about it. You are going to have to justify it. I won't say the staff just unilaterally imposes it, but they do make it more difficult to --

VICE CHAIRMAN ARMIJO: That's their expectation --

MR. BRADLEY: Right.

VICE CHAIRMAN ARMIJO: -- that you will --

MR. BRADLEY: Right.

VICE CHAIRMAN ARMIJO: -- use that.

MR. BRADLEY: And they should really speak to this, you know, let --

VICE CHAIRMAN ARMIJO: Okay.

MR. BRADLEY: -- let them say it as they would say it.

MR. HARRISON: This is Donnie Harrison from the NRC staff. I will just point out that the position of the staff is that if you are using a method that is different than what is in the 6850 consensus guidance, that you have a technical basis for the use of that method.

And so you should be able to justify why it is a technically correct method to be applied. And to get that information, we'd probably have to ask an RAI.

VICE CHAIRMAN ARMIJO: Okay. I'll just -- I'll wait.

MR. TRUE: Okay. I'm Doug True from ERIN Engineering. And I'm going to walk through some of the technical contents, and then Rick is going to take over and talk through the more research program part of the report. This report -- I wanted to preface with this is not an one individual's report.

In fact, the fire PRA task force at NEI chairs -- played an active role in helping identify issues, providing data that we used in compiling information in the report. And so it's really a compilation of work that was done by a lot of different people. I have become sort of the spokesperson for it, but it is actually -- a lot of different people's work went into it.

The fire PRA calculation, if we try to boil it down to just the simplest form of what we try and do is we -- we try to characterize some frequency of a fire, and we associate with that fire some severity characteristics, usually as a function of time, that a fire will grow to a certain size over a certain length of time.

We will account for some probability of suppressing that fire event over time, whether you have an automatic suppression system or you have a manual brigade response to that fire. And then, we take -- for the consequence of that damage condition, and we attach it to our PRA, and we calculate a conditional probability of core damage given that fire damage condition.

And so you can think of it sort of as a function of each of those elements goes into our overall calculation. There are many dimensions to it, and we spent several days talking through many of the details of those previously, and I'm not going to drag you through that again.

The thing that -- what we found in going back and trying to unravel what we're seeing coming out of these fire PRAs is that we have conservatism in almost every step of this.

And so while it would have been really convenient if we could have just said, "Oh, you know, the frequencies are too high, or the severities are too high," we found that it actually kind of tends to show up and there's a little bit of synergy between each of those elements that actually compounds the effect of these conservatisms, because the -- for saying we have a fire frequency and we are overstating its severity and how rapidly that severity builds, those combine to give us this frequency of a very severe fire happening very fast, which then minimizes the likelihood of being able to suppress it, and which minimizes -- which creates an overstated emphasis on the damage, which gives us a higher additional core damage probability.

So they all kind of tie together, and it's really hard to unravel and break it into any one place so we can tackle it. And so that was our first challenge was to -- how do we get this all unraveled and understand what's going on?

The conclusion from the analysts who have been doing these studies is that there is not any one single factor that we think we can focus on. And, in fact, as you will see in the -- in Rick's presentation, there's a whole bunch of things we think need to be tackled, not that they all have equal priority. There certainly are some that are more significant, and there are certainly some that can be done in a more timely manner.

But it is not just one thing we can point to to say that this is -- this is what's driving us to the results which we think don't reflect operating experience.

And then, the last thing is that you find when you go from plant to plant to plant, the thing that is driving each plant to slightly different -- because this is a very spatial problem, and all of these plants have different designs and different orientations, different system capabilities, and that makes drawing broad conclusions very challenging.

MEMBER STETKAR: When you talk about conservatism, when I think of numerical conservatism, there can be a couple of connotations that that word might apply. One is that if I have one estimate that is, let's say, 10^{-3} -- I'm not going to put units -- 10^{-3} plus or minus a factor of five versus 10^{-2} plus or minus a factor of five.

Those are clearly different values, because we have essentially the same confidence in those values, and it is clear that one is an order of magnitude higher than the other.

On the other hand, if I have very, very broad uncertainty, I might have a mean value of 10^{-2}, but it could be plus or minus a factor of 100. And it's not -- that's a different notion of conservatism compared to the first case. Is there any way you can speak to that? Because the notion of the influence of uncertainty on a particular numerical value I think is important to kind of understand in this.

In the one case, collecting more information really won't help you -- the first one -- because the uncertainties are rather narrow, and it just -- it is just apparent that if you're using the 10^{-2}, and you ought to be using the 10^{-3}, it's just clear you are using the wrong data, if you will.

In the second case, in the sense of collecting more information, if that information is available, one, in principle, depending on the shape of the distribution, ought to be able to improve your state of knowledge, reduce the uncertainties, and, therefore, have more realism, a better estimate of that mean value.

That's -- could you speak to that a bit?

MR. TRUE: I can speak to it. I'm probably going to give you a somewhat unsatisfying answer, because I think it depends a little bit on which dimension of this we're looking at.

MEMBER STETKAR: Okay.

MR. TRUE: I mean, certainly, data on how often fires happen, we have a reasonable amount of data for many of those fire events. So collecting more data isn't really an issue.

Some of the others related to the severity and the growth rate are certainly issues where there is a great deal of uncertainty, and the authors of 6850, from the industry and the NRC, I think, you know, made a reasonable first attempt to try and characterize that in a certain way, but -- and the uncertainties are large there.

There could be some benefit in gathering additional data, but, as we talked about in previous discussions, it is very hard to do a test of a realistic fire. It's a lot easier to do a test of a bounding fire, and so everything you are anchoring to is not really what you are trying to characterize in a PRA. So it is a challenging area.

I think I want to go back a little bit to the question about simplifications and bounding, because some of this is that we think that the simplifications -- for example, electrical cabinets, we spent a great deal of time talking about electrical cabinets. It is a pretty simplified approach to characterizing electrical cabinet fire severities and growth rates.

And we think that while there may be certain cabinets under certain conditions that could have those kind of characteristics, it probably isn't reflective of the vast majority of the cabinets and the different characteristics that exist in those cabinets.

So we simplified it, made it easy, to have a cookbook to be able to go and calculate things from, but those simplifications were skewed by certain anchor points that don't really reflect some of the conditions that we think exist.

And that's one of the things that EPRI is working hard on, particularly with respect to electrical cabinets, is to try and unravel that simplification and turn it into a more diverse set, a more reflective set, of inputs that more closely match what we think is really out there in the plants, and the way the plants would behave.

So that's another way that conservatism gets brought in. If we put everything together, we have to bound kind of that condition to make sure we are not understating risk. So I think that is another dimension in this.

One other thing I should say probably at this point, because I have taken some, you know, what might be considered shots at 6850. I think that the original authors did a good job of compiling together a lot of really good information into a very good framework.

I think it moved the state of practice forward considerably, but in their defense, in light of some of these criticisms, it was never tested completely. And so they didn't know what the ramifications of it being a little bit conservative here and a little bit conservative there, and when you combine all of that together, the answer doesn't come out to match it. They didn't have that opportunity.

I think they did a great job of trying to put this together. It was just untested until these first few NFPA-805 plants got through the process and got to the end and said, "Egads, this doesn't seem to be adding up."

So this is not a hindsight is 20/20 thing. It is just -- that was the situation they had. They couldn't have fully known the ramifications of that -- of these assumptions.

MEMBER STETKAR: They were -- back when they were developing that, there was an intent at that time, back in the -- whenever it was -- 2003, '04, '05 timeframe to actually do, you know, a pilot -- an integrated pilot of the whole process. It just never came to fruition.

MR. TRUE: Yes. What ended up happening was the industry was distracted. I mean, you have to have a plan, so you have to have a place to actually go apply it and go through the process. And I think the industry was a little bit distracted at the time.

Fire PRA wasn't really on the forefront of everything, and then we had this fire protection issue that got raised, and 805 got brought up as a solution, and then, oh, there's this EPRI NUREG document we can use to solve this problem, and all of a sudden we're off and running.

And it was just -- it was sort of an unfortunate, in my opinion, confluence of some events that rushed it into use a little bit before it had been fully tested.

And so that's a little bit off topic, but I think a fair perspective of sort of how we got here.

So one of the things that we wanted to look at was, how do we compare the fire PRA results we're getting out of these studies to operating experience? And, as Biff said, you can't do it on the basis of core damage events, because, thankfully, we don't have enough core damage events from fires to base it on.

We had the one, you know, significant

event at Browns Ferry that was a close call, and, in fact, involved some significant spurious operations in that plant in that fire. But we have done an awful lot to try and respond to that -- also, that fire -- in improving our fire protection programs.

And so one of the things we looked at was spurious ops. It's the main -- major focus of NFPA-805 and the new fire protection evaluations, whether you're falling 50.48(c) or the other path. And we realized that fire PRAs give us the ability to -- if you interrogate them properly, you can go in and actually calculate, "Well, how likely does the fire PRA say these spurious operations are? How likely will we expect it to be that we would have a fire that involved one or more spurious operations?"

And so we took a sampling of a few PRAs, went in and tried to figure out that interim state that is short of core damage, short of CCDP, but it is a condition where some spurious ops were predicted to have occurred.

And the way we did that was we pretty much went into the PRA, looked at each of the scenarios to see if it triggered a spurious op flag in the model, and those -- and then summed up those frequencies of all of those scenarios across the PRA.

MEMBER STETKAR: Before you get into the math here, because the math is going to be important -- I'm not going to interrupt you as you walk through the thought process -- oftentimes I need to get myself calibrated when you use the term "a PRA." Given the fact that the fire risk models are developed in a sequential or a hierarchical --

MR. TRUE: Iterative.

MEMBER STETKAR: -- iterative -- okay, iterative is a phrase also, in the sense that very often you insert -- you develop simplified, conservative models as a sort of screening process to focus you down successively to determine the locations or the scenarios that you really need to refine more.

In that context, you are going to start presenting results here from fire PRAs. And I think it's important for the Committee to understand at what level of refinement or sophistication, at least in your perspective because you are familiar with the studies --

MR. TRUE: Right.

MEMBER STETKAR: -- in that sort of iterative process or successive refinement process, if you will, where are these studies? I mean, how far have they progressed? Are they just after the beginning, or are they, you know, ready to go public?

MR. TRUE: No. These were all -- you'll notice if you inspect the study, I use Plant X, Plant Y, Plant A, B, C, 1, 2, 3, was all to --

MEMBER STETKAR: We don't need to know the plants.

MR. TRUE: -- protect the names of the innocent. So there's a spectrum of plants. There's actually a little bit of overlap between A, B, C, D, and 1, 2, 3, 4, 5, I think, and -- but we tried to use studies that were well down that road.

MEMBER STETKAR: Okay.

MR. TRUE: And in some cases, some of the studies cited are actually the pilots also. So those are very well down the road. And so, yes, we wanted to do a fair assessment of if we actually implement these methods, what are we -- what is the answer going to look like, and we didn't want to, you know, cook the books and use some, you know, quick and dirty thing that was the wrong way.

These are well developed. I wouldn't say they are necessarily the exact one that was -- will be submitted as part of the 805 submittal, but they were well down the road, so that we --

MEMBER STETKAR: It's just important

for --

MR. TRUE: -- follow some reasonable representation.

MEMBER STETKAR: Yes, a general context, because you are going to be using numerical examples to demonstrate conservatism.

MR. TRUE: The other thing is that we -- like I said, we had a couple of the pilot results in here, we had -- we had results from several different vendors who are different vendors that supported different utilities. And, in fact, at the first meeting we had Jim Chapman come, who is from ScienTech, who between ERIN and ScienTech we have done the majority of the support for the industry in this area.

And we have tried to make sure we weren't just using one company's bias for something to represent this. It was intended to be representative of a reasonably well completed fire PRA. So thanks for --

MEMBER STETKAR: That -- no --

MR. TRUE: -- bring it up.

MEMBER STETKAR: It's important, because --

MR. TRUE: It is important.

MEMBER STETKAR: -- two or three of us have heard this story, but --

MR. TRUE: Yes.

MEMBER STETKAR: -- most of us haven't.

MR. TRUE: So in this case what we did was we went into a couple of those PRAs, and we summed up the frequency of scenarios that would have been predicted to cause one or more spurious operations. In many cases, the fire -- significant fire could cause more than one spurious op. We just decided to lump them all together and say, "Just any one that causes one or more we will count them the same."

And for the two plants we looked at, the results came out around four times 10^{-3}. And if you take that and extrapolate it across the 100 plants in the industry, I would say that, you know, every couple of years -- two, three, four years, something like that, we would expect to maybe see a fire that has spurious ops occurring.

And we don't see that in the operating experience. There are anecdotal things here and there where certain things might have happened, cable failures in particular have happened, but actual spurious op, which is a shorting of either within a cable or between cables to spuriously cause something to change state, we are just not seeing that kind of a rate across the industry.

So we think that is an indication that we have -- we are overstating the severity of the damage, and, therefore, the spurious operation rate.

MEMBER POWERS: Is it assured that you would get accurate reporting? I mean, if it's a spurious operation in a non-safety system, would it be reported?

MR. TRUE: Well, yes, these are -- these are spurious ops we're predicting in -- in safe shutdown equipment primarily. So I think it --

MEMBER POWERS: So you are counting things about --

MR. TRUE: -- would be pretty accurate.

MEMBER POWERS: -- correctly, then.

MR. TRUE: I mean, certainly we can be off a little bit, but --

MEMBER POWERS: In factors of two, five.

MR. TRUE: Yes.

MEMBER POWERS: But they don't mean anything here.

MR. TRUE: I think we are -- we are seeing a pretty good-sized gap here, and, you know, there was some discussion in the second meeting I guess about some events that had had things happen. But even those events weren't the kind of things we are predicting here, that -- where safe shutdown equipment, the valve -- when the systems closes it, we need it to be open, that kind of thing. We have just not seen that happen.

MEMBER BLEY: I might be wrong. I thought the reporting requirements now -- maybe staff can help me on this -- were such that you have to effect both trains of a safety system before it has to be reported. I'm not sure about fires. So I'm not -- I wonder if you're right about these needing to be reported or you're having a pretty good case. Can anybody clarify that?

MR. KLEIN: This is Alex Klein. I'm the NRR Fire Protection Branch Chief. In terms of reporting requirements, it's not necessarily based on the consequences. It's based upon the time of the fire. So licensees report fires that last more than 10 minutes.

MEMBER BLEY: Okay. So all fires lasting more than 10 minutes are reported.

MR. KLEIN: That's one criterion.

MEMBER BLEY: That probably has to happen --

MEMBER SIEBER: Regardless of size or location?

MR. TRUE: Yes, just duration.

MEMBER SIEBER: That's --

MR. TRUE: For an LER report.

MEMBER SIEBER: That's probably one of the distortions in the whole process is the reporting of fires, because there aren't very many fires that actually have safety-related consequences. They don't occur at that frequency that -- to my knowledge. That would be the first thing I would look at.

MR. TRUE: Yes. We also have a fire events database that includes many other events beyond the LER reporting. So from a regulatory reporting process, I think that 10-minute rule is true, but the other events that we have access to through the EPRI data collection stuff haven't borne that out.

MEMBER BLEY: I'm trying to remember. Jim Chapman or Pat Baranowsky or you guys, one of you were talking about you are actually going back to all of the utilities and collecting additional --

MR. TRUE: Yes.

MEMBER BLEY: -- data.

MR. TRUE: That's one of the things Rick will talk about later.

MEMBER BLEY: Okay.

MR. WACHOWIAK: That's our highest priority activity.

MR. TRUE: I should probably get going here.

MEMBER STETKAR: We're good on time. I'll hustle you along.

MR. TRUE: All right. So another thing we looked at was the consequences of the fire and its effect on mitigating equipment. And we were -- in particular thought we'd look at the conditional core damage probability.

The way that the fire PRA calculation is done is there is sort of two pieces to it. There is one as the frequency of the scenario and the damage it causes, and then we hook that onto our PRA and we calculate, well, given that damage, what's the conditional core damage probability that results? So it's a nice, simple break point.

And we can look at for each scenario what its conditional core damage probability is. In a typical PRA today, there would be many hundreds, maybe a thousand, of these scenarios that would be present in the PRA. CCDPs are also used routinely in the accident sequence frequency program that NRC research does and the reactor oversight process, so it's a common metric we are all used to looking at.

And so what we did was we wanted to go back and look at some fire PRAs to see what the predicted frequency of fires were that involved these relatively higher conditional core damage probabilities.

We started looking at the -- what the Accident Sequence Precursor Program told us about these events. This is actual events that have occurred in the industry. Research culls through those, looks for the ones that appear to have effects on plant safety, and they go into each one of those events and use a SPAR model to calculate CCDP. And there is an iteration with the utilities to figure out, you know, does that really reflect what the utility thinks their PRA would say?

And they come up with a representative estimate of the CCDP for each of those events. And this is everything from, you know, a loss of offsite power event to a flood event to a fire or anything else. So it's all -- it's indiscriminate on which kind of events go into this.

They have a category they call significant precursors, and then -- that they have a list of actual events that -- for example, the Browns Ferry fires on there, Davis-Besse head is on there, and there's a lot of events you would be very familiar with on that list. And then, there's a trending done of the high CCDP events, which are those greater than 10^{-4}.

There hasn't been a significant precursor since Davis-Besse head, and there have been a total of 34 in the history of the industry. Only one of those involved a fire, and that was the Browns Ferry fire back in 1975. So that's significant over the 10^{-3} CCDPs.

So in this case we looked at five different PRAs, and we went in and just basically sorted the scenarios based on CCDP, and then summed up cumulatively the frequency of each bin's worth of scenarios. And so for the middle column there, the significant greater than -- CCDPs greater than 10^{-3}, we found that there was -- you know, it ranged from about one times 10^{-3} up to 10^{-2}, by an order of magnitude range on that, but a pretty well behaved distribution actually of results.

On the right-hand column, there we actually have a pretty tight grouping of somewhere between one times 10^{-3} and three times -- one times

10^{-2} and three times 10^{-2} frequency came out of these studies. So that would say on an industry basis we should be seeing these significant precursor events every one to 10 years, every handful of years if you will, whereas on the 10^{-4} CCDP event we should see one or more or a handful per year showing up.

MEMBER BROWN: For the uneducated like me, the previous page you said there are no significant precursor events since 2002.

MR. TRUE: Right.

MEMBER BROWN: And of all the 34 significant precursor events, only one involved a fire --

MR. TRUE: Right.

MEMBER BROWN: -- yet you develop all of these statistics for fire PRA from no data. I mean, that's what I drew out of -- I'm not sure whether I stated that right or not, but that's what -- that's the message I got. You've had one involving a fire, and yet you've got --

MR. TRUE: We would predict that we would have lots. That's the basic message.

MEMBER BROWN: Oh, that's the point.

MR. TRUE: Yes.

MEMBER BROWN: Oh, okay.

MR. TRUE: So we are predicting that we should be seeing one every handful of years or a handful per year, and in actuality we haven't seen that -- anything like that in the operating experience.

MEMBER BROWN: Yes, okay.

MR. TRUE: And then, this is just an excerpt from the most recent SECY-2010 on the -- the frequency of these events in the industry are a total of eight since 2001. None of them involved fires, whereas that previous chart would have said we should have seen, you know, 10-ish, 15, 20, 30-ish, across the industry, and we're not seeing that.

MEMBER SIEBER: Fifteen, yes.

MR. TRUE: Yes. So we think that the predictions that we're getting out of these methods are not really lining up with our operating experience. That's sort of our plan from the beginning.

MEMBER SIEBER: How safe you are.

MR. TRUE: Yes, we actually are versus how safe we predict we are.

So the ROP is another place where we look at CCDPs, and that is done based on actual plant conditions that would include events as well as any other non-conformance. And those range anywhere from 10^{-6} all the way up to 10^{-4}, and in the ROP process, since it was implemented 10 years or so ago, we haven't had any factual fire events that even got above a CCDP of 10^{-5}. So now we've gone another order of magnitude lower than the ASP considers, and we still don't see any actual fire events that are getting us CCDPs in that range. And we would have predicted, you know, even more than that, how many each year occurring from the fire PRA methods.

So we think there is a disconnect between what we are calculating and what we are observing, and it is a pretty sizeable disconnect. And that occurred both on -- whichever one of these metrics we wanted to look at, whether it was spurious ops or CCDPs. And that ends up, we think, in an overprediction of the computed fire core damage frequencies.

So the conclusions out of the technical portion of the road map that lead into Rick's plan for what we are going to try and do about this is that we think we don't conform with the operating experience. We've got an overprediction in the number of severe fires that are causing significant damage.

One of the specific technical details is we think that the fire growth rate and severity is overstated in the way that oil fires and electrical cabinet fires in particular are covered, and the methodology is leading to this calculation.

We spent a lot of time in the Subcommittee meetings talking about those two topics. And another thing which we don't have a good way of accounting for in the current methods is that sometimes when you have, for example, an oil fire that is burning, the response might be to control that and let it burn out.

As long as it's not causing any damage to the equipment around it, they will let it burn. But it is being characterized as a more significant fire than that, even though it's under control. And that's a nuance that's in part of EPRI's research in the long term.

The result of this is that since we don't conform with -- we don't see intermediate states conforming with our operating experience, we think that the CDFs and interim solutions of the fire PRA are overstating the frequency of these severe fires, and we don't have any operating experience that supports that. And in spurious ops, which we're spending a lot of time and effort trying to chase, it's not lining up with our operating experience either.

Finally, when it gets to decisionmaking, our concern is that if you have an uneven level of conservatism, and it's very -- it's almost impossible to have an even level of conservatism -- that you can mask risk insights, and that that can make decisionmaking very difficult, and that some of these simplifications and groupings of bounding treatments of different bins of different fire types are going to make it hard to know exactly what is really -- what really are the risk drivers.

Another thing which we go into some detail in an example in the report on is that just -- by overstating fire damage you can actually end up understating a delta risk calculation, and that's challenging because we have -- it's okay to -- it may be okay to have an overstated base risk, but when you're trying to judge the importance of a change to the plant, whether it's a design change or it's a -- taking equipment in and out of service for an application, we'd like to believe that that is representative, and we can show how you can underestimate that risk difference.

And then, we have some other aspects of the methodology, the way that plant trips are handled and the way administrative controls are credited that we spent some time talking with the Subcommittee about areas that we think are -- where we think those would help us improve the methods. So --

MEMBER STETKAR: In terms of timing, we are scheduled through 6:00. And we will probably take that. I'd like to leave the staff about 45 minutes, and maybe 15 minutes more, so in a sense we've got about half an hour more --

MR. TRUE: Right.

MEMBER STETKAR: -- for you folks.

MR. TRUE: Right.

MEMBER STETKAR: If I could, only because it got so much attention and I think it's really neat, and I know you have a backup slide for it --

(Laughter)

You know what's coming. Just put it up there and show the rest of the Committee something that they haven't seen. Well, go backward one. There you go.

MR. TRUE: John's favorite shirt.

MEMBER STETKAR: I love this. This is important, because it not only shows you -- you know, Doug has talked about overall conservatism, but this is a lot more information on this.

MR. TRUE: Yes. So, you know, it's one

thing to calculate spurious op frequencies and CCDPs and total CDFs. It's another thing to say, "Okay, what do we need to do about it? And how do we best attack it?" So one of the ways we tried to unravel and sort through the fire PRAs was we looked at the CDF contribution of different of these bins.

Each of the ignition sources is considered in a bin, and the x-axis of this chart along the front there is those bins from 6850, and then the y-axis is the relative contribution to CDF. So this is just a fraction of that plant's CDF, and some of these plants have higher or lower CDFs. It was just to sort of see what are the main contributors, and then the z-axis of course is a list of plants.

So, obviously, the first thing that jumps out quickly at you in this chart is that there is this -- every plant has a sizeable, and maybe even it's largest contribution coming from this -- what we call the ridge line or whatever of this chart, which is related to electrical cabinets.

Now, big surprise, I mean, that that's the case. There are a lot of electrical cabinets. We have a lot of electrical cabinet -- well, I don't know about a lot, but we have more electrical cabinet fires than we do any other type of fire in plants. But power is important to operating the systems in the powerplants, so it's -- it would be important.

But the thing I like about this chart is it says, "That's important, but if you look around the chart, depending upon the plant, other bins are also contributors." So if you did something to drop electrical cabinets, for example, in my green plant here, Plant 3, it is going to rapidly -- the next important thing is going to be the high-energy arcing faults followed by some in-plant transformers followed by some battery chargers in that particular plant.

This was the point I was trying to make early on, that it's very plant-specific and it's very scenario-specific. The second chart -- wrong direction. Second chart here, basically in this one all I did was I made the bin 15 electrical cabinets invisible, and I changed the scale, so it sort of like zoomed in and removed the big mountain in the middle.

And this gives you a little bit better view of the fact that it is kind of all over the place across the plants.

MEMBER STETKAR: Thank you.

MR. TRUE: Okay?

MEMBER STETKAR: We spent -- in the Subcommittee, we spent quite a bit of time on those charts, and I thought they are really informative and it's worthwhile for the rest of the Committee to at least be introduced to them.

MEMBER POWERS: I guess, John, I -- I wonder -- I'm puzzled why you are so enthusiastic about this chart. Doesn't it just say what we kind of know?

MEMBER STETKAR: It says what we kind of know from people who have done a lot of fire PRA work. If you haven't, it is worth recognizing it. But it also -- the reason I wanted to get it into the record and in front of the rest of the Committee members is it also is an integral part of some of the things I think we are going to hear in EPRI's path forward.

In other words, you know, why are they focusing in certain areas? Why are they maybe not focusing in other areas? So that's another reason why I wanted to get it in there, even though perhaps from a results perspective it might be intuitively obvious to some of us.

MEMBER POWERS: Well, I mean, we have the IPEEEs, we have the experience. Where else would you expect fires, except cabinets, transformers, and battery chargers? I mean, those are the kind of places that you'd kind of look for fires.

MEMBER STETKAR: Well, but it's also important -- I mean, Doug mentioned -- in the first line up there he mentioned things like oil fires. You don't see oil fires contributing.

MEMBER POWERS: If I walk through a plant, I see elaborate --

MR. TRUE: There's one right here.

MEMBER POWERS: -- efforts to maintain and control oil spills.

MR. TRUE: Diesel generator fire is an oil fire.

MEMBER STETKAR: After you cut out the cabinets.

MR. TRUE: After we've -- but it's still -- I mean, it's --

MEMBER STETKAR: Well, no, eventually -- you know, this is risk assessment, so eventually you get the grains of sand, one of which has a little higher knob and the other one doesn't, so --

Well, perhaps I erred in terms of my desire to have the Committee see that, but they've seen it now.

MEMBER POWERS: I think you just wanted to see where you were, you know?

VICE CHAIRMAN ARMIJO: I liked it, John.

MEMBER STETKAR: Thank you, Sam.

MEMBER CORRADINI: Do you count all electrical cabinets as being the same?

MR. TRUE: Sort of. There are a small number of bins. I think there are five bins for electrical cabinets, depending upon the type of cables and a couple of other factors.

MEMBER BROWN: Why differentiate between, say, instrumentation cabinets and what I call switchboards and/or a cabinet full of power electronics where I am, you know, trying to convert it from one form to another and run a pump or something like that where you have a lot of power?

So low power cabinets, I'm just going back through 40 years or 45 years, and I never had a fire in the vast majority of what I call the control instrumentation cabinets. They were almost always in a switchboard of some kind, you know, a regular switchboard, and they were normally localized in terms of locality to types of cabinets, at least in my Navy experience, the molded case circuit breakers, the 50 amp, 100 amp, 250 amp, 450-volt breakers.

We never did ever find out why we kept having fires in those other than the Navy ones are kind of compact, which creates another issue. The ACV cabinets, the ones with the big air circuit breakers, had few, if any, other than if you had an arc fault, where it kind of -- you never knew it.

It would kind of eat its way through the cabinet, saw no spurious operations, and then it would explode out of the cabinet when it started eating the metal, and then it would just explode out into the manned areas. Hopefully, there were no men there.

So that's why I asked about, you know, if you treat -- if every cabinet, then -- is then treated the same, then you get a different range of probabilities I guess or input into the spurious operation and possible problems. That's why I ask the question, just to see. If you're going to sort, you ought to try to fiddle stuff around, so that you don't count -- everything is not the same.

MR. TRUE: We're working in that direction. Today it's pretty simplistic, and --

MR. BRADLEY: Even more simplistic than you just stated.

(Laughter)

We don't want to go there probably today.

MEMBER SIEBER: That's probably one of the sources of the problem that you have. Unfortunately, I have experienced cabinet fires. Generally, they only take out one component, and they typically, unless it's a high energy cabinet, don't spread --

MEMBER BROWN: Exactly.

MEMBER SIEBER: -- to anything else.

MEMBER BROWN: Yes.

MEMBER SIEBER: There it is, and you've got a brown mark on the front of the cabinet, and something failed. And that's the end of the fire.

MEMBER BROWN: Exactly.

MR. TRUE: That's not what we're seeing in the application of these methods, so there's a -- there's a disconnect.

Okay. This is my handoff to Rick. Rick is going to go into the research activities. Is there any questions about the technical stuff I presented, which -- cover those now or we will just continue with Rick.

(No response)

MR. WACHOWIAK: Okay.

MR. TRUE: All right.

MR. WACHOWIAK: So just one last thing to bring up in -- in an area with the bar chart. From the results that we saw on comparing what the PRAs would predict to the industry experience, what we're seeing there is that we are off by at least an order of magnitude in those, and in some cases it is probably -- that would just barely bring us to where maybe you would expect zero events.

To get it right in the middle, you would have to go more than one order of magnitude. So that's why the bar chart is important to see that there is nothing on there, there is no one thing that if you fix electrical cabinets, it will bring this all into range. You have to fix some of the other ones, too. That's not the -- that's a significant piece of it, but it's not the only piece that needs to be addressed.

So, of that --

MEMBER BROWN: Can I ask one other technical question? Are there any fire protection methods incorporated in the commercial -- in the cabinets, the big power -- electrical switchboard cabinets and stuff like that in the commercial plants?

MR. TRUE: Do you mean, for example, incipient detectors and --

MEMBER BROWN: Yes. I mean, like when we -- to address our problem, we ended up installing a system called an arc fault detector to try to trigger and isolate sections of the bus, so that it couldn't spread, particularly in the high-powered ones. It works very, very well, and we have backfitted it into all of the -- almost all of the nuclear ships. So --

MR. TRUE: I don't know if those, for example, are --

MEMBER BROWN: I just wondered if they did. It was just --

MEMBER STETKAR: Charlie, for the most part, there aren't even automatic suppression systems.

MEMBER BROWN: There's not?

MEMBER STETKAR: There's --

MEMBER BROWN: Well, I guess ships would worry a little bit more about fire.

(Laughter)

Fires are a big deal on a submarine. There's no place to go to breathe.

MEMBER SIEBER: Big deal.

MEMBER BROWN: Okay.

MR. WACHOWIAK: Yes. There's not a lot of information on those types of protective equipment by nuclear powerplants.

MEMBER BROWN: Okay. I was just curious, that's all. Thank you.

MR. WACHOWIAK: So Doug described the issues, and what I want to talk about right now is what it is that the industry is actively doing about trying to rectify some of these things, and maybe give you an idea of the timeframe that -- where we think we will have significant results.

This slide, and the next three, essentially say the same thing. It's for different types of people, whether you think pictorially like this or whether you think in lists, we'll cover it -- most of the items on the list.

But what we wanted to do, as Biff said, back in 2009 we came up with an action plan, the industry came up with an action plan, that had a bunch of things that we were going to work on to address these things. They were -- it was organized based on expert opinion, and our gut feel for where we needed to address these things.

Since then, we have gone through and looked for the evidence of where we have issues, and we have also gone back through the genesis of the fire PRA fact process and the resolutions from the fact process to see what was left on the table from all of that.

And then, we took that -- took our action plan and compared it to the things that we were seeing were left -- left undone and the things that looked like they were significant contributors to the PRA.

And this is our organization for how we are doing this.

We are looking at things that are addressing the fire ignition frequency piece of it. We are looking at things that are looking at the damage assessment, like what happens in the different types of cabinets, and we are looking at things associated with how you put these phenomena into your PRA model. And we've got actions going on in all of those different areas.

VICE CHAIRMAN ARMIJO: Do you have mitigation in that category, or is that treated?

MR. TRUE: What aspect of mitigation?

MR. WACHOWIAK: Yes. What aspect? Fire?

VICE CHAIRMAN ARMIJO: Well, any aspect to put out the fire. Does it --

MR. WACHOWIAK: So non-suppression probability is in Category 1. That is, given a fire, what is -- given a fire of a certain type, what is the probability that the -- that operations at the plant will put the fire out?

So that's covered in there, and then there's some of the other things, the damage assessment and fire propagation kind of gets a little bit to mitigation once you have a fire that -- is there some aspect to the design of the cabinet or where it's located, things like that, that could prevent damage from occurring in other pieces of equipment? So the mitigation is -- is across the board I think there.

So in area one, the important things that we are working on now are the fire events database. We want to get a better idea of what are the frequencies of fires, and what do the fires look like once they happen.

There was a presentation in one of the Subcommittee meetings that went through the excruciating details of what we're collecting in the database and how we intend to use the data. But just to say that right now it's a collection of the data from about the last 10 years, 2000 to 2009.

We are reevaluating the events that are in the current database from about -- what is it -- 1990 to 2000, going back to the plants to see if we can get more information about those events and try to get a better feel for what are the kinds of fires and things that we are going to have, and where they have -- what types of equipment they happen in and what do those fires look like.

We are trying to gather more data into the database, or more information about each fire event into the database now, and so that we can look at what actually happened and maybe try to match the types of fires that have actually occurred up to the treatment in the PRA for what is -- how it proceeds to damage additional equipment or not.

We are looking at the severity characterization. Once again, that is by looking at the events that have actually happened. That is what we are doing in here. We are going to try to look at some aspects of incipient detection, and this is the -- some of the kind of things you are looking at here.

Our intent isn't to quantify, what is the reliability of incipient detection or things like that? What we want to do is look at the fires that are there and try to understand what types of incipient fire detectors could have been used to detect those types of fires, so that we can end up figuring out how to use them in a PRA model, should a plant decide to install those.

We think that the reliability of those detectors comes in in a -- from a different program, not from actual events that have happened in nuclear powerplants. Too few and far between to try to grab that type of data, at least at this point in time.

And then, we are also going to look at the fire suppression and control. One of the things that we are finding in the database now, as we are collecting the data, is if -- if the fires were small, very small or very well behaved, they didn't happen -- they didn't really write down much about it, and that's to be expected.

And when we're looking at things like fire suppression and control, those tend to be the things that work right, and they don't write a lot about that. So we are trying to figure out how we can -- how we can glean this data from the plants where things went well and where things worked like they were supposed to, so that we can more accurately --

MEMBER STETKAR: Since it's only the last 10 to 20 years, are you making any efforts to go back and talk to human beings who may have --

MR. WACHOWIAK: Yes.

MEMBER STETKAR: Okay.

MR. WACHOWIAK: Yes. So --

MEMBER STETKAR: -- the fires, because they might recall more.

MR. WACHOWIAK: Yes. As a matter of fact, in the most recent set of plants that are farthest along in the data collection effort, we have identified what we know from their reports and what we don't know that we would like to know from their reports.

And we have gone back to them and said, "Okay. Here is all the stuff that you didn't tell us about in your report. Can you get us this information? This is what we need to calculate fire frequencies, and this is what we need to identify credit for suppression and other things."

So we are trying to go back while the information is somewhat fresh in the minds of the people at the plants, and we are factoring that into the going forward, how do we do continuous data collection going into the future where everyone knows if you had a fire you need to keep track of these types of things, so that we can refine our models.

In the area of damage assessment, we are looking at the fire growth and how that compares with things that we see in the data, that we have seen in the database. That is one of the things that we are really going to need to collect the data up front or ahead of doing a lot of significant data reduction there. But that is a planned activity.

One of the things we are working on now is peak heat release rates in certain types of equipment.

We know that we have to work on electrical cabinets -- that is, the discrimination amongst the different types of cabinets, what is in there, what its potential for causing a severe fire needs to be characterized, and I think I talk about that on a slide toward the end.

We want to look at the damage that has actually occurred from some of these fire events. Hopefully, we will be able to get that out of the data that is there, and certainly in talking with the plants about some of these events.

The other one that falls into this range here -- I'm not sure if it's so much in Category 2, maybe it's in Category 3, is the guidance for doing fire modeling. Fire modeling is becoming more and more important, as we want to show that some of these fires do not actually damage adjacent equipment.

And there are various tools that are out there, and we have gathered a -- through a collaborative effort of EPRI and NRC Research, we are about to put out a guide for users of fire models and how they should be used in nuclear powerplants.

In Category 3, we are working with Research again on the treatment of hot shorts. There is an experimental data interpretation going on as we speak. It is in the early phases of that for the latest DC circuit tests that were done, and the team is also looking at the AC circuit tests that were done before to see if there's anything we can glean from the new information. That's a collaborative effort, and the PIRT panels that are working on that are made up of both NRC and industry experts.

We put out -- I think the report is out in draft now for the human reliability methods for -- in your fire PRAs. We will start to see some more and more use of that, and our intent with reports like this is to put it out for use, get feedback from the plants that are using them, and then, on approximately a year and a half to two-year timeframe, go back and refine those reports to pick up the information that came from the users and try to refine it to make it more usable or more realistic if -- as time goes on.

The human reliability is one of the first ones out of the chute in this -- in that sequence of events. We are looking at how to better model control room fires and control room evacuation, and then, in general, addressing or advancing the models. Are there better ways to do these calculations? Are there more efficient ways of doing them?

I think we mentioned this early, but I

just want to say again that all of these activities are being coordinated under one action plan. We have got the things on the action plan that are led by EPRI, but also things that are led by the owners' groups and by NEI, and, as a matter of fact, we have put the research and testing activities that have been going on at the NRC, integrated that into our matrix as well, so that we can see, in a broad way, what everybody is doing and how it ties together, and try to minimize duplication to the extent possible.

The road map document that Doug talked about earlier has a snapshot of that -- of the action plan or the action matrix as an appendix. So if you want to see what the specific activities are, you can go into that document that you have and see the specific activities.

We use the road map, and we use our -- use the industry committees to focus what it is we should be working on. Through NSIAC and the Executive Oversight Group at NEI, the utility executives, they have been through this plan. We have presented it to them, and they are on board with this being a priority for the next couple of years until we get the bulk of these activities in control and get the products out for use in the fire PRAs. It is a very high priority activity for the industry.

Let's see, I think I've talked about most of these already when I was talking about the specific things, but let me just make sure that I have covered it. One of the things that we want to make sure of with the new fire events database data is something that was left on the table with one of the earlier facts.

From the old fire events, the existing fire events database, EPRI had gone through and relooked at the data that was out there and noticed an inflection of the fire frequencies that happened at around 1990. But there was some concern that there wasn't enough data after 1990 to really confirm whether or not that was a trend or whether it was not real, something -- they were just looking there.

One of the things that we -- our intent here is to look at that. We will have another 10 years worth of data, it will put it on par with the earlier data that we have, and will investigate whether that trend was indeed -- or whether that change in frequency was indeed true. And it will -- we'll let it fall where it does when we look at the data.

We want to get better data about the

fires. And, as John said, we want to talk to the people who were there to the extent possible now and get better information for how these fires actually behaved and try to make -- try to be able to link what we are calculating in a fire frequency with what we are actually modeling as the effects of those fires in the PRAs.

We are going to look and see if we have enough data for doing component-based fire frequencies rather than the plant-based bin frequencies that we talked about in one of the Subcommittee meetings. We think in some of the bins, some of the types of components, we are going to have enough information to do that. In other ones, we won't have enough information to do that.

So we will -- we will look at what is there and determine whether we have a basis for doing that. And, to the extent possible, we will calculate component-based frequencies where it's warranted.

MEMBER STETKAR: The problem -- and I think you mentioned -- the problem there is not necessarily counting the numerator, because you are doing that. It's counting the denominator, the population of --

MR. WACHOWIAK: Right. We've got the --

MEMBER STETKAR: -- equipment per plant.

MR. WACHOWIAK: We understand that. We have the owners' groups working on an activity to collect the data from the plants on how many of the different types of components they have, and then try to link that with the records that are coming into the database. So we understand that difficulty. It's not a trivial task. We do think, though, that's best led by the owners' groups.

In our frequency report, we are going to address the plant-to-plant variability. I think Pat Baranowsky, in his presentation, discussed how they were going to do that when they reduce the data, and that will be addressed in the new version of the database.

The other thing that we are working on in the near term is this vertical electrical cabinet heat release rate. We recognize some of the same things that you brought up in terms of not all cabinets behave the same. And we didn't do any new experiments, but we went back through and looked at the experimental base that we had to try to understand what other types of information do we know about these cabinets in the plant that we can use to influence the kind of heat release rates that we would calculate from a power level of the equipment in the cabinet is one thing that we are looking at.

We are also looking at the ability for the cabinet to ventilate itself, so that the fire can grow inside the cabinet. Much of the testing that was done were with well-ventilated cabinets, and so we developed a model that could -- that could predict a maximum heat release rate based on the ventilation characteristics of the cabinet.

Double-edged sword of course. If you are going to use these methods, you have to know more information about your cabinets. That means you have to collect more information about a whole bunch of cabinets to put it into the model. But we're trying to strike a balance, and we've got -- in the reviewers that are looking at this, they are not only looking at the correctness of the methods, they are also looking at how can this method be implemented, and is it something that is actually useful to the plant, because we don't want to put something out there as the state-of-the-art method if nobody can do it, because it's just too hard.

MEMBER STETKAR: Yes. You showed some examples of thousands of cabinets in a plant.

MR. WACHOWIAK: Right.

MEMBER STETKAR: And the implication is somebody would have to go out and really examine each one of those.

MR. WACHOWIAK: Right. So if you had to know specifically, what is the combustible mass in every cabinet, that wouldn't be a useful thing to do. But what we think we were able to do in this report, which is under review right now, is correlate the type of cabinet and the size of the cabinet to a reasonable range of combustible material that is inside the cabinet.

So those types of things were looked at, so -- and we actually have two -- I believe it's two plants that are trying to implement the method as the test case for the review. So usability and accuracy are both being tested.

MEMBER BLEY: Are they focusing on screening especially the cabinets that essentially have nothing in them? I mean, we talked about that at the Subcommittee meeting, and it sounded like people were putting an awful lot of work into cabinets that they really, even by the NUREG, could have screened based on the fuel loading within the cabinet.

MR. WACHOWIAK: Probably. That is an aspect of it. And the method that is in the report that is in review right now addresses that, and that is one of the steps through the flowchart for that method is to characterize, what is the loading within the cabinet? And you can get out to a screening value to remove those cabinets from --

MEMBER BLEY: So the two plants are using that?

MR. WACHOWIAK: There are -- there is one that is using it, and we have solicited another that -- and the one that is using it actually has one of the authors of the report as their -- as one of their contractors.

Now, we wanted to have another plant with someone who is not one of the authors or one of the author's contractors to try to implement the same thing, because, as we all know, it's -- if you develop the method, you know how to do it right. But did we sufficiently write the report so that somebody else can pick it up and also --

MEMBER BLEY: But that hasn't begun.

MR. WACHOWIAK: That's not done yet.

VICE CHAIRMAN ARMIJO: Quick question, Rick. You mentioned plant-to-plant variability, and I was looking at your chart on page -- Slide 29. And there is -- I don't know if this is a fluke or if it's real, and that's Plant 7. It looks like they have -- they don't have very many -- they don't have any major contributors. Is that the way to interpret?

MEMBER CORRADINI: The arc transforms --

MR. WACHOWIAK: Yes, I --

VICE CHAIRMAN ARMIJO: They didn't have certainly not the big electrical cabinet thing. They didn't -- maybe I'm just not reading this right.

MR. WACHOWIAK: You can't tell from looking at this what they have. They could have a very large CDF, and their CDF for electrical cabinets is the same as everyone else's, and then there are just other things that are up. Or they have a different distribution. You just can't tell from looking at this chart, so I don't -- I don't know that that's the case.

MEMBER STETKAR: I think, Sam, in this context of the data, it is plant-to-plant variability and the frequency of fires.

VICE CHAIRMAN ARMIJO: Right.

MEMBER STETKAR: In other words, if you have 100 plants, it -- and 100 fires, if all 100 fires occurred in one of those plants, that's a much different measure of the uncertainty than if you had one fire in each of the 100 plants. And that's I think the context, not -- not in terms of these results, plant-to-plant variability, which are influenced by the plant-to-plant variability in the frequency, but also by the specific geometry and --

VICE CHAIRMAN ARMIJO: Okay.

MEMBER STETKAR: -- PRA vulnerabilities, etcetera.

MEMBER REMPE: You mentioned several times about the database for the heat release rate, and I'm not familiar with it. When was it done? Who did it? And give me a few details about how they did it. Were there a lot of different cabinets? I heard this was discussed a lot at the Subcommittee meeting, but I missed it. And you don't have to go into the --

MR. WACHOWIAK: There have been, oh, how many sets of tests that we looked at? Twenty? Twenty or so different tests. Some of them are written in NUREGs. Some of them are international documents that we have gone back and gotten the data from those tests, and, to the extent possible, we are trying to relook at, what are the common characteristics here?

So we could get for you the listing of what all of the different tests were, but they were essentially fire -- in-cabinet fire tests that were done at various labs.

MEMBER REMPE: Okay.

MR. WACHOWIAK: The intent of most of those were to determine, what is the maximum heat release rate you could get out of a fire in an electrical cabinet? And the focus of those -- of those tests were, how can we make the biggest fire possible?

And, as Doug was saying, we are taking the information from that and trying to apply it to every fire that happens in an electrical cabinet at a nuclear powerplant. And that is no easy task to do. You have to understand that smaller fires do behave differently than bigger fires, and we have a sparseness of data at the smaller, wider end of the spectrum.

CHAIRMAN ABDEL-KHALIK: I understand that this entire effort started because you did all of this work, and then you compared the results against plant data, and, lo and behold, there was a huge difference. And, therefore, you are now going back to change the models to add more data. So I assume you will define success of your current effort when whatever predictions you get will match the data, or closely resemble the data.

MR. WACHOWIAK: Rather than "match," I

would say "when they are not inconsistent with the data."

CHAIRMAN ABDEL-KHALIK: Okay.

MR. WACHOWIAK: Operating data, yes. So you could --

CHAIRMAN ABDEL-KHALIK: If that is the case, if that is the success criteria, what you are saying is that, you know, based on these results we expect the future to be the same as the past. And if that is the case, what additional insights would you actually gain from the PRAs beyond the insights that you could gain by just simply looking at the data?

MR. WACHOWIAK: Yes. I think you might be going a little farther along this path than we were intending to go. I don't think we were ever intending to continue to monitor high CCDP events or spurious operations and see how that matches up with the predictions.

What I think we're seeing right now, though, is in this first cut the predictions from the PRA are off by at least an order of magnitude, right? So where can we address -- with the methods that we are developing, how can we address getting some of these things into the range where you would predict very few events?

At that point, I don't think we would continue to look at that sort of data anymore. We may want to look at other things, but I don't -- I don't know that we would --

CHAIRMAN ABDEL-KHALIK: But the sanity check came when you did the comparison, right?

MR. WACHOWIAK: Right.

CHAIRMAN ABDEL-KHALIK: And you are telling me that, you know, if you just bring the numbers down, there is no need for a sanity check.

MR. WACHOWIAK: I'm not saying that we were just trying to bring the numbers down. You can't just bring the numbers down. You have to bring the numbers down based on some physical reality. Okay?

So the ignition frequencies, we think there are -- we think the ignition frequencies should be lower, because we saw what appeared to be a trend change back in 1990. We are going to confirm that, and if that trend has persisted, then, sure, we will say the frequencies really are lower now, but at that point we are not going to say, "Well, okay, what is the -- let's try to find some way to come up with the real number." It's there, the method is sound, and we will continue with that.

So I'm not sure that these same particular events would be used as the gauge of whether we are successful or not. I think we want to -- like in the internal events PRAs, we want to come up with methods that are -- that match up with the physics, that match up with the data collection, the statistics, and that produce results that you could say, "Yes, this predicts very few of these high-consequence events, spurious operation events."

And the model predicts very few, the data says there are very few. Let's go and -- we'll look at other ways of doing intermediate events at that point. I don't -- so I don't think we're ever going to try to say, "Let's match what the PRAs say to the data that we collect." It was not the intent.

CHAIRMAN ABDEL-KHALIK: I understand. But, nevertheless, that is sort of the only sanity check you have. And if that is the case, then the point I made is that, you know, you are essentially saying that the future will be the same as the past. And the insight that you would gain from reaching that state would be no more than the insight that you would gain by looking at the raw data.

MR. TRUE: Well, yes and no. I think --

MEMBER SIEBER: That's the case with all PRAs. It's all dependent on past history. Failure data and what have you, it's all -- and so what you're doing is saying, "I have looked at all the individual characteristics of this plant and matched its failure rates that I see over all plants, and, therefore, I assessed this probability of core damage at this amount." And I think you are doing the same thing by pursuing these objectives with -- in terms of the fire.

MR. WACHOWIAK: And I think one of the things that we want to make sure that we do here is that the objective of doing the PRA -- one is to get the insights, but we want to have it as a useful tool or a test bed to say, "If I'm going to change the plant, what will it do to my fire risk characterization?"

So if our fire PRA is matched, the real characterization in the plant, the real way that fires behave in the plant, and the risks from those fires, if we can reliably put a proposed change into the model and calculate a change in the risk, that will help us -- help inform us on how best to improve the plants or to not do things that are detrimental to the plant.

MR. BRADLEY: All right. I know we've got to give the staff their due time here, so I just wanted to close. I do appreciate all of the time we have had with the Committee and the Subcommittees and the opportunity that you have given us to make our case here.

We do believe that there is still work to be done. There is the remaining concern that we are in the middle of a large-scale regulatory application where we are using the results of these models to make large decisions relative to plant modifications and other activities. And we remain concerned that these decisions are being made ahead of the curve of getting these models to the point where we believe they need to be.

I know ACRS is going to be writing a letter to the Commission, and we hope that you will consider the points we have made. We believe this is a legitimate concern. We have done our best to try to give you a technical basis for it, and we encourage NRC. We hope ACRS can help us encourage NRC to continue our quest for realism.

I know it's a difficult thing, and we have state of knowledge --

MEMBER POWERS: They don't like realism, right, yes.

(Laughter)

MR. BRADLEY: I know since the time I wrote these slides last week things have -- there has been some action on the part of NRC relative to previous requests the industry had made back in November to consider extending the schedule for 805.

And as I understand it, and I guess the staff can speak to this, there is now an expectation that you can come in with something called a partial submittal. It -- I don't know how well that is defined at this point. I believe it would be important -- an important consideration for these submittals that may not be complete that more time might be needed to refine the PRA model and arrive at the correct decision relative to plant modifications.

And that's a legitimate and reasonable basis for a plant to request some additional time or to give a partial submittal that provides time to get that work done. And I believe that -- you know, if the ACRS -- if they are considering encouraging that, that would be useful.

MEMBER POWERS: Let me -- you have proposed, and are undertaking, some very creative and useful work that is reexamining things in some depth, and no question it is -- that is going to be valuable to see what would come out of there. But is not your real essence of your problem that you are identifying -- you are -- that we have not completed the pilot plants and examined the results of those in light of a document that EPRI and NRC completed and presumably revised in light of that?

Is that not the essential -- before we undertake applying these methods to other plants, is not the --

MR. BRADLEY: Yes.

MEMBER POWERS: -- essence of the difficulty here?

MR. BRADLEY: That is the essence, I think, to a great degree. The pilots haven't really -- we haven't had time to take those results and --

MEMBER POWERS: You need to take the pilot results and have a chance to digest it, and then probably carry out many of the things that you described here.

Where do things make sense? And where do they not make sense? And when they don't make sense, find out why they don't make sense and either change your sensibilities or change the methodologies. I mean, it could be either way, right? I mean, you don't know a priori.

I could prove my engineering judgment I

think has a batting average of pretty close to zero, you know? So, and after all, they pay baseball players thousands and thousands of dollars for being right only one-third of the time. So, I mean, we can't ask too much here. But one way or another, things need to be changed -- may need to be changed based on once you've had a chance to digest these results.

MEMBER STETKAR: Any other questions for the folks up front?

(No response)

If not, thank you very, very much for a really good compilation of stuff that was presented over three long days. So thanks for your effort. It came across I think quite well.

And with that, we will have the staff come up.

(Pause)

MR. WEERAKKODY: Would you like me to go ahead and start?

MEMBER STETKAR: Take it away.

MR. WEERAKKODY: Okay. I'm Sunil Weerakkody. I'm the Deputy Director in charge of fire protection in NRR, and Donnie Harrison is the Branch Chief of the PRA Licensing Branch, and Alex Klein is the Branch Chief of the Fire Protection Branch.

And sitting in the back, I know Mark Salley we invited, he is our peer -- right there -- he is our peer in the Office of Research campaigning a lot of fire research.

So with that, let me go to the next slide, Alex.

I always when I come to talk to the Subcommittee I brought this, just to remind myself, you know, what the Commission SRM means. And I have to say, like John said, we had I believe two Subcommittee meetings, and our staff was interviewed by the independent consultants that John hired.

So one thing to say is that the staff had ample opportunities during the Subcommittee meetings to share our perspectives, and the plan here today is to not take too much time, give you a high level overview, and then Donnie and Alex will do that. But the biggest purpose would be to answer any of the questions that the Committee members have.

For that purpose, we basically invited a number of cognizant staff sitting in the audience, people who, for example, completed the Harris safety evaluation. Harry Barrett is there, and then our senior-level advisor in PRA. So I basically said, depending on the question, the staff could get up and go to the front and answer your questions.

Let's go to the next slide, please.

A couple of the oral comments I wanted to make before hand over the presentation to Alex and Donnie is we have completed the pilot activities. What I specifically mean by that is we have issued the safety evaluation for our two pilot plants in Harris and Oconee, and Oconee was published in -- on -- Oconee SE was issued on December 29, 2010.

We used the pilot to update or create our infrastructure documents. These are the reg guides and the SRPs. And we are, at this stage, getting ready to proceed and begin the reviews of the large number of non-pilot LARs that we expect in the June timeframe.

I do want to -- I wanted -- just one technical issue, and I want to make it, too, just because of a number of the things that were in the presentations with respect to the consistency of the fire PRAs and the operating experience. I want to make one comment on that before I hand it over to Donnie.

First point, I have made the statement -- I made it in the Subcommittee also -- and I would like to really reemphasize with the full Committee members. We believe -- we, the staff, believe that the fire PRAs have matured sufficiently for the regulator to make regulatory decisions in support of implementing 10 CFR 50.48(c).

At the risk of boring the Subcommittee members who were here for that meeting, I still want to repeat what I said at that meeting. When we look at 50.48(c) or NFPA-804, it is an alternative to deterministic regulation. What we are telling the plant is we are enabling you to use PRAs to deviate from the deterministic requirements.

If I simplify this to a very simple example, typically in an area where they have redundant safety cranes, we would say those cables of those cranes should be either separated by 20 feet or separated by a three-hour barrier, or a one-hour barrier with a different separation.

And if you do that, and do that for all of your fire areas, going to 805 really is not necessary. If we conclude your plant is safe, you don't have to do anything else.

Now, we understand that there's a number of plants out there that does not have that -- those requirements fully met. And the intent of -- and I'm oversimplifying this. In terms of 805, it is to allow the licensees to go in and area by area look at their situations and make a determination of whether that deviation is acceptable.

For that purpose, I can say absolutely that PRAs -- fire PRAs I mentioned, but now I'm not -- you know, it could lead to occasionally conservative additions. Now, as regulators we don't lose a lot of sleep on that. Okay? but the fundamental point is the fire PRAs handled it sufficiently for the 50.48(c) application.

The second point I am going to touch upon this -- and hopefully down the line Donnie and some of the other staff in the audience can elaborate on that -- we have not fully analyzed the numbers that the industry presented with respect to, you know, support that the operating experience is, you know, far -- you know, inconsistent with the fire PRAs.

But what we can speak to is the two fire PRAs from the Oconee and Harris we carefully looked at. Okay? Both of those plants had mid to low, 10^{-5} times core damage frequencies. And the staff, having had the opportunity to look at the methodologies that they used, would agree that there are some conservatisms even on those numbers. Okay?

So if someone says, "Hey, you know, five PRAs have conservatisms," you know, based on our two full reviews you would say, "Yes. Yes, there are some." I think when I get concerned is when I hear numbers like, "Well, you my have a factor of 10, 15," you know, that type of conservatism, because what I want to be careful is in terms of looking at operating experience, it depends on how you pass it there.

I can use the same operating experience to come to a different conclusion. And, for example, if you think of our operating experience and throw away everything and look at the Browns Ferry event, and look at the contributors to the Browns Ferry event, so we have one event that almost came to -- I think conditional core damage probability was like .2. Okay?

So if you say you had a .2 core damage event, over the last, you know, 100 reactors, 30 years, you know, you are getting close to the 10^{-5} number. Now, one could argue, well, you have to throw away Browns Ferry, because it was so old and the conditions have changed. And I would argue that some conditions have. Some of the practices using -- to check for the, you know, temperatures, leak, we don't do that anymore.

But I would also say that number of the design -- like, for example, one of the other contributors that led to Browns Ferry was that the inadequate separation between cranes. And some plants have made significant changes; others have not. So I can't throw Browns Ferry totally away.

So if I do a Bayesian -- I don't know -- I have lost some of the terms -- you have 10^{-5} number. So that's why I'm concerned when the industry uses operating experience to say, not just conservatism, but there may be orders of magnitude. That's the part that I would have a little heartburn with.

I think I took too much time for the purpose of the staff introduction, but I really wanted to make those few points. So --

MR. HARRISON: If I can just jump on that --

MR. WEERAKKODY: I'm going to turn it over to you and Alex anyways, but I want to -- any questions for me from the --

MEMBER SHACK: Can I just ask you a regulator question? What was this thing we heard about from -- at the very end from Biff about partial submittals? Has there been some change now that we should know about?

MR. WEERAKKODY: Well, it -- let me -- we've got to be careful there, because we have a policy in place, and we have given the policy. We have a long public meeting yesterday with TRESPEC to -- you know, what kind of things should be accepted, transformed, and so forth. So I really got a look at the words that were said.

And I've got to be careful in terms of, you know, our -- I think -- I remember the words clearly. There will be -- what he said was -- what Dan Gobe said was like, "There will be certain limited circumstances under which we would doubt our flexibility." Why don't you speak to that. I can't remember the words.

MR. HARRISON: Okay. Yes, this is Donnie Harrison.

MR. WEERAKKODY: I just want to be careful in terms of policy -- or confusing policy meetings like this.

MR. HARRISON: Right. And it's worth clarifying, because I don't think the intent was to tell the industry to take another six months and work on things and don't worry about that submittal that's due in June. That was not the intent of that meeting, nor was it the intent of the actual comments that were made. It was more of a recognition that if licensees are -- licensees have -- their fire PRAs have to be peer reviewed.

Out of that peer review there might be findings that either are because of new methods are involving a task -- this task force the EPRI mentions. They may not have resolution on those methods. There might be findings that have come out that the licensee hasn't been able to resolve at the time of the June submittal.

The idea was licensees need to come talk to us if they were in that kind of a situation, so that we can understand when we get the submittal if there are any gaps in that submittal like that. It wasn't take two years to wait for Research, and in the meantime we'll wait for it. That wasn't the intent. And so just to -- I don't want to oversimplify it.

The real intent is if you have issues and you are working on those issues, but they are not going to be completely gone or they are -- you are waiting for something to come from this task force, come talk to us, and then you can move forward with your application.

MR. WEERAKKODY: Yes. And the clear message that I don't mind repeating, because Jack has said this many times, what Jack wants to see is that if a licensee has concerns that they may have deficiencies, Jack really will encourage them to come, have pre-meetings with us now, and talk to his staff -- his staff understands the gap -- and work on those gaps, so that in June they are probably -- that is clearly -- that he has communicated to us several times, and he wanted to come to the meeting.

Any other questions for me? Go ahead.

MR. KLEIN: Okay. Hand it over to me. I'm Alex Klein. I'm the NRR Fire Protection Branch Chief. Let me just go to several of my slides that I'll speak to, and I think the meat of it will be Donnie. So I think that's the guy you want to pay more attention to than me.

(Laughter)

MR. HARRISON: Thanks.

MEMBER BLEY: Nice try.

MR. KLEIN: But anyway --

MR. HARRISON: Remember there's payback.

MR. KLEIN: Right. I understand.

Just for the benefit of the Committee members who may be fairly new to NFPA-805, to give you a very brief background, let me just take half a minute, if I could. NFPA-805 is a national consensus standard. It was developed by the National Fire Protection Association back in the late 1990s/early 2000s. NFPA-805 was actually issued in 2001. It is a standard that allows licensees to use a performance-based approach.

You heard Sunil talk about the three-hour barriers, the one-hour barriers, and so forth. Those are -- under Appendix R, those are very prescriptive rules. So a licensee that wants to do something different from a three-hour fire barrier and is obligated to meet Appendix R would have to come in and see staff for an exemption request.

Or as opposed to an NFPA-805 approach using performance-based methods, the licensee has some flexibility in terms of demonstrating how they meet these performance goals that are outlined in NFPA-805. The rule was issued in 2004. It incorporates NFPA-805 by reference.

As Sunil indicated, it is a voluntary rule. Licensees can opt to stay with their existing licensing basis. And, as we know, approximately half the fleet has elected to transition to NFPA-805 at this point in time.

Let me go to the next slide.

MEMBER STETKAR: Alex, did --

MR. KLEIN: Yes.

MEMBER STETKAR: Since you wanted to go hide under a rock, I guess I have to ask you a question.

MR. KLEIN: I didn't say "hide under a rock."

MEMBER STETKAR: I think the -- and if the Committee isn't fully aware of this -- that the second sub-bullet at the bottom of the slide there is a bit important, because it -- the rule explicitly refers to the 2001 addition of NFPA-805.

MR. KLEIN: That's correct.

MEMBER STETKAR: Therefore, that's now law. NFPA-805 has been updated since then. It was --

MR. KLEIN: Yes.

MEMBER STETKAR: An update was issued in 2006. Are there substantive differences between the two versions in terms of guidance from --

MR. KLEIN: I do not know offhand the substantive differences. I don't know if we have other folks here, if Harry can speak to that, or Paul.

MR. BARRETT: Yes. Harry Barrett, Senior Fire Protection Engineer from Fire Branch. The update -- I tried to fix a couple of typos that were in the standard. Really, no substantial difference as far as the technical content in the standard.

MR. HARRISON: It did significantly renumber --

MR. BARRETT: Yes.

MR. HARRISON: -- a number of -- the layout of the standard, which creates some --

MEMBER STETKAR: Technical framework.

MR. BARRETT: Yes, there were no technical changes.

MEMBER STETKAR: Okay. Thank you.

MR. KLEIN: Thanks for that clarification.

MEMBER STETKAR: That has been brought up a couple of times in context, so it was worth --

MR. KLEIN: Because 10 CFR 50.48(c) referenced the 2001 edition of NFPA-805. So that becomes the regulation.

MEMBER STETKAR: Thanks.

MR. KLEIN: Just to give you a flavor for some of the history and the background of how we got where we are today, you heard Sunil talk about the infrastructure, and so forth. As we processed through the transition with these plants through NFPA-805, plants started working on their transition to NFPA-805 I believe near the end of 2005 or so timeframe.

Shortly thereafter, we issued a regulatory guide as one way for licensees to demonstrate their transition to NFPA-805. That Reg Guide 1.205 endorsed sections and portions of NEI-04-02, Revision 1, where we thought appropriate.

Now, as we went through the pilot process, we learned a lot of lessons. We then revised Reg Guide 1.205 and issued that revision to the reg guide in 2009, it looks like. Okay. I'm getting -- my years seem to run together here I have been involved in this issue for so long.

(Laughter)

So the infrastructure in terms of the regulatory guide I think is well in place. The staff also put together a standard review plan for an NFPA-805 transitioning licensee for the staff to -- staff guidance for the review of these. As part of that SRP, the staff also put together a safety evaluation template to help the staff be more efficient and consistent in terms of when we write our safety evaluations in the future moving forward.

Again, what I wanted to emphasize, too, is that when we stepped through this process of developing this reg guide, we had a lot of public meetings, a lot of I think collaborative -- kind of a working relationship with the industry to develop our reg guide in order for us to endorse their guidance document as appropriate.

As Sunil indicated, we issued the Harris safety evaluation first in June of 2010, and about half a year later we completed the second pilot plant, the Oconee pilot plant safety evaluation, in December.

Commensurate with all of that, or concurrent I guess with that, NEI and the industry had also been working on putting together a license amendment request template. The industry worked, again, with the staff in a collaborative manner over the last two months I think of last year.

We held I think meetings almost every two weeks to discuss the license amendment request template, and I think that was a fairly successful effort, and my understanding is is that the license amendment request template has been made available to the NFPA-805 task force members and to the rest of the industry.

So in terms of infrastructure, I think that we've got the right documents in place at the right level at this point in time.

For the next slide -- I'm going to hand the next slide over to Donnie. But before I move on, are there any questions with respect to the infrastructure?

(No response)

If not, Donnie is going to talk about fire PRA methods.

MR. HARRISON: And we are going to bounce back and forth just a little bit between these different slides as the topics fall into our different areas. But to followup on the infrastructure, there is the issue of fire PRA methods. And I'm just pointing out here that there has been -- fire PRA methodology guidance has existed for many decades.

It dates all the way back to NUREG/CR-2300, which was written in 1983, which is the PRA procedures guide. It was high level. It wasn't real detailed. It gives you a high-level expectation of what should be in a fire PRA.

That was developed with ANS and IEEE. There was a history between then and now that includes EPRI's work on FIVE methodology. I remember there were draft FIVE topicals and final topicals on the FIVE methodology, which is a fire-induced vulnerability evaluation I think, something like that, that was part of this process.

That gets us up to the more recent time. And as Biff had trouble with spelling NFPA, I have trouble with dates.

(Laughter)

NUREG/CR-6850 was actually originally issued in September of 2005, so the 2006 date there is wrong. It was supplemented in 2010. That was a collaborative effort between our Office of Research and EPRI in developing that. There is an EPRI number, and I always have trouble remembering the EPRI number, so I will stick with 6850. I will also say NFPA-805 instead of 10 CFR 50.48(c). They are synonymous in my mind.

I do want to point out in this slide -- as I go through, I'm going to touch on some of the presentation from the industry. The PRA policy statement says we should use realistic methods that are supported by state-of-the-art methods and data. And they are supposed to be used in a complementary fashion with the deterministic principles or approaches of defense-in-depth and safety margins.

It is not an optimistic, realistic approach versus a conservative approach. They are two different kind of paradigms. There is the deterministic way of doing things under defense-in-depth and safety margins, and then there is the PRA approach, which is an attempt to be a different way of looking at problems.

So it's not like you are balancing conservatism and realism. It is two different approaches. The deterministic world does tend to be conservative. In PRAs, the goal is to be more realistic. However, when you don't know something about a topic, you tend to be conservative even in PRAs.

So I just want to say that as we go through I'll give some examples from the internal events that are very similar experiences to what happens in the fire PRA realm at various times in their life.

I also want to point out that these are guidance documents. Again, you heard about the staff looking at these methods, when the industry thought that they met the PRA standard, that's all they had to do. I'm constantly correcting this view.

The PRA standard is what you have to do. It's a quality standard that says what is -- what does a PRA look like? What is the elements? These are not -- these guidance documents are not that. These are methodology guidance that tells you how to do that analysis. They are different. Okay? So you have to do both.

There is not -- you can't just run off and say, "I met the PRA standard, and oh, by the way, I'm using some method no one has ever even heard of, and I made up my data, and here it is. I meet the standard." You can't do that. There is methods behind everything.

MEMBER BLEY: Can I say -- you have to meet 1.200.

MR. HARRISON: Well, it's a regulatory guide. It's one acceptable approach to meeting PRA quality. Someone could actually come in and propose something else.

MEMBER BLEY: So both are --

MR. HARRISON: Guidance documents.

MEMBER BLEY: -- guidance documents.

MR. HARRISON: Right. There is no requirement for those.

MEMBER BLEY: If you meet those, you need to be happy. If you don't meet those, you want to understand --

MR. HARRISON: Right.

MEMBER BLEY: -- what they are doing.

MR. HARRISON: Right. That is a good summary. And, again, there is the acceptable methods path, which is a much easier review path. If you are not following that path, then you should expect to get questions for the staff to understand the acceptability of the method you are proposing.

And, again, so these are guidance documents. They're not regulations. They are not requirements. Licensees can deviate from those methods. And, in fact, NUREG/CR-6850 recognizes, just like all of the other fire PRA methodologies are, they are progressive screening approaches. I think you -- in an iterative approach, I always grew up in this area thinking of them as progressive screening methods.

You start at a high screening level. If you stop there, you are going to get a really high CDF. If you progress to the next level, you start to focus in on the areas that are risk-significant, you will bring that risk number down, and you progress to focus in on the risk-significant areas until you are satisfied with the results that you are getting. That's a decision a licensee needs to make. That is not something that the NRC dictates.

So they can do that. The process allows them to make those refinements. It may not tell them the details of how to do the refinements, but it does allow them to refine the method. And if you do refine the method, you need to have a technical basis for why you are doing that.

So you can't just say, you know, "I did this analysis, and I did a comparison to what I expected to see in the industry. And this is 10 times too high, so I'm going to divide by 10." That's not a sound technical basis. Okay?

I would also caution about using a micro approach -- again, Sunil kind of referenced this -- when the macro says you might be actually calculating close to the right numbers. There is a micro part where you are taking pieces, and then you are projecting what that means.

When the macro is done, you actually get a number that makes sense. So you've got to balance that all out. You can't just pick pieces and start -- and nickel and dime the analysis.

MEMBER SIEBER: Unfortunately, the macro approach sometimes causes you to fix the wrong thing.

MR. HARRISON: Correct. You would either be -- and, again, I'm a strong supporter of refining the methods. I'm a strong supporter of doing the research and evolving, looking for those areas that are critical and fixing them.

MEMBER SIEBER: Right.

MR. HARRISON: I am a strong supporter of that. I just don't want us to be deceived into thinking I looked at this piece, and that gave me this answer, therefore, there must be something drastically wrong with the methods. Again, these methods are evolving methods. They will continue to evolve.

The other point I want to make is sometimes licensees will not pursue a method refinement. It may be easier and cheaper to just fix something in the plant. And in the 805 arena, through the pilots, that happened. There were fixes that licensees -- both pilots are committed to implementing that reduce not just fire risk, but reduce the overall plant risk.

The Harris plant implemented a reactor coolant pump seal LOCA alternative injection system. Now, that wasn't their -- it may have been their dominant fire contributor, but that wasn't really why they put that mod in. That mod helps them on the internal event side, where that is one of their most dominant risk-significant contributors at that plant.

So sometimes a licensee, if they can find a smart fix, they gain some -- lots of benefit, they can live with a higher number or a simpler method, because now they can lower it, base it on a physical change at the plant. That has ramifications from the NRC side. I see that as safety enhancements through this process. And, again, it is being smart with how you do that.

And the other point I want to make is, you know, you saw a slide that said the staff is injecting conservatism into the PRAs. That's not true. I just want to make that clear.

The staff -- oftentimes you can have disagreements, different interpretations of data, data is incomplete sometimes, so you have to make judgments about what the right answer is. Sometimes you compromise and you pick a half of an event, which you really can't have a half an event, but without any information you decide, "I don't know, so I'll say it's half."

That doesn't necessarily mean it's wrong. It means you really just don't know. that's valid. And so it's not injecting in conservatism. It's actually looking at the information and making decisions. And, again, I do want to say Research -- the Office of Research has worked collaboratively with the industry, with EPRI, in a lot of this area.

This is not the NRC going off and looking at data and saying, "Here's the answer. Now that is

-- you have to use it." This has been many years of effort working together, and sometimes you just disagree on what the answer ought to be. so you have to make a decision and move forward.

I'll stop my rant and move on to --

MR. KLEIN: If I could, I would like to just spend a minute or two on the FAQ. You heard the industry speak about the FAQ process, the frequently asked question process, and, you know, their view of it and the success of it.

I've got the opposite view, actually. I think that the FAQ and the process that was there is very, very successful. The FAQ process was actually put in place to enable licensees to develop their license amendment requests. It provided them with a stable and predictable regulatory environment, as we process through these frequently asked questions.

We documented the question, we documented the results, all in public domain, so everybody had access to it. So as these lessons were learned from processes, this frequently asked question process was put in place back in 2006. So it has been five years in the running. We have met monthly.

We have dispositioned, I don't know, 50 or so some-odd issues ranging anywhere from these PRA issues down to, you know, what does something in NFPA-805 mean, for example, with power block. We have questions like that that where dispositioned through this FAQ process, which I think was a great success.

And so I think it facilitated licensees' ability to develop their transition in their license amendment request moving forward. So the fire PRA facts that you heard the industry speak about, we did put a slightly modified version of the FAQ process in place.

When we recognized that there were some delays, that things just weren't moving forward, we wanted to eliminate any of these further delays, so we put this process in place. And I think we stepped through that process and were able to at least in some manner disposition those facts.

You heard the industry say that they did not introduce any further facts into the process. I think you will hear Donnie talk about perhaps an alternative way that they will try and address some of the questions that they have got.

That's all I wanted to say about the FAQ process. Any questions from the Committee on this?

(No response)

Okay. Let me hand it back to Donnie, and he'll complete the rest of the presentation from here on out.

MR. HARRISON: And this follows on with the FAQ discussion. Again, as Alex said, again, the professionals can disagree on the interpretation of data, and I think that was -- the FAQ process early on was struggling with a number of issues, because there was -- through the process there was just disagreement on how to interpret things or how to model specific things.

The June letter that was referenced by NEI was actually a letter sent out to say we -- this is a revised way of resolving things, so that we can move forward. It was actually intended to solve the problem, not try to inject conservatism or try to balance. That sentence is just a paraphrase of -- in the midst of a paragraph, so the real intent was to move forward, not to make some policy decision in the midst of that letter.

Within the lessons that were learned through the pilots -- and, again, we had the facts that -- the 16 related to the PRA that have subsequently been put into the supplement to the NUREG/CR-6850. There were also lessons learned during the pilot reviews that resulted in us revising Reg

Guide 1.205.

We came to the Committee, I believe it was last year, with that revision, and talked through why those things occurred. We had some good Subcommittee and full Committee discussions on that reg guide and what led to it actually needing to be revised. And, again, those were direct lessons learned from the pilot reviews.

Those pilot reviews are also resulting in the industry developing a license amendment request template, us developing a safety evaluation template. Those are all geared towards, if you will, streamlining the path forward, making things a little more stable and understandable of how the reviews are going to be at least formatted and how license amendments are going to be presenting information to the staff.

The staff is also developing a paper on the additional lessons learned that have come out of the pilot process, and we plan to issue that lessons learned paper in I think May of this year.

Next slide, Alex.

Throughout this process, again, we recognize that as people use NUREG/CR-6850, and what it allows, that there would be new methods being proposed. Within, again, the fire PRA when you -- before you make your application to us, the expectation is the fire PRA gets peer reviewed by the industry. They have an industry peer review process. The guidance is NEI-07-12 that they follow. That is endorsed in Reg Guide 1.200.

However, it's my understanding that through the early part of the industry peer reviews they were identifying issues with these new fire PRA methods, partly because they hadn't seen them before. So without significant technical basis being provided as part of that peer review -- and there is a timing element to peer reviews -- you may not have had the time to actually -- as a peer reviewer, to get the information to decide if the method was acceptable.

It was difficult for the peer review teams to accept deviations from the NUREG/CR-6850. Again, this is the industry peer reviews we are having trouble accepting deviations.

MEMBER STETKAR: Donnie, just for the benefit of the Committee, neither of the pilot submittal -- the PRAs in the pilot submittals went through a full industry peer review. Is that correct?

MR. HARRISON: Correct. For their submittal, they had not been peer reviewed. The staff, through our Rev 0 of the Reg Guide 1.205, we stated that we would perform audits of their PRAs to determine their sufficiency/adequacy for the applications. Subsequently, I believe, is it correct, that Harris has subsequently been peer reviewed? So it wasn't as part of our review but afterwards they have been.

So, yes, but the expectation -- and, again, that was a pilot. That's an exception to what the normal expectation --

MEMBER STETKAR: But the expectation going forward is that they would come to you --

MR. HARRISON: Right.

MEMBER STETKAR: -- after at least the performance of the peer review, not necessarily with all of the -- as was mentioned earlier --

MR. HARRISON: Well --

MEMBER STETKAR: -- maybe without all of the peer review issues resolved.

MR. HARRISON: Right. And this is no different than any other risk-informed application. And, again, I say that recognizing this is a large application. Normally, a licensee makes a submittal to us. The expectation is that you had your peer review and you resolve findings from those peer reviews before you submit to us.

For the 805 plants, we understand there are situations both in just staffing the peer reviews, getting them conducted. Again, there is this issue of new methods that has created some issues. Because of all those things, there isn't -- we are open to the idea of them coming and talking to us, explaining what is left to be done on that aspect of it.

Again, it doesn't mean, you know, you don't have to have a PRA finished. The expectation is your PRA will be done. You may just have some issues out there. And, again, maybe this is a prime time to talk about this. The industry has formed this task force. I think you heard briefly about that.

The expectation is that task force will be dealing with new methods, so it's -- the peer review teams have a category that they call "unanalyzed methods."

So if that peer review gets to a piece -- and different peer reviews handle that differently -- some will get to something and they will say, "We don't understand this. We haven't seen this method before," and they will take an entire element of a standard -- again, this is my understanding -- and say, "We are not going to review this. We will just push this off to an unanalyzed methods category," let the task force and the industry then address that method.

And then, when the task force is done doing what it's going to do with that method, and I'm the interface with that task force, we want to be aware of what those methods are before they actually show up at the NRC. So this is a way for us to at least be engaged, to see them.

That then comes back and then can resolve that peer review. Again, if it's where the peer review just pushes it off, then there is a question about what do you have to do to close that review element. Does the peer review team have to do -- come back and review that element over again?

If a peer review actually looks at each of the supporting requirements in the peer review, and finds an unanalyzed method but goes ahead and says, "It looks like they implemented that method according to the standard," so we can have our own little findings, however, we don't know if that method is acceptable, again, that's another way to push it off to the task force.

That one is a little cleaner in the sense of when the task force is done. You've already got the findings and how that method was applied, if it was applied through the peer -- the PRA standard. So then they can just resolve findings from potentially what's clean and not have to do another focus scope peer review.

MEMBER STETKAR: If I recall right from the Subcommittee meetings, the task force has been established. There is this now interface with --

MR. HARRISON: Right.

MEMBER STETKAR: -- exist. Is the task force actively involved? In other words, is it currently reviewing -- it might be a question for the industry -- in other words, you know, there are in progress a reasonably large number of PRAs that are targeting submittal, you know, in now about four and a half months I think.

Is the task force actively involved in making determinations that, yes, indeed, for Plant X, Creative Method Y seems reasonable, and, therefore, you know, and NRC is signed on to that, so, therefore, all of the plants in progress could, in principle, use that?

MR. WACHOWIAK: This is Rick Wachowiak from EPRI. Where we are right now is that one vendor has submitted a document that contains new methods to

EPRI look at, and another vendor has indicated an intent to send in a method but has not actually sent it yet.

I looked at the one that was submitted and determined that the information that was submitted, while it explained the method, was not sufficient to go and put together a team and have it reviewed to accomplish what we are trying to do. So I sent back a list of things that I need in order to establish a team that has independence and has the right expertise and can review the method along with and an example implementation of the method.

MEMBER STETKAR: So they were saying what they were doing, but not necessarily why or the background.

MR. WACHOWIAK: Yes, there are some pieces missing. So right now that's where we are on the first one, and the other vendor that has not yet given their method, I also said this is all the things you need to have to make it a complete submittal.

So I am hoping that in the next few weeks we will have the information back, and I will be able to start establishing the first team that will pilot it on -- on the method.

MEMBER STETKAR: Thanks. Good. That

helps.

MR. HARRISON: So we're in the early stages.

MEMBER STETKAR: Yes, I just wanted to make sure that I --

MR. HARRISON: And, again, that's partly why the staff was wanting to have these conversations with licensees. One is to find out exactly how many plants are doing what method. And, again, the intent of the staff is to gain efficiency by -- and we mentioned this yesterday at the public meeting. If multiple plants are using the same method that is off with this task force, when that gets resolved then that will apply to all of those plants, all of those licensees. So we want to gain efficiency that way.

I will speed up, because I was reminded that we are approaching 6:00. I do want to point out that NFPA-805 -- well, I can do it on this one. NFPA-805 actually requires that the -- what does AHJ stand for?

MR. KLEIN: Authority having jurisdiction.

MR. HARRISON: Authority having jurisdiction. The NRC -- it requires the NRC to actually -- the methods used have to be acceptable to us. So that is a difference between normal applications that we get. We actually have a -- essentially a rule telling us that the methods have to -- we have to find those methods acceptable. And so that may be also why you're seeing the NRC is a little more engaged on methods, a detail that we might not be on other types of applications. That being --

MEMBER BROWN: Does that mean in advance, before they submit it, accept it in --

MR. HARRISON: What I would say is typically the way methods are approved are through topical report reviews or through industry guidance documents that get submitted to the NRC in advance of submittals. And then, we endorse those methods. We do this in risk-informed in-service inspection. There is at least two methods, plus ASME Code cases, that we actually review, endorse, and then people start making submittals that cite those topical reports.

MEMBER BROWN: Okay. That's what I meant. So you do it in advance, in other words.

MR. HARRISON: Right.

MEMBER BROWN: So they're not sending it in and then hoping that you will eventually agree.

MR. HARRISON: Right. Typically. I mean, I can't say categorically that is always the case. It is -- sometimes the method will come in. Sometimes we discover a new method in the midst of a review --

MEMBER BROWN: Okay.

MR. HARRISON: -- that we hadn't seen before, and then we start asking questions and driving towards, is that an acceptable method or not? But the normal pathway is to do it up front.

And, again, there are similarities between that part, because of the topical reports, and I will just say this quickly. Reactor coolant pump seal LOCAs -- again, that is important to the industry -- there were questions about the model that was being used and how you model that in your PRA.

There was arguments that it was overly conservative, and much of what you're hearing about fire PRA you heard about reactor coolant pump seal LOCA models. We then had two topicals, one for -- well, two different vendors made applications through topical reports to us to endorse different models. Those went through reviews by the staff.

We eventually endorsed, with certain conditions and limitations on those models, their use, and now they are used. So, again, that is the normal process.

And that takes me to this, actually. What usually drives model enhancements are because either there is large model uncertainties that -- the industry will say conservatism. I say there is large uncertainties. When you have large uncertainties, you tend to use conservative numbers, if you don't understand the topic that well.

So it is large model uncertainties can drive you to do -- to proceed towards trying to find ways to enhance the model. You might have to do testing. You might have to collect additional data to try to do that.

The other thing you look at is, what's driving your risk results? Is it a significant contributor to the results? If it is, that's an area where you want to look and say, "Let's start there to enhance the model."

This is true for internal events, external events, fires is part of that. So that's just the normal approach. The staff will continue to actively be involved in these activities.

Again, Research is involved with EPRI under a Memorandum of Understanding. NRR has established this interface with the industry fire PRA methods task force. Again, I do believe there are places in the method that are probably conservative and need to be worked on. However, I also don't think the ceiling is falling down on us either, so --

VICE CHAIRMAN ARMIJO: I just want to make sure that you clearly do not support any extension in the time, extended schedule for the submittals.

MEMBER BLEY: I don't think staff can do that.

VICE CHAIRMAN ARMIJO: You haven't made -- that's not your decision.

MR. HARRISON: That's not my job.

(Laughter)

VICE CHAIRMAN ARMIJO: But your arguments sound to me that it is -- they are ready to go now. They could submit stuff to you on time. That's what I got out of what you said.

MR. HARRISON: Yes. Yes, we can jump right to the conclusion. I -- I think it -- the proof is in the pudding. We have had two pilots. We wrote SEs. Somehow they got through this process. So they got -- they made submittals, we learned a lot of lessons through that, we issued safety evaluations for both of those pilot applications. They are 805 plants.

The pilots have identified practical safety enhancements. You have protected surface water at Oconee, which is a major benefit. You have the reactor coolant pump alternate fuel injection at Harris. Both of those mods are really not fire mods.

Harris also did incipient detection, which, by the way, I will caution. On the incipient detection model, the staff attempted to be as realistic as possible. Some would say we were actually overly optimistic about the performance of the reliability of those incipient detectors. Time will tell. We will be collecting data on their performance.

But, again, that is a wrinkle that we have to be cautious about -- again, this micro versus macro level. If you put in an incipient detector, you now can't count fires, because the incipient detector caught them before they got to be a fire.

How do you address that in your initiating event frequency? They are intertwined now. The system and the initiating frequency are intertwined together. So you can't just go use the generic industry data if you're that plant.

MEMBER BROWN: What's wrong with detecting a fire and putting it out before it --

MR. HARRISON: It's not that --

MEMBER BROWN: -- seems like a good plan to me.

MEMBER STETKAR: Part of it is that the -- we need to be aware of the time, but part of it is the industry data has gone through a screening process where they have thrown out fires that were really small.

MEMBER BROWN: And here it doesn't exist. I mean, it's not only very small, it is --

MR. HARRISON: Right. But now you're relying on -- what I'm saying is when that plant goes back to update its data, and it starts counting fires, well, there aren't any at that plant potentially unless the incipient detector fails. And then, you might get some surprises.

There is a tradeoff that is going on, and so you've just got to be aware of it. It's more to be aware how you count your generic data, because that doesn't apply to you anymore. You've got incipient detectors.

MEMBER STETKAR: But you could have a hundred shots at the incipient detector to work, and the one time it failed you then have a fire. But if you only counted one fire, because it was big enough, you can't take a 99 percent reliability of the incipient detector for that --

MR. HARRISON: You're double-counting the reliability of the system. So, again, it's just -- again, the caution you want to make is --

MR. WEERAKKODY: But they are good. We like the incipient detectors.

MEMBER BROWN: I'm just sorry. I would always opt to keep the fire from starting, even if I lost data.

MEMBER BLEY: Nobody is saying the opposite. They are saying be careful how you treat the data to say --

MEMBER BROWN: No. We're going to say, "Don't put this stuff in, because you're going to ruin our data."

(Laughter)

Excuse me for --

MEMBER STETKAR: Let's wrap up here, because we -- you guys get to go home. We don't.

MR. HARRISON: We believe the methods are sufficiently mature to be able to be used to support an application. And they are going to continue to evolve, and the staff is going to support working with the industry to make sure there is a technical basis for those new methods as they come through.

MR. WEERAKKODY: Okay. And I don't have anything else to say, unless there are questions.

MEMBER STETKAR: Very good. Any members have any questions for the staff?

(No response)

If not, thank you very much. Again, I really appreciate you compressing an awful lot of information into about 45 or 50 minutes, which is a heroic effort. So thanks. Thanks very, very much.

And with that, Mr. Chairman, I turn it back to you.

CHAIRMAN ABDEL-KHALIK: Thank you. All right. At this time, we are off the record.

(Whereupon, at 6:07 p.m., the proceedings in the foregoing matter went off the record briefly.)

MEMBER STETKAR: Keep us on the record, if you could. Are there any members of the public who would wish to make a statement?

(No response)

If not, thank you. So off the record.

(Whereupon, at 6:07 p.m., the proceedings in the foregoing matter went off the record.)

Palo Verde Nuclear Generating Station

ACRS Full Committee Meeting for License Renewal

February 10, 2011

PALO VERDE

John Hesser

Vice President
Nuclear Engineering

Palo Verde Nuclear Generating Station

Personnel In Attendance

- **Angela Krainik**, Department Leader, License Renewal
- **Mark Radspinner**, Supervisor, Mechanical Primary System Engineering
- **Glenn Michael**, Lead Licensing Engineer
- **Eric Blocher**, Project Manager, STARS
- **Technical Staff**
  - Randal Boyd, License Renewal Implementation Engineer

Agenda

- **Plant Overview**
  - Station Description
  - Plant History
- **Safety Evaluation Report**
  - Open Item and Confirmatory Item Closure
  - Additional Item Resolution
- **License Renewal Implementation Progress**
- **Concluding Remarks**

Our Mission…

<u>SAFELY</u> and efficiently ***<u>generate</u>*** electricity for the ***<u>long term</u>***.

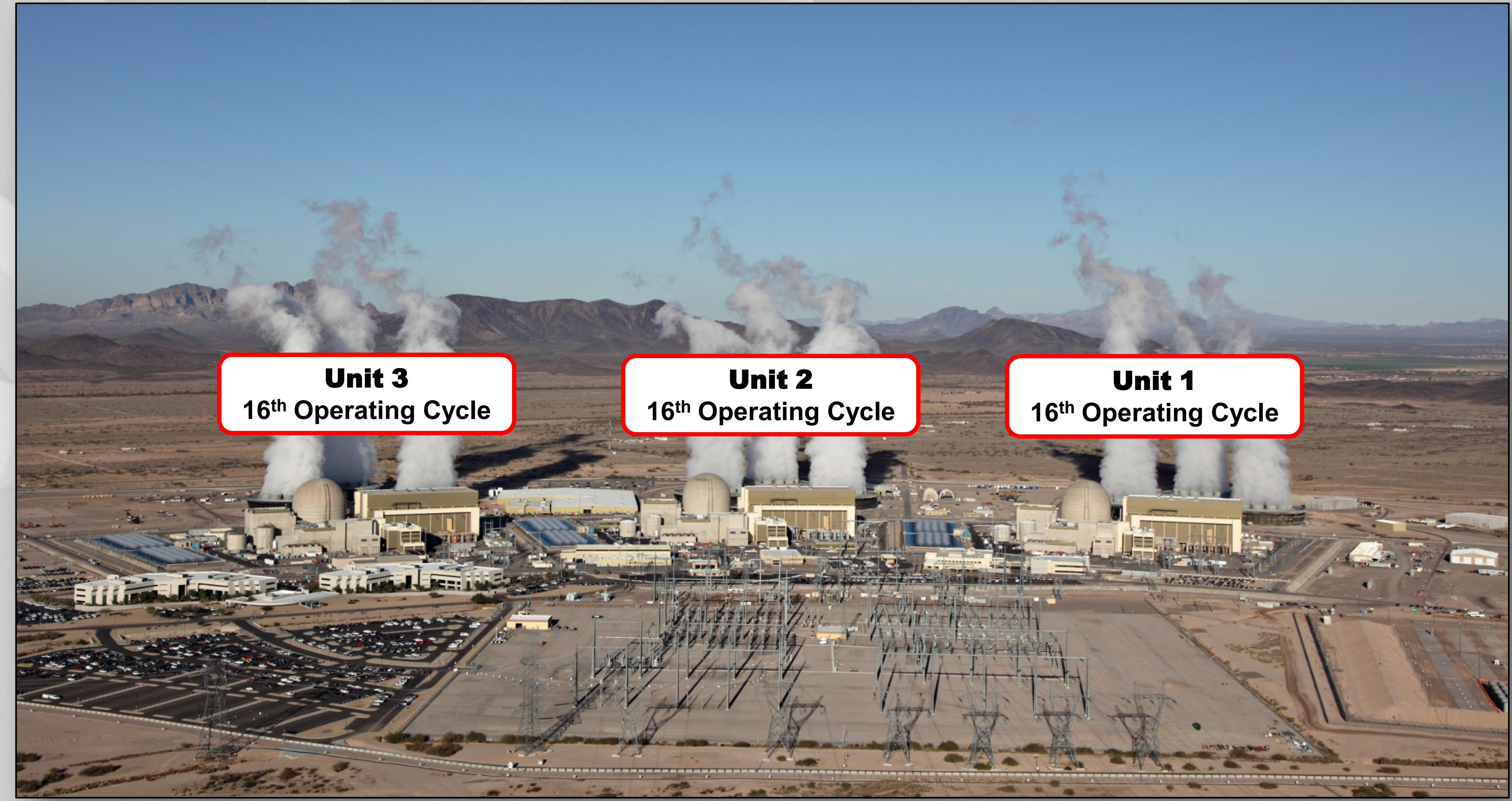
Station Description

- **Three Common-Design Units**
  - Common Operating Procedures
  - Maintain Common Design
  - 3990 MWt /1346 MWe per Unit
- **Combustion Engineering System 80 — Nuclear Steam Supply System**
- **General Electric — Turbine Generator**
- **Bechtel Power Corporation — Architect and General Contractor**

Plant History and Background

- **Initial Construction Permit — May 1976**
- **Operating Licenses Issued**
  - Unit 1: June 1, 1985
  - Unit 2: April 24, 1986
  - Unit 3: November 25, 1987
- **Operating Licenses Expire**
  - Unit 1: June 1, 2025
  - Unit 2: April 24, 2026
  - Unit 3: November 25, 2027

License Renewal



Angela Krainik

Department Leader
License Renewal

License Renewal Program

- Safety Evaluation Report items
- Implementation Status

Safety Evaluation Report (SER) License Renewal

- **Open Item - Closed**
  - Open Item 4.3-1 Metal Fatigue resolved
- **Confirmatory Items (5) – Complete**
  - Example – Confirmatory Item 2.1.4.2
    - Spray Chemical Addition Tanks drained

Safety Evaluation Report (SER) License Renewal (continued)

- <u>Additional Items</u> - Resolved
  - Inaccessible Medium Voltage Cable
    - Low Voltage Cable to be added to Aging Management Program
  - Buried Piping and Tanks
    - Diesel Fuel Oil pipe inspection included
  - NUREG/CR-6260 Limiting Locations
    - Commitment to Confirm Limiting Locations
  - Selective Leaching Sample Size
    - Documented Sample Size Criteria
  - Steam Generator - Divider Plate Bar Welds and Tube-to-Tubesheet Welds
    - Welds added to Aging Management Program

License Renewal Program Implementation Status

- **40 Aging Management Programs**
- **149 Procedures Required to Implement Aging Management Programs**
  - 132 Complete
  - 17 Work in Progress
    - 3 new procedures
    - 14 revisions in process

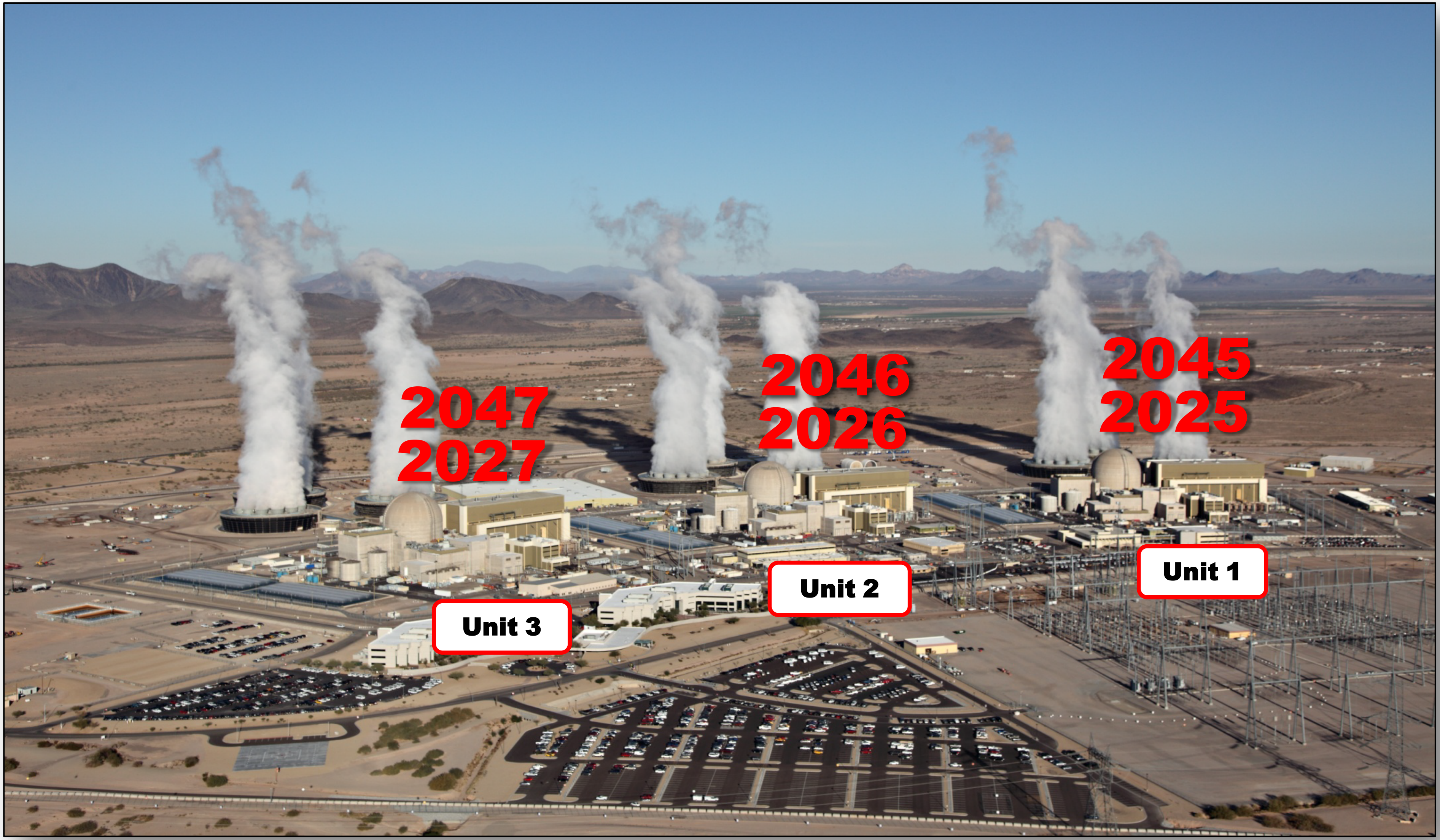
Implementation and Sustainability

- **Implementation Engineer on Staff**
  - Developing License Renewal Implementation Plan
- **Participating in NEI License Renewal Implementation Working Group**
- **Benchmarking Others in the Industry**
  - Lessons-learned captured
- **Incorporated into Palo Verde Long-Range Plan**

John Hesser

Vice President
Nuclear Engineering

License Renewal



Our Mission…

<u>**SAFELY**</u> and efficiently <u>***generate***</u> electricity for the <u>***long term***</u>.

PALO VERDE

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Advisory Committee on Reactor Safeguards

Safety Evaluation Report

Palo Verde Nuclear Generating Station

February 10, 2011

Lisa Regner, Project Manager
Office of Nuclear Reactor Regulation

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Introduction

- Overview
- Closure of Open Item
- Closure of Confirmatory Items
- Resolution of Other Topics of Interest
- Conclusion

Overview

- Safety Evaluation Report (SER) with Open Items was issued August 6, 2010
- The Open Item and Confirmatory Items for the SER are closed
- Region IV Adminstrator's Letter of Recommendation received January 7, 2011.
- The final Safety Evaluation Report (SER) was issued January 11, 2011

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Metal Fatigue Concerns Resolved

Reactor Vessel Instrument Nozzle CUF Differences

- All units consider the effect of vortex shedding
- Unit 1 more conservative, simplified analysis yielding higher CUF
- Units 2 & 3 used more refined analysis in critical areas

Environmental Factors (F_{en}) Analyses

- F_{en} for low-alloy steel and stainless steel components is conservative relative to the assumptions of dissolved oxygen content, max temperature, and strain rate.
- Committed to perform a reanalysis of pressurizer nickel-alloy heater penetrations using NUREG/CR-6909

Metal Fatigue Concerns Resolved

25 Percent Transient Occurrence Assumption

- Transient numbers verified by logs, LERs, operating reports, and test records
- Staff confirmed that applicant's use of 25% was conservative

Cycle-Counting Procedure

- Amended the program description and enhancement to reflect the applicable TS tracking and counting requirements in TS 5.5.5
- Committed to update the cycle counting surveillance procedure to include a transient that is not currently being counted (completed)

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Confirmatory Items

Scoping of Liquid-filled Tanks

Tanks were drained of liquid and are no longer in scope for license renewal.

Aging Management of Elastomers

Components were found not to be susceptible to erosion since they are in low-velocity systems with low particulate levels. Items will be managed by the Internal Surfaces Monitoring Program.

Cavitation Erosion

Applicant committed to complete inspections of susceptible piping locations by July 2012. Components found to exhibit flow-related degradation are incorporated into the replacement plan.

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Confirmatory Items

Steam Generator Feedring Flow Accelerated Corrosion

Staff confirmed that feedring material is FAC resistant. Further, the applicant's SG tube integrity program considers this aging mechanism during secondary side assessments performed every outage.

One-Time Inspection of Small-Bore Piping

Applicant committed to inspect 10% of its Class 1 socket welds for each unit (maximum of 25 welds) using ultrasonic testing, and use a sample selection methodology to inspect the most susceptible and risk significant welds.

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Resolution of Other Topics of Interest

- Inaccessible Medium Voltage Cables
- Buried Piping and Tanks Inspection
- Environmentally-Assisted Fatigue Analyses
- Selective Leaching Program Sampling Criteria
- Steam Generator Aging Effects

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Conclusion

On the basis of its review, the staff determines that Arizona Public Service Company has met the requirements of 10 CFR 54.29(a) for renewal of the licenses for Palo Verde Nuclear Generating Station, Units 1, 2, and 3.

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VC Summer Unit 2/3
Site Overview & SAR Section 2.5

Bob Whorton

SCE&G - Consulting Engineer

MAPQUEST
0
10
10km
LEE
SUMMER
VOGTLE
North Carolina
South Carolina
Cullowhee
Etowah
Hendersonville
Rutherfordton
Polkville
Cherryville
Stanley
Huntersville
Concord
Albemarle
Troy
Biscoe
Brevard
Flat Rock
Tryon
Caroleen
Shelby
Gastonia
Charlotte
Locust
Norwood
Tuckasegee
Glenville
Rosman
Landrum
Cashiers
Cleveland
Gaffney
Clover
Matthews
Oakboro
Mount Gilead
Pinehurst
Indian Trail
New Salem
Ellerbe
Pinebluff
Valley Falls
Boiling Springs
Spartanburg
York
Fort Mill
Monroe
Polkton
Wadesboro
Rockingham
Travelers Rest
Taylors
Saxon
Roebuck
Pacolet
Hickory Grove
Rock Hill
Waxhaw
East Rockingham
Pickens
Sans Souci
McConnells
Lesslie
Morven
Easley
Greenville
Jonesville
Lowrys
Laurinburg
Liberty
Lockhart
Pageland
Ruby
Walhalla
Simpsonville
Buffalo
Union
Chester
Lancaster
Chesterfield
Cheraw
Gibson
Seneca
Piedmont
Fountain Inn
Fort Lawn
Jefferson
Westminster
Clemson
Williamston
Cross Anchor
Carlisle
Cornwell
Great Falls
Bennettsville
Gray Court
Kershaw
Patrick
Martin
Anderson
Princeton
Laurens
Whitmire
Shelton
White Oak
Liberty Hill
Society Hill
Clio
McBee
Lavonia
Hartwell
Homeland Park
Ware Shoals
Clinton
Monticello
Winnsboro
Westville
Brownsville
Hartsville
Starr
Bethune
Royston
Donalds
Cross Hill
Kinards
Ridgeway
Cassatt
Darlington
Latta
Due West
Newberry
Camden
Iva
Coronaca
Bowman
Prosperity
Blythewood
Bishopville
Florence
Lowndesville
Abbeville
Ninety Six
Elgin
Lugoff
Lamar
Elberton
Verdery
Chapin
Rembert
Elliott
Timmonsville
Marion
Comer
Calhoun Falls
St. Andrews
Effingham
Kirksey
Dalzell
St. Charles
Fortsonia
Mount Carmel
Saluda
Columbia
Coward
Pamplico
Vesta
Lexington
Cherryvale
Olanta
McCormick
Batesburg-Leesville
Hopkins
Sumter
Eastover
Lake City
Ridge Spring
Shannontown
New Zion
Poston
Rayle
Lincolnton
Parksville
Edgefield
Gaston
Wateree
Cades
Maxeys
Washington
Modoc
Pelion
Swansea
Pinewood
Alcolu
Hemingway
Trenton
Manning
Woodville
Wagener
St. Matthews
Kingstree
Eureka
North
Foreston
Union Point
Summerton
Nesmith
Crawfordville
Graniteville
Aiken
Perry
Lone Star
Greeleyville
Appling
Siloam
Martinez
Neeses
Rhems
Springfield
Orangeburg
Santee
Lane
White Plains
Thomson
Augusta
Windsor
Andrews
Cordova
Vance
Pineville
Warrenton
Camak
Grovetown
New Ellenton
Norway
St. Stephen
Cope
Sampit
Williston
Blackville
Bowman
Holly Hill
Cross
Bonneau
Sparta
Blythe
Hephzibah
Bamberg
Jamestown
Jackson
Branchville
Mitchell
Gibson
Keysville
McBean
Snelling
Barnwell
Devereux
Wrens
St. George
Moncks Corner
Honey Hill
Stapleton
St. Clair
Olar
Kline
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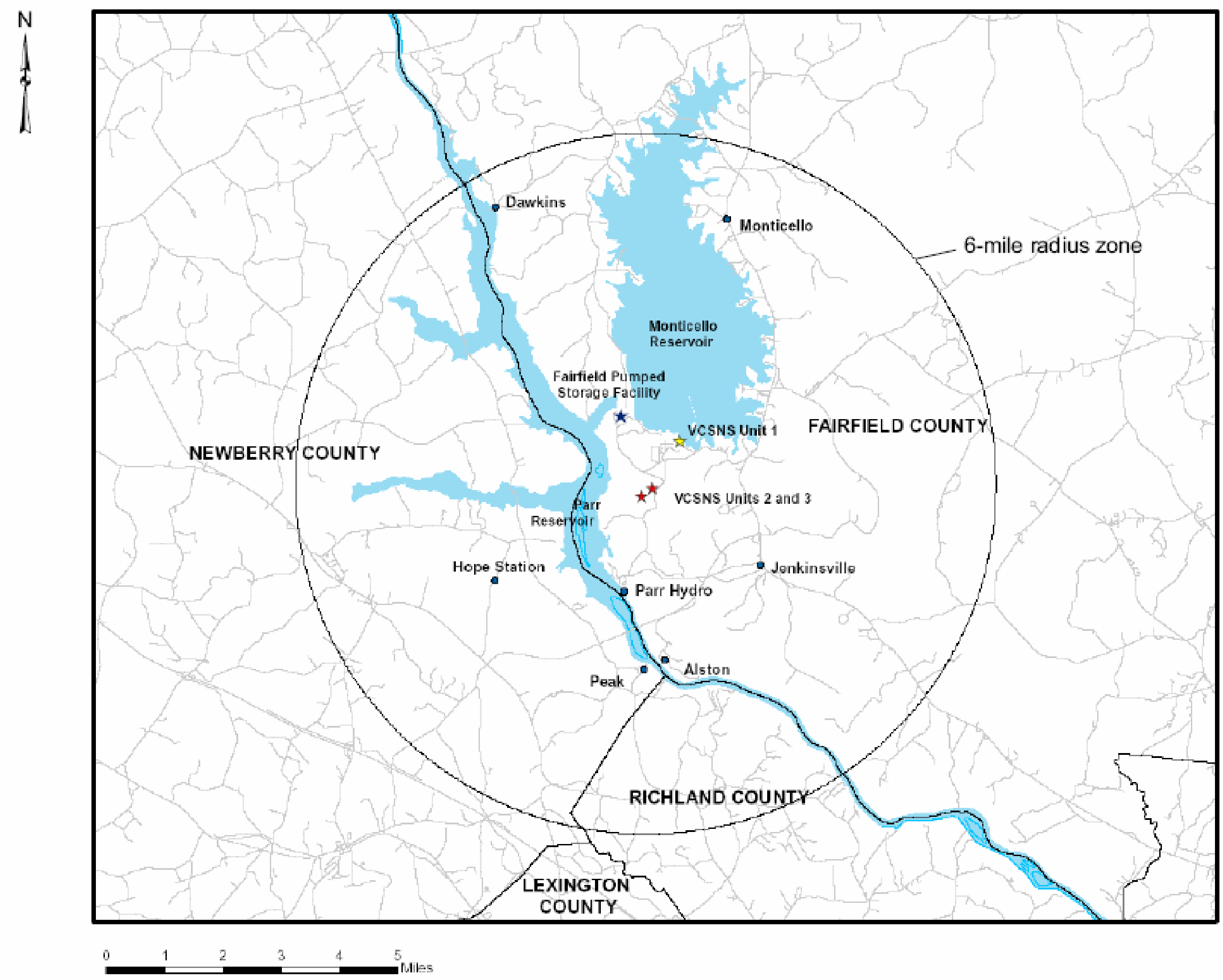
VC Summer Unit 2/3



Unit 1 – 2007 Aerial Photo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S Lake Access Rd
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U2 Power Block Excavation & Geologic Mapping

Unit 2 Power Block Excavation


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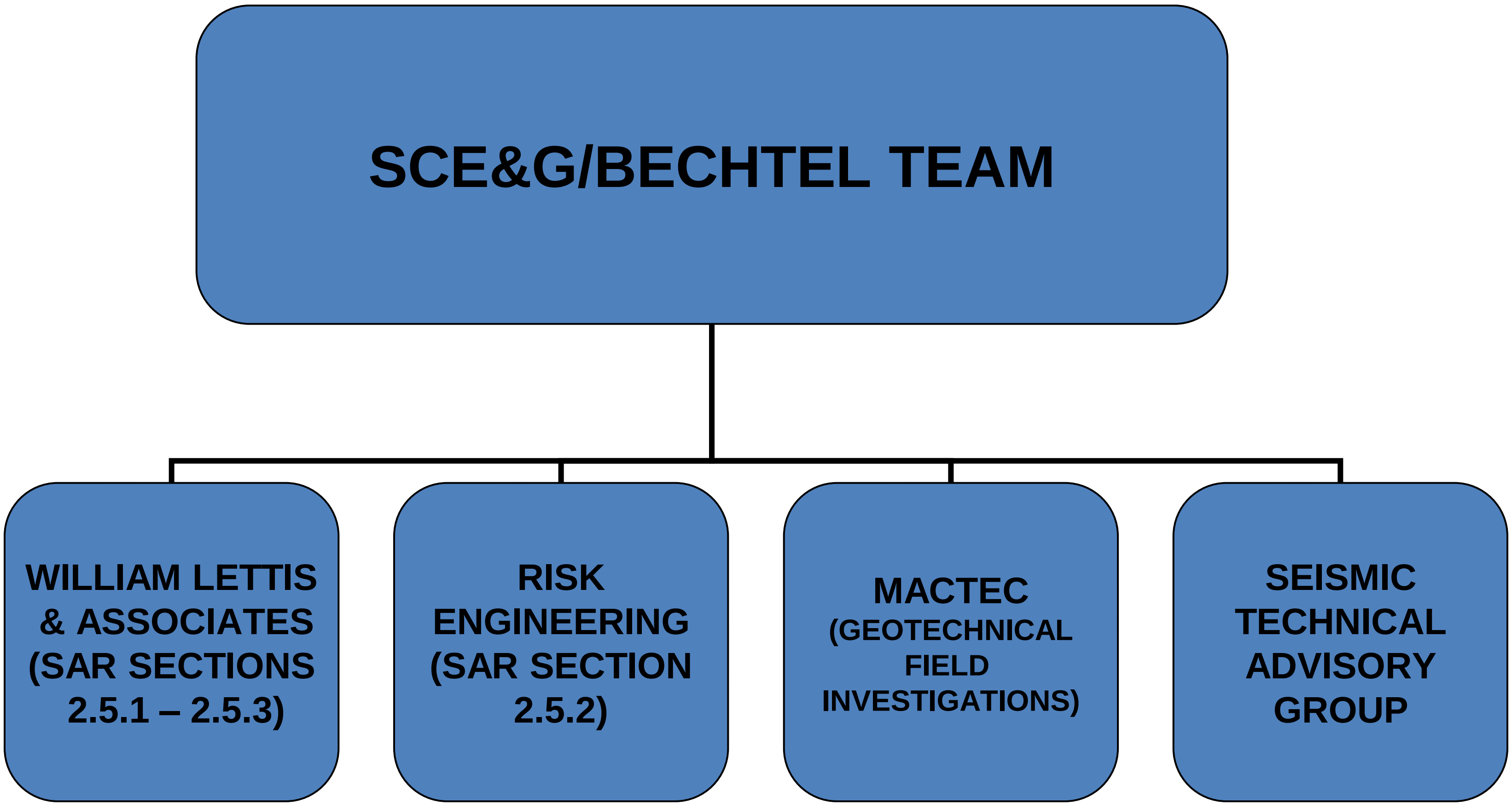
NUCLEAR ISLAND EXCAVATION – JANUARY 2011

SAR SECTION 2.5
TECHNICAL DEVELOPMENT



SUMMER - SEISMIC TECHNICAL ADVISORY GROUP (TAG)

- **Dr. Martin Chapman – Virginia Tech**
- **Dr. Allin Cornell – Stanford**
- **Dr. Robert Kennedy – Consultant**
- **Mr. Don Moore – Southern Company**
- **Dr. Carl Stepp – Consultant**

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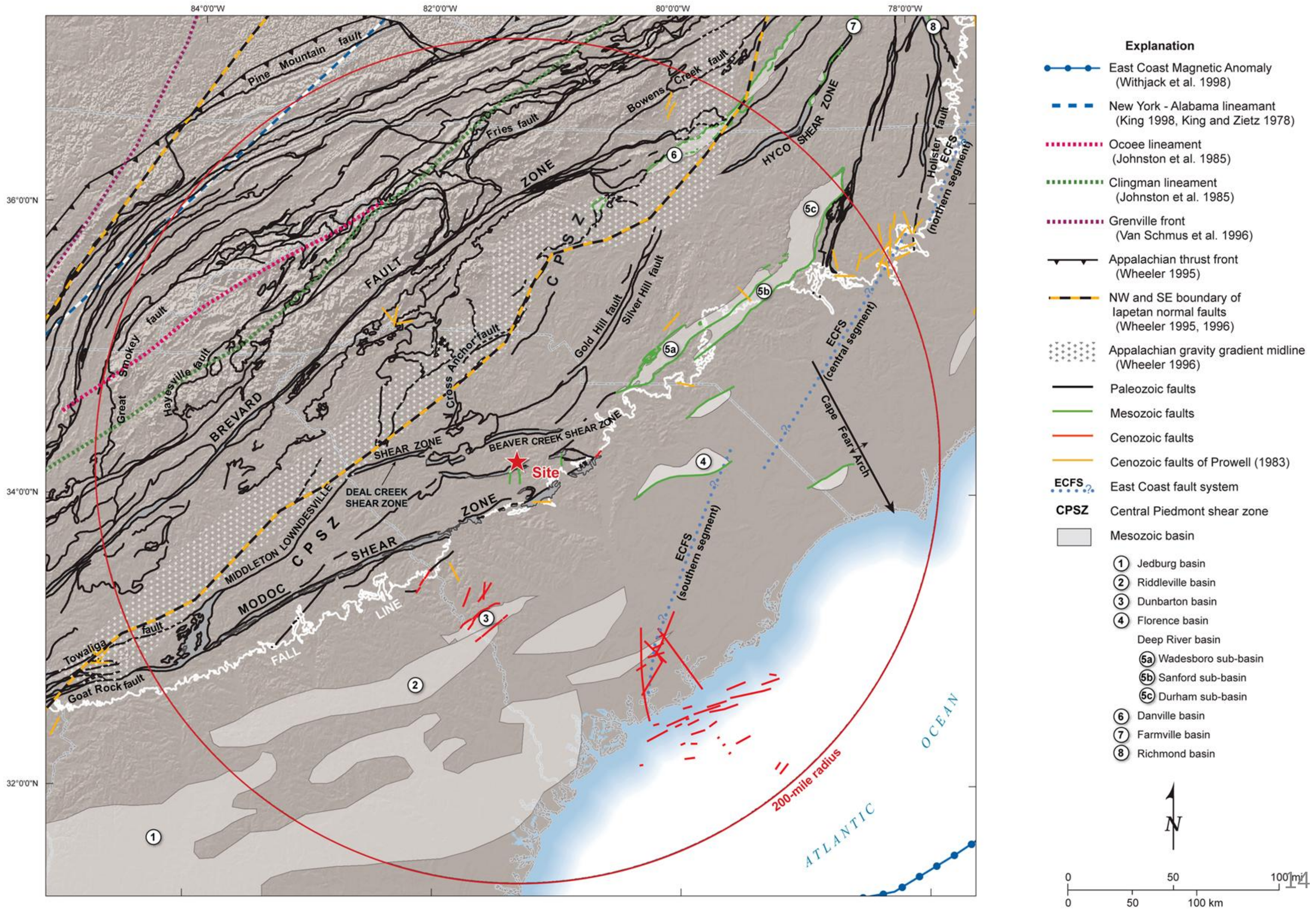
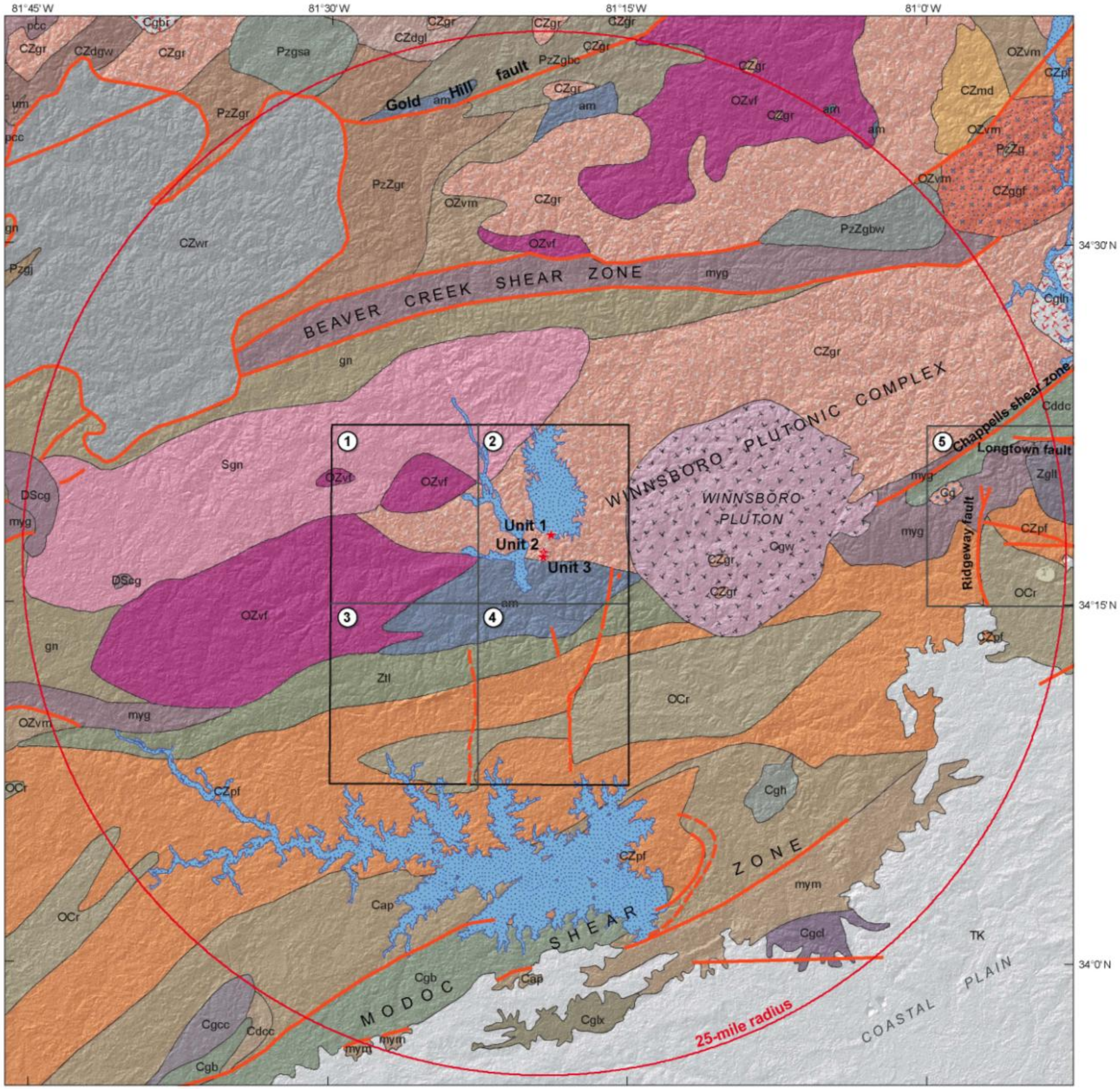
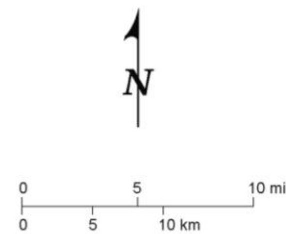
FSAR Sections
2.5.1 and 2.5.3

Basic Geologic and Seismic Information & Surface Faulting

200-mi Map of Tectonic Features



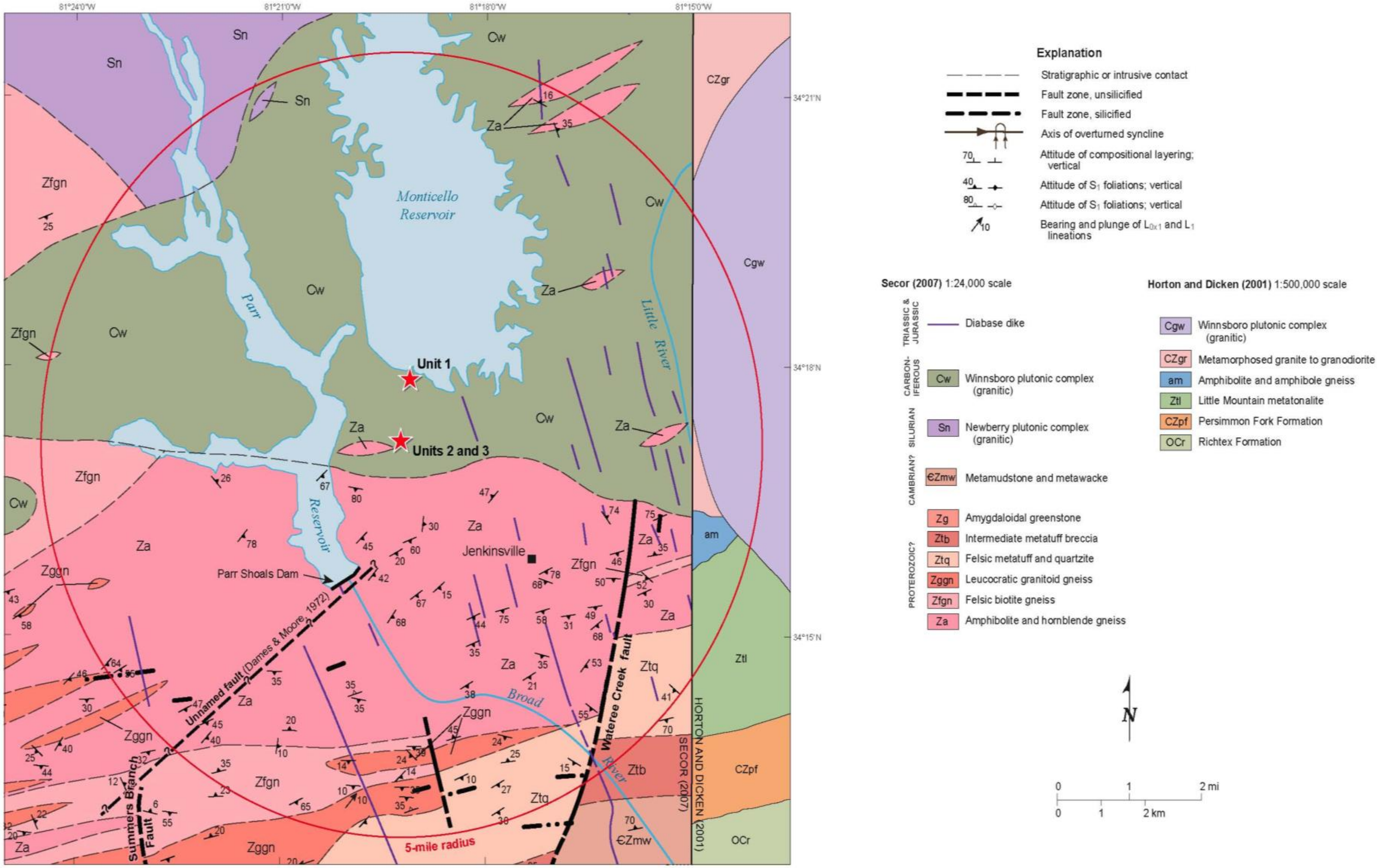




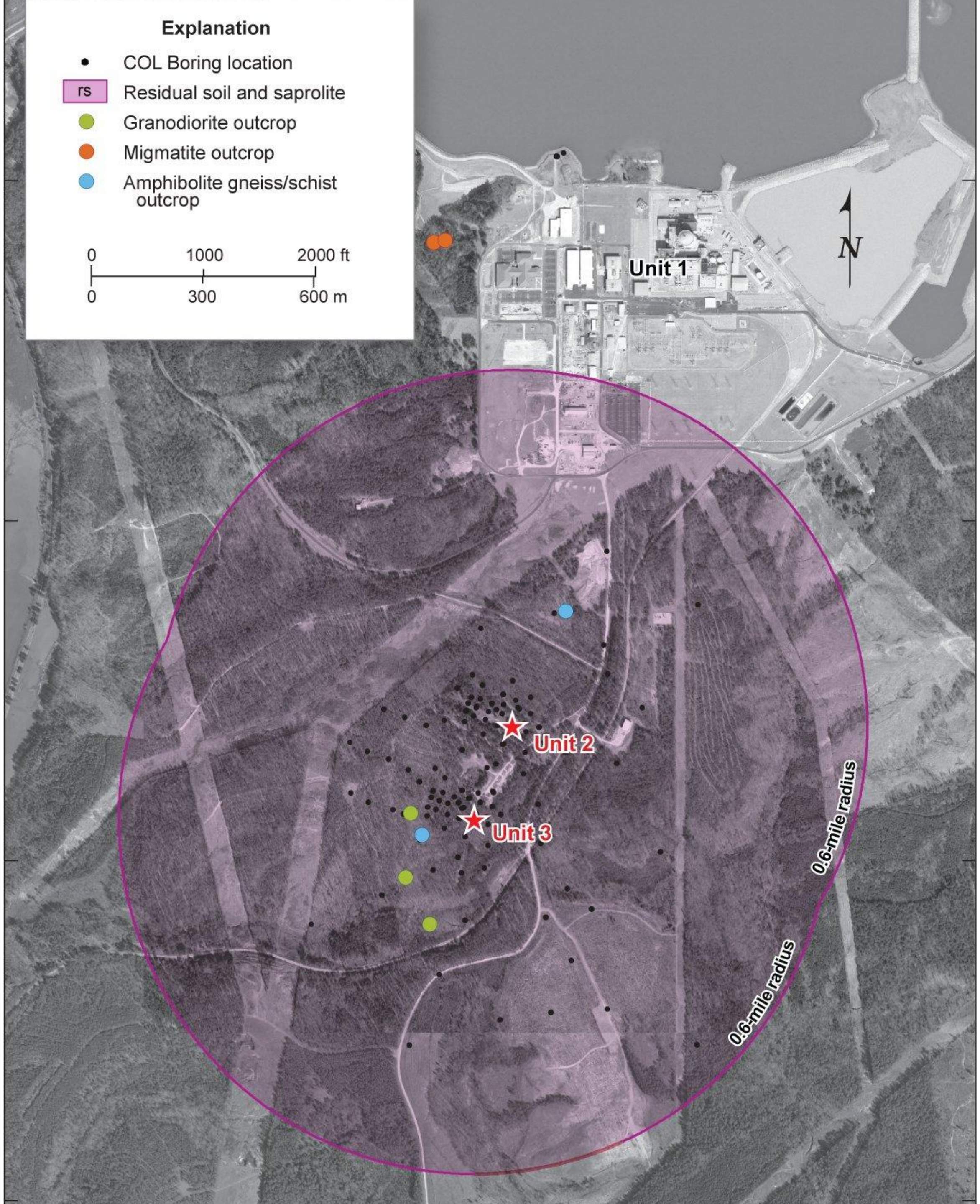
25-mi Geologic Map

Modified from Horton and Dicken (2001), Hibbard et al (2006), and Secor (2007)

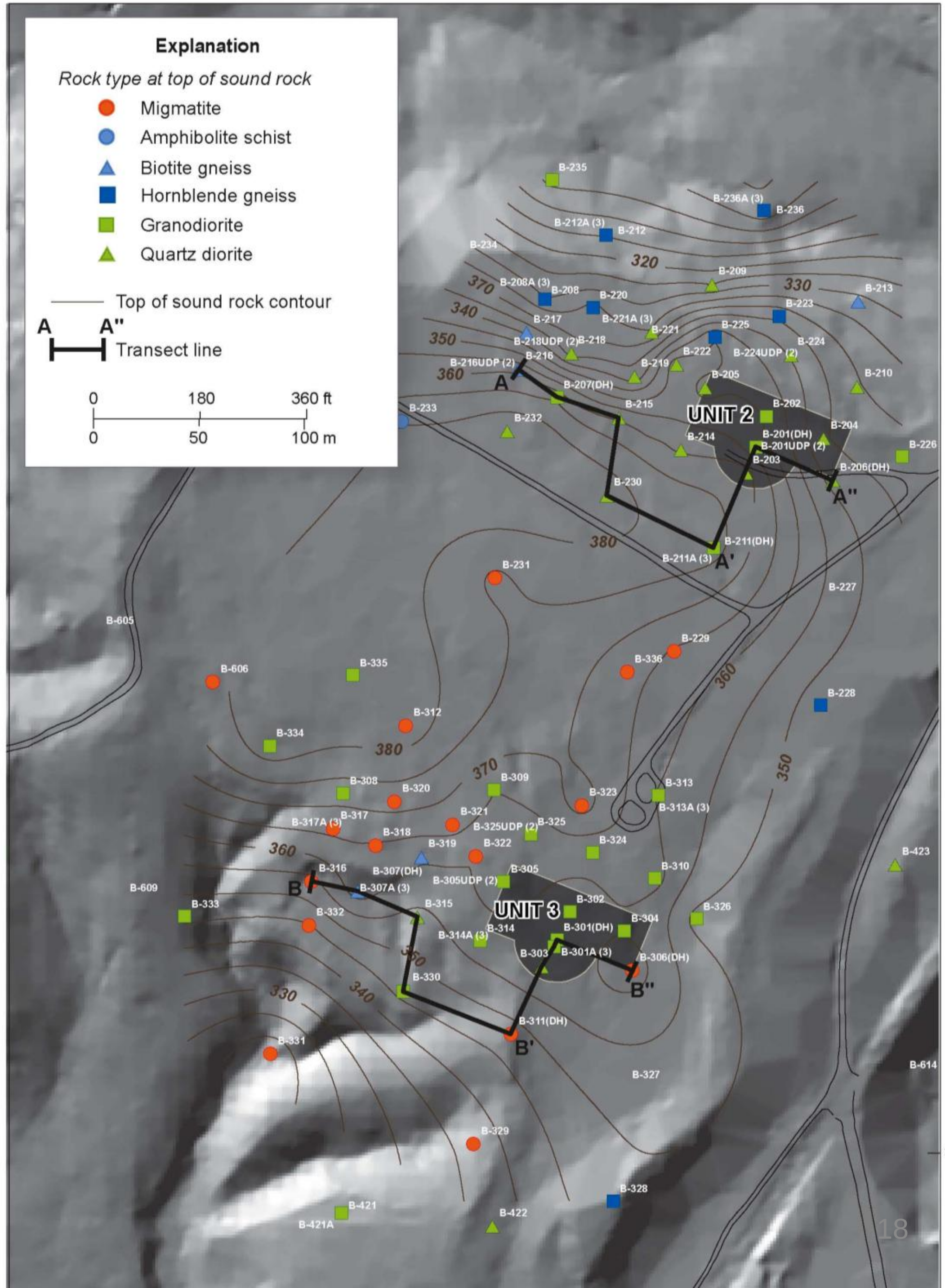
5-mi Geologic Map



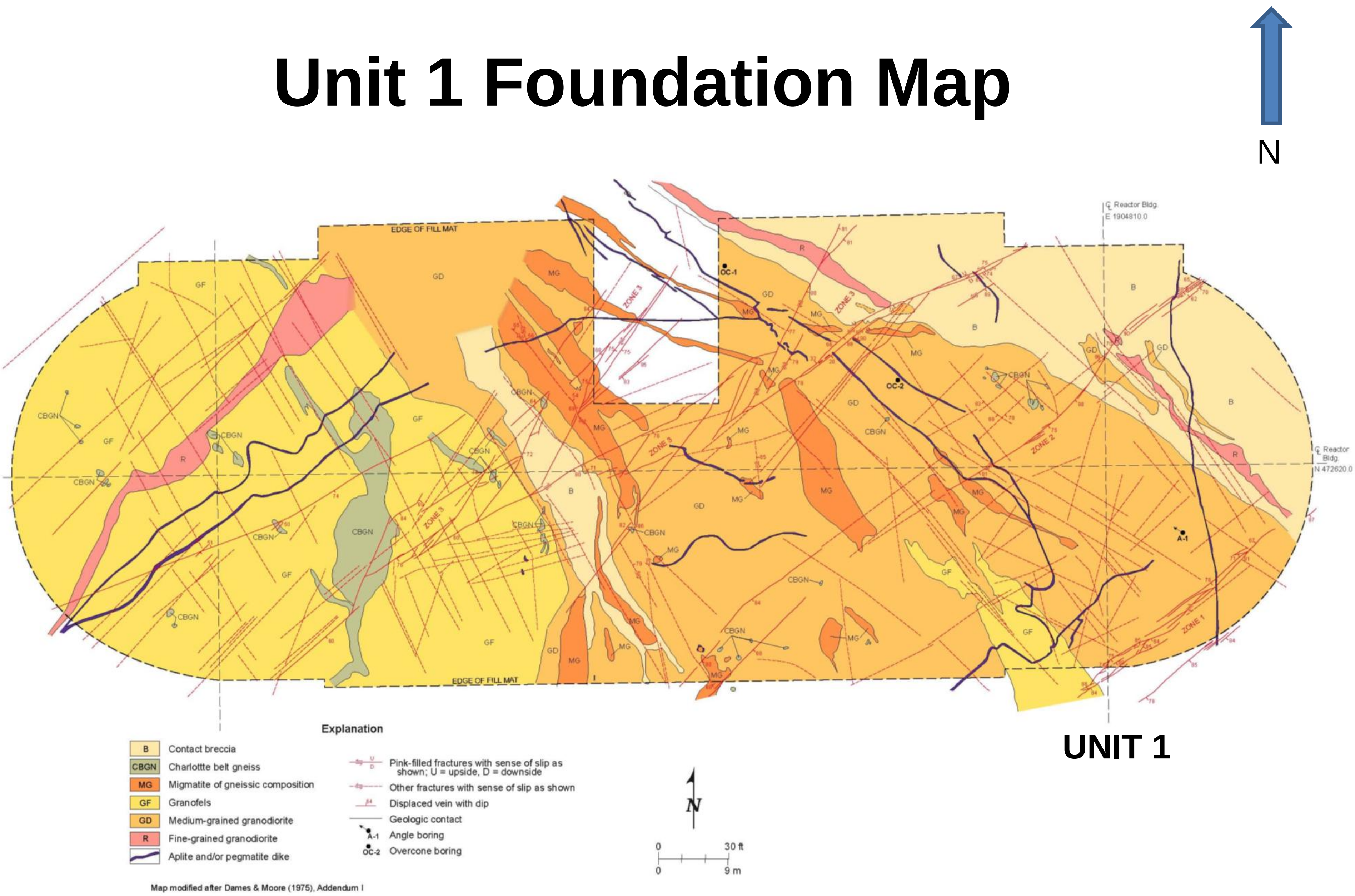
0.6-mi Surficial Geologic Map



Top of Sound Rock Beneath Units 2 and 3



Unit 1 Foundation Map



Unit 1 Surface Faulting Summary

- Small bedrock shears were mapped in the excavation. After extensive evaluations and age dating, these minor features were demonstrated to have last moved between 300 and 45 Ma
- It was concluded that minor bedrock shears exist throughout site area, but these <u>do not</u> represent a surface rupture hazard

Unit 1 Excavation (Northeast View)

1973

Unit 1 Excavation (South View)

1973

UNITS 2 & 3 CONCLUSIONS

- Consistent with the results of the Unit 1 investigation, it was expected that excavations for Units 2 & 3 would expose similar shear features, and a few minor ones have now been observed
- Units 2 & 3 excavation are being geologically mapped with results documented and reviewed by NRC Staff (initial visit in August 2010 and one planned for March 2011)

UNITS 2 & 3 CONCLUSIONS

- Current geological investigations have not identified any new data to change our current interpretations
- SAR Section 2.5.1 concludes that the shear features are not capable tectonic sources and do not represent ground motion or surface rupture hazards to the site

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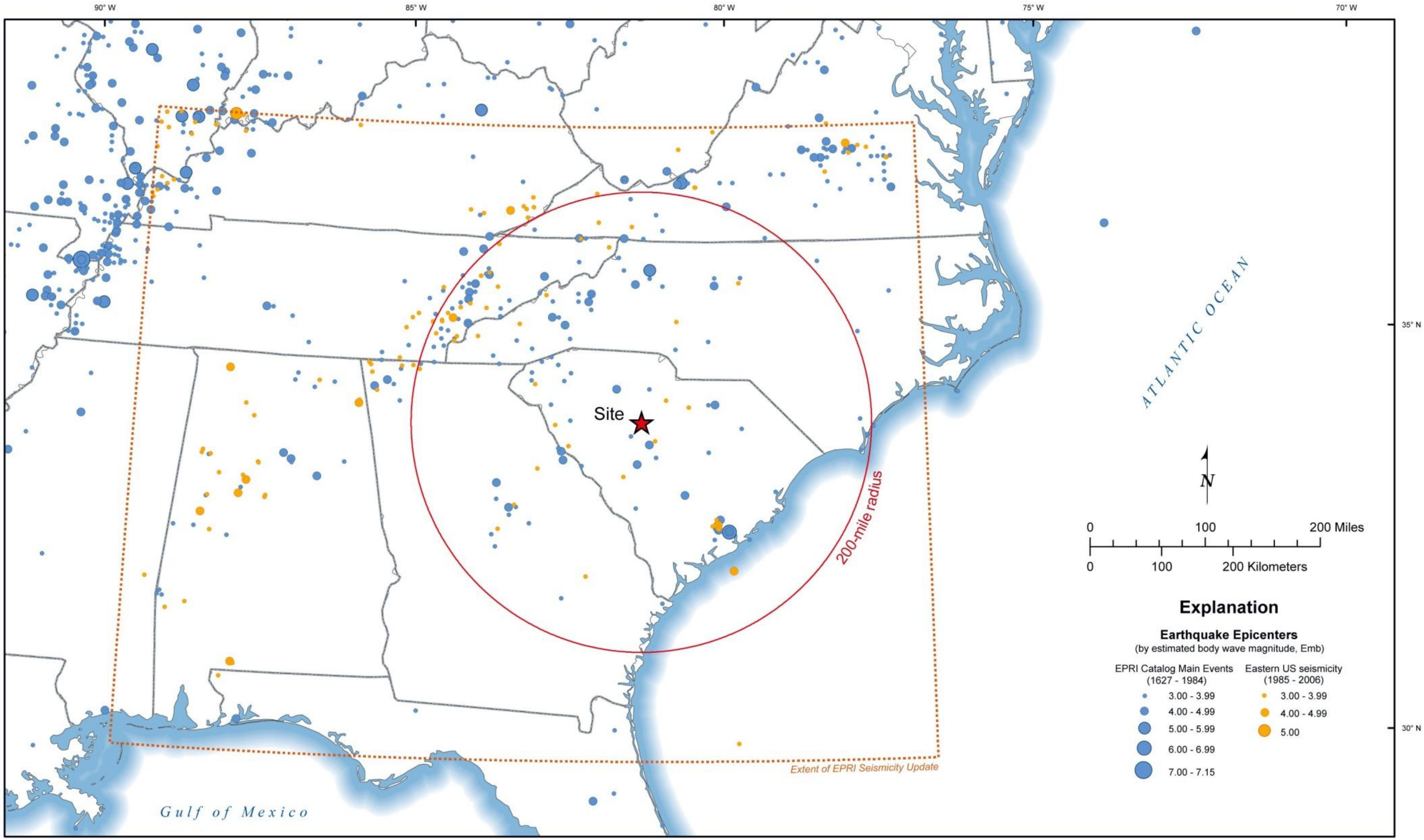
FSAR Sections
2.5.2

Vibratory Ground Motion

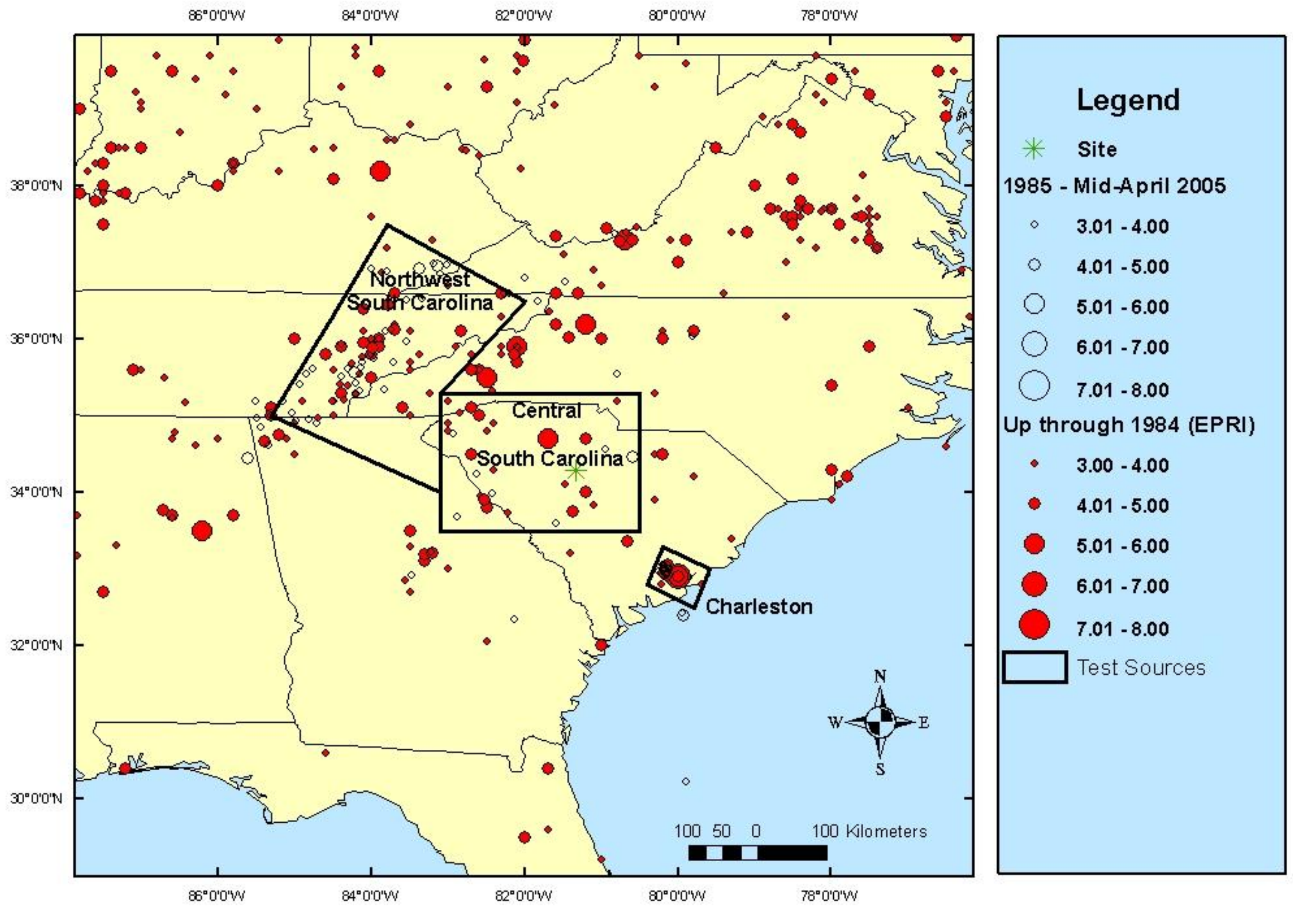
Updated Seismicity Catalogs



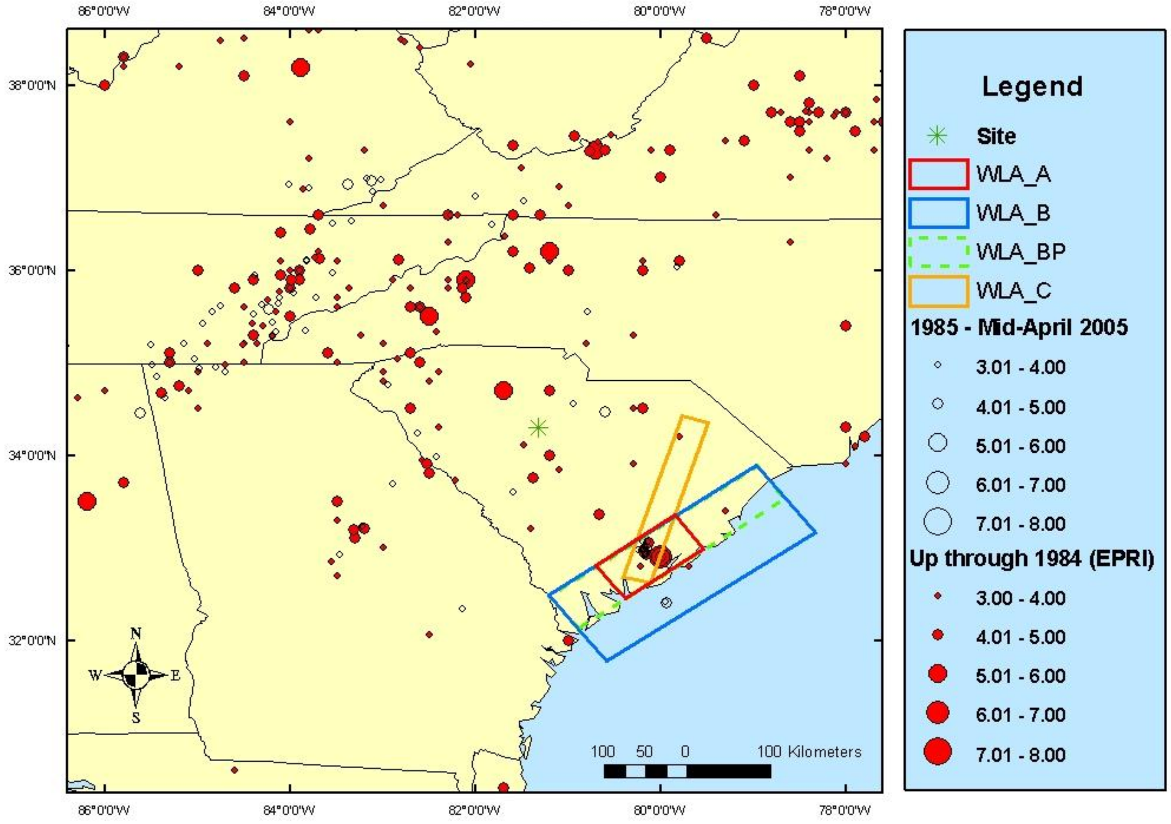
Probabilistic Seismic Hazard Analysis

- Replicated the 1989 EPRI hazard results
- Evaluated effects of updated seismicity
- Updated the Charleston seismic source zones
- Developed Seismic Hazard and UHRS (hard rock)
- Developed V/H ratios and GMRS (hard rock)

Historical seismicity in vicinity of Summer site and three areas used to test the effects of additional seismicity



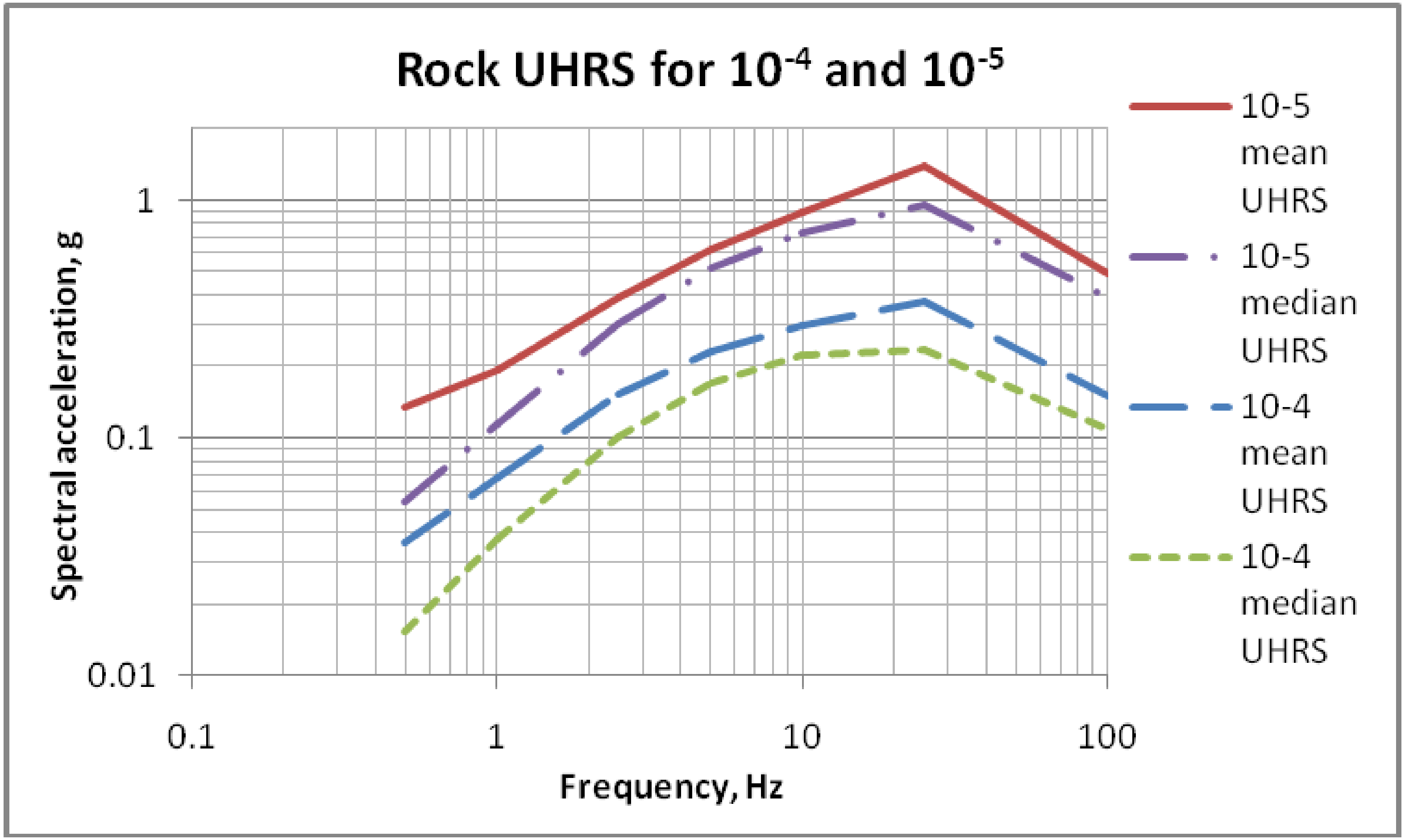
Geometry of Four Sources Used in Updated Charleston Seismic Source (UCSS) Model



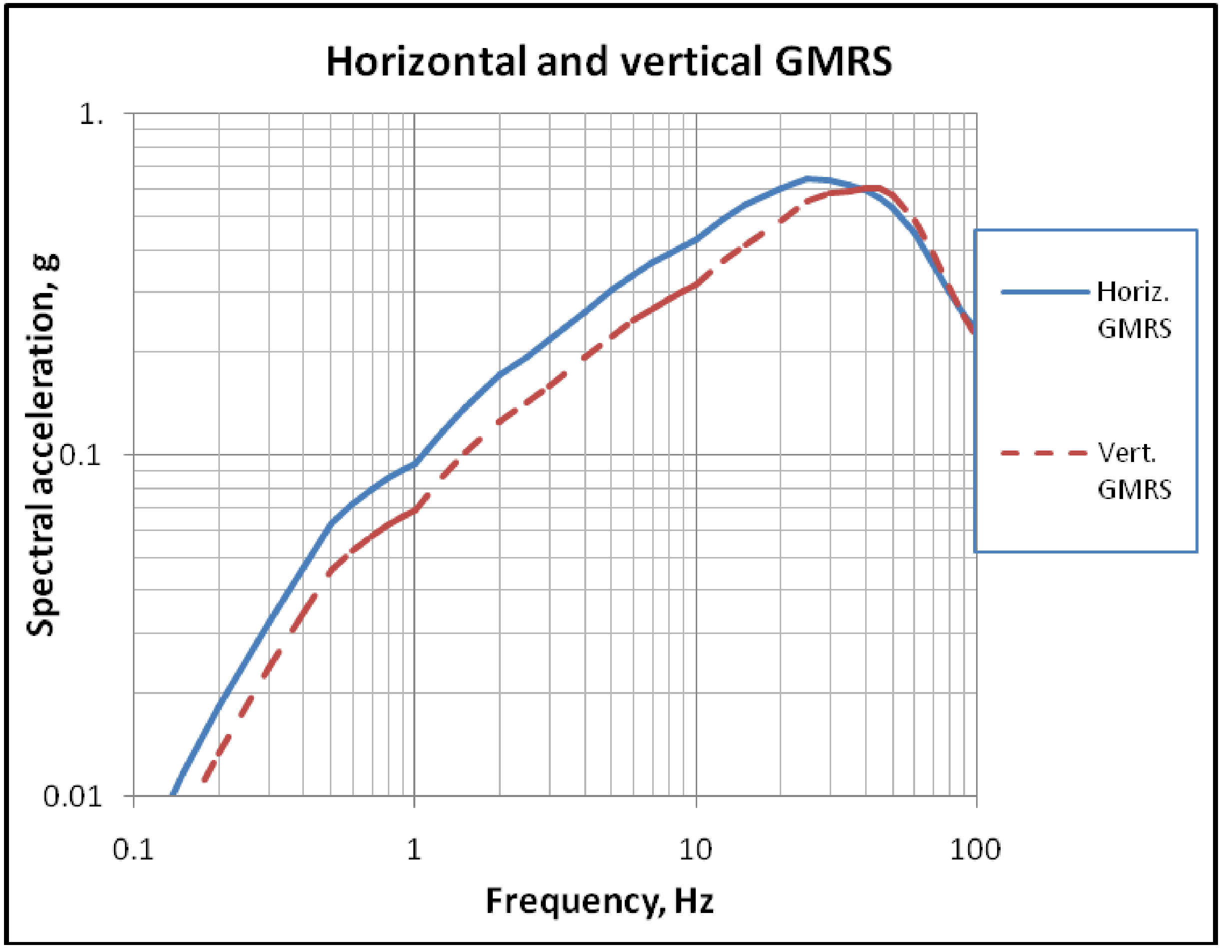
Summary of VC Summer Seismic Source Model

- No new Capable Tectonic Sources were identified within the site region
- No modifications to the Eastern Tennessee Seismic Zone were required
- Updated Charleston model replaced the EPRI sources (as adopted from Vogtle)
- New Madrid Source was added (which adopted the Clinton characterization)

Mean and Median Uniform Hazard Response Spectra



Horizontal and Vertical GMRS



V. C. Summer Nuclear Station, Units 2 and 3
COL Application
Part 2, FSAR

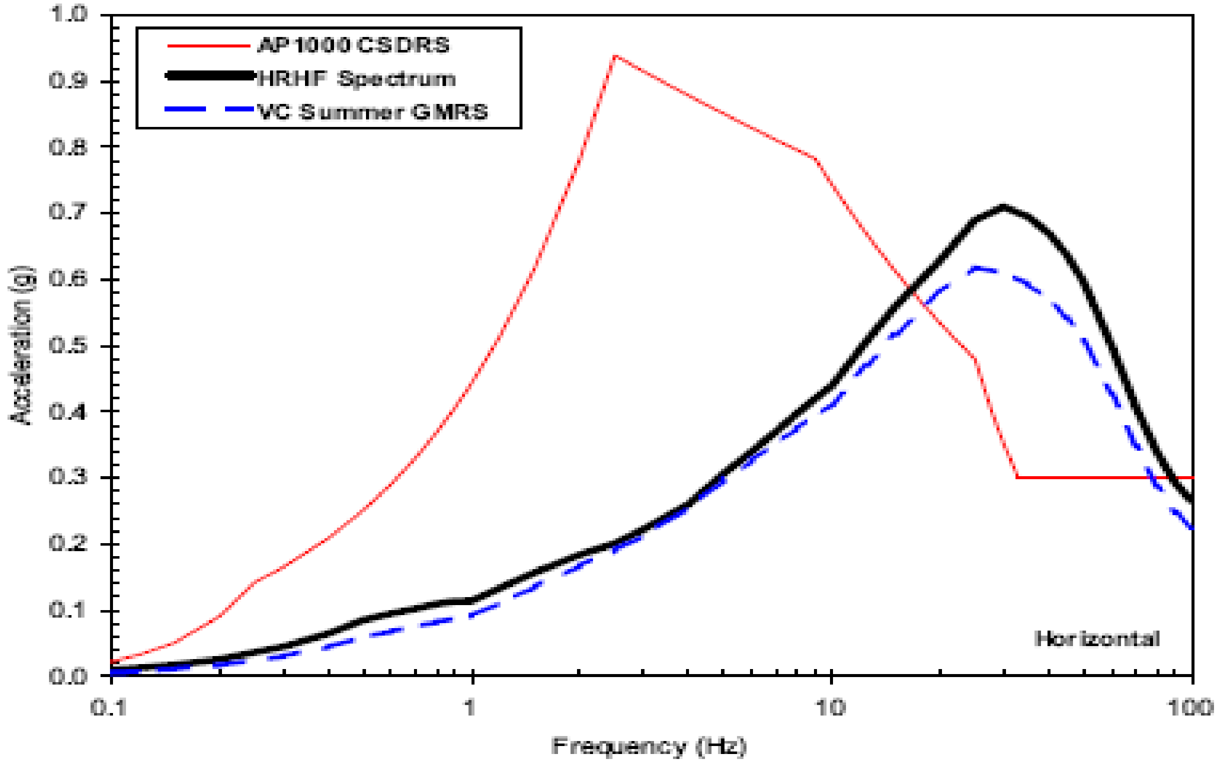


Figure 2.0-201. Comparison Plot of V. C. Summer GMRS and HRHF Spectra for the Horizontal Component of Motion

SCE&G VC Summer COL

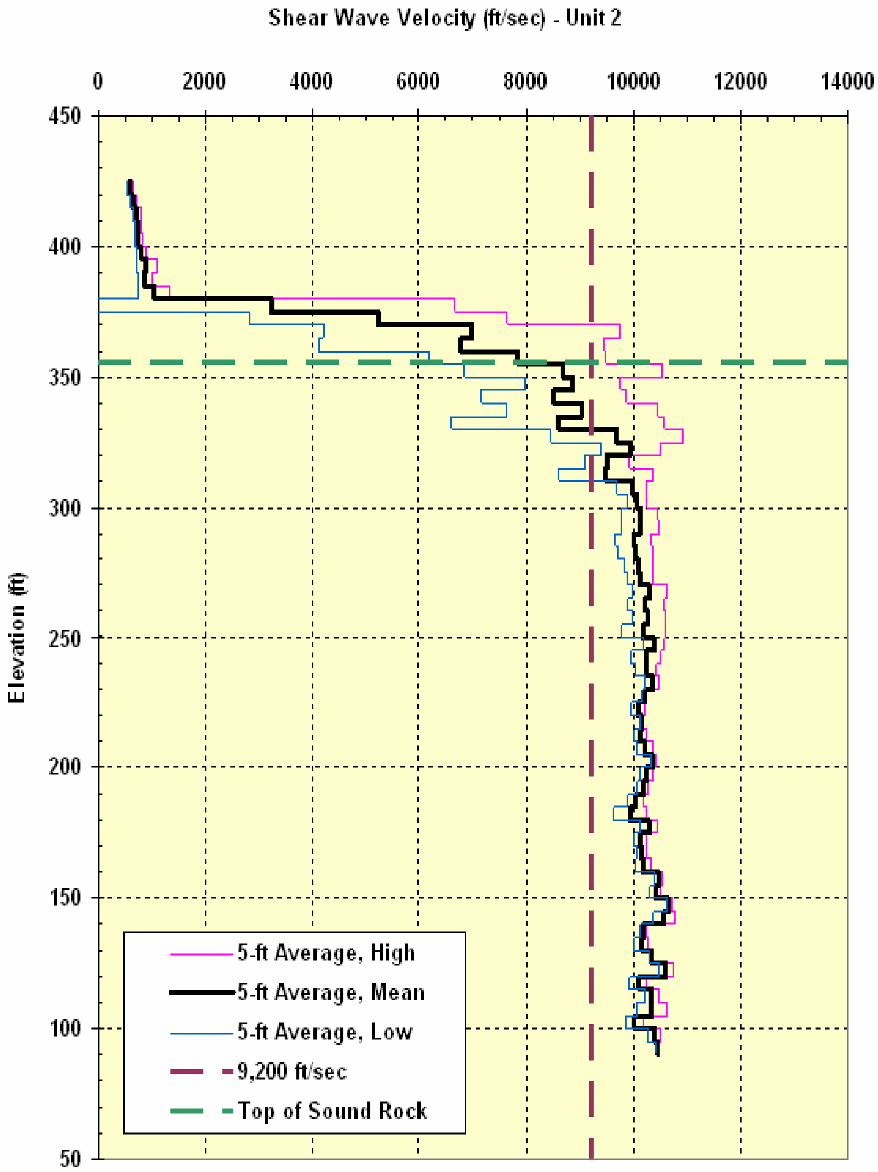
FSAR Sections 2.5.4

Site Geotechnical Characterization/ Foundations

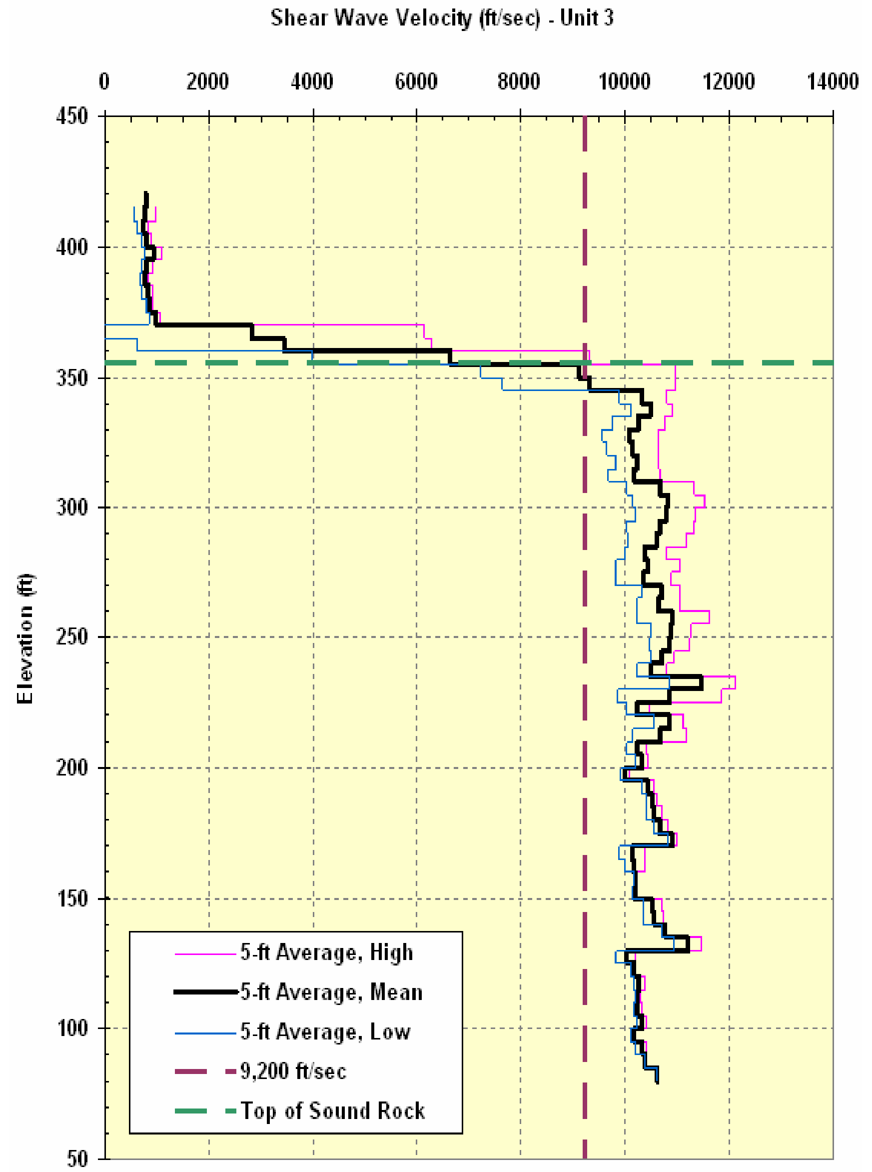
Description of Subsurface Materials

- **Residual Soil** – reddish silty sands and sandy silts with variable clay content
- **Saprolite** – completely weathered rock but w/preserved relict rock structure, mainly silty sands
- **Partially Weathered Rock (PWR)** – decomposed rock matrix mixed w/semi-hard rock fragments
- **Moderately Weathered Rock (MWR)** -- >50% by volume of sound rock interspersed w/decomposed zones
- **Sound Rock** – Hard fresh to slightly discolored rock (granodiorite, quartz diorite, gneiss, schist, migmatite)

2.5.4.7.2 Vs Average at 5 Ft Intervals



UNIT 2



UNIT 3

Section 2.5.4.8 Liquefaction Potential

- Nuclear Island is on sound rock or on concrete on sound rock
- Power Block structures, including Seismic Category II Annex Building and Turbine Building (1st Bay) are on compacted structural fill above rock
- There is no saprolite within the zone of influence of the foundation loading of the Seismic Category I / II structures

<u>CONCLUSION: Liquefaction cannot impact plant safety</u>

Comments

VC Summer Units 2 and 3
Liquid Radwaste/ Waste Water System Interface and Discharge

Tim Schmidt – Engineer
SCE&G New Nuclear Deployment

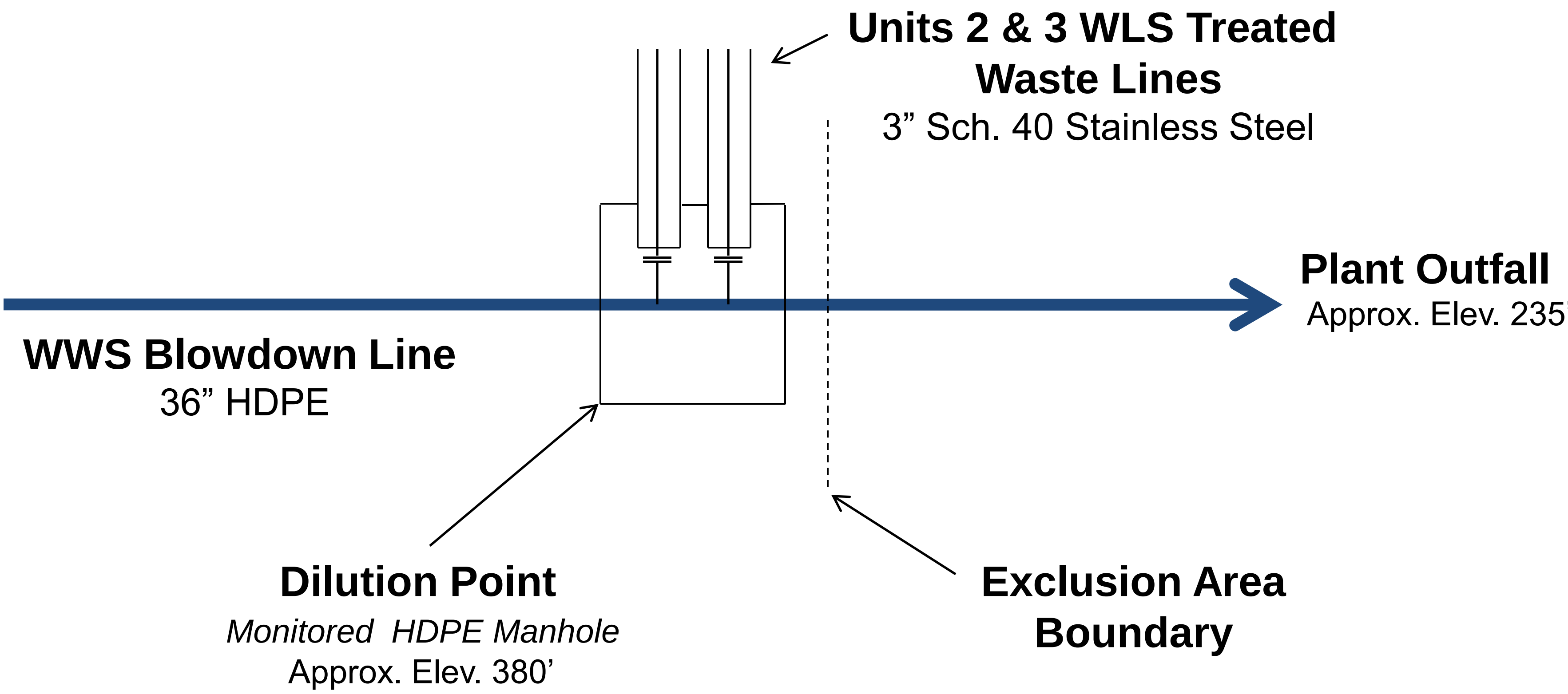
Topics of Interest

- Interface of the Liquid Radwaste System (WLS) with the Waste Water System (WWS)
- WWS blowdown line to the plant outfall at Parr Reservoir

Design Considerations

- Meets regulatory requirement (10CFR20.1406) and guidance (RG 4.21)
  - Monitored manhole at WWS/WLS interface
- Incorporated industry OE and lessons learned into the WWS design
  - HDPE utilized versus carbon steel, ductile iron or fiberglass
  - No pumps, valves or vacuum breakers along the line
  - Blowdown flow is via gravity

Design Overview



HDPE Installation Example

Construction Considerations

- Construction requirements ensure long-term integrity
  - Qualified welders and processes
  - Proven installation techniques based on operating experience
  - Weld inspections
  - Hydrostatic testing
- Expect long life with HDPE
  - Over 40 years industry experience with HDPE
  - Over 10 years experience in Nuclear HDPE applications

Summary

- Single wall design of the WWS beyond the dilution point provides reasonable assurance of leak free service
- WWS blowdown line installation and testing processes assure reliable long term operations

Comments

VC Summer Units 2 and 3
FSAR Section 13.3
Emergency Planning

Tim Bonnette

SCE&G – Emergency Preparedness

Presentation Overview

- Emergency Plan Design
- DCD Departure
- Emergency Facilities
- Emergency Response
- Emergency Planning Zone
- Public Awareness

Emergency Plan Design

- Single plan for all three Units
- Developed in accordance with:
  - NUREG-0654/FEMA-REP-1 Rev 1
  - 10 CFR 50.47
  - 10 CFR 50 Appendix E
- Emergency Action Level (EALs) developed in accordance with:
  - NEI 07-01 Rev 0 (Units 2 & 3)
  - NEI 99-01 Rev 5 (Unit 1)

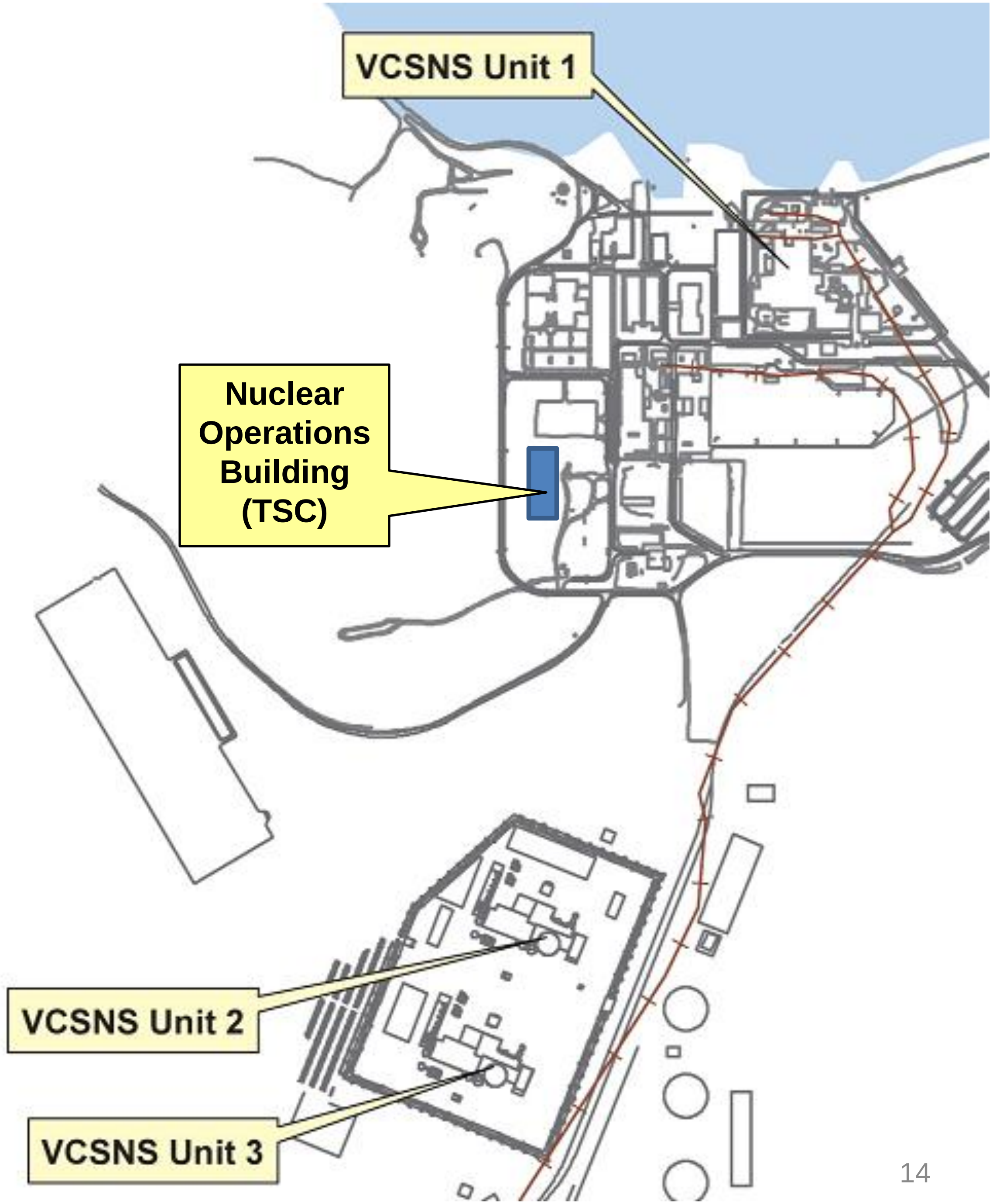
DCD Departure

- VCS DEP 18.8-1 – Locations of the Technical Support Center (TSC) and Operational Support Center (OSC)
  - TSC will be located in the New Nuclear Operations Building
  - Each OSC for Units 2 & 3 will be located in its respective Annex Building, in the area designated as the DCD TSC (DCD Elev 117’ 6”).

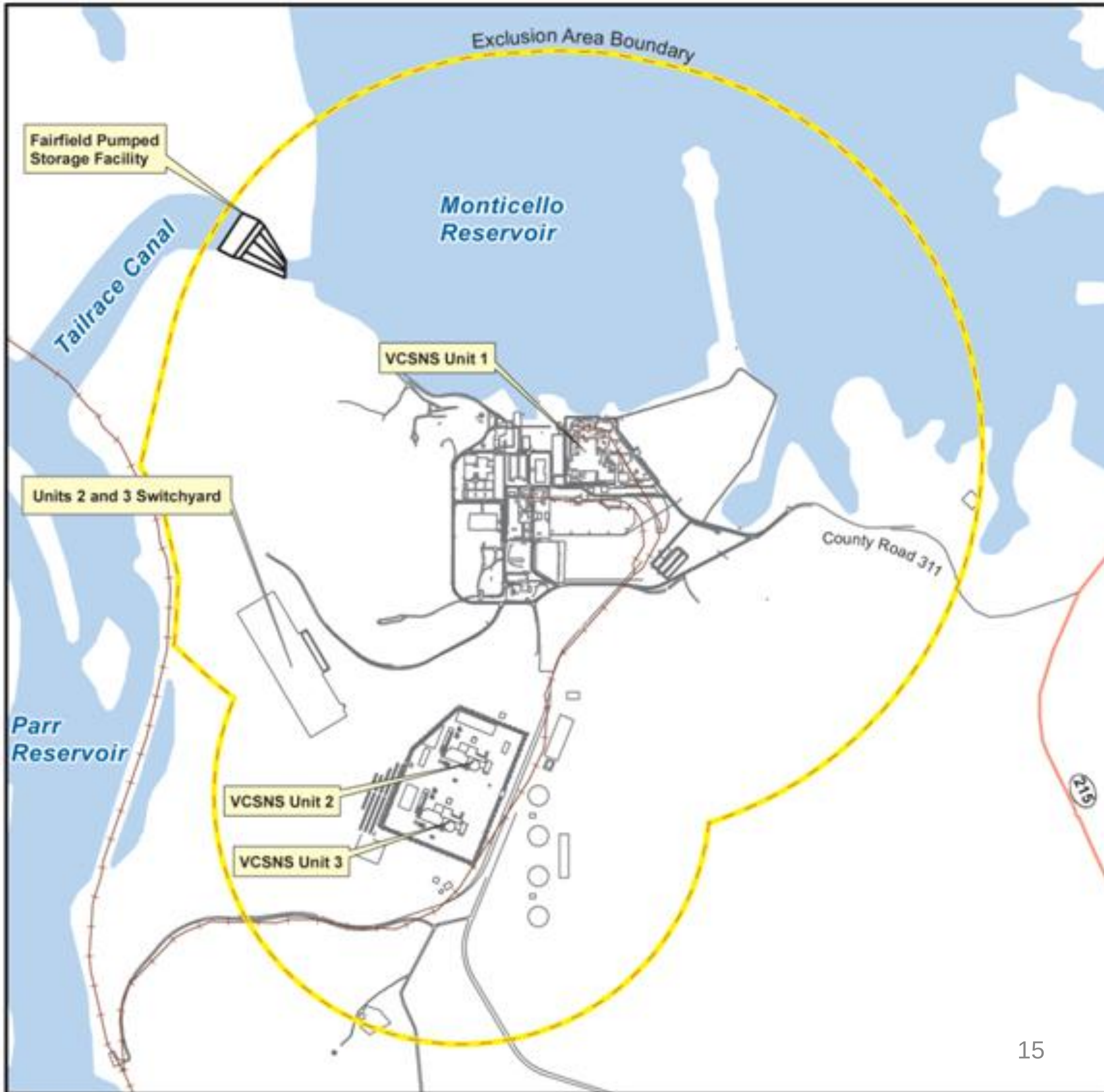
Technical Support Center

- Common for all three Units
- Meets the requirements of NUREG-0696, with exception of being adjacent to the Control Rooms
- Incorporates human factors engineering (HFE) to support emergencies involving one, two, or three Units

Technical Support Center Location



Site Map-Exclusion Area



Emergency Facilities

- 3 Control Rooms
- 3 Operational Support Centers (OSC)
- Technical Support Center (TSC)
- Emergency Operations Facility (EOF)
- Joint Information Center (JIC)

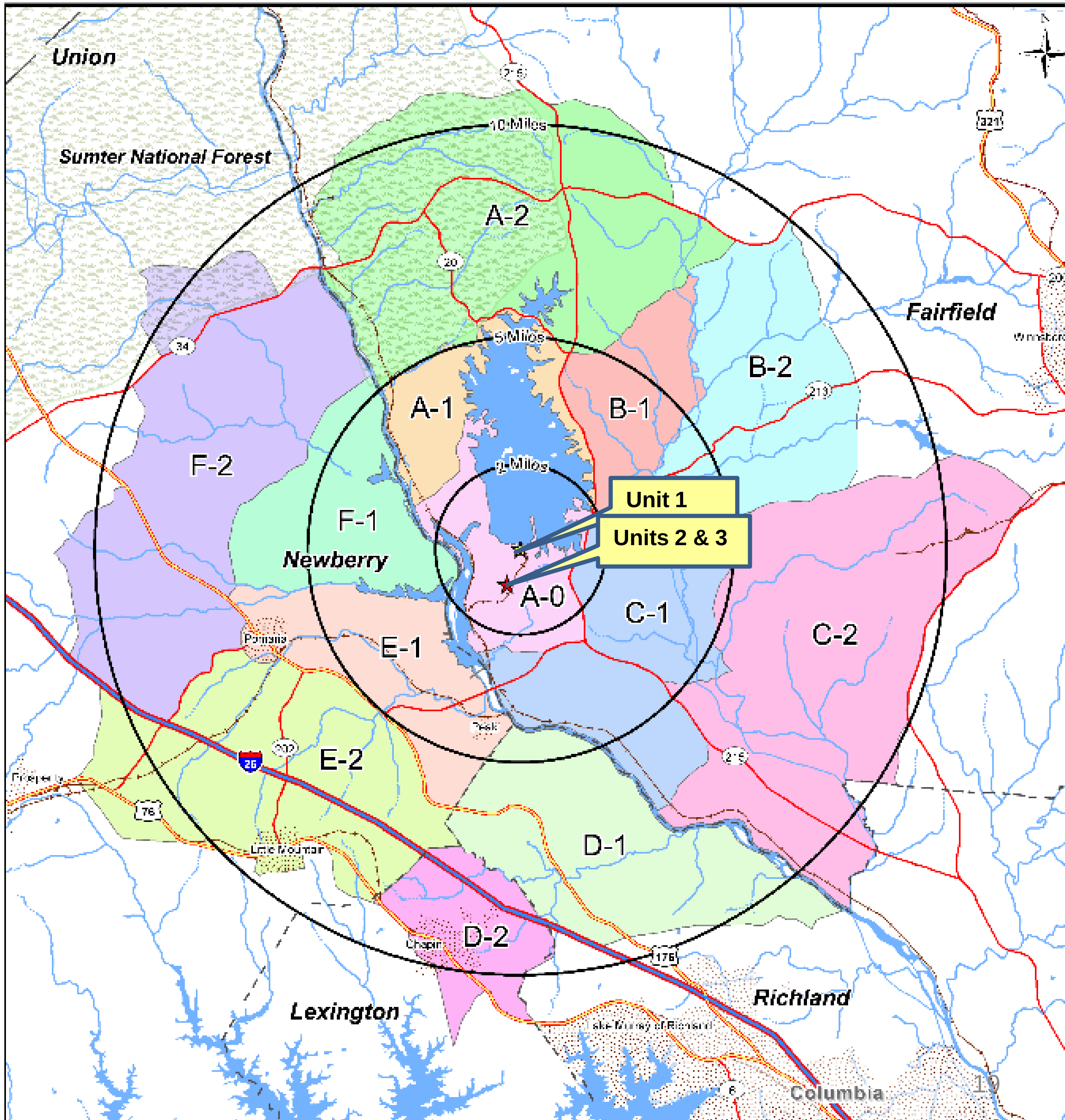
Emergency Response

- Site level emergency response
- Protected Area level emergency response
- Single Unit emergency response

Emergency Planning Zone (EPZ)

- EPZ boundaries remain the same
- Agreed upon by the State of SC and the risk counties (Fairfield, Lexington, Newberry, & Richland)
- Reviewed and accepted by FEMA

EPZ Map


Union
Sumter National Forest
10 Miles
5 Miles
2 Miles
A-2
A-1
A-0
B-1
B-2
C-1
C-2
D-1
D-2
E-1
E-2
F-1
F-2
Unit 1
Units 2 & 3
Newberry
Fairfield
Lexington
Richland
Columbia
Chapin
Peak
Pomaria
Little Mountain
Prosperity
Lake Murray of Richland

Public Awareness

- Annual Calendar Distribution
  - Details actions and guidance for members of the public
  - Distributed to all residents and businesses within the EPZ
  - Includes self addressed and postage paid cards for residents with special needs
- Press Releases
- Emergency Responder Training

Comments

SCE&G • Santee Cooper
Shaw • Westinghouse Electric Company

VC Summer Units 2 and 3
FSAR Chapter 8

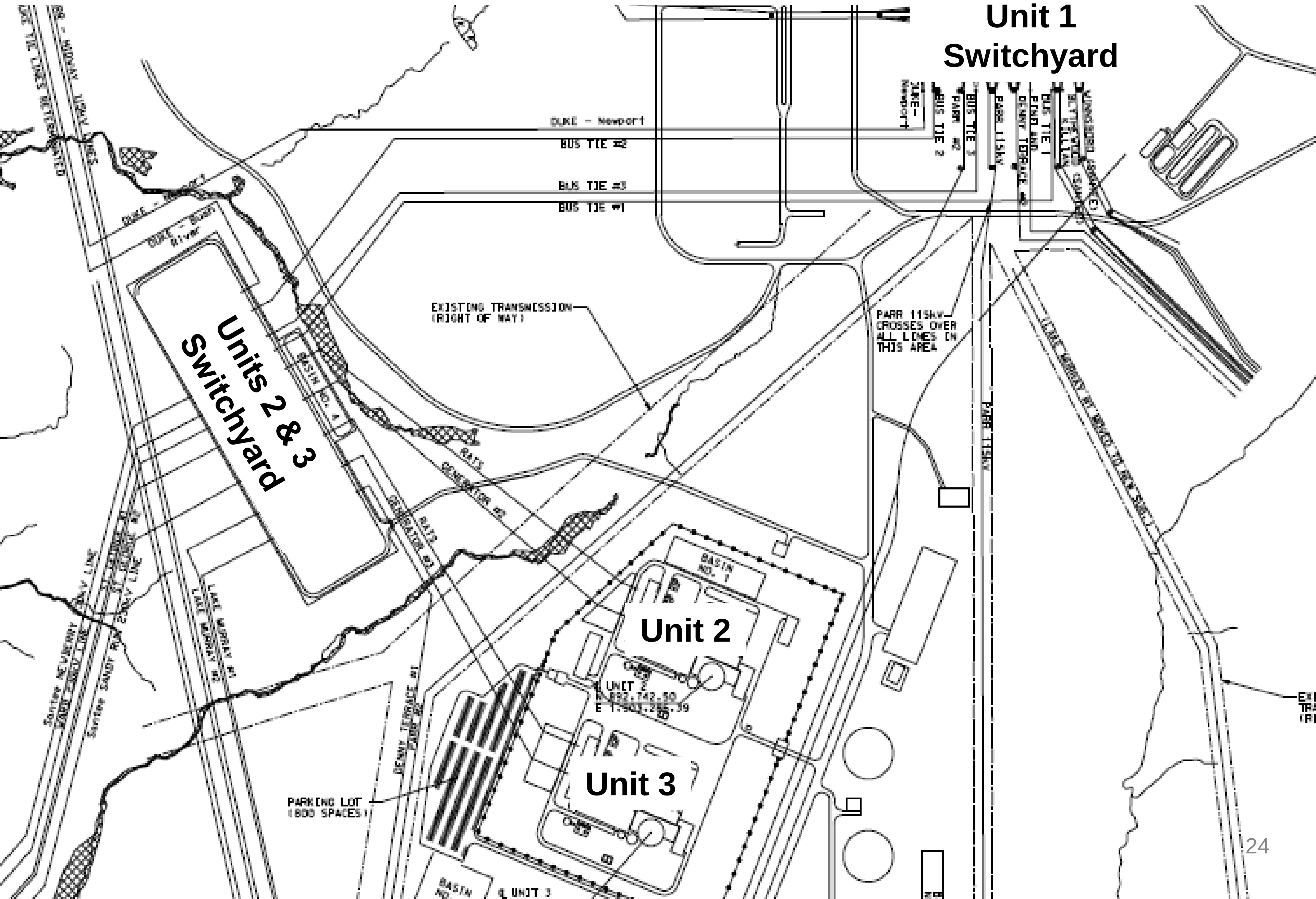
James LaBorde – Consulting Engineer

New Nuclear Deployment

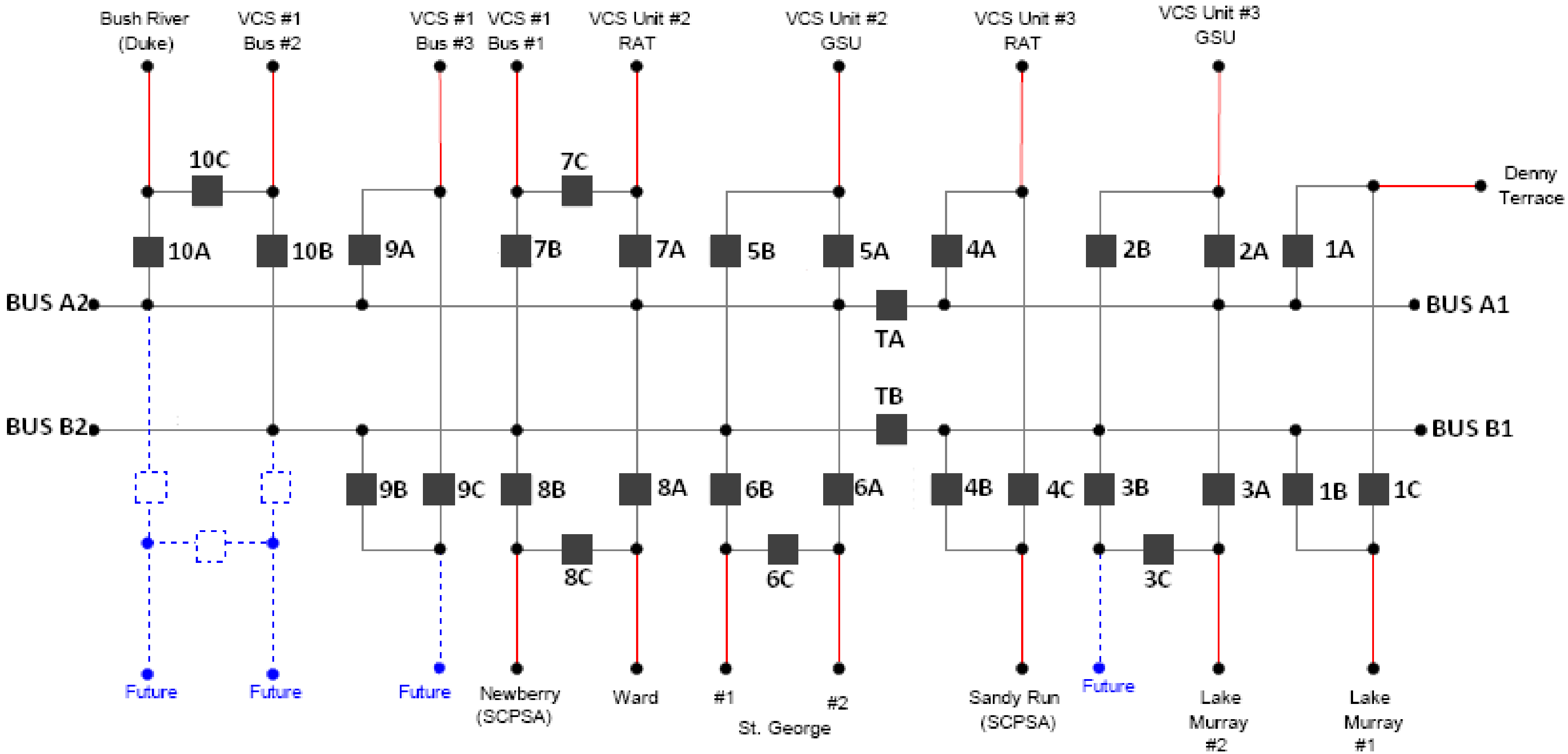
Section 8.2
Offsite Power

- 12 overhead transmission lines connect the new 230 kv switchyard to other substations
- Switchyard is robust
- Failure Analysis performed
- Grid Stability Study performed
  - Includes the Westinghouse interface requirement for maintaining Reactor Coolant Pump voltage for 3 seconds after a turbine trip

Units 1, 2, & 3 Transmission Lines



Switchyard Single-line Diagram



Comments

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Shaw • Westinghouse Electric Company

VC Summer Units 2 and 3
Application Overview and Required Siting Characteristics

Amy Monroe

SCE&G – Licensing Engineer


MAPQUEST
Cullowhee
Etowah
Hendersonville
Rutherfordton
Polkville
Cherryville
Stanley
Huntersville
Concord
Albemarle
Troy
Biscoe
Flat Rock
Caroleen
Shelby
Gastonia
Charlotte
Locust
Norwood
Brevard
Tuckasegee
Tryon
North Carolina
South Carolina
Landrum
Oakboro
Mount Gilead
Pinehurst
Glenville
Rosman
Matthews
Clover
Indian Trail
New Salem
Ellerbe
Pinebluff
Cashiers
Cleveland
Gaffney
Valley Falls
Fort Mill
Polkton
Boiling Springs
LEE
York
Monroe
Wadesboro
Rockingham
Travelers Rest
Spartanburg
Rock Hill
Taylors
Saxon
Hickory Grove
Pickens
Sans Souci
Roebuck
Pacolet
McConnells
Waxhaw
East Rockingham
Easley
Greenville
Jonesville
Lesslie
Morven
Liberty
Lowrys
Walhalla
Lockhart
Pageland
Laurinburg
Simpsonville
Buffalo
Union
Chester
Lancaster
Ruby
Cheraw
Gibson
Piedmont
Seneca
Chesterfield
Fort Lawn
Fountain Inn
Westminster
Clemson
Williamston
Cross Anchor
Cornwell
Jefferson
Bennettsville
Carlisle
Great Falls
Gray Court
Patrick
Kershaw
Society Hill
Clio
Martin
Anderson
Princeton
Laurens
Whitmire
Shelton
White Oak
Liberty Hill
McBee
Lavonia
Homeland Park
Ware Shoals
Clinton
Westville
Brownsville
Hartwell
Winnsboro
Bethune
Hartsville
Monticello
Starr
Cassatt
Darlington
Latta
Royston
Donalds
Cross Hill
Kinards
Ridgeway
Due West
Newberry
SUMMER
Camden
Iva
Coronaca
Bishopville
Bowman
Ninety Six
Prosperity
Blythewood
Florence
Lowndesville
Abbeville
Elgin
Lugoff
Lamar
Elberton
Verdery
Chapin
Elliott
Timmonsville
Marion
Calhoun Falls
Rembert
Comer
St. Andrews
Effingham
Kirksey
Columbia
Dalzell
St. Charles
Fortsonia
Mount Carmel
Saluda
Lexington
Coward
Pamplico
Vesta
Cherryvale
Olanta
McCormick
Batesburg-Leesville
Sumter
Hopkins
Lexington
Eastover
Lake City
Ridge Spring
Shannontown
New Zion
Poston
Rayle
Lincolnton
Parksville
Edgefield
Gaston
Wateree
Cades
Maxeys
Washington
Modoc
Pelion
Swansea
Pinewood
Alcolu
Hemingway
Trenton
Manning
Woodville
St. Matthews
Kingstree
Wagener
Eureka
North
Union Point
Summerton
Foreston
Nesmith
Graniteville
Aiken
Perry
Lone Star
Greeleyville
Crawfordville
Appling
Neeses
Rhems
Siloam
Martinez
Springfield
Orangeburg
Santee
Lane
Augusta
Windsor
White Plains
Thomson
Andrews
New Ellenton
Cordova
Vance
Pineville
Warrenton
Camak
Grovetown
St. Stephen
Norway
Cope
Sampit
Williston
Blackville
Bowman
Holly Hill
Cross
Hephzibah
Blythe
Bonneau
Sparta
Bamberg
Jackson
Jamestown
Branchville
Gibson
Keysville
Barnwell
Devereux
Mitchell
McBean
Snelling
Wrens
St. George
Moncks Corner
Honey H
VOGTLE
Stapleton
Olar
St. Clair
Kline
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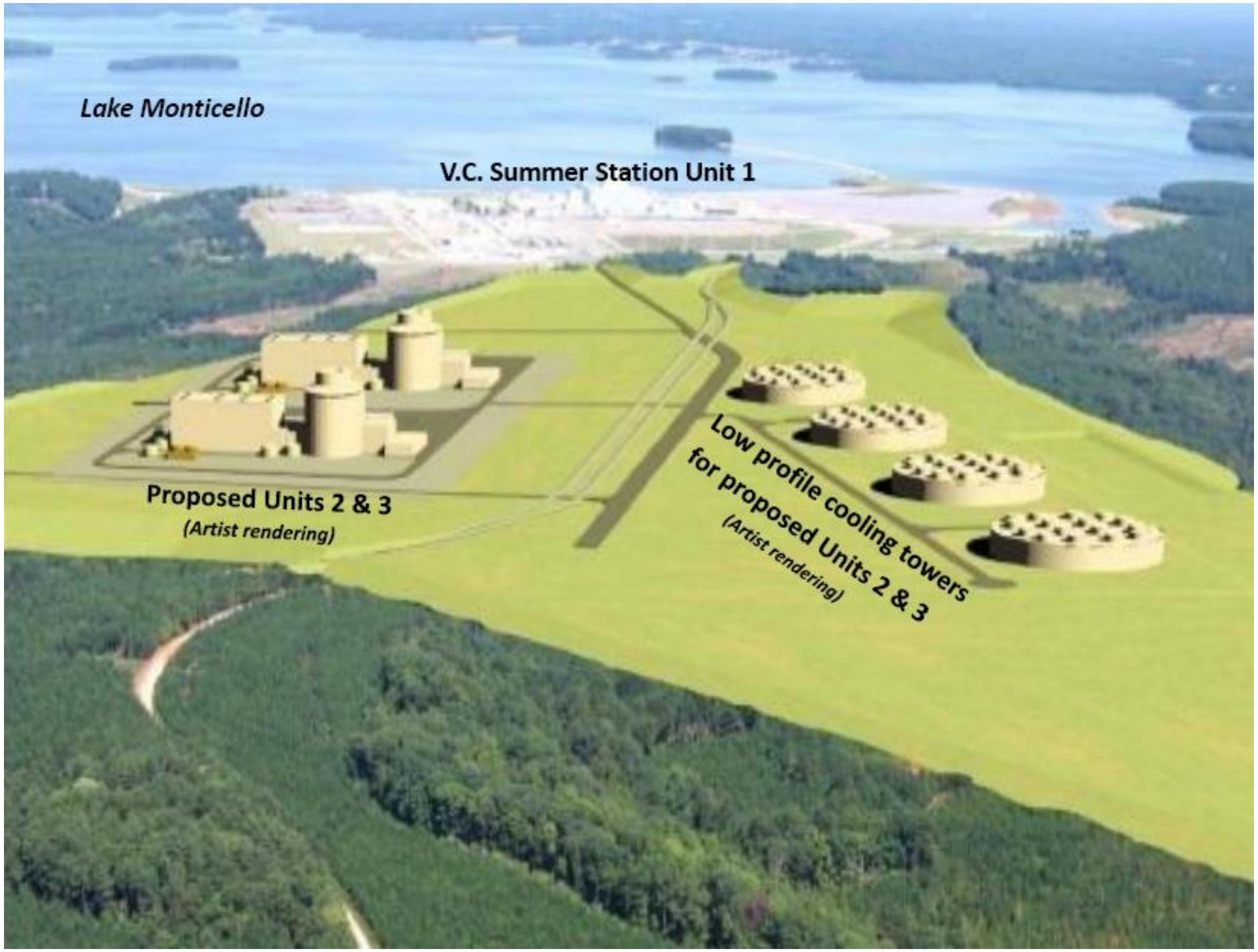
VCSNS Units 2 and 3
AP1000



Departures

- 2 Standard
  - Section numbering
  - Testing of the voltage regulating transformer
- 3 VCSNS site specific
  - Section numbering
  - Technical Support Center/Operational Support Center relocation
  - Wet bulb temperature

Exemptions

- 2 Standard
  - Section numbering
  - 10 CFR 70
- 1 Site Specific
  - Wet bulb temperature DCD siting requirement

Project Overview

- Co-owned with South Carolina Public Service Authority (Santee Cooper)
- EPC with Consortium – Westinghouse Electric Company and Shaw Group
- Other Technical Support

Site Characteristics

- Typical southeastern climatology
- Wind and tornado conditions bounded by DCD wind and missile design requirements
- No flooding issues
- Consistent with DCD requirements, VCSNS is characterized as a hard rock site

Regional Climatology

- The general climate in the region is characterized by mild, short winters; long periods of mild sunny weather in the autumn; somewhat more windy but mild weather in spring; and long, hot summers.

Meteorological Data

- Initially 3 years of data obtained from VCSNS Unit 1 Metrological Towers
- Subsequently data from newly constructed Units 2 and 3 Metrological Tower was utilized to update COLA
- Overall conclusions remained consistent based on new data

Exemption

- Humid conditions resulted in a maximum safety wet bulb (noncoincident) air temperature of 87.3ºF, a value 1.2ºF above the AP1000 DCD value of 86.1ºF
  - The technical basis for the acceptability of the exemption is documented within the FSAR.

Hazard Sources

- VCSNS Unit 1 is located approximately 1 mile to the north
- Railroad line runs along Broad River west of the site
- Gas Pipeline runs from the south to the Parr Facility which is located approximately 1 mile south of the site
- Marine, aeronautical, additional industrial hazards are either N/A or probabilistically insignificant

Comments

VC Summer Units 2 and 3

Chapters 5, 6 and 9

Site –Specific Wet Bulb Temperature Exemption

Amy M. Monroe – Licensing
New Nuclear Deployment
Mark Stella - Westinghouse

Basis for Exemption Request

- NRC RAI on site temperature limits generated during COLA review
- 100-year ambient wet bulb return temperature for site determined to exceed DCD maximum safety wet bulb limit
- Several areas potentially affected by the higher wet bulb temperature at the site

Wet-Bulb Temperature Exemption

- Site-specific maximum safety non-coincident wet-bulb temperature was determined to be 87.3ºF (1.2ºF above the AP1000 DCD Tier 1, Chapter 5, Table 5.0-1 value) based on the 100 year return value.

Evaluation of Impacts

- Evaluated AP1000 systems to determine those affected by change in maximum safety wet bulb temperature
- Assessed performance of systems and components affected by quantitative evaluations and calculations
- Performance of systems still acceptable with increased wet bulb temperature

AP1000 DCD Areas Potentially Affected and Outcomes of Assessments

- 6.2.2 – Passive Containment Cooling System Performance – *negligible pressure increase*
- 5.4.7.1.2.3 – Normal Residual Heat Removal System – In-Containment Refueling Water Storage Tank temperature control – *minor increase in IRWST fluid temperature; remains well below saturation temperature*

AP1000 DCD Areas Potentially Affected and Outcomes of Assessments

- 9.2.2.1.2.1 – Component Cooling System – Normal Operation temperature limit – *maximum CCS temperature remains below limiting temperature for acceptable RCP cooling (100ºF)*
- 9.1.3.1.3.1 – Spent Fuel Pool Cooling –Partial Core shuffle (Normal refueling pool temperature control) – *SFS pool temperature remains below 120 ^{o}F*

AP1000 DCD Areas Potentially Affected (continued)

- 9.2.7.2.4 – Central Chilled Water System – Normal Operation - *effect of increased wet bulb temperature on MCR cooling, instrument and battery room cooling, and pump room cooling can be accommodated within the available capacity margin of the air-cooled chiller units*

Safety Systems Not Impacted

- Systems affected only by Maximum Safety Dry Bulb Temperature
- Systems whose performance is based on the Maximum Normal Non-coincident Wet Bulb Temperature or on the Coincident Maximum Dry Bulb and Wet Bulb Temperature

Comments

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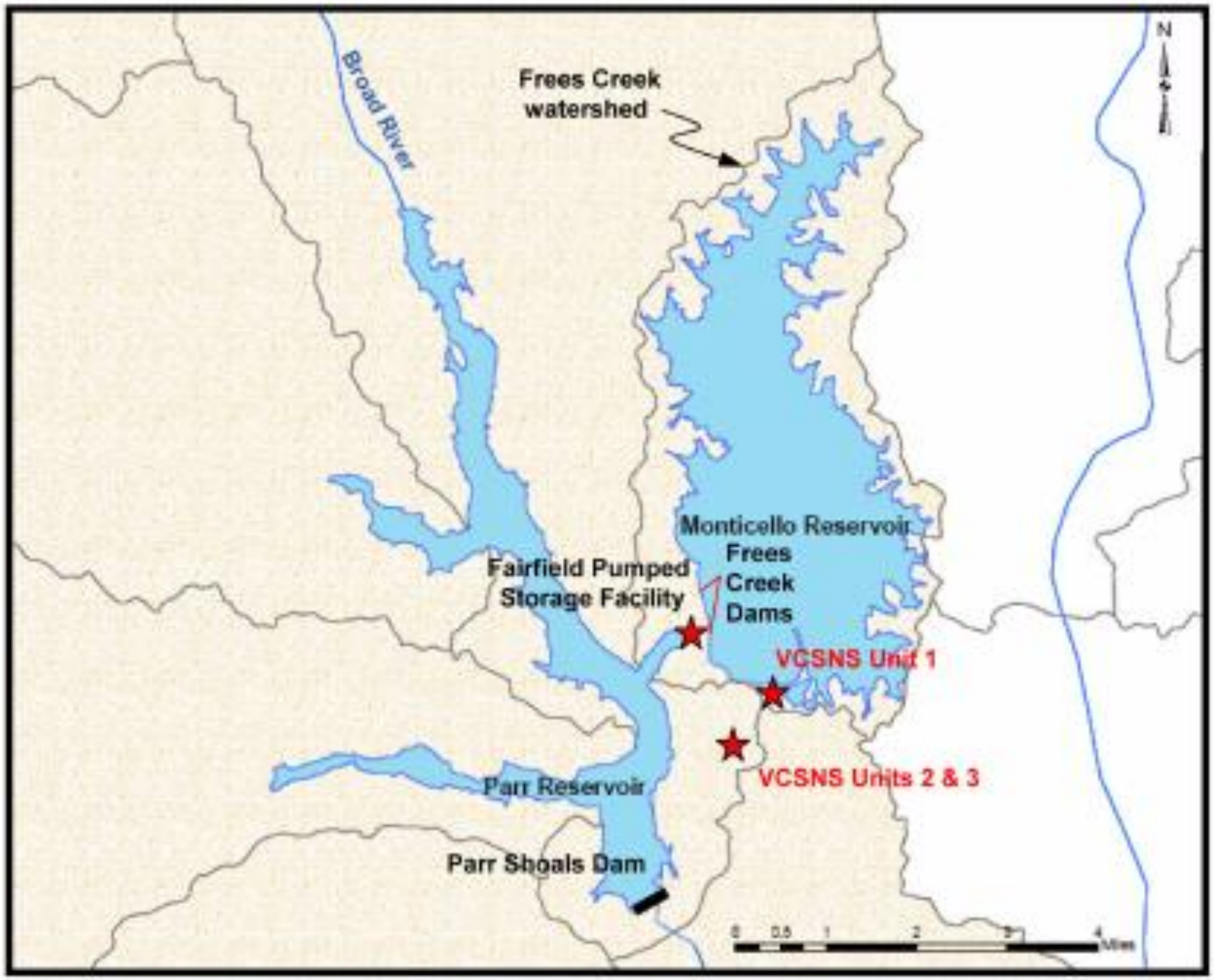
VC Summer Units 2 and 3
FSAR Section 2.4

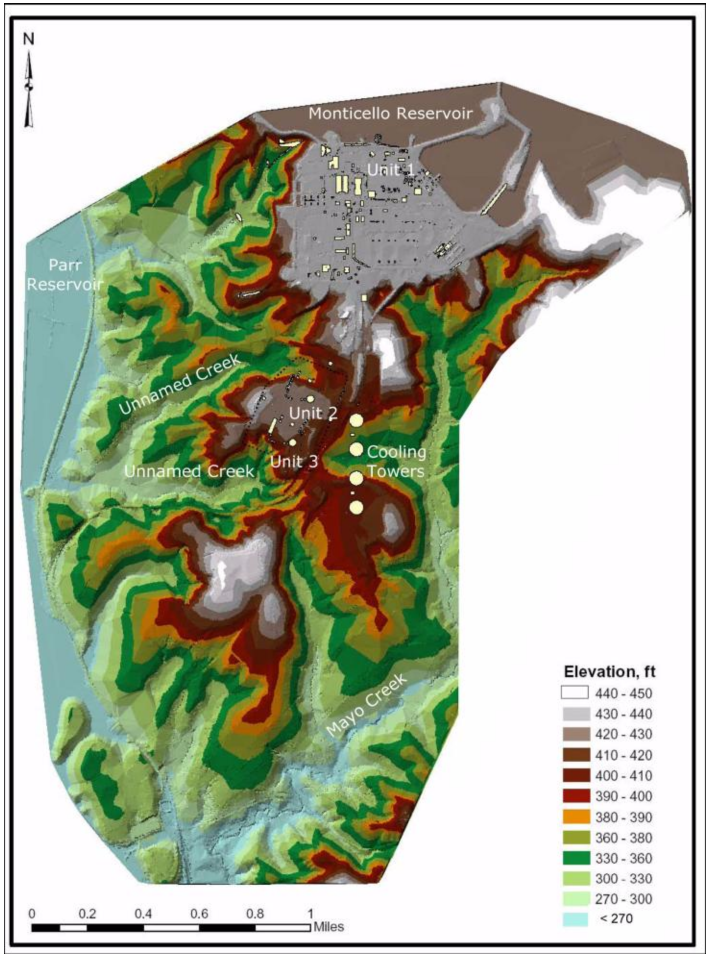
Steve Summer

SCANA Services – Supervisor
Environmental Services

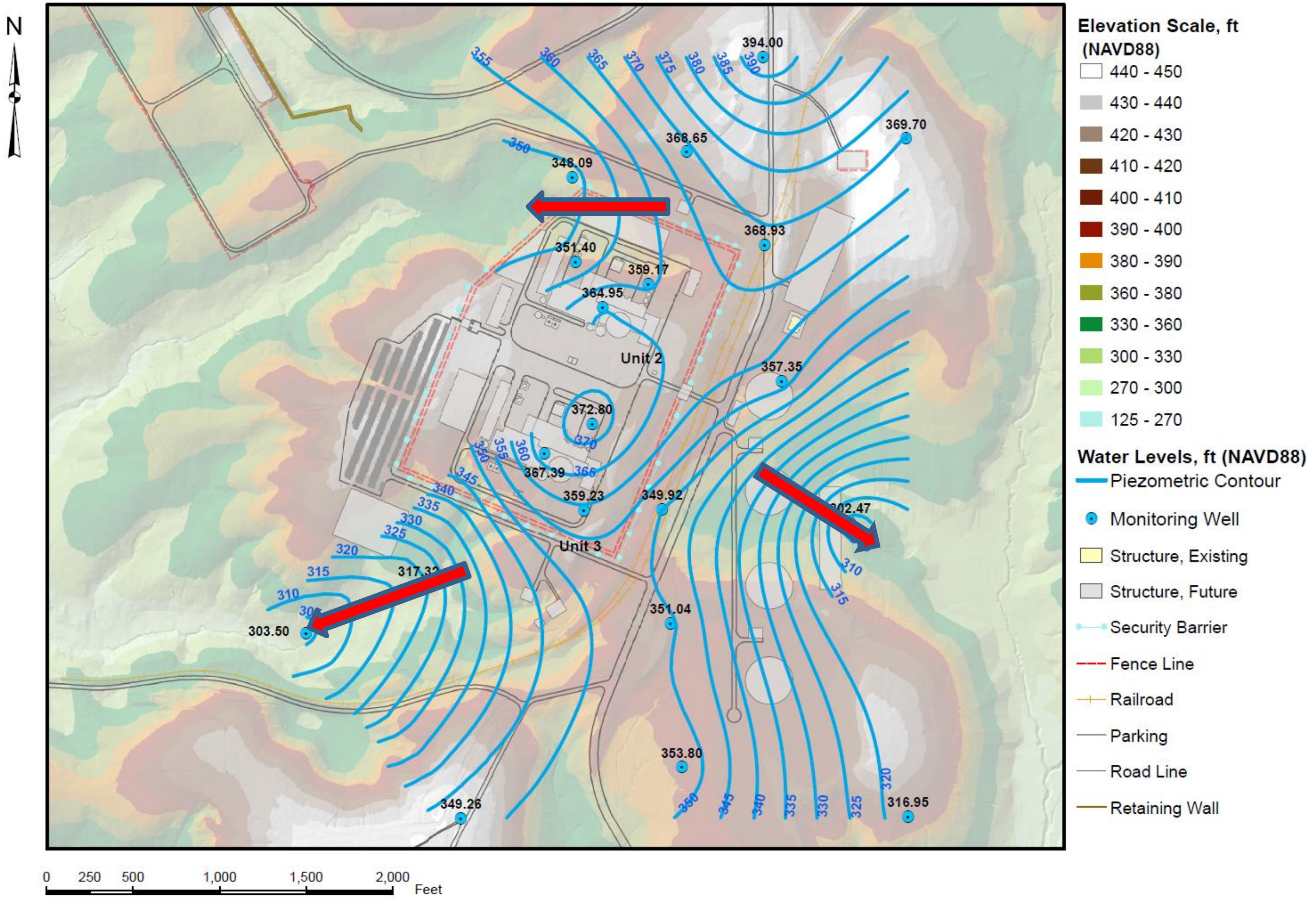
Major Surface Water Features



Site Topography



Groundwater



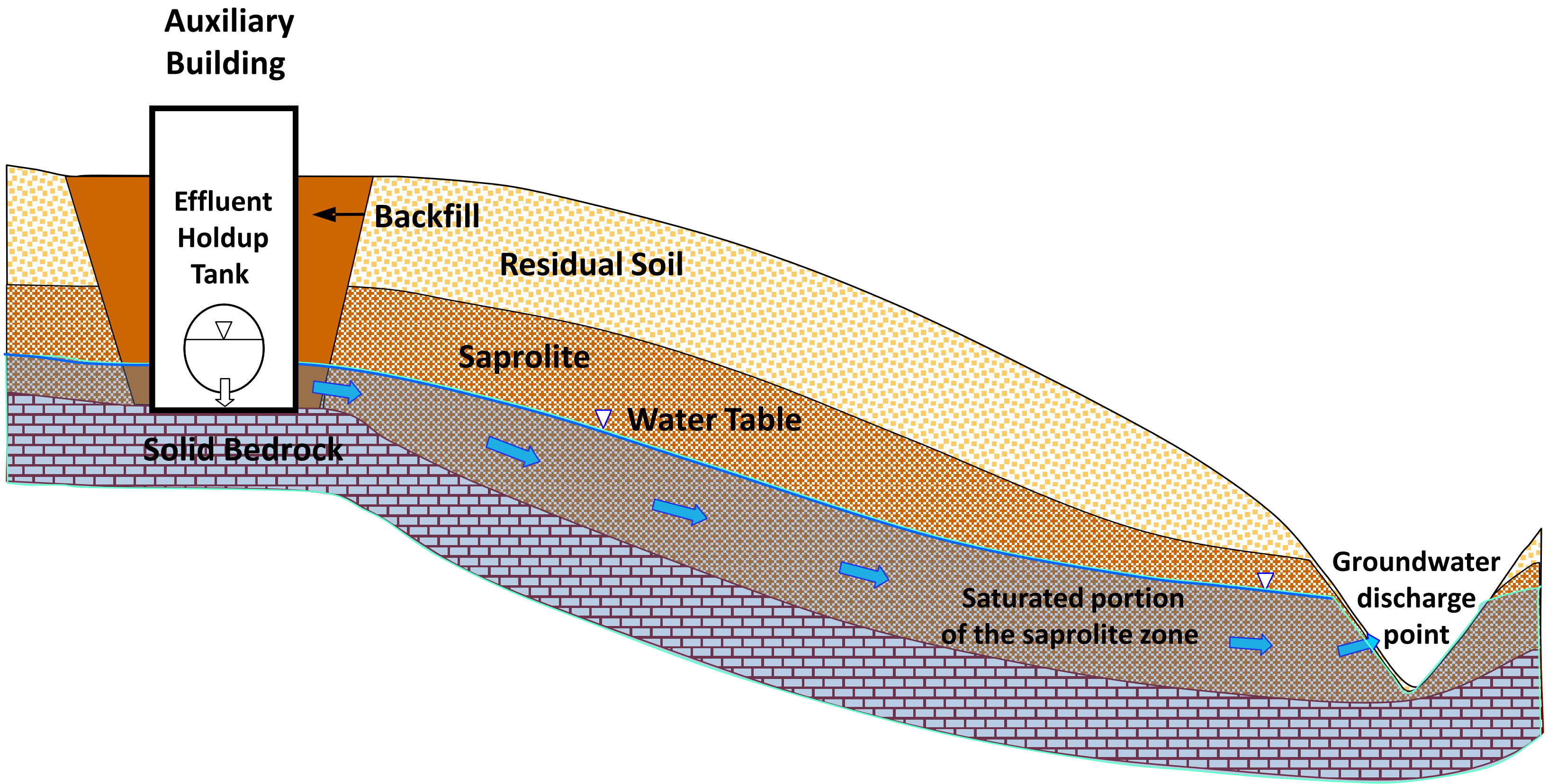
Groundwater

- Design plant grade elevation is 400 feet NAVD88.
- The maximum allowable groundwater level is 398 feet NAVD88 (AP1000 DCD).
- The maximum expected groundwater level is 380 feet NAVD88 (20 feet below the plant grade elevation), well below DCD value.

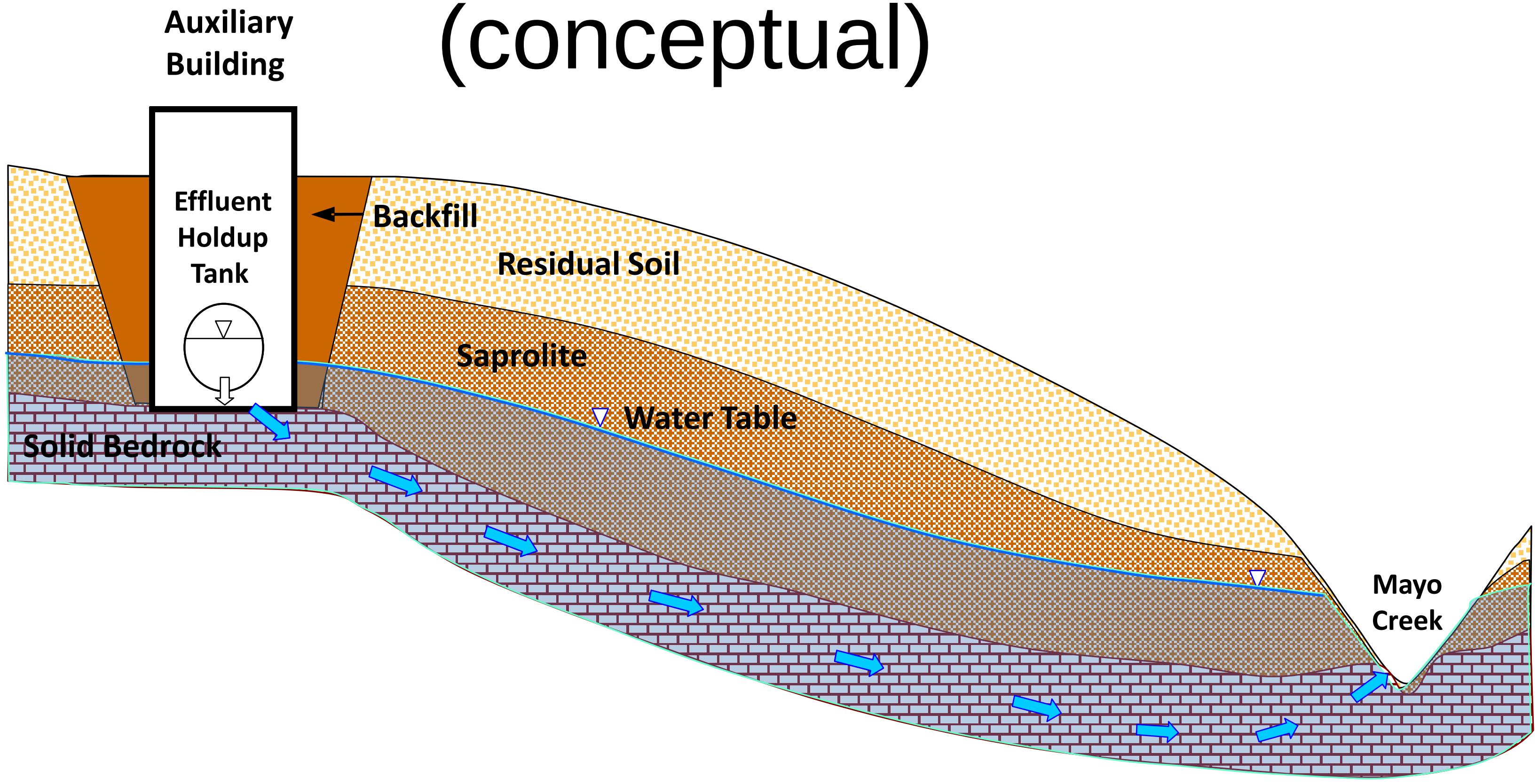
Major Items of Interest

- Accidental Release of Liquid Effluents into Ground and Surface Water
  - Evaluation shows that an accidental liquid release of effluents in groundwater would not exceed 10 CFR Part 20 limits.
  - Three conceptual flow transport models (one saprolite and two bedrock) are presented.

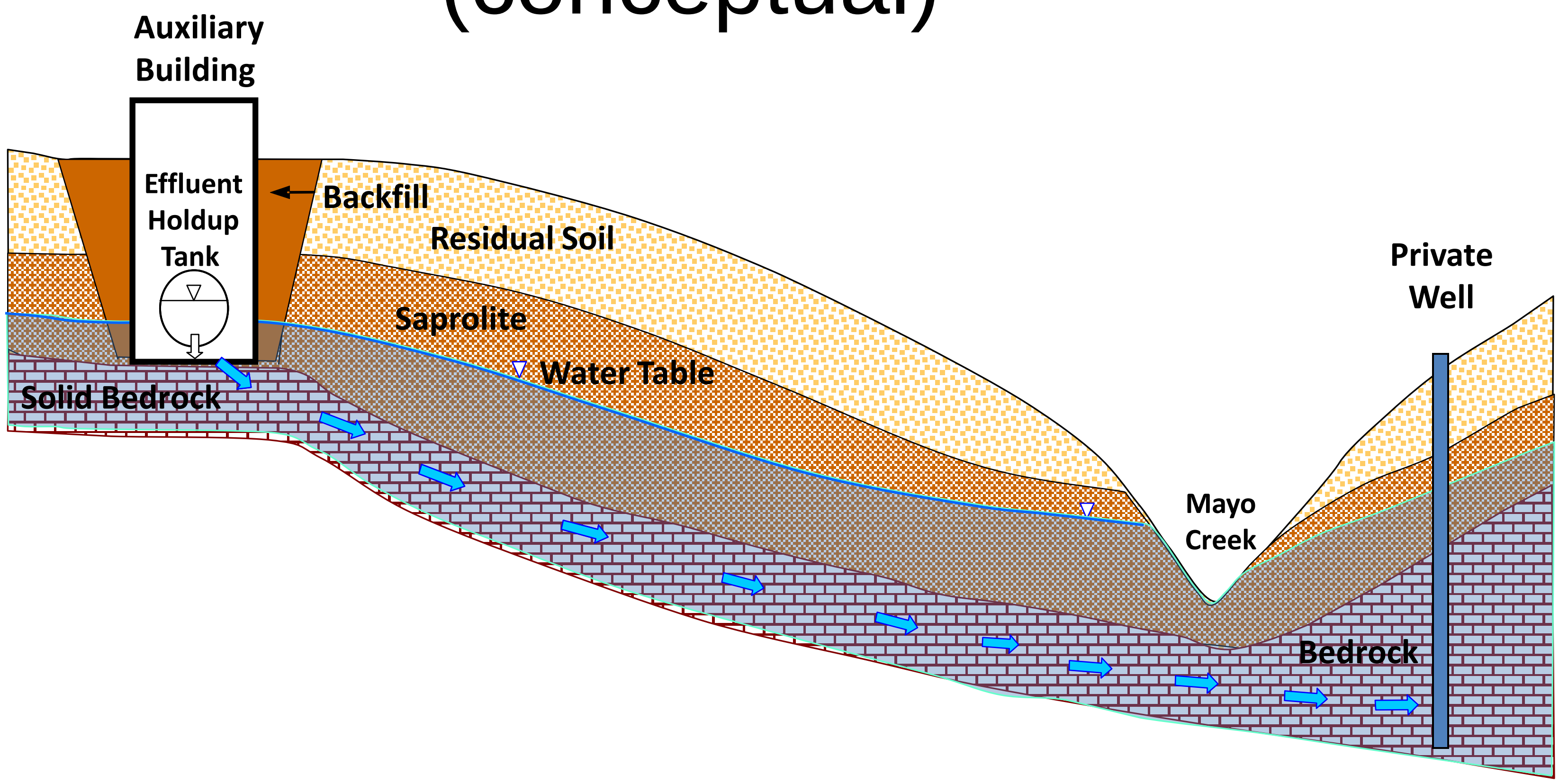
Saprolite Pathway (conceptual)



Bedrock Pathway to Broad River or Mayo Creek (conceptual)



Bedrock Pathway to the site boundary below Mayo Creek (conceptual)



Comments

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UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Presentation to the ACRS Full Committee

V.C. Summer Nuclear Station Units 2 and 3 COL Application Review

Advanced Safety Evaluation Section 2.5

Geology, Seismology, and Geotechnical Engineering

February 10, 2011

Staff Review Team

- Technical Staff
  - Dr. Clifford Munson, Senior Level Advisor and Seismologist
  - Dr. Yong Li, Senior Geophysicist
  - Dr. Gerry L. Stirewalt, Senior Geologist

Overview

- Section 2.5
  - Topics of Interest
    - Action item from July 2010 ACRS meeting to compare EPRI seismic source model used by applicant with most recent USGS model
    - Field observations by NRC geologists on geologic mapping of the Unit 2 excavation for assessing the presence of potential tectonic features (August 2010)

EPRI and USGS Seismic Source Model Comparisons

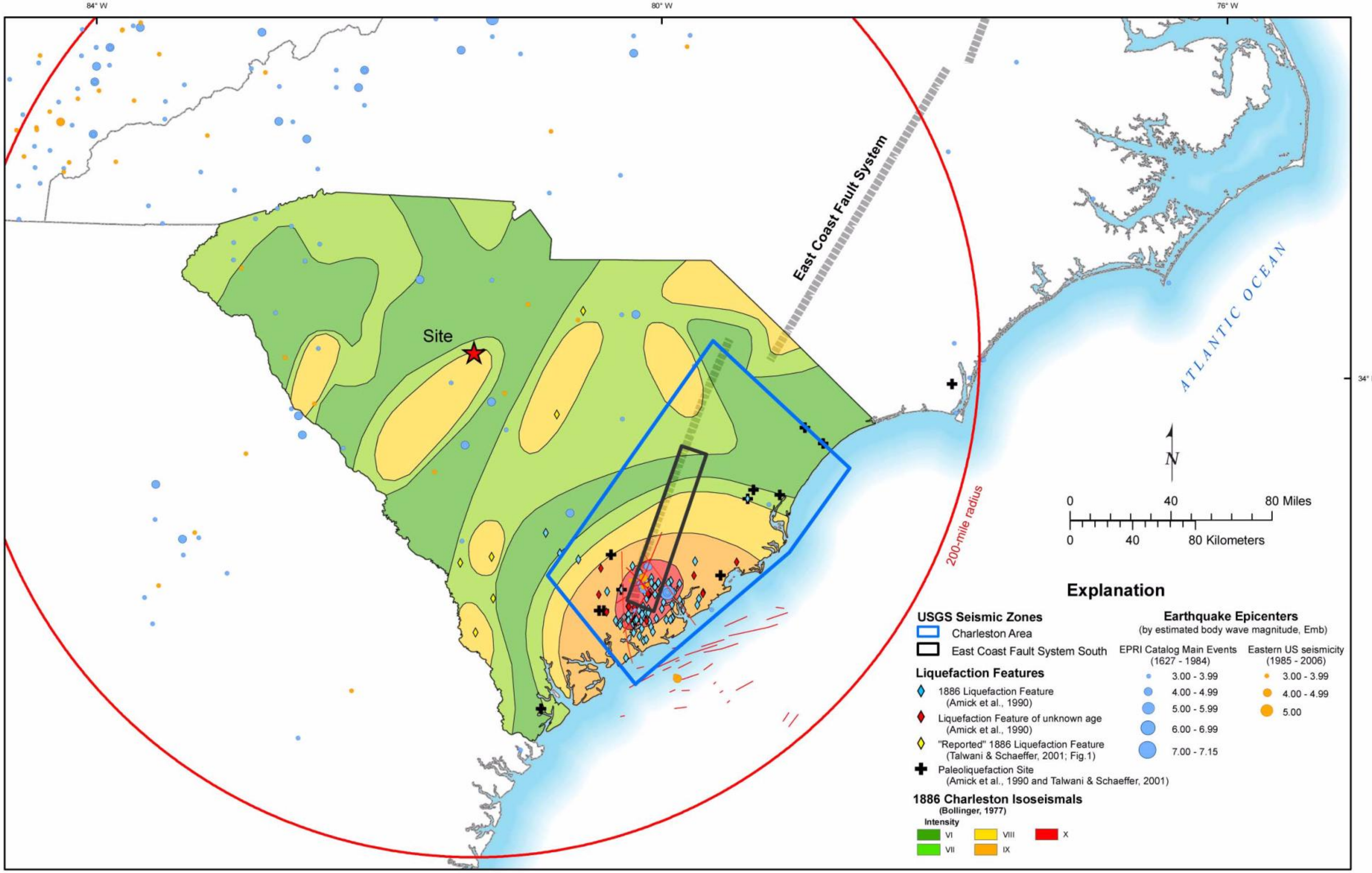
- Applicant compared EPRI seismic source model with USGS (2002) but not USGS (2008) models
- USGS seismic source models used to develop National Seismic Hazard Maps
  - Maps used for Building Codes and National Standards
  - Maps Target 500 yr to 2500 yr ground motions
- NRC Regulatory Guide 1.208:
  - Specifies a minimum ground motion return period of 10,000 years for site SSE
  - Recommends use of EPRI or LLNL seismic hazard models as a starting point to develop site SSE
  - Recommends using USGS source models for comparison (magnitude, earthquake recurrence, etc.)

EPRI and USGS Seismic Source Model Comparisons (cont.)

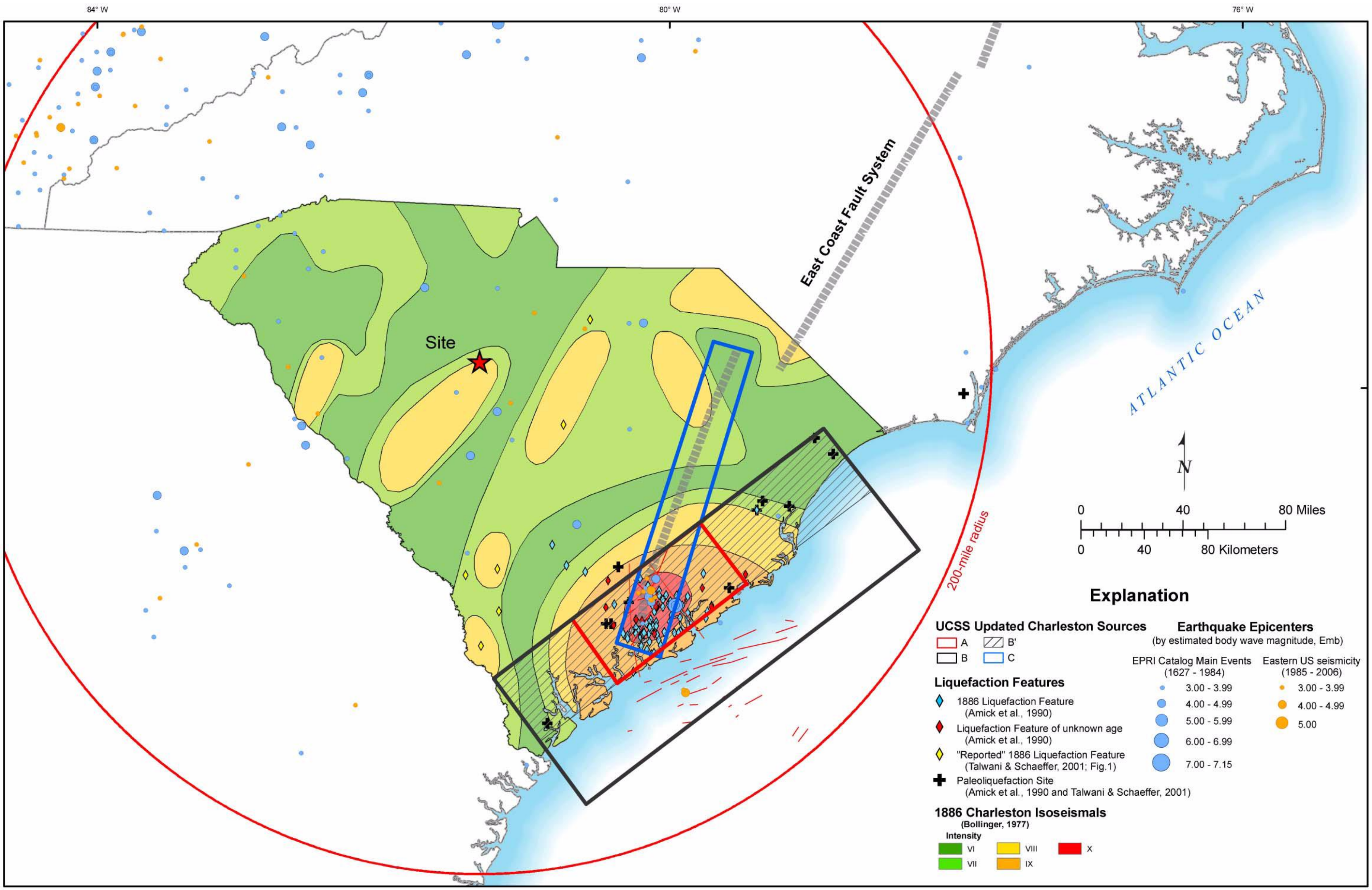
- USGS uses a single M_{max} value of 7.5 for one large extended margin seismic source zone
- EPRI developed many source models which have M_{max} values ranging from about M5 to M7
- EPRI and USGS Charleston seismic source models are similar
  - Maximum Magnitudes: M=7.2 (USGS) vs M=7.1* (EPRI)
  - Recurrence Interval: 550 yrs (USGS) vs 630 yrs* (EPRI)
  - EPRI Source Geometries more detailed than USGS

* average value

USGS Source Model for Charleston



Updated EPRI Source Model for Charleston



USGS (2008) Seismic Source Model Updates

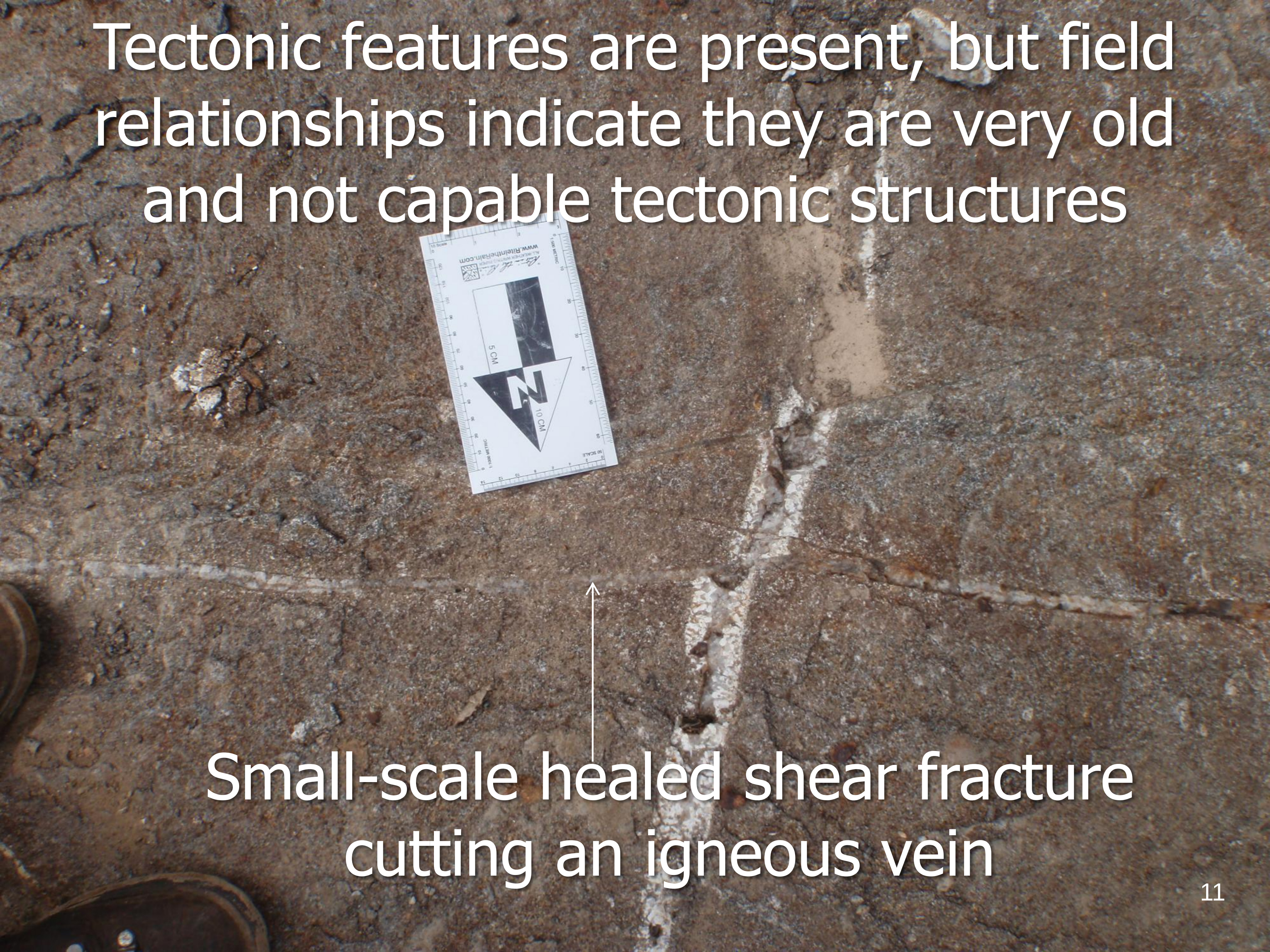
- USGS (2008) updates
  - Maximum magnitude distribution replaced single value (M=7.5 vs M=7.1 to M=7.7)
  - Updated ground motion attenuation models
  - Charleston source model enlarged offshore
- Overall USGS (2008) results 10 to 15% lower than USGS (2002) for CEUS (USGS OFR 2008-1128)
- Staff to update Summer SER to include latest USGS models

2.5.1 Basic Geologic and Seismic Information

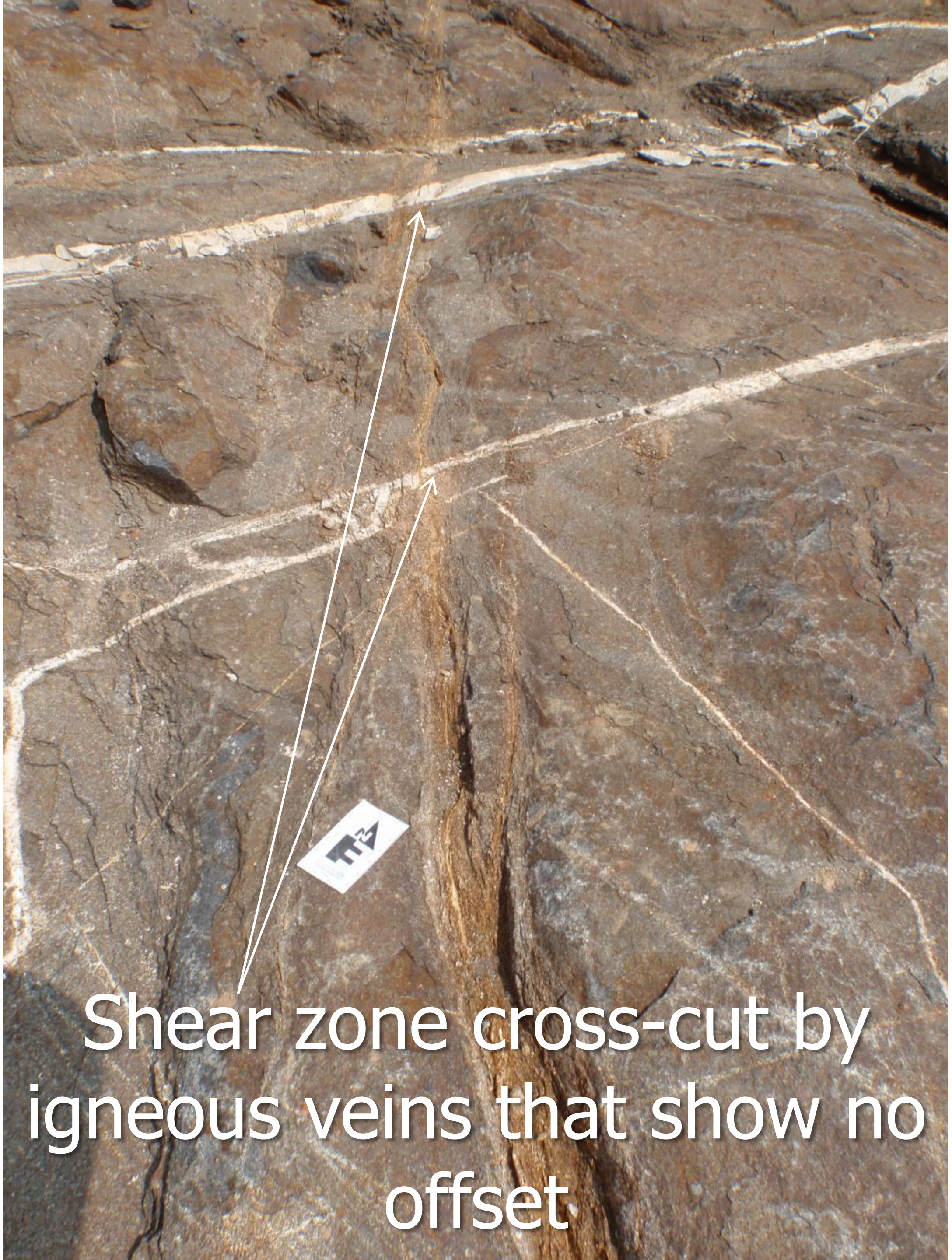
- **Update on observations by NRC geologists on geologic mapping of the Unit 2 excavation to assess the presence of tectonic features**
  - License Condition 2.5.1-1 requires the applicant to perform geologic mapping of excavations for safety-related structures; evaluate geologic features discovered; and notify NRC when excavations are ready for examination.
    - Minor shear zones proven by the applicant to be at least 45 Ma in age were mapped in the Unit 1 excavation, and similar features may occur in the excavations for Units 2 and 3.
  - In August 2010, staff directly examined geologic features being mapped by the applicant in the Unit 2 excavation to ensure that no capable tectonic structures existed therein.

Potential tectonic features were carefully examined by NRC geologists

Tectonic features are present, but field relationships indicate they are very old and not capable tectonic structures



Small-scale healed shear fracture cutting an igneous vein


Shear zone cross-cut by igneous veins that show no offset

2.5.1 Basic Geologic and Seismic Information

- **NRC geologists found that descriptions provided by the applicant in AFSAR Section 2.5 are fully consistent with geologic features observed in the Unit 2 excavation to date.**
  - A follow-up visit to the Unit 2 excavation by NRC geologists and a geotechnical engineer will occur after controlled blasting to reach the foundation level is completed.
  - Similar visits to carefully examine the Unit 3 excavation will also be conducted.

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Presentation to the ACRS Full Committee

Summer Units 2 and 3 COL Application Review

Overview of staff review including wet bulb temperature exemption, toxic gas, and hydrology

February 10, 2011

Overview of Safety Evaluation

- Received Summer COL application – March 27, 2008
- Acceptance Review Completed – July 31, 2008
- Advanced Safety Evaluation Report was issued on a chapter-by-chapter basis – Completed December 10, 2010
- Two ACRS subcommittee meetings (July 21 – 22, 2010 and January 11 – 12, 2011)
- Summer application consists of
  - Material incorporated by reference from the AP1000 DCD
  - Standard content material (applicable to all AP1000 COL applicants
  - Summer plant specific information

Overview of Safety Evaluation

- Summer is a subsequent COL
  - Summer's safety evaluation for standard content references Vogtle's advanced safety evaluation report
  - Standard content evaluation material is double indented and italicized
  - Standard content evaluation contains some language from the Bellefonte safety evaluation report with open items to capture evaluations that were performed when Bellefonte was the reference COL

Summer COL Overview

Part Number	Description	Evaluation
1	General and Administration Information	Section 1.5.1
2	Final Safety analysis Report	In appropriate SER Chapters
3	Environmental Report	Final Environmental Impact statement
4	Technical Specifications	Chapter 16
5	Emergency Plan	Chapter 13
6	Limited Work Authorization	Not applicable
7	Departure Reports	In appropriate SER Chapters
8	Security Plan	Section 13.6
9	Withheld Information	In appropriate SER Chapters
10	Proposed Combined License Conditions (Including ITAAC)	In appropriate SER Chapters
11	Subsurface report detailing the results of geotechnical exploration	Section 2.5
12	Seismic Technical Advisory Group review letter	Section 2.5
13	Quality Assurance Program Description	Chapter 17
14	Mitigative Strategies Document for loss of large areas of the plant due to explosions or fire	Appendix 19.A
15	Cyber Security Plan	Section 13.8
16	Special Nuclear Material Control and Accounting Program Description	Section 1.5.5

Maximum Safety Wet-bulb (noncoincident) Air Temperature Exemption

- COL Revision 2, maximum safety wet-bulb (noncoincident) air temperature increased from 86.1°F to 87.3°F
  - Based on 100 year return temperature (Chapter 2)
  - Maximum coincident wet bulb temperature (86.1°F) and maximum dry bulb temperature (115°F) have not changed from the standard AP1000 values
- Evaluations Affected
  - 2.0, Site characteristics comparison
  - 2.3, Meteorology
  - 5.4.7, Normal residual heat removal system
  - 6.2, Containment systems
  - 6.4, Habitability systems (for main control room)
    - Nuclear island nonradioactive ventilation system (VBS)
    - Low capacity chilled water system (LCCWS)
  - 9.1.3, Spent fuel pool cooling system (SFS) –nonsafety
  - 9.2.2, Component cooling water system (CCS) –RTNSS
  - 9.2.7, Central Chilled Water system (VWS) –nonsafety

Chapter 2 and Section 6.4 – Toxic Gas Review

- Staff evaluated chemical hazards stored or transported within 5 miles of the site
- Staff used ALOHA to determine safe distances
- Distance to the control room at ground level was less than the calculated safe distances for the majority of the chemicals
- Three site-specific chemicals could exceed IDLH at the Control Room Intake:
  - 28% ammonium hydroxide (Unit 1)
  - Cyclohexylamine (Norfolk Southern rail)
  - Chlorodifluoromethane (Norfolk Southern rail)
- Staff conducted an audit of the applicant's calculations and performed confirmatory calculations with HABIT
- Independent of the Summer COL review, staff is pursuing validation of some aspects of the HABIT code.

VCS COL 6.4-1, Concentrations of Site-Specific Chemicals,Staff Confirmative Calculation Results (HABIT)

- Staff analysis confirmed the applicant's licensing basis analysis and staff found the chemicals would not pose a threat to the control room operators.

Chemical	MCR Concentration	IDLH Limit
28% Ammonium hydroxide (VCSNS Unit 1)	68 ppm	300 ppm
Cyclohexylamine (Offsite railcar)	4 ppm	10 ppm
Chlorodifluoromethane (Offsite railcar)	357 ppm	1,200 ppm

FSAR Sections 2.4.4: Major Hydrologic Surface Water Features

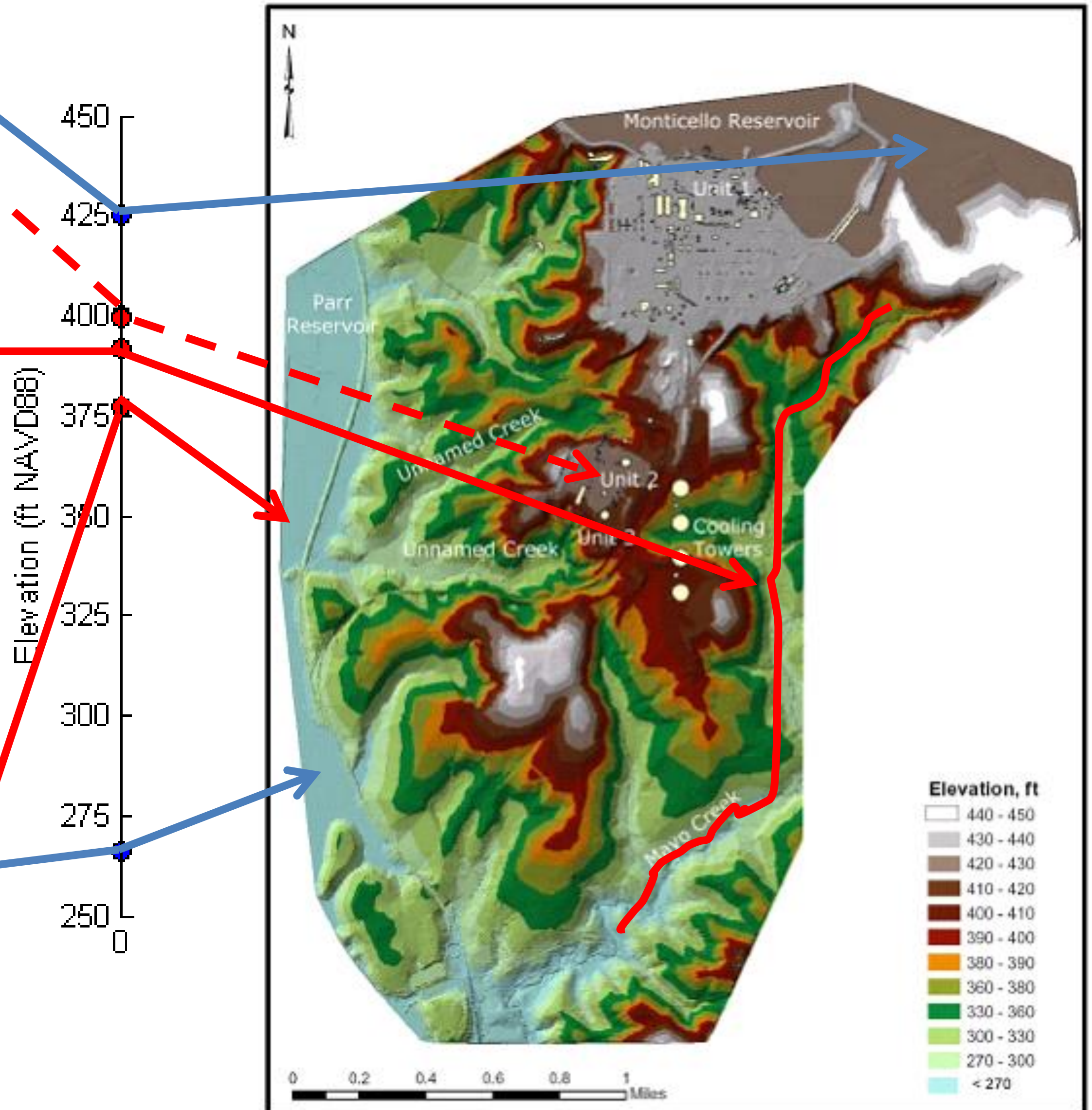
Monticello Reservoir Max Operating Pool Elevation

Site Grade (400) & Local Intense Precipitation Peak Elevation (399.4)

Monticello Reservoir Dam Breach Peak Elevation Near Site

Upstream Broad River Dam Breach Peak Elevation at Parr Shoals

Parr Shoals Max Operating Pool Elelvation



Presentation to the ACRS Full Committee

V. C. Summer Units 2 and 3 Combined License (COL) Application Review

Overview of Site-Specific Information in Summer COL Application

February 10, 2011

Overview of Site-Specific Information in Summer COL application

- In the ACRS July 2010 and January 2011 subcommittee detailed presentations were provided for:
  - All sections in Chapter 2, “Site Characteristics”
  - Section 13.3, “Emergency Planning”
- Because of the lack of site-specific information, no presentations were provided to the ACRS subcommittee for the following chapters
  - Chapter 4, “Reactor”
  - Chapter 7, “Instrumentation and Control”
  - Chapter 14, “Initial Test Program”
- Slides 3 through 22 provide a high-level overview of the site-specific information that is in the remaining chapters
  - Yellow highlight indicates that the ACRS subcommittee was briefed on a topic
- ACRS subcommittee briefed on site-specific differences in loss of large area of the plant due to fire or explosion evaluation in a session that was closed to the public

Overview of Summer COL FSAR Chapter 1

FSAR Section	Summary of Departures/Supplements
1.1 Introduction	Incorporated By Reference (IBR) with standard and site specific supplements
1.2 General Plant Description	IBR with site-specific supplements
1.3 Comparisons with Similar Facility designs	Completely IBR
1.4 Identification of Agents and Contactors	IBR with site-specific supplements
1.5 Requirements for Further Technical Information	Completely IBR
1.6 Material Referenced	IBR with standard and site-specific supplements
1.7 Drawings and Other Detailed Information	IBR with site-specific supplements
1.8 Interface for Standard Designs	IBR with site-specific supplements
1.9 Compliance with Regulatory Criteria	IBR with standard and site-specific supplements
1.10 Nuclear Power Plants to be Operated on Multi-Units Sites	Standard and site-specific supplemental information

Summer FSAR Chapter 3
Design of Structures, Components, Equipment and Systems

FSAR Section	Site-Specific Evaluations
3.1 Conformance With Nuclear Regulatory Commission General Design Criteria	• None*
3.2 Classification of Structures, Components, and Systems	• None*
3.3 Wind and Tornado Loadings	• VCS COL 3.3-1 Wind Velocity Characteristics • VCS COL 3.5-1 Tornado Velocity Characteristics
3.4 Water Level (Flood) Design	• VCS COL 3.4-1 Dewatering System and Water Levels
3.5 Missile Protection	• VCS SUP 3.5-1 Turbine Missile from Unit 1

* This section is entirely IBR or IBR/standard

Summer FSAR Chapter 3
Design of Structures, Components, Equipment and Systems

FSAR Section	Site-Specific Evaluations
3.6 Protection Against the Dynamic Effects Associated With the Postulated Rupture of Piping	• None*
3.7 Seismic Design	• VCS SUP 3.7-3 Design Ground Motion Response Spectra
	• VCS COL 3.7-1 Seismic Analysis of Dams
3.8 Design of Category I Structures	• VCS COL 2.5-17 Waterproofing Material for Category I Structures
3.9 Mechanical Systems and Components	• None*
3.10 Seismic and Dynamic Qualification of Seismic Category I Mechanical and Electrical Equipment	• None*
3.11 Environmental Qualification of Mechanical and Electrical Equipment	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 5
Reactor Coolant System and Connected Systems

FSAR Section	Site-Specific Evaluations
5.2.1.1 Compliance with 10 CFR 50.55a 5.2.1.2 Applicable Code Cases 5.2.1.3 Alternate Classification 5.2.2 Overpressure Protection 5.2.3 Reactor Coolant Pressure Boundary Materials 5.2.4 Inservice Inspection and Testing of Class 1 Components 5.2.5 Detection of Leakage through Reactor Coolant Pressure Boundary 5.3.1 Reactor Vessel Design 5.3.2 Reactor Vessel Materials 5.3.3 Pressure Temperature Limits 5.3.4 Reactor Vessel Integrity 5.3.5 Reactor Vessel Insulation	• None*
5.4 Component and Subsystem Design	• VCS DEP 2.0-2, Maximum Safety Wet Bulb (Noncoincident) Air Temperature

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 6
Engineered Safety Features

FSAR Section	Site-Specific Evaluations
6.1.1 Engineered Safety Materials Features, Metallic Materials	• None *
6.1.2 Engineered Safety Materials Features, Organic Materials	• None *
6.2 Containment Systems	• VCS DEP 2.0-2, Maximum Safety Wet Bulb (Noncoincident) Air Temperature
6.3 Passive Core Cooling System	• None *
6.4 Habitability Systems	• ACRS Action Item #63, Staff confirmatory calculation regarding VCS COL 6.4-1, Concentrations of Site-Specific Chemicals • VCS DEP 2.0-2, Maximum Safety Wet Bulb (Noncoincident) Air Temperature
6.5 Fission Product Removal and Control Systems	• None *
6.6 Inservice Inspection of Class 2, 3, and MC Components	• None *

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 8 Electric Power

FSAR Section	Site-Specific Evaluations
8.1 Introduction	• VCS SUP 8.1-1 Summer Units 2 and 3 connection to the utility grid • VCS SUP 8.1-2 Additional information on regulatory guidelines and standards
8.2 Offsite Power System	• VCS COL 8.2-1 Transmission system description, and its testing and inspection plan • VCS COL 8.2-2 Switchyard description and protection relaying • VCS SUP 8.2-1 FMEA of the switchyard • VCS SUP 8.2-2 Transmission system requirements and studies • VCS SUP 8.2-3 Transmission system planning • VCS SUP 8.2-4 Stability and reliability of the offsite transmission power system • Interface Requirements
	• VCS Conceptual Design Information (CDI) describing the transformer area located next to each unit's turbine building

.

Summer FSAR Chapter 8 Electric Power

FSAR Section	Site-Specific Evaluations
8.3.1 AC Power Systems (Onsite)	• VCS COL 8.3-1 Grounding system and lightning protection • VCS SUP 8.3-1 Site-specific switchyard and power transformer voltage • VCS SUP 8.3-2 EDG rating based on site conditions
8.3.2 DC Power Systems (Onsite)	• None*

*This section is entirely IBR or IBR/Standard

.

Summer FSAR Chapter 9

FSAR Section	Site-Specific Evaluations
9.1.1 New Fuel Storage	• None*
9.1.2 Spent Fuel Storage	• None*
9.1.3 Spent Fuel Pool Cooling System	• VCS DEP 2.0-2, Maximum Safety Wet Bulb (Noncoincident) Air Temperature
9.1.4 Light Load Handling System	• None*
9.1.5 Overhead Heavy Load Handling Systems	• None*
9.2.1 Service Water System	• VCS SUP 9.2-3 provides additional information regarding the service water system cooling tower potential interactions
9.2.2 Component Cooling Water System	• VCS DEP 2.0-2, Maximum Safety Wet Bulb (Noncoincident) Air Temperature
9.2.3 Demineralized Water Treatment System	• None*
9.2.4 Demineralized Water Transfer and Storage System	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 9

FSAR Section	Site-Specific Evaluations
9.2.5 Potable Water System	• VCS COL 9.2-1, Potable water system description outside the power block
9.2.6 Sanitary Drains	• VCS SUP 9.2-1, Sanitary waste system discharge description
9.2.7 Central Chilled Water System	• VCS DEP 2.0-2, Maximum Safety Wet Bulb (Noncoincident) Air Temperature
9.2.8 Turbine Building Closed Cooling Water System (TCS)	• VCS CDI provides the source of cooling water for the TCS heat exchangers
9.2.9 Waste Water System	• VCS COL 9.2-2 provides information on the waste water retention basins and associated discharge piping
9.2.10 Hot Water Heating System	• None*
9.2.11 Raw Water System	• VCS SUP 9.2-2 provides site-specific information related to the raw water system
9.3.1 Compressed and Instrument Air System	• None*
9.3.2 Plant Gas System	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 9

FSAR Section	Site-Specific Evaluations
9.3.3 Primary Sampling System	• None*
9.3.4 Secondary Sampling System	• None*
9.3.5 Equipment and Floor Drainage Systems	• None*
9.3.6 Chemical and Volume Control System	• None*
9.4.1 Nuclear Island Nonradioactive Ventilation System	• VCS COL 9.4-1b provides local toxic gas evaluations
9.4.2 Annex/Auxiliary Buildings Nonradioactive HVAC System	• None*
9.4.6 Containment Recirculation Cooling System	• None*
9.4.7 Containment Air Filtration System	• None*
9.4.8 Radwaste Building HVAC System	• None*
9.4.9 Turbine Building Ventilation System	• None*
9.4.10 Diesel Geneartor Building Heating and Ventilation System	• None*
9.4.11 Health Physics and Hot Machine Shop HVAC System	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 9

FSAR Section	Site-Specific Evaluations
9.5.1 Fire Protection System	• VCS COL 9.5-1, qualification requirements for the fire protection program • VCS COL 9.5-2, site-specific hazards analysis of the yard areas and outlying buildings
9.5.2 Communication System	• VCS COL 9.5-9, offsite interfaces • VCS COL 9.5-10, emergency offsite communications • VCD COL 9.5-11, security communications
9.5.3 Plant Lighting Systems	• None*
9.5.4 Diesel Generator Fuel Oil System	• None*
9.5.5 Standby Diesel Generator Cooling Water System	• None*
9.5.6 Standby Diesel Generator Air System	• None*
9.5.7 Standby Diesel Generator Lubrication System	• None*
9.5.8 Standby Diesel Generator Combustion Air Intake and Exhaust System	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 10
Steam and Power Conversion

FSAR Section	Site-Specific Evaluations
10.1 Summary Description	• None*
10.2 Turbine Generator	• None*
10.3 Main Steam Supply System	• None*
10.4 Other Features of Steam and Power Conversion System	• VCS CDI, relating to COL Section 10.4.2 for the site specific cooling water source for the vacuum pump seal water heat exchangers. • VCS CDI, relating COL Section 10.4.5 for the site specific Circulating Water System design information. • VCS COL 10.4-1 relating to the Circulating Water System design parameters. • VCS COL 10.4-2 relating to Condensate, Feedwater and Auxiliary Steam System Chemistry Control.

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 11

Radioactive Waste Management

FSAR Section	Site-Specific Evaluations
11.1 Source Term	• None*
11.2 Liquid Radioactive Waste Management	• VCS COL 11.2-2, Liquid waste discharge cost-benefit analysis • VCS COL 2.4-5 and VCS 15.7-1, Doses from accidental release from liquid waste tank failure • VCS COL 11.5-3, Compliance with 10 CFR Part 50, Appendix I, Sections II.A and II.D for liquid waste discharges • VCS SUP 11.2-1, Liquid waste discharge pipe
11.3 Gaseous Radioactive Waste Management	• VCS COL 11.3-1, Gaseous waste discharge cost-benefit analysis • VCS COL 11.5-3, Compliance with 10 CFR Part 50, Appendix I, Sections II.B and II.C for gaseous waste discharges
11.4 Solid Radioactive Waste Management	• None*
11.5 Radiation Monitoring	• VCS COL 11.5-2, QA for effluent and environmental monitoring program • VCS COL 11.5.3, Compliance with 10 CFR Part 50, Appendix I

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 12
Radiation Protection

FSAR Section	Site-Specific Evaluations
12.1 Assuring ALARA	• None*
12.2 Radiation Sources	• None*
12.3 Radiation Protection Design Features	• VCS DEP 18.8-1, Relocation of Operations Support Center • VCS SUP 11.2-1, Liquid waste discharge pipe
12.4 Dose Assessment	• VCS SUP12.4-1, Construction worker dose
12.5 Health Physics Facility Design	• VCS DEP 18.8-1, Relocation of Operations Support Center

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 13
Conduct of Operations

FSAR Section	Site-Specific Evaluations
13.1 Organizational Structure of Applicant	• VCS COL 13.1-1 Organization structure • VCS COL 9.5-1 Fire protection • VCS COL 18.6-1 Qualifications of the nuclear plant technical support personnel • VCS COL 18.10-1 Responsibilities of the manager in charge of nuclear training
13.2 Training	• None*
13.3 Emergency Planning	• Presented separately
13.4 Operational Programs	• None*
13.5 Plant Procedures	• VCS SUP 13.5-1 Plant Procedures • VCS SUP 13.5-2 Plant Procedures
13.6 Security	• Not presented to ACRS
13.7 Fitness for Duty	• None*
13.8 Cyber Security	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 15

Accident Analysis

FSAR Section	Site-Specific Evaluations
15.0 Accident Analysis	• None*
15.1 Increase in Heat Removal from Primary System	• None*
15.2 Decrease in Heat Removal by the Secondary System	• None*
15.3 Decrease in Reactor Coolant System Flow Rate	• None*
15.4 Reactivity and Power Distribution Anomalies	• None*
15.5 Increase in Reactor Coolant Inventory	• None*
15.6 Decrease in Reactor Coolant Inventory	• None*
15.7 Radioactive Release from a Subsystem or Component	• VCS COL 15.7-1, Consequence of Liquid Waste Tank Failure
15.8 Anticipated Transients without Scram	• None*
15A Evaluation Models and Parameters for Analysis of Radiological Consequences of Accidents	• **VCS COL 2.3-4, DBA Radiological Consequences Analyses**
15B Removal of Airborne Activity from the Containment Atmosphere Following a LOCA	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 16

Technical Specifications

FSAR Section	Site-Specific Evaluations
16.1 Technical Specifications	• VCS COL 16.1-1 related to technical specifications for use as a guide in development of the plant-specific technical specifications.
16.2 Design Reliability Assurance Program	• None*
16.3 Investment Protection	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 17

Quality Assurance Program

FSAR Section	Site-Specific Evaluations
17.1 Quality Assurance During the Design and Construction Phases	• VCS COL 17.5-1 QAP prior to COL issuance
17.2 Quality Assurance During the Operations Phase	• None*
17.3 Quality Assurance During the Design, Procurement, Fabrication, Inspection, and/or Testing of Nuclear Power Plant Items	• None*
17.4 Design Reliability Assurance Program	• None*
17.5 Quality Assurance Program Description – New License Applicants	• VCS COL 17.5-1 QAP following COL issuance
17.6 Maintenance Rule Program	• None*

*This section is entirely IBR or IBR/Standard

Summer FSAR Chapter 18
Human Factors Engineering (HFE)

FSAR Section	Site-Specific Evaluations
18.1 Overview	• None*
18.2 HFE Program Management	• VCS COL 18.2-2, Location of the Emergency Operations Facility
18.3–18.7	• None*
18.8 Human-System Interface Design	• VCS DEP 18.8-1, Location of the Technical Support Center (TSC) and Operational Support Center (OSC)
18.9–18.14	• None*

* This section is entirely IBR or IBR/standard.

Summer FSAR Chapter 19
ProbabilisticRisk Assessment

FSAR Section	Site-Specific Evaluations
19.1–19.54, 19.56, 19.57	• None*
19.55 Seismic Margins Analysis	• VCS SUP 19.59.10-6 Site-Specific Seismic Margin Analysis
19.58 Winds, Floods, and Other External Events	• VCS SUP 19.58-1 External Event Frequencies
19.59 PRA Results and Insights	• None*

* This section is entirely IBR or IBR/Standard

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

A COMPARISON OF INTEGRATED SAFETY ANALYSIS TO PROBABILISTIC RISK ASSESSMENT

for the
Advisory Committee on Reactor Safeguards

Dennis R. Damon
Senior Advisor for Risk Assessment
Office of Nuclear Material Safety and Safeguards

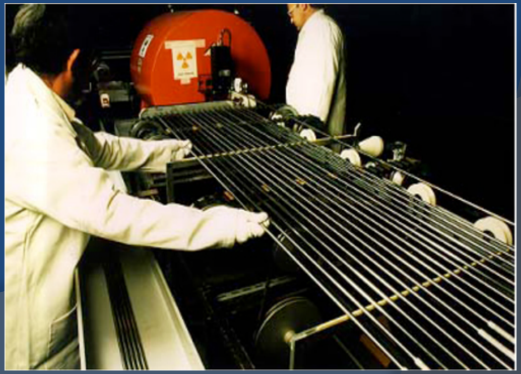
February 10, 2011

Objective

- Present paper comparing Integrated Safety Analysis (ISA) and Probabilistic Risk Assessment (PRA)
- Obtain ACRS Review – ACRS Letter

Key Points

- ISAs are acceptable for establishing the safety basis for fuel facilities
- Quantitative analysis to determine risk significance: a case-by-case basis is efficient



Fuel Facilities Performing ISAs

- Enrichment
  - LES
  - AREVA Eagle Rock*
  - USEC ACP*
  - GE-Hitachi*
- Fuel Fabrication
  - MOX FFF*
  - NFS
  - AREVA-Richland
  - B&W NOG
  - Global Nuclear Fuel
  - Westinghouse
- Conversion/Deconversion
  - Honeywell†
  - International Isotopes*†

* Not yet operational, under review or construction

† Part 40 rulemaking will require ISA for these facilities

ISA – PRA Comparison

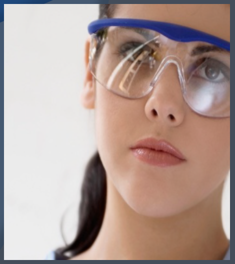
- A comparison and critical evaluation with respect to use…
  1. for safety under 10 CFR 70 Subpart H
  2. for risk significance determination of inspection findings

Contents of Paper

I. Integrated Safety Analysis
II. Probabilistic Risk Assessment
III. Evaluation for safety under 10 CFR 70
IV. Potential risk significance determination for fuel cycle oversight program
V. Evaluation for use in risk significance determination, with example

Sections I ISAs and II PRAs

- Functions of ISAs under Part 70 Safety Program:
  - IDENTIFY hazards, accidents, and items relied on for safety
  - EVALUATE compliance with (likelihood / consequence) performance requirements
- Functions of PRA:
  - QUANTIFY risk metrics as needed to inform regulatory decisions



What do ISAs produce?

- Each differs but:
- List of accident sequences with …
  - Items Relied on for Safety (IROFS)
  - Accidents are assigned to consequence categories (high, intermediate, low)
  - Likelihood of each sequence evaluated: 2 quantitative, 1 qualitative, 7 risk index

Fuel Cycle Facilities

- Many separate process steps (series)
- Multiple process units for each step (parallel)
- Conversion, enrichment, UF_6 -> UO_2 powder, blending, milling, pellets, grinding, pins, assemblies, scrap recovery, absorbers, etc.
- For process upsets or IROFs failures: stop process or render safe
- Control failure may not cause parameter to exceed safety limit
- Key point: a deficiency in one process typically does not affect others; hence risk impact only involves that process (Sec. V)
- Relatively few accident sequences that could affect the public

Why is ISA acceptable for Safety under 10 CFR 70?

- ISA consequence-likelihood evaluations differ from PRA: conservative evaluation establishes adequate safety
- ISA used systematic methods from chemical industry / OSHA Process Hazard Analysis (PHA) experience, including fault/event trees
- Licensee ISA experience and NRC reviews: improved guidance
- ISAs can be quantitative

ISAs and Risk Significance Determination

- Most ISAs have some quantitative information on consequences/likelihood
- BUT: ISAs were not done to produce accurate risk, hence sometimes results would need to be supplemented
- E.g. safety controls not credited, bounding consequences – not average, safety margins not credited
- ISAs are not standardized like SPAR models

V. Evaluation for Risk Significance Determination

- Example of <u>quantitative</u> risk significance
- The example is typical: only a few accident sequences are affected
- Few significant inspection findings/plant-year
- Key point #2: risk-significance evaluations on a case-by-case basis are efficient

ISA-PRA Key Points

- ISAs are adequate for establishing the safety basis for fuel facilities
- Analysis to determine risk significance: a case-by-case basis is efficient

Questions?

Summary

- Present paper comparing ISA and PRA
- Obtain ACRS Review – ACRS Letter
  - ISAs are acceptable for establishing the safety basis for fuel facilities
  - Quantitative analysis to determine risk significance: a case-by-case basis is efficient

Supplementary Slides

- More detailed discussion of ISA-PRA comparison follows.

Commission Direction

- "… a concise paper comparing Integrated Safety Analyses (ISAs) for fuel cycle facilities and Probabilistic Risk Assessments (PRAs) for reactors."
- "The Commission looks forward to the staff's concise comparison of integrated safety analyses and probabilistic risk assessment, along with the accompanying review and letter report of the Advisory Committee on Reactor Safeguards, to better inform proposed enhancements to the oversight process."

Commission Direction

- Prepare a paper comparing ISA for fuel facilities and PRA for reactors
- Develop a set of cornerstones
- Provide assessment and recommendations for next steps

- Provide incentives for licensees to maintain a strong corrective actions program

Why Revise the Fuel Cycle Oversight Process?

- Existing process is effective and ensures safety and security
- But the process could be made more:
  - Focused on risk-significant performance issues
  - Objective (transparent)
  - Consistent (predictable)
- Risk-significance process, plus licensee Corrective Action Programs, should make progress possible

Next Steps

- ACRS review and feedback on ISA/PRA comparison
- Develop cornerstones
- Integrate knowledge gained to provide recommendations for next steps

- Develop criteria for an acceptable CAP and coordinate changes to the Enforcement Policy

Contents of Paper

I. Integrated Safety Analysis
II. Probabilistic Risk Assessment
III. Evaluation for safety under 10 CFR 70
IV. Potential risk significance determination for fuel cycle oversight program
V. Evaluation for use in risk significance determination, with example

I. What is ISA?

- 10 CFR 70: ISA is a systematic analysis to <u>identify</u>:
  - (1) hazards
  - (2) accident sequences
  - (3) consequence and likelihood of each sequence
  - (4) items relied on for safety (IROFS);and
  - (5) <u>evaluate</u> compliance with performance requirements of sec. 70.61.

I. ISA defined in Part 70

- ISA results are used by other requirements in Part 70
- 10 CFR 70.62(d): "..management measures shall ensure that…IROFS…are available and reliable to perform their function when needed to comply with the performance requirements of 70.61 of this part."

I. What is ISA?

- ISA was based on chemical industry PHA.
- Differences from chemical PHA:
  - Integrated analysis of radiation, nuclear criticality, and chemical hazards
  - Evaluation of compliance with consequence – likelihood “performance requirements” of 70.61

I. ISA Performance Requirements

- High consequence accident sequence must be "highly unlikely"
  - Worker high consequences =
    (1) 100 rem or more (criticality or rad)
    (2) Chemical – 'endanger the life'

  - Public (outside "controlled area") high consequences =
    (1) 25 rem or more
    (2) ≥30 mg soluble U intake
    (3) Irreversible chemical injury

I. Performance Requirements

- Intermediate consequence accident sequence must be “unlikely”

  Worker intermediate consequences:

  (1) 25 rem to 100 rem

  (2) Irreversible chemical injury

  Public intermediate consequences:

  (1) 5 rem to 25 rem

  (2) Chemical transient illness

I. Performance Requirements

- Environment (outside “restricted area”)

  Conc. > 5000 times 10 CFR Part 20, Appendix B, Table 2 values
- Evaluation is of single accident sequences, not the sum to an individual as in PRA
- The structure of the evaluation of performance requirements is dictated by the regulation

I. ISA Guidance

- NUREG-1513, “Integrated Safety Analysis Guidance Document,” May 2001
  - Accident identification methods based on extensive experience with chemical industry / OSHA Process Hazards Analysis
- NUREG-1520, “Standard Review Plan for the Review of a License Application for a Fuel Cycle Facility, Rev. 1”, May 2010

III. Evaluation for Safety under 10 CFR 70

- ISAs identify (hazards, accidents, IROFS)
  - This function is, in principle, the same as PRA
  - But fault/event trees only for complex events
  - Problems are mostly in execution, not methods. (e.g. unanticipated scenarios)
- ISAs evaluate likelihoods and consequences; but not fully quantitative
  - quantitative better in some cases, but generally ISAs are conservative, which is acceptable and efficient.

III. Evaluation of Technical Features

- End states:
  - ISA – high or intermediate consequence sequence,
  - PRA – sum of frequencies
- Completeness: in principle no difference.
- Accident quantification:
  - Most ISAs have some sequence frequency information
  - PRA – quantified sequences
- Human error – Simple error lists, sometimes very conservative.
- Hardware failures – ISA at level of IROFS

III. Evaluation of Technical Features

- System interactions – 70.4 Definitions. ISA: "…An ISA can be performed process by process, but all processes shall be integrated, and process interactions considered."
- Dependencies / common cause: Some ISAs evaluate via checklists. Some use dependency factors for likelihoods. Criticality safety: double contingency standard (ANSI/ANS 8.1)
- Uncertainties: ISAs usually handle with conservative assumptions
- Importance metrics: Not used in the safety program under Subpart H

III. Evaluation for Safety under 10 CFR 70

- ISAs have been developed, updated, reviewed, revised, and improved over an extended time frame
- Methods borrowed from chemical industry
- NRC reviews of ISAs were substantial. A risk-informed selection of process designs were reviewed in detail

III. Evaluation for Safety under 10 CFR 70

- PRA methods have been used in certain areas; and could be applied in others as recommended in NRC guidance.
- Difficulties in doing ISAs: anticipating all credible accidents, large number of processes, errors of commission
- Bottom line evaluation: NRC Staff has approved ISA programs as acceptable for safety

V. Evaluation for Risk Significance

- ISAs were not done to provide a good estimate of risk.
- Most ISAs do have some quantitative risk information, but…
- ISA quantitative results sometimes very conservative
- ISA quantitative evaluations not consistent between different licensees

V. Evaluation for Risk Significance

- Common large conservatisms:
  - Not crediting a safety control (non-IROFS)
  - Worst case dispersion for offsite releases
  - No credit for safety margins
- Other risk quantification gaps:
  - No NRC validated hardware failure data
  - Quantifying human errors of commission
  - Probabilistic chemical consequences
  - Criticality magnitudes

V. Evaluation for Risk Significance

- Factors that aid in quantifying risk significance of fuel cycle inspection findings:
  - Very few significant findings per plant per year
  - Simple designs: few accident sequences are affected by one inspection finding
- Risk significance metric: delta frequency of high consequence event caused by deficiency x duration of deficiency
- Fuel cycle needs multiple metrics: worker/public, high/intermediate, other

V. Example Risk Significance Calculation

- Example Risk Significance Evaluation
  - Typical simplicity: few affected sequences
  - Only need delta risk for these sequences
  - but has none of the quantification difficulties (failure data is provided for all quantities).
- Key point: Quantitative risk significance can often be done for fuel cycle inspection findings on a case-by-case basis. A priori re-evaluation of all sequences by licensees would not be efficient.

V. Example Risk Significance Determination

- Process: geometrically safe tank, containment dike
- Potential accident scenarios:
  - fissile solution leaks or overflows into dike, dike leaks, solution accumulates into critical geometry, criticality accident
  - Two scenarios: 1) leak initiator 2) overflow
- Normal accident frequency = initiator frequencies x dike failure probability

V. Example Risk Significance Determination

- Deficiency: dike found to have been in leaking condition for 4 years
- Frequency of accident during these 4 years had increased to frequency of initiators
- Significance metric = delta frequency x duration of deficiency

ISA – Chemical Industry PHA

- 29 CFR 1910.911 Process safety management of highly hazardous chemicals
- 1910.911(e) Process Hazards Analysis (PHA): what-if, what if-checklist, HAZOP, FMEA, fault trees
- OSHA-NRC Memorandum of Understanding

Fire PRA Impacts to NPFA 805 Transitions

ACRS Committee Meeting

February 10, 2011

Biff Bradley, NEI

reb@nei.org

NEI

NUCLEAR ENERGY INSTITUTE

Industry Introduction

- Industry very supportive of achieving closure of fire protection issues
  - Goal: Achieve stable regulatory state
- Adoption of 50.48(c) is a major undertaking
  - Nearly half of the industry well on their way
- Fire PRA a major element of the transition effort
- These Fire PRAs should be usable for all risk-informed applications

NEI

Realism of Fire PRAs

- NRC PRA Policy Statement calls for realism in PRA
- NEI first identified lack of realism with NUREG CR/6850 (EPRI 1011989) in January 2008
  - Letter to NRC staff outlining specific technical concerns, requesting collaboration on resolution
- FAQ process for Fire PRA
  - Over two years, most topics only partially addressed, but process was slow and ineffective.
  - By late 2009, industry stopped submitting FPRA-related FAQs

NEI

Realism of Fire PRAs (Cont.)

- In December 2009, NEI notified the Commission of industry's continued concerns and initiation of EPRI FPRA Action Matrix
- Industry committed to improving FPRA methods for use in risk-informed decision-making in NFPA-805 and other risk-informed applications

NEI

Industry Feedback

- Industry has provided detailed presentations in two PRASC meetings
- Provided evidence of the issues based on actual PRAs completed and detailed plan for enhancing methods
- PRA results (e.g. high CCDP events, spurious operations) were compared with operating experience

Realism in Fire PRAs

- By their nature, risk-informed applications provide for “changes” from deterministic licensing basis
- Fire protection and NFPA 805 are not unique in this regard
- Other elements of the NRC risk-informed regulatory decision making process (Reg Guide 1.174) were established to provide conservatism as appropriate, and have been effective in application
- Injection of conservatism directly into PRA sets a troubling precedent for risk-informed regulation

Industry Perspective on Path Forward

- Establish an improved process for regulatory interaction on PRA methods
  - NFPA 805 is the first case where NRC approval of all PRA methods has been expected in addition to meeting Regulatory Guide 1.200
  - June 1, 2009 NRC letter to NEI states: "FAQs must give appropriate consideration of the balance between realism and conservatism in the fire PRA...."
  - This is inconsistent with NRC PRA policy statement
- We believe the revised process should focus on realism

NEI

Industry Roadmap

- Use results & insights from industry fire PRAs to identify the important areas where bounding assumptions/simplifications are skewing FPRA results
- Objectives of industry report:
  - Provide objective evidence of conservatism in FPRA results
  - Identify key areas needing additional realism
  - Inform & update the EPRI FPRA Action Matrix
  - Provide a vehicle for discussion

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Roadmap For Attaining Realism In Fire PRAs

Rick Wachowiak, EPRI
Doug True, ERIN Engineering & Research

ACRS
February 10, 2011

Computation of Fire CDF

- In the simplest form, the risk from an individual fire scenario is a function of:
  - The frequency of the fire event (Ffire)
  - The fire severity characteristics as a function of time (S(t))
  - The probability of suppressing the fire event as a function of time (NSP(t))
  - The conditional core damage probability given the damage caused by the postulated fire (CCDPdamage)

$$\text{Scenario CDF} = f\left(F_{fire}, S(t)_{fire}, NSP(t), CCDP_{damage}\right)$$

Computation of Fire CDF (Cont.)

$$\text{Scenario CDF} = f(F_{fire}, S(t)_{fire}, NSP(t), CCDP_{damage})$$

- Conservatisms exist in each of these components
  - Some fire frequencies overstated
  - Fire severities overstated
  - Suppression under-credited
  - Resulting CCDPs overstated
- No single factor causing the unrealistic results
- Results are very scenario specific, i.e., plant, location, ignition source

Conformance with Operating Experience: Spurious Operations

- Addressing spurious operations is an important element of a comprehensive FPRA
  - Essential part of 50.48(c)
- Operating experience has not indicated significant spurious operations have occurred in real fire events (except Browns Ferry)
- Investigation of FPRA results shows over-prediction of spurious operations
- Sampling of PRAs investigated to compute the predicted frequency of one or more spurious operations

Conformance with Operating Experience: Spurious Operations

- The FPRA model scenarios include spurious operations (SOs) caused by assumed fires
- Fire scenario damage "vectors" identify those with one or more SOs
- Plant-wide SO frequency (one or more SOs):

$$\Sigma \text{ Frequency of Scenarios involving one or more SOs}$$

- Results:
  - Plant X: 0.0041/yr
  - Plant Y: 0.0043/yr
- If extrapolated to entire U.S. industry (100 plants):
  - Expect to see a fire involving SO every 2 or 3 years
- No operating experience to support such a rate

Likelihood of spurious operations significantly overstated in FPRAs versus operating experience

Over-Prediction of Fire Risk

- Difficult to use CDF values for comparison with industry performance
- However, it is straightforward to identify scenarios involving a high conditional core damage probability (CCDP) for comparison to industry experience
- CCDPs are routinely assessed by:
  - NRC's Accident Sequence Precursor (ASP) Program
  - Reactor Oversight Process (ROP)
- Approach:
  - Review set of representative FPRAs to identify the frequency of fires involving high CCDPs

Over-Prediction of Fire Risk: Industry Experience with Fire CCDPs (Cont.)

- ASP Program
  - Maintains a list of “significant precursor” events
    - CCDP $\geq$ 1E-3
  - Trends high CCDP events
    - CCDP $\geq$ 1E-4
- “Significant precursor” events are relatively rare in recent operating experience:
  - No “significant precursor” events have occurred in the industry since 2002
- Of the 34 “significant precursor” events, only one involves a fire (1975 Browns Ferry)

FPRA Model Prediction of High CCDP Damage Conditions

FPRA Model	Predicted Frequency of "Significant Precursor" Events (CCDP > 1E-3)	Predicted Frequency of High CCDP Events (CCDP > 1E-4)
Plant A	1.0E-3/yr	1.0E-2/yr
Plant B	9.9E-3/yr	2.0E-2/yr
Plant C	3.3E-3/yr	1.4E-2/yr
Plant D	1.3E-3/yr	3.2E-2/yr
Plant E	4.7E-3/yr	3.2E-2/yr
Range	1.0E-3/yr to 9.9E-3/yr	1.0E-2/yr to 3.2E-2/yr
Industry-wide Recurrence Interval	Every 1 to 10 yrs	1 to 3 per year
Actual Experience	Extremely infrequent. No evidence of such a rate	None from 2001-2009 based on SECY-10-0125

SECY 10-0125 Results for CCDP >1E-4

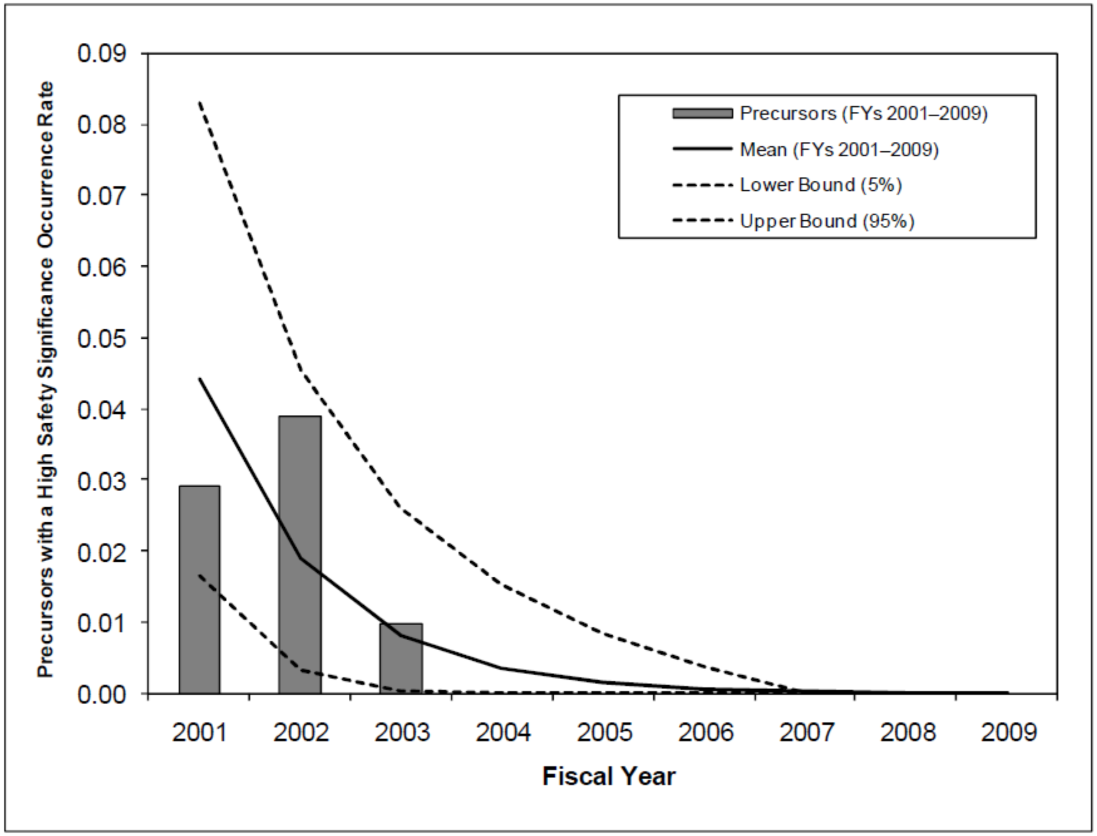

Figure 2. Precursors with High Safety Significance.

- Total of 8 events
- None involved fires
- FPRAs would have predicted ~9 to ~30 fire events, industry-wide for same period

FPRA prediction of high CCDP conditions does not comport with actual operating experience

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ROP Experience

- ROP routinely evaluates CCDP of events and conditions
  - Based on actual plant condition
- ROP Criteria:
  - Green: CDP/CCDP < 1E-6
  - White: CDP/CCDP 1E-6 to 1E-5
  - Yellow: CDP/CCDP 1E-5 to 1E-4
  - Red: CDP/CCDP >1E-4
- To date, no actual fire events have been considered Red or Yellow (CCDP >1E-5)
- Fire PRA models would have predicted many each year across the industry

Over-Prediction of Fire Risk: Conclusions

- Evidence that FPRA methods are significantly over-predicting the frequency of:
  - Spurious Operations
  - High CCDP conditions

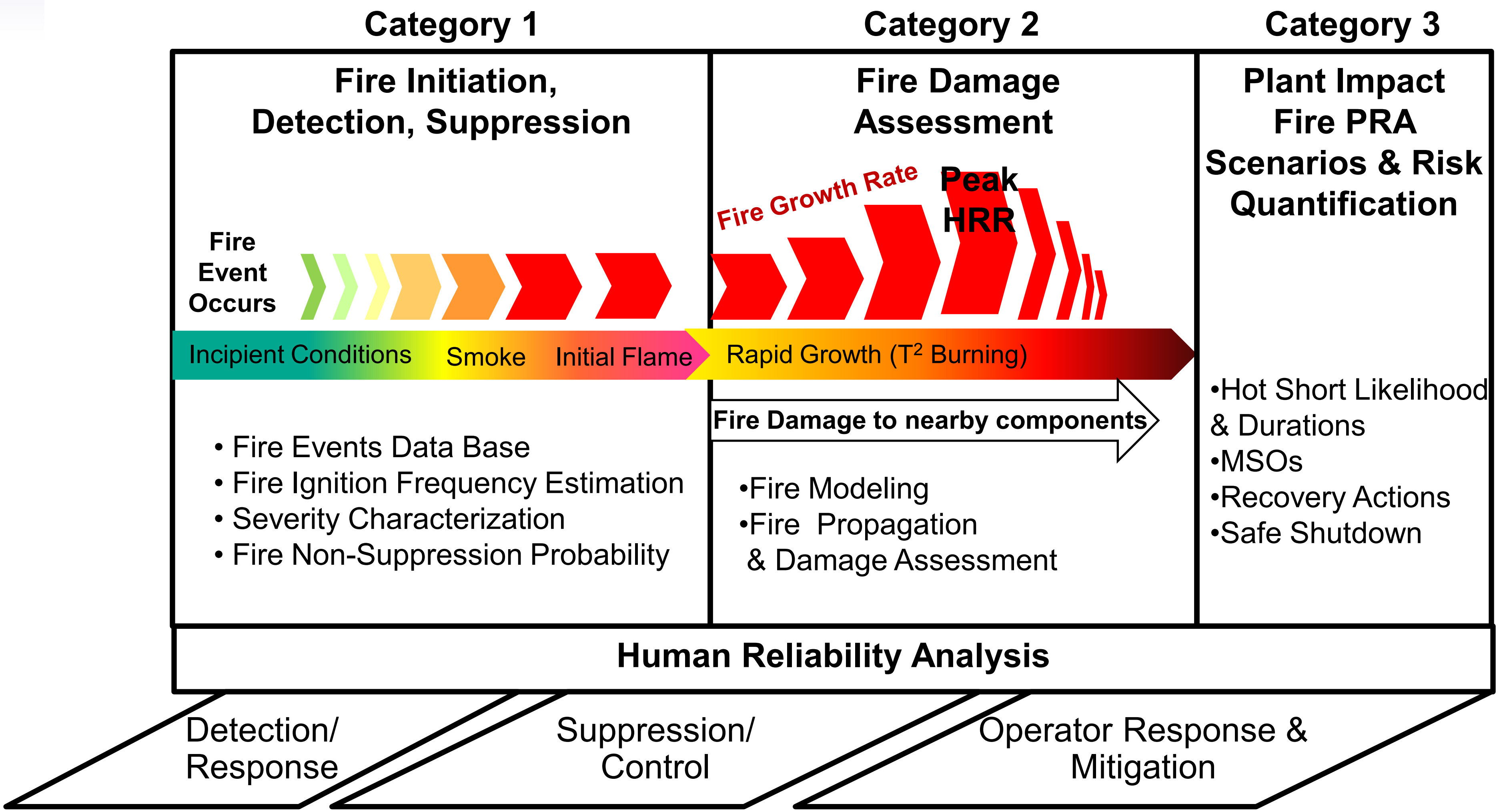
  as compared to actual industry experience
- This directly contributes to the over-prediction of computed Fire CDF

Summary of Roadmap Conclusions

Conclusion	Primary Bases
Fire characterization does not conform with operating experience	• Over-prediction of number of severe fires • Assumed rate of fire growth & severity, e.g., 12 mins in electrical cabinets, oil fire severity • No credit for control of fires
The level of quantified risk is overstated	• FPRAs based on NUREG/CR-6850 predict high frequency of fires with high CCDPs, but NRC's ASP & ROP have not demonstrated this • Predicted frequency of spurious operations not consistent with operating experience
Uneven level of conservatism can mask key risk insights and lead to inappropriate decision-making	• Simplifications result in bounding treatment of "bin" • Overstated fire damage can lead to underestimation of risk increases from plant changes • Assumes plant challenge for all fires, e.g., plant trip • No credit for administrative controls

Many areas of expedited research needed to provide enhanced methods

FPRA Issues Framework



Category 1: Fire Initiation, Detection, Suppression

<u>Areas In Need of Additional Realism</u>:

- Fire Event Data Characterization
  - Fire Events Database
  - Fire Ignition Frequency
- Fire Severity Characterization
  - Incipient Fire Growth in Electrical Cabinets
  - Oil Fire Severity
- Incipient Detection
  - Credit for Incipient Detection
- Fire Suppression & Control
  - Credit for Fire Suppression & Control

Category 2: Fire Damage Assessment

Areas In Need of Additional Realism :

- Fire Growth Assumptions
  - Fire growth and comparison with data
- Peak Heat Release Rates
  - Electrical cabinet peak heat release rate (HRR)
  - Transient Ignition Source HRR
  - Hot Work HRR
  - Other HRRs
- Damage Assessment
  - Switchgear High Energy Arcing Faults
  - Bus Duct High Energy Arcing Faults
  - Damage to Sensitive Electronic Equipment
- Fire Propagation
  - Electrical cabinet propagation
- Fire Modeling
  - Fire Modeling Guidance

Category 3: Plant Impact, Fire PRA Scenarios & Quantification

<u>Areas In Need of Additional Realism</u>:

- Treatment of Hot Shorts
  - AC Circuits Hot Short Probability and Duration
  - DC Circuits Hot Short Probability and Duration
- Human Reliability
  - Human Reliability Methods (HRA) methods and performance shaping factors for fire PRAs
- Modeling of Control Room Fires
  - Control Room Modeling and Treatment in the Fire PRA
- PRA Model Advancement
  - Address unrealistic model simplifications

EPRI Fire PRA Action Plan

- Initiated in late 2009 as a means to clarify and coordinate industry activities related to fire PRA methods
  - Updated as new issues are identified
- Includes activities led by EPRI, NEI, PWROG, BWROG
- Roadmap used to align and help establish priorities
- Reports to NSIAC via an Executive Oversight Group
- Technical tasks coordinated within the NEI FPRATF

EPRI's Immediate-term Focus

- Fire Events Database (through 2009)
  - Pre-2000 data in NUREG/CR-6850 shows a reduction in fire frequencies around 1990 (EPRI-1016735). Updated FEDB will investigate this trend
  - Gather more information about the events to better couple with treatment in FPRA
  - Determine if and when component based frequencies are warranted
  - Begin to address plant-to-plant variability
- Vertical electrical cabinet heat release rate
  - Incorporate more information on actual configuration
- Review of alternative methods that address conservatisms

EPRI ELECTRIC POWER RESEARCH INSTITUTE

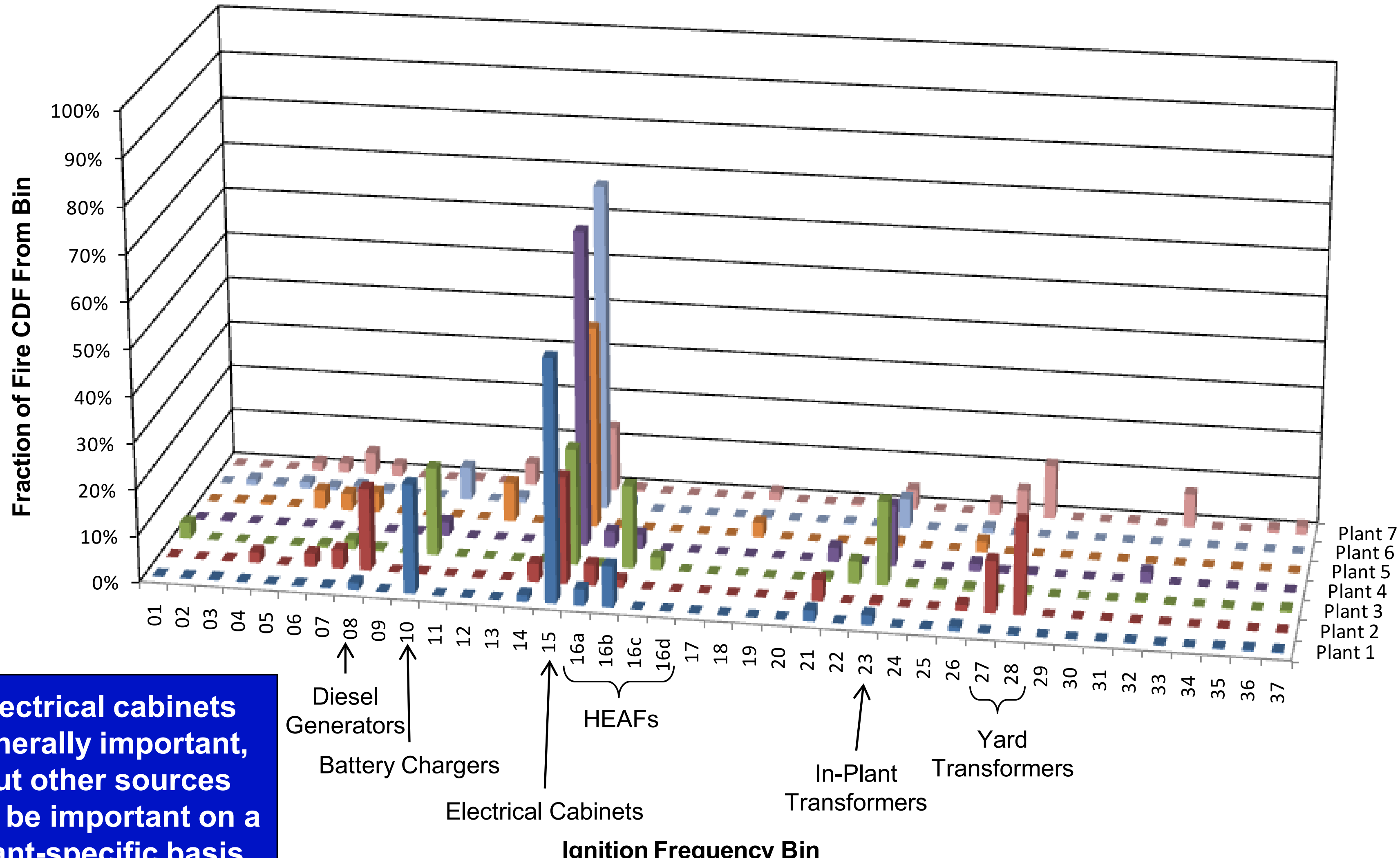
Summary

- Results using current fire PRA methods do not comport with operating experience and make good risk-informed decision-making difficult
- EPRI actively working to provide more realistic methods and data
- Industry requests that the ACRS:
  - Confirm the legitimacy of industry's concern
  - Encourage NRC Staff to embrace need for additional realism
  - Support an extended schedule for NFPA-805 submittals, consistent with NEI's November 15 letter

NEI

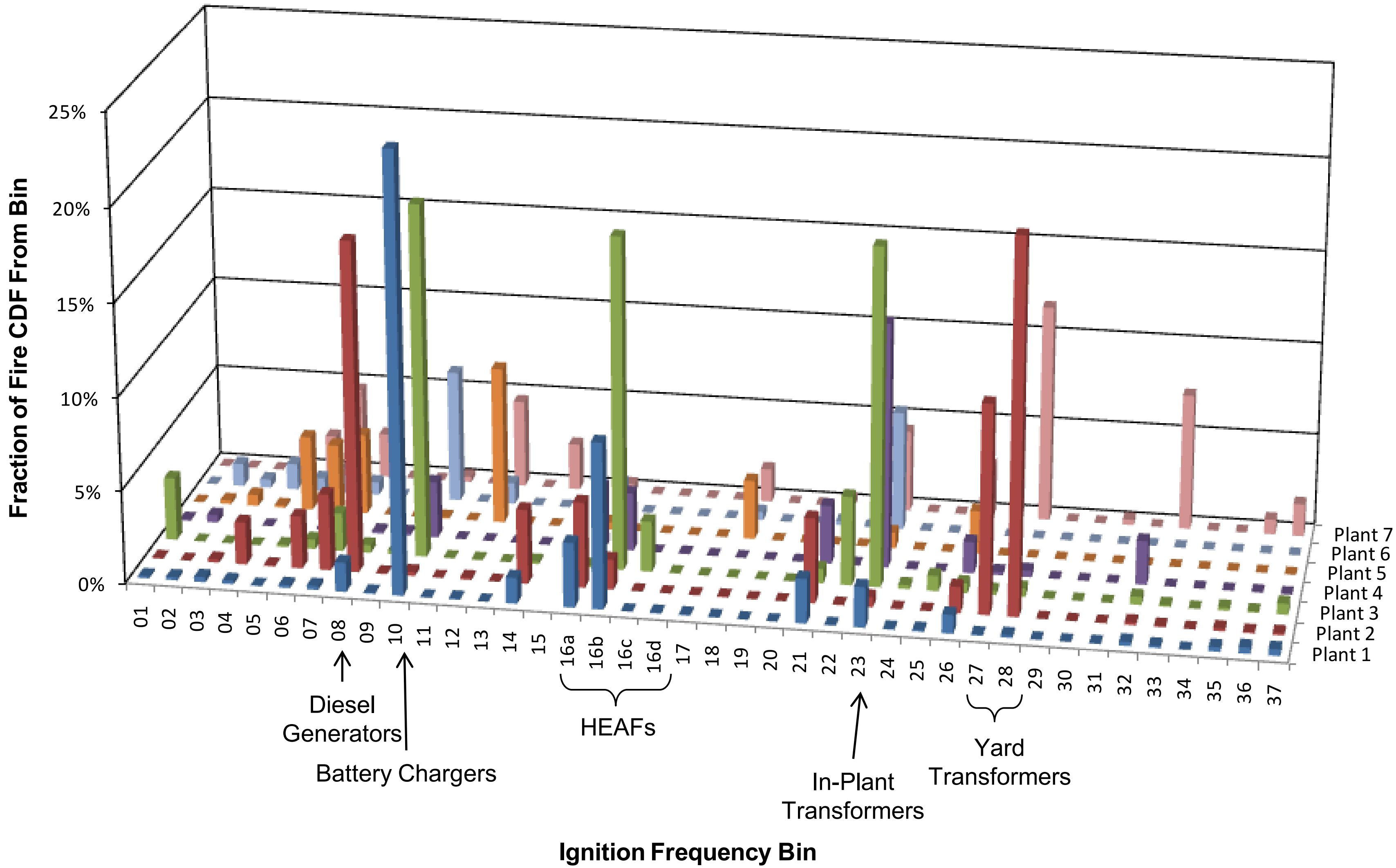
BACKUP SLIDES

Fire CDF Contribution by Ignition Source



Electrical cabinets generally important, but other sources can be important on a plant-specific basis

Fire CDF Contribution by Ignition Source (without Electrical Cabinets)



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Transition to 10 CFR 50.48(c), NFPA 805

Presentation to Full ACRS Committee

February 10, 2011

Sunil D. Weerakkody, Ph. D – Deputy Director – Fire Protection
Division of Risk Assessment – Office of Nuclear Reactor Regulation

Commission SRM – 6/25/2010

"The ACRS should conduct a review and report back to the Commission on the current state of licensee efforts to transition to National Fire Protection Association (NFPA) Standard 805. The review should include methodological and other issues that may be impeding the transition process, lessons learned from the pilot projects and recommendations to address any issues identified. The review should determine whether the level of conservatism of the methodology is appropriate and whether any adjustments should be considered. This review should not influence the staff's actions regarding the pilot projects or the pending license amendment reviews."

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Status

- Pilot activities are complete.
- Infrastructure documents are complete.
- NRR plans to begin receiving and reviewing LARs from non-pilots.
- Fire PRAs have matured sufficiently for the regulator to make regulatory decisions in support of implementing 10 CFR 50.48(c).

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ACRS Briefing on NFPA 805

Alexander Klein – Chief of Fire Protection Branch
Donnie Harrison – Chief of PRA Licensing Branch

Office of Nuclear Reactor Regulation
Division of Risk Assessment

Performance-Based Fire Protection

- NFPA 805 is a national consensus standard that allows licensees to utilize performance-based methods to demonstrate that the installed fire protection systems and features are sufficient to meet specific fire protection and nuclear safety goals, objectives and performance criteria.
- 10 CFR 50.48(c) "National Fire Protection Association Standard NFPA 805"
  - Issued June 16, 2004
  - Incorporates by reference NFPA 805, "Performance-Based Standard for Fire Protection for Light Water Reactor Electric Generating Plants – 2001 Edition" with limited exceptions
  - Performance-based fire protection program is a voluntary alternative to the existing prescriptive, deterministic fire protection regulations.

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History of Performance-Based Fire Protection Guidance

- NEI 04-02, Revision 1 issued September 2005
- RG 1.205 issued May 2006
- NEI 04-02, Revision 2 issued April 2008
- RG 1.205, Revision 1 issued December 2009
- SRP 9.5.1.2 issued December 2009
- Harris NFPA 805 safety evaluation issued 6/28/2010
- Oconee NFPA 805 safety evaluation issued 12/29/2010
- NEI made an updated LAR template available to NFPA 805 Task Force members December 2010

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Fire PRA Methods

- Fire PRA methodology guidance has existed for several decades, involving industry and standards organizations
  - NUREG/CR-2300 (1983)
    - Developed under auspices of ANS and IEEE
  - NUREG/CR-6850 (2006) & Supplement (2010)
    - Collaborative with EPRI
- As guidance documents, they are not regulations or requirements
  - Licensees can deviate from these methods and process allows for methods refinements
  - Methods used must have a sound technical bases

NRC FAQ Process

- As lessons were learned through the pilot process, licensees asked for a semi-formal process to address guidance document changes
- Frequently Asked Question (FAQ) process established to provide interim staff approval of changes to NEI 04-02 guidance
- Process has had substantial impact on transition
  - Facilitated resolution of over 50 significant technical/regulatory issues related to NFPA 805 transition
  - Dispositioned 16 fire PRA related FAQs (e.g. modeling Incipient Fire Detection Systems)

Incorporating Lessons Learned

- PRA-related FAQs incorporated in Supplement to NUREG/CR-6850
- Lessons learned during pilot reviews reflected in:
  - Revision to RG 1.205
  - License amendment request template
  - Safety evaluation template
- Staff developing a paper on additional lessons learned from pilot process

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Reviews of New Methods

- Early industry peer reviews identified issues with new fire PRA methods
  - Without significant technical bases provided, difficult for peer review teams to accept deviations from NUREG/CR-6850
- NEI fire PRA peer review guidance (NEI 07-12) revised to include additional guidance and address previously “unanalyzed methods”
  - Industry formed a task force to review these unanalyzed methods
  - NRC interface established with the task force

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Going Forward

- Fire PRA methods will continue to evolve
  - Similar to all PRA methods, areas of modeling uncertainty or model simplifications usually have some conservatism
  - Method/modeling enhancements are typically driven by risk significant contributors to results and large model uncertainties
    - RCP seal LOCA modeling
- NRC will continue to be actively involved in these activities
  - NRC/RES involved with EPRI under MOU
  - NRC/NRR established interface with industry fire PRA methods task force

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Conclusion

- NRC has reviewed and issued safety evaluations for both pilot applications
- Pilots have indentified practical safety enhancements
- NRC staff believes the fire PRA methods are sufficiently mature to support NFPA 805 applications
- Fire PRA methods will continue to evolve and the NRC staff will continue to work interactively and collaboratively with industry