# Official Transcript of Proceedings

# NUCLEAR REGULATORY COMMISSION

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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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593RD MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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THURSDAY

APRIL 12, 2012

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ROCKVILLE, MARYLAND

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The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., J. Sam Armijo, Chairman, presiding.

COMMITTEE MEMBERS:

J. SAM ARMIJO, Chairman

JOHN W. STETKAR, Vice Chairman

HAROLD B. RAY, Member-at-Large

SAID ABDEL-KHALIK, Member

CHARLES H. BROWN, JR. Member

MICHAEL L. CORRADINI, Member

DANA A. POWERS, Member

JOY REMPE, Member

MICHAEL T. RYAN, Member

STEPHEN P. SCHULTZ, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

GORDON R. SKILLMAN, Member

NRC STAFF PRESENT:

KATHY WEAVER, Designated Federal Official

CHARLES ADER, NRO

SURINDER ARORA, NRO/DNRL

RAJENDER AULUCK, NRR/DLR

ANGELA BUFORD, NRR

MICHAEL CANOVA, NRO/DNRL

ARTHUR CUNANAN, NRR

MARK DELLIGATTI, NRR

DONALD DUBE, NRO/DSRA

HOSSEIN ESMAILI, RES/DSA

RANI FRANOVICH, NRR

RON FRUHM, NRR/DIRS

MELANIE GALLOWAY, NRR

MICHELLE HART, NRO/DSEA

DON HELTON, RES

ALLEN HISER, NRR/DLR

MATTHEW HOMIACK, NRR

SHANLAI LU, NRO/DSRA

GEOFF MILLER, Region IV*

DENNIS MOREY, NRR
ANDREW T. MURPHY, RES/DE
A.J. NOSEK, RES/DSA
BO PHAM, NRR/DLR
GREG PICK, Region IV*
JOSE PIRES, RES/DE
WILLIAM RULAND, NRR
MICHAEL SCOTT, RES
JOHN SEGALA, NRO
RAO TAMMARA, NRO/DSER
KATIE WAGNER, RES
JOHN WISE, NRR

ALSO PRESENT:

DALE ATKINSON, Energy Northwest
BIFF BRADLEY, NEI
MARK FINLEY, UniStar
DON GREGOIRE, Energy Northwest
ROBERT LEYSE*
STEVE RICHTER, Energy Northwest
JOHN RUTKI, UniStar
VI&CENT SOREL, UniStar
SEBASTIEN THOMAS, UniStar
JOHN TWOMEY, Energy Northwest

**By telephone.

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P R O C E E D I N G S

8:30 a.m.

CHAIR ARMIJO: This is the first day of the 593rd meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following: Chapters of the Safety Evaluation Report, SER, with open items, associated with Calvert Cliffs Unit 3 combined license.

Two, spent fuels scoping study. Three, final safety evaluation report associated with the license renewal application of the Columbia Generating Station. Four, Risk-Informed Regulatory Framework for New Reactors, and five, Preparation of ACRS Reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Ms. Kathy Weaver is the designated federal official for the initial portion of the meeting. We've received no written comments from members of the public regarding today's sessions.

Mr. Bob Leyse has requested time to make an oral statement regarding the spent fuels scoping study. There will be a phone bridge line. To preclude interruption of the meeting, the phone will be placed in a listen-in mode during the presentations and committee discussion.

The 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.

At this point, I'll turn it over to Dr. Powers, to lead us through the first session, right?

MEMBER POWERS: Sure.

CHAIR ARMIJO: Okay, great. He's accepted the assignment. That's good.

MEMBER POWERS: A joyful assignment. Joyful because of the people we get to work with on this particular project. As all of you are aware, we are conducting a review both of design certification for the U.S. EPR and for the referenced COLA, which is Calvert Cliffs Unit 3, and that the process that will proceeding the following involves the staff bringing to us their safety evaluation report with open items.

We view those open items are ones that they see, they and the applicants, see a route forward on resolution, and then we're looking at that material. Once we've looked at it moves to Phase 4 where they will actually carry out the resolution of those open items.

So we do this somewhat piecemeal, and

today we're going to do some chapters for the referenced COLA. Those are the Chapter 6 on Engineering Safety Features, Chapter 7, Instrumentation and Controls, Chapter 15, Transient and Accident Analysis, and Chapter 18, Human Factors.

The procedure we're going to follow for this, staff is going to give us some opening comments, and then the applicant will describe how they have been addressed those chapters in the FSAR for the referenced COLA. In many cases, that's going to be, they've incorporated them by reference to the EPR certification.

With that, the intention then is that we will write a letter to the staff, commenting on those chapters for the referenced COLA. So unless there are any comments the Subcommittee or members would like to make at the beginning, I'll turn it over to Surinder Arora from the staff, to give us some opening comments.

MR. ARORA: Thank you, Dr. Powers. Good morning, everyone. My name is Surinder Arora, and I'm the lead project manager for Calvert Cliffs Nuclear Power Plant Unit 3 combined license application renewal project. We are here today, in front of the full Committee, to provide a briefing on four

chapters, as Dr. Powers pointed out.

The chapters are 6, which is Engineer Safety Features, 7, Instrumental and Control, 15, Transient and Accident Analysis and 18, Human Factor Engineerings. These chapters have been previously presented to the ACRS Subcommittee. The full Committee meeting, this full Committee meeting is our second for this project.

Previously, about a year ago, on April 7th, we had briefed the ACRS 582nd full Committee, under the chairmanship of Dr. Said Abdel-Khalik, when we presented nine complete chapters and one partial chapter.

A letter dated April 19th, 2011 was issued by the full Committee chairman, confirming that the Committee had no issues with these chapters that merit further consideration by the Committee.

The staff responded to that letter on May 20th, 2011. Following the order of presentation, as is stated on the meeting agenda, UniStar will be briefing the Committee first. After Unistar's briefing, I will start with an overview of the status of the project, basically letting you know where we are in the review process for Calvert Cliffs' application.

I will also briefly go over the new strategy, how we perform the reviews in the office, which will then be followed by a brief summary of the review results for each chapter on the agenda today.

Once we've done these chapters, I will also touch upon the specific staff efforts, such as an independent evaluations and/or confirmatory analyses that staff performed to establish their conclusions.

If the Committee desires to discuss any specific details of the staff's review, I have a panel of staff members here in this room, who will be supporting me to discuss those details. With that, I would request Mr. Finley, Vice President of UniStar Energy, to introduce his team and start Unistar's presentation. Thank you.

MR. FINLEY: Thank you, Surinder. I am Mark Finley. I'm Senior Vice President of Regulatory Affairs and Engineering for UniStar. I appreciate the opportunity to be here in front of the full Committee of ACRS today to demonstrate we're still actively pursuing the combined license for Calvert Cliffs, and we appreciate the opportunity to move the process forward with the full Committee.

My background, I think most of you have met me here before, but my background is nuclear power

essentially all of my career. I've been with UniStar five years. Before that, Constellation Energy at the Calvert Cliffs site. Before that nuclear Navy and before that Naval Academy in terms of education. I do have a PE license in the state of Maryland.

I'm assisted today by Vincent Sorel, Director of Regulatory Affairs and Sebastien Thomas, our nuclear island engineering manager, and also Mr. John Rutki to help with the slides. Slide 2, I think, covers that introduction. Slide 3, this will be a high level presentation today. We'll focus on, as Surinder said, the four chapters 6, 7, 15 and 18, focus on the departures that we have, which I think you'll see are minor, and we can discuss open items that remain, and they're all on a good track for closure.

Slide 4. Just by way of context, UniStar is responsible for design of the Calvert Cliffs Unit 3 site. The RCOLA is generally authored by AREVA and Bechtel. We don't have AREVA and Bechtel here today, given the high level nature of the presentation, but we can follow up on any questions that might need that level of detail, if necessary.

As we said, the focus will be the four chapters that we mentioned. This will give us 13-1/2

chapters completed in the Phase 2. We do have 5-1/2 remaining. That half a chapter is a partial on Chapter 2. So we do have 5-1/2 chapters remaining for Phase 2, for completing that phase.

Slide 5, just an aerial photograph there of the Calvert Cliffs site. In the upper right-hand corner, that is a computer graphics of the new site. That's not actually -- I have this vision in my mind and it's on paper here, but it's still a dream at this point. But you can see a real picture of the existing site on the shores of the Chesapeake Bay.

There is a map to give you the geographic context on Slide 6. Located, as you see, about 40 miles southeast of Washington, D.C., and tied to the PGM grid to the north through Baltimore, essentially the Waugh Chapel connection, and tied through Chalk Point through the grid in Virginia.

Slide 7, just a list of the chapters again, and Slide 8 the same way. As you can see, we'll discuss some of the departures and then a short summary for each chapter. The next slide, if you would, Slide 9.

So the first chapter is Chapter 6. So this is engineered safety features, and we do have one departure and exemption in this chapter, and it

relates to the toxic gas process.

So at Calvert Cliffs, we have analyzed all of the large quantities of toxic gases, both at the planned new site, Unit 3, and at the existing site, Units 1 and 2, and even in the worse scenario, none of the releases from those volumes of toxic gases reach a toxic level in the control room for the Unit 3 site.

Therefore, we don't need any automatic features to protect against releases of the toxic gases. So this is a departure at this time from the U.S. EPR design certification, as it requires automatic response to release of toxic gas.

So we've done the analysis, but the results are below what would be toxic for the operators and don't require any automatic type actions.

MEMBER SKILLMAN: Mark, let me ask why you wouldn't include that feature, simply because of the protection that it provides for what you don't know?

MR. FINLEY: I think that that's something that we could consider in the detailed design for the site. At this time, we've prepared the COLA without that protection, establishing the requirements. We will consider that in the detailed design phase.

Certainly, we'll have indication for some

of these releases on site. We just don't plan to have automatic features on the ventilation system in the main control room at this point.

MEMBER SKILLMAN: I think of examples where a huge grass fire has put down a blanket of particulate that's similar to fog, and if you're confined to the control room, even though you have excellent filtration, even though your control room and the load might be almost at a hospital ventilation quality, there can still be issues.

It just seems that with the magnitude of this investment, this is, in all candor, a 25 cent feature that protects your operators.

MR. FINLEY: I understand the point. We will still have the opportunity. Certainly, the operators, in the case of a fire, for example, the smoke, the operators would still have the opportunity. Obviously smoke is a visual thing, and they can take manual actions and place the ventilation system on recirculation manually.

I don't think that, you know, a fire or a smoke situation would be a challenge in that regard. So we take your point. We don't feel we need automatic features to address all of the toxic chemicals, but we do have the manual capability to

isolate the control room and protect the operators if we did have such an occurrence.

MEMBER SKILLMAN: Thank you, thank you.

MR. FINLEY: Next slide, John please. Moving quickly through each chapter --

MEMBER POWERS: I would have taken -- when we discussed this in the Subcommittee, in my own mind, I took a different view on that. That view was that if I don't have to introduce complexity, don't introduce complexity. Complexity is a challenge. Just maintaining it, invoking it, and dealing with it when complexity doesn't work.

At least that was my thinking when you presented this material, and we spent a little while, because we were fairly suspect of your argument that there were no inadvertent instances when you could get toxic chemicals, since are right on a waterway and what-not.

So I wondered why you didn't follow my thinking on that.

MR. FINLEY: Well, I do follow your thinking, Dr. Powers. Certainly any additional instrumentation or automatic features in terms of damper operation and so forth, that does add complexity.

So I don't disagree with that. I also don't disagree with the main point that there's not a major expense involved in this, but we feel comfortable that the operation will have adequate protection, given their abilities to take manual action, if there is something beyond design basis, so that should come up.

MEMBER POWERS: Yeah. I mean certainly in the instance of a grass fire, manual actions are going to be odd. I mean grass fires develop somewhat slowly and they're pretty obvious when they occur. The automatic feature is the sudden event, the explosion of a barge or a truck or something like that. It's not common in your particular location.

MR. FINLEY: Well certainly we've analyzed those kinds of things, the traffic, in terms of the largest size of the truck on the nearest road, and then on the Bay traffic with the tankers. We've analyzed all of those occurrences.

CHAIR ARMIJO: Do the other units on the site, the operating units, have those automatic detection and isolation features for the control room?

MR. FINLEY: I'm not aware of any, Mr. Chairman. I'm not aware of any. I can't be certain about that. It's been a while since --

CHAIR ARMIJO: Can you find out? I just want to make sure it's consistent.

MEMBER POWERS: When we discussed it in Subcommittee, the answer was no.

MR. FINLEY: I'm not aware of any. I can confirm that. It's been a while since I've been there.

CHAIR ARMIJO: Okay. You get my points. If there were on the existing units, and you aren't going to put it on the new unit, you'd have inconsistency.

MEMBER POWERS: Again I've, for a variety of reasons, I've become very concerned about the issue of complexity, and even if there were, and I couldn't justify complexity. I would not put complexity in.

CHAIR ARMIJO: I don't disagree. I'm just saying that it looks, sounds, looks like a different --

MEMBER POWERS: And I wonder, it seems to me our ability to analyze complexity, especially as it interfaces with the human being, is still at a relatively primitive state.

One of the things that has been brought to my attention by my esteemed colleague, Mr. Skillman, is the issue of management complexity on three unit

sites, and I have in fact pursued that, to see if we can quantitatively assess the impact of management complexity, and my conclusion is that we cannot.

But it's a very real thing, and so I worry about it. Please continue. My soapbox is going to get weak here, if I keep pounding on it. I'll leave it alone.

MR. FINLEY: Slide 10 just shows a summary for Chapter 6, and again essentially we follow very closely the U.S. EPR FSAR for Chapter 6. We talked about the one departure exemption. There are no ASLB contentions related to this chapter.

There are two SER open items. One relates to the toxic gas response, and one also relates to analysis of an accident at the Unit 1 and 2 site, how that affects the dose at Unit 3. Those are in process. In fact, we've submitted our responses, and those are being analyzed by the staff.

There are three confirmatory items related to Chapter 3, and two of them relate to the codings problem, excuse me, codings program on site, and we've responded to those, and are on a track for resolution there, and one that relates to again codings, but the standards that would be applicable for a codings program on site. But not significant confirmatory

item.

MEMBER POWERS: And I will comment that the Subcommittee had raised an issue, a generic issue that it relates to, but it's not part of this particular licensing activity, on how the staff implements its coding standards, and in particular the synergism between thermal and regulated effects.

MEMBER SKILLMAN: Mark, I would like to ask one more question, and forgive the timing of my question, because I've not been deeply involved until recently. But in your Chapter 6A, in the document that we have for review, you have provided this wording:

"The extra borating system's designed to inject concentrated boron solution into the reactor coolant system at a rate sufficient to maintain some criticality during cool-down from any operational or anticipated transient, and is required to maintain subcriticality for the steam generator 2 rupture event."

That strong comment is somewhat softer in your Chapter 15. But I am curious about the requirement for the extra borating system on steam generator 2 rupture, and how thoroughly the words "is required" have been cemented into your thinking for

this unit.

MR. FINLEY: Okay. So this is a -- it's a generic item. It's essentially we're following AREVA completely in terms of the design certification and the design for responding both to a large break, small break LOCA and a tube rupture.

So this is not a site-specific departure or open item for the Calvert Cliffs site. I do understand that extra borating system is required for accident response. It will be safety-related.

MEMBER SKILLMAN: So this would be a comment that we should probably discuss with the design cert EPR AREVA-type folks.

MR. FINLEY: Yes, yes.

MEMBER SKILLMAN: Thank you, thank you.

MR. FINLEY: Okay. If no other questions on Chapter 6, we can move to Slide 11, and that just shows we're on to Chapter 7, and Chapter 7, of course, is Instrumentation and Controls, and again, we primarily follow the U.S. EPR design certification for Chapter 7, in terms of instrumentation and controls.

We do have some discussion, obviously, for instrumentation and controls on site-specific systems in this chapter, and also some programmatic-type discussion, in terms of programs that we will have at

a future date prior to operating the site.

One of those relates to the post-accident monitoring program, and the variables that we would have in our program at the site for maintaining instrumentation and indication in the control room, and specifically we've supplemented what's in the design certification regarding the UHS cooling tower basin, and regarding meteorological data. These are both site-specific type inputs that we've added to the list of PAM variables.

And Slide 13 just summarizes for chapters --

MEMBER ABDEL-KHALIK: Let me ask you a question about instrumentation. The EPR has a minimum DNBR reactor trip of based on in-core flux measurements and measurements of total core flow pressure and temperature. Can you tell me how that works if you ever have a mixed core, or have you given up the option of ever using a mixed core?

MR. FINLEY: Can you help me define what you mean by "mixed core"?

MEMBER ABDEL-KHALIK: A core that has fuels provided by different vendors.

MR. FINLEY: Okay. So again, this is really a generic question for AREVA, but I can tell

you from our experience in terms of an owner and oversight, we've made sure in our scope documentation for AREVA that we have the capability to have a mixed fuels from different vendors in the core, and the way that would be addressed would be in the safety analysis.

So in the safety analysis, you would set aside whatever margin is needed to address the differences in the fuel and the core, and assure that your set points are adjusted accordingly before you started up with that core. So we've made --

MEMBER ABDEL-KHALIK: But how was that assurance provided to you? Would that ever work if you have a mixed core?

MR. FINLEY: Certainly, it would work. It's no different, from my understanding, no different than the way it works now, in terms of operating plants changing fuel vendors. We get information related to the new fuel. We have information related to the --

MEMBER ABDEL-KHALIK: Not with an automatic calculator based on in-core flux measurements.

MR. FINLEY: I guess I don't understand the difference. In other words, there's still -- in

fact, with the in-core flux measurements, we get more detail than with ex-core instrumentation.

There's certain uncertainties that are calculated, and there's certain margin can be quantified, and those margins have to be demonstrated to bound any new deltas that are introduced by the different fuel tanks.

MEMBER ABDEL-KHALIK: But they're based on the assumption of uniform individual channel flow within the core, and if that's the case, I'm not sure how that would ever work in a mixed core.

MR. FINLEY: Okay. I must confess not being a safety analysis expert, and that really being a question for AREVA. I'll leave that one for them to --

MEMBER ABDEL-KHALIK: But still, I mean I raised the question because, you know, perhaps you've given up the option of ever using a mixed core.

MR. FINLEY: No, I can tell you we haven't, and we in fact have specified in our scope documents that we have the ability for changing the fuel, which means we need to have a mixed core. So we have that expectation, and frankly I don't see why that's not possible.

MEMBER ABDEL-KHALIK: So what you're

suggesting is that we bring that issue up in the design certification, or is that something that we --

MR. FINLEY: I think that is -- certainly, if we can't, we wouldn't go that direction and start-up. It would be more of a business decision, right? We would confirm, prior to loading that fuel, that the safety analysis supports it, or we wouldn't go that direction.

Our intention now is to go that direction, or to have the option to go that direction, and I feel that we have that option. In terms of the safety analysis and how it would address that condition, that's really a question more for AREVA than for us.

MEMBER ABDEL-KHALIK: Mr. Chairman, it's up to you, I guess, to decide how to proceed with this.

MEMBER POWERS: Well, I mean it's correctly stated. It's part of the design certification. I think it's been raised with AREVA.

MEMBER ABDEL-KHALIK: Right, but not with regard to the use of mixed cores.

MEMBER POWERS: Yeah. No, explicitly that question has been raised with AREVA.

MEMBER ABDEL-KHALIK: Right.

MEMBER POWERS: I've taken a note asking

them to address it. They'll be here in May. I mean it's been raised with them at Subcommittee.

I think the answer, at the time they gave it, was very close to what Mark Finley just said, and we asked them for some more information on it. So I guess it will be addressed. I mean it's part of the design, and they are the ones who have to address it.

MR. FINLEY: So in terms of a summary for Chapter 7, Slide 13 again, there are no departures or exemptions, no ASLB contentions. The three open items relate to providing some additional detail to the ultimate heat sink I&C system. We've had RAI from the staff that we are in the process of responding to.

Site-specific PAM variables is also an open item. We have an open item on calorimetric uncertainty, which is just to confirm that when we procure the instruments, that we incorporate uncertainty in those specific instruments that we procure, in the calculation of the calorimetric uncertainty. So --

MEMBER BROWN: When you say uncertainty in the instruments, you really mean the accuracy capability of those instruments in their monitoring?

MR. FINLEY: That's correct. So the accuracy of those instruments and the specific loop

when we design them.

MEMBER BROWN: Okay. I just wanted to make sure I'm shifting between analysis stuff and actual performance characteristics. Thank you.

MR. FINLEY: On slide, back to the general agenda again, Slide 14. So we'll move on to Chapter 15 now. Chapter 15 is the safety analysis chapter. We do have one departure and exemption in this chapter, and it relates to the site-specific chi over q values.

You can see the details here. As it turns out for the Calvert Cliffs site, the zero to two hour chi over q for the low population zone is slightly greater than that which is in the U.S. EPR. U.S. EPR carries a value of 1.75 E to the minus 4, and for Calvert Cliffs, it was calculated as 2.15 E to the minus 4, so about a 25 percent delta there.

We've specifically addressed that through analysis for all of the releases from the Chapter 15 events for the Calvert Cliffs site, using this site-specific chi over q. If you look at the next slide, we show the results for all of the analysis affected by this chi over q, and you can see for the Calvert Cliffs Unit 3 site, we're demonstrating significant margin to the acceptance criterion for each of these

events, even with the site-specific chi over q, which is a bit higher.

That's really the important issue for Chapter 15. We can move to Slide 17.

MEMBER REMPE: Before you leave, in Chapter 15, and I'm not sure if I should ask you or the staff, but you mentioned -- someone has used some shifting, time shifting of the chi over q values apparently, and is that -- could you just clarify what exactly was done?

MR. FINLEY: I'm going to ask you to ask the staff.

MEMBER REMPE: Okay.

MR. FINLEY: I'm not aware of time shifting in chi over q values.

MEMBER REMPE: Okay.

MR. FINLEY: Slide 17, just a summary of Chapter 15. So the one departure and exemption I mentioned. There are no SER open items or confirmatory items, and there are no ASLD contentions for Chapter 15.

And Slide 18, so we'll move on to Chapter 18, which is on Slide 19, and the only real significant item here, and it's not significant from my point of view, is the departure that we've taken

that relates to the human performance monitoring program.

Essentially in Chapter 18, we incorporate by reference what's in the U.S. EPR FSAR. With respect to the human performance monitoring program we -- in our view, we've updated the program to incorporate some additional information available through INPO.

You see this INPO-09-011. It has some additional information about -- let's turn to operator aggregate index, that incorporates -- it's a metric that incorporates main control room deficiencies and operator work-arounds and other quantifiable measures that could affect operations, and it aggregates that into a metric that we've included in our program.

We've emphasized that we're going to use our Corrective Action Program in terms of monitoring issues that relate to human factors, and we won't have a separate HFE tracking program to monitor those kinds of issues. So two, would I say, slight departures from what's in the U.S. EPR FSAR.

MEMBER STETKAR: Mark, do you use that same monitoring process for Units 1 and 2 currently?

MR. FINLEY: I believe that's correct. I'd have to confirm that, not having been at the site

in a while. But I believe they have also updated their program to include the current INPO guidance.

MEMBER STETKAR: Again, in the sense of consistency, you know, among all three units at the site, especially when you're dealing with human performance and trying to measure that at a corporate level, or at a site management level.

MR. FINLEY: We'll do that. We'll do that.

MEMBER SKILLMAN: Mark, could you give us an idea of how strong your Corrective Action Program is?

MR. FINLEY: Certainly. We have a robust Corrective Action Program now, you know, for the functions we're performing now, and of course right now, our focus is design and licensing, and that's where we have our expertise and that's where our corrective action focus is.

We don't yet have this human performance monitoring program in place. So the aspects, in terms of indicators and trending with respect to this program, are not yet part of our Corrective Action Program.

But we have a fully functional Corrective Action Program for the functions we're performing now,

engineering and licensing primarily.

So, you know, we have periodic management review meetings of that program, and track indicators, just like you would for an operating plant. It's just the focus is a bit different.

MEMBER SKILLMAN: What is the highest level of senior management that participates in those meetings?

MR. FINLEY: Our chief nuclear officer, in fact, Greg Gibson, participates in those management review committees.

MEMBER SKILLMAN: Thank you, Mark.

MEMBER CORRADINI: Maybe this is the wrong time to ask it, and you guys can tell me to hold on. So is the senior management you're speaking about separate from 1 and 2 now? We're talking about a totally different management chain; is that correct?

MR. FINLEY: Yes, that's correct.

MEMBER CORRADINI: This is the wrong time to tell me, but I want to understand that, since they're co-located plants, or will be, I should say.

MR. FINLEY: That's correct. So as you recall, in 2010 essentially, Constellation EdF came to an agreement on the ownership of UniStar, and Constellation is no longer part of the ownership of

UniStar. So we have a separate management structure from Constellation.

MEMBER CORRADINI: It's as if, from the standpoint of management, as if the other two plants are separate, don't exist down the road?

MR. FINLEY: That's correct, that's correct, that's correct.

MEMBER CORRADINI: Okay. So from a human performance standpoint again, if they're separate, how are you going to interact in case of safety-related issues between the two units? There's an agreement being formed, so that if something occurs one place, there's an immediate set of actions that have to be taken in the others? You know what I'm asking.

MR. FINLEY: Yes certainly. We expect in many areas, human performance I think is one, where we're going to have to cooperate certainly with the existing units.

So we'll have -- we don't have the program set up at this time, but we will have a program set up where we communicate on human performance issues that could affect the opposite site, and of course other matters as well. Certainly security.

MEMBER CORRADINI: I just wanted to make sure I had it correct in my head. That's all. That's

all I wanted.

MEMBER RYAN: Mark, I guess on emergency response and all those kind of things require that same --

MR. FINLEY: Exactly. Emergency response even moreso, given the current recommendations with Fukushima, yes.

MEMBER CORRADINI: A work in progress would be the best way to describe it at this point?

MR. FINLEY: That would be a good way, yes.

MEMBER CORRADINI: Thank you.

MEMBER SCHULTZ: So Mark, just to back up a moment with regard to the explanation of the connection between the two sites, the information that was provided related to Chapter 15, the chi over q values, are those from the Calvert Cliffs site? Is it uniform between the two units existing now and what you've described here?

MR. FINLEY: Yes. So the data that was used to calculate these chi over qs came in part from the meteorological tower for the existing units. Obviously, given the close proximity of the existing units to the new site, we think that's well indicative of the chi over q that we'll have for the new site.

So in that sense, it is a calculation of chi over q for the existing units.

MEMBER ABDEL-KHALIK: So these units will have a completely separate switchyard?

MR. FINLEY: So the question on the switchyard. So we will have a separate switchyard. However, our intention is to have two tie lines to the existing switchyard, and in addition, we'll have two separate lines that essentially bypass the existing switchyard, to tie directly into the Unit 3 switchyard.

So multiple interconnections, if you will. We will be connected to the existing switchyard.

MEMBER ABDEL-KHALIK: So that sort of pertains to Mike's question about the connection with the existing units?

MR. FINLEY: Certainly, certainly. That's one, another area. Any operations in the switch yards that could affect one site or the other, we would have to have some overlaps.

MEMBER ABDEL-KHALIK: We'll see you about that.

MR. FINLEY: Okay, and summary for Chapter 18 is on Slide 20, and I talked about the one departure. There are no open items. We've responded

to all the RAIs. There are two confirmatory items.

One relates to guidance for writing procedures in accordance with human factors engineering criteria. We've responded to that, and one relates to this departure that I talked about today already.

That, I think, brings me to the close of my presentation. Slide 22, just to summarize. There are no ASLB contentions with any of these chapters. We talked about the three departures, and two of those are exemptions as well.

We have incorporated the confirmatory items in our most recent Revision 8, submitted at the end of March, and we've responded to the staff on four of the five open items.

The one remaining open item is the details of the instrumentation and controls system for the UHS in Chapter 7. I talked about that. So as of today, we would have 13-1/2 of the 19 chapters for the Calvert Cliffs Unit 3 FSAR completed through Phase 3. Any other questions for me?

MEMBER SKILLMAN: Yes sir. A brief question. Let me get my thinking cap on here. There's a piece of Chapter 6 that's still out there, and I'm curious. 6.2.1 and 6.2.2, containment

function design and containment heat removal systems. When are those up for review please?

MR. FINLEY: I think this would again be for the design certification and AREVA.

(Simultaneous speaking.)

MR. FINLEY: Yes, for us.

MEMBER SKILLMAN: They're still open. Thank you, understand. Thank you.

MR. FINLEY: Anything else for me? Okay, thank you very much.

MEMBER POWERS: Thank you.

MEMBER ABDEL-KHALIK: I guess philosophically, when questions arise during these discussions, that the judgment is made that they pertain to the design certification. Does the staff carry over these questions, or do we just rely on the record, that the questions are conveyed to the design certification?

MEMBER POWERS: I am sure that staff pays attention to them. But should they not, Ms. Weaver and I assure that they are communicated when they arise in discussions, when they belong to the DCD.

MEMBER ABDEL-KHALIK: I understand that this is the practicality of it, but shouldn't it be some more formal way of connecting questions that

arise during the discussions of the COLA, that are judged to be design certification-related, rather than relying on ACRS essentially transmitting the questions to the design certification applicant?

MEMBER POWERS: You're asking a question of cosmological and philosophical nature. I have no idea. All I do is assure that the questions get passed on to the applicant, and we usually get an answer.

MEMBER ABDEL-KHALIK: Good, thank you.

MEMBER POWERS: And usually that's not the problem. Usually, the problem is that the DCD applicant comes to us and says can you explain better what this question is, because we've identified it on the transcript?

I looked for confirmation at from Ms. Weaver, and I think that's true, that they tend to be fairly aggressive identifying those questions and asking us what they are, and I tend to be very reliant on Ms. Weaver helping me out on that.

I mean all I can say is it seems to work well. Whether there needs to be some formality, I'm not wild about formality. I'm wild about getting answers. Surinder. More interesting to me is when we identify things that need to be recognized in the

inspection and enforcement, especially during construction, how those get transferred on, because there's a gap in our span of control there.

MEMBER CORRADINI: "Our" meaning "us"?

MEMBER POWERS: Us, and we have at the Subcommittee raised that exact question. Is there a formal mechanism? The staff assures us that they have one, when they identify them in the DCD, that they flag those, so that the inspection people pay attention to those areas.

MEMBER CORRADINI: But that's more generic that we've identified for all groups.

MEMBER POWERS: I mean episodically, thinking of the last Subcommittee meeting, and you know, I mean I take them at their word, that yeah, they flag them and what-not. I have not gone back and looked.

MEMBER CORRADINI: I meant your point was after the DC and COLA or the COL is done, then there's this generic gap that --

MEMBER POWERS: Yeah, yeah. I mean it's good they're a different body of people looking at those, and you know, I make no assurance that that body from the ACRS would raise the same question. But the staff says that they definitely flag them, and

there's a communication there. I cannot say that I've gone back and identified it.

But that's where, yeah, I think I would welcome a little more formality there, just because there is a gap. Here, between the RCOLA and the DCD, it's so coupled that I'm not too concerned about formality there.

MEMBER BROWN: Related to Chapter 7 DCD, I mean I had -- we had two open items on the I&C, and we incorporated those into your letter. So they are explicitly stated in the paragraph in the letter.

So those are -- I mean that is a formal -- for those items. I'm not speaking to the other one, but that is a mechanism when they get cranked into our letter, from that standpoint.

MEMBER ABDEL-KHALIK: My concern is the other direction.

MEMBER BROWN: Yeah. No, I understand that. I didn't repeat them for the COL, because we already had -- they were really AREVA-type items.

MEMBER POWERS: I mean, there's nothing they can do about it except tell us the same thing louder. Surinder.

MR. ARORA: Thank you, Dr. Powers. Good morning again. As I previously mentioned, we'll start

our presentation with a general presentation, giving you the status of projects. Mike, we can move to --

My first slide here shows in chronological order when the COLA revisions were submitted by UniStar for staff's review. As shown in the slide, the Calvert Cliffs COL application was received in two parts, and several supplements, starting with initial submittal of Part 1 in July 2007, which was followed by Revision 1 of Part 1 and along with that was submitted Part 2, which completed the initial application.

That was in March 2008. Part 2 was accepted for review and the application was docketed as Docket No. 52-016 in June of 2008. Several updates were submitted after the submittal of the initial application, and the latest revision that we have today is Revision 8, which came to us on March 27th this year, very recently.

The COLA reviews are being performed concurrently with the EPR design certification application review. As I previously stated, the staff has completed Phase 2 reviews on nine full chapters and one partial chapter. The partial chapter was Chapter 2, which remains to be presented. The two parts are 2.4 and 2.5 sections.

As I will show on the next slide, the Phase 2 reviews, they comprise of production of the safety evaluation with open items identified. Next one. This slide identifies the six phases of staff's review process. This applies to any chapter in the application. We are currently working in Phases 2, 3 and 4 on various chapters of the review process.

The target dates, which are the phase completion milestone dates, are being reevaluated for several phases, as stated on the slide. The reason for the reevaluation is that we recently received a response schedule for all the RAIs which are pending, a letter UniStar provided on February 21 this year.

We are reviewing our schedules to reestablish these milestones, based on the dates that have been provided to us. Staff is planning to issue a schedule letter providing all those milestone dates by end of this month.

Next slide. With that, I will go over our review strategy. Basically, this slide provides major characteristics of our review process in general. The process starts even before the combined license application is received by the staff from the applicant.

The pre-application activities involve one

or more public meetings near the proposed site, to make the public and the neighboring areas aware of the applicant's intent to build a new nuclear power plant, and to explain the NRC's review process after the application is received.

The pre-application activities also include interactions with the applicant as needed, for planning to reviews by the staff. After receiving the application, the staff performs a review of the contents of the application for its completeness, and issues an acceptance letter conveying the decision to docket the application and starts its review.

As we all know, the Part 52 licensing process allows COL applicants to incorporate by reference the sections of the design certification application. This streamlines the review process by eliminating duplicacy and redundancy in review.

The Calvert Cliffs Unit 3 COL application took advantage of this provision, because of which several sections of the FSAR incorporate by reference the EPR DC FSAR sections.

The EPR DC application is concurrently being reviewed under Docket No. 52-020. The staff's review of the COL FSAR for the chapters all sections which incorporate U.S. EPR FSAR by reference, ensures

that the combination of the information incorporated by reference from the DC FSAR and the site-specific information included in the COL FSAR represents the complete scope of the information relating to the specific review topic.

In most cases, same technical staff reviews the DC and COL applications. This approach helps in keeping the review consistency between the two applications. A generic RAI applicable to all COLA chapters which have IBR information has been created, and has been issued for tracking the open item pertinent to the concurrent review process.

This will assure that the final revision of the EPR FSAR is fully complied with when we close this RAI. This open item will apply to all COLA chapters, as I said, and will be closed after the design certification is complete.

During its review, the staff uses several tools like eRAI system to track the requests for additional items, teleconferences with the applicant and public meetings as required, to request and discuss any additional information that staff may need.

Staff also conducts audits to review any supporting information or reference documentation,

which are not included with the application but are referenced in the application. For that, they conduct the audits and look at that documentation, review it at site.

Before bringing the issue with open items to the Subcommittee, it is assured that all the issues are either resolved and closed, or there exists a clear resolution path forward, in which case an open item is created to track the issue until it is finally resolved and closed.

The chapter being reviewed remains in Phase 2 until all staff's RAIs are satisfactorily answered, and any outstanding issues are fully resolved, or we have a clear path forward, in which case we'll create an open item. So that's basically our review strategy, how we conduct reviews on any application.

Next slide, Mike. With that, I will start now presentation on each of the chapters which are on today's agenda. As stated in this slide, we had several sections of Chapter 6, namely 6.2.1, 6.2.2 and 6.3, which were excluded from presentation to the Subcommittee, because these particular sections were IBR sections. They were incorporated by reference into the COLA.

However, they were not fully resolved or reviewed in the DC space of the application. So we didn't put in those sections and we will be bringing those in the Phase 4, after Phase 4 ACRS meeting.

MEMBER SKILLMAN: Surinder, let me ask this.

MR. ARORA: Sure.

MEMBER SKILLMAN: Just from an optics perspective, why is it okay to IBR a critical technical chapter that is not yet fully reviewed? Why is it acceptable to IBR an important technical chapter that is not fully reviewed?

MR. ARORA: I think my understanding of that would be the regulation allows that they can incorporate sections of the design certification into COL application, and the section is there in the EPR design certification. However, we may be having some questions or RAIs which are pending at this time.

So we don't close that item in the COLA environment, because if it is not resolved in the DC, we will not declare victory in COL space.

MEMBER SKILLMAN: I think I understand, if you will, the acceptability of doing that the way Part 52 is written. So I respect your answer.

But it seems to me to be somewhat of a

perversion to say we're going to IBR this chapter, even though the chapter's not been hammered out and slugged out and vetted and reviewed and approved and all the figures, all the tables and all of the calculations that back up the conclusions are by golly complete and known to be accurate.

It just seems like there's a cog in this mechanism that is not as strong as it needs to be.

MEMBER CORRADINI: Can I ask a question? I guess I want to clarify, because the only reason I'm listening closely to this is because we're doing this with other design centers. Is your point that because it's still being held in abeyance in the certification, that associated chapter in the COL should be left open? Is that your point?

MEMBER SKILLMAN: Yes sir. That's this man's opinion, yes sir.

MEMBER CORRADINI: But I guess my only reflection back is at least in my experience, staff is well aware of what's going on back in the world of the DCD, and doesn't bless the associated chapter here, no matter whether it's -- even though it says IBR. I guess that was my interpretation of how staff behaves like that.

MEMBER POWERS: Yeah, and there is a

subsequent review of this, and in that subsequent review, this chapter will be completed, and the staff will look at it. If the -- I mean the person at risk here is the applicant.

MEMBER SKILLMAN: Yes. It just seems to me to be peculiar we would say we're going to IBR this chapter, but we're not quite sure what it says yet.

MR. ARORA: I think the problem is because we are having comprehensive review of EPR design certification and COLA at the same time. It's a valid review. If DC would have only being certified or designed, then you will not be asking that question.

MEMBER SKILLMAN: That is accurate, and I understand that.

MR. ARORA: But we are not there yet. So they are being concurrently reviewed, so we are making sure that we are using the same staff members to review both applications, so there is a continuity between the two applications.

MEMBER STETKAR: And if this were a meeting on, at Phase 5 of the review, there would be a problem.

MEMBER POWERS: There will be a problem.

MEMBER STETKAR: But it's not yet. Thank you.

MR. ARORA: Summary of Chapter 6. Most sections of the chapter were incorporated by reference, and therefore the bulk of the review of those sections was performed under design certification effort.

There were still ten questions, RAI questions which were issued, requesting additional information from the applicant, and most of the questions, six of ten were in the area of habitability.

During the review of Section 2.2, the staff identified that one chemical, hydrochloric acid, may have the potential to challenge the control room habitability. To evaluate this, the staff performed an independent calculation to confirm that no design basis toxic gas threat exists.

In addition, they provided that input to 6.4 reviewers, to perform further analysis in their chapter, and Chapter 6.4 reviewers performed a confirmatory analysis for this chemical, along with other chemicals, for control room habitability, using NRC HABIT code, to verify that the control room hazardous chemical concentrations were well below the IDLH limits.

So that was staff's initiative, doing the

confirmatory analysis in this case.

MEMBER STETKAR: Surinder, can you help me? We're pretty good on time here, and this is kind of a self-education question, so bear with me. How, going forward through the life of this facility, 40 years, 60 years, however long it's there, what process is in place?

For example, suppose chemical company X decides to build the world's largest source of toxic gas directly upwind of this site on their property, you know, ten years in the future? What process then assures that the design is reexamined, for perhaps the need for automatic isolation?

MR. ARORA: This will be when the plant is already in operation?

MEMBER STETKAR: Yes, yes.

MR. ARORA: It's constructed, built and operating?

MEMBER STETKAR: That's why I used ten years in the future, because we're at zero operation now. Ten years after whenever the plant might start. So that a new, essentially a new hazard is introduced, circumstances beyond the licensee's control, because it's off site.

MR. ARORA: Right. Well, I appreciate the

concern and I have a technical staff who has volunteered --

MR. TAMMARA: My name is Rao Tammara. I do the evaluations of these external factors in Chapter 2. So in Chapter 2, we cover for the new facility, all the existing facilities within five miles of the site. Say for example into the future, if this new facility happens to come into being, that facility has to be, get licensed by the locality, state or county or whatever, whichever. If it is a new facility, that has to go through the licensing process or whatever.

So in that case, that has to be evaluated what would be the impacts of that facility on the nearby facilities? Like an example, Coal Point at Calvert Cliffs, we have a natural gas storage facility, that has been there in existence. But they applied for an expansion, and in the process of that expansion, Maryland Natural Resources and the state has to do the expansion license.

In that process, they evaluated what would be the impacts of the expansion on Calvert Cliffs, and also Calvert Cliffs is aware of the project, and that NRC's regulations for leading to the new facility, proposed facility, Unit 3.

So to answer you the question, if it is a new facility, NRC doesn't have a regulatory requirement to control what it affects, I mean, from the regulatory point of view. However, it is the other licensing experts will take care, one thing, and if there is a big, significant difference that is anticipated to impacting the plant, of course, the applicant will naturally evaluate the total processes.

Any public can put application allegation through that process. NRC might well reevaluate what would be the -- or force the applicant to make an evaluation, what is the impact? Did you look at it? So these are the avenues available to answer. But it is a regulatory process. I mean that answer can --

MEMBER STETKAR: Okay, thanks. That at least helps me to understand how the process works in practice.

(Simultaneous speaking.)

MR. ARORA: Thank you, Rao. Other thing John, I would like to add to that is at this time, we are basing our reviews on what we have been provided.

So in that COLA application, what were additional toxic gas sources that they have given to us, we are evaluating those and basing our reviews on that. If something is added later --

MEMBER STETKAR: No, I understand that. I was asking -- it's not really a question that's relevant to this particular proceeding. It was, given the fact that we had a little bit of extra time, self-education. Thank you.

MR. ARORA: Thank you.

MEMBER BROWN: Yes. I wanted to -- you said you evaluate the information given to you for that site. I take that to mean you don't independently look to make sure they gave you all the information, or you do do that?

MR. ARORA: No, we do that -- we will. We do ask questions. We send out --

(Simultaneous speaking.)

MEMBER BROWN: I wanted to make sure.

MR. ARORA: No. What I said is we are performing the review of the application that has been turned in to staff.

MEMBER BROWN: Yeah I know, but you don't -- that doesn't exclude you from ensuring that they gave you all the relevant or correct information.

MR. ARORA: But at the same time, we can't foresee the future, what's coming up in ten years.

MEMBER BROWN: Not future. I'm talking about right now, and if they missed a facility that

you think should be included --

MR. ARORA: Sure. We will definitely pick that up.

MEMBER BROWN: Okay. I just wanted to ensure that there weren't blinders here. I didn't think there were. I just wanted to hear you say it, that's all.

MR. CANOVA: I'm Mike Canova. I'm supporting him today, but I'm actually the Bell Bend lead also. Rao does audits when we do these reviews, and goes out and surveys the area, to make suer nothing's been excluded from the application.

MEMBER BROWN: Okay, thank you.

MEMBER SCHULTZ: If the basis for the license is the existing facilities, then a new facility ought to go into the licensee's Corrective Action Program for evaluation.

MALE PARTICIPANT: Right.

MEMBER CORRADINI: You would think so, for self-preservation if nothing else.

MR. CANOVA: I believe it would also require an environmental impact statement, which would also bring out the same issues.

MEMBER SKILLMAN: Well, part of this discussion alarms me. I'll give you an example. I

know of one site where the potential for toxic gas or gas cloud explosion was fairly well explored, and the answer was you can't have toxic gas. You just won't have it.

But if you put on your hard hat and safety glasses and walked out onto the property, there was an 18-wheeler nitrogen truck delivering not really a toxic gas but a suffocant, about 35 or 40 feet or 50 feet from the primary air intake for the control room.

That kind of bypassed everybody's field review. Taking on nitrogen is a normal process. It's used for a lot of applications at a nuclear power plant, and here was a well-intending gentlemen backing in his 18-wheeler, and he ran over some pipes and guess what? We had a nitrogen release.

The distance to the air intake is about as far as from here to the corner office, not very far, maybe 80 feet. Oh gee whiz, is that different than what we thought? Well you know what? It really was. It wasn't toxic, but it was an event that could have had significance had the amount of gas that was released been great.

MEMBER POWERS: But it did not escape our attention in the review of this material, because we specifically looked at where gas deliveries were

taking place.

MEMBER SKILLMAN: Good, all right. A fine point. Some of this stuff is very subtle, and it's easy to march over it when one might need to be a little more circumspect when reviewing this information. Thank you.

MR. ARORA: Thank you. Continuing with Chapter 6, based on the RAI responses of the ten RAI questions that were sent by the staff, all questions were resolved and there were only two open items left to be resolved when the chapter was last presented to the Subcommittee on 5th of April last year. Both RAIs related to the open items have already been answered by UniStar, and staff is reviewing the responses currently. We will be closing those open items in the Phase 4 effort.

Next one. Summary of Chapter 7, Instrumentation and Control. Again, most of the sections of these chapters are also incorporated by reference, but there was a lot of effort put in by the staff to review the sections interactions between the APR design certification and COLA.

A total of six requests for additional information were issued in this case. Three of the six questions were resolved fully and closed. Based

on the responses provided by UniStar, the other three were identified as open items when the chapter was last presented in November to the Subcommittee.

In the first question of the three open items, the staff had asked applicant to provide specific I&C instrumentation for certain site-specific systems, such as ultimate heat sink system, makeup water, ultimate heat sink makeup water intake structure, ventilation system, etcetera. The question has not yet been responded by UniStar, and we are waiting for their response. I think it's scheduled to be coming to us some time in July.

The second question that staff had asked was in Section 7.5 of the FSAR, and it addresses a new COLA item that was added by AREVA, relative to the site-specific and monitoring variables. UniStar has provided a response to this question a few days ago, and it is currently in review by our staff. If found acceptable, this item will be closed.

The last RAI related to the open items requested UniStar to update Section 7.7 of COLA FSAR, to address a COL action item pertinent to primary power calorimetric uncertainty. UniStar had provided a response to this RAI, which was found acceptable by staff. This open item will therefore be closed during

the Phase 4 review effort.

As you see, the staff is asking questions relative to the inconsistencies between EPR and EPR DC and COLA applications. This is a good example of where we have taken advantage of using the same technical reviewers for both applications.

Next chapter. Chapter 15. A lot of sections of this chapter were IBR, with no departure and exemptions from the DC. Generally, the supplementary site-specific information provided in the COLA was the focus of staff's review. The review resulted in only one RAI, which was adequately addressed by the applicant.

Based on the information provided in the RAI response, there was no open item identified for this chapter. However, in Section 15.0.3, the applicant had taken a departure and exemption from the U.S. EPR FSAR, which the applicant also discussed, and this was to use site characteristic accident chi over qs to calculate site-specific dose values at LPZ.

The staff performed an independent DBA dose analysis to verify the results of the applicant site-specific analysis reported in the FSAR. To perform this analysis, the staff used the computer code models that were developed for completion of the

U.S. EPR DC review, and they used the site-specific chi over qs to calculate the site-specific doses for all DBAs at LPZ.

The results were found acceptable, and I have the staff's report here if any member of the Committee has any additional questions or clarification on that analysis.

MEMBER REMPE: So again, I was looking at, let's see, page 15.6, and it references that they actually did time shifting of the chi over q values. I assume that means they took the higher one, and when the release was high, they applied it. But I was surprised that they did that, actually the applicant did that, and then you checked them?

MS. HART: That is correct. In fact, this is Michelle Hart. I'm in the Radiation Protection and Dose Analysis Branch, and I did that review for both the DC and for this COL. The DC, AREVA did that in the DC.

They time-shifted the LPZ, and it is correct. Your interpretation of what that means is you take the zero to two hour chi over q for the LPZ and apply that during the worse release time.

Then you put what would have been during that time before and after, and then continue with the

different dispersion characteristics. So you're having the least dispersion during the time that you have the worse release. I asked UniStar if they did that for Calvert as well, and they did. That was in, also in relation to the question because they only had the one chi over q for the 0 to 2 hour period, that was higher than the DCD values.

Did they use just that value, or did they use all of the site-specific values, and they used all of the site-specific values. So that's, the reason I had to ask that question is because their LPZ, site-specific doses were actually lower than the DC values.

So if you had a higher chi over q, that didn't make sense on the face of it. But yes, it was just for that one time period that it was slightly higher, and when you apply all of them, because the rest of them were lower than DC, the overall dose was lower in most cases.

MEMBER REMPE: Okay, thanks.

MR. ARORA: Thank you, Michelle. It may also be noted that the rest of the DBA doses results for exclusionary boundary, control room and DFC doses, they were all incorporated by reference. The staff found that these were acceptable, because the Calvert site characteristic chi over qs were lower than those

values which were used as site parameters in U.S. EPR.

Next chapter, Chapter 18. The only branch that was involved with the review of this chapter was the operator licensing and human performance branch. Only two RAI questions requesting additional information from the applicant were issued.

One question was on the procedure development section of the application, and the other on the human performance monitoring. Both these RAIs were answered very promptly by the applicant, and the staff was fully satisfied with the responses received.

The review was completed without any open item being identified. The staff's review ensured that the HFE design responsibility for emergency operation facility was specifically stated in the COL application, and that the application provided a statement of standards that would be met.

All COL information items identified in the EPR design certification were addressed properly in the COLA. That was also made sure by the staff during their review. There was an ITAAC for verification requirement, to verify that the staffing levels derived from task and staffing analysis, they remain bounded by the regulation.

So those were the certain salient items

that staff looked at during their review, and there was no open items, as I said. All the responses were satisfactory. That was my last chapter presentation, okay.

We have staff representation here for Chapter 18 also, if any member has any additional questions.

MEMBER POWERS: Any other questions to present to the presentation? I would just comment that as to Aurora's earlier slide, he put down a simple bullet that said "phase discipline." That is a more significant comment than you might think from a simple line.

The only reason this kind of piecemeal review works is because both staff and applicant exhibit a very strong phase discipline, and I thank them very much for that. With that, Mr. Chairman, I think we're done.

CHAIR ARMIJO: Thank you very much.

MEMBER POWERS: John, did you have a comment you wanted to make?

MR. SEGALA: Yeah. This is John Segala from Licensing Branch 1. I'm a branch chief. We have a reviewer here that could talk a little bit about the mixed fuel issue, if you want to take a couple of

minutes.

MEMBER POWERS: A couple of minutes, I think, is totally acceptable.

MR. SEGALA: Okay.

MR. LU: Okay. My name is Shanlai Lu from the Rad Protection Branch, and lead reviewer on the EPR. I heard that there was questioning about a mixed core configuration, what are the limitations of the setpoint methodology, based on the SPND.

That's one of the limitations as a part of staff's approval. They have to use -- they can't have a mixed core, but each fuel bundle has to have identical set of correlation package. However, neutronically, if you're loading the uranium enrichment, maybe it could be different.

So I think that's the limitation we already imposed on that part of the SER. Did I answer your question about that?

MEMBER ABDEL-KHALIK: That's fine. We can pursue it in more detail later. Thank you.

MEMBER POWERS: Thank you. I think we're done.

CHAIR ARMIJO: Okay. Well, thank you, Dana. I think we're a little bit ahead of schedule. So we'll take a break and reconvene at 10:15.

(Whereupon, a short recess was taken.)

CHAIR ARMIJO: Okay. Let's come back to order. The next topic is the spent fuel pool scoping study, and the purpose of this meeting is to receive a briefing from the Office of Nuclear Regulatory Research on this study.

Our Subcommittee on Materials, Metallurgy and Reactor Fuels met with the staff on March 6th of this year in a closed forum, and at that meeting, some pre-decisional information was presented, as well as some official use only information.

That information will not be presented today or discussed. This will be an open session. We'll hear presentations from representatives of the Research staff, who will discuss the seismic and structural methods, the scenario delineation, accident progression and consequences analysis methods for the study.

Also, we've had a request from a member of the public, Mr. Bob Leyse, to give some remarks and comments for about five minutes, and I believe he also submitted a one-pager entitled "Spent Fuel Pools Bioresearch Overview: Phase 1 Testing," which all the Committee members have received.

With that, I'd like to turn it over to the

staff, whether it's Katie or Michael.

MR. SCOTT: Good morning, thank.

CHAIR ARMIJO: Okay, Michael.

MR. SCOTT: I'm Mike Scott. I'm the Deputy Division Director in the Division of Systems Analysis in the Office of Nuclear Regulatory Research, and I'd like to just make a few opening remarks.

The study that you'll be briefed on this morning to assess the potential safety benefits of expedited movement of spent fuel to casks was born from a steady interest in spent fuel consequences, expressed by members of the public and by Congress.

The Research staff was tasked with developing updated information on key aspects of potential spent fuel pool accident consequences on an aggressive one-year schedule. The staff was directed to move expeditiously, but also to conduct our work in a technically rigorous manner, using state of the art tools.

To accomplish this task, the staff has reviewed and is reviewing past consequence and risk assessments related to spent fuel storage, as well as other reports of relevance that have been developed by external stakeholders. The staff identified seismic hazard as a key piece of the overall spent fuel risk,

and you'll hear more about that from the team.

For that reason, seismic hazard was considered a logical place to start in probing the continued applicability of past studies, developing insights for the current spent fuel storage situation. Depending on the results gained from this study, additional work might be appropriate to obtain a more holistic answer on the path forward on this issue.

Along with providing general updates to past information, the study can provide a number of insights for scenarios investigated. For example, through accident progression time lines for spent fuel pools proceed more slowly than previously thought, as the agency has found to be the case for reactor events in the recent SOARCA analyses.

Do seismically-induced station blackout scenarios contribute significantly to overall consequences, or are the consequences dominated by seismically-induced pool drain-down? Do low density loading storage cases produce substantially different results in terms of public health effects and off-site consequences, compared to high density storage cases?

Do situations with successful mitigation substantially reduce the off-site consequences? We expect that insights such that we will obtain will

address issues such as these, and be very helpful in framing the ongoing discussions about whether expedited fuel movement produces any substantial safety benefits, and informing next steps.

Other ongoing efforts, such as plan site Level 3 PRA will complement and build on this work. Unless you have questions for me, I'll now turn it over to Katie Wagner to begin the presentation.

CHAIR ARMIJO: Mike, I have some comments, not necessarily questions. In the course of the presentation, I'd like to understand why this work is being done on an expedited basis, when we have demonstrated at the Fukushima event that the spent fuel pools performed their function, despite the severe seismic event, and despite hydrogen explosions and other problems?

So from a standpoint of priority of work by the staff, I'm struggling to understand what the reason or justification for this level of effort, other than -- and on this expedited schedule.

It seems that we're ignoring the facts of what actually happened in one of the most, in fact the most destructive event that happened in fuel pools of -- that we design and use in the United States.

So as the presentation goes forward, I'd

like to try and understand what is really driving this thing, because I just don't see a technical justification. That's a personal opinion that may or may not be shared by other members.

But it just seems odd to me that we're spending this kind of effort on this kind of study, and ignoring the facts of what happened at Fukushima. With that, I'll --

MR. SCOTT: I'd like to respond to that if I could. The emphasis on this task, which of course is only a relatively small part of the agency's resources that are being focused on lessons learned from Fukushima, the emphasis that has been provided on this task is focus both on the potentially significant consequences of this event, recognizing it's highly unlikely, and as I mentioned in my remarks, the high stakeholder interest in this subject that emerged from Fukushima.

So this is -- it is our, it's been our judgment that we need to address this issue as part of but not a major part of the efforts that are being focused on Fukushima and lessons learned from that. Okay?

CHAIR ARMIJO: Yeah. I think I understand the code words "high stakeholder interest," and I'll

leave it at that. But I was looking more for a technical justification. But let's move on. Katie, the floor is yours.

MS. WAGNER: All right. Good morning, and welcome to this briefing on the Office of Research's Spent Fuel Pool Scoping Study. I'd like to quickly introduce my colleagues.

We have Jose Pires, who's our structural analysis lead; Don Helton, who is our boundary conditions and probabilistic aspects lead. To the side is Andy Murphy, our seismic analysis lead; Hossein Esmaili, our accident progression lead; and A.J. Nosek, our off-site consequence lead.

Moving to Slide 2, the agency has a rich regulatory basis for its current position on spent fuel storage. A number of events, such as the change in path forward on long-term storage in the Fukushima accident, motivated the reassessment of the underlying knowledge base.

To launch this reassessment, an expedited limited scope consequence study was undertaken, to provide insights in one year. The objective of this study is to reexamine the impact of moving older spent fuel to dry cask storage in an expedited manner.

The results of this study will inform our

regulatory decision-making process, guided by a Tier 3 Japan Lessons Learned item entitled "Transfer of Spent Fuel to Dry Cask Storage."

Moving to Slide 3, you'll see on this time line that many activities have addressed spent fuel pool issues in the past, such as the resolution of Generic Issue 82 in the late 1980's, action plan activities to increase spent fuel pool cooling rates reliability in the mid-90's, the NUREG-1738, study for decommissioning in 2001, the post-9/11 security assessments, and comprehensive site-level 3 PRA, which is just starting.

Please note that on this slide, the two past studies, which include a probabilistic risk assessment, resolution of Generic Issue 82 and NUREG-1738 are surrounded by a box. Moving to Slide 3.

MEMBER SKILLMAN: Katie, what is the context of that comment, "surrounded by the box"? What are you communicating there please?

MS. WAGNER: It's just simply that there's no significance. It's just we wanted to point out which studies did and did not have a probabilistic risk assessment as part of the study.

MEMBER SKILLMAN: Thank you, thank you.

(Off record comment.)

MS. WAGNER: Obviously, spent fuel pool risk involves many components, several of which include spent fuel pool seismic hazards, cask drop hazards for spent fuel pools and emergency preparedness considerations on other topics. Past studies have indicated that spent fuel pool seismic hazard is an important piece of overall spent fuel pool risk, or overall spent fuel risk.

For this reason, spent fuel pool seismic hazard is the logical place to start probing the continued applicability of past studies in developing insights for the current spent fuel storage situation. Depending on the results gained from the study, additional work might be necessary to obtain a more holistic answer.

Moving to Slide 5, as you'll see on this slide, past studies show that seismic hazard is the most prominent contributor to spent fuel pool fuel uncovery, as shown by these plots, showing the frequency of fuel uncovery. I'd like to point out that in NUREG-1738, few hazards were used, and we chose to use the Livermore hazard curves, because they more closely match the updated USGS curves for the plant that we are studying, which is Peach Bottom.

Moving on to Slide 6, now I'd like to give

a brief overview of the spent fuel pool scoping study. The focus of the study is to reexamine the potential impacts on spent fuel pool safety in the event of a challenging beyond design basis seismic event.

For this study, emphasis has been put on obtaining timely results, by using available information and methods, a representative operating cycle for a BWR Mark I plant, which is Peach Bottom in this case, and past studies to narrow the study scope.

The time line of the study, which Mike Scott already pointed out, is very aggressive. The study plan was finalized in July 2011, and the Office of Research will be sending study results to NRR in June 2012.

The closely-related Japan Lessons Learned Tier 3 item from SECY 12-0025, Transfer of Spent Fuel to Dry Cask Storage, addresses the bigger picture, with the spent fuel pool scoping study being a key component.

MEMBER STETKAR: Katie, before you switch to the next one, I mean for the benefit of the full Committee explain why you in particular selected boiling power reactor rather than a pressurized water reactor, because the main genesis of this question is the different configurations of the spent fuel pools,

different connections to the spent fuel pools and boilers, versus pressurized water reactors and perhaps different vulnerabilities to seismic failures for the two fuel pools?

MS. WAGNER: Certainly. I'm going to ask Don to take that one.

MR. HELTON: Yes. I guess the first comment I'll make is, and something that we plan on making clear in the report, and it came up in the Subcommittee discussion, is we did not pick a boiling water reactor because we viewed them to be inherently more vulnerable. That was not part of the decision-making process.

There were a number of considerations that did, that were part of the decision-making process, including the level of stakeholder interest, the availability of MELCOR and MACCS-2 models, as well as finite element structural analysis models, the availability of information on the plant that we chose from some past studies.

Of course, the Peach Bottom plant is a BWR Mark I. Of course, the Fukushima had BWR Mark I's on the site. I won't say that that was -- I mean that was not a key part of the decision, but that it was another aspect of it.

So in the end, it was a combination of these different considerations that prompted us to choose this site.

MEMBER STETKAR: But generic conclusions across the entire operating fleet are going to be drawn as a result of this scoping study. Is there some chance -- you mentioned you didn't select the boiler, because you thought it might be more vulnerable? Is there some chance that it might be less vulnerable?

MR. HELTON: There is certainly that possibility. Our intent was not to do one, a site-specific analysis that could then be extrapolated to the industry, in terms of the fleet, without a tremendous amount of caution in doing so.

Our goal was to do a site-specific analysis of a plant that is fairly typical of the 20 or so Mark I BWRs in the U.S., and to go from there.

MEMBER STETKAR: Okay. That means the results have to be cast pretty carefully, because this -- so that it's not necessarily misinterpreted, that the results of the scoping study are indeed generically applicable to the entire fleet, in terms of policy decisions and, you know, what one should do going forward.

MEMBER POWERS: Don, is Peach Bottom representative? What I'm thinking is Peach Bottom among BWRs is the plant that has been analyzed most within the regulatory context, PRA and accident analysis.

Everybody does Peach Bottom, and consequently, any flaws or oversights or deficiencies have presumably been corrected at Peach Bottom, whereas others have not been subjected to that kind of scrutiny. So is Peach Bottom representative?

MR. HELTON: I guess what I meant by that was from a high level, from a design perspective, the Mark I's have a fairly typical design. Even that said, there are important differences from AE to AE that can affect things like the structural assessment.

We're not trying to make the case at this point that from an as-operated perspective, that globally it is or is not typical. Rather, we will try as much as possible to say, to point out cases along the way in our analysis, where we believe that particular aspects are typical or atypical.

An example of that is the way that Peach Bottom chooses to do its fuel loading in the spent fuel pool. They've actually gone beyond what is required in regulatory space, in terms of the

arrangement of their fuel, to have an arrangement that is even more coolable, to use that terminology, than what is required.

That is something that we view as good, but atypical. So therefore in our study, we're looking at what the regulatory requirement is. So again, I don't want to make global statements about typical versus atypical, but in cases where, or in specific instances where we know it to be very typical, we'll try to identify those at that level.

MEMBER POWERS: If I were to ask you about PWR containments and their variability, you would point to a NUREG report that went through, deliberately comparing and contrasted all the structural features of PWR containments.

If I asked you for a similar thing about the structures of spent fuel pools in Mark I BWRs, is there a NUREG that you would point me to, that would say here, all 23 of them have been looked at and here's the information.

MR. HELTON: I'll defer that to Jose.

DR. PIRES: I have not seen a report that we did the level of detailed information that is for the containments, the reports that have containment information. There are some previous studies that

have looked at the spent fuel pools. There are some databases collected.

But I have not seen a report myself with the level of detail that are in the reports that have containment databases. We are trying to start one, but it's a slow process.

MEMBER POWERS: Yeah. I think that would be a -- I mean it strikes me how often I refer to that report that the staff prepared on the structural details of all the containments. I mean my copy has lost its binding and most of its cover, I pull it out so often.

A similar thing, given the interest in spent fuel pool, it might be something to consider, maybe not as part of this study, but as some follow-on activity, because you know, these questions come up, and like I say, I pull my containment thing down every time a containment question comes up.

DR. PIRES: Yes. We have a contract with Sandia Labs to develop some --

(Simultaneous speaking; laughter.)

DR. PIRES: As a varied utility that has a lot of information on containments, and we have been debating whether to expand it, to include information on spent fuel pools in that project. I know that for

some security studies, there has been information collected on numerous spent fuel pools, but the budget for that --

CHAIR ARMIJO: That's accessible to you, but not to the general public.

MS. WAGNER: Let's move to Slide 7. For the technical approach of the study, we will be specifically considering two conditions. One is representative of the current situation for the selected site, with a high density loading and a relatively high density loading configuration, and a relatively full spent fuel pool.

The other is representative of a situation in which ex-bed movement of the older fuel to a dry cask storage facility has taken place, with a low density loading situation. The elements of the study include a seismic and structural assessment, a scale analysis of reactor-building dose rates, a MELCOR accident progression analysis, and emergency planning assessment, a MAX-2 off-site consequence analysis and probabilistic considerations.

MEMBER REMPE: What version of MELCOR is it you're using? Is it 2.1 or is it another version?

MR. HELTON: We're using 1.86 right now for the scoping study. We've also been playing around

with doing the same calculations in 2.1. But there's some unique aspects of MELCOR that were added to the 1.85 version and carried forward to 1.86 for a spent fuel pool analysis.

So like I said, at this point, we're doing it in 1.86, and then also exploring the feasibility of basically doing the same thing in 2.1.

MEMBER REMPE: So some of the models in 1.86 are not in 2.1?

MR. HELTON: I think from a reactor standpoint, the answer is everything that's in 1.86 is in 2.1. There are potentially some unique features for spent fuel pool analysis.

MEMBER REMPE: That were not carried forward?

MR. HELTON: That were not carried forward, and if I've misspoken, then the MELCOR guru back there will correct me.

MR. ESMAILI: All the models that are in 1.86 are now -- Hossein Esmaili. All the models that are in 1.86 are in 2.1. So we just made the choice, because we had the model available in 1.86, and we didn't want to convert it to 2.1 because it would take a long time. So this is what will work.

(Off record comments.)

MS. WAGNER: Thank you. If those are all the questions on that slide, then now I'll turn things over to Jose Pires, who will discuss seismic and structural methods used in the study.

CHAIR ARMIJO: Katie, just before you do that, this study takes you the point where you've damaged, you've drained the pool at some extreme, you know, for some extreme conditions. You get to a situation where you're draining the pool and you've had a zirconium oxidation and hydrogen release.

In this study, will you just let that released radioactivity be dispersed in a normal way, or would you, will you also incorporate at some point a hydrogen explosion resulting from the cladding?

MS. WAGNER: I'm going to turn that to Don, since he's presenting on that.

MR. HELTON: Yeah. Let me give you a quick answer, just to answer that, because I think when we go through we'll answer some of this. What Jose is going to talk about is the fact that we don't presume failure of the pool.

We study the pool from a finite element analysis, impose this event on it, and then predict what's actually going to happen.

CHAIR ARMIJO: I appreciate that, Don. But

as you crank up the seismic, the magnitude, you'll get to a point where you can fail just about anything.

MR. HELTON: Of course.

CHAIR ARMIJO: Yes, and so if you take it to that point and you fail the structure or the liners and you drain the pool, and you get a zirconium oxidation in the hydrogen release, do you then incorporate the hydrogen explosion into your analysis?

MR. HELTON: The answer is if we produce sufficient hydrogen, and this depends on when the oxidation is occurring and to what extent it's happening in an arid environment, which will not produce hydrogen, versus a steam environment, which will.

But if we produce enough hydrogen and it transports, and the conditions are such that a hydrogen deflagration would be predicted, then yes, we'll model that.

CHAIR ARMIJO: Thank you.

MEMBER POWERS: But he asked you about an explosion.

CHAIR ARMIJO: Well, yeah. I was saying the worst case, a real explosion. If it can't happen, that's good to know. If it does happen, can happen --

MEMBER POWERS: It could happen and not

calculated to happen are two different things.

MR. HELTON: We would expect it if sufficient hydrogen was generated to have a deflagration or detonation event, that would at a minimum blow out panels on the refueling floor, and potentially cause additional damage, and we will, to the best of our abilities, model that.

CHAIR ARMIJO: Okay.

MEMBER POWERS: Can you model the DDT?

MR. HELTON: I'm sorry?

MEMBER POWERS: Can you model a deflagration to detonation transition?

MR. HELTON: We will use the resident models in MELCOR to predict the combustion of hydrogen.

MEMBER POWERS: You're deliberately not answering my question.

MR. HELTON: I'll deliberately defer your question to Jose.

(Laughter.)

DR. PIRES: No, we do not, Dr. Powers. We just, if there is the conditions for detonation, we just flag it, that there are conditions for detonation. But we do not model DDT. We only model a hydrogen burn.

MR. HELTON: But just to be clear, that

hydrogen burn has the capability and will produce pressure differentials that will again, at a minimum, fail blowout panels on the refuel floor.

DR. PIRES: Yeah, and for this particular case, you know, if there are no igniters, the MELCOR default for the onset of hydrogen combustion is about ten percent hydrogen, that you can really achieve very quickly.

MEMBER POWERS: But how do you flag when you're ripe for DDT?

MR. HELTON: I'm sorry. I'm not trying to be difficult. I've lost hearing on my right ear, so --

MEMBER POWERS: I've been accused of speaking too softly.

MEMBER CORRADINI: Accused or guilty?

(Laughter.)

MEMBER POWERS: Accused.

(Simultaneous speaking.)

MR. HELTON: He's got my good ear.

(Laughter.)

MEMBER POWERS: Now the question is, and I'm bringing it up because there's been a lot of work lately on the issue of deflagration to detonation transitions, and it becomes very pertinent in thinking

about the Fukushima accident, and the statement was that they flag when they're ripe for DDT, and I just wondered how they did that.

DR. PIRES: Again, in MELCOR, we don't have such a model.

MEMBER POWERS: Oh, I misunderstood.

DR. PIRES: And you know, the refueling bay is an open environment. So the conditions for a DDT, it could happen, but you know how you get into a very open environment, it's probably going to burn, as opposed to going through the --

MEMBER POWERS: An open environment like a reactor building?

DR. PIRES: Yeah, in top of the refueling floor.

MEMBER CORRADINI: So can I ask Dana's question a bit differently? The last time I remember this being looked at in great detail was essentially for ice condensers, because of the run-up of the channel surrounding the baskets. I guess to reverse the question, is there any characteristics in some of the geometries that essentially look like where the NRC's research, from many years ago, were concerned about that, because it's a geometrical effect?

DR. PIRES: Yes. And again, I haven't

looked. Again, since we don't have the model in MELCOR --

MEMBER CORRADINI: Okay.

CHAIR ARMIJO: Jose.

DR. PIRES: I will talk about the peak ground seismic scenario and the structural analysis that we are -- the approaches that we are utilizing. The seismic scenario for this event is a challenging event, but with a very low frequency of occurrence that has been estimated to be 1 in 60,000, 61,000 years.

The PGA for, peak ground acceleration for this event, if you would characterize the earthquake in those times, is in the range from .5 to 1G, and specifically we have been looking at an earthquake with an acceleration of .71G peak ground acceleration.

If you see how that compares to the safe shutdown earthquake and the operating basis earthquake, it is about six times greater. So it's a very challenging event. Why did we pick this event, and that was because of some review of past studies indicates that you would have to go to events in this range to start challenging the spent fuel pool structure.

So if you move to the next slide, the other

--

MEMBER CORRADINI: Can I ask a question that we've been debating from your Subcommittee meeting, and we'll do it out in the open a bit? So you're picking a -- you don't have to go back -- but in the previous slide, a range of what I'll call single large seismic events.

From the standpoint of seismic analysis, is one big one worse than a bunch of little ones that add up to the same energy?

DR. PIRES: No, I don't think so, not for this structure.

MEMBER CORRADINI: So then if I -- you see where I'm going with this? So then if one did a series of smaller seismic events, could I end up with more accumulated damage? That's where I'm going with it.

DR. PIRES: Right. No, I don't think so for this structure. My understanding of the behavior of the spent fuel pool structure is that this tends to be relatively brittle, and so it is more of a threshold-type event. If you have many, many loading cycles before certain level, you have almost no damage. Then you start exceeding certain levels, you start seeing damage.

So it's pretty much the intensity of the motion with a certain duration that controls.

MEMBER REMPE: So even a big one followed by some smaller ones would not cause some aftershocks, would not cause --

DR. PIRES: I also --

CHAIR ARMIJO: If you really damage -- if it's big enough to start cracks, and you have subsequent ones, it's not going to help. That's what happened in Fukushima. They had 7, greater than magnitude 7 after the initial big one, and then a bunch at greater than 5, and hundreds after that, smaller ones. So nature has a way of making it worse.

MEMBER CORRADINI: The reason that we were asking the question on this site is it's the -- the way you answered, I want to make sure I get clear. The way you answered it is the initial big one, because of the brittle behavior thing, really does the damage, and all the accumulated other ones, if I never had the big one, would never be noticed?

DR. PIRES: Exactly, the one previous to that, yeah. And I will repeat, it's not completely brittle damage, but it's on the brittle side. Not totally brittle, in terms of at least of the cracking.

CHAIR ARMIJO: I just get -- I'm not a

seismic guy, but I'm just curious, .71. Why not .70 or .75, some bigger point, you know?

DR. PIRES: It's sometimes on estimating the central point of an interpole (ph). You either use the arithmetic mean or the geometric, and the geometric mean was used here, so that it was just -- because some of these things tend to be linear on logarithmic scales, and so what's convenient.

CHAIR ARMIJO: Okay. I just thought there was something magical about that number.

MR. HELTON: It's the square root of 1 times .5.

CHAIR ARMIJO: That's a lot.

MEMBER SCHULTZ: But the way it's presented here, and I'll just make this comment now; I may come back to it later. The way it's presented here, given that this is going to be a high profile, well-read document, is that we are dealing with accurate numbers.

MEMBER CORRADINI: Right.

MEMBER SCHULTZ: And it will be perceived, then, that the agency has developed a very accurate analysis, therefore, of what could happen. So presenting .71 or 1 in 61,000 years for the event suggests that we really know about this event, and

we're really going to tell and evaluate what will happen, not what can happen or might happen, but what will happen. We need to be very cautious about that and present --

CHAIR ARMIJO: On what's presented, yes.

DR. PIRES: That's a good point.

MEMBER SCHULTZ: That's where using something like .7 or 10 to the minus 5th or 10 to the minus 6th, picking one makes more sense.

MEMBER CORRADINI: Yeah, because really you're -- I mean the easy way of saying it is that your uncertainty might be an order of magnitude. So showing anything less than -- showing anything with more precision than order of magnitude conveys almost too much certainty.

MEMBER STETKAR: Or doing an actual uncertainty analysis.

MEMBER CORRADINI: Or doing an actual uncertainty analysis that goes along with that.

MEMBER STETKAR: That has uncertainty in both the seismic hazard and the seismic fragilities.

DR. PIRES: Yeah, I agree with that. It's more accuracy --. The seismic, in addition to the peak ground acceleration, it is also important to characterize the vibration of the ground to response

spectra. What is the frequency content in the vibrations of the ground?

So what -- we also use the USGS 2008 seismic hazard models for that, and these were similar to the models that were used for the Generic Issue 199.

So based on that, we obtained what's called the ground motion response spectra for that site, and then that was scaled up to the intensity that we are considering, that is actually greater than what the ground motion -- that for the ground motion response spectra.

One comment here is that compared to two points, the design earthquake and earthquakes used in PRAs for this plant, and earthquakes used in previous studies for spent fuel pools, these earthquakes is rich in the I frequency, and it's a rock site too here, and natural frequencies of the spent fuel pool structure are also in that range, up to 20 hertz. That was different from previous studies. If you go to the next slide --

MEMBER SKILLMAN: So -- go ahead. Go to your next slide.

DR. PIRES: So this shows just that we compared the ground motion response spectra for this site and for this study, which is the red line in that

picture. We did the purple line, which is the design basis earthquake, the safe shutdown earthquake.

You can see it's much far in excess of the design basis earthquake, and you can see that there is some energy carried on the I frequencies of the ground, of the motion.

MEMBER CORRADINI: So, and this was simply -- I mean maybe I missed it in the Subcommittee meeting. This is simply a multiplicative factor of a smaller curve? It seems a bit more stylized than that, and I don't remember why it's more stylized, I guess.

DR. PIRES: The ground motion response spectra for the site is about half of the red line there, but the shape is the same. So that was scaled up for the intensity that we used for the study.

MEMBER CORRADINI: Right, on the low frequency side. But on the high frequency side, it's --

DR. PIRES: The shape is the same. The shape of the earthquake, based on the more recent seismic hazard models, is the one given by the red line which, as you can see, shifts the energy to the I frequencies.

MEMBER CORRADINI: Okay, I'm sorry.

CHAIR ARMIJO: Yes. That's a new model.

DR. PIRES: The new model.

CHAIR ARMIJO: Okay.

MEMBER CORRADINI: Right. The new model, though, with six -- where you've essentially amplified it by just a constant?

DR. PIRES: Yes.

MEMBER CORRADINI: Okay. That's what I missed. All right, sorry. Thank you.

DR. PIRES: Sure.

MEMBER RAY: Well but okay. Then I have to ask this question. We start off the proposition that it's six times the PGA and six times the SSE for existing plants. Of course, new plants typically are .3.

DR. PIRES: Right.

MEMBER RAY: So you wouldn't want the inference to be that that's the way plants would be licensed today, six times that. It's six times for the existing plant, or I guess for Peach Bottom, or the 25 plants you referred to.

It just bothered me a little bit that the inference would be that it's six times what a plant in the central and eastern U.S. would be designed to today. It's a similar comment to the one Steve made,

I think. It's what is the perception of what you're saying that is being conveyed.

DR. PIRES: I was just referring to the particular site here. If you will consider the ground motion response spectra, that will be similar to what the plant would be designed for today. That is only about a factor of two.

MEMBER RAY: That's right.

DR. PIRES: Two, a little bit over two. From .3 to .7.

MEMBER RAY: Yeah, and I think that that message is -- I mean I understand what you're saying is accurate. It's just what do people hear that I'm commenting about.

CHAIR ARMIJO: Okay.

DR. PIRES: For the spectral analysis, or the objective of the spectral analysis is to determine what the initial conditions for the remaining part of the study, the accident progression analysis.

What we looked for primarily here was I start with the bullet right at the bottom, was for what would be the distortions and the displacement strengths in structure of the pool and the liner.

And so that was the primary results that we are trying to obtain. We are going to -- we follow an

approach that was used in a previous study, that looked at the fragilities of spent fuel pool structures, that was done for the resolution of the Generic Issue 82.

So we followed the general approach. We modified it somewhat to do more detailed analysis of the structure of the pool itself. They did some end calculations.

Here, we did finite element modeling. So a little bit more detail there, because the structure of the pool is complex and we were trying -- you know, part of the purpose here is to look at cracking patterns.

We have been leveraging data that existed for the NUREG-1150 PRA, the flaw response spectra data was calculated there, that is accelerations at various points on the structure. So we can leverage that data, and scale it as an input for this study. That was an advantage. Like Don pointed earlier, this information was part of the reasons why we chose this plan.

So if you move to the next slide. These are just some pictures to illustrate the configuration of the building. The reactor building is down there on the upper left corner. We ended up not modeling the

entire building. We just isolated -- we used loads already calculated in previous studies, and then isolated the structure of the pool itself.

You can see that on the right, which shows the spent fuel pool and also the dryer-separated pool. You can model the other part. Spent fuel pool structurally supported on the reactor shield building on one side, and then on the other side it's supported on the exterior wall.

It's a reinforced concrete structure. It's very thick walls, very strong walls. It also has embedded beams and girders on the floor, which provide additional strengths to the stretcher.

MEMBER SKILLMAN: Jose, in the upper left image, there are colors from the base mat to the steel bracing. What do the colors represent please?

DR. PIRES: They don't represent anything of significance. It's that we were -- at some point we thought it would be useful to do an entire finite element model of the structure, and actually generate our response spectra.

But we realized we would not have possibility of doing that in the scope of time that we have, and that is just we were dividing the models in parts for your convenience.

So there is nothing special. You can see at the top the spent fuel pool floor, and that area above the spent fuel pool floor tends to be metallic in some of these reactors.

It tends to be a metallic frame. It carries the crane. It's a very heavy crane, rated for over 120 tons, and it's an open area. That's an entire open area there. So that's, I guess, the open space that was referred to before.

MEMBER SKILLMAN: Thank you.

DR. PIRES: And then shield panels in between those empty spaces there, that are, tend to be metallic panels.

MEMBER ABDEL-KHALIK: The analysis was done with the gates up?

DR. PIRES: Yes.

MEMBER ABDEL-KHALIK: Does it make any difference if you're in a refueling configuration?

DR. PIRES: Not a significant difference within the approximations that we are considering.

MEMBER ABDEL-KHALIK: How about sloshing?

DR. PIRES: The sloshing tends to be longer period, long period, and affected by the long period components on the ground motion. And it might make some difference, but the sloshing, we would not expect

it to be an important component on the loss of water from the --

MEMBER ABDEL-KHALIK: And this is just intuitive?

DR. PIRES: It's not completely intuitive. We did some preliminary calculations, simply by calculation by hand, just to see what the results, range of the results would be, and that came up with numbers for sloshing that are relatively small.

MEMBER ABDEL-KHALIK: But aside from sloshing, the presence of the gates, does it make any difference?

DR. PIRES: In my opinion, it does not make a difference, on the loads calculated and on the damage to the pool. It's my opinion. The other place where it could make some difference, for instance, would be there is an autodynamic load that is the impulsive load of the water.

But on -- these are almost 40 feet deep or 40 feet wide. So that mass of water there is going to be moving with the pool during the earthquake, and the small dimensions of that gate will not have a significant effect on that, in my opinion. But we didn't verify it with analysis.

MEMBER ABDEL-KHALIK: My concern would be

the coupling between both sides of the pool.

DR. PIRES: Yeah. I don't expect that it will be a measure. Can you go to the next slide?

I should make a comment before moving to the next slide, that was a question that was brought up before, is ordinarily, you'd use the pool, and there will be differences between the pool, depending upon the architect engineer, not only on the amount of reinforcement and other details on the floors.

Also, there will be differences, for example, on how the liner is attached. So some architects and engineers would have different choices on those details. However, they would all be trying to achieve the same goals, just with different details, I presume.

After I said we have looked at where, and we used simpler approaches for that, was penetrations. The displacements would be very small. These are very stiff structures, very thick. So the displacements would be small and likely the penetrations will be damaged.

We looked at AC and DC power fragilities, and took a look also at fragilities estimated for other buildings, like the building that would house the B5B equipment. That's not a seismic integrity

warrants action.

MEMBER POWERS: I'm intrigued by the statement that the systems are very stiff, and it's unlikely that the penetrations would be damaged.

I'm familiar with a variety of tests of containment structures, which I presume are stiff, and I cannot think of a single case in which the penetration regions survived an overpressurization, which is quite different than what you're talking about here.

But in every case, I think the damage to the structure was most noticeable around penetrations. So I ask you what do you have as far as experimental validation of this argument that the penetrations are going to be invulnerable to damage in these stiff structures?

DR. PIRES: Yeah. The containment structures are different. It's the entire wall of the containment is pretty much under the same uniform strength. The strength is very uniform over the entire wall, because of the internal pressurization.

Then there are strength concentrations around the penetrations, and because of that, either the containment structure around the penetration you start developing of tear points in the concrete

containment on the liner. The containment will not fail catastrophically, but the tear -- if you are going to develop tears, they would be in the regions of strength concentrations.

In this case, but still other penetrations, you know, there have been tests of barrels. Penetrations are designed to accommodate some of these deformations. They themselves have not failed in some of the tests that I have looked at, but it was the region of the containment where it transitioned to the penetration, where you have strength concentrations.

In this case here, the displacements that exist, and even those are small, tend to be near the bottom of the walls and they're very small, very, very small displacements. They concentrate near the bottom at the intersection of the walls and the pool. At that level, you don't have penetrations. Penetrations are further up, above the level of the racks.

So and there, the displacements are very, very small. So that's the basis for my argument, and we are looking at models to calculate strength concentrations in the outer area, in the liner, similar to what was done for containments.

Some approximations we made here is because this ground motion is high frequencies, and there is

incoherency on the vibrations of the ground, there are matters that have been used recently to take into account that incoherency, because that will reduce the loads that I've seen through the structure.

Those were -- here, we're just using approximations. Although this is probably not a structure where there will be much reduction from those incoherency facts, but we still accounted for them in approximation, in a manner that was probably somewhat conservative in this case.

So some coupling of the structure and the pool itself might also lead to some reductions in the load. Those were not accounted for here, and so those are some approximations that we made, that may be on the conservative side.

And what else? Oh, another thing is the load from the racks was using approximation. The assumption made here is what that for these floating racks that are allowed to slide, they tend to be -- the movement of the racks tends to be longer periods.

So they are decoupled dynamically from the structure. So there are dynamic amplification of -- the inertial loads on those would be calculated using a factor of one, so doubling essentially their dead weight. And that the spent fuel damaged state, we are

assuming that that damaged state to the envelope, potential leakage from the transfer gate or from the dryer pool for the conditions, some conditions on the operating cycle, in which the gates would be open.

And so what the end result that we are looking for is a few discrete damage states that will be minimal in terms of their relative likelihoods.

MEMBER SCHULTZ: So with regard to the first three items here, the impression is that you could have done more detailed or more complex analyses, and demonstrated what these assumptions, the effect these assumptions had on the results that have been produced?

DR. PIRES: It is happened. Yes, it is always possible to do that. In the case of the I frequency, for example, many of the reductions that I have been seeing have been claimed for structures with a very deep place mat, say 15 feet, in some places 20 feet. Very few place mats are uniform over the foundation.

That's not the case in this structure. It's only, the foundation is only four feet thick, and it's not uniform. Near the drywell foundation, it is thicker, so it's not -- the dimensions.

So the drywell pretty much is the structure

that transmits the vertical motions to the pool, and that's only about 60 feet in diameter at the foundation, not at the size of the foundations in which you have seen large reductions from this incoherency effect. So this judgment made us conclude that that was probably not where we should put our effort at this time.

MEMBER SCHULTZ: What I'm trying to get to is were these not investigated in more detail because of lack of time? Would you have wanted to look at these in more detail, or did you assume we're really trying to develop -- we're really trying to develop a damage state for the spent fuel pool.

Therefore, we could identify these in more detail, but then if we didn't damage the spent fuel pool substantially enough, we would increase the magnitude of the seismic event, and so we would get there?

DR. PIRES: No, that was not the reason. The main reason was these arguments that I told you, that these -- that incoherency effect is normally observed for dimensions of 150 feet. This reactor building is 150 feet, but the foundation is not uniform in thickness, and it's thinner than the others.

So our judgment was that that reduction would most likely not be of significance, given other uncertainties for us to spend time doing that with these models.

MEMBER SCHULTZ: Good.

MEMBER STETKAR: Jose, and just to be clear, there's no effort in this study to develop any type of fragility-type curve for any of these structures or connections, was there?

DR. PIRES: The only effort is down at the bottom, to when we tried to calculate the likelihood of those damage states.

MEMBER STETKAR: But damage states given that specific acceleration?

DR. PIRES: Exactly.

MEMBER STETKAR: Not what I'm talking about is fragility curve, as a function of applied acceleration?

DR. PIRES: It's not the full fragility curve, but it's just we did some sensitivity or we are doing some sensitivity. But just for that purpose, to see what would be the uncertainty around that, so that you can estimate some standard deviations to calculate the relative likelihoods.

MEMBER STETKAR: Yeah. That's a different

concept there than what I'm discussing. Thanks.

DR. PIRES: And that's it. That is my last slide.

MR. HELTON: Okay. This is me. I'm Don Helton, and I'll be talking to you about the scenario delineation part of this, the MELCOR modeling and the MACCS-2 modeling.

The next slide here just tries to show you how we've discretized this problem in the time domain. So we're looking at a typical operating cycle of 23 months, almost two years.

The first 25 days of that, just under a month, is the outage, and then followed by the post-outage period. Obviously, in terms of decay heat and movement of fuel, there's more going on or at least movement of recently discharged fuel, there's more going on during the first part of the operating cycle. So we've preferentially weighted that part of the cycle, in terms of discretizing the time domain.

So basically we've broken it up into five, what we would term as operating cycle phases, and the first two of those are during the outage, and then the remaining three cover the remainder of the operating cycle.

MEMBER SKILLMAN: Don, to what extent would

an emergency offload of the entire core at the end of OCP No. 3 do to your, if you will, to your results?

MR. HELTON: It would certainly affect -- for the sort of instantaneous part, or for that little part of time while the emergency offload had taken place, then it certainly could affect the results.

We would expect it to affect the results for both the high density and the low density case, and other than that, the only other thing I'd offer is that, you know, this was a point of discussion at the Subcommittee.

So I did go, just anecdotally go and talk to some folks in our Office of Regulation, to try to get a feel myself for how typical that sort of occasion is, and at least anecdotally, the information was is that it would be highly atypical, but certainly possible.

MEMBER SKILLMAN: Thank you.

MR. HELTON: The next slide just tries to orient us a little bit with regard to the mitigation assumptions. So at this point, I just want to remind you that we are looking at a situation with high density loading, and then a separate situation with low density loading, where the fuel older than five years has been removed from the spent fuel pool.

For the high density configuration, we're basically looking at two alternatives there. One is a situation where the licensee has re-arranged the fuel prior to the outage, such that the recently discharged fuel goes directly into a one by four pattern, and that is consistent with what the plant that we're studying, Peach Bottom, does, but recognizing that that's not necessarily the case for all licensees.

We also have another alternative where during the outage, the fuel is stored contiguously, and then placed into a one by four configuration after the outage. So we're going to talk about -- we're going to use this terminology, and we recognize it's not perfect.

We're going to use the terminology "unmitigated" and "mitigated," and we've wrestled with other terminology like optimistic and pessimistic and other things, and certainly welcome any thoughts you guys have on that front.

But for the moment, we're going to use this unmitigated and mitigated terminology. For the unmitigated scenarios, what that means is that no operator action is taken for 72 hours, and 72 hours right now is the time that we're using to truncate the

calculations and the pool has either reached a stable steady state, or has not gone to release by that point.

So for unmitigated cases, no operator action, and I'll touch upon this again in a minute. But what that means is we are also not considering repair and recovery of the spent fuel pool cooling and other systems, and basically what this comes down to is non-recovery of AC power, because that's clearly what's prohibiting the use of the equipment that's used for dealing with the spent fuel pool.

MEMBER CORRADINI: So I'm sure you said this in the Subcommittee, but I guess I forget. So that's going to be viewed as a high density, no mitigation of bounding calculation, to show what?

MR. HELTON: Let me -- do you need to do a calculation? I think I could surmise where we're going with that one.

MEMBER CORRADINI: No. I think you definitely need to do that calculation. I'm also going to object a little bit to the use of the term "bounding," because as you guys would point out, we could have chosen other things like an emergency offload.

MEMBER CORRADINI: That's fair. We could

have done that. But still it is a pessimistic case.

MR. HELTON: Okay. But it's not the same as saying that all hope is lost, in the sense that we will have any number of conditions that by 72 hours will not have had a release. If you don't -- for instance, if you're in a pure boil-off situation and let's say you're --

MEMBER CORRADINI: Okay, that's fine, that's fine. I'm with you.

MR. HELTON: Does that make sense?

MEMBER CORRADINI: Yes. I just -- and then the, and again maybe I asked this in the Subcommittee meeting. I don't remember. Is this a matter of just time to the end of the study, that you didn't do some sensitivities, in terms of operator actions at a day, three days, some time, to see if that a big effect on it?

MR. HELTON: I wouldn't really say that it was a function of the study being expedited, so much as we -- it was decided at the beginning that we were not going to do an HRA.

MEMBER CORRADINI: That's fine. That helps me.

MR. HELTON: So that sort of sets you down --

MEMBER CORRADINI: So it's essentially kind of two --

MR. HELTON: Right, not extremes, but two situations, an optimistic and a pessimistic.

(Simultaneous speaking.)

MR. HELTON: Okay. For the mitigated scenarios, what that means is first of all, we're assuming diagnosis of the need to take mitigation based on a loss of level and time for observation.

In terms of the capacities and the timings of the 5054 HH2 equipment, or the B5B equipment, for those more familiar with that vernacular, we are in general following what's prescribed in any NEI-06-12 Revision 2, which is the industry guidance for this equipment, and which has been endorsed by the NRC for operating reactors. There's a separate revision that's been endorsed for new reactors.

Then once deployed, again in the vein of an optimistic/pessimistic situation, once deployed, then we assume that either other on-site capabilities or off-site capabilities are brought to bear to continue operation of that equipment to the end of the simulation.

MEMBER STETKAR: And Don, I've forgotten from the Subcommittee meeting also. Was there some

likelihood that that B5B equipment was damaged, destroyed, unavailable, due to the seismic event, or was it always presumed to be available, as long as the operators had this time delay?

MR. HELTON: The way we're treating it, obviously there is some unquantified, in terms of this study, probability that the equipment would be damaged, and in the context of this study, that represents the unmitigated case. The unmitigated case treats the situation where it is unavailable.

MEMBER STETKAR: Okay.

CHAIR ARMIJO: Where did the five feet come from, five feet plus 30 minutes for diagnosis?

MR. HELTON: That was simply something was developed subjectively, and then discussed internally and viewed to be reasonable. Now as a starting point, now that we've done the analyses, what we're finding is is that you could make slightly different assumptions, and you wouldn't see any large effect in the results.

But that's -- so again, it's somewhat of a subjective determination --

CHAIR ARMIJO: It's a starting point, and you just -- did you pick it from experience or something --

MR. HELTON: I mean I guess the best way to characterize it, it was subjective. The intent was to take into account the situation that AC power is unavailable. DC power may be unavailable, and --

CHAIR ARMIJO: And you don't know what's going on.

MR. HELTON: And now there's a lot going on at the site. The site we're studying specifically has provisions in their earthquake response procedures, to go check the level of the pool, as one of the many things that they're doing.

So but again, this was not intended to be prescriptive or performance-based in any way. It was just a logical way, what we felt was a logical way to approach diagnosis, given that diagnosis is not defined. It's one of the things that's not defined in the underlying NEI document.

MEMBER STETKAR: Well, and I think the key is you said you explicitly did not perform a human reliability analysis. You didn't examine anything about timing or feasibility or any of that, any of those issues that you would examine more carefully.

MR. HELTON: And then my final point here is just to point out that we do have these cases of successful or unsuccessful deployment of the

mitigation equipment. But whether or not that equipment is successful in preventing the release or decreasing the source term is something that we attempt to simulate mechanistically.

MEMBER SKILLMAN: How would the results be affected if you were required to consider a 60-day decay on the third of the core that you just offloaded, plus 24 or 30 hours of decay on a full core that you were forced to offload? So now you have 1-1/3 core arranged in the pool, one full core that's just freshly discharged, because you've got a casualty on the primary where you're forced to offload.

I understand you to say that's a typical. But what's typical of all white water reactors is decay heat, and you can't get away from that. It is a phenomenon that comes with this technology. So if you were to be forced to consider the third that you offloaded 60 days ago, plus the three thirds that you just irradiated for 60, 90, 100 days, and you interspersed that new full three-thirds core into your pool, how significant would the result change?

MR. HELTON: I guess I'm not prepared to answer that quantitatively. We haven't analyzed that, so I don't have an answer for you. The one thing I will offer is that we continue to think about this in

terms of both the likelihood and the consequence.

So now there is at least the potential, certainly we'd grant there's at least the potential that the consequences would go up during that situation, but they also have to be combined with the fact that we now have had that particular situation, which is potentially not common, combined with this event, which is obviously not common.

And so again, I can't answer you quantitatively, which I think is what you would want. But by the same token I would offer that qualitatively, you've got competing demands here, in terms of potential for increasing consequences versus the decreasing likelihood.

MEMBER SKILLMAN: Well, I'm not persuaded by the idea that it can happen or that it's atypical. It would seem to me that this would be a scenario that should be included, just to assure that however one might look at the path forward for loading these spent fuels, accommodates even that unlikely event where the operator is forced to go to a full core offload.

Even though that's atypical, I believe that's almost a design basis that one ought to consider.

CHAIR ARMIJO: But Dick, is that the only

option that the operator would have? Just stay put for a while, keep it in the core. Rearrange your pools for a favorable offload, you know.

MEMBER. SHACK: A short earthquake's not going to happen.

CHAIR ARMIJO: I mean if you just -- the only option that you point out is that you shut down, you start offloading immediately, and if you're aware that there's a vulnerability here, wouldn't you look at other options?

MEMBER SKILLMAN: You'd look at all options.

CHAIR ARMIJO: Yeah.

MEMBER SKILLMAN: But the one thing I would do is pull the fuel -- I think removing fuel is one that one would think of. It would seem to me that's --

CHAIR ARMIJO: Other than what scenario you're talking about, when you're forced to offload, you know.

(Simultaneous speaking.)

MEMBER STETKAR: I think we're getting into time issues here, but I think you're all dancing around the fact that this is not a probabilistic risk assessment for a fuel pool. It is not a full-scope probabilistic risk assessment. It is a specific

calculation for a specific configuration, under a specific applied acceleration with specific assumptions, where there is some variability in those assumptions, like the optimistic versus pessimistic conditions.

It's not a full-scope risk assessment that would account for, you know, frequency and variability and frequency, different types of scenarios, different types of consequences, and uncertainties in terms of the frequency of an applied acceleration or the fragility of any of the equipment. It is not that. It is simply what it is.

MR. HELTON: For time considerations, I'll keep going. We'll take that under advisement.

CHAIR ARMIJO: Keep moving, okay.

MR. HELTON: We know that stating assumptions and limitations are --

MEMBER CORRADINI: I'm sorry. I know that he wants to move on, but because of what John said, which I agree with, then I'd be very careful to take selected calculations, then to move on to some decision-making based on selected calculations. That's, I think, where we're all kind of going here, and there's a lot of heads nodding on this. That's what I think --

(Simultaneous speaking.)

MEMBER CORRADINI: --relative to the Subcommittee meeting. Is that fair?

MEMBER SKILLMAN: Yes.

MR. HELTON: And that's where the bigger picture issue comes in, in terms of the Tier 3 item, and I mean that's part of what we're wrestling with there, is you know, there's a good knowledge base here.

We are probing portions of that knowledge base, to see if they're generally challenged or corroborated. But it's that overarching knowledge base that needs to be used to make a regulatory decision.

Okay. Just real briefly, we've touched upon many of these, either at Subcommittee or today, but we know that stating, clearly stating assumptions and limitations is important. So I just, here, we've put down a few of them with full core offload, both as an outage for vessel inspections or in the way that it's been brought up today.

These are not typical for a BWR, and so because of the way the study is structured, we're looking at the more typical situation. But we recognize that as an assumption.

MEMBER STETKAR: On the other hand, full core offloads are typical for pressurized water reactors during re-outage.

MR. HELTON: That's correct, that's correct. I guess another thing that I would point out there, that had not really occurred to me or not really sunk in with me previously, is keep in mind that when we have the pool in a situation where it is hydraulically connected with the reactor, so when it's in a refueling configuration and the gates are down, the reactor well's flooded and it's hydraulically connected to the pool, and we're in -- and we're doing our analysis, for as long as they're hydraulically connected, we're actually accounting for the decay heat in both the reactor and in the pool.

So in some senses, we are doing a full core offload, and that as long as they're hydraulically connected, we're accounting for the decay heat in both.

MEMBER STETKAR: But until you drain down --

MR. HELTON: Until they become hydraulically disconnected --

(Simultaneous speaking.)

MR. HELTON: Correct, and then it becomes a reverse to being a spent fuel pool study.

MEMBER STETKAR: Yes, that's correct.

MR. HELTON: But you know, we felt like -- that's an area where we felt like that was just too arbitrary and invisible line to draw, when you knew that decay heat in the reactor, in part heating up the water in the spent fuel pool.

So I want to touch upon multi-unit effects, because that's a little bit of what we just talked about. Inadvertent criticality events is something that we're currently is not within our scope, and we've already talked about the recovery and repair aspect. To the extent that we can address some of these issues and others that we're identifying by a sensitivity analysis, then we endeavor to do that.

CHAIR ARMIJO: Your election to look at uncertainties via sensitivity studies is because of the computer codes that you're using, or you just wanted to provoke Professor Apostolakis?

MR. HELTON: Well first of all, you can use global sensitivity analysis methods, that might not provoke him. But --

CHAIR ARMIJO: No, it would provoke him. I know that.

MR. HELTON: No. At this point, that's not a part of it that we spent a lot of time focusing on

or cataloguing the assumptions and limitations that we're making, and as we have these thoughts of you know, hey, this is one we can chase after, once we have the time, then we're cataloguing that as well.

You know, you can have those arguments as to which one is more efficient or effective at getting what you're getting at. At the moment, we propose sensitivity analysis. But it's not an inherent limitation of the tools codes that we're using, as demonstrated by the fact that we're doing quantitative uncertainty analysis as part of the SOARCA project, using essentially the same tools.

MEMBER POWERS: So you just want to provoke Professor Apostolakis?

MR. HELTON: Yeah, sure.

MEMBER POWERS: I kind of enjoy that myself, so --

MR. HELTON: Real quickly, I just want to touch upon the use of MELCOR for spent fuel pool analysis. This slide is just intended to give you some reassurance that we didn't enter into this blindly. MELCOR, as a tool for spent fuel pool analysis, has been in use for roughly a decade now.

As part of the security assessments that were done post-9/11, we did a large number of separate

effects and integral analyses, and we in fact briefed the ACRS on several occasions on those analyses.

In addition to that, we've done limited comparisons to the COBRA-SFS study, or actually COBRA-SFS code. We've done some computation fluid dynamics analysis to support some aspects of the MELCOR modeling, and there was also an experimental program that looked at ignition, well looked at hydraulic, thermal hydraulic and ignition phenomena related to fuel during a spent fuel pool accident, again to confirm or modify the use of the code in this context.

CHAIR ARMIJO: Don, are you analyzing channel or dechanneled BWR fuel, or both?

MR. HELTON: We are analyzing channeled BWR fuel.

CHAIR ARMIJO: Which probably from a cooling is not as conservative. Inability to cool it tends to isolate it from the other. You know, like compared to your cartoon there of the PWR assemblies, they're pretty open, unless the poisons --

MR. HELTON: For a case where you have a complete drain down spent fuel pool accident, keep in mind that the air has to get under the racks and through the inlet nozzle of the racks and the assembly. So the channel box can have some effect

there. Keep in mind that these are high density racks, so they are fairly close-pitched and the rack walls are closed.

So the rack walls, in some respects, represent an outer channel. So I wouldn't argue that there would be some effects, but there are some other factors that would also --

CHAIR ARMIJO: So you don't see that as a big effect, channeled or dechanneled?

MR. HELTON: I wouldn't expect it to have a big effect, because of the closed frame racking.

CHAIR ARMIJO: Okay.

MR. HELTON: And also keep in mind the channel boxes add zirconium to the mix. So they have good and bad effects in that sense.

This next slide is just intended to give you a picture in your head, as to what MELCOR is trying to represent here. So we have up on the upper right-hand corner a picture of the spent fuel pool layout during operating cycle Phase No. 3. So this is post-outage. The fuel is in a one by four pattern.

One of the things that occurred to me might have gotten confusing at the Subcommittee, the blue here, in case it's not obvious, is not water. It's the cold fuel. So and then in terms of orienting the

older fuel, and to some extents we allow the modeling conveniences to guide that, since that's not the fuel that's going to have the first order impact on whether or not you go to release, what the initial release would look like.

Then there are a couple of other figures off to the side and at the bottom here that just attempt to show how you take a code like MELCOR and represent this type of geometry.

MEMBER POWERS: One of the features of the code you're using doesn't solve the momentum equation, and so if you look at this assembly, you say -- or this projection, you say gee, this looks to me like a whole bunch of parallel channels, flow channels.

Why is it immune to parallel flow instabilities, so that I don't need to solve the momentum equation? In other words, I could have steam roaring up through one channel and air coursing down through another channel.

The difficulty you have is that once you establish an air downward flow, it's a vacuum, because the oxygen component gets completely consumed, whereas in everything else, the steam reaction produces an equivalent amount of hydrogen.

Why are you immune to parallel flow

instability over this large range sludge pattern of reacting fuel assemblies?

MR. HELTON: Let me take a crack at that, and then Hossein can jump in, if he elects. In terms of what the overall flow pattern is going to be, and to what extent you're going to get up or down flow, we did try to do or we did do computational flow dynamics analyses, to try to get at that issue, and to look at the flow in the building, the downflow through the downcomer area and under the racks, and then upflow through the assemblies.

In general, those analyses showed that you would set up this -- that if a pool were completely drained, you would set up a situation where the downcomer area, in this case the cask area for the pool, and the gaps between the racks and the pool walls, will establish that downflow, and that flow will preferentially go to those areas, and that flow will preferentially go up through even the colder assemblies, as well as, of course, the hotter assemblies.

It's not to say that can preclude downflow through assemblies on the very periphery. But in general, we didn't see that type of behavior.

(Off record comments.)

MEMBER CORRADINI: You're worried about it, Dana, when there's water above it or once I start getting to the top of the channel?

MEMBER POWERS: Once you get to the top of the channels, it seems to me and if it was one assembly, I think you can argue that the steam flux is enough, so that you don't have to worry about this parallel flow instability problem.

But now you're talking about many, many feet of assemblies. Small fluctuations in the steam flux will set up, and once you start air being set down and reacting with an assembly, because the oxygen gets completely assumed, that becomes a very stable downward flow.

It does tend to preserve itself, and then you'll have steam roaring up in one area and air coming down in another area, and it's a very complicated-looking flow pattern.

MEMBER CORRADINI: What you're really asking, though, is -- I mean what I think you're asking is how much of a power difference and hydraulic difference do you need to cause that to occur? I wouldn't expect it to occur, but if I made enough of a disparity of the power that each one's giving and the frictional losses, you could get it.

MEMBER POWERS: Remember I had tried to push air through a porous plate that looks like this. What I find is always I get a downward flow around the periphery, and it's just because there's more resistance to upward flow there, and so it concentrates in the center.

I would expect you have the same thing trying to come down. I certainly don't know, but this is clearly a highly stylized thing, and in fact having air coming down into this system might actually be less risky, because you'll promptly burn all the hydrogen. You'll get no accumulation of hydrogen in this situation, I suspect. But again, I don't know. So I just asked.

MEMBER ABDEL-KHALIK: Would you get any air flow through these bundles until the entire bundle clears, I mean you've got a gap in the bottom?

MEMBER POWERS: Once you get, expose a little hot zirconium, it's going to go after air like you will not believe. It will create a flow toward it.

MEMBER SKILLMAN: But you've got to be completely uncovered to get that, though?

MEMBER POWERS: No. All you have to do is expose the top.

MR. HELTON: We would predict that for a good portion of -- I mean obviously, we're talking about after you started to uncover the fuel.

MEMBER SKILLMAN: Right.

MR. HELTON: While the top I'll say half, for notional thinking purposes, while the top half of the fuel is uncovered, but the bottom half, again for notional thinking purposes, is covered, then we would predict that you would still get a lot of steam cooling from the boiling taking place.

Once you've lost adequate steam cooling, then you would have some circulation, as Dr. Powers was talking about, but you would not set up the once-through natural circulation cooling until you had substantially cleared the base plate, as you're referring to.

CHAIR ARMIJO: You mean the whole pool has to be emptied?

MR. HELTON: That's correct.

MEMBER CORRADINI: But I think, I'm just eating. So Sam's, somebody's got to tell us to stop talking. But it just strikes me that I remember these calculations for TMI. Let's not talk about today's latest event. Let's go back.

But in TMI, once I had just a little bit of

water left, I could again, under different conditions, I could imagine if I had enough disparity in power or hydraulic resistance, I could imagine what Dana's suggesting is possible.

I know it's half and half, but a little bit of water. Then, you're going to get a downward flow, because as you said, you're going to basically suck in the gases. It's a quantitative question.

CHAIR ARMIJO: I think you'd better note that and keep moving. We've got -- we're behind schedule, and we do also have one public speaker.

MR. HELTON: I will try to get us there. Okay, so this is the high density case. Let's take all the assemblies older than five years out. This is the low density case. Again, one by four for the most recently discharged, and just due to physical space limitations in the pool, you can't put the other two offloads in a one by four. So we've represented them here in a checkerboard pattern.

Okay, I'll try to -- because we're behind time, I'll try to move quickly through actually the highlights of the off-site consequence piece of this. We are using the Max-2 (ph) code. It is the choice domestically and in a lot of other places for doing this type of analysis.

It takes its input, the source term and other aspects of the release from MELCOR. It takes its inventory from ORIGEN ARP (ph) calculations, and then uses other site-specific information like weather and population as inputs, and then outputs, consequences from an atmospheric release.

We are leveraging the SOARCA best practices as much as appropriate. We've also done an update of the economic and population data for doing this analysis, and of course there are also emergency planning considerations that go into the off-site consequence analysis.

This is just a cartoon that tries to orient us about the fact that we've got a postulated radioactive material release from the site. Max-2 takes that release and transports it off-site, and then it handles things like deposition, including deposition caused by rainfall, the direct exposure shine from the plume, as well as exposure from deposited material, and then exposure from inhalation and so on.

Oops. I'm too far in my notes. Okay, and then finally in terms of consequence modeling, just to continue just a little bit more on that, we will be modeling prompt and latent health effects, and we are

following the lead of SOARCA in considering three different dose response models and planning to report results for those three different models.

Those are the linear no threshold model, the linear low dose model with truncation at 620 millirem, and again, with truncation with five rem per year or ten rem lifetime.

In terms of consequence reporting, we're planning on reporting health effects, again in terms of early fatalities and latent cancer fatalities, and also land contamination, in terms of total land, total square area of land contaminated above the specified dose level.

MEMBER POWERS: I just have to ask. The Health Physics Society has come out and said not to quantify below, what is it, 100 millirem?

MEMBER CORRADINI: Ten. You're saying below ten.

MEMBER POWERS: Ten millirem? Why isn't that one of the alternatives?

MR. HELTON: It's another one that could be considered. I will let somebody jump in if I misspeak, but my understanding, not having been directly involved, is that that was one of the sensitivities that was considered for the SOARCA.

MEMBER CORRADINI: I think it's there, isn't it?

MEMBER POWERS: Yeah.

MEMBER CORRADINI: I think it's there, though.

(Simultaneous speaking.)

CHAIR ARMIJO: It's three HPS.

MR. HELTON: Are you talking about why we don't apply low dose with a truncation at ten millirem?

MEMBER POWERS: I think what they're saying is that's the one.

MEMBER CORRADINI: Okay, that's the one. Okay.

MEMBER POWERS: I just misremembered the exact number.

CHAIR ARMIJO: It's a ten.

MEMBER RYAN: Ten rem.

CHAIR ARMIJO: Katie?

MS. WAGNER: All right. I'm going to try to do this expeditiously. So of course there will be a SECY paper that will be submitted in July 2012, that runs through the plan for the resolution of the broader item on expedited transfer of spent fuel pool dry cask storage.

We've been seeking input from the program offices, and we have been giving briefings for senior management and Commissioners. We've also been interacting with the licensee to ensure that the team understands how our assumption apply to the operating facility, and we understand that ACRS may write a letter and we would definitely consider that feedback, if it were given.

A communication plan has been drafted, and we plan on sending the study results to NRR by the end of June 2012.

MEMBER ABDEL-KHALIK: How do you intend to communicate all the limitations associated with this study?

MS. WAGNER: You can go ahead.

MR. HELTON: In terms of -- let's just talk about in terms of the June product right now to NRR, because that's what we're focused on, it's somewhat our intent to be in keeping with past guidance from ACRS on research quality. At the moment, our draft report has a chapter dedicated to stating major assumptions and limitations.

CHAIR ARMIJO: Okay. Is there going to be a conclusion from this study, other than we need to do more work? For example, from this study as it's

structured now, could you possibly conclude that we don't see much benefit in unloading the old fuel, from a safety standpoint.

Is that possible? Or we see great benefit, but a conclusion that you may have to, you know, expand on its applicability. But for the particular study that you did, you come to a conclusion.

MR. HELTON: Mr. Ruland would like to take that question.

MR. RULAND: Mr. Chairman, Bill Ruland from ESS. We, of course, the Office of Research is going to give us the study, and we've formed no opinion yet about what this is going to tell us. As you've Don talk about some of the limitations and the Committee's pointed out some of the limitations of the study, we recognize, hopefully we recognize what those limitations are.

It's going to be our job to put this in context with all the other information. So just want to, you know, that's going to be our job. You know, we're the Regulatory Office, and as, you know, as you know, I think that's our job to put it in context.

CHAIR ARMIJO: They'll give you results and you'll draw a conclusion if you can?

MR. RULAND: That's correct.

CHAIR ARMIJO: Okay, got it. Okay. Any other comments, questions from the Committee, taking into account we are a little late and we have a member of the public. Go ahead, John.

MEMBER STETKAR: Yeah, just a quick one, Don. You mentioned that you're going to carefully -- I think it's vital that you carefully describe your assumptions. Keep in mind that oftentimes it's important to explicitly describe what the study is not.

That's a little bit different than saying what you did, you know, and sometimes people reading what you did don't necessarily appreciate what wasn't done. So that's just a constructive sort of suggestion.

MR. RULAND: Right, and like I said, and one way in which we're hoping to do that again is having, at least in terms of the internal product that we're delivering to NRR, having this chapter dedicated to the major assumptions and limitations.

CHAIR ARMIJO: Okay. With that, I'd like to open the bridge line.

MR. LEYSE: Can you hear me?

CHAIR ARMIJO: Is this Mr. Leyse?

MR. LEYSE: This is Leyse, right.

CHAIR ARMIJO: Leyse, okay. Please go ahead with your comments.

MR. LEYSE: Oh, they're all extemporaneous, based a little bit on what I heard regarding quality and research. If you look at the slide, it talks about prior research. ACRS should look into the quality of that program.

I'm going to start off with something that I'll mention at the very end also. I've asked NRC to explain why more conventional LOCA studies, such as the rod bundle heat transfer at Penn State. Why is it that those studies do not require zircaloy bundles, such as the spent fuel pool Phase 1 testing? I'll repeat that later.

Starting off with my written stuff, a single zircaloy tube, sufficiently heated in air, will smoulder like pot, or somewhat like a cigarette.

NRC staff may have discerned that, so they went to bundle assemblies for the spent fuel pool LOCA fire research. At the top of the slide, the cross-section of the 17 by 17 test bundle is something that I copied and enlarged with another slide that NRC used at a closed meeting with EPRI last year.

Apparently, the NRC now recognizes the fundamental importance of including the geometry of

the stationery zircaloy reactor, in combination with the thermohydraulic or aerodynamic conditions of the air in natural circulation for spent fuel pool LOCA research.

From the slide, it is unfortunate that NRC has not applied similar resources in responding to Petition for Rulemaking BRM-50-76. Instead, NRC repeatedly extols this program that cites the role of reaction kinetics during LOCA.

For example, the Leyses' brief presentation to ACRS Subcommittee on thermohydraulic phenomena, Monday, October 18th, 2010, asserted that the 2,200 degree Fahrenheit limit for peak cladding temperature in the LOCA is non-conservative.

Mark Leyse and Robert Leyse discussed Petition for Rulemaking PRM-50-93, which requests that the NRC revise its regulations to require that the calculated maximum fuel element cladding temperature not exceed a limit based on data from multi-rod assembly severe damage experiments.

At that same October 2010 meeting, the Subcommittee listened for hours of presentations by rod bundle heat transfer staff. Those presentations did not include any consideration of the role of chemical reaction kinetics, and the impact of

volumetric hydrogen generation during LOCA.

So as I started, I've asked the NRC to explain why its LOCA studies, such as rod bundle heat transfer at Penn State, do not require zircaloy bundles like the fuel pools Phase 1 testing.

Finally, maybe the Japanese will lower the 2,200 degree Fahrenheit heat cladding temperature limit if they probe the NRC's non-conservative technical review, pertinent to the denial of BRM-50-76. Thank you. Any questions?

CHAIR ARMIJO: Okay. Thank you, Mr. Leyse. Any questions from the members of the Committee?

(No response.)

CHAIR ARMIJO: There being no questions, again I'd like to thank you for your submittal and presentation, and without any other comments or questions from the staff, I'd like to thank the staff for an excellent presentation. We will write a letter, I'm sure, I'm pretty sure.

But with that, I'd like to take a break for lunch. We're a little late, but we will reconvene at 12:45.

(Whereupon, at 11:55 a.m., a luncheon recess was taken.)

A F T E R N O O N S E S S I O N

12:44 p.m.

CHAIR ARMIJO: Okay. Let's come to order. The next topic will be the Final Safety Evaluation Report associated with the license renewal application for the Columbia Generating Station, and Jack Sieber will lead us through that. Jack.

MEMBER SIEBER: Okay. Thank you, Mr. Chairman. This afternoon, the full Committee of the ACRS will hear presentations by the staff members of the Division of License Renewal, and the applicant, Energy Northwest License Renewal Subcommittee had a meeting on the Columbia Generating Station, held on October 19th, 2011.

At that time, there were six open items and no confirmatory items from the Safety Evaluation Report. Six open items consisted of first, high voltage porcelain insulators; second, use of future operating experience information; third, upper-shelf energy; fourth, metal fatigue; fifth, core plate rim hold-down bolts; and sixth, fatigue analysis of the polar crane.

The applicant and the staff will explain to the Committee this afternoon the resolution to those open items. We will now proceed with the meeting, and

I call upon Melanie Galloway of the Office of Nuclear Reactor Regulation, to begin.

MS. GALLOWAY: Thank you, Mr. Sieber. My name is Melanie Galloway. I'm the acting Division Director of the Division of License Renewal, and as always, we are very pleased to be here today, to present to you the results of our review associated with the Columbia license renewal.

Before we get started, I'd like to introduce a few members of the staff that are here in support of this meeting. First to my left is Mark Delligatti, who is the acting Deputy Division Director of the Division. In addition, we have representation of a number of our branch chiefs.

Dennis Morey is our Projects branch chief, responsible for the Columbia safety review. In addition, we have with us Raj Auluck and Bo Pham, two of our technical branch chiefs in the Division. Michael Marshall, another technical branch chief, was not able to be here today because of an emergent technical issue that he's working, but he is the newest member of our management team in the Division, and we're glad to have him.

In addition, I wanted to note that there is representation by all of our technical branch staff

here, as well as regional individuals on the phone. Geoff Miller, the branch chief in Region IV, as well as Greg Pick, the senior inspector, Region IV, are available via that phone connection.

In addition, beyond the staff in the Division of License Renewal, we have representatives from other technical organizations in NRR that have supported this review, including balance of plant branch, the vessel internal branch, and the electrical branch.

First of all, there are a few things I want to note before turning it over to the applicant for their presentation. The first is we want to thank the Committee for being flexible in terms of the scheduling of both the Subcommittee meeting and the full Committee meeting.

The original schedule for Columbia was a 22-month schedule, but in order to accommodate the requirements of the applicant, in terms of responding to RAI, as well as some of their on-site scheduling, we did extend the schedule by seven months. So thank you for your flexibility in that regard.

I do want to note in particular one open item that was open at the time of the Subcommittee meeting, and is of course now closed, and that is the

open item that had to do with operating experience. I want to note that, because that is an area of review that has gotten increased importance for the staff.

We recently issued an interim staff guidance document in March of this year, talking about and providing additional clarity in the area of operating experience reviews. We've recognized over time that this is a very significant area that required more definition.

As more plants get into the period of extended operation, we recognize the importance of operating experience in terms of ensuring the effectiveness of aging management programs. So the Columbia review was the first license renewal review that had the full benefit of this additional codification, which we had provided in operating experience, and the staff, as well as the applicant, will go into additional detail, talking about the type of information that was provided, that allowed us to close this open item.

With that, I would like to turn it over to the applicant, Dale Atkinson, for their presentation.

MEMBER STETKAR: Melanie, before you stop, you said that there was an ISG just issued in March of this year?

MS. GALLOWAY: That's correct.

MEMBER STETKAR: Do you happen to have that ISG number?

MS. GALLOWAY: Sure. It's ISG-2011-05. The exact title is "Ongoing Review of Operating Experience."

MEMBER STETKAR: Thank you.

MS. GALLOWAY: Sure.

MR. ATKINSON: All right. Thank you, Mr. Chairman. Are you ready to begin?

CHAIR ARMIJO: Yes sir, all right.

MR. ATKINSON: I'd like to introduce myself. Dale Atkinson representing Energy Northwest, and I appreciate the opportunity to appear today before the ACRS and discuss the license renewal application for Columbia Generating Station.

I'd like to take just a moment to introduce our team. To my immediate left is Don Gregoire, Manager of Regulatory Affairs, and to his left is John Twomey, Project Manager for License Renewal. Additionally, we have several members of our staff here for support around the room.

We've provided an agenda, which we think will address the closure of the open items and other topics of particular interest, and with that, Mr.

Chairman, I'd like to draw your attention to what we have as Slide No. 4. Slide No. 4 is an aerial view of the Columbia Generating Station and surrounding area.

I know many of the members of the ACRS have been out to visit the site. If I can go back to that particular slide. One moment. There we go. Okay. I'd like to point out a few features on this. In particular, you'll note in the bottom center of the slide here, Columbia Generating Station itself, the Hollis Building is the reactor building.

To its immediate left is the Turbine Generator building, and the Rad Waste building is the shorter structure there. There are several support buildings around as is typical. To the right over there is a collection of six four-strap cooling towers. Immediately above them are the two ultimate heat sinks, with two spray rings in service. You can see by the white circles there.

As you had towards the top of the picture, which is actually looking east, at the top of the picture is the Columbia River. It flows left to right in this picture, and roughly in the middle of that shot of the river is the river intake structure, that provides cooling water to Columbia Generating Station.

You'll note in the land that exists between

Columbia Generating Station and the river are two cancelled nuclear plants. I'd like to point out some elevation features that are not obvious when you look at this aerial photograph. There is a fair bit of elevation change.

In particular, I point out that the Columbia River itself has a normal river high water elevation of 353 feet above mean sea level, and the plant itself, the area right around the base of the reactor building, is actually at elevation 441 feet above sea level. So there's typically an 88-foot delta in there.

I guess I'll also remind the Committee that Columbia Generating Station is located on the Hanford Nuclear site, and consequently you can see not a lot of other features surrounding it there.

I draw your attention to the next slide please, Slide 5. Just a general overview. Columbia Generating Station is a General Electric BWR Series 5 reactor with a Mark II containment. As I showed in the picture, the cooling water supply and the plant circulating water in the ultimate heat sink from the Columbia River, very nice, clean cool water.

The plant is rated at 3,486 megawatts thermal, and has had an upgrade, which I'll address in

the next slide.

MEMBER. SHACK: Is that a venting? Is venting in this Mark II?

MR. GREGOIRE: As in hardened vents?

MEMBER. SHACK: Yeah.

MR. GREGOIRE: We do not have hardened vents. A brief history, with the construction permit in 1973; the operating license on December 20th, 1983. We did conduct a five percent uprate in 1995, and then applied for license renewal of January 2010, and I'll just point out our present license is set to expire December 20th of 2023.

With that, I'd like to turn the presentation over to Don Gregoire. Don?

MR. GREGOIRE: Thank you. On Slide 8, it covers briefly our aging management programs we're crediting for license renewal. 55 in total; 35 currently existing; 13 enhancements to those; and then 20 additional ones. We do have 71 commitments. 55 of those are specifically for each of the programs we're committing to or crediting for this process.

On the next slide is a summary of the six items that were considered open at the time of the Subcommittee meeting, and I'll touch base on each one of those rather briefly, and if you have questions,

please let me know.

The first one is Slide 10, closure of the open item related to high-voltage porcelain insulator. Now we have been asked to include this in our program, and on August 17th, we provided a response to the staff that we were including these insulators in our program, and that closed out that item.

In regards to the next slide, Slide 11, operating experience. As Ms. Galloway had mentioned, Columbia was one of the first in the queue there to expand on how we were going to communicate use of future operating experience for modifying or implementing changes to our aging management program.

We had gone through a number of iterations, teleconferences with the staff, to try to make sure that we captured the appropriate language in our FSAR. We implemented a few enhancements to our existing programs, and we provided responses in December to close this item with the staff.

MEMBER SKILLMAN: Don, I would like to ask this question please. In the status report that the ACRS has been provided, the forward-going strength of your OE program is really tied to your Corrective Action Program.

MR. GREGOIRE: The Corrective Action Program

also includes the operating experience program, that's partnered with that. So it's internal and external, yes.

MEMBER SKILLMAN: Describe to us the strength of your Corrective Action Program, please.

MR. GREGOIRE: Okay. I will note that during the inspection from the NRC, there was a comment made on a couple of items that had not been entered into the Corrective Action Program during the inspection, due to corrosion issues. Since then, we've instituted a number of strengths or changes to our Corrective Action Program and our engineering walk-downs.

I just reviewed the engineering walk-downs performed for this last quarter. There were a number of CRs that were written to address issues from leaks to gasket issues, to a number of things that demonstrate or prove that we had taken action to make sure that we're identifying and using Corrective Action Program to address any signs of aging.

We have implemented some changes to our operating experience program, to ensure that we have a license renewal implementing coordinator, who sits on the program to ensure that they evaluate and identify any new aging issues, and that includes new

failures or possibly new, not just failures that are non-safety related, but failures that are safety-related.

And so we have active involvement with our License Renewal Committee or our team in the operating experience, as well as in the Corrective Action Program. We review all the CRs, condition reports every day, every working day, to identify those that would or need to be captured in our aging management program. So we have done a number of things to strengthen the program in this regard.

MR. ATKINSON: Yeah. Nonetheless, I think what I'd offer, I do think it's a strong program. So I don't feel that we're particularly exposed in that area. We have had external people take a look at it. We've got a nuclear safety culture assessment underway this week, which includes a major focus on the Corrective Action Program.

The involvement of all the staff is quite significant. As Don mentioned, we each get all of the corrective action items every working day. We go through them. We have several reviews during the day in challenge meetings. We keep very detailed metrics, to make sure that they're resolved in a timely manner, and then of course are audited not only by the Nuclear

Regulatory Commission, inspected by them, but also by our Quality staff and outside groups we bring in to do so.

We continue to learn opportunities to improve the program. But overall, I think the program is strong.

MEMBER SKILLMAN: When you meet to describe what you've discovered in CAP, what level of senior management is present?

MR. GREGOIRE: Every morning, business morning, we have an ops management or plant management meeting that reviews all the condition reports, to make sure they have the right categorization, the right ownership and the right urgency associated with that. That happens on a daily basis in the morning.

MEMBER SKILLMAN: Who's involved?

MR. GREGOIRE: The managers from most departments, Operations, Maintenance, Engineering, Chemistry, RP.

MR. ATKINSON: And typically a plant manager, the site vice president and the chief nuclear officer are present.

MEMBER SKILLMAN: Is that common or --

MR. ATKINSON: That is very common at that daily meeting.

MEMBER SKILLMAN: Thank you.

MEMBER SIEBER: Maybe I can ask a question that gets back to what the issue is. These insulators are 230 kV insulators.

MR. GREGOIRE: These are 500 kV insulators.

MEMBER SIEBER: Pardon?

MR. GREGOIRE: 500 kV.

MEMBER SIEBER: 500 kV insulators, okay, and they are not located on the station property. They're located at Ashe substation which, if I read your map, that Ashe substation is to the east of the major buildings, and the issue was that you had these five cooling towers sitting to the south of the station, maybe a little bit southwest, and the drift from those cooling towers would impact the Ashe substation, which is an ultimate station blast out power supply. It's not the main one.

How far away from those cooling towers, approximately, is the Ashe substation?

MR. GREGOIRE: You can see in the image above here, the cooling towers are south of the plant. The Ashe substation is at the top of the screen there. It's about three-quarters of a mile. Now we did have some experience with some cooling tower drift coming into our transformer yard, which was just north of the

plant.

We did some studies early in the 90's that showed that that drift really was occurring close to the plant, but wasn't being seen much past that.

MEMBER SIEBER: Now your commitment was to either inspect the insulators or, as an alternative, just replace on some time-limiting basis; is that correct?

MR. GREGOIRE: Well, not to replace but clean. Now we did have a test done during this last refueling outage in the May-June time frame, to test to see what kind of accumulation was occurring on the insulators in the switchyard. Very low build-up was identified during, in those tests.

We plan to have a PM that's conducted about once every eight years, which is consistent with the transmission organization, Bonneville Power Administration, who owns that switchyard, to make sure that we go and reevaluate this buildup.

MEMBER SIEBER: Okay.

MR. ATKINSON: I think the issue surrounding the corrective action program as it pertains here came up because we ultimately ended up including this action that wasn't there originally, to go do this inspection out at the Ashe substation.

We actually have an individual in the room that was involved in the evaluation that was done in the 90's, to figure out where to go or how far out this was problematic. Basically, we concluded we didn't need to do anything all the way at the Ashe substation.

MEMBER SIEBER: The projects are desert --

MR. ATKINSON: Right. It's desert, and it's quite a ways to Ashe. Nonetheless, we were unable to recover the test data that showed the actual fall-off of material as you approached it. So we thought it prudent to go ahead and add the preventive maintenance activity to go look out there at it, and in fact the tests to date has confirmed that it does not appear to be problematic out there.

MEMBER SIEBER: Yeah. Well, I concluded that the chance of significant accumulation was probably not there, but the corrective action would take care of it anyway.

MR. ATKINSON: Absolutely.

MEMBER SCHULTZ: Yes. So Don, it's issues like this that, based upon the improvements to the Corrective Action Program, you would feel would be identified by the station staff, and put into the Corrective Action Program?

MR. GREGOIRE: This was a little bit unique, in that there's no history of any kind of failures in the Ashe substation, and the staff asked us to look a little bit beyond it.

If you're referring to our ability to identify issues that may come up during our current plant, I mean there's a number of things that we're doing right now. But I'm not sure. Are you referring to this insulator issue or --

MEMBER SCHULTZ: That, plus those that you're about to discuss, the other issues as well. But I'm -- given the going-forward approach associated with license renewal, that we're looking for the connectivity between your Corrective Action Program and then, on inspection and discussion, what was identified by the staff.

Obviously, the Corrective Action Program is the much better way to identify these issues and address them.

MR. GREGOIRE: Now I will tell you that we provided aging management training to our Engineering staff in April of this year. During the refueling outage, which occurred right after that, we had a number of items that were identified, issues with corrosion or wear, that were entered in the corrective

action process.

So you could actually see or demonstrate that the engineers got the message. They understood it, and they were using the corrective action process to drive change. We had quite a few that were identified during the process of the outage, especially because you're much more exposed to equipment that's torn apart and what-not.

MEMBER SIEBER: I would point out that in my experience, insulators fail even if they're not fouled from the environment. It depends on the porosity, the insulation material and so forth. So this inspection is not a waste of time for this.

MEMBER ABDEL-KHALIK: So typically, how many CRs are written per year at your plant, just a demonstration of people's willingness to write CRs?

MR. GREGOIRE: I don't have the total numbers, but it's in the thousands. I would just be guessing. It would be somewhere between five to ten thousand CRs that are written a year. Now we have an inspection that's --

MEMBER ABDEL-KHALIK: 5,000 would be on the low end?

MR. ATKINSON: Yeah, but I think it's closer to ten. You have to understand that we, a few years

ago, incorporated the work orders and everything to go into that. So it's a very large database of information. But it is --

MR. GREGOIRE: I apologize. I don't have the exact number, but I will say that we get a regular inspection from the NRC staff, both from the residents and the regions, and we've had very few violations with our Corrective Action Program over the years.

MR. TWOMEY: But I do know, speaking back to when they were separated as problem evaluation requests. So you could count the numbers. We were up around between eight and ten thousand.

MR. GREGOIRE: That's what I recall too.

MEMBER ABDEL-KHALIK: Very fine.

MEMBER SIEBER: What's the average time for you to clear an open item for your corrective action folks?

MR. GREGOIRE: So the priority with corrective actions is it's in accordance with safety significance. Those that are much more safety-significant are resolved in much quicker time. Those that are not take much longer. So I don't have a number for you.

MR. GREGOIRE: We do use a very typical

industry metric, you know, for having corrective actions closed in 120 days. We track all of them. But we do have some that are tagged to long-term program changes or even outages. So we try and separate those out, so the staff doesn't become numb to seeing a very long-term corrective action item.

MEMBER SIEBER: Well that -- the big numbers concern me, because that's the attitude that we'll get forward.

MR. ATKINSON: And that's why we've spent a lot of time making sure that the metrics keep it in front of people and the different reviews.

MR. GREGOIRE: And in the morning meeting with the management team, they identify the different levels of classification for those that are alpha or Bravo level. Those get immediate attention, because they have immediate safety significance, and they get resolved much, much quicker than those of the Charlie or Deltas.

MEMBER SIEBER: Thank you.

MR. GREGOIRE: I'd like to move on to the next item on Slide 12, which is the closure of our item related to upper-shelf energy. In the information we had provided the staff, there was questions that were raised about the technical basis

for initial transverse upper-shelf energy and copper content for certain instrument nozzles that were in the belt line region.

We have since provided that information to the staff, and satisfied their concerns for the technical basis.

The next item is associated with metal fatigue. In this area, there was -- the standard review plan was revised, challenges our licensees to consider other possible locations.

That may be more limiting than those identified in NUREG-6260. Our staff was aggressive in going out and evaluating those. We took the action to complete the analysis. We actually had, were audited by the staff in November of this year, and we provided closure on a final item in January on this subject.

There were no items that were identified that were more limiting than those that we had previously provided in our application, and then all values were less than the 1.0 of the SAME code.

The next item is associated with the closure of the subject of lower core plate rim hold-down bolts. We were asked to provide information with regard to TLAA and the hold-down bolts. We have included information in our application for aging

management review on these bolts, and we all dispositioned this as a TLAA with classification Charlie One Triple I, which means that the effects of aging will be adequately managed for the period of extended operation.

MEMBER SKILLMAN: Don, let me ask a question about this. This whole issue seems to tie back to the presence or non-presence of the core plate wedges.

MR. GREGOIRE: That's correct.

MEMBER SKILLMAN: And originally, you communicated that you had these wedges in place, and later discovered that you did not?

MR. GREGOIRE: That's correct.

MEMBER SKILLMAN: Was there any 50.9 consequence for that activity?

MR. GREGOIRE: Well, this was initial license information. Back in 1983, it was our understanding that these wedges had been installed.

It was something we did communicate to the staff in accordance with 50.9, to make suer that they understood, especially when we did an evaluation in the last outage, we actually sent a camera down there to verify that and found that they were not there. So we communicated right away with the staff, both with the resident and with NRR.

MEMBER SKILLMAN: Okay. Let me go a little bit further on this. So as I envision this mechanical coupling of these bolts, I can imagine some movement of the core thermal shield complex that's causing these bolts to either fatigue or simply loosen.

How will the treatment of the fatigue, remaining fatigue life of those bolts be handled once you install the wedges, which is the commitment that you have made? What I'm really wondering about is how you calculate the usage to date, because once the wedges are installed in theory, that usage decreases significantly?

MR. GREGOIRE: Right. The wedges prevent lateral and vertical motion. We do have a study that was done to evaluate it, and Steve Richter is our lead on this, but we do have a slide showing the sequence.

MR. RICHTER: Steve Richter, Energy Northwest Engineering. Slide 41, I believe. No, 42. I'd like to see 41 first, just to get an idea of where we're at. Thank you. So this is a drawing of our reactor pressure vessel. You see the core plate is in the middle there, and the insert is the bolt itself.

There's 30, 32 or 30 bolts around the core plate itself. You've got all the way to the active fuel line top of it. They prevent the lateral motion.

We had a study done, as part of our deviation when we found the problem, entered it into our Corrective Action Program, had the study done and updated, to make sure that the pre-load and life of the bolt would neither exceed our current license.

As we committed to, we will have it addressed two years prior to the period of extended operation. Now fatigue wasn't identified as one of the failure mechanisms. Relaxation, loss of fuel load and cracking are the mechanisms of concern, according to the BWR VIP 25 (ph), excuse me, boiling water reactor Vessel Internals Program dash 25 guidelines.

CHAIR ARMIJO: Which is the mechanism of greatest concern, stress corrosion cracking --

MR. RICHTER: Stress corrosion cracking.

CHAIR ARMIJO: And you're addressing that with hydrogen water chemistry, noble metals, things like that?

MR. RICHTER: True, but now you can go to the next slide and see.

CHAIR ARMIJO: Okay.

MR. RICHTER: What you see here is the loss of life. Zero percent losses, they're at the bottom, and then at 40 years, shortly after 40 years, it drops off quickly, assuming that five years into it we have

a crack and it grows.

This study does not take credit for hydrogen water chemistry. But we do have it, and we are mitigating hydrogen water chemistry. So that's an added conservatism in the calculations.

MEMBER. SHACK: And how many of those bolts do you need?

MR. RICHTER: I have not seen the calculation. I don't know that we've done the calculation to determine how many we need. But this shows that it's there, and if you assume, I believe the assumption in the analysis is that all of them have a crack five years since service initiates, and begins growing. You still have plenty of margin with pre-load.

MEMBER SKILLMAN: Does this assume the wedges are or are not installed?

MR. RICHTER: Are not installed. Our design is no wedges.

MEMBER SIEBER: Now when hydrogen water chemistry first came out, you did not employ it because of other materials --

(Simultaneous speaking.)

MR. ATKINSON: That's correct. We had a lot of copper. It was a challenge at that time to do

that.

MEMBER SIEBER: And you changed materials in all places?

MR. ATKINSON: And the biggest key to the chemistry change was the replacement of the main condenser frankly, to remove the copper, replace the metal with titanium, a very large project, and then as well as noble metals, you know, the advent of that chemistry. The tool list helps quite a bit as well.

MEMBER SIEBER: Okay.

CHAIR ARMIJO: Are those bolts inspectible? Have you -- not really?

MR. ATKINSON: Not really, but Steve can talk to that. That's the challenge here.

MR. RICHTER: You can look at the top of them. The industry requirement is that you either perform UT, or you inspect the bottom to make sure they haven't fallen out. Neither one of those is a feasible inspection. So that answer is no, they are not.

MEMBER SIEBER: Can't you UT down through the top of the bolt?

MR. RICHTER: I couldn't hear.

MR. GREGOIRE: Can you UT though the top of the bolt head?

MR. RICHTER: No, you can not. There's a keeper on top which prevents effective UT. The industry is looking into that.

MEMBER. SHACK: You can't even identify broken bolts?

MR. RICHTER: We cannot, other than -- yeah.

MR. ATKINSON: So this is -- as you've honed in on, here's the challenge we have to deal with, as we face the end of the 40-year lifetime, and plan for the wedge and the securing going forward, which is why we have this commitment to work that out, and working with the BWR owner's group to resolve.

CHAIR ARMIJO: What is a bolt material? High strength alloy? It's not just plain old 316 --

(Simultaneous speaking.)

MR. RICHTER: Stainless steel, I believe. 304 stainless steel.

CHAIR ARMIJO: I hope it isn't 304.

MR. ATKINSON: We can check on that, and while they're getting that specific, I did get some information back on CRs, our condition reports. We are running about 12,00 condition reports per year. 50 percent of all of them are closed within 30 days. So we invest quite a bit of time and effort into that Corrective Action Program.

MR. GREGOIRE: If you would like, we can move on, and then --

MEMBER SIEBER: Did you pass over the upper-shelf energy?

MR. GREGOIRE: We had, just prior to metal fatigue, we talked about upper-shelf energy yes, back on Slide 12.

MEMBER SIEBER: That was just a technical argument that --

MR. GREGOIRE: Yes. It was just making sure we had given them, the staff, the technical information that supported our conclusion for what the copper content was and what the initial upper-shelf energy was.

MEMBER SIEBER: Great.

MR. RICHTER: Excuse me, Dale?

MR. ATKINSON: Yes.

MR. RICHTER: I do recall that the bolting material and the nut are SA-193 and 194.

CHAIR ARMIJO: Okay. Bill, translate that to me. Is that -- I don't know what that is.

MR. RICHTER: It's 304.

CHAIR ARMIJO: It's 304, yeah. So it's plain vanilla.

MEMBER. SHACK: Geez, stress relaxation.

CHAIR ARMIJO: That's just calculated.

MEMBER. SHACK: Well, but I'm surprised that you would use 304 for something where stress relaxation was the critical issue.

MR. GREGOIRE: All right, next slide, John.

MEMBER ABDEL-KHALIK: So what would be the impact of a broken bolt falling into the bottom of the vessel?

MR. ATKINSON: Well, I'll tell you what. While Steve gathers his thoughts, you know, I've seen quite a few different lost part analyses conducted for boiling water reactors, formerly for GE and now at Columbia Generating Station, and my experience is a component of that kind of mass is going to settle to the bottom of the vessel around the subtubes.

The biggest challenge would be whether the debris ended up settling in the bottom head drain, and caused some sort of blockage down there, either a flow problem or an isolation problem. Is that the type of information you wanted?

MEMBER ABDEL-KHALIK: Right. I was just -- if you had actually looked at that, due to the fact that you can't inspect them.

MR. ATKINSON: Right. We have been in the bottom of the vessel invert, but that's not a very

frequent activity to go down there. It's a difficult inspection to perform. So it's been a number of years since we've been in the internal side of the vessel invert.

We do not have any signs of flow degradation in the bottom head drain flow or any other observable delta there.

CHAIR ARMIJO: Well Dale, has there been any operating experience on 5's with the same hold-down bolt design, either a failure or open bolts?

MR. ATKINSON: I think for that, I am going to need the BWR VIP representative. So Steve.

MR. RICHTER: Due again with the wall, I couldn't very well hear you.

CHAIR ARMIJO: Yes. There's a question, operating experience in the same bolts in the BWR-5?

MR. RICHTER: Yes. There's quite a few that have this same configuration. There are no reports of any failed bolts.

CHAIR ARMIJO: And no one has been able to inspect them or remove one for whatever reason? It's just --

MR. RICHTER: To the best of my knowledge, all that has been done is a visual from on top. A few utilities have done that. Of course, we are

committed, all of us, if the opportunity arises and you're down there, to try and look at everything in the area.

I do not recall any report of anybody being able to capture a bolt. But there's been no OE of a failed bolt either.

CHAIR ARMIJO: Okay.

MR. GREGOIRE: And there are a number of plants that it's similar.

CHAIR ARMIJO: Yeah.

MR. GREGOIRE: The last item is Item 15, associated with fatigue analysis for power crane. Just as a point of clarification, we have an overhead crane, not a puller crane, that you would typically find with a dome. But nonetheless, we were asked about whether there was a TLA, and we agreed with the staff, that there should be a TLA associated with this crane and all of our in-scope cranes.

So we have included it in our TLA analysis and concluded that it meets the criteria of Charlie 1-I, which is remains valid for the period of extended operation, and we provided that information to the staff back in October.

So with that, that is the last of the items that were identified as being open, and if there's no

further questions, I'll turn it over to John Twomey to discuss any of the subjects that were raised during the Subcommittee meetings, if preferred.

MR. TWOMEY: So after we left the Subcommittee meeting, we had six topics that we were required to submit additional information to the Subcommittee. There was on the slide, we submitted the closure information December of 2011, and the next topic I'd like to talk about is implementation.

You know, we are a few years out from our period of --

MEMBER STETKAR: John, hold on.

MR. TWOMEY: Yes.

MEMBER STETKAR: Excuse me. You said you submitted closure information on those six items last December?

MR. TWOMEY: Yes, I did.

MEMBER STETKAR: Huh.

MEMBER RAY: To the staff?

MR. TWOMEY: To the staff, yes.

MEMBER STETKAR: Huh. I don't think we've seen that. I was going to try to follow up on some of these six, to see what the resolution was, and I was surprised to hear that --

MEMBER SIEBER: It's in Kent's status report

on the SER, but it's pretty high level --

MEMBER STETKAR: Yeah, high.

MEMBER SIEBER: But there is an exchange of mail back and forth on each one of these, and you can go and look at that, with some of it, not all of it.

MEMBER STETKAR: Okay. I missed that. Thanks.

MR. TWOMEY: All right. Moving on, the final topic we were going to cover was implementation overview. The implementation activities anticipating moving forward, have been incorporated into Columbia's long-range plan.

We're looking at this being approximately 11, 12 years out as an advantage to getting our program set up, so we run right into them, the full ten years prior to the period of extended operation.

Some of the items we've done, completed, are an implementation coordinator on our staff has been identified. That is myself. I will transition from the program manager into the implementation coordinator. We've also issued, approved the implementation procedure.

This is the first procedure to outline roles and responsibilities for the implementation coordinator, aging management program owners and

management staff that would be involved with that, get everybody on board and ahead of the ball here.

Then the next item will be development of the AMPS, of the Aging Management Programs. As Don mentioned before, we have 35 existing, 13 required enhancement and 20 new. Our target is to have all that work done by the end of 2013. That aligns with we will then roll into our ten years prior to the period of extended operation.

So we'll have basically the full time frame to fulfill all our commitments and obligations under aging management, prior to entering the period of extended period. We've also actively participated in the License Renewal Implementation Working Group for the last couple of years.

And we've benchmarked other sites currently through the Implementation Working Group, and we will go do benchmarking. This is at other sites that are ahead of us in the process. This way, we can gather lessons learned from those that have gone before us and done well. With that, I'd like to turn it back over to Dale for his program comments.

MR. ATKINSON: All right. Thank you, John. Well in closing, Mr. Chairman and distinguished members of the ACRS, I do appreciate the time to come

here today and discuss Columbia's license renewal. I will point out that the plant itself is well-funded, well-supported, and we have a community of support in south central Washington.

As a point I wanted to make, I did review, since the Subcommittee the long-range plan, just to go over for myself on the level of investment in the plant that's planned for the next ten years as a typical item, and the next fiscal year, which for us begins in July, we'll be investing $270 million in the operating and maintenance of Columbia.

In addition, there's another $50 million in capital projects. So it's a very, I think, well-invested in ongoing concern, many of these programs. We had some discussion last time about the time out for us, given that the license doesn't expire until 2023.

We have taken advantage of that, to actually go out, do some inspections and basically get our feet wet in the process of running the plant for the additional 20 years. I would like to recognize a lot of the hard work that has been put into this process, both by the team at Energy Northwest and the NRC staff.

We at Energy Northwest do understand our

responsibility and are committed to the long-term safe and reliable operation of Columbia Generating Station. With that, Mr. Chairman, I'd like to turn it back over to you, sir.

CHAIR ARMIJO: Yeah. I think we have the -- Jack, it's the staff.

MEMBER SIEBER: The staff's review.

MEMBER. SHACK: Just a quick question.

MR. ATKINSON: Yes.

MEMBER. SHACK: The wedges are a complete substitute for the bolts. That is, once the wedges are in, you could have complete failure of the bolts? This is really a lateral motion kind of thing?

MR. RICHTER: Yes. That's the discussion we've had, yes. Steve, confirm that please?

MR. RICHTER: Yes, that is absolutely correct. The wedges replace the function of the bolt.

MEMBER. SHACK: Okay.

MEMBER SCHULTZ: Dale, in your plans over the next ten years, is there any plan for an additional power uprate?

MR. ATKINSON: We do not have an additional power uprate planned right now. We continue to do cost-benefit analyses, and right now for the power condition in the Northwest, it simply doesn't pencil

out. For us, the next change, I pointed out in the presentation, we've done a five percent uprate.

For us, the next uprate is substantial in the amount of equipment that has to change. So as we've gone through kind of a living program of obsolescence and replacement, we've tried to retain the option on all the equipment that's replaced, to support an uprate should we choose to do it some day.

For example, we replaced the main generator rotor last outage, and provided a rotor that has the capabilities to support an uprate. Additionally, the condenser, same type of situation. But right now, the rest of the steps necessary to conduct an uprate simply aren't penciling out as cost beneficial.

MEMBER SCHULTZ: With regard to the issue on the bolt evaluation, and the wedge addition, is there -- what is the limiting factor that is affecting schedule? The commitment, what I heard was that the commitment was by 2021, this would be addressed?

(Simultaneous speaking.)

MR. ATKINSON: No later than two years prior to that.

MEMBER SCHULTZ: What's affecting schedule for implementation at this point?

MR. ATKINSON: Steve, why don't you address

that? I'll give you a high level view. It's the challenge of the solution, but go ahead.

MR. RICHTER: It's the challenge of the solution. I believe the design for wedge installation has been done before at other utilities. Looking at it from the process, it's the term of identifying, planning, budgeting and implementing, and if you do a cycle approach, that's a couple of cycles right there.

We are also working with the industry, to see if this is not a manufacturer problem. In other words, we have the analysis already the industry is committed to, by 2015. So whether this is a problem that has to be resolved.

In other words, there might be enough life to go 60 years, and every electrical power resurgence through the BWR vessel during this inspection program is committed to having a document out on the streets by 2015.

So we'll see what that says, and then planning our own destiny and methodically approaching this.

MR. ATKINSON: Yeah. From my own experience, it's not the most elegant solution. So while it's workable, we'd like to see where the development of the program goes, to see if that's the

path to take. Beyond that, we've installed wedges and other things in the past, and the industry has a fair bit of experience doing, putting other mechanisms in there.

And, you know, very change has its challenges, either on that day or some day down the road. So we just want to spend some time with the industry, and make sure we provide the best solution.

MR. RICHTER: And if you recall, this is by two years prior due. It doesn't mean we'll wait until the last year necessarily.

MR. ATKINSON: Right.

MEMBER SCHULTZ: Thank you for the additional explanation.

MEMBER SIEBER: Okay. Any other questions?

(No response.)

MEMBER SIEBER: If not, I think we're ready for the staff presentation. Thank you very much, gentlemen.

(Pause.)

MS. GALLOWAY: I'd like to introduce the staff who are going to be presenting today. Arthur Cunanan is our project manager for the Columbia safety review, and he'll be giving the presentation. Angela Buford is also a project manager in our organization,

and she will be handling the slides.

Matt Homiack is a mechanical engineer in our organization, and he was the initiator of the operating experience interim staff guidance document and we'll be talking about that open item, and Dr. Allen Hiser is our senior level staff, and I'm sure the Committee is well familiar with Dr. Hiser. He's usually here at our ACRS presentations. So with that, I'll turn it over to Arthur.

MR. CUNANAN: Thank you, Melanie. Good morning Chairman and members of the ACRS staff. My name is Arthur Cunanan, and I'm the project manager for the Columbia Generating Station license renewal application.

I'm here to discuss the staff's review of the Columbia license renewal application, as documented in the safety evaluation report. Melanie has made introductions of who is at the table. Also seated in the audience are members of the technical staff, who participated in the review of the license renewal application, or were at the audits conducted at the plant.

Also Greg Pick and Geoff Miller from Region IV is available on the phone. As always, you can ask questions at any time during the presentation. Here

is an outline of today's presentation. This is an overview of Columbia Generating Station. We received a regional administrator's letter, and have issued the final SER.

For internal corrosion of buried piping, this slide addresses a takeaway from the ACRS Subcommittee meeting. The ACRS questioned the staff's position on the applicant's not including additional inspections of internal surfaces of buried piping, when they had operating experience of leakage due to internal corrosion.

After the ACRS Subcommittee meeting, the applicant conducted a search of plant-specific operating experience and determined that the buried pipe, which leaked, was out of scope PBC piping, and that the failure was not due to internal corrosion.

Applicant then amended the LRA AMP and the staff revised the LER to reflect the amended letter in the final SER. The staff has confidence that the aging effect of internal corrosion of buried and above-ground piping is appropriately age-managed by several programs, such as the fire water program and open cycle cooling water program.

Given that the ACRS Subcommittee meeting expressed interest in internal corrosion of buried

pipe, we would like to take this opportunity to discuss the following. There have been two examples of recent industry operating experience noted by the staff during LRA AMP audits and other plants that are requesting license renewal.

One plant had pervasive microbiological influence corrosion MIC, and another had extensive selective leaching of aluminum bronze. The staff has developed extensive RAIs to address these issues.

Given these examples of operating experience related to internal corrosion, the staff is currently developing an ISG, and expects to issue the draft ISG by summer of 2012.

MEMBER STETKAR: How is that -- I'm glad you had a slide. I don't have a copy of your slides here, so I'm glad you brought this up, because it was one of the questions that I had, and I was trying to do some real-time scanning here.

I think the reason we brought this up at the Subcommittee meeting was, as you've explained, the previously-cited operating experience did note that there -- did cite, apparently incorrectly, internal corrosion as a source of the observed failures.

In particular, this applicant has not proposed any volumetric or internal inspection of any

of the buried piping; is that correct? They're only, not only going to do the excavation of a sample and internal inspection of their buried piping, right?

MR. CUNANAN: Yes.

MEMBER STETKAR: When you develop this ISG to be developed, how will that apply to already-issued license extensions?

MR. CUNANAN: I'll have John Wise talk to you about this.

MR. WISE: Good afternoon. John Wise, License Renewal staff. This ISG was brought up to address specifically plants that have pervasive operating experience. So what it's addressing is when we run across plants that have internal corrosion issues, to date we have been using the RAI process to get some competence that their programs are going to manage those issues.

And so as Arthur describes, this ISG is intended to take us away from the RAI process, to provide proactive guidance, you know. As plants experience this, we're inspecting them. You know, using this ISG, we're going to give them guidance to how to craft a plant-specific program to address pervasive internal corrosion.

Now in this case, and for Columbia, we don't

have that issue. So specifically this ISG isn't applicable in this case. But we thought it was appropriate at this time to bring it up, so you're aware that we keep track of these things, and we do handle it with RAIs. But in the future, we are going to have some guidance, provide more direction.

MEMBER STETKAR: Thanks. That helps a lot.

MS. GALLOWAY: And John, in response to your question as well, this is an issue, then, that marries up quite nicely with our recent ISG and operating experience, because for plants that have already been licensed-renewed, to the extent that they encounter operating experience, we would fully expect them to analyze it.

If they determine they need to do something more than what they're already doing, the ISG then would be an appropriate guidance document to them, that we would expect them to use, to continue to demonstrate to us that they're effectively managing aging.

MEMBER STETKAR: Yeah, and that makes sense. Thanks. That helps a lot. Okay. Thank you, John.

MEMBER RYAN: Arthur, one other just follow-up question, just for my information. You mentioned that there a biological brand of corrosion. Is that

common?

MR. CUNANAN: From what I spoke to with John Wise, he said that if they have -- if they don't have the right corrosion inhibitor, then you would get microbiological --

MEMBER RYAN: I understand that part. But is this kind of -- I mean has that been a mismatch in a lot of places, or is that a fairly rare type of corrosion?

(Simultaneous speaking; laughter.)

CHAIR ARMIJO: It's everywhere, Mike.

MR. CUNANAN: It's everywhere.

MEMBER RYAN: It's everywhere. Thanks, right.

MR. CUNANAN: Next slide. The first open item addresses how the applicant would consider future operating experience to inform its aging management activities. To provide an overview of how this item was closed, I'd like to introduce Matt Homiack of the staff. Matt.

MR. HOMIACK: Good afternoon. Thank you, Arthur. As Melanie Galloway highlighted in her opening remarks, operating experience is important, because it serves as the feedback mechanism, to ensure the continued effectiveness of aging management

programs.

Similar to other plants, programs are currently being implemented at Columbia to review operating experience on an ongoing basis, such as doing the Corrective Action Program.

The issue of how the applicant would consider future operating experience was an open item for Columbia, because although the applicant indicated that it would continue to review operating experience, it did not specifically describe how its existing programs will address potential issues related to aging.

The staff reviewed several aspects associated with the applicant's ongoing review of operating experience, in order to determine whether this review will provide for the adequate evaluation of operating experience related to aging.

The areas reviewed were consistent with the guidance in the staff's final license renewal, in terms of Staff Guidance LR ISG 2011-905, "Ongoing Review of Operating Experience."

As a result, the staff determined that the applicant's operating experience review activities are adequate for the capture, identification, processing and evaluation of both plant-specific and industry

operating experience related to aging, and for the implementation of changes to the aging management activities, as identified through these evaluations.

In addition, the applicant will provide training on aging to those personnel that screen, evaluate and submit operating experience, and report Columbia operating experience on aging to the industry. This addresses the staff's concern that future operating experience would not be adequately incorporated into the aging management programs.

MEMBER SKILLMAN: Matt, let me ask this question. In the homework information that the ACRS has been provided, there are 35 existing aging management programs and 20 new programs, 55 programs. That is a wide swath of administrative activity for this licensee.

The licensee has just communicated about 12,000 CAPs per year, 6,000 will be done within 30 days. That sounds like a pretty good closure rate.

In the staff's evaluation of the effectiveness of this corrective action program, which is really the workhorse to ensure to this information is gathered and evaluated and used properly, by chance did you look at the physical condition of this nuclear station, to determine whether or not the CAP close-out

is effective?

For instance, did you look at maintenance role, the number of A1 systems, and the closure rate of the material condition issues facing the plant, to develop confidence that the team at Columbia really gets the job done?

MR. HOMIACK: The staff's review with respect to operating experience was both somewhat of a process perspective of how operating experience would be reviewed and translated into the AMPs.

As part of the staff's review, we looked at corrective action entries from the past as part of every aging management program, in order to determine how those past issues are going to be addressed.

MEMBER SKILLMAN: So you look at it from a programmatic perspective?

MS. GALLOWAY: We have regional representatives on the phone, and I'm wondering if they, if either Geoff or Greg would have first-hand information regarding what's been observed at the plant?

MEMBER SKILLMAN: That would be quite helpful. Thank you.

MS. GALLOWAY: Geoff or Greg? Are the lines open?

DR. HISER: Is the line open?

MEMBER SKILLMAN: We probably have it muted. They're probably screaming at their phones right now, as we speak.

DR. HISER: Well, I guess -- this is Allen Hiser, License Renewal. The Corrective Action Program is not unique to license renewal. So this is a program. It gets a lot of reactor oversight, okay, from the residents onsite and also regional inspections.

So I think that is really where the confidence that we have, is that we want to ensure that the programmatic aspects of the Corrective Action Program are kept robust for license renewal, in terms of aging management needs. But in terms of the overall effectiveness of the program and implementation aspects of the program, that would be a part of the current reactor oversight process.

MR. MILLER: This is Geoff Miller, Region IV. Can you hear me?

MEMBER SKILLMAN: Yes, yes sir.

MR. MILLER: I apologize. I was in fact screaming at the telephone.

(Laughter.)

MR. MILLER: The little red light that said

mute was off, but apparently it wasn't working. I was just trying to say that yes, we did do a problem identification and resolution inspection at Columbia.

That was just completed in September of last year, that did do a look at their Corrective Action Program and the effectiveness of their current program resolving problems.

The results from that, we did conclude that the Columbia Generating Station or program was being implemented effectively, and that they were resolving those issues, including the use of operating experience and the closure of items in the CAP. Is that kind of what you were looking for?

MEMBER SKILLMAN: Yes sir, it is. This is Dick Skillman. Thank you for the answer.

MR. MILLER: Sorry about that.

MEMBER SKILLMAN: Thank you.

MR. HOMIACK: Is there any further questions?

MEMBER SCHULTZ: Just to follow up on that for a moment. I'm a bit surprised that we would lead into this with activities that will be implemented throughout the term of the renewed license, and then go into assuring that the licensee is going to have a program of this type.

But the program, as we've just heard, it does exist now. So I would expect and hope that the guidance is really indicating the importance of this for any licensee, whether or not they're going to renew license, but becomes more important as the plant moves into a different realm of operation, 40 to 60 years.

MS. GALLOWAY: And you're absolutely right, and you know, I know from the staff's standpoint, we're glad to hear you say that, because one of the things we did clarify in the ISG is the fact that you can't have a situation where you're reviewing operating experience at the time you're going through license renewal, and then you don't enter the period of extended operation for 10, 15, X number of years later, and you don't do anything.

So our ISG makes it clear that there's an expectation that once you go through the license renewal process and get a renewed license, that you are carrying on that program, so that you take advantage of the operating experience that's gained from the license renewal time frame, until your period of extended operation, without missing a beat.

It's a continual process, and we think that is extremely important, in order to be in the best

position you can be at the PEO, to manage aging, to manage the effectiveness of aging.

MEMBER SCHULTZ: Thank you, Melanie.

MEMBER SIEBER: Actually, the license renewal application in the accompanying SER is a list of commitments that licensee make that are bound as license conditions, and they have to be implemented before the current license expires, and they are held accountable by inspections for those actions.

One of the reasons why the staff fusses around to make each of these commitments in sufficient detail, is to make sure that the aging management programs and the timing of the aging management routines meet the regulations.

This thought has come up in the past among Committee members, that this is a beginning step, and at this point, once a license renewal is issued, it represents a lot of commitments that the licensee has to perform, or suffer the penalties of not performing commitments that the licensee has made, which ultimately could lead to shutdown of the plant.

That's my understanding of what goes on. We should not expect all these programs to be in place right now.

MS. GALLOWAY: Just one clarification which

I think is very important. We at the staff are doing a lot of look at commitments, and how they are to be implemented at the time of the period of extended operation. One thing that we are clear on is that our expectation is that the commitments will be fulfilled by the applicant by the time the period of extended operation starts.

However, the content and the substance of each one of those commitments is not in and of itself a license condition. So once the applicant enters the PEO, they do have the ability to alter those commitments, after having gone through a 5059 evaluation process, because those commitments are incorporated as part of their FSAR.

So we just want to make it clear that they're not license conditions directly; they're part of what we require as a license condition, that they be implemented by the PEO, and then they do have latitude to change them if undergoing the regulatory process of 5059.

MEMBER SIEBER: The changes made under 5059, particularly changes that reduce requirements, 5059 is a lot tougher than it was 30 years ago, and those should not be lightly made.

MR. CUNANAN: Okay. We'll move to the next

slide, if there's no further questions. For the high voltage porcelain insulator program, the applicant has addressed this issue in their presentation.

The applicant included the 230 kilovolt post insulator as part of their program, with testing every eight years and cleaning if needed. The staff finds this acceptable and has closed this item.

For the crane load cycle limit, the applicant already discussed identifying these crane analyses as TLAAs, and disposition analyses under 10 C.F.R. 54.21(c)(1)(i). The staff has no further concerns regarding this issue.

For metal fatigue, I'd like to introduce Allen Hiser to present this item.

DR. HISER: Thank you, Arthur. With the increased neutron fluence as a result from plants going to license renewal, 60 years of operation instead of 40, for Columbia, the N12 instrumentation nozzles will achieve a neutron fluence greater than 1 times 10 to the 17th. Therefore, they have to consider the effects of radiation on the properties of those nozzles.

In response to staff RAIs, the applicant provided an analysis for those nozzles that included copper content measurements and also Charpy test data,

including test temperature, absorbed energy and shear percentage.

The applicant, based on that data, cited an initial upper-shelf energy of 62 foot pounds from its evaluation of the data, which was sufficient in combination with the copper content of 0.27 percent, to project the upper-shelf energy to exceed the Appendix G of 10 C.F.R. Part 50 required value of 50 foot pounds. So it would meet that criteria.

The cooper content was reviewed by the staff and we found it acceptable, because it was an appropriately conservative value from the data that was provided by the applicant. Upon further staff questioning, the applicant identified that certain of the Charpy data they provided were actually from the same heat numbers as the forgings used to fabricate the N12 nozzles.

Segregating that data from the data provided by the applicant indicated that the upper-shelf energy and the longitudinal orientation for these heat numbers is on the order of 230 foot pounds or more, which crates to an upper shelf energy in the transverse orientation of something that's significantly greater than 62 foot pounds, probably on the order of 150 foot pounds.

So based on that analysis and the data provided by the applicant, the staff found that the applicant's conservative value of 62 foot pounds to be acceptable, and the applicant's upper shelf energy evaluation was found acceptable. Thus, this open item was closed by the staff.

MEMBER SIEBER: I think they were lucky to find matching samples.

DR. HISER: It's always very good to have data from your own material.

MEMBER SIEBER: That's right, and that doesn't always occur.

DR. HISER: No, that's correct.

MEMBER SIEBER: It's always kind of rare.

MR. CUNANAN: All right. Thank you, Allen. Environmental-assisted fatigue is a generic item that the ACRS has seen before with previous plants, such as Salem and Hope Creek, where contrary to the standard review plan and GALL report, the applicant had not considered other plant-specific locations to analyze for EAF, environmental-assisted fatigue.

The staff had asked similar RAIs to those applicants regarding these concerns. The staff wanted to know whether the applicant's plan-specific configurations may have additional locations that need

to be analyzed for the effects of EAF, other than those identified in NUREG-6260.

The applicant submitted its results of addressing EAF to the staff, and the staff conducted an audit on November 29th through December 1st, 2011, to verify critical locations that the applicant looked at. Based on this audit, the staff was able to verify the applicant's approach in identifying locations that can be affected by EAF.

The staff concluded that the applicant had appropriately addressed EAF for its plant-specific configuration. For the core plate rim hold-down bolts, I'd like to give the presentation back to Allen, to discuss this item.

DR. HISER: As you heard earlier in the applicant's presentation, when they submitted their license renewal application, they thought that they had core plate wedges installed, and so they did not treat the core plate rim hold-down bolt degradation as an aging effect requiring management.

When they sent a letter to us indicating that they do not have wedges installed, we had questions on how they would resolve the TLAA associated with stress relaxation, and also had questions about were there, you know, what the aging

management review line items are. So what would be the aging effects that would require management, and how would they appropriate manage those items.

In response to our RAI, the applicant evaluated the TLAA of stress relaxation, in accordance with 10 C.F.R. 54.21(c)(1)(iii), and also provided an AMR line item for stress relaxation of the bolts, that ties directly to the TLAA.

There also is a line item related to cracking, due to stress corrosion cracking, that was picked up as well by the applicant. In its response, the applicant also committed to install the core plate wedges at least two years prior to the period of extended operation, which you have heard earlier.

The staff has decided that we will issue a license condition, requiring the applicant to install these wedges on or before December 20, 2021, which is two years before their PEO, and this license condition will also require the applicant to submit a report to NRC staff, summarizing the results of the installation of the wedges, and if applicable, any corrective actions that they implemented.

Based on this license condition that will be put on the license, the renewed license for Columbia, this item was closed by the staff.

MEMBER ABDEL-KHALIK: Does the uncertainty regarding either the presence or lack of the wedges point to a bigger problem with regard to configuration control?

DR. HISER: I think that's a very good question.

MEMBER ABDEL-KHALIK: I beg your pardon?

DR. HISER: I think that's a very good question, and I think this is something that we did discuss with the applicant, in particular with their internals and the inspections that they did in the May time frame, provided us with confidence in that area that there are no other deviations, such as not having the wedges.

MEMBER ABDEL-KHALIK: So you have explicitly evaluated their configuration controls and determined that they are adequate, this is just a fluke?

DR. HISER: We did not do a systematic review such as that, no.

MEMBER ABDEL-KHALIK: Would that be appropriate, given the significance of this issue?

MS. GALLOWAY: Again, maybe our regional counterparts on the phone can talk about what inspections they have done over the last several years regarding configuration control. Geoff or Greg?

MEMBER STETKAR: Don't start yelling yet. We need to turn you on on this end. It's not your problem.

CHAIR ARMIJO: A little time.

(Off record comments.)

MEMBER STETKAR: Say something.

DR. HISER: Hi Geoff.

MR. MILLER: Can you hear me?

MEMBER STETKAR: Yes.

MR. MILLER: Okay. I was hitting every button I can think of on this phone.

MEMBER STETKAR: No, no. It's this end. We have you muted here because the system here makes a lot of noise.

MR. MILLER: Oh, okay. I'm sorry about that. Sorry for the delay. Yes, I did hear the question, configuration control. It is something that we look at, as part of our baseline inspections here in the region. We do have component design basis inspections that look at configuration control on a sample basis, and our resident inspectors at the plant do do, they are involved in continuous reviews of items that are entered in the CAPs, and they do a semi-annual review for trends.

I'm not aware of them having identified any

trends involving configuration control, and I haven't looked at our most recent CDBI report. But I don't recall there being an issue with configuration control identified at the station. There's not a history there that I'm aware of, that's come up in our baseline inspections or as part of our assessment process.

MEMBER ABDEL-KHALIK: But given the significance of this issue, wouldn't this be something, an item that you should have looked at explicitly?

MR. MILLER: This particular item is something that would have been identified in the Corrective Action Program. I can't recall if we pulled that as a particular sample.

MEMBER SKILLMAN: This is Dick Skillman. I would like to join Dr. Khalik in the question, and for me, the real issue is extent of condition. Here is a piece of information that was believed to be accurate, and it turned out be not correct.

Where else in the information that you are using to justify extended operation, other vulnerabilities, where an absence of information is critical? This is an extent of condition question.

(Off record comments.)

MEMBER SKILLMAN: Maybe another way to ask the question is in the Corrective Action Program, was this item closed to fix, or was this item root cause and develop an extent of condition assessment, please?

MS. GALLOWAY: Is that a question the applicant can answer?

MR. RICHTER: Yes. Steve Richter, Energy Northwest. The issue was closed with actions, and among those actions was to perform an extent of condition, first of all to look at the specific information provided by the OEM, the corrected information, to make sure there was no other additional areas of concern there, and then a review of the vessel internal program, to make sure there were no other omitted inspections based on presumed, or presumptions of configuration.

MEMBER SKILLMAN: When is that information to be made available to your staff?

MR. RICHTER: Excuse me, what are you asking?

MEMBER SKILLMAN: Is this a six month or 12 month or 24 month or a 36 month bring back? When is the extent of condition and cause going to be done?

MR. RICHTER: Oh, it's completed. I'm sorry. It's been completed.

MEMBER SKILLMAN: And what is your conclusion?

MR. RICHTER: The conclusion was that there were no other missed inspections. There were no other impacts, based on the corrected information from the original equipment manufacturer.

MEMBER ABDEL-KHALIK: But that sounds very narrow, in terms of an evaluation of the extent of condition. We're looking at the impact on configuration controls in general.

MR. GREGOIRE: In a broader perspective, there's a number of things. Obviously, the first thought is what about the vessel?

What else in the vessel do we not know? So again, relying on the BWR VIP guidance with what you inspect in a vessel, we did go and evaluate internally what possibly could also be overlooked here, didn't find anything else there.

With regard to configuration management in the plant, again, we do have regular CDBI inspections that do assess the health of that process, to determine if there is anything that we're not managing appropriately. There have been a few violations in that area over the years.

It is always something of a concern for us

to manage that, but in this case here, we did, like I said, focus our efforts on addressing the vessel itself and any other possible areas that we might have overlooked in our inspection process.

MEMBER ABDEL-KHALIK: Is the staff satisfied with this response?

DR. HISER: I don't believe we have any outstanding issues on this.

MEMBER ABDEL-KHALIK: Has the staff asked the question?

DR. HISER: I think we relied on the regional inspection, and again, the regulatory oversight process on things like this. This is not specific to a license renewal issue that's addressed under Part 54. This is part of really ongoing regulatory oversight.

MEMBER ABDEL-KHALIK: But not everything is a cookie-cutter. I mean if you run into a problem, you try to sort of nail it down.

DR. HISER: Well, and I think as Geoff mentioned, on the 71002 inspection, that is something that is considered there. The implications in this case of not having the wedges, we did follow up on, to ensure that the license renewal aspects of that would be appropriately addressed by the applicant.

MEMBER ABDEL-KHALIK: Okay, thank you.

MR. CUNANAN: All right. That's the last of the open items.

MEMBER SIEBER: The last issue is a current operating issue, is it not, in terms of closed license renewal issue?

DR. HISER: That's where it's appropriately addressed, is under the current licensing basis, if you will, of the plant.

MEMBER ABDEL-KHALIK: Has it been?

DR. HISER: I would have to defer to the regionals.

MEMBER ABDEL-KHALIK: Root cause provided to the staff, and determined to be of sufficiently broad scope to identify the extent of condition?

MR. GREGOIRE: Typically, we don't provide the root cause to the staff for their approval, but we do certainly make it available to them for their understanding. We have not received any feedback with regard to whether we had looked broadly or not. So I can't say much more than that. This is Don Gregoire.

MR. CUNANAN: Are there any further questions?

MEMBER SIEBER: Nope.

MR. CUNANAN: Okay, in conclusion, the staff

determined that the requirements of 10 C.F.R. 54.29 Alpha have been met for the license renewal of Columbia Generating Station. This concludes my presentation. Do you have any further questions?

(No response.)

MR. CUNANAN: Thank you.

CHAIR ARMIJO: Jack, you done?

MEMBER ABDEL-KHALIK: Mr. Chairman.

MR. ATKINSON: Mr. Chairman?

CHAIR ARMIJO: Yes sir.

MR. ATKINSON: This is Dale Atkinson with Energy Northwest. I guess I see the Committee kind of quibbling with that issue, and I'll offer that the executives, senior management at Energy Northwest, were similarly troubled by this.

So as a way perhaps to understand it, we did take a look at why, in this particular case, we have this situation, where we didn't have what we thought we had.

The short answer is over-reliance on vendor information in an area that you don't easily get access to to do inspection. So a lot of the discussion you've heard is around going back and looking for that kind of vulnerability.

Because in the cases where we have access,

where we control for the rest of the configuration, we've actually done quite well in configuration management. So I think that's why you're hearing a lot of this discussion, focusing on where we might have had an over-dependence on the vendor.

In this case, we relied on information from General Electric that turned out not to be accurate, and so --

CHAIR ARMIJO: They couldn't have been happy about it either.

MR. ATKINSON: No.

CHAIR ARMIJO: Did they provide any kind of explanations that were satisfactory to you, how they would have made that mistake?

MR. ATKINSON: Yeah, I'll offer. I have not heard anything that was very satisfying. So that's why we decided let's drop a camera down, take a look, and then consider any other areas we might be concerned about. So that's where that went.

I'd also like to make one other correction. I heard the question earlier about the porcelain insulators. Having been at the plant for 23 years, I remember a lot of these events.

The flashover event that actually caused this concern with the insulator fouling occurred on

500 kilovolt lines. For the purpose of the license renewal, it's the 230 kilovolt that's in scope.

So in fact we did add the inspection to a 230 kilovolt porcelain string out at the Ashe substation. We verified the adequacy really previously for a 500 kilovolt line count. All right, thank you.

CHAIR ARMIJO: Okay. Jack, it's okay? All right. Well, Jack are we completed then?

MEMBER SIEBER: It appears that we are, and if there are no more questions from the Committee, I turn it back to you, Mr. Chairman.

CHAIR ARMIJO: Okay, thank you very much. I'd like to thank the presenters of the staff and the applicant. Very good presentations. What we'll do now is we'll take a break and reconvene at 2:30.

(Whereupon, a short recess was taken.)

CHAIR ARMIJO: Okay. Let's come back to order. The next topic is the risk-informed regulatory framework for new reactors. John will lead us through this presentation.

MEMBER STETKAR: Thank you, Mr. Chairman. Some background for the other Committee members. We've had a couple of Subcommittee meetings on this topic last year and in March of this year. The staff,

I'm sure, will fill us in on some of the details. They're sending a SECY paper up to the Commission I believe in -- it's scheduled to go up in June, early June.

CHAIR ARMIJO: Early.

MEMBER STETKAR: And as a background, they've been running for almost the better part of a year, I guess, right, on a number of tabletop exercises and public workshops, where the goal was to look at a range of possible risk-informed applications for new reactors, evaluating them in the context of existing regulatory guidance, to see how the current regulatory guidance and current metrics that are applied as a result of that guidance, what sort of conclusions you can draw in terms of applicability of the guidance. Is there a need for updates to the guidance, and as a result of those exercises, the staff has developed some options that they're going to send up to the Commission going forward.

So we'd be writing the letter on the SECY paper that the staff will, I believe, present some of the results of the table top exercises and a couple of the more interesting applications, and then go through the SECY paper.

With that, I'll turn it over to the staff,

and I think Charlie Ader would probably like to say something.

MR. ADER: I'd just say I'd welcome the opportunity again to discuss this with the ACRS. We've had a number of interactions over the last couple of years. They've all been, you know, very beneficial interactions. The staff has done a lot of work. We've had excellent cooperation with stakeholders too in developing this paper.

So I think we're coming, hopefully coming to the end of this process here pretty soon. I'll turn it over to Don.

MR. DUBE: Thanks Charlie. Thanks, Mr. Chairman and John and members. I want to acknowledge Ron Fruhm from NRR, who's handled the reactor oversight process end of things, and also a couple of people who aren't here.

Eric Powell, who works with me, he's on rotation; and Chris Hunter did a lot of the calculations. He's out of Research, Office of Nuclear Regulatory Research, and he did many, many of the calculations for the reactor oversight process.

So I just want to acknowledge them, and as Charlie said, we had excellent participation by industry and other stakeholders. So we're here to

discuss the staff's response to the staff requirements memorandum, in response to the Commission paper 10-121, and to request a letter.

On the agenda this afternoon, we'll give very brief background. It will emphasize two table top exercises, Risk-Informed Tech Spec Initiative 4b, which is on completion times, and then Ron will talk about the reactor oversight process.

We'll touch upon the other table top results and some of the recommendations, our next vessel severe accident Tier 2 change process, and this long-standing issue of converting from large early release frequency to large early release frequency. But the emphasis will be on RITS 4b and ROP.

Then conclusions, options and recommendations in the draft paper, and highlight a couple of small, in the way of editorial changes, that we've made to the paper, just very briefly.

So as a reminder, way back over a year ago, a year and a half ago now, where the staff presented the Commission with three options to address the risk-informed guidance for new reactors, and it was in light of the fact that new reactors have quite a bit different risk profile than the current fleet.

Generally, significantly, one to three

orders of magnitude lower calculated core damage frequency, at least for internal events. Probably not so much when one takes into account external events like seismic, for example. But still, as a general rule, somewhat lower, in some cases significantly lower than the current fleet, and what does one do with that observation.

In fact, does one still apply the same risk metrics, the same thresholds in the reactor oversight process, or should there be new and different thresholds? So the staff presented the Commission with three options. One was basically status quo, we'll treat them the same as the current fleet.

Second -- well, I'll talk about the third. The third was actually develop lower numeric thresholds for the new reactors, and option 2 was kind of in between, which says well, let's look at the guidance and maybe there's some tweaking we can do, but we won't actually change the thresholds.

The Commission came back in an SRM dated March 2nd of last year. They approved a hybrid of Options 1 and 2, which was continue the existing risk-informed framework, but do a series of table top exercises.

They actually spelled out four or five

specific areas for us to table top, and we table topped all of those areas, and then a couple of other risk-informed application areas.

But very profoundly, the Commission reaffirmed the existing safety goals, safety performance expectations, subsidiary risk goals in the risk guidance, and the key principles that are in, for example, Reg Guide 1.174, and these are principles such as small change would result in a small increase in core damage frequency, and risk, maintain defense indepth, maintain margin of safety and monitor the performance over the existence of that risk-informed application.

They also reaffirmed the quantitative metrics, and they stated that, I'm paraphrasing here, new reactors with enhanced margins and safety features should have greater operational flexibility than current reactors.

So that kind of set the boundary conditions for what the staff would look at. We couldn't go so far as proposing lower numeric thresholds, so we need it to work within the directive from NSSRM.

So we did a very aggressive series of table top exercises. We actually started out before the SRM, because we knew we had to look at the change

process for severe accident design features.

These are spelled out in VIII(b)(5)(C) of each design certification rule, and it states if there's a substantial increase in probability or public consequences associated with a change, a Tier 2 change to a severe accident feature, that there's a number of steps that the applicant or license holder has to go through.

So we did that. We started out with that first, and then a series of very busy and very aggressive table top. Risk-informed in-service inspection of piping, Risk-Informed Tech Specs Initiative 4b on completion times, and affiliated with that is the Maintenance Rule (a)(4), which is monitoring and managing risk during equipment outages and maintenance.

We did the other half of Risk-Informed Tech Spec initiative, kind of a little bit of twin 5(b) on surveillance frequency control program. We looked at 5069, which is categorization of structure systems and components, and special treatment thereof.

We looked at guidance in aiding NEI-9607 Appendix C. This is one-stop shopping for all the change processes for new reactors. So it's not just -- it's a 5059-like process, severe accident features.

Everything from aircraft impact assessments and large area fires. Everything is a go-to one-stop shopping, and it may have the licensee go out in different directions, but basically it is a one-stop shopping, if you will. We looked specifically at the change process for ex-vessel severe accident features.

Then we jumped into Reg Guide 1.174, which is risk-informed changes to the licensing basis. We wanted to tackle this long-standing issue of large early release frequency and I'll briefly touch upon that, and then we did a large number of table top exercises on the reactor oversight process.

This includes the significance determination process, reactive inspections under Management Directive 8.3 and the mitigating systems performance index, and then we had a follow-up meeting.

So I mean it was very extensive, and we were basically finishing up one table top, summarizing the results and preparing for the next table top just a few weeks later, in a couple of cases.

So what is a table top exercise? Basically what it is is we looked an outline of the guidance, especially the risk aspects of the guidance, and we said -- we had representatives from industry and our own staff and said what's been the experience with the

current fleet? What's been -- as a result of proposed applications, what was the level of risk increase?

Some of it was a little theoretical, but what's been the experience? Has it been good, bad, indifferent? Has it been risk-neutral, and what might this guidance look like if we applied it to a new reactor?

So we actually looked at, depending on the particular exercise, one to five of the new reactor types. I mean in the case of Risk-Informed Tech Spec Initiative 4b on completion time, we had all five reactor design centers there. The new reactor design centers with combined license applications all participated in doing calculations.

In other cases, we had less data to work from. But we did apply it and said what would it look like for new reactor, what are the lessons learned and is there any concerns here, in terms of could there possibly be a significant decrease in the enhanced level of safety of the new reactor as a result?

So in many cases, we actually did many, many calculations. In some cases, it was looking more at a lot of situations. So getting to the major conclusions right off the top, during the table top exercises for the licensing application, so that's

Risk-Informed Tech Spec 4b, 5(b), a risk-informed in-service inspection, those were where a license amendment would be needed.

Staff did not identify any potentially significant decrease in the enhanced safety margins for new reactors. Now a little bit of this is, like I said, is inductive reasoning, inductive reasoning in the sense of we did many, many calculations, many, many applications, well over 100, and we tried to generalize, you know, what can one generalize from these regarding the overall guidance?

So like I said, in that regards, it is a bit of inductive reasoning, but it's the best one can do. We did identify a potential gap in the Tier 2 change process regarding severe accident features that are not related to ex-vessel severe accident prevention and mitigation.

I have my Venn diagram from the Subcommittee meeting, which I'll show. But the staff did identify a gap. We don't think it's a significant gap, but it's probably something that should get addressed by the NRC.

Current risk thresholds are appropriate for the reactor oversight process. Ron will talk about this, but there's a few changes that could be made,

particularly that might be warranted, consistent with the integrated risk-informed principles in Reg Guide 1.174.

A lot of this has to do with barrier integrity, and if one goes through a calculation and calculates if there's a degradation of a barrier such as reactor coolant system barrier, and one relies on the calculations, such as conditional core damage probability, one inevitably gets low numbers.

And yet, you know, relying on margin of safety and defense indepth, does one feel comfortable with the regulatory response, just based on, solely on the risk calculations. So we believe there's areas here that will change, or some change will probably be needed, especially for the new reactors, but some of it might be applicable to the current fleet as well. There's always some improvement in guidance that could be found.

So that's the background of where we are, and over the next couple of slides, I'm going to talk about one specific exercise, but probably the most intriguing exercise, and that is on Risk-Informed Tech Spec 4b completion times. We found time and time again on this that built into the guidance, into the overall program, are two key programmatic controls,

that the risk-informed completion time is limited to a deterministic maximum of 30 days, referred to as the backstop completion time, from the time the tech spec action statement was first entered.

So the risk-informed completion time is kind of like an online monitoring of risk. Equipment is either found to be in a failed condition, degraded condition, or voluntary entry to take maintenance action on a particular piece of equipment and monitor to the performance.

There's a guidance where one calculates how long can the plant remain in that configuration, maintenance configuration, and still meet certain quantitative metrics, and sometimes it might be a value calculated by the PRA to be days, tens of days, hundreds of days, I'll show you a case, thousands of days.

But the backstop says notwithstanding that calculation, there will be no more than 30 days would be allowed. Then a second programmatic control is voluntary use of the risk-managed tech spec for configuration, which represents a loss of tech spec safety function or inoperability of all required trains would not be permitted.

So we may have a boiling water reactor that

has, let's say, three trains of high pressure injection and three trains of lower pressure injection. A situation where all three trains of high pressure injection would not be allowed. You always have to have some degree of defense indepth.

Even though the plant could depressurize, open the pressurization valves and use low pressure injections, one would always have to make some kind of tech-spec specified safety function, and not allow it to go bad, even if the risk numbers were say theoretically permissible.

MEMBER BROWN: Before you change the page --

MR. DUBE: Sure.

MEMBER BROWN: Risk-informed completion time. Is there -- it's going to be applied, so theoretically this would be utilized throughout the fleet; correct, or is that --

MR. DUBE: No. They would have to come in with a license amendment, an applicant --

MEMBER BROWN: Okay. They'd have to change their existing basis, if they wanted to go this way?

MR. DUBE: Yes, right.

MEMBER BROWN: All right now, thank you. I messed that part up.

MR. DUBE: There is one design center COL

applicant, this would be the Mitsubishi USAPWR and the applicant, COL applicant is Luminant for Comanche Peak 3 and 4, where right from the start they want to implement.

MEMBER BROWN: Okay. Now let me get on with my -- if you have multiple people, who develops the algorithm or the risk-informed methodology for each? Are these dictated by the NRC?

MR. DUBE: The methodology is in a guidance that the staff's endorsed, and the numerical values are in the guidance. But the license holder has PRA-2 that has to meet requirements for technical adequacy, and has procedures, station procedures for implementing.

MEMBER BROWN: Okay. So if you had one particular plant design that was replicated, I'm assuming they all implemented this risk-informed via some license amendment?

MR. DUBE: Exactly.

MEMBER BROWN: And say you had eight plant sites that had all said we're going to go do it this way, and they're all identical plants. But they all have their own PRA and therefore they could all come up for the same down or degraded condition? They could come up with different completion times?

For just a backstop, let's assume they all came up with something less than 30 days. One of them could say well gee, I'm only going to operate for five days based on my analysis, and the other one will say well my methodology says ten; somebody else's says eight; somebody else's says 15.

MR. DUBE: We wouldn't expect that.

MEMBER BROWN: Well, I know I wouldn't expect it, but I'm just saying if you don't have a consistent --

MR. DUBE: Every situation is unique, and so AP1000, you have a Shearon Harris, you have -- I mean no, Summer and Vogtle.

MEMBER BROWN: Vogtle, right.

MR. DUBE: And their PRAs are mostly very similar. In fact, it's probably at this point maintained by Westinghouse. Since it's very similar to the same equipment outage, those different unit sites for the same amount of time should be very comparably the same value.

MEMBER BROWN: Well, what do you mean by -- but why shouldn't they be the same?

MR. DUBE: Well, you may have external events, so you have some -- you have to take into account external events. So you have the seismic risk

at one site may be different than at another site. So there could be some differences there. The internal event, you have power, fire, internal flooding, based on the current standard design, should be identical.

But there will be some site-specific differences in the risk assessment. External flood, tornado, seismic. So when they go through the number, if Plan A has high pressure injection train A out for, in this case it would be a little bit different for AP1000, but one train out for so many days.

They may have a certain number, and it might be different from the other site because of the contribution from external events may be different. That's why I say it should be somewhat similar. Does that make sense?

MEMBER BROWN: Not -- I understand what you said, but it doesn't make sense to me that I've got identical trains, identical whatever in terms of the plant design in AP1000. I would expect that one or two, I think division or a channel or a train, whatever it is, is out of service. I would expect I'd have limited operating --

Inelegant is the specification of a time for each one. You'd get consistency to plants. Now I've got inconsistency from plant to plant, based on the

theoretical thought process, that gee, my risk from all these other things, whether it be tornadoes or seismic or tsunamis or flooding or what have you, gives me more or less external effect.

Therefore, I can let this thing stay out for 20 days instead of five --

(Simultaneous speaking.)

MEMBER BROWN: I'm saying, I said that for, just to make the point clear. That was the only reason I said that.

MEMBER STETKAR: Yes.

MEMBER BROWN: So that's just -- personally, I understand. You all love this stuff. I just don't.

MEMBER STETKAR: Charlie, if you built your plant on top of a volcano compared to another plant, there would be a difference.

MEMBER BROWN: Well, if I had trains out, I'd --

MEMBER STETKAR: Charlie, if you only think about internal events, that's true. If you think about the entire spectrum of contributors to risk, it's different. You must consider -- if Fukushima had been built in the middle of the island of whatever.

MEMBER BROWN: Krakatoa.

MEMBER STETKAR: You know, we wouldn't be

having the discussions we're having these days. You do need to consider those external events, and they do, they can make a difference. In most cases, not very much, but --

MR. DUBE: The methodology is consistent. The tools are consistent, but the plant-specific unique risk profile can result in slight differences, and I don't think it would be 20 and 5 days; it would be 20 and 19.

MEMBER BROWN: No. Only to, that was not meant to be characteristic. I understand that point.

MEMBER STETKAR: And for new plants, they are required to look at the whole spectrum of, to a greater or lesser extent, full spectrum of internal and external events, in all operating modes.

MR. DUBE: Well yeah. I mean that -- for new reactors, at the time of initial fuel load, they have to have a PRA that addresses NRC-endorsed standards one year before, and NRC's endorsed internal events, fire, external events, seismic, and all other external events.

So when the plant, the first plant starts up, it's going to have a full PRA covering --

MEMBER STETKAR: For full power anyway.

MR. DUBE: For full power, and probably

lower power shutdown. So yeah, I understand your point. I mean but there's consistency in methodology and guidance and approach, pretty much consistency in the pool that's being used, and if there is a difference, it's because of site differences.

MEMBER STETKAR: Well, of course going forward, there can be operational experience differences.

MR. DUBE: Over time, yes.

MEMBER STETKAR: That over time could cause some deviation from plant to plant.

MEMBER. SHACK: You might even have procedural differences.

MEMBER STETKAR: You might even have procedural differences.

MEMBER. SHACK: People just do things differently.

MR. DUBE: So continuing on this, we did a series of calculations. All together on Risk-Informed Tech Spec Initiative 4b, we did about 100 calculations. That was done by the staff and industry participants, and we had -- one way or another, we addressed the advanced boiling water reactor, the advanced pressurized water reactor, the ESBWR, AP1000 and EPR, U.S. EPR.

We, staff used a standardized plant analysis risk model, and we just used the internal events. But we're trying to see, you know, what does it tell us? Some of the other design centers had some representation of other events, but I'll go over the AP1000, some of the examples and calculations.

So we simulated the removal from service or inoperability by choosing, in PRA terms, a basic event in a PRA model and setting it to true, and for some of these, subsystems and components like here I'm showing check valves that really don't do online maintenance per se, and it wouldn't make sense. It's a passive system. You're not going to go inside containment and start working on a check valve.

But we chose the basic event there so we could represent a subsystem or train or a pathway being declared inoperable. So that was just a convenient tool. The AP1000 has four Class 1E DC systems, A, B, C, D, 24 hour battery on A and D, and 24 hour and 72 hours on B and C. So you're already starting with a bit of a asymmetry there.

We looked at all various combinations of DC power outages, and also passive cooling system train and subtrain outages, everything from accumulators to core make-up tanks, to the drain line from the in

containment refueling water storage tanks.

MEMBER STETKAR: Don, before you get into some more details, for the benefit of the Committee members who haven't attended the Subcommittee meetings, and I've honestly forgotten also, on the RITS 4b, were all of those done through the SPAR models, or did some of the design centers use --

MR. DUBE: AP1000 participators sat in a meeting. While they did not numerically present results that confirmed all of our findings and say yeah, that's true, that's correct. That's the kind of value that we see.

MEMBER STETKAR: But RITS 4b was actually run only on the SPAR models?

MR. DUBE: For AP1000, yes.

MEMBER STETKAR: For AP1000, okay.

MR. DUBE: ESBWR was just GE Hitachi did the calcs. APWR was Mitsubishi. EPR was AREVA, and ABWR, staff did the calculations using the SPAR model.

MEMBER STETKAR: But the other three, ESBWR, EPR and ESBWR did their calcs with their own PRA models?

MR. DUBE: Yes, that's right.

MEMBER STETKAR: Okay. It's kind of an important perspective for the Committee to understand,

you know, these aren't necessarily all SPAR model calculations.

MR. DUBE: Yeah, correct, and when we, you know, these are two full day meetings. Two full days of workshops.

MEMBER CORRADINI: But the point being, John, I just want to make sure I understand. Your point being that there's kind of a double check --

MR. DUBE: Well, there's some limitations of SPAR models.

(Simultaneous speaking.)

MEMBER STETKAR: Yeah, I mean you know, if there's some limitations of SPAR models, and one always has a bit of concern about are those limitations driving any of the results. If you have various participants using their own models, you get a little bit better confidence in consistency.

MR. DUBE: Right, yeah. So for the first day of the table top, it was mostly staff results, and then once the industry got an idea of how we did calculations, then the second workshop, which was about a week later, they came in with their calculations, and they were pretty extensive.

So here is three out of a couple of dozen cases that were ran for the AP1000. There's a lot of

information here, but I'll walk you through. I'm only showing base case and three cases. So if I can take the time to walk you through.

So these were three cases, as I mentioned, out of the order of 100 that we did for all the reactor design centers. So on the top line, showing the case, the equipment that's not functional, that we assumed was either in a failed state or was out of service for maintenance, the core damage frequency, the change of core damage frequency from the base, the calculated completion time, what the tech spec limit would be, what the allowed completion time would be, based on the RITS 4b and what the incremental core damage probability would be, and what the other available equipment is.

That's important, because you have to maintain some defense indepth and some safety function for the various configurations, or else one has to basically immediately start a shutdown. So the base case, the SPAR model core damage frequency, with no testing and maintenance of any equipment, so everything's available, core damage frequency at that point in time is an annual rate of 2 times 10 to the minus 7. That's just internal events at power.

So that's the base, what we call the base

value. So then in Case 1, the next line, we started simple, one thing at a time, and then we really built up later on, to two pieces of equipment, three pieces of equipment, four, five, six pieces of equipment, really stretching it.

But here, we just kept it simple. We took out the A Class 1E DC power supply. In other words, called it operable and at maintenance state. So the core damage frequency would go from 2.1 E to the minus 7, to 5.9 E minus 7. You'll see the delta CDF the next column over. You see the 3.8 E to the minus 7.

So that's the delta. That's the change, and we started at a baseline 2.1 and went up to 5.9. So that delta's 3.8 E minus 7. Now by the guidance, the incremental core damage probability is allowed to go up to 10 to the minus 5, and t hat's a straight probability. It's an integral of the change in core damage frequency over time.

So per year times year is a unit-less number. It's a probability. That, by the guidance, would be allowed to go up to 10 to the minus 5. So if you --

MEMBER CORRADINI: 10 to the minus 5, it would be allowed to go up before what?

MR. DUBE: Before they have to take

corrective action and begin, either restore it or shut down.

MEMBER CORRADINI: Okay. What's the next column? Maybe you said it, but calculation completion time.

MR. DUBE: I'm going to talk about it right now. So if you take that eight, the change in core damage frequency, 3.8 E times 10 to the minus 7, by how many years can I multiply that to get 10 to the minus 5, using days, some incredible number, like 9,623 days?

Well, remember I said by the backstop, can't go more than 30 days, so and the tech spec limit is only six hours.

MEMBER BROWN: The existing tech spec by the DCD?

MR. DUBE: Right, the standard tech spec. So that's a pretty extreme case, but the tech spec would only allow the configuration six hours. The risk would allow 9,000 days, but by the backstop, they would only be allowed to be in this configuration for 30 days.

If you take the change in core damage frequency, 3.8 times 10 to the minus 7 times 30 days, converted to years. So the actual incremental core

damage probability for this change in risk, integrated over 30 days, would be 3 times 10 to the minus 8.

So that's substantially lower than, you know, 10 to the minus 5 by the guidance. So what's the -- and by the way, the other available equipment they have, one 24 hour division remaining, and two 24 by 72 hour divisions remaining. So they still have three divisions of DC power available.

So what's the message from this is that tech spec limits are very stringent, and we found that on the AP1000 ESBWR. So in risk space, they're very, very stringent. If you want to rely just on a risk number, it would be 9,000 days. But you know, by the guidance, they would be restricted to 30 days.

So this is providing operational flexibility, right? Going from six hours to 30 days provides operational flexibility, but the risk calculation is still low. 3 times 10 to the minus 8 is a very low change in core damage probability. Any questions on that one line, that first line?

MEMBER CORRADINI: John, can I ask about the next two lines?

MR. DUBE: Well, the next two lines are what if we took -- what if the licensee was in a situation where for whatever reason, one drain line, injection

line from the in-containment refueling water storage tank, I'll call that line B, were out? So there's two passive train lines, and they come into a direct vessel injection path that goes into the reactor vessel.

Well, that would -- in that instant it's inoperable or not functional, core damage frequency would be 1.1 E to the minus 4. The delta would round off. It's still 1.1 E to the minus 4. The calculated completion time would be 33 days. Tech spec limits are very stringent, one hour. In other words, shutdown right away.

Would it be allowed to go 33 days, because that's what the calculation says? Well, the answer is no, because in design basis space, you have two drain lines feeding into the vessel injection.

If the D line is inoperable and there was a pipe break on the A line, the core makeup tank and drainage from the IRWST on the A line and the accumulator, we assume to go out that break, and it could not mitigate a design basis accident, the design basis accident being, you know, failure of this passive system and break on the other division.

So even though theoretically they could operate and meet the incremental core damage

probability of 10 to the minus 5 for up to 33 days, this configuration would not be allowed, and it would require --

MEMBER CORRADINI: Why wouldn't it? That's what I didn't catch. I figured by putting one hour in parens, you weren't going to use 33 days, and why?

MR. DUBE: Because --

MEMBER BROWN: So the methodology doesn't work.

MR. DUBE: No.

MEMBER BROWN: You can't get a 30 days.

MEMBER SIEBER: It's margin.

MR. DUBE: No, it's restricted. The risk calculation is necessary but not sufficient. One still has to demonstrate that the risk increase is small, and that defense indepth is maintained. In this configuration, there is no defense indepth.

MEMBER CORRADINI: Meaning there's no redundant system. You lose one, you're toast.

MR. DUBE: Exactly. If the LOCA were to occur in the direct vessel injection line, based on a design basis question.

MEMBER CORRADINI: Yeah.

MR. DUBE: But even PRA, you have --

(Simultaneous speaking.)

MR. DUBE: --say that that's core damage.

MEMBER CORRADINI: I don't know. You guys are kind of way out there. That was just for John.

MR. DUBE: See, certainly voluntary use is not allowed, or inoperability of all required safety training is not permitted. So in this case, there is no redundancy. So you cannot meet the tech spec safety function.

MEMBER CORRADINI: So but the reason you're -- I guess I'm kind of with Charlie. The reason that one hour works, one hour needs to be used here is not because of your backstop; it's because from a design basis standpoint, you have no redundancy?

MR. DUBE: Exactly.

MEMBER STETKAR: I mean in principle in this case, whoever wrote the tech specs essentially gave them an hour to try to fix the problem.

MR. DUBE: You're not going to fix it in an hour.

MEMBER STETKAR: In principle, it's a disallowed --

MR. DUBE: An hour is -- having been in an operating company, an hour is enough time to call the dispatcher and say "I'm shutting down." Especially since these are passive systems inside

containment.

MEMBER BROWN: So the point being, you have to have a backstop methodology engineering deterministic thought process, in order to come up with the right answer? I thought of that one, just to be aggravating.

MR. DUBE: Yeah, yeah. The real answer is a small increase, risk increase is necessary but not sufficient. Remember the principles of Reg Guide 1.174 and risk-informed regulation. One has to have a small risk increase and demonstrate defense indepth, and demonstrate margin of safety and monitor performance.

MEMBER BROWN: The incremental core damage probability increases only --

(Simultaneous speaking.)

MEMBER BROWN: One point is smaller than the other one.

MR. DUBE: Right. So the risk increase is small. That meets the necessary condition, but it's not sufficient. There is not enough -- there is no defense indepth against a certain accident.

MEMBER CORRADINI: So can I say, if only on this example, because you'll tell me the example is too isolated for this, is that the two examples you

gave are one, I had multiple redundancies, and the other I had only a single redundancy?

MR. DUBE: Right.

MEMBER CORRADINI: That's the essence of why one is big and the other is small?

MR. DUBE: What's big, the allowed completion time?

MEMBER CORRADINI: Yeah.

MR. DUBE: Yeah.

MEMBER BROWN: So the risk-informed methodology can't be applied to those things with one redundancy?

MR. DUBE: Yeah.

MEMBER BROWN: So you don't want anybody to think about it. You just want them to go do it.

MR. DUBE: But for most of the reactors, now this is an extreme case that I'm presenting. It's an interesting case, Case 7 here. But for most of the plants, their three trains or four being redundant. So ABWR typically has three trains of high pressure injection, low pressure injection.

The EPR, APWR has four trains. The APWR they have 50 percent trains, but still four trains. ESBWR has multiple trains, many systems.

MEMBER CORRADINI: But let's try the problem

backwards. What if there were three lines for the IRWST. You would probably come up with an allowable 30 day fix on it?

MR. DUBE: Possibly, yeah, yep.

MEMBER CORRADINI: So it's going from four to two that made the big difference? That what I guess I'm trying to do. I'm trying to --

(Simultaneous speaking.)

MEMBER STETKAR: Yeah. I mean in that case, in that case it would be like the Example No. 1. You'd back up to the 30 days if you do that.

MR. DUBE: Yes. It would be backed up.

MEMBER CORRADINI: Okay, that's fine.

MEMBER ABDEL-KHALIK: But the two key programmatic controls that you're talking about, the second one talks about loss of tech specs specified safety function, not loss of redundancy in tech-spec safety function.

MR. DUBE: Now there's a whole -- we have some tech spec people, experts in the audience. There's a whole section in the tech specs that provides guidance on loss of safety function.

MR. BRADLEY: It's 303 in the existing specs. I assume that's the same --

MEMBER STETKAR: Biff, you have to identify

yourself.

MR. BRADLEY: I'm sorry. Biff Bradley, NEI. Tech Spec 303, LCO 303 precludes entering a condition of loss of function. It pus that one hour completion time for a loss of function, and that's not affected by this initiative.

MEMBER BROWN: So you have to have a process that people don't use the risk-informed methodology where it can't be applied?

MR. BRADLEY: It's right there in the tech specs.

MR. DUBE: Yeah. This is in the tech specs.

MR. BRADLEY: Yeah.

MEMBER BROWN: Yeah, I know. But I didn't read like Said over here. I read that and I said oh, voluntary use of a risk-informed tech spec for configuration, which represents a loss of safety under the design condition, I presume. If you've got one out of service you could have the other one fail, and therefore you're not permitted to use the methodology. But that, I didn't think of it in terms of redundancy. This is so --

MEMBER ABDEL-KHALIK: Well, the example you gave earlier pertained to loss of high-head safety injection, rather than loss of redundancy in the

ability to provide high-head safety injection, and you said, you know, even though the plant can depressurize and can use low-head safety injection, you don't allow the plant to operate in a condition where you don't have the ability to inject that high pressure. That's where the confusion came about.

MR. DUBE: In the tech specs, in the bases for the tech specs, they describe any -- this in great detail, and fine, okay. Then the bottom 9A is very similar, so in the interest of time, I won't go through it. But it's the same kind of a thing.

MEMBER ABDEL-KHALIK: As seven?

MR. DUBE: As seven. Core make-up tank and accumulator. The calculated completion time is 24 days, but this configuration would not be allowed. So in all, many cases that were done, the staff did identify some configuration of equipment, outages that would represent ten years' worth of core damage probability.

Now that's a theoretical case, and in order to get this situation in the advanced boiling water reactor, for example, which is three divisions.

There's three electrical divisions; there's three trains of high pressure injection, three trains of low pressure injection, and then there's kind of an

unaffiliated division, if you will, such as the AC independent water addition, the containment vent and the reactor core isolation cooling, which is steam-driven.

To get these configurations, we were taking equipment almost across the board on all the divisions, to get in this situation. We were doing this to stretch the limit, but they weren't realistic conditions or situations.

In fact, there's not, you know, in many cases, under the tech specs, there's nothing prohibiting plants from being in similar configurations, and they have even less controls than if one implemented risk-informed tech specs.

MEMBER ABDEL-KHALIK: Can we go back to the previous slide?

MR. DUBE: Sure.

MEMBER ABDEL-KHALIK: I understand why this is not allowed change in the completion time, but where did the one hour come from in the first place?

MR. DUBE: That's in the tech specs right now. See the tech specs?

MEMBER ABDEL-KHALIK: I understand the tech spec, but just out of thin air.

MR. DUBE: Engineering judgment. Immediate

shutdown is really what it represents. I mean one hour is just enough time to think about --

MEMBER STETKAR: Same place that the 30 days came from.

MR. DUBE: Well, okay.

MEMBER BROWN: Can I ask one more question related to this?

MR. DUBE: Yes.

MEMBER BROWN: Is this meant to be a real-time tool, or this is a -- or that's another worry then. In other words, something happens in the plant, and now they go and they generate, they turn on their computer and say oh, I input the data and okay, I can stay in this convention for 20 days, as opposed to having it predetermined, based on so you can think about it, and see if it makes sense.

MR. DUBE: When I say "real time," it's real time in the sense that you're monitoring what equipment's out of service at any particular point in time. But you look, you know, we had South Texas in here, and they're the only ones that have implemented it so far, Units 1 and 2.

Those are Westinghouse 14-foot cores with three trains, and they pre-solved all the single equipment and many of the double combinations. So

it's already been pre-calculated way ahead of time.

So they know, I mean you know, the plant's running along and all of a sudden the A HPSI pump is out. They know what the risk increase is without even doing the calculation yet. If something comes along and if it's aux feedwater pump, chances are they've pre-solved that.

So they already, when I say "online," it's online in the sense of it is an instantaneous monitoring of it, but most of the calculations for most of the configurations have already been done.

MEMBER STETKAR: Don, but that's only because South Texas decided to do it that way. Indeed, it could be if you had an online running PRA, you know, your standard risk monitor. This is a real time calculation.

MR. DUBE: Yeah, but if -- again, with South Texas' here is, you know, things happen odd hours. Three o'clock in the morning, you know, something's out and you have a tech spec that allows you three hours, four hours.

You know, you're going to call some PRA expert who's on vacation in Florida to do the calculation. You don't want to put yourself in that situation, so --

MEMBER STETKAR: That's a different issue. But I think Charlie's concern was is this something that you do in real time, and the answer to that is yes.

MR. DUBE: The monitoring is real time.

MEMBER STETKAR: You make decisions in real time as the plant configuration changes. Regardless of whether it's pre-solved or you have your shift technical advisor is PRA-qualified, and he's running the risk model for you.

MR. DUBE: Right.

MEMBER STETKAR: This is real time decisions.

MR. BRADLEY: Yeah, that's correct. I just want to mention Vogtle 1 and 2 is in the process of applying for 4b, and they're using -- EPRI's produced an updated version of EOS, that will do a real time calculation to support the Vogtle 1-2 app.

MEMBER BROWN: How does the data get input? If something goes, I mean, is it monitored and it automatically happens, or does somebody have to input the fact that something else has failed or gone down while you've got some other operating configuration?

MR. BRADLEY: You have to input the data. It's an operator tool. It's in the control room.

It's just the operator, it's a tool for the operator.

MEMBER BROWN: Okay. So you subject yourself at three o'clock in the morning to the ability of a guy that may not be as good, if it's a system that's --

MEMBER STETKAR: Charlie, you turn something off.

MEMBER BROWN: Oh, I don't know. It could be anything. I have no idea.

MEMBER STETKAR: No, you turn something off. You've failed a piece of equipment. You aren't inputting failure rates for things. That's already in there. You're just --

MEMBER BROWN: Yep. Gotta make sure the data gets input correctly. That's all I -- that's the only point I'm making. You've got to make sure it gets input correctly.

MEMBER STETKAR: Well, but you do when you have a paper system and have to make decisions on the fly about whether or not you violate the tech specs. Somebody needs to recognize that something isn't working.

MEMBER BROWN: Yeah, but then you're recognizing it's not working. But you still have to input the data properly, even after you recognize it.

MEMBER STETKAR: The data is turning something off.

MM. I think all he's saying, Charlie, all I think he's saying is there would be a working model that best represents the plant, and then they'd look for essentially out of service conditions of the system. At least that's what I --

MR. DUBE: Right. They would toggle a switch --

(Simultaneous speaking.)

MEMBER BROWN: Or it's knowing which switch to toggle.

MR. DUBE: They're trained on this, and this is every operator. One reason why Luminant, on behalf of Comanche Peak 3 and 4 want to go straight to this, rather than use, go to standard tech specs and then have to get this program accepted down the line and have to retrain. Their goal is to start out with this Risk-Informed Tech Spec 4b, risk management tech specs right from the beginning, and train the operators right from the beginning.

MEMBER BROWN: But the risk-informed output is still not going to output one hour. It would output 33. You've got to keep in mind that hold it, I'm in this other configuration --

MR. DUBE: No. There's software that handles that.

MEMBER BROWN: So it would come up one, if the software's written correctly. Line 7. If that really happened, and you had this online system and it went down, and the guy inputted it. Instead of coming up with 33 days, it would have said one hour.

MR. DUBE: Configuration 7 would, may take -- I can't speak on behalf of what might be designed into it, but --

MEMBER BROWN: As opposed to 30 days.

MR. DUBE: Yes, for that situation.

MEMBER STETKAR: So this by the way, the whole discussion that we're having here really is irrelevant to new reactors in particular, because it's being applied for existing reactors. RITS 4b is being applied for existing reactors. As Don mentioned, South Texas already has it in place. It is not a new reactor metrics issue, you know. Concerns about implementing this apply to currently operating reactors.

MEMBER BROWN: No, I understand that.

MR. DUBE: And during the workshop --

MEMBER BROWN: It had to be, since 3 and 4 is not in place yet, and we talked about South Texas.

MR. DUBE: Right. During the workshop, South Texas was in before us and gave a demonstration of the experience capabilities. So I mentioned, you know, repeated entry would be a concern, but that's no different than the current tech specs, that allows multiple entries and doesn't even require the degree of monitoring that the program requires, RITS 4b.

And you know, in order to get these configurations that I mentioned, we were taking -- one would have to literally take equipment out from virtually all the trains, which is just not the way operators run plants. Typically, it's a one train at a time outage, and yeah, it could be an emergent failure on the second division, the second train. But extremely improbable to be the situation across all trains.

MEMBER BROWN: Is that what you mean by repeated entry?

MR. DUBE: No.

MEMBER BROWN: What did you mean by repeated? I didn't understand.

MR. DUBE: Right now a license has, let's say, a tech spec of three days on a diesel generator, and it's declared inoperable, enters the action statement, takes some action for one or two days. A

week or two later, some other configuration occurs, some other situation on the diesel. Enters the action statement, so that's one or two-three days.

MEMBER BROWN: In other words, it's not staying available?

MR. DUBE: Right. Whereas here, one of the requirements is to monitor performance over time. In fact, that's actually a requirement, and this is why I say, my third sub-bullet here, "Performance monitoring is a key programmatic control, and by regulation, the new reactors, under 50.71(h), have to maintain and upgrade the PRA," and part of that is monitoring performance.

I mean they have to -- if their past experience has been that these outages are contributing to train and unavailability, that has to be reflected in the PRA model. So we, the staff concluded after two days of exercises for the thought that there's no substantive changes to the methodology that's necessary.

Now there are some changes that might be necessary because of implementation issues, but they're not fundamental to the risk calculation. Probably I'm running way, probably running way behind time, and I know I was asked to, just in passing,

touch upon these.

So real quickly, one of the programs, one of the table tops had to do with the change process for severe accident features, and the black circles shows the containment challenges that are identified in 52.47(a)(23) and 52.79.

These include specifically those five containment challenges from severe accidents. Core concrete interactions, steam exposure and high pressure, melt ejection, hydrogen explosion containment bypass.

But the statements of consideration, and in this case for the advanced boiling water reactor, is very specific on what is a next vessel severe accident feature, and they say it applies only to features where the intended function of the design feature is relied upon to resolve postulated accidents, when the reactor core has melted and exited the reactor vessel, and the containment is being challenged.

That's the red circle. So the change process under Tier 2 would definitely address features that are there to mitigate against core concrete interactions, high pressure melt ejection accidents. Steam explosion, maybe, maybe not. It wasn't specific whether it was an in-vessel steam explosion or ex-

vessel steam explosion.

In hydrogen explosion, it's not necessarily a situation occurs just because the core has melted through the bottom of the vessel and exited. So changes associated with that may or may not be included, and containment bypass, which is like an interfacing systems LOCA, are not, by definition, a feature, next vessel reaction feature.

So the long and short of it is when we went through this methodically, we found that the rule as written regarding the change process for ex-vessel severe accident leaves a gap.

There are severe accident features not there to address ex-vessel severe accidents, but to mitigate accidents and retain in in-vessel, that are there and the change process is not, there's a void. There's a gap. It doesn't say what to do with those.

MEMBER CORRADINI: Can you try that again? I'm trying to understand what you just said.

MR. DUBE: Okay. The rule says there cannot be an increase, substantial increase in probability or consequences of ex-vessel severe accidents. But it doesn't say anything about design features that are there to mitigate and keep the core in-vessel.

MEMBER CORRADINI: Now we're talking operating plants or future plants?

MR. DUBE: Just the new plants.

MEMBER CORRADINI: New plants.

MR. DUBE: It's part of the rule for the change process. So what does that mean? That means there's no guidance there for Tier 2 change process, or severe accident features that are there just for in-vessel mitigation.

MEMBER CORRADINI: So I guess you jumped to in-vessel, because I thought you were -- you started off what, there is no change process for ex-vessel.

MR. DUBE: No. There is a change process for ex-vessel severe accidents.

MEMBER CORRADINI: There is none for in-vessel?

MR. DUBE: Exactly. One would default -- in theory, a license holder could make a change to a severe accident design feature that's there, just to mitigate in-vessel accidents. For example, the independent water addition for the advanced cooling water reactor.

Unless there was details in Tier 2, they could make a change under Tier, I mean unless there was specific details in Tier 1, they could make a

change under Tier 2 and not require prior NRC approval. You still look perplexed.

MEMBER CORRADINI: I am. I know what you said; I'm still trying to figure out. So that would not be reflected -- that is, they could do it without prior notification?

MR. DUBE: Prior NRC approval.

MEMBER CORRADINI: And that's what's bugging me.

MR. DUBE: Yes.

MEMBER CORRADINI: There's a gap. So in current plants --

MR. DUBE: Under the current regulation, a Tier 1 change is a very high level statement.

MEMBER CORRADINI: Yes, I understand.

MR. DUBE: They cannot make -- any change to that, even if it's somewhat minor, requires prior NRC approval. Tier 2, they go through a 5059 like process. Is there a substantial increase in probability or a substantial increase in consequences?

But it only applies to ex-vessel severe accident features, not features there to mitigate in-vessel phenomena.

MEMBER CORRADINI: Is the AP1000 in-vessel retention in-vessel or ex-vessel?

MR. DUBE: That would come under probability, and is there an increase in probability of an ex-vessel severe accident previously reviewed and deemed acceptable by the staff, and therefore deemed incredible.

MEMBER CORRADINI: It's a probability. It's not a feature that's a mitigation of consequence?

MR. DUBE: The flooding up of the lower reactor cavity, and cooling of the outside of the vessel is a feature to maintain the core debris inside the vessel. If they were to go through a -- so that --

MEMBER CORRADINI: Let's say they change the insulation, they change --

MR. DUBE: That makes high pressure melt ejection accidents incredible.

MEMBER STETKAR: I hate to stop this right now, but this actually is a really, really subtle part of what they dealt with, and I want to get to more of the risk metrics sort of issues, so we want to move off this point.

MR. DUBE: But in answer to your question, they did something so that they would not be able to have assurance of cooling the outside of the vessel and maintaining it. That would be a substantial

increase in probability and require prior NRC approval.

MEMBER CORRADINI: Okay, fine.

MR. DUBE: So Recommendation 1 to the Commission is to address the potential gap by ensuring there are sufficient details on all key safety accident features in Tier 1, and including a change process in future design certifications in Section VIII, for non-ex-vessel severe accident features similar to Section VIII.B.5.c.

So we have two here, because you know how long it takes a rulemaking. It takes a lot of time. So in the interim, we want to change, have ensure, and we can do this by changing one of our standard review plan items, if you will, relatively quickly.

So we can ensure that there's sufficient details in Tier 1, but the long-term would be design certification rulemaking, to make sure that features to arrest and mitigate core damage in-vessel get the same treatment as ex-vessel, the long and short of it.

A second item in passing has to do with the fact that for design certifications, large early release frequency has been the metric, and in the interest of time, because I'm really running out fast, as part of our exercises, the staff's recommending an

option where one would convert from the use of large early release frequency, and leave that to design certification and combined license application, at or around the issuance of the combined license and during the construction phase.

Core damage frequency, large early release frequency and conditional containment failure probability would still be the metrics of use, but at or before initial fuel load, to be consistent with large early release frequency, which is the metric that operating reactors are using.

The COL holder would convert from large early release frequency to use of large early release frequency metric.

MEMBER STETKAR: Now that last bullet, and I want to keep us on schedule here, but the last bullet is also important, because the recommendation also says that Reg Guide 1.174 will be updated to note the containment performance also. Although you don't calculate a CCFP, that notion will be retained.

MR. DUBE: Right. There's two Commission papers, and there's an associated staff requirements memorandum, 90-016 and 93-087, which have to do with containment performance objectives, and I'll just really read it quickly.

"The containment should maintain its role as a reliable leak-tight barrier, for example, by ensuring that containment stresses do not exceed ASME service level C limits for metal containments, or fractive (ph) load category for concrete containments for approximately 24 hours following the onset of core damage, under the more likely severe accident challenges," and so on and so forth. So they would still have to meet that requirement.

So those are the two recommendations. They're kind of ancillary to many of the table top exercises, but they were findings as a results of the table top exercises. You know one, is that there was a gap in the change process that didn't address mitigation of in-vessel phenomena, and the second one, new reactors and operating reactors are using two metrics, and at some point, the Commission told us make them the same.

So at some point they have to transition, and Option 2C, Recommendation 2 is what staff has proposed. I'm just going to list here to note that we looked at the maintenance rules, 50.65(a)94). We found no gaps. We looked at Risk-Informed Tech Spec Initiative 5b on surveillance frequency, found no gaps.

We looked at 50.69, and no gaps, and Reg Guide 1.174, other than that one point that I made on containment performance. But in terms of the risk metrics and reliance on defense indepth, we found no gaps.

Now I'm going to -- unless there's questions, I'll turn it over Ron Fruhm, who will talk about the ROP.

MR. FRUHM: Okay, and I'll try to do this fairly quickly, based on time constraints, because we do still want to talk about next steps, and quickly review some of the changes we made to the draft SECY paper.

I'm Ron Fruhm in the Performance Assessment Branch of NRR. I just wanted to recognize that Rani Franovich is also with us today. She's the branch chief of that branch.

In addition to those licensing table tops that Don's been talking about, we ran several case studies on the risk-informed aspects of the reactor oversight process, to confirm their adequacy for use for new reactors.

We used a broad cross-section of real cases from the previous ten or so years of ROP experience, to ensure a realistic and representative sample,

because the SRM did say that we should do realistic scenarios.

The case studies covered the significance determination process for the risk-informed safety cornerstones of initiating events, mitigating systems and barrier integrity. We also ran case studies on the mitigating systems performance index and Management Directive 8.3 for regulatory response to events.

We then applied similar situations based on those case studies to the new reactor designs, filling in any gaps with realistic hypothetical situations and reasonable assumptions. Then we compared the risk values and resultant regulatory response, to see if we ended up in the right place.

A summary of these case studies was included as an enclosure to the October 26th meeting summary.

The first set of table tops we ran was for the significance determination process. These table tops indicated that the existing risk thresholds for determining the significance of inspection findings are generally acceptable, and greater than green thresholds could be crossed, but would produce an increased regualtory response.

However, these greater than green inspection

findings would likely involve common cause failures across multiple systems or long exposure times of risk-significant components.

Further, we found that the existing process would not always ensure an appropriate regulatory response for degradation of passive components and barriers. So for the SDP, we concluded that these analyses could be augmented with additional qualitative considerations, such as deterministic backstops, to appropriately address the performance issues.

As noted in the draft paper, some of the potential deterministic backstops could include an emphasis on barrier integrity, limiting extensive equipment outage times, similar to the RITS 4b that Don talked about, and addressing repetitive or common cause equipment failures.

I would like to point out that the backstops would be designed to capture those infrequent yet potentially significant issues that may not be captured directly by the risk calculations, in order to ensure that we end up in the right place with our regulatory response.

Next, the second set of table tops was for MD 8.3 for event response, and these table tops

demonstrated that the existing risk thresholds for invoking reactor inspections are adequate for the new reactor, and these thresholds could be crossed, such that we would invoke reactive inspections, including augmented inspection teams.

They did reveal that the deterministic criteria already play an important role in this process, but they are used initially for event screening, and are then considered again within a range of response determined by the risk values.

So as a result of this current structure, which applies to the current fleet as well, the risk values heavily influence whether or not a reactive inspection is warranted, and at what level we would engage.

We also noted that variations in or minor revisions to the risk models used could potentially result in an inadequate response. Based on the MD 8.3 table tops, we concluded that the contribution of the existing criteria could be modified, or new deterministic criteria could potentially be developed for initiating reactor inspections for new reactors, similar to those previously discussed for the SDP.

The third set of table tops we ran for the ROP was for the MSPI, and quite conclusively, we

realized that the existing MSPI would be largely ineffective in determining an appropriate regulatory response for active new reactor designs, and a meaningful MSPI might not even be possible for the passive designs.

We did note that the existing performance limit or backstop used in the MSPI process could potentially be further leveraged for the active new reactor designs, and so our conclusion for the MSPIs was that alternate PIs in the mitigating systems cornerstone could be developed, or additional inspection could be used for the new reactors, to supplement insights currently gained through the MSPI for the current fleet.

MEMBER SKILLMAN: Ron, back on that slide, number 20 please. With the result that the existing MSPI is not adequate and would be ineffective, why in your conclusion do you communicate that an alternate PI could be developed, versus should be developed?

MR. FRUHM: Well should is more like a recommendation to me. Here, our conclusions, our recommendation is that it should be developed, if that helps.

MEMBER SKILLMAN: Well then why isn't the wording "must be," just so it's clear?

MS. FRANOVICH: This is Rani Franovich from the staff. I don't know that the staff really has established a position on this.

I think what we really need to do is work with the industry and other external stakeholders, to get a better feel for what kinds of PIs might be leveraged, what it would look like, and then determine if that's really going to be adequate, or do we need to look in the inspection area to cover that.

So we're not tied to PI. If we find that there is a viable approach to an alternative PI, then that's great. The other thing is the industry has to be agreeable. So using inspection is another way to do this.

MEMBER SKILLMAN: Okay, thank you.

MR. FRUHM: And we are just talking the mitigating systems cornerstone here. That's one of the seven cornerstones, and within each cornerstone there are PIs and inspections.

MEMBER SKILLMAN: Okay, thank you. Thanks.

MR. FRUHM: Okay. So based on the table top results, we developed three options for the Commission's consideration. Consistent with the SRM direction, each of these options maintains the current risk thresholds for the new reactor designs.

They're also consistent with the integrative risk-informed decision-making concepts in Reg Guide 1.174, and in addition, they would not infringe upon the greater operational flexibility afforded by the enhanced safety margins of the new reactor designs.

Under the first option, use as is, we would simply use the existing risk-informed tools for new reactor applications without making any changes. An obvious advantage to this approach is that no additional action or resources would be needed. But a pretty obvious disadvantage is that these existing tools might not always provide for an adequate regulatory response.

MEMBER STETKAR: Ron, for the benefit of the -- again, for the Committee members who weren't in the Subcommittee meeting, we had -- I had to wait until we got here -- quite a bit of discussion about kind of what feeds into that second bullet under A, and I want to make sure I understand it pretty clearly.

I mean the way that you interpreted the SRM was a very literal interpretation of the SRM. In other words, whatever is spelled out in the current regulations is what was applied. In particular, for example in the significance determination process, there are absolute measures that are used.

If the core damage frequency increases by 1.0 times 10 to the minus 6, or if the large early release frequency increases by 1.0 times 10 to the minus 7, you transition from bringing **. Those are absolute measures of the change, and some of your examples demonstrated that it's extremely difficult to meet those absolute changes in risk.

We questioned in the Subcommittee why not use relative changes in risk, for example, the risk increase by a factor of 10 or 100 or 1,000 or two percent.

I think the response that we heard was well, that's not the way the current regulatory guides are fashioned. So that was beyond that you thought about. Is that a fair characterization?

MR. FRUHM: That's fair. We did interpret it very strictly. That was based on the words themselves, as well as looking back at the vote sheets from the Commissioners and all of our interactions with stakeholders. We were all looking at it from the same angle, and that was that the risk thresholds were -- they were what they were.

Test them, see where we come out, and if they're grossly off base, then we need to, you know, come up with examples and really convince them. And

basically they said no, but you know, if you really find something wrong, come back to us and convince us, and we didn't feel like we got there.

MEMBER STETKAR: Okay. You didn't look at -- I mean we discussed using type relative measures.

MR. FRUHM: We never considered relative risk in that, as we discussed during the Subcommittee.

MEMBER STETKAR: I just, the other Committee members didn't have the benefit of that discussion, and we're kind of limited on time here, but thanks.

MS. FRANOVICH: This is Rani Franovich. If I could just interject, I'm a little concerned that if we even propose that eight percent change in the risk, the relative risk, could be perceived by the Commission as a back door way of really establishing new risk thresholds for new reactors. A factor of ten is really a factor of ten reduction in the risk.

So we really did not consider that as a viable option that the Commission left on the table. But that was just the staff's read, based on, as Ron said, the vote sheets and the SRM.

MEMBER STETKAR: Thanks.

MR. FRUHM: That would be more towards Option 3 from the original paper.

MEMBER STETKAR: Right.

MR. FRUHM: And we saw it as -- they said Option 1 or 2 are hybrids, so we kind of left that off the table.

MEMBER STETKAR: Thanks, Ron.

MR. FRUHM: Okay. Moving on to the second option. Option B is to augment the existing processes. Here, we would use the existing risk-informed SDP, but augment the risk aspects with deterministic backstops, to ensure an appropriate regulatory response to address performance issues.

We would modify the contribution of the existing deterministic criteria in Management Directive 8.3, or potentially develop new criteria, to determine the appropriate regulatory response to plant events.

Finally, we would develop an alternative PI and a mitigating systems cornerstone, or argument existing guidance to emphasize the performance limit, or increase inspections for the active new reactor designs, and we would also increase the inspection of passive mitigating systems for the passive new reaction designs, because we do have both PIs and inspections as approaches to evaluate performance.

A key advantage of this option is that you probably noticed that it nicely aligns with the

conclusions from the previous slides. Another advantage is that these proposed enhancements could be developed using existing resources, and working with stakeholders over the next few years, well in advance of the operation of new reactors.

They do, however, introduce more qualitative decisions with regard to not yet developed deterministic backstops, as they're presented here, which in some sense seems to be a retreat from the whole notion of developing a quantitative risk-informed regulatory framework.

The reason quantitative is nice is it's well-defined. It's unbiased and it's reproducible, as opposed to my making a determination of how you may or may not comply with some well-defined or not so well-defined deterministic criterion.

MEMBER STETKAR: Right. Well, that's a bit of -- we had some of this discussion also in the Subcommittee meeting, that it seems a bit of a retreat from that process that was implemented, and has been working quite well, you know, with the existing reactor fleet.

MR. FRUHM: And we still will be extremely risk-informed. That's one of the tenets of the ROP, to be risk-informed, and we want to be repeatable,

etcetera. These deterministic backstops will not be subjective.

We'll try to make them as repeatable and, you know, concrete as we can. We would not make for subjective decision-making. It would be a value, a numeric threshold we would envision it to be. That's what we would envision today. I mean obviously we haven't gone through the process, but that's what we're thinking.

MS. FRANOVICH: Yeah. If I could interject here too, Rani Franovich. There are four other cornerstones of the ROP that don't rely on risk tools, but we still consider the outcomes of SDP to be repeatable, because we use the same deterministic process for each case, to arrive at a significance outcome.

I think that that would still be true in this case, although that would be for those few cases where the backstops are achieved. I think most cases will be resolved and characterized with the risk threshold that we have in place today.

MR. FRUHM: In fact, we would envision applying the same guidance to both the current fleet and the new reactor fleet. But we would expect the risk thresholds would be tripped more frequently for

the current reactors, and we probably never would get to those deterministic backstops. For the new reactors, we would get there on occasion, but also not frequently.

Okay. Moving on to the next slide, the third and final option, Option C, is to develop deterministic tools, where we would essentially not use the existing risk-informed ROP tools, but would instead develop deterministic tools specifically designed for the new reactors.

An obvious advantage to this is that, or a disadvantage is that additional resources would be necessary, and another disadvantage is that this approach would be less risk-informed than it is for the current fleet.

Probably as no surprise, we would recommend Option D, to augment the existing processes, and going this route, we would obtain Commission approval for any proposed changes to the ROP at least one year prior to implementation, and the process enhancements could be further refined over the years, based on experience and lessons learned, which is consistent with the continuous improvement philosophy of the ROP. That really concludes the ROP portion of the presentation.

MR. DUBE: Yeah, we're pretty much done. I would just --

MR. FRUHM: I'll turn it over to Don to wrap it up.

MR. DUBE: The next two steps, that's all that's left after several years of working on this effort. Finalize the Commission paper based on ACRS and stakeholder feedback. The paper is due to the EDO end of May; to the Commission early June.

As of now, we've only had positive feedback from external stakeholders, and so we're not planning any changes on that account. We're not planning as of now to make any substantive changes to the draft. We have, you know, been making continuously editorial changes. We've made wording changes.

I know some Subcommittee members expressed some concern with words about the PRAs, so the use of PRA in the ROP in particular. We've made those changes already.

We've shortened it, and under Recommendation 1, at one time there was an option 1A and 1B, which is either fill the gap for the ex-vessel severe accident change process, or don't fill the gap. It's kind of a little bit of a non-choice. So we just eliminated the option and just made the recommendation.

MEMBER STETKAR: Don, that's kind of important, because we will be writing a letter from this meeting, and the letter that we're writing will be referenced to the February 3rd version of the SECY paper, which is the only thing that we've seen, and that one's still -- for example, I noticed 1A and 1B have disappeared, and it's only 1 now.

MR. DUBE: Yeah, right.

(Simultaneous speaking.)

MEMBER STETKAR: So we've not seen any editorial changes since that February 3rd revision version?

MR. DUBE: Right.

MEMBER STETKAR: So just to make you aware of that. I mean you said there's nothing substantive that's been changed.

MR. DUBE: Well, when I say --

MEMBER STETKAR: We're limited to anything you see from us in our letter.

MR. DUBE: Okay. The conclusions are the same. The background's the same. Like I said, I don't know if you call that substantive, but we deleted Option 1A and 1B, and just used the same arguments to go straight to the Recommendation 1.

MEMBER STETKAR: That's fine. Just you'll

see, for example in our letter, a discussion of 1A and 1B, you know, if the Committee so decides to cast it that way. Just because our version of record is indeed that February 3rd version.

So we'll take it on face value, that there hasn't been anything substantively changed, that would make us look really silly.

MR. DUBE: No. For advantages and disadvantages, the reasoning behind both the conclusions, the recommendations, both haven't changed. Thanks.

MEMBER STETKAR: Great. Any other members have any other questions, comments? I'm sure there are comments, but anything else?

MALE PARTICIPANT: Nothing.

MEMBER STETKAR: If not, amazingly enough, Mr. Chairman --

CHAIR ARMIJO: Right on time.

MEMBER STETKAR: Oh, we're early. Twenty minutes early.

MALE PARTICIPANT: I've got credit in the bank.

(Simultaneous speaking.)

MEMBER POWERS: Those four minutes are my four minutes.

# Presentation to the ACRS Full Committee – 593rd Meeting

**Briefing on Calvert Cliffs Unit 3 COL Application Safety Evaluation Reports with Open Items for FSAR Chapters 6, 7, 15, and 18**

**Surinder Arora**
**Project Manager**

**April 12, 2012**

# Major Milestones - Chronology

U.S.NRC
United States Nuclear Regulatory Commission
*Protecting People and the Environment*

| DATE | MAJOR MILESTONE |
|---|---|
| 07/13/2007 | Part 1 of the COL Application (Partial) submitted |
| 12/14/2007 | Part 1, Rev. 1, submitted |
| 03/14/2008 | Part 1, Rev. 2, & Part 2 of the Application submitted |
| 08/01/2008 | Revision 3 submitted |
| 03/09/2009 | Revision 4 submitted |
| 06/30/2009 | Revision 5 submitted |
| 07/14/2009 | Review schedule published |
| 09/30/2009 | Revision 6 submitted |
| 04/12/2010 | Phase 1 review completed |
| 12/20/2010 | Revision 7 submitted |
| 11/15/2011 | ACRS reviews complete for Chapters 2 (Group I), 4, 5, **6, 7,** 8, 10, 11, 12, **15,**16, 17, **18** & 19 |
| 03/27/2012 | Revision 8 submitted |

# Review Schedule

| **Phase - Activity** | **Target Date** |
|---|---|
| **Phase 1** - Preliminary Safety Evaluation Report (SER) and Request for Additional Information (RAI) | April 2010 (Actual) |
| **Phase 2** - SER with Open Items | Schedule under Review |
| **Phase 3** – Advisory Committee on Reactor Safeguards (ACRS) Review of SER with Open Items | Schedule under Review |
| **Phase 4** - Advanced SER with No Open Items | Schedule under Review |
| **Phase 5** - ACRS Review of Advanced SER with No Open Items | Schedule under Review |
| **Phase 6** – Final SER with No Open Items | Schedule under Review |

NOTE: The target dates for Phase 2 to 6 are currently being evaluated based on the RAI response dates provided by UniStar in their February 21, 2012 letter.

# Review Strategy

- Pre-application activities
- Acceptance Review of the application
- COLA has chapters and sections incorporated by Reference
- Review of COLA site specific information in conjunction with the DC review. Same technical reviewers in most cases.
- Generic Open Item that ties DC and COLA Reviews
- Frequent interaction with the applicant via
  - Teleconferences
  - Audits
  - Public meetings
- Use of Electronic RAI (eRAI) System
- Phase discipline

# Summary of SER with OI: Chapter 6 Engineered Safety Features

U.S.NRC
United States Nuclear Regulatory Commission
*Protecting People and the Environment*

| SRP Section/Application Section | | Number of RAI Questions | Number of SE Open Items |
|---|---|---|---|
| 6.1.1 | Metallic Materials | 1 | 0 |
| 6.1.2 | Organic Materials | 3 | 0 |
| 6.2.1<br>6.2.2<br>6.3 | Containment Functional Design<br>Containment Heat Removal<br>Emergency Core Cooling System | These Sections were not delivered in the Phase 2 SE | N/A |
| 6.2.3<br>6.2.4<br>6.2.5<br>6.2.7<br>6.5 | Secondary Containment Functional Design<br>Containment Isolation System<br>Combustible Gas Control in CTMT<br>Fracture Prevention of CTMT Pressure Vessel<br>Fission Product Removal & Control Systems | IBR | 0 |
| 6.2.6 | Containment Leakage Testing | 0 | 0 |
| 6.4 | Habitability Systems | 6 | 2 |
| 6.6 | Inservice Inspection of ASME Class 2 & 3 Components | 0 | 0 |
| Totals | | 10 | 2 |

# Summary of SER with OI: Chapter 7 Instrumentation and Controls

United States Nuclear Regulatory Commission
*Protecting People and the Environment*

| SRP Section/Application Section | | Number of RAI Questions | Number of SE Open Items |
|---|---|---|---|
| 7.1 | Introduction | 2 | 0 |
| 7.5 | Information Systems Important to Safety | 2 | 2 |
| 7.7 | Control Systems | 1 | 1 |
| 7.9 | Data Communication Systems | 1 | 0 |
| Totals | | 6 | 3 |

# Summary of SER with OI:  Chapter 15 Transient and Accident Analyses

| SRP Section/Application Section | | Number of RAI Questions | Number of SE Open Items |
|---|---|---|---|
| 15.0 | Transient and Accident analysis (except Section 15.0.3) | 0 | 0 |
| 15.0.3 | Radiological Consequences of Design Basis Accidents | 1 | 0 |
| Totals | | 1 | 0 |

# Summary of SER with OI: Chapter 18 Human Factors Engineering

| SRP Section/Application Section | | Number of RAI Questions | Number of SE Open Items |
|---|---|---|---|
| 18.8 | Procedure Development | 1 | 0 |
| 18.12 | Human Performance Monitoring | 1 | 0 |
| Totals | | 2 | 0 |

CHAIR ARMIJO: You want to say something?

MEMBER POWERS: I started us off four minutes early.

CHAIR ARMIJO: That's true, that's true. Thank you very much. Okay. Well look. I think we can afford to take about a five minute break, in addition to the four minutes we have. So let's say five after.

MALE PARTICIPANT: Ten after.

CHAIR ARMIJO: Five after, okay, and we will get the letters. Thank you much.

(Whereupon, at 3:56 p.m., the meeting was concluded.)

UNISTAR NUCLEAR ENERGY

**Presentation to ACRS Full Committee**
**U.S. EPR$^{TM}$**
**Calvert Cliffs Nuclear Power Plant Unit 3**
**FSAR Chapters 6, 7,15 & 18**
**SER with Open Items**
**April 12, 2012**

# Introduction

- Mark Finley, Senior Vice President, Regulatory Affairs & Engineering, will lead the Calvert Cliffs Unit 3 presentation.
- Presentation was prepared by UniStar and is supported by:

− Vincent Sorel (UniStar – Director Regulatory Affairs PRA & EPR Design)

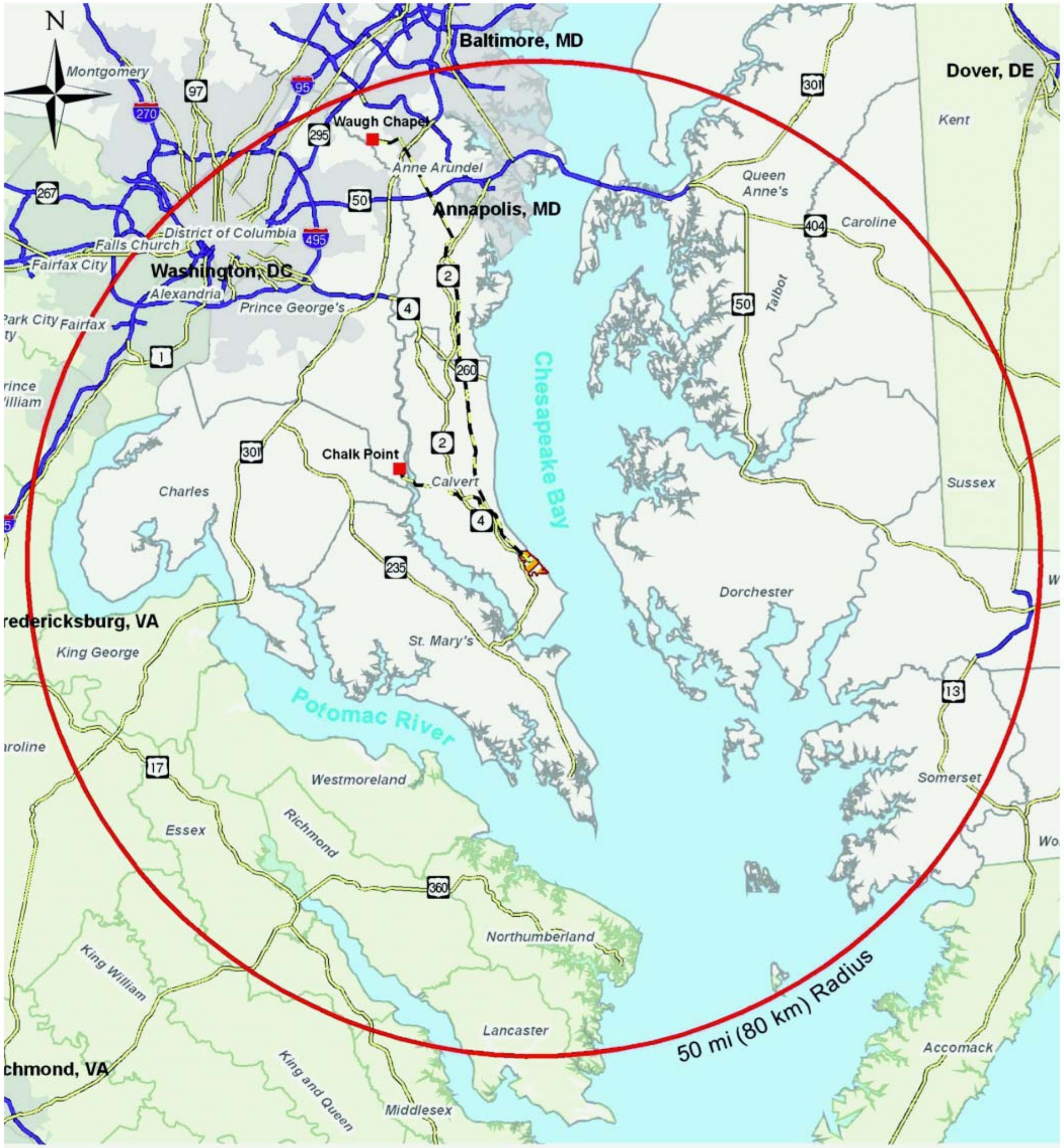
− Sebastien Thomas (UniStar – Manager of Nuclear Engineering)

# Calvert Cliffs Unit 3 Overview

| Calvert Cliffs Unit 3 Summary | | | | |
|---|---|---|---|---|
| Chapter | # Departures | #Exemptions | # SER Open Items | # SER Open Items Responses Submitted |
| 6 | 1 | 1 | 2 | 2 |
| 7 | 0 | 0 | 3 | 2 |
| 15 | 1 | 1 | 0 | N/A |
| 18 | 1 | 0 | 0 | N/A |
| Totals | 3 | 2 | 5 | 4 |

# Calvert Cliffs Unit 3
# ACRS Full Committee Meeting
# Introduction

- UNE is responsible for the design of Calvert Cliffs Unit 3 and develops the design primarily through contracts with Bechtel and AREVA who have joined in a Consortium to develop the detailed design of the US EPR.
- RCOLA authored using 'Incorporate by Reference' (IBR) methodology.
- The focus of today's presentation will be a summary of the second set (four) of FSAR Chapters that have been presented to the U.S. EPR ACRS Subcommittee.
- The initial Calvert Cliffs Unit 3 ACRS Full Committee meeting, addressing the first set (9½) of FSAR Chapters, was conducted on April 7, 2011.
- For today's presentation only supplemental information, or site-specific information, departures or exemptions from the U.S. EPR FSAR are discussed.



N
Baltimore, MD
Dover, DE
Montgomery
Waugh Chapel
Anne Arundel
Annapolis, MD
Queen Anne's
Kent
Caroline
District of Columbia
Falls Church
Fairfax City
Washington, DC
Alexandria
Prince George's
Fairfax
Talbot
Chesapeake Bay
Chalk Point
Calvert
Charles
Sussex
Dorchester
St. Mary's
King George
Potomac River
Westmoreland
Somerset
Essex
Richmond
Northumberland
King William
Lancaster
50 mi (80 km) Radius
Accomack
King and Queen
Middlesex

# List of Chapters

- Chapter 6, Engineered Safety features
- Chapter 7, Instrumentation and Controls (I&C)
- Chapter 15, Transient & Accident Analysis
- Chapter 18, Human Factors Engineering (HFE)

# ACRS Full Committee Meeting Agenda

- Chapter 6
- Departure/Exemption
- Summary
- Chapter 7
- Site-specific Post Accident Monitoring Variables
- Summary
- Chapter 15
- Departure/Exemption
- Summary
- Chapter 18
- Departure
- Summary
- Conclusions

# Chapter 6
# Engineered Safety Features
# Departure and Exemption

- Habitability Systems – Main Control Room, Toxic Chemicals

➢ For Calvert Cliffs Unit 3, the detection of toxic gases and subsequent automatic isolation of the Control Room Envelope (CRE) is not required and is not a part of the site-specific design.
  - The evaluation of the Calvert Cliffs Unit 3 toxic chemicals in Calvert Cliffs Unit 3 FSAR Section 2.2.3 did not identify any credible toxic chemical accidents that exceeded the limits established in Regulatory Guide 1.78.
  - No specific provisions are required to protect the operators from an event involving a release of a toxic gas.
  - Therefore, Seismic Category 1/Class 1E toxic gas detectors and automatic isolation are not required and will not be provided at Calvert Cliffs Unit 3.

# Chapter 6
# Engineered Safety Features
# Summary

- COL Information Items, as specified by U.S.EPR FSAR, are addressed in Calvert Cliffs Unit 3 FSAR Chapter 6
- One Departure/Exemption from U.S. EPR FSAR
- No ASLB Contentions
- There are two (2) SER Open Items and responses have been submitted (March 25, 2011).
- There are three (3) Confirmatory Items and they have been incorporated into the COLA (Revision 05).

# ACRS Full Committee Meeting Agenda

- Chapter 6
- Departure/Exemption
- Summary
- Chapter 7
- Site-specific Post Accident Monitoring Variables
- Summary
- Chapter 15
- Departure/Exemption
- Summary
- Chapter 18
- Departure
- Summary
- Conclusions

# Chapter 7
# Instrumentation and Controls
# PAM Variables

- ➢ Site-specific Post Accident Monitoring (PAM) Variables
- ✓ PAM variables supplemented with site specific variables
  - ▪ Ultimate Heat Sink (UHS) Tower Basin water level
  - ▪ Meteorological data
- ✓ PAM variables list confirmed prior to fuel load after completion of the Emergency Operating procedures (EOPs) and Abnormal Operating Procedures (AOPs)

# Chapter 7
# Instrumentation and Controls
# Summary

- All COL Information Items, as specified by U. S. EPR FSAR, are addressed in Calvert Cliffs Unit 3 FSAR Chapter 7, Instrumentation and Controls.
- No Departures/Exemptions from the U.S. EPR FSAR for Chapter 7 of the Calvert Cliffs Unit 3 FSAR
- No ASLB Contentions
- There are three SER Open Items and No Confirmatory Items
- The responses to two SER Open Items (RAI 326 and RAI 325 Question 07.05-2) have been submitted and the response to the remaining Open Item is in progress. (RAI 325 Question 07.05-1)

# ACRS Full Committee Meeting Agenda

- Chapter 6
- Departure/Exemption
- Summary
- Chapter 7
- Site-specific Post Accident Monitoring Variables
- Summary
- Chapter 15
- Departure/Exemption
- Summary
- Chapter 18
- Departure
- Summary
- Conclusions

# Chapter 15
# Transient and Accident Analysis
# Departure/Exemption

➢ <u>Site Specific χ/Q Values</u>

- Conservative estimates of atmospheric Accident values for the Exclusion Area Boundary (EAB), Low Population Zone (LPZ) and Main Control Room are presented in the U.S. EPR FSAR and bound the Calvert Cliffs Unit 3 values <u>except the 0-2 hour value for the LPZ</u>.

- The U.S.EPR FSAR provides the Accident χ/Q of 1.75E-04 sec/$m^3$ at the LPZ - 1.5 miles during the 0-2 hr period. The corresponding calculated site-specific short-term atmospheric dispersion factor for Calvert Cliffs Unit 3 is 2.15E-04 sec/$m^3$ which <u>exceeds/departs from the U.S. EPR value.</u>

- The site-specific Accident Dispersion factors were used in calculating doses from accident scenarios specified in the U.S. EPR FSAR Chapter 15. Calvert Cliffs Unit 3 doses are conservatively within the limitations of 10 CFR 50.34 and GDC 19.

# Chapter 15
# Transient and Accident Analysis Departure/Exemption

**Table 15.0-2— {CCNPP Unit 3 LPZ Radiological Consequences of U.S. EPR Design Basis Accidents}**

| Design Basis Accident | | Offsite Dose CCNPP Unit 3 LPZ rem (TEDE) | Acceptance Criterion rem (TEDE) |
|---|---|---|---|
| LOCA | | 9.1 | 25 |
| Small line break outside of Reactor Building | | 0.4 | 2.5 |
| SGTR | Pre-incident spike | 0.3 | 25 |
| | Coincident spike | 0.3 | 2.5 |
| MSLB | Pre-incident spike | 0.1 | 25 |
| | Coincident spike | 0.2 | 2.5 |
| | Fuel rod clad failure | 2.6 | 25 |
| | Fuel overheat | 2.8 | 25 |
| RCP locked rotor/broken shaft | | 0.9 | 2.5 |
| Rod ejection | | 3.4 | 6.3 |
| Fuel handling accident | | 1.2 | 6.3 |

# Chapter 15
# Transient and Accident Analysis
# Summary

- One COL Information Item, as specified by U. S. EPR FSAR, is addressed in Calvert Cliffs Unit 3 FSAR Chapter 15, Transient and Accident Analysis.
- One Departure/ One Exemption in Chapter 15 from the U.S. EPR FSAR for Chapter 15 of the Calvert Cliffs Unit 3 FSAR
- There are no NRC SER Open Items or Confirmatory Items
- No ASLB Contentions
- Responses to all RAIs have been submitted.

# ACRS Full Committee Meeting Agenda

- ➢ Chapter 6
- • Departure/Exemption
- • Summary
- ➢ Chapter 7
- • Site-specific Post Accident Monitoring Variables
- • Summary
- ➢ Chapter 15
- • Departure/Exemption
- • Summary
- ➢ Chapter 18
- • Departure
- • Summary
- ➢ Conclusions

# Chapter 18
# Human Factors Engineering Departure

- <u>Human Performance Monitoring (HPM) Program - Departure</u>
- – The U.S. EPR HPM is replaced by the UniStar HPM Program entirely
- – The key differences are summarized below:
- ▪ An Operational Focus Aggregate Index is used to trend performance of key variables that can impact Operations Human Performance
    - ✓ Aligns with INPO 09-011, Achieving Excellence in Performance Improvement
    - ▪ UniStar Corrective Action Program is utilized:
    - ✓ To track HFE issues in lieu of a separate program (HFE issue tracking system)
    - – The UniStar Nuclear Energy Human Performance Monitoring Program meets the requirements of NUREG - 0711

# Chapter 18
# Human Factors Engineering
## Summary

- Five COL Information Items, as specified by U.S. EPR FSAR, are addressed in Calvert Cliffs Unit 3 FSAR Chapter 18
- No ASLB Contentions
- The Departure from the U.S. EPR Human Performance Monitoring Program implements the requirements of NUREG - 0711
- No SER Open Items
- All RAI responses have been submitted
- There are two SER Confirmatory Items and they have been incorporated into the COLA (Revision 08)

# ACRS Full Committee Meeting Agenda

- ➢ Chapter 6
- • Departure/Exemption
- • Summary
- ➢ Chapter 7
- • Site-specific Post Accident Monitoring Variables
- • Summary
- ➢ Chapter 15
- • Departure/Exemption
- • Summary
- ➢ Chapter 18
- • Departure
- • Summary
- ➢ Conclusions

# Chapters 6, 7, 15 and 18 Conclusions

- No ASLB Contentions
- There are three (3) departures and two (2) exemptions
- All Confirmatory Items have been incorporated in the COLA (Revision 08)
- Responses have been submitted to four (4) of the five (5) SER Open Items. The response to the remaining SER Open Item is in progress
- As of April 12, 2012, thirteen and one-half (13½) of the nineteen (19) Chapters of the Calvert Cliffs Unit 3 FSAR have completed Phase 3

# Acronyms

- ACRS – Advisory Committee on Reactor Safeguards
- AOP – Abnormal Operating Procedure
- ASLB – Atomic Safety & Licensing Board
- CFR – Code of Federal Regulations
- COL – Combined License
- COLA – Combined License Application
- CRE – Control Room Envelope
- DC – Design Certification
- EAB – Exclusion Area Boundary
- EOP – Emergency Operating Procedure
- FSAR – Final Safety Analysis Report
- GDC – General Design Criteria
- HFE – Human Factors Engineering
- HPM – Human Performance Monitoring
- I&C – Instrumentation and Controls
- LPZ – Low Population Zone
- MSLB – Main Steam Line Break
- PAM – Post Accident Monitoring
- PRA – Probability Risk Assessment
- RAI – Request for Additional Information
- RCP – Reactor Coolant Pump
- SER – Safety Evaluation Report
- SGTR – Steam Generator Tube Rupture
- TEDE – Total Effective Dose Equivalent
- UHS – Ultimate Heat Sink

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*Protecting People and the Environment*

# Spent Fuel Pool (SFP) Scoping Study


Katie Wagner
General Engineer
Office of Nuclear Regulatory Research

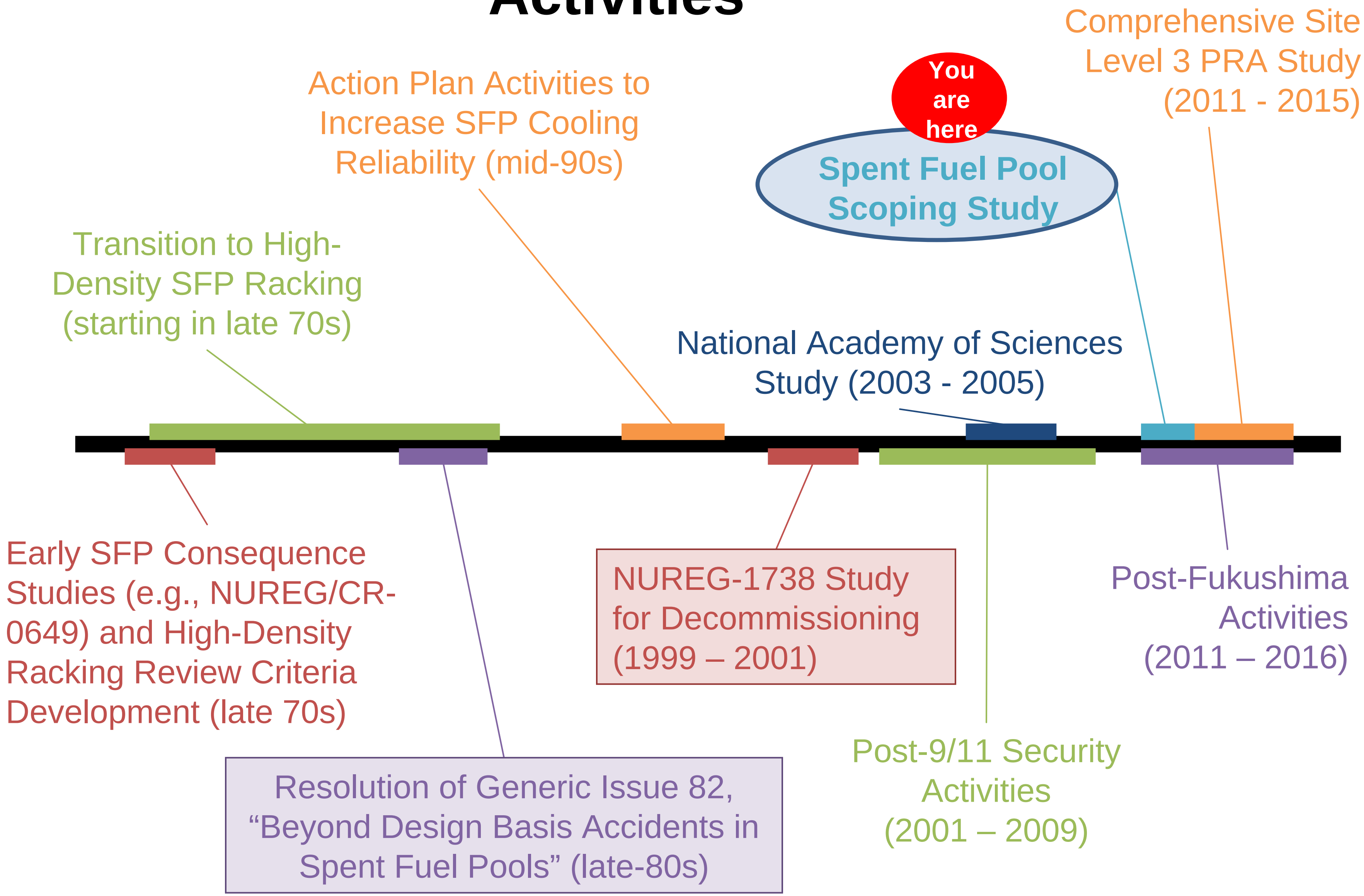

Briefing for the Advisory Committee on Reactor Safeguards (ACRS)

*April 12, 2012*

# Background

- The agency has a rich regulatory basis for its current position on spent fuel storage
- A number of events (e.g., change in path forward on long-term storage; Fukushima accident) motivated re-assessment of the underlying knowledge base
- To launch this re-assessment, an expedited limited-scope consequence study was undertaken (to provide insights in 1 year)
  - Objective: to re-examine the impact of moving older spent fuel to dry cask storage in an expedited manner
- Results from this study will inform a regulatory decision-making process guided by the “Tier 3” Japan Lessons-Learned item entitled Transfer of Spent Fuel to Dry Cask Storage (referenced in SECY-12-0025)

# Timeline of Major SFP-related Activities



# Motivation for Focusing on SFP Seismic Hazards

Spent fuel storage considerations include:

- SFP Seismic Hazards
- Dry Cask Storage Risk *(e.g., NUREG-1864)*
- Cask Drop Hazards for SFPs *(e.g., NUREG-1738)*
- Repackaging For Transportation
- Fuel Storage Infrastructure *(e.g., 2010 EPRI study)*
- Worker Dose *(e.g., 2010 EPRI study)*
- Emergency Preparedness *(e.g., NUREG-1738)*
- Part 50, 72 & 73 Regulatory Requirements
- Multi-Unit Risk *(e.g., SECY-11-0089 project)*
- Design/Operation Differences Between Sites
- Boraflex Degradation & Inadvertent Criticality
- Protection Against Malevolent Acts *(e.g., post-9/11 security assessments)*
- Other SFP Hazards *(e.g., NUREG-1353)*
- Actions in Response to Japan Events *(e.g., Near-Term Task Force Recommendation 7)*

SFP Seismic Hazard

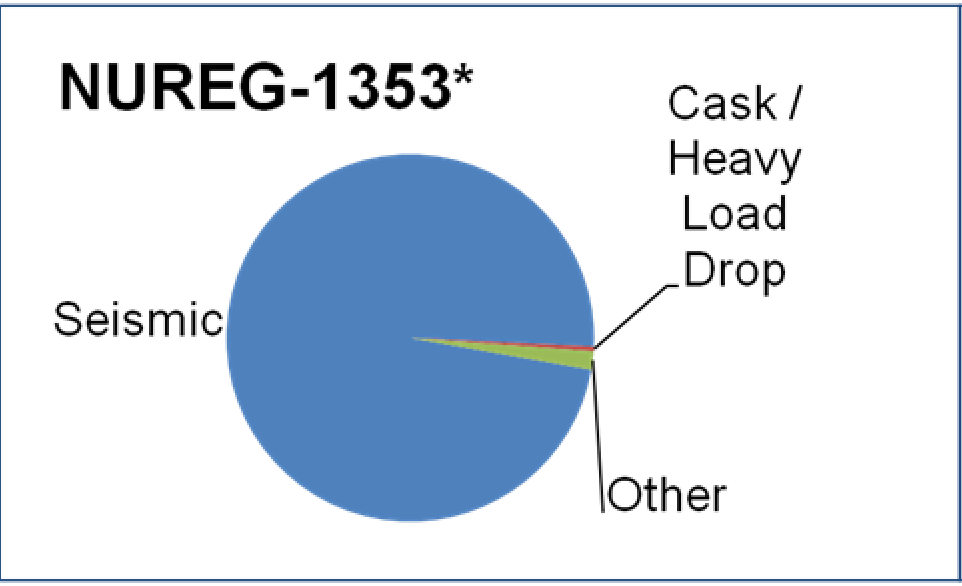
*Past studies have indicated that SFP seismic hazard is an important piece of overall spent fuel risk.*

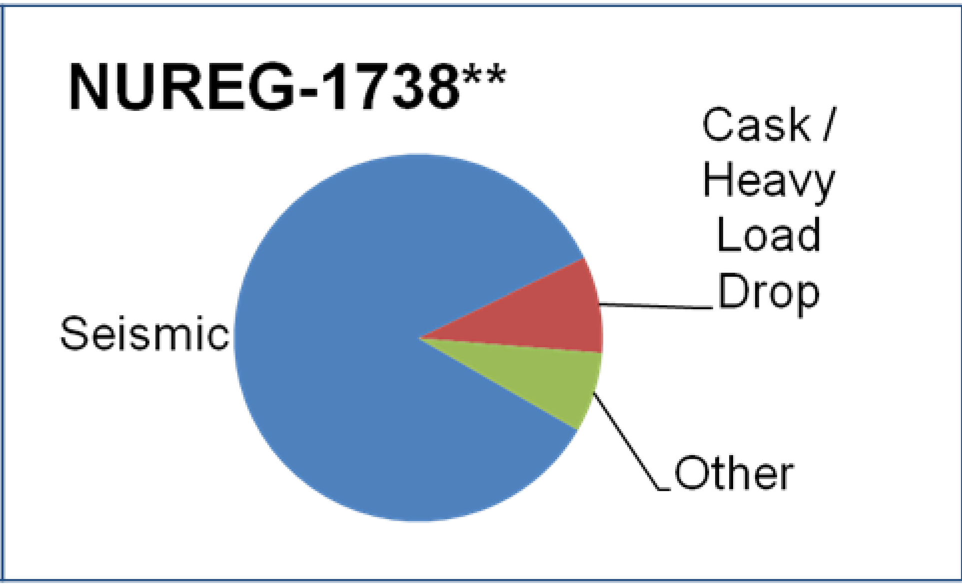
*For this reason, SFP seismic hazard is the logical place to start in probing the continued applicability of past studies and developing insights for the current spent fuel storage situation.*

*Depending on the results gained from the study, additional work might be necessary to obtain a more holistic answer.*

# Motivation for Seismic Study

Annual frequency of SFP fuel uncovery as reported in previous SFP risk studies




*BWR, best estimate results

**Based on Livermore hazard curves which generally more closely match the updated USGS curves for the studied plant

Past SFP risk studies indicate that seismic hazard is the most prominent contributor to SFP fuel uncovery. While these studies have known limitations, this is sufficient motivation to focus on this class of hazards in the SFPSS.

# Overview of Spent Fuel Pool Scoping Study (SFPSS)

- Focus: re-examine the potential impacts on SFP safety in the event of a challenging, beyond-design-basis seismic event
- Emphasis is given to acquiring timely results for ongoing deliberations and external stakeholder interest. The project is using:
  - Available information / methods
  - A representative operating cycle for a BWR Mark I (Peach Bottom)
  - Past studies to narrow scope
- Plan finalized in July 2011; study results to be sent to NRR: June 2012
- The closely related Japan Lessons Learned Tier 3 item from SECY-12-0025 (Transfer of Spent Fuel to Dry Cask Storage) addresses the bigger picture, with SFPSS being a key component

# Technical Approach

- Two conditions to be considered:
  - Representative of the current situation for the selected site (i.e., <u>high-density loading</u> and a relatively full SFP)
  - Representative of expedited movement of older fuel to a dry cask storage facility (i.e., <u>low-density loading</u>)
- Elements of the study include
  - Seismic and structural assessments based on available information to define initial and boundary conditions
  - SCALE analysis of reactor building dose rates
  - MELCOR accident progression analysis (effectiveness of mitigation, fission product release, etc.)
  - Emergency planning assessment
  - MACCS2 offsite consequence analysis (land contamination and health effects)
  - Probabilistic considerations

# Seismic and Structural Methods

*Jose Pires*
Senior Structural Engineer
Office of Nuclear Regulatory Research

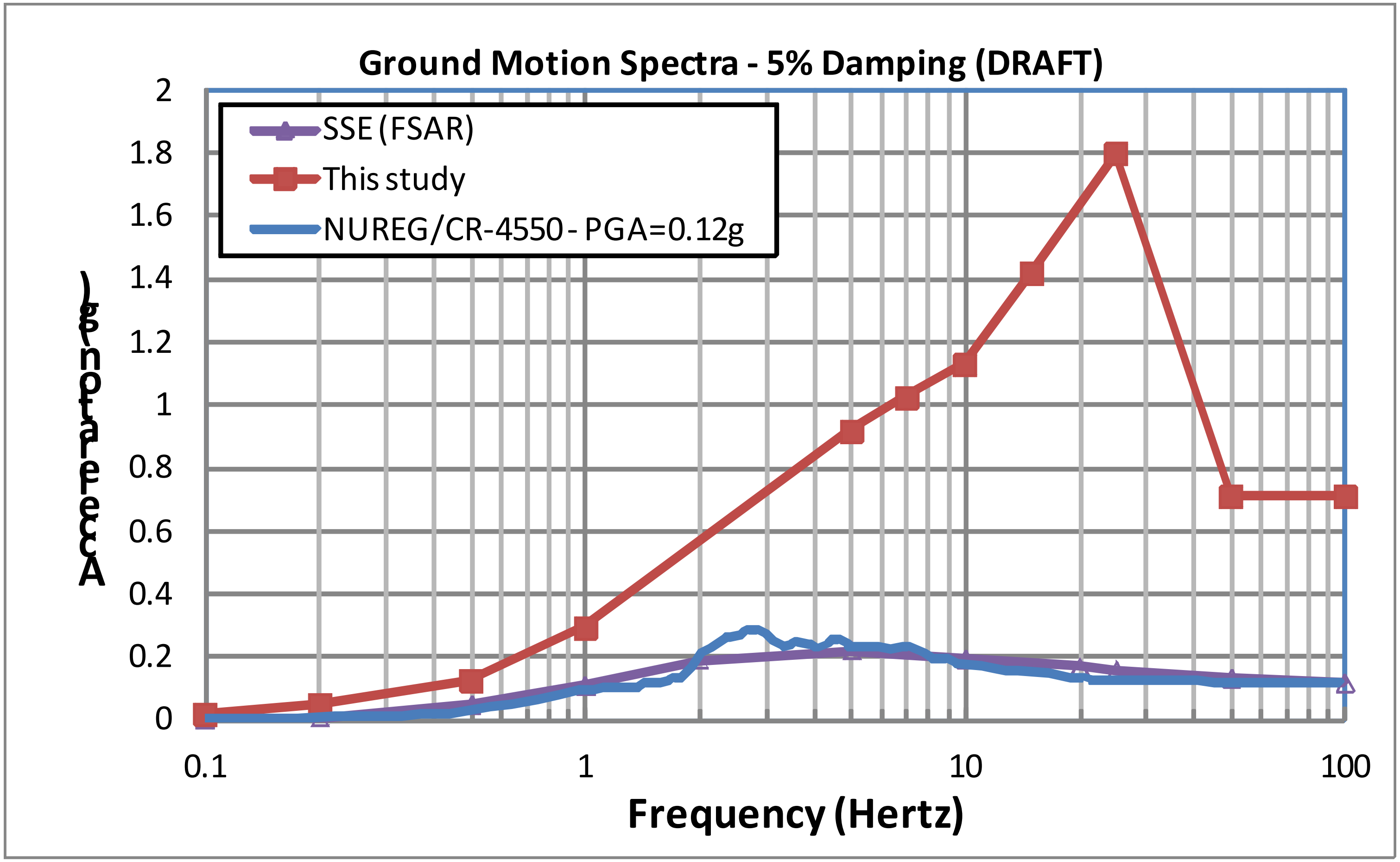
# Prescribed Seismic Scenario

- Seismic event: 0.5 g to 1.0 g peak ground acceleration (PGA)
  - Challenging event, but very low frequency of occurrence (one event in 61,000 years)
    - OBE is 0.05g
    - SSE is 0.12g
    - Scenario PGA is 0.71 g -- It is about 6 times that for the SSE and beyond the seismic design basis for Eastern US plants
  - USGS hazard data and models (2008) being used as starting seismic hazard model
- Review of past studies indicates that less severe events would not challenge the SFP

# Seismic Input

- Objective: to provide initial ground motion characteristics
  - Site Ground Motion Response Spectrum (GMRS)
- Rock site
- USGS Hazard Assessments (2008) used to obtain site GMRS (Similar to GI-199 resolution)
  - Site GMRS scaled up to obtain input ground motion spectra for the 0.71 g scenario
- Site GMRS rich in high frequencies (10 to 25 Hz)

# Seismic Input

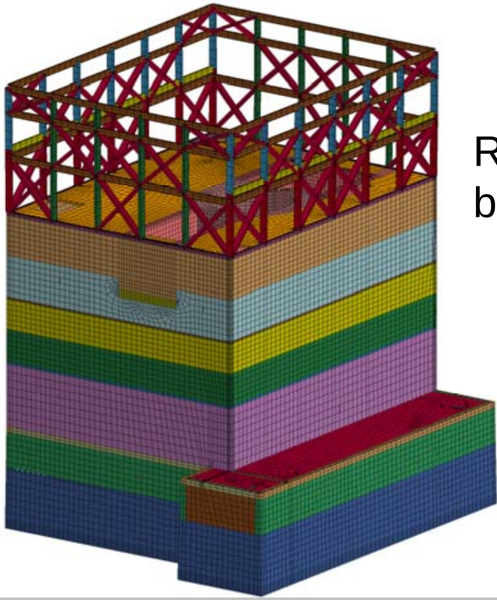


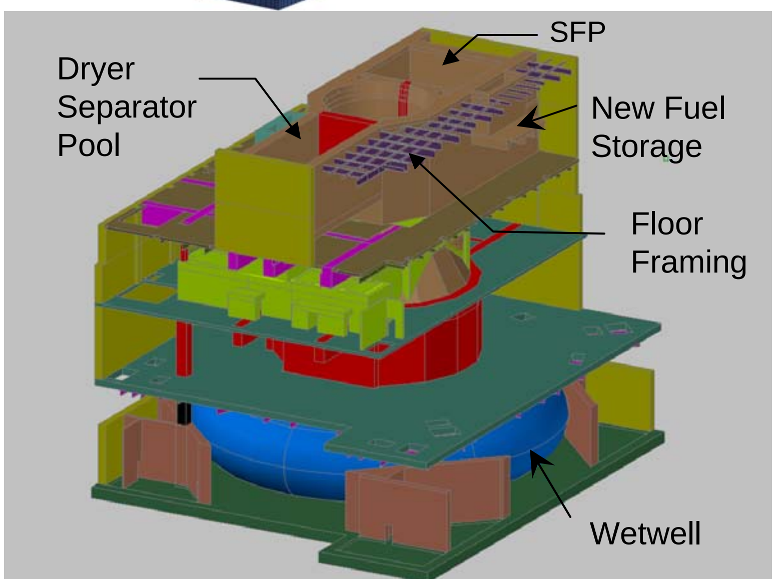

Comparison of ground motion spectra: this study, SSE, and spectrum for the NUREG-1150 PRA (scaled to the SSE PGA) (NUREG/CR-4550)

# Structural Input

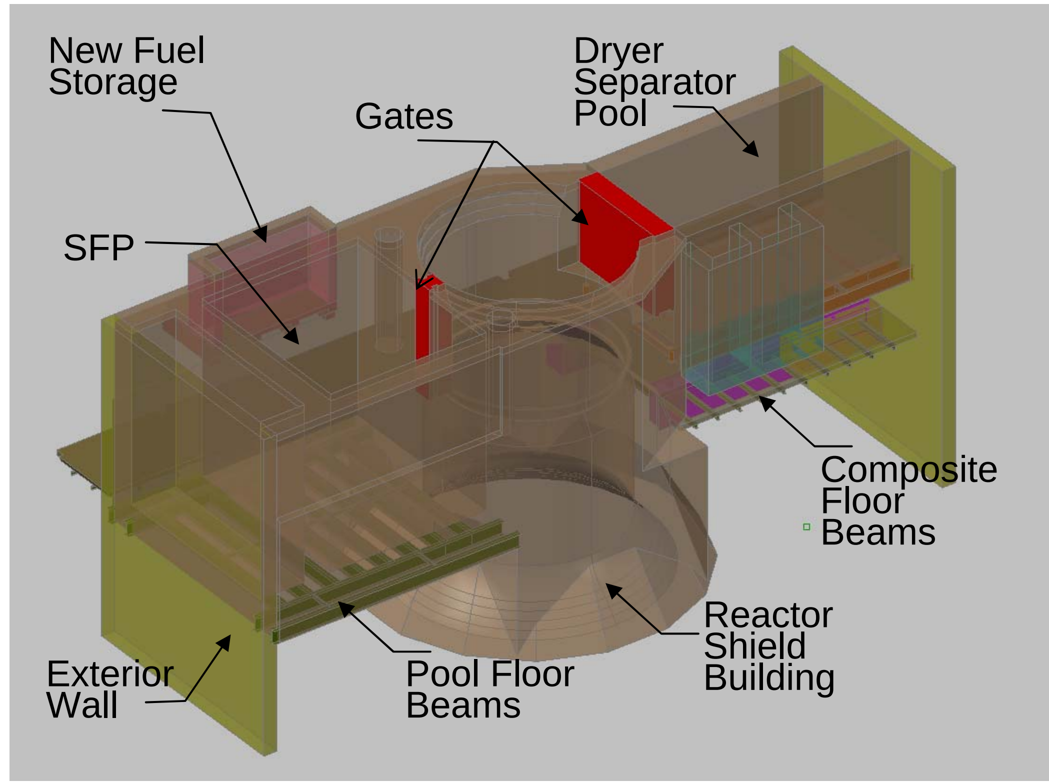
- Objective: to determine starting point for subsequent accident progression analysis
- Approach:
  - Generally follows approach used for GI-82 (NUREG/CR-5176)
    - Enhanced to address specific study aspects (Finite Element Modeling)
  - Uses in-structure response spectra (accelerations) calculated for the NUREG-1150 study (NUREG/CR-4550, Vol. 4, Part 3)
    - Scaled for increased PGA (from 3xSSE to about 6xSSE)
    - Scaled to account for high frequency content in the site GMRS
  - Uses 3D nonlinear finite element analysis of the SFP structure and its supports (subjected to equivalent static loads) to calculate:
    - Displacements, concrete and reinforcement strains and stresses, structural distortion, and liner strains

# Reactor Building and SFP




**SFP Details**




**Used to generate 3D finite element models of the SFP structure and its supports**

# Structural Input

- Simpler approaches to assess damage to:
    - Penetrations, support systems, AC and DC power, other SSCs necessary for accident mitigation (e.g., building housing a portable diesel pump), other structures
- Approximations / assumptions
    - Effects of ground motion incoherency on high-frequency components of floor spectra approximated (possible conservatism)
    - Floor spectra do not account for coupling of SFP components to building (possible conservatism)
        - Hydrodynamic pressures based on scaled floor response spectra
        - Dynamic time-history analyses of the whole reactor building including the SFP were not done at this stage
    - Seismic loads from spent fuel racks and assemblies approximated
        - May need adjustment based on the analysis reports submitted by the licensee at the time of the license amendment for high density loading
    - Uses the SFP damage state to envelope potential leakage from the transfer gate, reactor piping, or dryer pool
- Starting conditions for accident progression analysis
    - Binned into a few discrete states with relative likelihood estimates

# Scenario Delineation, Accident Progression Methods, and Consequence Analysis Methods

*Don Helton*
Senior Risk and Reliability Engineer
Office of Nuclear Regulatory Research

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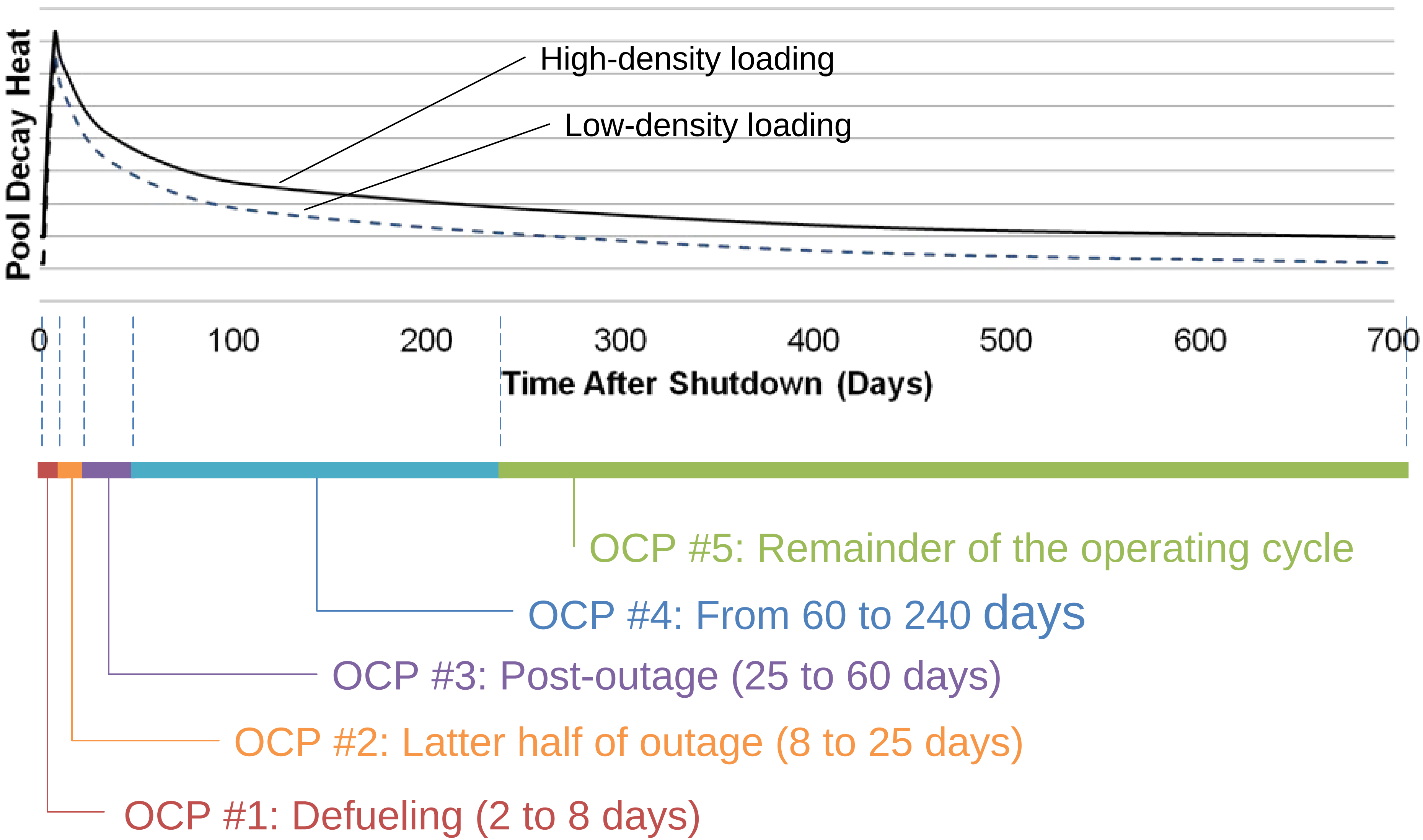
# Illustration of Pool Decay Heat and Operating Cycle Phases (OCPs)



# Mitigation Assumptions

- For high-density loading, two alternatives are considered for required arranging of recently discharged fuel in to a pattern that facilitate passive cooling:
  - pre-arrangement
  - arrangement following the outage
- For scenarios not including mitigative actions:
  - No operator action is considered
- For scenarios including mitigative actions:
  - Diagnosis is assumed to take until SFP level drops 5 feet + 30 minutes for observation/decision-making (recall unavailability of AC power)
  - Capacities / timings generally follow underlying endorsed guidance in NEI-06-12, Revision 2
  - Once deployed, equipment runs indefinitely
    - Represents successful arrival of offsite support or deployment of other onsite assets
- <u>Effectiveness is determined by MELCOR</u>

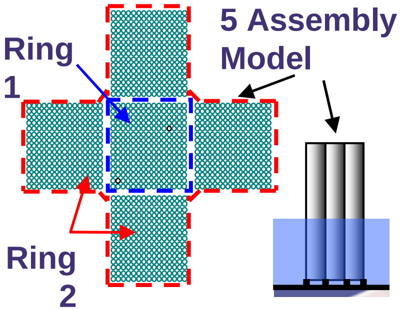
# Other Issues Not Addressed in Defining Scenarios

- Full core offload outages for vessel inspections
  - Not the typical situation for BWRs
- Presence of new fuel in the SFP as source of zirconium
  - Present for a short period of time
- Multi-unit effects
  - Only addressed until reactor/SFP become hydraulically decoupled
  - A focus of a recently initiated site Level 3 PRA project
- Inadvertent criticality events
- Recovery and repair actions

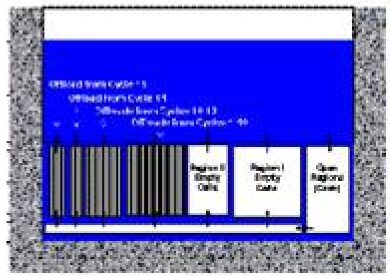
➢ The intent is to address as many uncertainties as practical via sensitivity studies

# Use of MELCOR for SFP Analysis

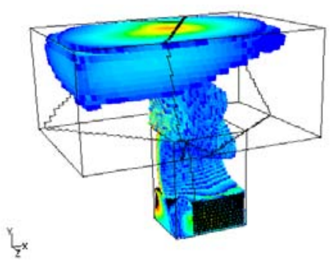
## Analysis




MELCOR Separate Effects Analysis

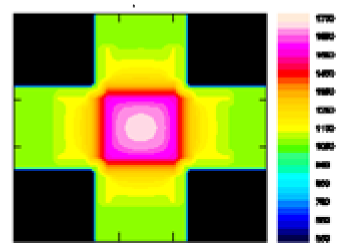


MELCOR Whole-Pool (i.e. Integrated) Analysis



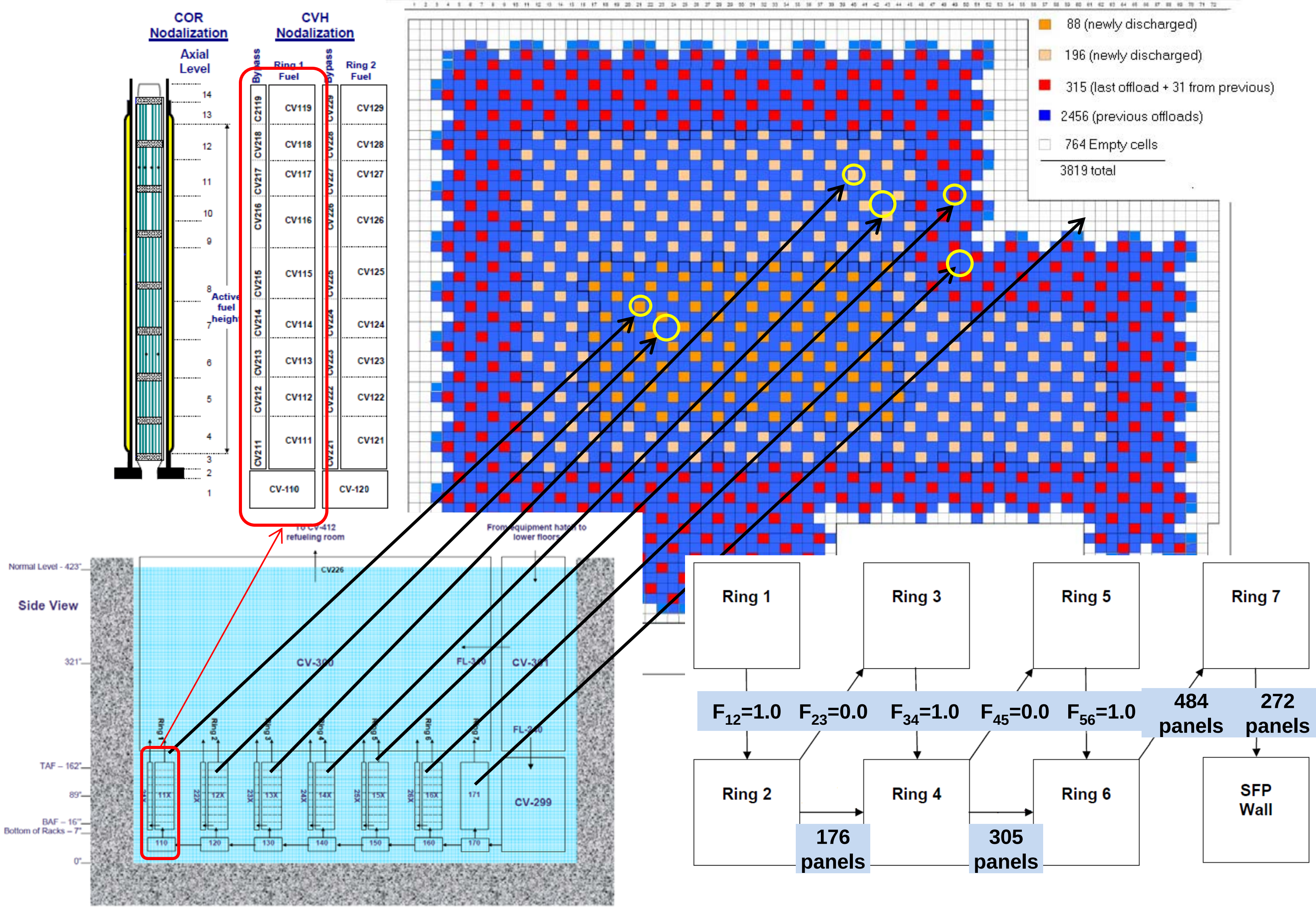
Computational Fluid Dynamics

## Experimental studies

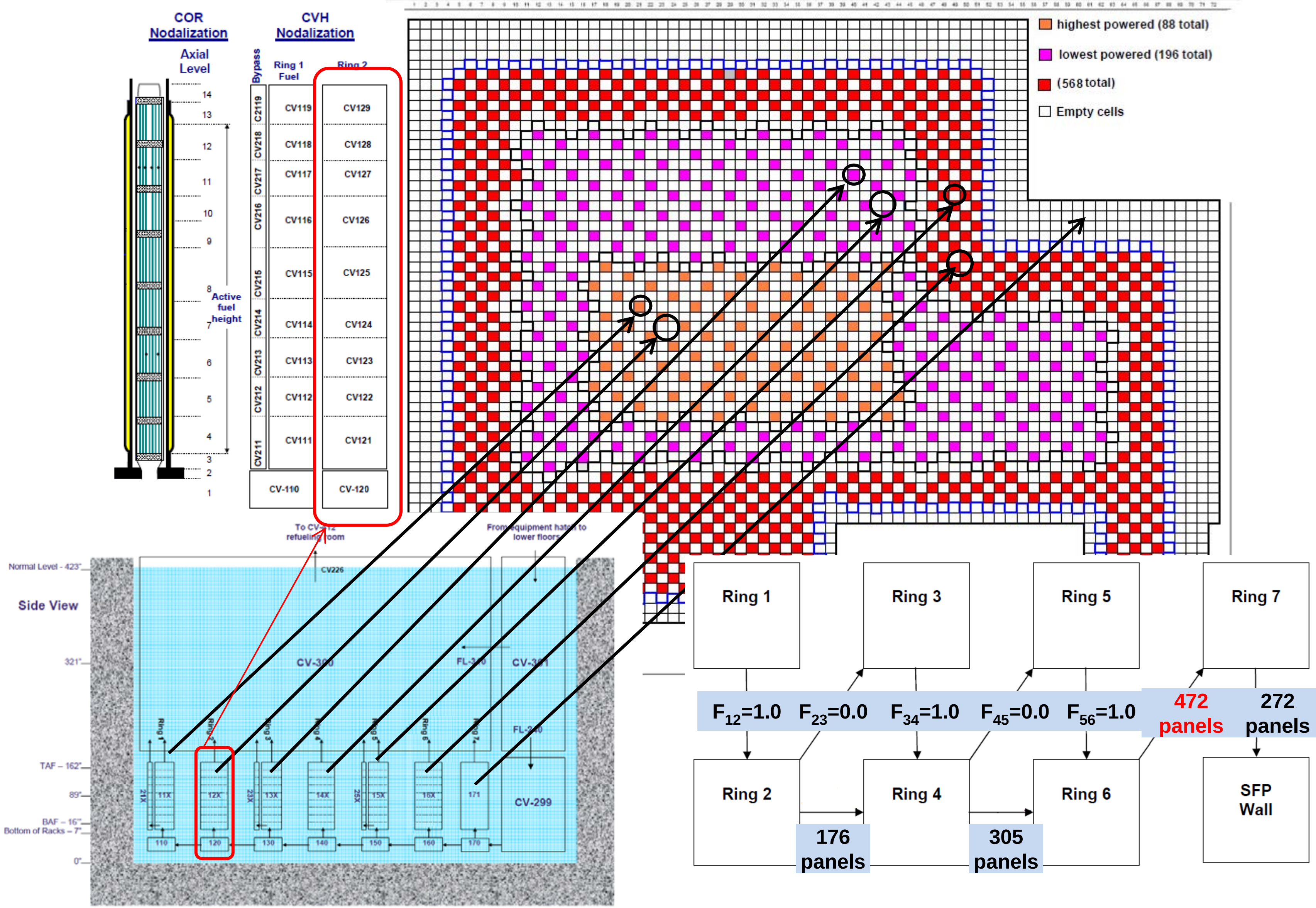



COBRA-SFS Analysis

# High-Density Post-Outage SFP MELCOR Model



# Low-Density Post-Outage SFP MELCOR Model

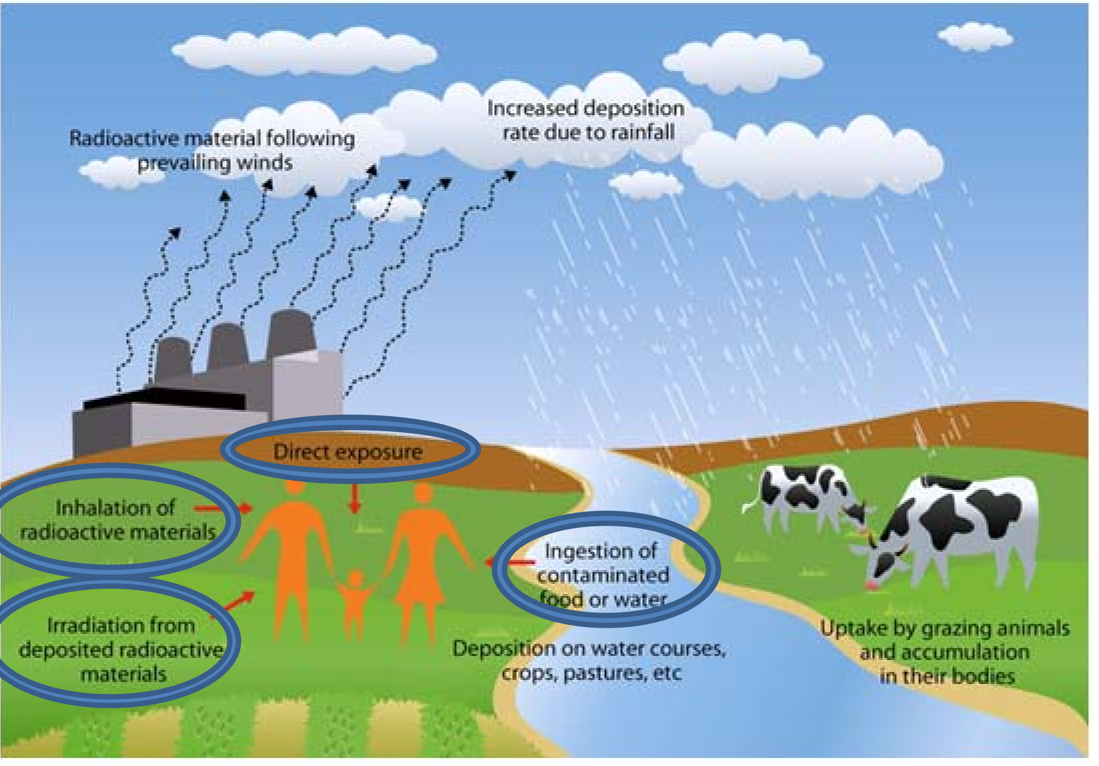


# Offsite Consequence & Emergency Preparedness Modeling

- MACCS2 code will be used
  - Input: Accident source term (from MELCOR/ORIGEN), weather, population and economic data, protective measures
  - Output: Consequences (e.g. contamination, health effects) from atmospheric release
- Modeling will leverage best practices from draft NUREG-1935 (SOARCA)
- Population and economic data updated for 2011
- Emergency preparedness considerations
  - Pennsylvania specific evacuation
  - Cohorts to represent different groups of the public
  - Road network
  - Scenario-specific

# MACCS2 Modeling: Atmospheric Release and Exposure Pathways

**MACCS2 models the radioactive release to the atmosphere (e.g. plume rise, dispersion, dry and wet deposition)**




**MACCS2 estimates the health effects from: inhalation, cloudshine, groundshine, skin deposition, and ingestion (e.g. water, milk, meat, crops)**

# Consequence Modeling & Reporting

- Consequence Modeling (continued):
  - Stochastic health effects (e.g. latent cancer fatalities)
  - Three dose response models
    - Linear, no threshold (LNT) hypothesis
    - Linear, low-dose truncation - 620 mrem/yr (U.S. average dose)
    - Linear, low-dose truncation - 5 rem/yr or 10 rem lifetime (HPS position)
  - Deterministic health effects (e.g. early fatalities)
  - Federal Guidance Report 13
    - Most current federal guidance published by EPA
- Consequence Reporting:
  - Health Effects - conditional risk of early fatalities and latent cancer fatalities as related to distance from the site. (Ideal for informing individual members of the public)
  - Land Contamination - total land contamination for the site region above a specified dose level (e.g., the habitability criterion for the selected site of 500 mrem/year)

# Concluding Remarks and Questions

*Katie Wagner*

# Coordination and Communication

- SECY paper to be submitted in July 2012 will include a plan for the resolution of the broader item on expedited transfer of spent fuel to dry cask storage
  - Commitment was made in SECY-12-0025
- Input from program offices
- Briefings for Senior Management and Commissioners
- Interactions with licensee
- Consider feedback provided by the ACRS
- A communication plan has been drafted
- Study results to be sent to NRR by: June 2012

# SFPSS Project Team and Other-Office Working Group Representatives

- Katie Wagner – Overall project lead
- Hossein Esmaili – Accident progression lead
- Don Helton – Boundary conditions and probabilistic aspects lead
- Andy Murphy – Seismic analysis lead
- AJ Nosek – Offsite consequence lead
- Jose Pires – Structural analysis lead

**Working Group Members**

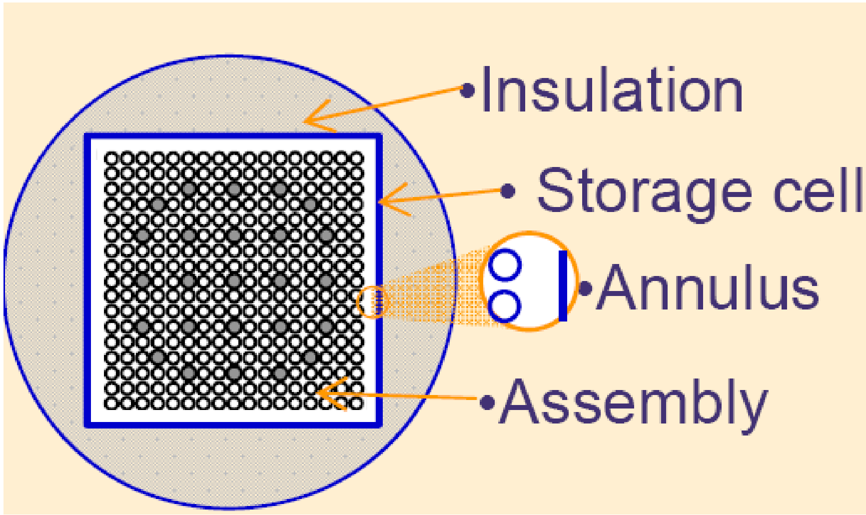
- NMSS – Drew Barto
- NRO – Eric Powell, Bret Tegeler
- NRR – Steve Jones, Jeff Mitman, Eric Bowman, Kent Wood, Rick Ennis
- NSIR – Randy Sullivan, Eric Schrader

# Acronym List

- 3D = Three-Dimensional
- AC = Alternating Current
- BWR = Boiling Water Reactor
- COBRA-SFS = COBRA Spent Fuel Storage
- DC = Direct Current
- GI = Generic Issue
- GMRS = Ground Motion Response Spectra
- HPS = Health Physics Society
- LNT = Linear No Threshold
- MACCS2 = MELCOR Accident Consequence Code System
- MELCOR – Not an acronym
- NMSS = Office of Nuclear Material Safety and Safeguards
- NRO = Office of New Reactors
- NRR = Office of Nuclear Reactor Regulation
- NSIR = Office of Nuclear Security and Incident Response
- OBE = Operating Basis Earthquake
- OCP = Operating Cycle Phase
- ORIGEN = Oak Ridge Isotope Generator
- PGA = Peak Ground Acceleration
- PRA = Probabilistic Risk Assessment
- SCALE – Not an acronym
- SECY = Office of the Secretary
- SFP = Spent Fuel Pool
- SOARCA = State-Of-The-Art Reactor Consequence Analysis
- SSC = Structure, System and Component
- SSE = Safe Shutdown Earthquake
- USGS = United States Geological Survey

# SFP Zirc-Fire Research Overview

## Phase 1 Testing



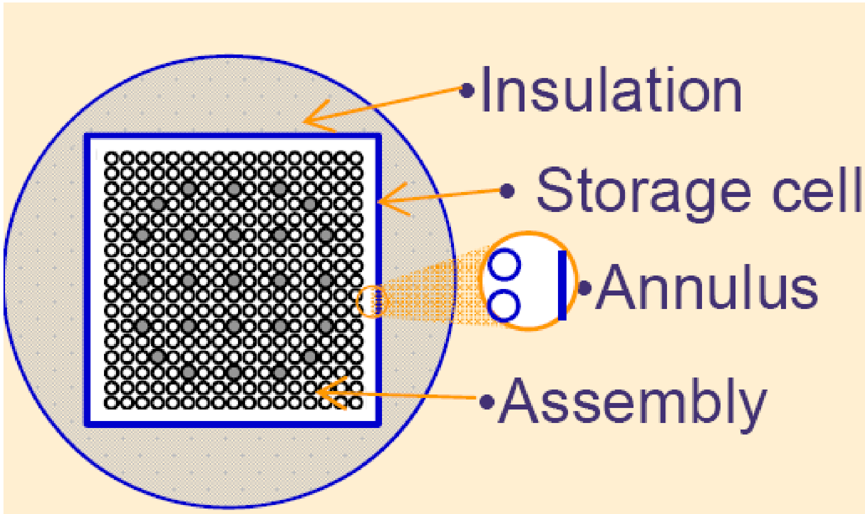

This Phase 1 bundle is a detailed PWR assembly (17 by 17). This testing includes the complex thermal hydraulic conditions that strongly impact the reaction kinetics of Spent Fuel Pool LOCAs. It is unfortunate that NRC has not applied similar resources in responding to PRM-76. Instead, NRC repeatedly extols its programs that sidestep the role of the reaction kinetics during LOCAs.

**In promoting the denial of PRM-50-76 on June 29, 2005, ML050250359, the NRC Staff asserted:**

*According to him* (Robert H. Leyse)*, it is fundamentally important that the determinations of LOCA transient chemical kinetics include the geometry of the stationary Zircaloy reactant in combination with the thermal-hydraulic conditions of the flowing-water/steam reactant.*

# SFP Zirc-Fire Research Overview

## Phase 1 Testing

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# Columbia Generating Station

## ACRS License Renewal Committee Meeting

April 12, 2012

# Columbia Generating Station

| | |
|---|---|
| **Dale Atkinson -** | **Vice President, Emp Dev/Corp Services** |
| **Don Gregoire -** | **Manager, Regulatory Affairs** |
| **John Twomey -** | **Project Manager, License Renewal** |

# Agenda

- Station Overview
- Aging Management Programs and Commitments
- Closure of Open Items
- Subcommittee Topics Requiring Additional Information
- Implementation Overview
- Closing Remarks


N
4

# Station Overview - Description

- General Electric Boiling Water Reactor
  - BWR-5 / Mark II Containment
  - Plant circulating water & ultimate heat sink makeup supplied from the Columbia River
- 3486 MWt/1230 MWe



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# Station Overview - History

- Construction Permit – March 19, 1973
- Operating License – December 20, 1983
- 5% Power Up-Rate - May 1995
- License Renewal application submitted-Jan. 2010
- License Expires – December 20, 2023



ENERGY NORTHWEST

# Aging Management Programs and Commitments

**Don Gregoire**
**Manager, Regulatory Affairs**

# Aging Management Programs & Commitments

- Aging Management Programs (AMP)
  - 55 Programs Credited for License Renewal
    - 35 Existing
      - 13 Enhancements
    - 20 New
- License Renewal Commitments – 71 total

# Closure of Open Items

- High-Voltage Porcelain Insulators
- Operating Experience
- Upper-Shelf Energy
- Metal Fatigue
- Core Plate Rim Hold-Down Bolts
- Fatigue Analysis of Polar Crane

# Closure of Open Items

- <u>OI 3.0.3.3.7</u>

  **High-Voltage Porcelain Insulators**

  230 kV Station Blackout recovery source insulators at Ashe substation were not included in the Insulator Aging Management Program

  <u>Resolution</u>

  – Insulators are now in program
  – Tests performed in July 2011 conclude minimal accumulation and within industry limits
  – Testing on 8 year frequency consistent with operating experience



ENERGY NORTHWEST

# Closure of Open Items

- OI B.1.4-1

  **Operating Experience (OE)**

  Future operating experience evaluations for aging effects were not specifically included in the License Renewal Application (LRA)

  Resolution

  – LRA amended to clearly call out intent to review internal and external OE on an on-going basis
  – Operating Experience program revised to specifically address evaluation of OE for aging effects
  – Initial/recurring training for plant staff

# Closure of Open Items

- OI 4.2-1

  **Upper-Shelf Energy (USE)**

  Technical basis not provided for initial transverse USE and copper content for instrument nozzle forgings

  Resolution

  – Technical basis was provided

  – Supports acceptability through end of period of extended operation

# Closure of Open Items

- OI 4.3-1

  **Metal Fatigue**

  Columbia's metal fatigue Time Limited Aging Analysis (TLAA) performed for sample of critical locations listed in NUREG/CR-6260 may not be limiting

  Resolution

  – The other limiting locations were identified and evaluated for Columbia

  – All locations have an environmental cumulative usage factor below 1.0

# Closure of Open Items

- <u>OI 4.7.4-1</u>

  **Lower Core Plate Rim Hold-Down Bolts**

  Neither an Aging Management Review (AMR) line item nor a TLAA for the reactor pressure vessel lower core plate hold-down bolts were provided

  <u>Resolution</u>

  – LRA was amended to include:
    - AMR line item for TLAA
    - TLAA disposition for 10 CFR 54.21(c)(1)(iii)



ENERGY NORTHWEST

# Closure of Open Items

- <u>OI 4.7.5-1</u>

  **Fatigue Analysis of Polar Crane**

  Columbia's LRA did not include TLAA for polar crane

  <u>Resolution</u>

  – Columbia has an overhead crane but not a polar crane

  – TLAA performed for all fifteen (15) in-scope cranes and hoists

  – TLAA remains valid for the period of extended operation as per 10 CFR 54.21(c)(1)(i)

# Subcommittee Topics Requiring Additional Information

Following are topics for which additional information was provided to subcommittee in December 2011:

- Microbiologically Influenced Corrosion (MIC) in systems
- Metal-Enclosed Bus (MEB) catastrophic failure
- Makeup water line from river
- Scope of Plant Service Water (TSW) piping to Reactor Closed Cooling (RCC) system
- Internal inspection of raw water buried piping
- Additional long-term plans for copper reduction

# Implementation Overview

- Implementation Activities incorporated into Columbia's Long Range Plan
  - Implementation coordinator on staff
  - Implementation procedure in place
  - Development of remaining AMPs scheduled
  - Active participation in License Renewal Implementation Working Group
  - Benchmarking of other sites with renewed licenses



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# Closing Remarks

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# Columbia Generating Station

## ACRS License Renewal Committee Meeting

April 12, 2012

# Columbia Generating Station

| | |
|---|---|
| **Dale Atkinson -** | **Vice President, Emp Dev/Corp Services** |
| **Don Gregoire -** | **Manager, Regulatory Affairs** |
| **John Twomey -** | **Project Manager, License Renewal** |



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# Agenda

- Station Overview
- Aging Management Programs and Commitments
- Closure of Open Items
- Subcommittee Topics Requiring Additional Information
- Implementation Overview
- Closing Remarks


N
4

# Station Overview - Description

- General Electric Boiling Water Reactor
  - BWR-5 / Mark II Containment
  - Plant circulating water & ultimate heat sink makeup supplied from the Columbia River
- 3486 MWt/1230 MWe



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# Station Overview - History

- Construction Permit – March 19, 1973
- Operating License – December 20, 1983
- 5% Power Up-Rate - May 1995
- License Renewal application submitted-Jan. 2010
- License Expires – December 20, 2023



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# Aging Management Programs and Commitments

**Don Gregoire**
**Manager, Regulatory Affairs**



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# Aging Management Programs & Commitments

- Aging Management Programs (AMP)
  - 55 Programs Credited for License Renewal
    - 35 Existing
      - 13 Enhancements
    - 20 New
- License Renewal Commitments – 71 total

# Closure of Open Items

- High-Voltage Porcelain Insulators
- Operating Experience
- Upper-Shelf Energy
- Metal Fatigue
- Core Plate Rim Hold-Down Bolts
- Fatigue Analysis of Polar Crane



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# Closure of Open Items

- OI 3.0.3.3.7

## High-Voltage Porcelain Insulators

230 kV Station Blackout recovery source insulators at Ashe substation were not included in the Insulator Aging Management Program

Resolution

- Insulators are now in program
- Tests performed in July 2011 conclude minimal accumulation and within industry limits
- Testing on 8 year frequency consistent with operating experience



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# Closure of Open Items

- OI B.1.4-1

  **Operating Experience (OE)**

  Future operating experience evaluations for aging effects were not specifically included in the License Renewal Application (LRA)

  Resolution

  – LRA amended to clearly call out intent to review internal and external OE on an on-going basis
  – Operating Experience program revised to specifically address evaluation of OE for aging effects
  – Initial/recurring training for plant staff

# Closure of Open Items

- OI 4.2-1

  **Upper-Shelf Energy (USE)**

  Technical basis not provided for initial transverse USE and copper content for instrument nozzle forgings

  Resolution

  – Technical basis was provided

  – Supports acceptability through end of period of extended operation



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# Closure of Open Items

- OI 4.3-1

  **Metal Fatigue**

  Columbia's metal fatigue Time Limited Aging Analysis (TLAA) performed for sample of critical locations listed in NUREG/CR-6260 may not be limiting

  Resolution

  – The other limiting locations were identified and evaluated for Columbia

  – All locations have an environmental cumulative usage factor below 1.0

# Closure of Open Items

- OI 4.7.4-1

  **Lower Core Plate Rim Hold-Down Bolts**

  Neither an Aging Management Review (AMR) line item nor a TLAA for the reactor pressure vessel lower core plate hold-down bolts were provided

  Resolution

  – LRA was amended to include:
    - AMR line item for TLAA
    - TLAA disposition for 10 CFR 54.21(c)(1)(iii)



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# Closure of Open Items

- <u>OI 4.7.5-1</u>

  **Fatigue Analysis of Polar Crane**

  Columbia's LRA did not include TLAA for polar crane

  <u>Resolution</u>

  – Columbia has an overhead crane but not a polar crane

  – TLAA performed for all fifteen (15) in-scope cranes and hoists

  – TLAA remains valid for the period of extended operation as per 10 CFR 54.21(c)(1)(i)



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# Subcommittee Topics Requiring Additional Information

Following are topics for which additional information was provided to subcommittee in December 2011:

- Microbiologically Influenced Corrosion (MIC) in systems
- Metal-Enclosed Bus (MEB) catastrophic failure
- Makeup water line from river
- Scope of Plant Service Water (TSW) piping to Reactor Closed Cooling (RCC) system
- Internal inspection of raw water buried piping
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# Implementation Overview

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# Closing Remarks

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# RISK-INFORMED REGULATORY FRAMEWORK FOR NEW REACTORS

## Advisory Committee on Reactor Safeguards

Contacts: Don Dube, NRO/DSRA, 301-415-1483
Ron Frahm, NRR/DIRS, 301-415-2986

**April 12, 2012**

# Meeting Purpose

**Discuss staff's response to the SRM on SECY-10-0121 and request a letter**

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# Agenda

- Brief background
- Tabletop exercise results
  - RITS 4b, completion times
  - Reactor oversight process
- Conclusions, options and recommendations in draft paper

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# Options Provided in SECY-10-0121

1) No changes to existing risk-informed guidance (status quo)
2) Implement enhancements to existing guidance to prevent significant decrease in enhanced safety (NRC staff recommendation)
3) Develop lower numeric thresholds for new reactors

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# Commission SRM Dated March 2, 2011

- **Commission approved a hybrid of Options 1 and 2**
  - Continue existing risk-informed framework pending a series of tabletop exercises that test existing guidance
- **Commission "reaffirms" existing**
  - safety goals
  - safety performance expectations
  - subsidiary risk goals and associated risk guidance
  - key principles (e.g., RG 1.174)
  - quantitative metrics
- **New reactors with enhanced margins and safety features should have greater operational flexibility than current reactors**

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# Tabletop Exercises

- December 2, 2010: 50.59-like change process for ex-vessel severe accident (EVSA) design features under Section VIII.B.5.c of each design certification rule
- May 4, 2011: Risk-informed inservice inspection of piping
- May 26, 2011 and June 1, 2011: Risk-Informed Technical Specifications (RITS) Initiative 4b on completion times and the Maintenance Rule (a)(4)
- June 29, 2011: RITS Initiative 5b (surveillance frequency control program)
- August 9, 2011: 50.69 and guidance in NEI 96-07 Appendix C on the change processes for Part 52 specific to EVSA design features
- October 5, 2011: RG 1.174; transition options from large release frequency (LRF) as a risk metric to large early release frequency (LERF); and ROP risk-informed case studies including SDP, reactive inspections under Management Directive 8.3, and MSPI
- October 26, 2011: Follow-up discussions with stakeholders on the ROP

# Major Conclusions

- During the tabletop exercises for licensing applications, the staff did not identify any potentially significant decreases in the enhanced safety margins for new reactors
- Identified potential gap in the Tier 2 change process regarding severe accident features that are not related to ex-vessel severe accident prevention and mitigation
- Current risk thresholds are appropriate for ROP; however, a few changes to the ROP may be warranted consistent with the integrated risk-informed principles in RG 1.174

# Key Tabletop Exercise Results

- **RITS 4b (completion times): Two key programmatic controls**
  - The risk-informed completion time is limited to a deterministic maximum of 30 days (referred to as the backstop completion time) from the time the TS action was first entered
  - Voluntary use of the risk-managed TS for a configuration which represents a loss of TS specified safety function, or inoperability of all required safety trains, is not permitted

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# AP1000: RITS 4b Case Study

| Class 1E DC System (IDS) | | | |
|---|---|---|---|
| **Division A** | **Division B** | **Division C** | **Division D** |
| 1 - 24hr Battery | 1 - 24hr Battery | 1 - 24hr Battery | 1 - 24hr Battery |
| | 1 - 72hr Battery | 1 - 72hr Battery | |

| Passive Core Cooling (PXS) | |
|---|---|
| **DVI Line A** | **DVI Line B** |
| Accum.-A (CKV) | Accum.-B (CKV) |
| CMT-A (CKV) | CMT-B (CKV) |
| IRWST-A (MOV) | IRWST-B (MOV) |
| IRWST-A (CKV1) | IRWST-B (CKV1) |
| IRWST-A (CKV2) | IRWST-B (CKV2) |

# AP1000 SPAR Model Results

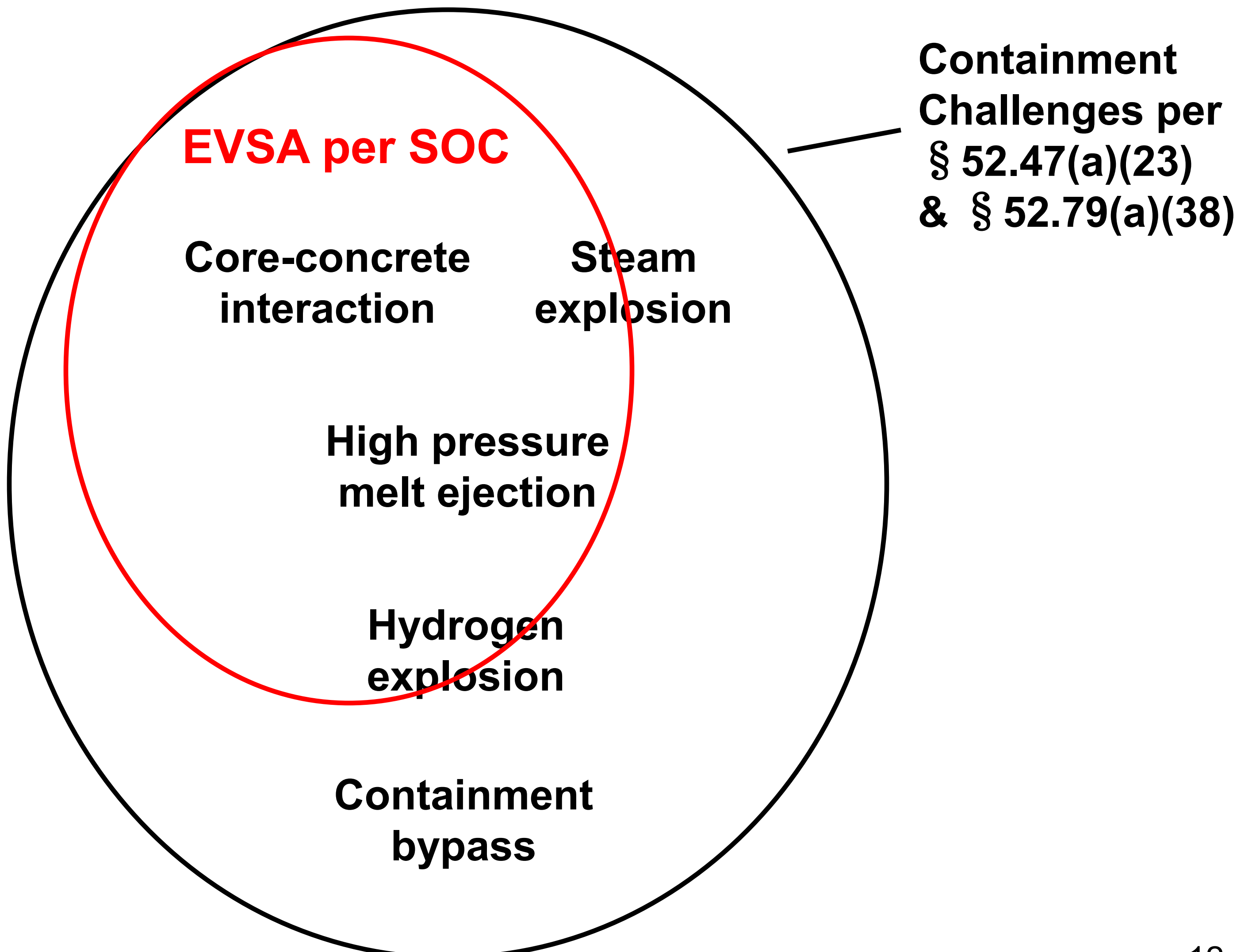
| RITS 4b Case | Equip. Not Functional | CDF (/yr) | ΔCDF (/yr) | Calc Completion Time (days) | Tech. Spec. Limit (hrs) | Allowed Completion Time (days) | ICDP | Other Available Equip |
|---|---|---|---|---|---|---|---|---|
| Base | None (no T&M) | 2.1E-07 | -- | -- | -- | -- | -- | All |
| 1 | 1 - 1E-DCP-A (DC/AC) | 5.9E-07 | 3.8E-07 | 9623 | 6 | 30 | 3.1E-08 | 1 - 24hr division and 2 - 24/72hr divisions |
| 7* | 1 IRWST Injection Line-B | 1.1E-04 | 1.1E-04 | 33 | 1 | [1hr] | [1.3E-08] | 2 Accum., 1 IRWST ILs (2 flow paths), 2 PHRHs flow paths, and 2 CMTs |
| 9-A* | 1 CMT-A and 1 Accum.-A | 1.6E-04 | 1.5E-04 | 24 | CMT - 1 Accum. - 1 | [1hr] | [1.8E-08] | 1 Accum., 2 IRWST ILs (4 flow paths), 2 PHRHs flow paths, and 1 CMT |

# Key Tabletop Results (cont.)

- **RITS 4b staff exercises**
  - Staff identified some configurations of equipment outages that would represent 10 years' worth of core damage probability
  - Repeated entry into such condition over time could increase CDF by one or more orders of magnitude, which could approach the baseline CDF of currently operating plants
  - Staff believes these configurations are unlikely or unrealistic, and that there were additional regulatory and programmatic controls that would limit the aggregated risk increase (e.g., performance monitoring, periodic PRA maintenance and upgrade under 50.71(h))

- **Staff concludes no substantive changes to methodology is necessary**

# Tier 2 Change Process: Gap identified for ex-vessel severe accident features



# Key Tabletop Results (cont.)

**Recommendation 1**

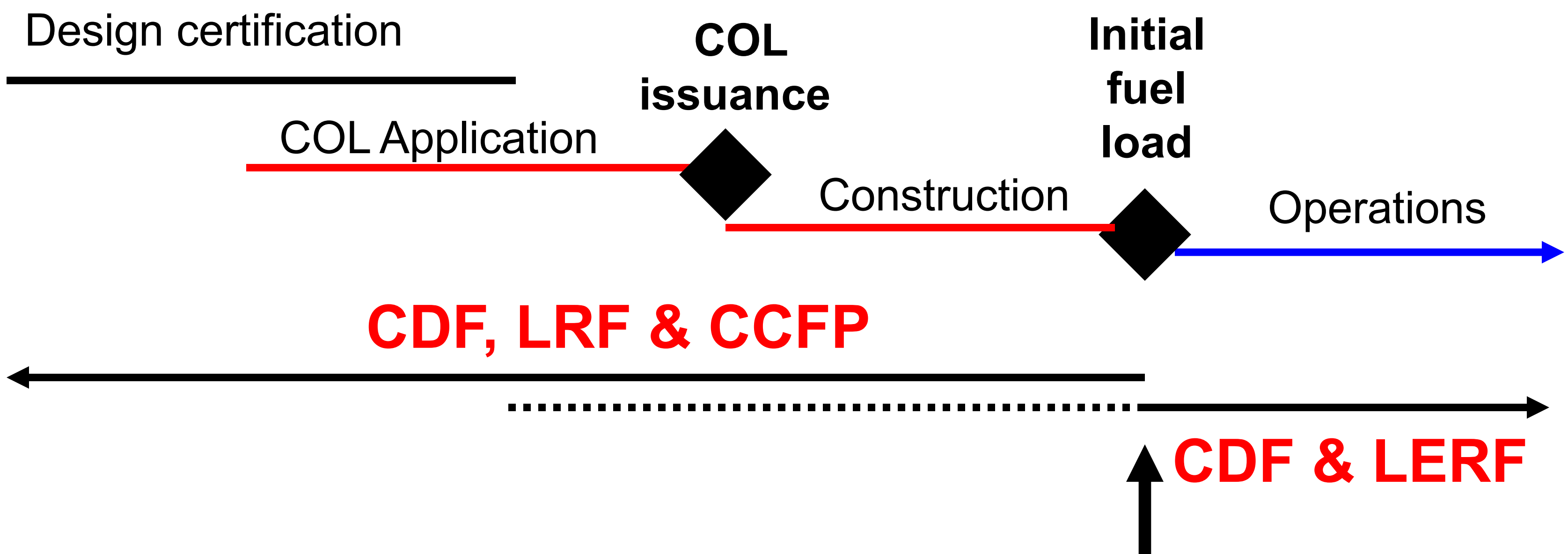
Address the potential gap, by a) ensuring that there are sufficient details on all key severe accident features in Tier 1, and b) including a change process in future design certification rulemakings in Section VIII for *non-ex-vessel severe accident features* similar to Section VIII.B.5.c for *ex-vessel severe accident features*

# LRF-to-LERF Transition

- **LRF vs. LERF**
  - Commission goals for new reactors are based on a conditional containment failure probability (CCFP) of less than 0.1, and a LRF of less than $10^{-6}$/yr, as well as $10^{-4}$/yr for core damage frequency (CDF)
  - Operating reactors use CDF and LERF as risk metrics

- **LRF issues**
  - LRF (and CCFP) have not been defined by the staff
  - Each design center has chosen different definitions
  - LERF is used in the ASME/ANS level 1 PRA standard, in risk-informed staff guidance (e.g., RG 1.174), and ROP
  - No existing or proposed level 2 PRA standard provides a universal definition of LRF

# Recommendation 2: Option 2C




- LERF calculated at or prior to initial fuel load. CDF & LERF used for RG 1.174 acceptance guidelines going forward.
- Last regulatory use of LRF & CCFP
- Continue to meet containment performance objective following core damage per SECY-90-016 and SECY-93-087

# Tabletop Results on Other Licensing and Operational Programs

- **50.65(a)(4) – no gaps**
  - Defense in depth and plant transient assessment often more limiting in terms of risk management  action level
- **RITS 5b (surveillance frequency) – no gaps**
  - Much more deterministically oriented, with risk impact only a secondary consideration in the criteria for changing surveillance test interval
- **50.69 (SSC categorization) – no gaps**
  - Rule has built-in measures to monitor RISC-3 components and take corrective actions (e.g., periodic program review every 2 refuel cycles)
- **RG 1.174 – no gaps**
  - Considerations such as defense in depth and margin of safety often more limiting than risk impact

# ROP Tabletop Approach

- Tested various realistic scenarios to confirm the adequacy of the current ROP risk-informed processes for regulatory decision-making or identify areas for improvement
- Used a broad cross-section of well-vetted cases, developed from actual greater-than-green examples from the current fleet of reactors:
  - Significance Determination Process (SDP) findings
  - Mitigating Systems Performance Index (MSPI) data
  - Management Directive (MD) 8.3 applications
- Applied similar situations to the new reactor designs, filling in gaps with realistic hypothetical situations and reasonable assumptions, and then compared the risk values and resultant regulatory response

# SDP Tabletops

**RESULTS**

- Existing risk thresholds for determining significance of inspection findings are generally acceptable
- Greater-than-green inspection findings would likely involve common cause failures and/or long exposures of risk-significant components
- Existing process does not always ensure an appropriate regulatory response for degradation of passive components and barriers

**CONCLUSION**

- SDP analyses could be augmented with additional qualitative considerations (deterministic backstop) to appropriately address performance issues

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# MD 8.3 Tabletops

## RESULTS

- Existing risk thresholds for invoking reactive inspections are adequate for new reactors
- Deterministic criteria used initially for event screening and then within a range of response determined by risk values
- Risk values heavily influence whether or not a reactive inspection is warranted and, if so, at what level
- Variations in or minor revisions to risk models used can potentially result in an inadequate response

## CONCLUSION

- Contribution of existing deterministic criteria could be modified or new deterministic criteria developed for initiating reactive inspections for new reactors

# MSPI Tabletops

**RESULTS**

- Existing MSPI is not adequate and would be largely ineffective in determining an appropriate regulatory response for active new reactor designs
- Meaningful MSPI may not even be possible for passive systems using the current formulation of the indicator
- Existing performance limit (backstop) could be further leveraged for active new reactor designs

**CONCLUSION**

- Alternate PIs in the mitigating systems cornerstone could be developed and/or additional inspection could be used to supplement insights currently gained through MSPI

# ROP Options

**OBJECTIVES FOR ROP OPTIONS**

- Maintain current risk thresholds for new reactor designs
- Consistent with integrated risk-informed decision-making concepts in RG 1.174
- Afford greater operational flexibility based on enhanced safety margins

**A. USE AS IS**

- Use the existing risk-informed ROP tools for new reactor applications without making any changes
- No additional action or resources needed, but existing tools may not always provide for an appropriate regulatory response

# ROP Options (cont.)

## B. AUGMENT EXISTING PROCESSES

- SDP: Use existing risk-informed SDP, but augment with deterministic backstops to ensure an appropriate regulatory response to address performance issues
- MD 8.3: Modify the contribution of existing deterministic criteria or develop new criteria for determining the appropriate regulatory response to plant events
- MSPI: Develop alternative to MSPI or augment existing guidance to emphasize performance limit for active new reactor designs, and increase inspection of passive mitigating systems for passive new reactor designs
- Proposed enhancements could be developed using existing resources and working with stakeholders

# ROP Options (cont.)

**C. DEVELOP DETERMINISTIC TOOLS**

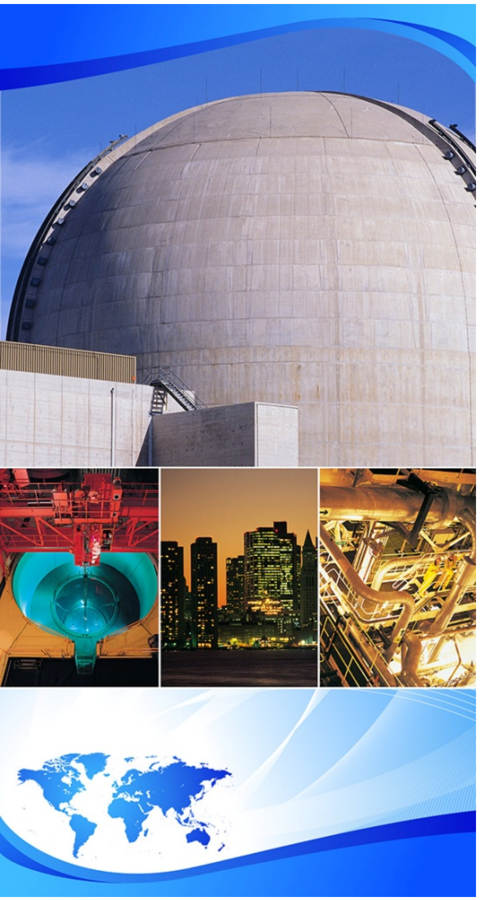
- Do not use the existing risk-informed ROP tools
- Capture risk insights to a lesser extent than the current fleet using deterministic guidance consistent with new reactor design certification and licensing basis
- Additional resources may be necessary to research and develop the new guidance documents

**Staff Recommendation: Option B**

- Staff would obtain Commission approval for proposed changes to ROP at least one year prior to implementation
- Process enhancements could be further refined based on experience and lessons learned

# Next steps

- Finalize Commission paper based on ACRS and stakeholder feedback
- SECY due to be issued early June, 2012



# EPRI/NRC-RES FIRE HRA GUIDELINES, NUREG-1921/EPRI 1023001


Mark Henry Salley and Susan E. Cooper (NRC/RES/DRA)
Stuart Lewis (EPRI)


ACRS Full Committee Meeting
April 13, 2012
Rockville, MD

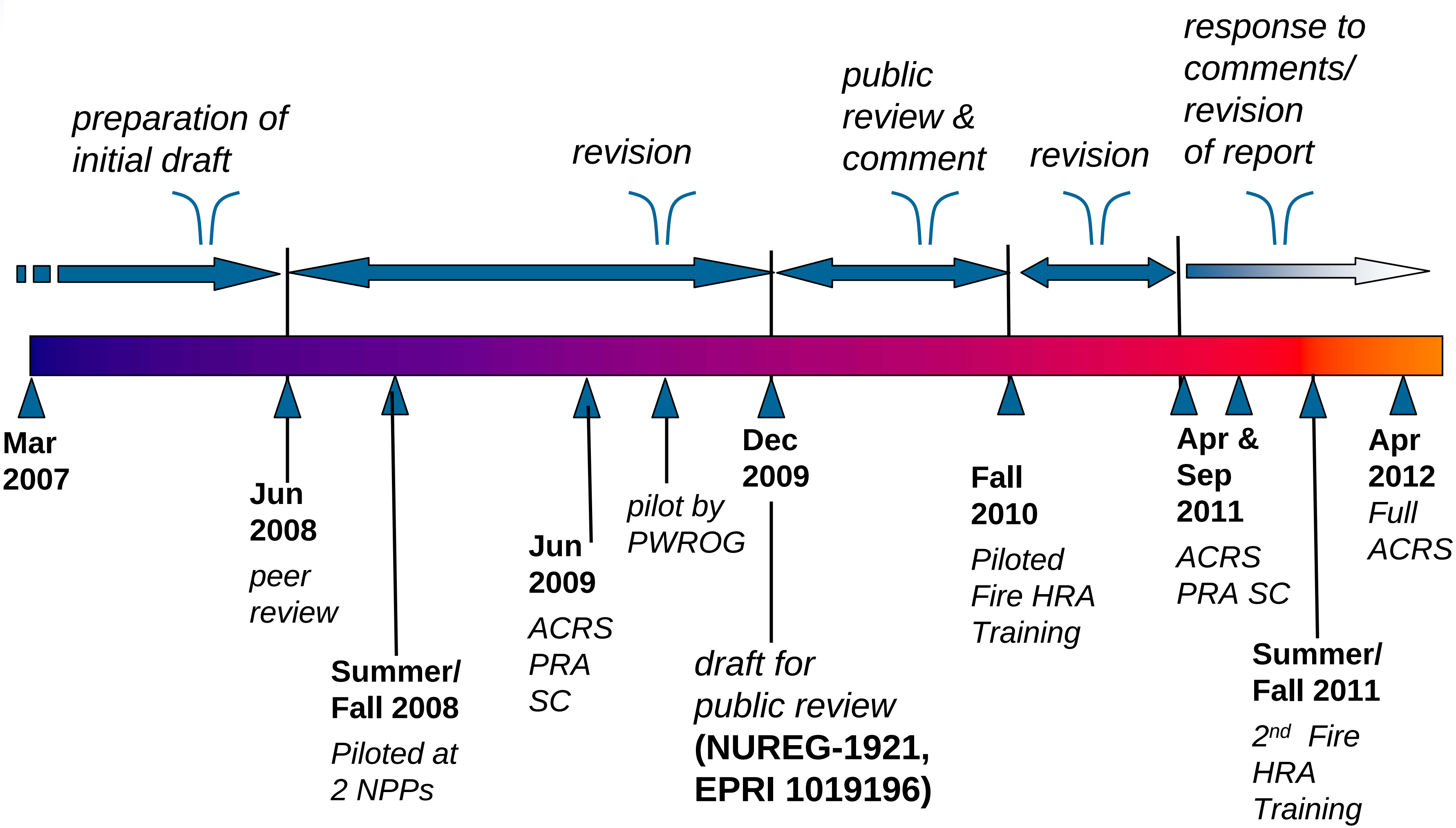
***A Collaboration of U.S. NRC Office of Nuclear Regulatory Research (RES) & Electric Power Research Institute (EPRI)***

# Today's Presentation

- Short history and background of the project
- Project objectives
- Examples of challenges
- Industry perspective
- Review, Testing and Trial Applications
- Uses for other HRA projects

**Project Team requests letter from ACRS**

# Evolution of the Fire HRA Guidelines



# Background on Fire HRA

## Status of fire PRA at project initiation

- About half of US NPPs transitioning to NFPA-805
- NUREG/CR-6850 [EPRI 1011989] provided detailed guidance for fire PRA to support transition to NFPA-805

## HRA for fire PRA

- Guidance in NUREG/CR-6850
  - Conservative screening human error probabilities (HEPs)
  - Performance shaping factors (PSFs)
- Needs beyond NUREG/CR-6850
  - Approach for detailed/best-estimate HRA
  - Guidance to satisfy requirements in PRA Standard

# Objectives of Fire HRA Guidelines

- Address HRA needs beyond NUREG/CR-6850
  - Detailed quantification method for fire PRA context
  - Treatment of relevant PSFs
  - Steps to satisfy PRA Standard requirements

- Satisfy NRR User Need 2008-003, Rev. 1, Task 13

  "…*expand existing HRA methods* … *to incorporate the effect of fires in full-power PRA models*."

**Pursued via joint EPRI/NRC MOU analogous to NUREG/CR-6850**
***(third major joint fire-related project)***

# Examples of challenges addressed

- Need for advances in state-of-the-art for fire HRA
  - Full delineation of HRA process for fire context
  - Feasibility of human actions
  - Guidance for:
    - Response to spurious signals/actuations from cable failures
    - Potential errors of commission (EOCs)
    - Distractions in control room
    - Uncertainties (e.g., for timing information)
  - Appropriate quantification methods
    - New scoping approach
    - Adaptation of (two) existing methods for detailed analysis
  - Implications for ex-control room actions

# Examples of challenges addressed (continued)

- Piloting of methods and guidance
- Guidance to meet evolving requirements in PRA Standard
- Evolving approaches to implementing fire PRA tasks
- Continuing improvements to fire procedures in plants
- Need to develop training material in parallel with report

# Industry Perspective

- Focus has been on
  - Assuring guidance meets technical needs of users
  - Ensuring adequate review, testing and trial application

- Important attributes of technical approach
  - Addresses range of fire response strategies in place at plants
  - Coordinates with development of actual fire PRA models
  - Capable of producing useful insights
  - Consistent with HRA for internal events

# Review, Testing and Trial Application

- Peer review (June 2008)
- Pilot applications
  - Scoping tested by project team at two NPPs (2008)
  - Pilot by PWR Owners Group (2009)
- Public review of full draft (early 2010)
- Applications
  - Use of draft guidance to complete fire PRAs (eight sites, all with peer reviews)
  - Feedback from students in training courses (2010 and 2011)
- Review by ACRS Subcommittee on Reliability and PRA

**All elements tested via variety of applications**

# Review, Testing and Trial Application (cont'd)

## Examples of changes to report from feedback

- Increased guidance on qualitative analysis (especially feasibility assessments)
- Simplified scoping approach to quantification
- Modified timing considerations for scoping approach
- Enhanced guidance for walkthroughs/talkthroughs
- Expanded treatment of spurious actuations/operations
- Simplifications in recovery analysis, dependency analysis, and uncertainty

**Review and experience substantially improved Guidelines**

# Advances Beneficial to Other Projects

- Fire HRA guidelines directly benefit other NRC HRA projects
  - New HRA development per SRM M061020
  - Site-wide Level 3 PRA Project
- Commonality of team members among projects facilitates coordination

# Advances from Fire HRA Guidelines: Examples

- Comprehensive guidance for all steps in HRA process
- Examples on how to address PRA Standard requirements
- Integration of HRA with larger PRA study
- Example of a quantification approach that addresses traceability concerns (i.e., scoping fire HRA approach)
- Detailed guidance on feasibility assessments
- Guidance on HRA tasks for ex-control room actions and challenging environmental conditions
- Framework for HRA for other challenges, e.g.,
  - Seismic PRA

# Examples of Advances (continued)

- Situations involving problems with cues and distractions
- Development of timing estimates (including treatment of uncertainties)
- Use of procedures other than EOPs
- Training materials for all HRA process steps

# Conclusions

- Project objectives have been satisfied
  - Comprehensive, useful guidance for fire HRA
  - Approach refined through testing and application in production PRAs
- Elements of Guidelines of significant value to other HRA research and development

**Project Team requests letter from ACRS**