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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT OPERATIONS AND FIRE PROTECTION

SUBCOMMITTEE MEETING

+ + + + +

Thursday, May 21, 2015

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Conference Room

NRC Region IV

1600 E. Lamar Boulevard

Arlington, Texas

9:45 a.m.

SUBCOMMITTEE MEMBERS:

GORDON SKILLMAN, Chair

DR. RON BALLINGER

DR. DENNIS BLEY

DR. MICHAEL CORRADINI

DR. JOY REMPE

DR. PETER RICCARDELLA

DR. STEVE SCHULTZ

DR. JOHN STETKAR

A G E N D A

P R O C E E D I N G S

MR. SKILLMAN: The meeting will now come to order. To the Region IV crew, thank you very much for permitting us to come here today. We have been looking forward to this meeting.

This meeting is a meeting of the Advisory Committee and Reactor Safeguards Plant Operations and Fire Protection Subcommittee. My name is Dick Skillman and I'm chairman of the subcommittee.

ACRS members in attendance are Dr. Peter Riccardella, Dr. Michael Corradini, Dr. Ron Ballinger, Dr. Michael Bley, Dr. John Stetkar, Dr. Joy Rempe, and Dr. Steven Schultz. The designated federal official is Mike Snodderly.

The ACRS meets annually in one of the NRC's four regions to discuss that region's oversight and inspection of those facilities. The purpose of today's briefing is for the Region IV staff to discuss items of mutual interest, namely regional inspection and operational activities. The subcommittee will gather information, analyze relevant issues and facts, and formulate a proposed position and action as appropriate for deliberation by the full committee if needed.

The rules for participation in today's meeting were announced as part of the notice of this

meeting previously published in the Federal Register on May 13, 2015. The meeting will be open to public attendance with the exception of portions that may be closed to protect information that is proprietary, and that is pursuant to 5 USC 522(b)(c)(4). We have received no written comments or requests for time to make oral statements.

A transcript of today's meeting is being kept and will be made available as stated in the Federal Register notice, therefore, we request that meeting participants use the microphones located throughout the meeting room. When addressing the subcommittee, participants should first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. A telephone bridge line has been established for this meeting. To preclude interruption of this meeting, I ask that you please mute your electronic devices.

We will now proceed with the meeting, and I call on Mr. Kriss Kennedy, deputy regional administrator of Region IV, to make introductory remarks. Thank you.

MR. KENNEDY: Thank you, Mr. Skillman.

Good morning. On behalf of Mark Dapas, the Region IV regional administrator and the dedicated

members of the Region IV staff, I want to welcome the members of the Advisory Committee on Reactor Safeguard to the NRC Region IV office in Arlington, Texas.

My name is Kriss Kennedy. I'm the deputy regional administrator in Region IV. Mark Dapas was not able to be with us today. He's up at headquarters participating in a Commission meeting; they're briefing the Commission on the results of the agency action review meeting, and I did have an opportunity to watch a little bit of that this morning.

Region IV is excited and honored to host this meeting today. We have prepared briefings on a number of different topics that we hope you'll find interesting and informative. We also look forward to your questions and discussions on these topics.

I want to thank the Region IV staff for all their hard work in preparing for this meeting, and I'll introduce the presenters for today's meeting. Although not presenting, I do want to introduce Tony Vegel. Tony is the director of the Division of Reactor Safety, and most recently he completed work as the leader of the oversight panel for Fort Calhoun Station.

Ryan Lantz is the deputy director of the Division of Reactor Projects.

John Mateychick, senior reactor inspector in

the Fire Protection area. John, did you raise your hand? There you go.

And Brian Tindell. Brian is the senior resident inspector at Arkansas Nuclear One.

David Loveless is one of the senior reactor analysts in Region IV.

Greg Warnick is a branch chief in the Division of Reactor Projects. Most recently he was the senior resident inspector at San Onofre.

Wayne Walker is a branch chief in the Division of Reactor Projects.

Tom Farnholtz is a branch chief in the Division of Reactor Safety. And did we get all the presenters? Okay, good.

I also want to thank the other staff members who helped the presenters prepare their discussion topics and their presentations, and also our IT staff that helped us set this up today.

Before I start with just an overview of Region IV, I wanted to provide a short safety briefing. We are in the first floor conference room. If for some reason we had to evacuate the building, we would go out the front door that you came in this morning and we'd go to the far end of the parking lot, assemble at the far end of the parking lot towards the main road. We may get

a little wet today if we have to do that, but that's where we would assemble.

If we have a need to shelter in place, the staff would assemble in the interior rooms, including this one, so although we don't forecast any need to do that this morning, I just wanted to let you know what the protocol was. The bathrooms are down the hall as you leave this room to the left, just across the lobby.

And please let myself or any other member of the Region IV staff know if you need anything or if we can help you in any way during your visit today.

Before we begin the presentations, I'd like to provide a high level overview of Region IV. So Region IV licensees are in a geographic area that encompasses essentially the western half of the United States. Our licensees include 13 operating reactor sites with 19 operating reactors and approximately 600 materials licensees.

In addition to our inspection and oversight function, we maintain the capability to respond to plant events and impacts from natural phenomena 24 hours a day. Working in concert with response by the headquarters staff, our response could include the staffing of our instant response center here in the Region IV office and dispatching a team from the region

to the affected site.

We have approximately 200 staff in Region IV.

MR. SKILLMAN: Kriss, would you go back one, please?

MR. KENNEDY: Yes, sir.

MR. SKILLMAN: I see you write 13 operating reactor sites and 14 ISFSIs. Is the 14th San Onofre, the non-operating site, is that what that is?

MR. KENNEDY: I'd have to look at the specific inputs to the numbers, but I think the 14th is the ISFSI, independent spent filed storage installation.

MR. SKILLMAN: Thank you, Chris.

DR. BALLINGER: Chris, the last bullet says many times a year. Can you modify that?

MR. KENNEDY: Thank you. Because our sites are on the Gulf, we have a lot of opportunities to respond to hurricanes, and so a majority of our response to natural phenomena deals with hurricanes.

DR. BALLINGER: And where does that start? Are you talking about unusual event alerts or just when the phenomena is going to occur you assemble?

MR. KENNEDY: About 72 hours before the onset of a hurricane we will start in our monitoring mode, we will bring people into the incident response center and

start the process of monitoring the hurricane, monitoring plant response to the hurricane, and then our onsite inspectors are also monitoring licensee actions to prepare for the hurricane.

Another unique thing that we do is in consideration for the onsite inspectors, we will actually dispatch one or more inspectors from the regional office to allow the resident inspectors to take care of their own families and their property. So in advance of a hurricane, we'll dispatch staff from the region to fill that inspector role such that the inspectors can take care of family and property.

We've been lucky. it's been a couple of years since we had a significant hurricane that would impact one of our sites, but it hasn't -- it wasn't that way several years before that.

DR. CORRADINI: What about preparation for tornado response or tornado events?

MR. KENNEDY: In the case of a tornado -- obviously you can't predict tornadoes -- licensees do have procedures for abnormal weather that includes high winds, and so licensees typically have some advance notice if there's a tornado watch, tornado warning, and they will take actions to prepare the site for that high wind event, primarily

making sure that there's not loose equipment in the yard, that equipment is tied down or placed inside. And then if there was an actual event, some damage caused by the tornado, we would be in a response mode for that, including response by our resident inspectors.

Any other questions?

DR. BLEY: Yeah. What is the real issue regarding the Air Force Master Material License?

MR. KENNEDY: Well, it's not an issue. It's just a program that we have responsibility for in the licensing and oversight of that master materials program.

DR. BLEY: Is this weapons material or is this diagnostic material?

MR. KENNEDY: No, no. It's any of the radioactive sources, byproducts that they may use in their operations, not weapons.

DR. BLEY: Thank you, Kriss.

Again, we have about 200 staff members in Region IV. In addition to the Office of Regional Administrator, we have four divisions. It's fairly standard from region to region. Region II is a little different in that they do not have a materials division, they have a fuel facilities division, and of course, Region II also has the construction inspection program.

Division of Nuclear Materials Safety has oversight for nuclear materials licensees.

Division of Reactor Projects, they own the resident inspectors. The resident inspectors are in the Division of Reactor Projects, and so the branch chiefs in the Division of Reactor Projects manages the inspection oversight and assessment of the plants that they're responsible for.

Division of Reactor Safety, their inspectors are located here in the region and they conduct the more specialized inspections, some of which you'll hear about today, including fire protection and the component design basis inspection.

And then we have the Division of Resource Management Administration that does our budgeting, human resources, acquisitions, and financial management.

This is just a quick graphic and depiction of the geographic area that we have and where our reactor sites are located. You were at the Palo Verde the last couple of days. And then this is a depiction on the materials side the states that are agreement states and non-agreement states.

The NRC has regulatory authority for materials licensees in those states that we refer to as

non-agreement states, and those states that have assumed NRC regulatory authority for material licensees under the Atomic Energy Act of 1954, we refer to those as agreement states. Our area includes the western half of the United States, Alaska, Hawaii and Guam, so our materials inspectors conduct inspections in Guam.

DR. BLEY: The 600 licensees, that's just in the non-agreement states?

MR. KENNEDY: That would be non-agreement states and federal facilities in agreement states.

DR. BALLINGER: With the non-agreement states, the yellowish group, do you have then folks that travel there and do inspections?

MR. KENNEDY: Yes, sir, we do.

DR. BALLINGER: But nobody in residence? Nobody -- there's no office that --

MR. KENNEDY: There's no office, no full-time resident inspectors at those sites. I was going to mention this. You know, because of the large geographic area that we have, it is a challenge for both materials inspectors and the Division of Reactor Safety inspectors to conduct those inspections, to travel to conduct those inspections. To fly to Columbia Generating Station takes a day.

DR. STETKAR: How long does it take to get to

Guam?

(General laughter.)

MR. KENNEDY: Tony how often -- we go to Guam once a year, and you have to factor that in. So it creates a challenge but we've gotten good at it. Some of these materials sites are very remote.

DR. CORRADINI: What interaction do you have to have with the agreement states? Do you track what's going on there?

MR. KENNEDY: We do. We provide oversight of the agreement states' implementation of the inspection program and we conduct periodic reviews of their programs to ensure that they're consistent with the NRC's programs. It's a formal review, we will send people to the state offices, review their programs and provide them feedback on the results of that program.

DR. BLEY: Have you ever run into problems that they're not doing what you expect?

MR. KENNEDY: Yes, we have.

DR. BLEY: They're not licensees, so what is the administrative way you deal with that?

MR. KENNEDY: Tony, can I get your assistance on answering this question.

MR. VEGEL: Absolutely.

MR. SKILLMAN: Make sure you're at a

microphone, because we have to have it on a transcript.

MR. KENNEDY: Tony was -- prior to his current position, he was a director of Division for Material Safety.

MR. VEGEL: We have a program, Kriss talked about the periodic reviews, and if we see where there's gaps in alignment, we can increase the oversight by increased meetings with them, and then also, every time we do a review, we develop recommendations and they may have to follow up on that. And we do have the option of taking the program back.

DR. STETKAR: Has that ever happened anywhere?

MR. VEGEL: Not that I'm aware of, but there has been some, I think it was in Region II, the Georgia program that came very close to that.

I think it would be important to note that we have staff dedicated, state agreements officers, that constantly communicate with the agreement states and have that point of contact with the agency and what the agreement states are doing, and then also it tells you if there's events within the agreement states, that there's communications and awareness of what the states are doing in response to issues.

Does that help?

MR. KENNEDY: Thanks, Tony.

I mentioned emergency response. I want to highlight the role that our response coordination branch plays in helping us meet our mission. And so we do inspection, we do oversight, we do assessment, but we also do emergency response, and that's a key mission for the regions and for the agency. So the Response Coordination Branch helps Region IV maintain 24-7 readiness to respond to events, but they do more than that, they also do outreach with licensees with state, local and federal responders that may be involved in response to site events.

And they also plan and implement periodic exercises that we conduct in conjunction with licensees where we will staff our instant response center, we will actually dispatch a site team to participate in the exercise with the licensees, and it helps train our staff, it helps our readiness to respond to events, it also helps the licensees train because it will be more realistic in how they would interact with us if they were at a real event. So I did want to highlight that role that we play.

DR. BALLINGER: I guess I can guess the answer, but depending on the incident, so you also do drills on potential incidents?

MR. KENNEDY: Yes, we do.

DR. BALLINGER: So as you develop the scenario, is it chosen primarily by the region office and then coordination as to who essentially has the various roles by the regional office? Or do they make a recommendation? I guess I should have asked it that way.

MR. KENNEDY: What we do is the licensees are required to conduct periodic exercises so the licensees are responsible for developing the scenario to test various portions of the response both onsite and offsite, so they will develop the scenarios. As part of our inspection process, we review the scenarios but we do not develop them, they develop them.

From a training standpoint, not in conjunction with the licensees, our response coordination branch does develop tabletop scenarios that they will use to train our staff. In fact, in preparation for an upcoming exercise, we just had a tabletop exercise training yesterday in preparation for the Comanche Peak hostile action based EP exercise coming up.

MR. SKILLMAN: Kriss, as you're monitoring the licensees' emergency preparedness drills, the creation of the scenarios and the actual conduct of the

exercises, has there been evidence of specific weaknesses that have emerged that are new or different over the last eight to ten years? Is there something new that's beginning to show itself that we hadn't anticipated in the past?

MR. KENNEDY: It's a good question because what's happened in the last ten years obviously is the implementation of the hostile action based exercises that licensees are now required to conduct on a periodic basis. I think it's every six years they have to conduct a hostile action based exercise. So that actually created whole new scenarios and a whole new way to interact, both with the NRC, with offsite organizations and even internally, and so I think that has created some new observations/findings, as we would expect. And that's the purpose of the exercises is to help licensees improve, help NRC improve.

I'm just trying to think of some of the ones we've had in the last couple of exercises. Primarily it's communication, command and control, how licensees interact with local law enforcement who are actually staffing the incident command posts and the overall coordination of that response, because it's a security-centric response as opposed to what we've been used to in the past with our exercises which were all

focused on the plant and the reactor.

MR. SKILLMAN: Radiological.

MR. KENNEDY: Yes, radiological.

MR. SKILLMAN: As you speak to that, let me just describe a scenario, and maybe you're moving into safeguards here, and if so, just tell me to back off. We had an incident at TMI in 1997, a guy drove through the gate, Sunday morning, beautiful gorgeous morning -- it's the Pierce Nye event, it's well known -- and in a matter of about an hour and fifteen minutes we had 150 Pennsylvania State Police onsite, we had the majority of those in the vital area and they were all armed. The Pennsylvania State Police force was overwhelming compared to the site security force. And we all learned a lesson: who gets through the gate and who doesn't.

I've often wondered in the new world in which we live in after 9/11 how have adjustments been made to allow the site to protect itself but also to allow call-up resources when those call-up resources are necessary.

MR. KENNEDY: Without going into too much detail, what I can tell you is that based on the hostile action based exercises I've participated in and have been involved in, I think the response that we would see

today would be similar to the response that we saw at TMI, but maybe more coordinated. I think the coordination is better now with respect to the overall command and control of that event, and also the provisions and understandings that have been made to allow offsite law enforcement to respond to the plant. I can tell you that the exercises I've seen, there has been significant response from offsite law enforcement agencies to those events, to those exercises and events.

DR. BLEY: Well, I think, at least the way I interpreted Dick's question -- I was just at the INMM risk-informed security workshop they had out in Idaho a few weeks ago and heard some stories from another -- and if we're crossing into areas that we can't talk about, just tell us -- but there someone was reporting that in an exercise not too long ago that if hostile get inside the gate, that by law the FBI has authority to track them down. And actually, in the exercise they were threatening to shoot operators who were trying to save the plant. And I think that's kind of where Dick was going, if you've got armed people inside who are good guys but they're interfering with the safety of the plant, how hard are we working?

MR. KENNEDY: I can say that there are measures that the licensee puts in place to minimize

that possibility.

DR. BLEY: At least we brought it up and I guess you can't talk more about it, but it was a striking audit concern and the folks at that meeting were mostly security folks.

MR. KENNEDY: I can tell you on the three or four or five hostile action based exercises I've been that's never come up.

DR. BLEY: But it has somewhere and they claimed the right of law to do what they were doing, and they would have created a worse situation than the bad guys.

MR. SKILLMAN: I think that's worth hearing two times. Here we all think we're doing the right thing, at least in our case, that security scenario unraveled very, very quickly. It was underway before anybody knew what to do about it, and in that case we went from a 100 percent normal operation on a beautiful Sunday morning to a site area emergency because of the way our EALs were written.

Dr. Bley has introduced this issue, but who has got the right to shoot, and particularly, who has got the right to stop an operator from taking important action that might save the core. I think that needs some ventilation. That's all I'm going to say.

MR. KENNEDY: I don't know the specifics of that case, but based on the exercises and responses I've seen, I'm confident that licensees have measures in place to address that.

Any other questions for me?

(No response.)

MR. KENNEDY: Okay. At this point I'd like to turn it over to Ryan Lantz, and Ryan is going to provide an overview of the Reactor Oversight Process in Region IV.

MR. LANTZ: Thank you, Kriss.

I'll just start out, I'll apologize for the acronym on the slide, ROP, that is our Reactor Oversight Process. It would have fit on the slide but it would have looked a little cumbersome, so I'll start with that apology.

I have two main goals this morning. I'd like to talk to you a little bit about what the ROP is and how it does what it does, and then I just want to cover briefly what the current status of the outcome of the ROP is with each of the Region IV operating reactor sites.

So this is kind of in a nutshell what the ROP is, and if you look at the very top of this diagram -- we'll start at the top, of course, that's a

good place to start -- the goal of the Reactor Oversight Process is the continuous assessment of the safety status of the operating reactor plants. So by safety status I mean what's going to impact, with the operation of a nuclear power plant, what is going to impact public health and safety. So that's what we're concerned about.

So we divide up all those things that might impact public health and safety into three strategic performance areas, that first block, and those are reactor safety, radiation safety, and then safeguards. Then we further break those three strategic areas into cornerstones of safety, and there's seven cornerstones of safety. The reactor strategic area has four: it's an initiating event, mitigating systems, barrier integrity, and then the emergency preparedness cornerstone.

The radiation strategic performance area has two cornerstones: that's public health and safety, public radiation health, and then occupational which is the workers at the plant radiation safety.

And the safeguards area has only one cornerstone and that's the security of the plant and the information at the plant.

On both sides of the top you'll see baseline

inspection results and performance indicators. We spend roughly, on average at each plant 2,700 hours devoted to inspection, the baseline inspection program at each reactor facility, at each reactor site. Those inspection procedures are all public, they're all visible, and we take the results of those inspections, and I'll talk briefly about how significant each one of the results of those inspections and the findings that come out of those inspections.

Similarly, for the performance indicators this is a voluntary program that every licensee is participating in, and performance indicators set some data and information that they collect and report to us every quarter and they're broken up also into each one of the seven cornerstones of safety. So they provide a set of data every quarter, things like how many unplanned reactor scrams occurred per the last 7,000 critical hours, how effective have their offsite sirens been, what is the percentage of the releases that were done outside the plant and how they compare to certain limits that we have set, so what percentages.

DR. BLEY: Ryan, I'm pretty familiar with how the left side, the inspection side part works. How the right side works, especially with respect to the thresholds and what they are and what happens if you

don't meet those, I haven't heard much about. If you could expand on that just a little. I know you don't have much time.

MR. LANTZ: Absolutely. So like I said, performance indicators are all well defined, they have thresholds that are all predetermined. One thing you may be familiar with, the significance determination process for inspection findings, there's a risk-based grouping where we actually assign a risk of core damage frequency, change to core damage frequency, and then there's some more deterministic, like emergency preparedness findings are put through a process. It's not risk-based but it does relate to significance. And the outcome of that is green, white, yellow or red, and I think you're all fairly familiar with those terms. So that's the significance determination for inspection.

Very similar on the performance indicator side, but on that side the data is compared to predetermined thresholds that are advertised, and the outcome is if the performance indicator is functioning like we expect, like say there's no unplanned scrams during the quarter, they report a number of zero, that produces a green threshold, they're in that green band.

If they exceed a threshold that's predetermined -- and I'll give you one example,

unplanned scrams with complications -- they're only allowed one in the time period of that assessment. If there's two, then that crosses a threshold into white.

DR. BLEY: But it only goes to white. Do any of those --

MR. LANTZ: No. They do go -- some do go further, and I think yellow is the most for a performance indicator. So the same way that reactor inspection results result in green, white, yellow and red outcomes, and they're related to risk to the public, performance indicator results are the same way. They'll get green inputs, white inputs, yellow inputs, not a red input.

MR. SKILLMAN: Ryan, let me just fact-check my own understanding. Let's say in this operating cycle you have one trip in 7,000 hours and it's a not complicated trip, it's a rod drop, the plant comes down, and 36 hours later you're back in power.

The following year you have two. One of them is a very similar event, just a mild trip, the instrument system has a hiccup, and then two months later after you're back stabilized, you have another one, same system, leading to complications, a couple of valves stuck open, you drop reactor coolants and compressor doesn't ignite when it should, and now you're into a complicated trip. I believe that could conceivably

take you to a red; I don't think you're limited to a yellow. I think if you line up enough pieces, STP might even take you to red.

For instance, you had incidents up at Fort Calhoun that came out red, and we're saying wait a minute, what's cooking here. All I'm saying is you had said as far as it goes is probably a yellow. I'm challenging saying I think you can get worse than that, given particular circumstances.

MR. LANTZ: So now the fact that there were scrams, maybe there was a scram with complications as you described, those would feed into the performance indicator, and as I understand, there are no red performance indicators. I'm looking at my body of knowledge over there.

MR. ALEXANDER: I just looked it up to remind myself, they're pretty high thresholds. This is Ryan Alexander, a senior project engineer in Division of Reactor Projects.

For example, the unplanned scrams per 7,000 critical hours, if you had more than 25 unplanned scrams per 7,000 critical hours, yes, you could cross into red, and also in the mitigating systems performance index, those systems all at the one E four range of that calculation can result in yellow.

VOICE: What about repeated events, do repeated events have a special treatment?

MR. ALEXANDER: It depends on where they fall in the time frame of that calculation in most cases.

MR. LANTZ: So one thing I wanted to make a point, we talked about the scram, so that feeds into performance indicators, the fact there was a scram, there was a scram that feeds into performance indicators, we don't stop at that. We need to look at why did the scram occur, was there a performance deficiency, so something that the licensee should have been able to know, predict and prevent. And so we will factor that into our inspection side and that's where maybe you've only had two or three trips, but if there's some significance, we'll feed that in, and you can actually get up to a red flag for a performance issue that occurred at the plant that they should have been able to see and prevent.

VOICE: One last question in this area. We recently had a briefing that included some folks from EPRI and NEI and they were talking about what they think they've come up with -- and we don't have the details -- that they think is truly a leading indicator that's a combination of several kinds of indicators of the sort you have and some others. I wonder if you're

hearing about that or if you're tracking that work, or if that's something that maybe is back in headquarters.

MR. LANTZ: That's something that I have not heard about here. I will say our performance indicators, they're a metric, essentially, and all metrics need to reevaluated periodically to see if they're measuring what we want. If we have a performance indicator that is continuously green and not providing any assessment of value, we should reevaluate that performance indicator and re-baseline that indicator.

DR. SCHULTZ: To summarize what I understood you to say is that you have the performance indicator results, they can feed directly into an action matrix finding because there are thresholds associated with them, but there's also a line, dotted or whatever you want to call it, over to inspection or questioning programs associated with the inspection side that is likely also to then lead to other findings, other action matrix determinations.

MR. LANTZ: Absolutely. As Kriss had mentioned, we do have resident inspectors on the sites at all times. They're observing activities day to day, and if there is an event that occurs -- and this would be an event -- we would want to investigate that event

and look for performance issues that caused the event. Performance indicator is just a set of data that is collected. We would definitely look at the causes and potentially prosecute that as another finding.

DR. SCHULTZ: But that doesn't happen within the performance indicator side, it needs to be coming in on the inspection side.

MR. LANTZ: That's correct. It would come on the inspection side.

DR. SCHULTZ: Thank you.

DR. BALLINGER: So in effect, those are not really black and white separate. If you have performance indicator results that are continuously bad that's got to have resulted at some point in inspection issues.

MR. LANTZ: I would totally agree with that, absolutely.

MR. SKILLMAN: One more question. The significance threshold is really a product that comes from your significance determination process.

MR. LANTZ: Correct.

MR. SKILLMAN: And that really is a PRA of sorts.

MR. LANTZ: Definitely for most of the reactor safety cornerstones it is based on probabilistic risk assessment. That's correct.

MR. SKILLMAN: And so the question is how do you know that tool is accurate.

MR. LANTZ: I would say we have our experts here that talk about risks and the actors have that tool.

MR. SKILLMAN: We've got ours here.

(General laughter.)

MR. LANTZ: I mean, that's a good question. We have to struggle with that. One of the things we can do in this process -- and we do do this -- is this is a very public process, we follow this process, however, we are still the regulator, we still have to step back after a finding is analyzed and run through our significance determination process, should it really be a yellow finding, should it really be. Because there's consequences in the action matrix, as I'll talk briefly about, for us to give that result as a final determination. We have always got the ability to make a deviation from what the ROP tells us we should do and do what we think is the right thing. I hope that answers that question.

MR. SKILLMAN: Thank you. Yes, sir.

DR. STETKAR: Let me follow up on it because it's something -- and this is why I like to get feedback from the folks who are actually out here trying to make these determinations -- I've seen events that have

happened either during plant shutdown or that could affect the availability of systems during plant shutdown, and in many cases the PRA tools that are available to the NRC don't cover those shutdown modes. How do you handle in practice significance determination under those conditions when you don't have the calculator?

MR. LOVELESS: This is David Loveless, senior reactor analyst.

It's a good thing you brought that up. We're going to be talking about that.

DR. STETKAR: I'll wait then. Thanks. I didn't look ahead. We'll wait and bring it back up. Thanks.

MR. LANTZ: To try and move on, so action matrix inputs are the green, white, yellow and red that come from both sides of this graph. They go down into the action matrix, and ultimately what that does is tells us what we should do different than what we normally do in our baseline inspection process and our normal level of oversight, management oversight at the particular facility.

So just briefly to try and catch up on time because I see we're running a little bit, there's five columns in the Reactor Oversight Process oversight

matrix. To the far left is Column 1, that means all green inputs. Most of the licensees are actually in that column. As you step to the right, that's because you've had findings that are white, yellow, red as you go more severe, and the level of NRC interaction, the amount of inspection just increases as you go to the right, and the level of management oversight, even on routine activities at the site, will go up. The full action matrix has a column that describes all these issues and it's all publicly available as well.

There is a fifth column which is the unacceptable performance column which to my knowledge we've never put a site in yet. That means they cannot operate if they're in that column. There really is not a described action matrix input to put you there, but the assessment that is done through the ROP, if we've got two reds or three reds or something, we may not necessarily say the plant is unsafe to operate. If you look at Column 4, you can get in there, one red finding, two yellow findings, and then there's some various combinations of extensions, bu that's not to say that the plant is unsafe to operate. Column 5 we may determine that is unsafe to operate.

DR. BLEY: Not to bicker, but there are kind of informal things to kind of put you here. There are

cases where there's a serious event and nobody pushes real hard to come back online until everything gets worked out. You're kind of de facto over here until that gets straightened out, although there's never a ruling that says you're out.

MR. LANTZ: I think you could consider that but it's really not the ROP.

DR. BLEY: Okay, fair enough.

MR. LANTZ: That has to do with maybe orders or confirmatory action letters where the licensee makes a commitment that they will not start up until we say we think it's safe for you to do so. Not really in this process.

DR. BALLINGER: But if they do get into that region, Column 5 where you can't operate -- well, you've never had anybody go there so you don't really know how to get somebody out of there.

MR. LANTZ: I sure hope we have good procedures saying how we do that, but I've personally never explored that arena.

DR. BLEY: One last thing along this area, it's not part of the ROP, I guess, but after there's an event and you go and take a quick look at it, are there specific triggers that lead to a special investigative inspection, an augmented inspection and an integrated

inspection?

MR. LANTZ: Absolutely, and Greg Warnick is actually going to talk a little bit about that.

DR. BLEY: Again, I'll be happy to wait.

MR. LANTZ: So just quickly to give you a status of where we are in Region IV with the action matrix, there are 19 operating reactors at 13 sites. When we assess the action matrix at one of the sites, say Palo Verde, for instance, Palo Verde is a three unit site, but if any one of those units fell into an elevated column in the action matrix, the site is considered to be at that. So there are nine sites in Column 1, there's three in Column 2, and there's only one in Column 4 and it's the only one in the nation right now.

So just quickly, Diablo Canyon is one of the sites in Column 2. They had an inspection finding in the emergency preparedness cornerstone which was white, and that was effective in that quarter. River Bend and Comanche Peak both essentially got into that from security cornerstone findings that were greater than green and we don't in a public forum advertise what that level actually is. River Bend also had a white performance indicator and that was in unplanned scrams with complications. Since those are two different cornerstones, that actually did not elevate them into

a higher column in the action matrix.

And then Arkansas Nuclear One, that site is in Column 4. They moved into Column 4 from Column 3 because of these two yellow findings. The first yellow finding moved them to Column 3, and we're going to talk more about those, Brian Tindell and Dave Loveless will be speaking about those two examples very specifically. So that moved them to Column 4 with both the stator drop issue which I'm sure you're all fairly familiar with, and then the identification of flooding barrier deficiencies. Both of those determined to be yellow and we're going to talk extensively about those issues later on. They also had a white PI for in-plant scrams during that period which really did not elevate them in the action matrix.

And then as I said, once you're elevated in the action matrix there are supplemental inspections. One thing to note for this, I said 2,700 hours of baseline inspection, on average, at all the reactor sites. A Column 4 plant will get an additional 3,000 or so hours of inspection activity for that supplemental inspection. Arkansas Nuclear One, because there's two different reactor types -- they have a Babcock Wilcox and a Combustion Engineering site -- we will probably do more than 3,000 hours, and that reserve number of

hours is for the entire NRC. We suppose we might have to do one of these inspections a year, so we will be using probably that full 3,000 more hours.

Any questions for me?

MR. SKILLMAN: Thank you.

MR. LANTZ: Very good. Thank you. And next I think we have John Mateychick.

MR. SKILLMAN: Just for the sake of full disclosure, John and I were running partners at GPU for many years, we were part of the team that got TMI-1 restarted and cleaned up TMI-2, and we had the unusual experience of being at a plant that got sold, first in the country.

John, good to see you again.

MR. MATEYCHICK: I'll start with just a quick overview of our fire protection programs in the region. Out of the 13 sites, six of them are transitioning to NFPA 805 base programs. We'll actually have to inspect seven programs since the Arkansas Nuclear One units are of different designs. All of our older Appendix R sites are transitioning to new programs, and so far four of our licensees have received their license amendments, their programs are approved. The rest are scheduled to be approved by early 2016.

We completed our first NFPA 805 program

inspection last week at Callaway. That plant had 83 fire areas, 28 remain in deterministic analysis, the other 55 were analyzed in the performance-based/risk-based methodology. The table on the slide is out of the safety evaluation report for the unit. It's an easy way to give you some perspective how significant the contribution of fires are to overall plant risk.

DR. STETKAR: That table, John, you said 55 areas were evaluated by NFPA, so you have numbers for those 55. Twenty-eight met deterministic requirements. The risk from those 28 isn't zero, it just wasn't calculated. The core damage frequency from fires being two times ten to the minus five, how does that relate to the real core damage frequency from fires.

MR. MATEYCHICK: I'm not the SRA who was on the inspection, but in their fire PRA summary report they do -- on this slide you'll see the deterministic compliance areas do have a very small risk contribution to the overall plant risk. There's the plant risk for fires in those areas and there's the delta risk between a fully compliant program and a risk-based program.

At Callaway, the main contributor, its highest hitter is the control room, as we would expect.

Then almost three-quarters of the risk comes from the other risk-based areas; there's very little risk from the deterministically compliant areas.

DR. STETKAR: The truth is we don't know. I mean, we might like to think because they're deterministically compliant the risk is really low, but we don't know if we haven't looked.

MR. MATEYCHICK: In deterministic space in the old programs, you assumed all will have burned up but you also assume that all systems and components were in operation and nothing was subject to a random failure. In the fire PRA space you have factors in there for auto service equipment and random failures, so even though they're deterministically compliant, there's still some contribution in the fire PRAs.

DR. STETKAR: I think I see what you're saying. You're saying in their PRAs, even thought they didn't full evaluate those fires, they have some pieces of it showing up.

MR. MATEYCHICK: They still know which systems and components are being used in those fire areas, so they still have factored into their fire PRA. Now, remember, we have a sample size of one because this was our first plant.

DR. STETKAR: I'd be real careful about

generalizing.

MR. MATEYCHICK: So this s just our first experience with this. That's what we found.

On our samples for the inspection we picked four fire areas: the main control room, a ventilation room which was the second highest risk significant fire area, a switchgear room which is in the top ten, an ESF switchgear room, and the reactor trip switchgear room which came out to be a lower safety significance but we know there are issues in the deterministic problems, so we wanted to look at how those were addressed under the new program

DR. STETKAR: John, those first two bullets there, the main control room and control room AC infiltration unit and whatever that is, to me those two numbers look the same despite the apparent precision in those numbers. Do you guys look at the uncertainty in those analyses and have some sense of the confidence that you have in those very precise numbers?

MR. MATEYCHICK: WE did not look into that. That was all handled during the review and approval process, but uncertainty was part of the standards for these programs being developed. The team members really were not involved with that and we weren't inspecting to that.

Our inspection team had five inspectors and a senior reactor analyst, and of course, I also sent out a representative who has been involved in the review and approval of these programs. We spent significant amount of time in preparations trying to get familiar with all the new documentation to understand the new program.

Callaway reported to us that to implement this new standard that has 19 pages of text they generated 32,000 pages of documentation. Having a senior reactor analyst with us was critical since so much of this is risk-informed.

VOICE: I'm unfamiliar with any of this so I'm just watching Stetkar and Bley asking questions, but 32,000 pages of documentation?

MR. MATEYCHICK: Yes. There is a table dealing with circuit analysis of cable routing that has over 6,700 pages

DR. REMPE: Could you say that a little louder? There was something with circuit analysis I couldn't quite hear.

MR. MATEYCHICK: I said there's a table that summarizes some of the circuit analysis work and it has over 6,700 pages.

DR. STETKAR: Did you have anyone from

headquarters on this inspection?

MR. MATEYCHICK: Yes. We had a representative with us to help us through it and an interface with headquarters if we had questions.

Our sample areas. For the control room we focused on the control room evacuation procedure and the analyses that back up that timeline and response to any plant transients. At Callaway this is the only fire area where that would not be detected from the control room, and now what was their remote panel is the only primary control station in the new NFPA 805 terminology.

The other sample fire area, we locked the areas down, we looked at the detailed fire modeling reports, we used the circuit analysis for those areas, also looked at operator actions that have to be done outside of the control room which are now recovery actions of the new programs.

The table below shows you the number of fixed emission source fire scenarios and transient scenarios --

MR. SKILLMAN: John, are you on slide 25?

MR. MATEYCHICK: The bottom table is the summary of the fire modeling that was done under the risk-based approach for these programs for these fire areas. Fixed emission sources and transient

scenarios. We logged these down, compared the results to the physical configurations.

Since this was the first inspection of the program, we also looked at a large sample of the items they were supposed to implement during the transition. This table is referenced in the license condition that they had a time period to implement these items. We selected 42 out of the 74. There were also seven modifications that they take credit for in the new program. We looked at a sample of those modifications.

DR. STETKAR: John, do you have some examples of the modifications that Callaway installed as a result of this?

MR. MATEYCHICK: Yes. They added additional control power fusing to many of their control circuits. They added some additional isolation and transfer switches to isolate the control circuits between the main control room and motor control centers that take local control of valves. There's some cable rerouting. They also took credit in the options for shutting down the plant and incorporating the PRA. The non-safety grade auxiliary feedwater pump they installed for a different purpose, and also now include the station blackout diesels in the program.

DR. STETKAR: I know some plants have made

decisions to install so-called incipient fire detection.

MR. MATEYCHICK: No incipient at this unit.

DR. STETKAR: Okay. Thank you.

MR. MATEYCHICK: Let's go to the challenges we had during our first inspection.

DR. BLEY: Let me just ask you a little different question, John. When you go out to do the inspection, after you've reviewed all their documentation to some extent at least before you go, how do you decide what areas to look at? Did you look at any of the areas that they concluded were not significant and see if you agreed with that?

MR. MATEYCHICK: Yes, as a matter of fact, we did. See the reactor trip switchgear room, that is very low significance compared to the others, but because we're familiar with that area and we know there are alpha and bravo trans circuits through there that aren't deterministic to compliance, we were interested to see how that was resolved to generate such a low number for that area. We picked the main control room and the ventilation room were the top two areas. The ESF switchgear room that was number 9 or 10, we went to that reactor trip switchgear room to understand why that is such low risk significance.

DR. BLEY: Do the residents help you in that process to decide what areas to look at?

MR. MATEYCHICK: No. We did this, we used our past experience reviewing the summary report from the fire PRA which lists the top fire areas and fire scenarios and just our past experience with post-fire safe shutdown.

DR. BLEY: The only reason I brought that up is I would think that being more familiar with some details of the plant that they might have raised some issues that would be helpful. But you didn't do that. That's okay.

MR. MATEYCHICK: No. More familiar with details of the plant but not post-fire safe shutdown analysis.

The challenges we had was working through the new techniques for fire modeling, fire PRA, just the sheer volume and number of documents involved. We did spend a lot of time confirming that the implementation items were completed satisfactorily, and there the SRA was critical since many of these implementation items were changes to methodology in fire PRA. We used different acceptance criteria before the performance-based approach and the old deterministic approach, and also we treat control room evacuation

somewhat differently in plant response compared to the old programs so we had to work through that.

DR. BLEY: Can you elaborate on that a little bit? We've heard that you believe the numbers that the control room was at the top of the heap.

MR. MATEYCHICK: It's always fire significant.

DR. BLEY: Well, but you say use of different acceptance criteria for the control room evacuation. That's what I was curious about.

MR. MATEYCHICK: Appendix R and it's mimicked as a specific set of requirements for alternate shutdown and dedicated shutdown. Appendix R, Section 3(g)(3) and 3(l) basically are control room specific in the older plants where there's only one cable splitting room, you might also have to evacuate for a fire there. There's no distinct requirements in NFPA 805 for a control room evacuation scenario, it's just used the overall performance-based, risk-based.

DR. BLEY: It does mention habitability.

MR. MATEYCHICK: You have to have the ability to have a safe shutdown path for every area in the plant, but there are no special requirements for the control room. They did the fire modeling a little differently and we're satisfied that they worked their way through

the control room and they addressed all potential issues and had a sound control room evacuation procedure.

One thing we did have an issue with is that these amendment requests in the transition reports that are submitted to get them did use a generic disposition statement for risk-based issues. Each variation for a deterministic requirement has to be resolved and addressed in performance-based analysis and they keep using a statement that essentially says the fire area had problems under deterministic criteria, we applied the risk-informed performance-based criteria and we were successful. The risks, the defense in depth, the safety margins are acceptable. Doesn't give you a clue if it was detailed circuit analysis, fire modeling, fire PRA numbers, use of recovery actions. The trail to the right place in those 30,000-plus pages of documentation is sometimes difficult to follow but we did work through that.

DR. SCHULTZ: John, you mentioned you've got these four bullets here and this is the first inspection, you've got several more to come. Are you concerned that you're going to run into the same four major challenges with the other inspections? And if so, how are you getting the word out as to what you found here? Is there an activity that's transmitting,

communicating the results of this inspection to the other sites that are using the technique with their applications?

MR. MATEYCHICK: Their applications are in. They're in the review process so we're not going to get changes to their documentation here, we'll just be talking to them up front that we're going to need even more extensive support from their side of the inspection to help guide us through here effectually.

DR. SCHULTZ: But using this to indicate these were the problems we found here and when we come to do your inspection perhaps you can help us through in a different way and just highlight these things and prepare yourselves for addressing these issues.

MR. MATEYCHICK: We'll be talking to them well in advance of our inspections. And the fire protection people from all the regions we'll have a seminar once or twice a year and we'll compare our notes and what we've found, what is a worthwhile technique and what is just not effective use of our time.

DR. SCHULTZ: You said twice a year the regions get together?

MR. MATEYCHICK: Once or twice a year.

DR. SCHULTZ: Because Region II has done more inspections. Right?

MR. MATEYCHICK: They've done more inspections, Region III has done a few, I don't recall if Region I has done their first yet. We actually had a meeting up in Region III last fall, I believe it was, where we had headquarters and Region II people talking to what to look at and how things are structured. These programs may look a little different from site to site depending on the contractors that are used to develop the program, the documents may be structured a little differently, but all the basic concepts we expect to see at each site.

MR. SKILLMAN: John, let me ask you this. You've been doing fire inspections for a long, long time. This is not an area that I'm particularly familiar with so I may be more objective because I don't have any skin in the game, but it sounds to me like when a licensee says by golly, we're going to do NFPA 805, they've just signed up for a bag of worms. And I'm wondering has the level of safety really increased, or is this just a humongous smokescreen that doesn't really give a significant increase in nuclear safety? It's a loaded question.

MR. MATEYCHICK: Go back to that room we picked that was of low safety significance but we know it didn't meet deterministic requirements, there's

alpha train circuits in there which we had assumed were burned up under the old bow ramp. Looking at the detail work that was done under the new program, it confirmed that there is no fire int that room which would damage that stack of cable trays. All that equipment is available to the operators in the control room, they can shut down the plant using the alpha train from the control room. So it confirmed that area is actually safer than we would have given it credit to be under deterministic rules.

DR. CORRADINI: Can I ask this question differently? Again, since I don't follow this. I wouldn't use the word smokescreen but is there a story that's told here that you as an inspector or your colleagues are doing that makes it more understandable? Because I'm still back at 32,000 pages. I'm concerned that I can't understand what I'm getting which makes the inspection all that more complex or problematic.

MR. MATEYCHICK: Under the old program we talked about having one train of equipment necessary to get the hot shut down free from fire damage. Under the new program we are looking at having one success path of equipment available to get the plant into a safe and stable condition. We're still looking at the plant systems, we're still looking at the components, we're

looking at the cabling that supports them, the power supplies, so we're getting to the same bottom line: for each and every fire area is there a set of equipment that will keep the plant in a safe condition. So we focus on that in each fire area, and all of the rest of this is supporting documentation.

DR. CORRADINI: I didn't hear that.

MR. MATEYCHICK: All the rest of these analyses are supporting documentation that document that.

DR. CORRADINI: So to go back to Steve's question, so given these four things, given the conversations between the regions, do you feel that the next set of inspections are going to go easier for your, that they know what you're looking for, or is it going to be just the same thing all over again? That's what I thought Steve was kind of worried about.

MR. MATEYCHICK: We know that we're going to have to talk to the other licensees and line up that additional support pretty much on an inspector with a counterpart kind of basis in order to work through all this because now we have the traditional fire protection people, operations people, electrical people, fire PRA people, the fire modeling person, there's must more people to interface with, more documentation to work

your way through.

And an extra complicating factor for Callaway was the only one of our licensees who performed their modifications at risk before their license amendment requests were approved. All the rest of our licensees are not going to have all of their modifications done during their first triennial under the new program. So we'll have the extra complication of saying: Okay, you have all these variations for deterministic requirements, these modifications were going correct, they're not finished, these are outstanding, so what was your review and results of reviewing those for establishing compensatory measures to have acceptable safety until the modifications are done? So there's an extra complication.

Last slide is what we found that was good. We spent a significant amount of time looking at the fire modeling, we were pleased that they were still in what we believe is a very conservative manner, so if anything, the number of circuits impacted by any given fire is going to be a little overstated than reality would dictate.

The fire response procedures the operators use, they have a separate attachment in that procedure for each and every fire area, and we're very pleased with

the amount of information and the structure of it. It tells them what trains of which systems are available to conduct the shutdown, it tells them what their reliable instrumentation is, their specific actions to take in response to the fire for the reactor operator in the control room and the safe shutdown operator out in the plant to perform recovery actions. Operations people are very pleased with the final product they have to work with in case a fire does occur.

DR. BLEY: Can I ask you a question about that, John? I'm familiar with a number of fire procedures in plants that have been there a long time, but I'm hearing about some that are now in some sense integrated with EEOP so even if you're in an EEOP, when you're called off to the fire that the fire response procedures pick up all the things that are in the EEOP so you're only in one procedure. Are these written that way or is this more the kind I've seen in the past?

MR. MATEYCHICK: No. That was not generally what we found. The control room evacuation is so much outside the box of a normal shutdown that they have unique complete stand-alone procedures.

DR. BLEY: Okay. For that condition.

MR. MATEYCHICK: For that condition. All the rest you use your normal post-trip plant procedures,

EEOPs in parallel with a fire response procedure.

DR. BLEY: Okay. Thanks.

DR. SCHULTZ: John, with regard to the first bullet there, have we got covered -- when you make conservative assumptions and analyses, you run the risk of masking the right decisions that should be made when you're comparing one potential course of action versus another. You make conservative assumptions here, you make other conservative assumptions there, and you get the wrong answer compared to if you did a best estimate analysis in both places. Is there a concern that that's happening?

MR. MATEYCHICK: No, because this was all done on a fire area basis. It's what's in that fire area that could potentially be damaged, so saying that one or two in additional balance might spuriously operate doesn't impact the risk numbers in other parts of the plant, it doesn't divert resources. Like I said, 83 fire areas, this is all done in the individual fire area, each one has to have a safe shutdown capability.

DR. SCHULTZ: If I'm trying to decide where should I put resources to improve the plant's capability to respond to fire, I might come up with the wrong choice of area.

MR. MATEYCHICK: They have to respond in all

areas, so all this does is perhaps slightly change the fire PRA results, but it doesn't take away resources. Like I said, every fire area has its response procedure, every fire area has a fire brigade preplan, a fire strategy for fighting the fires in that area.

And the last bullet was, in fact, the control room evacuation procedure, they do have much more guidance, not only for the actual evacuation but what to monitor in the control room where it starts, to look for spurious actuations and problems they have to respond to. It gives them more guidance on when to make the decision to evacuate.

And that's it. Questions?

MR. SKILLMAN: John, thank you very much.

Colleagues, any questions for John?

(No response.)

MR. SKILLMAN: John, thank you.

All right. Next up Brian and David, please, ANO yellow findings.

MR. TINDELL: Good morning, everybody. My name is Brian Tindell. I'm the senior resident inspector at Arkansas Nuclear One. This is David Loveless. He's one of our senior reactor analysts here in Region IV, and he had primary responsibility for the significance determination for these two findings we're

about to discuss.

Before I start, I want to talk about ANO overall. First of all, ANO is safe to operate, in part due to their strong operator performance during the stator drop event. They've also, in general, had good equipment reliability. These performance deficiencies, however, are of substantial safety significance, so those bring some challenges, of course. One of the challenges is that there's performance issues that allow these substantial significance issues to occur, and the NRC in some cases has had to drive those actions to ensure the licensee is addressing those performance issues.

DR. REMPE: Brian, I probably should have asked Ryan earlier, but educate me on what happens when you have all these additional hours of inspection. Is that something where you charge it back to the licensee as part of the fine, or how does the financial modeling work on that?

MR. TINDELL: Well, in the Reactor Oversight Process we have the option of doing a fine, that's typically not done. That was not done in these two cases. All the additional inspection that will be done will be directly billable to the licensee.

All right. Let's talk about the stator drop

event. On March 31, 2013, ANO Unit 1 was in a refueling outage and was replacing their main generator stator due to it being at its end of life. They had contracted out that project, as well as the contractor had subcontracted to an experienced and well known heavy lift expert to move the stator. So the main generator stator was one million pounds, and the way that they were going to move this out of the turbine building is they designed a system with two rails and a trolley. They were going to pick it up, trolley it over to what we call the train bay -- this is the train bay here -- put it onto a vehicle down here in the train bay and move it out of the turbine building.

DR. BLEY: This is the old stator going out?

MR. TINDELL: That's correct.

This is a picture of that day, March 31. This s while they were picking the stator up and trolleying it out, and of course, they lifted it slowly, did not see any issues with the crane during the initial lift, and began to trolley it. And this is the configuration that the crane actually failed in, so as you can imagine, the majority of the static vertical load was on the tripods over here during the initial lift, and as they trolleyed the load over, the vertical load transferred to these columns here.

So when the engineer designed this custom rig, he treated these columns individually for column buckling and these columns individually for column buckling, but failed to look at the column buckling for the entire height of this column. And so this column actually failed from static column buckling load, and when that happened the stator fell, impacted the turbine building deck here, and then rolled down into the train bay.

This is a picture after the event. You can see the massive floor deformation from the stator impacting the floor here. The crane actually fell over too and caused substantial damage to both units as well. This resulted in an loss of offsite power to Unit 1. The operators immediately restored shutdown cooling to that unit because it was in a refueling outage after the emergency diesels powered the safety buses back up.

DR. RICCARDELLA: Brian, could you point out where the control rooms are?

MR. TINDELL: This is the entrance to the control rooms here. This is what they call an extension. This is not the safety related portion of the control rooms but this is the normal entrance and exit to the control rooms so the operators had to use an alternate entrance and exit during the event.

VOICE: What caused the loss of offsite power?

MR. TINDELL: We'll get to this here, I've got a slide next. But this floor is over the non-vital switchgear and when that floor deformed it actually crushed the non-vital switchgear which is their normal offsite power source to the safety buses.

Unit 2 was operating at the time, they had a reactor trip, and there was a crushed fire main in the train bay that actually sprayed equipment and caused a fault in their non-vital switchgear, again, non-safety related, but that resulted in a loss of one offsite power source and also a loss of instrument air which complicated that trip.

So this is the Unit 1 non-vital, again, non-safety related switchgear. It was underneath the floor so the stator drop impacted above and it deformed that floor about three feet and it came down so much that it crushed the cubicles for the non-vital switchgear and resulted in a fault so they completely lost offsite power and non-vital power.

VOICE: No fires.

MR. TINDELL: There was no fire. There was an electrical fault on Unit 2 due to water intrusion.

So Unit 1 was actually at a loss of offsite

power status for six days. The emergency diesels powered up and there was no safety equipment damage, but an extended loss of offsite power like that can be risk significant, as we'll talk about in a second.

Again, the immediate corrective actions were to restore shutdown cooling once these safety buses were powered up by the emergency diesels, and after six days the licensee constructed a temporary switchgear out in the yard which allowed them to re-power the vital buses.

VOICE: Did they lose all instrument air or just one train?

MR. TINDELL: Instrument air is a single train system, they lost all instrument air. It's a non-safety related system but it can complicate the reactor trip due to a lot of valves being air operated.

As far as the long term restoration from the event, Unit 2 repaired the faulted buses and then started back up, and then Unit 1 had a very long restoration. They had to repair the crushed switchgear as well as the major turbine building damage, and then do essentially startup testing of all of that equipment before they could start up.

The performance deficiency was that the licensee failed to follow a procedural requirement which mirrored code requirements that the design of the

crane be adequate for the load and that a load test be performed. Now, the licensee has taken extensive corrective actions in their heavy load program, but we have had some challenges in that the initial Arkansas Nuclear One root cause only looked at the contractor's activities and what their contribution was to the event and did not find any fault with their own actions.

And it's critical here that the licensee is responsible for licensed activities at the site, so the NRC actually came in and identified this performance deficiency and drove licensee actions to address their own performance issues. Now, subsequent to this when we issued the yellow finding, ANO did initiate a second root cause that has found fault with their own performance and they are addressing that at this time.

DR. RICCARDELLA: Is the design calculation a 10 CFR Appendix B violation?

MR. TINDELL: Well, the heavy load program is a safety related program and the performance deficiency we just talked about was an Appendix B violation, so we determined that although it was not directly related to safety equipment, it affected safety equipment, so it was under the Appendix B program.

DR. RICCARDELLA: And it was Appendix B violation by the contractor? The contractor did that?

MR. TINDELL: Well, as I said before, ANO was responsible for all licensed activities at the site so it was a violation against ANO, not the contractor.

DR. SCHULTZ: But you're saying that ANO did not take responsibility at the outset.

MR. TINDELL: That's correct.

DR. SCHULTZ: How did that impact your finding related to the event?

MR. TINDELL: Well, the NRC had to come in and do the inspection to determine ANO's responsibility, and we did that.

DR. SCHULTZ: But both the NRC and the licensee should have known that it was their responsibility. How did they feel they could shed that responsibility?

MR. TINDELL: Well, there is a little bit of complication. A man actually died during the stator drop and there's some ongoing litigation. There is some sensitivity to pointing fingers at who's at fault, but still we expect the licensee to understand and evaluate and address their performance issues and that was not done here.

DR. STETKAR: Had the licensee -- you mentioned heavy load drop program and I'm somewhat familiar but not very familiar with how one conducts

those analyses in terms of scoping in the things that they need to look at. People look at polar cranes, people look at things that are in safety related areas. Had ANO actively excluded cranes in the turbine building from their heavy load drop analyses? I mean, this was a temporary crane but I'm thinking about the main turbine building crane.

MR. TINDELL: So this performance deficiency here is related to their own procedures. Their own procedures had a requirement to review the design calculation and that a load test be performed in accordance with the calculation, so it was done, it was just done inadequately.

DR. REMPE: Is that limited to just the heavy load activities, or are there other different types of activities where they're supposed to be performing reviews of design calculations for work done at the site, and did this evaluation go beyond the heavy load program?

MR. TINDELL: At this time they're taking a broad look at programs and how they affect equipment. Those types of design reviews, decision-making is a critical piece of what went wrong here. Verification of assumptions, and the licensee has taken a good scrub at those performance issues, and then our inspections

will come in and look at and confirm that they did a good scrub of those as well. Does that answer your question?

DR. REMPE: Yes. I'm just thinking of other examples where if they're procuring something or other things that they need to look at too and review.

MR. TINDELL: Absolutely, and that's why I wanted to bring home the point that although they've fixed the issues with the heavy load program, those calculations, these performance issues may be broader than that and that's why we're going to take a good scrub of those.

DR. RICCARDELLA: I'm chairing an ACRS lessons learned activity on the San Onofre steam generator issue, and one of our concerns is that in that case the licensee failed to enforce an Appendix B QA program on his vendor, and this would seem to be very similar. The person who did that calculation, if this is under Appendix B, there should have been a vendor QA on that.

MR. TINDELL: There were definitely some vendor issues as well, that person that designed it, but as far as the NRC is concerned, we hold the licensee responsible for those actions. I can't say much about this but I will say that we are looking at the contractor's contribution to that.

DR. RICCARDELLA: You know, I think the lessons learned for the NRC is to somehow confirm that the licensee is enforcing Appendix B QA requirements on his vendors.

MR. TINDELL: Yes, sir. That's absolutely something we'll look at in the supplemental inspection. The supplemental inspection does a great job of asking those questions that are maybe one or two levels deeper than what we typically look at in an inspection to find those kind of contributions to the event.

MR. SKILLMAN: Brian, did the NRC produce an information bulletin or some type of formal communication to the industry that says: Heads up. Here is a case where a man died, the utility was depending on the capability of the contractor -- they probably signed a contract and put all the liability on Bigge, that's what I'd guess -- each licensee has a heavy loads program, each of those programs is an Appendix B program, beware, you own the accountability no matter what happens.

MR. TINDELL: There's actually been several events recently in the industry. I think Crystal River Containment, San Onofre is another example, and this is another example.

MR. SKILLMAN: But I'm asking if the NRC has

turned on the spotlight and said, Hey, we are keen on top of this, here are a couple of examples, and those of you who have licenses beware. I'm asking if there's been a formal communication to industry.

MR. TINDELL: I believe there has, I can't remember exactly what it was, though. I'm looking at Ryan; he was my branch chief at the time.

(General laughter.)

MR. SKILLMAN: INPO puts out SOERs, and by golly, if you're at a plant and an SOER comes in, it's resource time, you've got jobs to do, you've got work you've got to get done.

MR. LANTZ: The NRC does have the vendor branch, they look at the activities that our quality vendors do undertake. In the case of San Onofre it's not a strong bite but there was a notice of non-conformance issued to that vendor, Mitsubishi Heavy Industries, for their essentially failures in the design of the generators. I don't know if that's going to occur with Bigge, if that's still processing. Brian mentioned the litigation so there's some complicating factors there as well.

VOICE: But did we put out a risk?

MR. LANTZ: That I do not know.

MR. SKILLMAN: It seems to me that that's the

real question.

MR. VEGEL: Let me check into that to see did we put a regulatory issue or bulletin or generic letter or anything like that. Let me check on that.

MR. SKILLMAN: Tony, thank you.

DR. STETKAR: But the key is not just focus to the drop of that stator, to the broader issue.

MR. SKILLMAN: The broader issue is the licensee owns the accountability for what happens on the licensee's site, period. That's what you're saying. I think we all agree with that. But in this environment, this financial environment, we are well aware that the economic pressures are so great that these utilities will sign a contract to have somebody else do for them, therefore, avoid having to spend their own personnel resources and this is the kind of thing that can happen unless that activity is very carefully engineered and controlled.

Tony, let us know.

DR. RICCARDELLA: But in the case of San Onofre, there's no way the licensee had the technical capability to perform the necessary reviews of that calculation. What he needed to do was ensure that the vendor had the proper quality assurance program in place, and he didn't do that.

MR. SKILLMAN: In this particular case it's a heavy load program that is, in my view, very well understood throughout the industry, and Bigge has done this work at other sites so this is not new.

DR. RICCARDELLA: But under Appendix B that buckling calculation should have been subject to an independent review by a third party, and I would think that somebody would admit that the independent review wouldn't have missed that.

DR. BALLINGER: Either that, or they just didn't consider the double height. In other words, the buckling calculation was done on one set, and so nobody realized or missed or something.

VOICE: The question is were the proper reviews done, was it done within the organization that did the work, was it done as an oversight. Most licensees will do oversight work on the vendor programs in spite of the fact that they may or may not have that regulatory responsibility. In addition, though, there is an extent of condition issue here that needs to be examined as well.

MR. TINDELL: The only other thing I didn't mention. You did mention INPO. INPO did put out an SOER for the industry to look at oversight of projects and contractors like that, and it did take those three

examples I talked about into account. The NRC has had a lot of visibility on that too. I know that Mark was actually talking to the Commission today about that very issue. We'll get the exacts about what we issued, though.

MR. SKILLMAN: Thank you, Brian. I would ask, you started a little late, if you can move ahead and maybe finish not too many minute past noontime, that would be very good for us. Thank you.

MR. LOVELESS: Good morning. I'm David Loveless.

At the time of the stator drop, the units were in different configurations and they were differently impacted by the event, therefore, the risk we had was calculated separately for each unit, so I'll go a little bit into each unit.

Unit 1 was shut down with the reactor coolant system open, fuel was in the reactor and the refueling pool was filled for fuel movement. The impact to the stator on the turbine deck crushed non-vital buses causing a complete loss of offsite power. The damage was so extensive that it took months to recover offsite power via normal plant process equipment. Both emergency diesel generators did start and provide power to their respective buses. Approximately six days

after the event, the licensee established power from the offsite power to vital buses using a series of temporary cabling, switchgear and transformers. During the evaluation the licensee calculated that Unit 1 had approximately 4.8 days to core uncovery if there was a postulated station blackout.

Stepping back a little bit over what Brian had talked about, this drawing is of the level just below the turbine deck. The two primary incoming non-vital buses for Unit 2 are A1 and A2. Both received crushing damage that resulted in the complete loss of offsite power to Unit 1. Vibrations caused by the impact on the turbine deck affected relays and the switchgear for Unit 2 and caused a tripped reactor coolant pump which resulted in an automatic reactor trip.

As Brian also discussed, there's an eight-inch fire main that runs right along here that the stator hit as it was falling into the train bay. There's also cabling coming from this switchgear which is the alternate AC power source at the plant for station blackout, and that cabling normally ran across here into Unit 1 and it ripped those cables out of that switchgear.

For the next 45 minutes water continued to pump out of the fire main that had broken. Most of it poured into the train bay, much of it made its way into

the Unit 1 auxiliary building and caused flooding, but also a large amount of water made it onto this deck here, and as we'll discuss later, the incoming power supply to this bus to Alpha 1 faulted from the water and caused an explosion and the failure of that start transformer.

One of the questions you asked was how do we calculate shutdown risk. We have multiple tools for calculating shutdown risk. The simplest we have screening tools and some simplified PRA type models that's in our inspection manual Chapter 0609, Appendix Golf. That appendix handles screening check sheets for both PWRs and BWRs that go through and screen out issues that are not risk significant because of what occurred, and those would all be determined to be green. It also provides event trees that can be used by the SRA to look at rough calculations, order-of-magnitude estimates. In the most cases those are used only to determine that a finding would be of very low safety significance.

Beyond those tools we do have SPAR models which are PRA models that have shutdown capabilities for at least one of each of the large block reactor designs, one for a three-loop Westinghouse, one for a four-loop Westinghouse, one for a BWR-6, that sort of thing. Now, those are unique to a specific unit in the industry, but because shutdown risk is mostly driven by operator

action, those can relatively easily be modeled or modified to look at a specific site that the model was not written for.

DR. STETKAR: You really think that's true?

MR. LOVELESS: Yes. I'm not saying that it's as good as having a unique PRA.

DR. STETKAR: I would really caution you on stretching that assumption too far, because every plant that I've ever looked at -- and I've probably done about eight shutdown risk assessments -- they all have unique problems.

If you only look at mid-loop operation in one particular plant operating state, you might have some insights, but be careful about making those broad assumptions based on one simplified model for a particular plant, especially during shutdown.

DR. BLEY: Just one more aside on that. Plants handle their maintenance activities during shutdown differently, and take out whole hunks of the plant for maintenance, and if you don't do that on a plant specific basis, you can be missing a lot. On the other hand, you can focus on where the problems might be.

DR. STETKAR: Electric power supplies, for example, might not be too bad, but many of the other

subtle things that can and do happen, it's dangerous to extrapolate.

MR. LOVELESS: Absolutely. And don't get me wrong, I don't pull an off-the-shelf model and go push a button and say here's the answer. We do large amounts of work in determining the exact plant configuration.

Brian will attest that I spend large amounts of time asking him to do additional inspections and to make sure we understand the configuration of the plant. Usually at this level we have plant visits where I'll go out and my headquarters counterparts will go out to the site and hand over hand walk down the critical portions that the models help us to determine what they are.

DR. STETKAR: Let me -- for example, the good news at ANO is that neither one of the diesels on Unit 1 were out of service for maintenance; they weren't apart in pieces on the floor, so therefore, you made the observation that both diesels started and that the Unit 1 dominant risk is shown as recovery of offsite power within 72 hours.

Suppose that event had occurred when one of the diesels was apart in pieces in the floor, how would your risk metrics have changed when you pushed that button? You don't have to answer that question.

That's our whole point about looking at plant configuration management. Extrapolating generically can lead you to sometimes excessively conservative results and sometimes optimistic results just because when the event happened the plant happened to be in a good configuration.

MR. LOVELESS: And I think, unfortunately, at times our program does drive us to provide some of that luck in the calculations we do. We looked at potential; the models would show a potential that that equipment was out of service or failed, but in the case where it actually was out of service there would be a detriment provided into the model for that so we would show that in the way we did our risk analysis.

All that aside, in this particular case this was unique enough of a circumstance that we did develop our own model specific to the configuration of this plant, specific to what happened. PRA models don't model large chunks of equipment crushed -- well, that's not -- you know, they model random failure of this component, and so whenever there's large impacts to the plant, we tend to have to make adjustments and/or completely new models for that.

Was there another question?

DR. BALLINGER: We spent the last couple of days in Palo Verde where there was a number of presentations where the emphasis was on using risk methods -- I'm probably not using the right terminology -- to try to make sure that during maintenance they're never above green. Now, did the licensee ever do anything beforehand, before this operation, to sort of make an assessment of if A happens, this is a problem, so therefore we need to make sure that A doesn't happen?

MR. LOVELESS: There is a requirement -- I'll start there -- in (a)(4) of our maintenance rule that requires licensees to look at their maintenance configurations and determine what the added risk is for the configuration therein. Unfortunately, in this case the vast majority of the people and the mindset of those that were doing risk evaluations for the outage at ANO was that this stator couldn't drop, and so there wasn't an analysis of what would happen if we dropped this stator.

DR. BALLINGER: So is there a lesson learned here that gets transmitted out to the rest of the fleet?

MR. LOVELESS: We have talked about that many times and with my counterparts. I can't make any 4-0 statements but I would be surprised if we did not find

those type of risk analyses at other plants in the future.

DR. RICCARDELLA: Also, considering where we've been on this trip earlier, in your opinion if the flex equipment or the flex procedures had been in place here, would it have been helpful in reducing the risk after this event?

DR. BLEY: If you included them in your model, of course.

DR. RICCARDELLA: Well, I mean, if you had the situation like John said where you only had one diesel and had some returns there you'd have had that equipment to maintain power.

MR. LOVELESS: I think for the Unit 1 risk flex would have been a benefit to have because it would have direct lineups into the refueling pool and that was what they were missing.

DR. RICCARDELLA: It's good to know that that $2 billion spent would have actually done some good.

MR. SKILLMAN: I'm going to ask you to pick up the pace, if I may, please.

MR. LOVELESS: Sure. Any other questions?

MR. SKILLMAN: Colleagues, let's let the gentleman proceed.

MR. LOVELESS: Okay. Unit 2 was at 100

percent power, the stator dropped and caused the reactor trip, water from the broken fire main caused an explosion in the supply breaker that resulted in a lockout of the startup transformer 3. One of the two power sources from offsite power was that startup transformer 3, so they lost that. One of the non-vital buses was provided by startup transformer 2, the other non-vital bus was locked out because of limitations of startup transformer 2, and it was provided by its associated emergency diesel generator.

Also, I did note here on the slide that the alternate AC diesel generator for the site had those cables pulled out. Turns out there's questions about whether that source would have been available in Unit 2 or not. The licensee seems to believe it would have been but the mindset of the operators was that there was damage and that they could not use that source.

One point that I wanted to make, the 2 Alpha 2 bus was energized by its associated diesel generator. 2 Alpha 1 bus had the explosion in its supply breaker that locked out startup transformer 3. It was re-energized by an alternate breaker. Now, that breaker was two cubicles away from the breaker that faulted; it was also in the same area that was wetted and had large amounts of water pouring underneath the

switchgear. You were talking about luck --

DR. STETKAR: Did they recluse that breaker pretty soon in the event?

MR. LOVELESS: It was automatic transferred to the other.

DR. STETKAR: That's an element of luck.

MR. LOVELESS: That's what I'm saying. You have the same bus, same water environment, one supply faults, the other one ties in and stays tied in. I can't call it anything but luck.

DR. STETKAR: Or that a high energy arcing fault euphemism didn't damage another cubicle two cubicles away or the basic bus bars.

MR. LOVELESS: And that's a good example of where we were talking about do you believe your models, do you push the button. No model is going to show you that kind of situation, although my analysis did account for that potential loss in that environment.

The agency's SPAR models often can't be used off the shelf for significance determination, and I will say for everyone else, neither can the licensee's models. There's often this argument that the SPAR models are not that good of a model. They're very good models, but we receive lots of situations that the modelers never believed would occur or hadn't thought

that far into it.

In this case the SPAR models don't model offsite power from the switch yard into the plant very well. They're low failure probability equipment and it assumes that if we have a source of offsite power that it's at the vital bus. So we had to do some significant modifications and use several surrogates in the evaluation of the Unit 2 risk. As I show, the dominant risk here, about 90 percent of the risk was the loss of main feedwater with a postulated failure of emergency feedwater and then failure of operators to establish once through cooling.

Any questions on Unit 2?

(No response.)

MR. LOVELESS: We'll move on to the flooding.

MR. KENNEDY: I think the recommendation, where we're at in the timeline now, I guess we'll just offer it up as a choice, do we want to talk about the flooding portion of the ANO discussion or would you like to defer that?

MR. SKILLMAN: I would recommend we move from that portion to page 52, flood licensing basis. And I'm going to suggest you started with a minus fifteen, if you can catch us up at minus ten that would be good. If we can break at ten to a quarter after noon, that would

be beneficial for all of us.

MR. LOVELESS: All right. Arkansas Nuclear One is located on a peninsula in the middle of Lake Dardanelle, it's in the middle of Lake Dardanelles, it's part of the Arkansas River System. It's a regulated river but it's regulated for navigation and some minor flooding, it's not regulated for large floods. During a large flood, flood waters would pass over the navigational dams, resulting in essentially open channel flow.

Here's the site on the peninsula, the main channel of the river is running through here, and one point I'd like to point out is right here is a relatively thin channel, it runs about 6,000 yards to the Dardanelles Dam, and that channel has high cliffs on either side and provides the choke flow that would cause this lake to back up and cause flooding at ANO if there were a major flooding event.

The major limitation in applying a significance determination process to flooding issues at nuclear power plants is the absence of a valid flood hazard. In this graph you'll see right here is the 500-year flood that was calculated by the Army Corps of Engineers prior to plant licensing. The difference in each of these curves is based on a range of end points

that we have from various experts on what the frequency of a probable maximum flood might be.

DR. CORRADINI: What's the exact feet in the horizontal scale?

MR. LOVELESS: This is elevation above mean sea level, feet above mean sea level. Just for reference, the site elevation is about 354, normal river elevation is between 336 and 338.

DR. CORRADINI: So 354 is what, the site elevation?

MR. LOVELESS: The site elevation. That's the elevation of safety related structures.

DR. CORRADINI: All of those are above 354.

MR. LOVELESS: I guess the major message here is that we have 75 years worth of river data on the Arkansas River showing what levels might be and we have a very wide potential range of what a flood hazard might look like when you get out into the more rare events.

DR. CORRADINI: We've been pressing research to give us this kind of probabilistic data and we've been told it's impossible to do that for flooding. What kind of an expert process was used to develop that set of curves?

MR. LOVELESS: These end points characterize the range of what a group of experts determined was the

likelihood of a probable maximum flood, and the probable maximum flood previously defined at ANO was 358 feet.

DR. CORRADINI: So it was an expert elicitation process.

MR. LOVELESS: That's what it was.

DR. RICCARDELLA: Maybe I'm still not there. So the X axis is site elevation above sea level, the Y axis is probability?

MR. LOVELESS: The Y axis is the frequency of exceedence. This is water level for flood elevation and this is frequence of exceedence per year.

DR. CORRADINI: And the lower curve, the one that says extrapolation, what is that?

MR. LOVELESS: If you look here at ten to the minus four, that's the frequency that you will exceed 358 in any given year.

DR. CORRADINI: And then the green, the purple and the blue are just composited into the red? The one with the red squares is a composite of the other three? That's what I'm trying to understand.

MR. LOVELESS: Each of these represents a -- the whole package represents the range that the expert elicitation came out with. We had experts that said this point is at ten to the minus six, we had experts that said this point is at ten to the minus three.

DR. STETKAR: If I could help. I think everybody sets the PMP at 358. Right?

MR. LOVELESS: All of these experts.

DR. STETKAR: Set the PMP flood level at 358.

MR. LOVELESS: 358 is the designed PMP at the Arkansas.

DR. STETKAR: And if I ask Joe, Joe says, well, I think that's going to happen once in a million years, and if I ask Mary, Mary says I think that's going to happen once in ten thousand years.

DR. CORRADINI: So these are four different Y estimates but all the same X estimate.

DR. STETKAR: I believe that's the case.

DR. BALLINGER: But you mentioned the Army Corps of Engineers somewhere in this conversation a little while back. What was their role?

MR. LOVELESS: The Army Corps of Engineers provided that point right there, that's the 500-year flood. That's as far as the Army Corps of Engineers calls credible in flood analysis.

DR. BALLINGER: And so research and regulatory experts that drew the rest of the curves?

MR. LOVELESS: They provided the end points.

DR. CORRADINI: And that lower curve that says extrapolation.

MR. LOVELESS: Well, I haven't got to that. This blue portion here is what the licensee provided us and the licensee did a number of things. The first thing they did was they redefined what their probable maximum flood was for the site. Then they used a number of methods to come up with this curve. The only reason for the extrapolation backwards was to show that the licensee's curve didn't converge with the 500-year flood which was one of the reasons that we questioned their curve initially. I am going to show their curve here in a minute for a different reason.

Do we have any other questions on this?

DR. BALLINGER: So what you're saying is the Corps supplied one number, the licensee chose another number, and that was it.

MR. LOVELESS: That's true. But the main purpose of looking at this is you can ask a whole bunch of experts, ask the licensee, and you get a very wide range of what the flood hazard might look like at that site.

DR. BLEY: And the only thing I still don't understand is the expert elicitation that did those top four curves, whose experts were they? Did you guys do that, did the licensee, who did those?

MR. LOVELESS: It was came out of a

conference that included the USGS and agency personnel, I believe the Corps was there, and it was not specific to ANO, it was specific to a probable maximum flood. The goal was to say, okay, what is the frequency of a probable maximum flood because a probably maximum flood is a deterministically calculated number.

DR. REMPE: But even though the conference was not specific to ANO, it was that site all the experts looked at?

MR. LOVELESS: No. We simply took that site --

DR. STETKAR: David, let me see if I can understand, though. You said that this was a conference that people said what is the probability -- I'll use that term -- of a probable maximum flood. Is that like saying the probability of a Styrofoam cup -- in other words, without telling people a particular site or just saying what would you think the probable maximum flood probability would be? In a generic sense, regardless of the site, regardless of the hydrology, what question were they asked at this conference?

MR. LOVELESS: The probable maximum flood is deterministically calculated but it uses probabilistic information.

DR. STETKAR: But my silly analogy is I can call this thing a Styrofoam cup, but taken out of context it doesn't mean anything unless I say probable maximum flood at a particular location.

DR. BLEY: I'm not sure even the analogy helps, but for me what would help is what question were those guys asked.

DR. STETKAR: Were they asked probable maximum flood on the Arkansas River at the location of the ANO plant?

MR. LOVELESS: No, they were not.

DR. STETKAR: Or were they told there is a probable maximum flood of 358 feet, what's the probability of that without knowing anything else?

MR. LOVELESS: No. They were asked if you use industry standards at any location -- it wasn't even nuclear site -- any location in the U.S. and you use the deterministic methods and the probabilistic type data that you collect to calculate a probable maximum flood, how frequent is that flood.

DR. CORRADINI: So can I try it a different way? You're saying that they basically put a probability number regardless of site or location based on data.

MR. LOVELESS: Given that you have a specific

method, given that you have a specific type of data that you pull in, that that data has a probabilistic nature to it.

DR. STETKAR: But site independent.

MR. LOVELESS: Right.

DR. REMPE: You've been given the 358.

DR. STETKAR: So this would be the uncertainty and the frequency of a probable maximum flood at Palo Verde.

DR. BLEY: Anywhere. If I understand what he's said to us, he said, You guys know or you think you know how the probable maximum flood is calculated. Given that if one has been calculated, what is the frequency of that flood. But it was that general is what it sounds like.

MR. LOVELESS: The fundamental problem is we have 75 years' worth of data and we're trying to extrapolate it out into the 10,000 year, 100,000 year and million year flood, and we can't do it. It's exactly that you're saying. That's what our point is, we can't do it, none of these are valid curves.

DR. STETKAR: But David, this type of comparison now, I'd question why are those top four curves at all relevant to ANO. Why are we looking at this comparison for ANO? I don't understand what went

into the licensee's calculation but why is it relevant to ANO?

MR. LOVELESS: The two things that make this relevant to ANO is that it starts with the 500-year flood.

DR. STETKAR: And that is the Army's estimate for that point on the Arkansas River.

MR. LOVELESS: Correct. And it ends with the probable maximum flood over a range --

DR. STETKAR: From what I've heard, I have absolutely no confidence or understanding on anything to the right-hand side of the Y axis.

MR. LOVELESS: And that's what I was trying to tell you is I don't either.

DR. SCHULTZ: All it does, John, as I see it, there's one point that the Corps of Engineers calculated over on the axis, then there's four points that are on the right-hand side, one is at ten to the minus three, ten to the minus four, ten to the minus five, ten to the minus six, happens to match up with 358.

DR. RICCARDELLA: No. 358 is a solid point from somewhere. Right?

MR. LOVELESS: 358 is a site specific calculated probable maximum flood.

DR. STETKAR: But the experts who estimated

those four numbers weren't given 358, they were just saying if you use generic methods for determining something called a probable flood --

DR. SCHULTZ: And I'm questioning whether this chart is trying to represent expert elicitation at all. All I see is that there's one point there, four points there, ten to the minus two, three, four, five, six, and lining up and compared to what the licensee has calculated, that's all that's doing.

DR. STETKAR: But my point is that the right-hand -- the points in between are irrelevant because I don't think anybody actually calculated. See, I have two points: you have a vertical slice at 358, you have a vertical slice at 340, the Corps calculated a number of 340. Some other people were asked to estimate something about what they thought the frequency of something called a probable maximum flood on a generic basis might be, and this curve is somehow trying to relate that to a number that was calculated by the Corps for that site.

DR. SCHULTZ: Well, I know that's what we heard earlier but I'm not sure that's the case with this curve.

DR. BALLINGER: But the 358 is their design basis, ANO's design basis? Where did the 358 come from?

MR. LOVELESS: It is the probable maximum flood that was calculated for their licensing basis when they were licensed.

DR. BALLINGER: So that's their license. Right?

MR. LOVELESS: Well, they have a slightly higher licensed flood, but that's the probable maximum flood.

DR. BLEY: I think he's going to get to that question in a second, but I have one more about this. Given what we just all think we understand, that we have one point on the left, four points on the right, you sketched in these multi-colored curves just to connect them back to that original point.

MR. LOVELESS: Correct.

DR. CORRADINI: Just so everybody gets it, let me repeat it. So the Corps' number is on the 340 axis, and who computed the 358?

MR. LOVELESS: That was a probable maximum flood came from a combination of the Corps and the USGS.

DR. CORRADINI: So the Corps computed both the 340 and the 358.

MR. LOVELESS: Well, the Corps computed the 340 was at the 500-year flood. The Corps computed that the probable maximum flood was 358. The problem is we

don't know what the frequency of a probable maximum flood is.

DR. RICCARDELLA: And the Corps doesn't assign that.

DR. CORRADINI: But you know precisely how 358 was calculated?

MR. LOVELESS: We know how it was calculated. Correct. Very specific methods that were used to calculate that number.

DR. RICCARDELLA: But the experts who came up with these probabilities also knew how the 358 was calculated.

MR. LOVELESS: Correct. They weren't looking at the 358, they were looking at the process. They said, If you follow this process, what will the probability of the resulting number be for any site?

DR. BLEY: And my last question on this chart -- and I'm sorry that we're dragging this out -- at this conference were there four individuals or did they have like four little subgroups, or are these four points things that came out of some kind of joint process?

MR. LOVELESS: You're beyond my area.

DR. BLEY: Is there a paper or something?

MR. LOVELESS: There were a number of papers

that were written in the area. You can't find a paper that has these four points.

DR. BLEY: Where did you find them?

MR. LOVELESS: Well, we have several papers that showed the ranges of numbers that were given, and this was the range.

DR. REMPE: So I think I sort of understand what you've done here, but the fact that the licensee has a much different curve, could it not be because of specific -- in some cases specific insights related to their site that would make them have more knowledge and maybe we should believe their curve a bit more?

MR. LOVELESS: There are a couple of different things to answer that. I guess the first thing I'll tell you, again, is that they went in and recalculated this 358 and said, Well, we believe this number is really 353-1/2.

DR. BLEY: Based on the same process.

MR. LOVELESS: Well, they used a new process.

DR. BLEY: But that was ANO.

MR. LOVELESS: Yes. We haven't reviewed it or evaluated it and determined that's appropriate, and then they used a very river specific model to show that curve.

DR. BLEY: And when you say they used a new

process, is that a new Corps of Engineers process or some new process that they invented?

MR. LOVELESS: This is a new process that their contractor invented.

DR. STETKAR: And one more thing from me on these curves -- we'll let you get to it eventually -- you show what I'll characterize the blue-orange curve and you said they recalculated, they did something to redefine their probable maximum flood at 353-1/2 or something. Tell me more about the blue curve. Who calculated the blue curve or more than one point? I know how the E to the minus six, at I'll call it 354 -- I don't know how it was calculated but I understand that somebody did that. What's the rest of the blue curve? And this is from their submittal?

MR. LOVELESS: This is a draft of their submittal.

DR. BALLINGER: So is this to re-analyze the flooding hazard? Is that what we're talking about here?

MR. LOVELESS: Yes.

DR. BALLINGER: So that's the Fukushima mandated.

MR. LOVELESS: Right.

DR. BLEY: And they have uncertainty bounds.

MR. LOVELESS: The primary thing I want to show here is most of our parameters in a PRA have error factors in the three to five range, some items we end up with the error factor on the order of a single order of magnitude.

DR. BLEY: So error factor means uncertainty this way.

MR. LOVELESS: It's our uncertainty bounds, yes.

In this case, if we take the point that we're of interest in, we have over five orders of magnitude of data uncertainty. There is no modeling uncertainty in this.

DR. BLEY: Their curve they claim is based on data or is it judgment?

MR. LOVELESS: Well, it's based on their extrapolation of data.

DR. BLEY: Of data, but it's data based.

MR. LOVELESS: Remember, all of this, anything we do in flooding is an extrapolation of whatever the data set we had, and for the Arkansas River at ANO, that data set is 75 years worth of data. And we're trying to extrapolate out it into here they've got a million, 10 million, 100 million years.

Now, for all your digging to try to find out

what this data meant, what it meant to us was that we couldn't come up with a valid flood hazard for ANO. Because of that, a significant enforcement review planning panel, what we call SERP, has determined that we should use our Inspection Manual 0609, Appendix M, which is a qualitative approach to significance determination process. We say that we do not have the tools, we don't have the data, we don't have whatever to use significance determination to give a risk-based answer to the risk of a performance finding.

Appendix M asks us to do two things. First thing it asks us to do is, if we can, develop a qualitative and quantitative upper bound. So we looked at what is the upper bound using the licensees here and 95 percent upper confidence intervals and upper bound, got about 11,000-year return period which is like somewhere around two E minus five per year, and that's at the flood elevation of concern which was anything above 354.

DR. CORRADINI: So return period means?

MR. LOVELESS: It's the inverse of the frequency of exceedence. It's supposed to be for the public to say, okay, how often do we expect to see this type of flood. We expect to see one every 10,000 years, that's return period.

DR. BALLINGER: So you guys really went after it as good as you could. That's what you came up with, that's the best you could do in terms of you couldn't determine it.

MR. LOVELESS: And that was an upper bound. We went and said, okay, this is as high as it can be. Actually, our quantitative upper bound was above ten to the minus four and we used some qualitative factors we knew under the process and estimated that the upper bound was below one times ten to the minus four.

DR. BALLINGER: What I'm trying to get at fill in the blank, Plant X -- everybody is going to have to do this -- are they going to be faced with the same kind of issues that you had here?

MR. LOVELESS: We've done this either ten or eleven times over the last five or six years and we've run into the same issues every time.

DR. BALLINGER: But for different plants.

MR. LOVELESS: For different plants, yes.

DR. BLEY: Although nobody believes those pictures on the previous page, the uncertainty bounds are kind of like what these folks developed from very different starting points.

MR. LOVELESS: Absolutely. We don't believe the curves because they're extrapolations, and

there's uncertainties that are amazingly large.

DR. RICCARDELLA: But looking at that previous slide, your number is more like the mean of that series of curves. Right? You go to 354 and you look at those four curves up above, the number that you were using, like ten to the minus four, it was like the mean of those curves, isn't it? You said two times ten to the minus five, so it's near the bottom curve.

MR. LOVELESS: Well, two times ten to the minus five was the licensee's upper bound. Our upper bound would have been this point here. But we looked at a number of qualitative factors and determined that it was somewhere below this.

DR. BALLINGER: The 500-year flood from the Corps is actually uncertain.

MR. LOVELESS: Correct. A lot less uncertain than this.

DR. BALLINGER: I mean, the point where you started the extrapolation is actually uncertain.

MR. LOVELESS: True, true.

So after you have an upper bound and decide it can't go any higher than this, our Appendix M process has us look at the defense in depth that's remaining after the performance deficiency. So if we had this flood we looked at what would fail at ANO. Well, here

we go: emergency feedwater, high pressure injections, spent fuel pool cooling, diesel fuel oil, decay heap removal. Essentially we failed all feedwater to the steam generators and all makeup to the reactor.

DR. BLEY: And what level was this at?

MR. LOVELESS: This is just above 354.

DR. BLEY: So even regardless of where they calculated their PMP or all this other stuff, for what they calculated, they aren't protected.

MR. LOVELESS: Right. They are protected to their design. That's the problem we started with. They're supposed to be protected to 361 and we found that they couldn't protect the plant to flood something just above 354.

DR. BLEY: But this is based on this re-analyzed flood pageant.

DR. BALLINGER: The original was 358.

MR. LOVELESS: The flood hazard and all has to do with the frequency of the flood. I'm saying if there's a flood to 354, we would lose all of that. If you go back through the pictures that we skipped through, there were holes that the aux building was a sieve.

DR. BLEY: Ron's question wasn't about probabilities or anything, this doesn't have anything

to do with recalculated. The original probable maximum flood, the requirement was 361.

MR. LOVELESS: Correct.

DR. BLEY: That's something above their original PMP. The design basis for plants in this region was the PMP plus a flood-induced failure of the upstream dam.

DR. BALLINGER: So you're saying that the original design basis was wrong. They calculated a number. Their building wasn't built to survive what they said it was designed for.

MR. LOVELESS: No. We're saying that they had -- we skipped over --

VOICE: We skipped over the very first part of this, so what we found was performance deficiencies, we found inadequate flooding seals, so that's what got us into a performance deficiency.

MR. ALEXANDER: If I could. I'm Ryan Alexander and I was on the inspection team. The performance deficiency was revealed during the stator drop and the flood on the fire water went to the aux building and showed up places that it shouldn't have been which got us looking at their flood protection measures.

DR. RICCARDELLA: But if they had all those

sealed and everything proper they would have been able to survive to 361.

MR. LOVELESS: Right. They should have been able to survive a 361 foot flood, and they are today.

DR. RICCARDELLA: They've fixed all that stuff.

MR. LOVELESS: Right. Licensing came in during a regulatory conference and discussed a number of things that they thought should reduce the risk. They said that they would have time; if a flood was imminent, they would know it and they would be able to prepare the plant for that flood. They showed a number of methods, including inflatable water berms, sandbags and sheet metal on doors to raise the elevation that the site could take about two feet which any increase in a flood decreases risk.

They also came in and their service water system is above the flood grade of concern and they indicated that they would be able to provide water to the steam generators through their service water system. They had portable pumps from their B5B equipment; they indicated pathways that they could get water to the steam generators using that. They also showed a method that they could go into containment and use the safety injection tanks to make up to the reactor.

DR. RICCARDELLA: None of those deficiencies you found in the inspections, just skimming through them, appear to have been due to the stator drop, they were preexisting.

MR. LOVELESS: Correct. The only reason the stator drop is tied to the flooding is it revealed that they had a problem with flooding. Water into the train bay that should have stayed in the train bay or gone out the door went into the auxiliary building, and it was a lot of water that went into the auxiliary building.

In an after conference inspection, Brian and his team found that a number of the methods that the licensee said that they would have would not have worked during the specific timelines of a flood, they wouldn't have been able to get water into the steam generators, and/or called into question how well those would be, and so they got very little credit for that. In the final analysis we determined that it was a high safety significance, or yellow.

DR. SCHULTZ: So you said they got very little credit for it. I think they ought to be penalized if they come forward and say: Well, we could have done these things. And then you look and find that they couldn't have done those things. I'm sure further discussions were held as a result.

DR. BLEY: Is there any reason to believe all the deficiencies you found are unique to one plant? Are we nosing around anywhere else? I mean, we haven't looked for this for a long time.

MR. LOVELESS: Well, like I said, this is either the tenth or eleventh flood issue that we've had, the first one being one I worked on which was Fort Calhoun back in 2011 which was before the Fukushima. All the rest of them were discovered as part of the walk-downs and/or the agency's review of the walk-downs. So at ANO, one of the biggest concerns was that their initial walk-downs did not find a lot of these problems.

DR. SCHULTZ: So this is in the process of gradually getting corrected is what you're saying.

MR. LOVELESS: Yes, for the industry.

DR. BLEY: So what elevation did they design their flex equipment to?

MR. LOVELESS: I don't have the answer to that.

MR. SKILLMAN: Colleagues, we really have run out of time. Any other final questions before we break?

(No response.)

MR. SKILLMAN: I'm going to take a 35-minute

break. Let's come back at five minutes after 1:00 on that clock.

(A recess was taken.)

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

MR. SKILLMAN: We are now back in session, and I welcome Greg.

Greg, go ahead.

MR. WARNICK: Good afternoon. My name is Greg Warnick. I'm a branch chief, Branch C here in the region. I'm responsible for some of the boiling water reactors in the region and today we're going to talk about the River Bend Station, GEBWR6, where we've had a couple of events over the last several months that had us do special inspections.

There were some questions earlier about the NRC's incident investigation program that Ryan talked to, as well as some questions about our performance indicators and what additional inspections could we do. This is an exact example actually referring to River Bend Station that you were asking about earlier. River Bend Station had a reactor trip in December of last year. That was actually the additional input for a complicated reactor trip that put them into the white band for the performance indicator that is one of the reasons why they're in Column 2 of the action matrix.

Well, in addition to the input from the performance indicator, we also apply our reactive inspection program to see if there's more information we need to go out and look at to evaluate performance,

to see what lessons learned, what the licensee needs to be addressing. So we're going to talk about those things today.

So our NRC Incident Investigation Program is defined or outlined in Management Directive 8.3. Management Directive 8.3 is the agency policy for ensuring that significant events that involve reactor and materials facilities are investigated in a timely, objective, systematic and technically sound manner. And like I was just talking about, for a reactor trip to happen, complicated reactor trip, there could be some things that happened during that trip that we need to go out and investigate in a little more timely fashion to understand better such that performance issues can be addressed in a more timely manner.

The objectives of the management directive are here. I'm going to focus on the third bullet there to kind of drive the point to illustrate why we did the inspections at River Bend Station, and specifically it helps the NRC increase the efficiency and effectiveness of our regulatory programs and licensee operations by the prompt dissemination of the facts, conditions, circumstances and causes of significant events and the identification of appropriate followup actions.

The management directive talks about three

different types of inspections, and they were asked about earlier. Our lowest level of reactive inspections is a special inspection, next is the augmented inspection, and finally for those higher significance events we have incident investigations.

The NRC's guidance that we have is our NRC Inspection Manual Chapter 0309. That's the guidance to the regional staff for implementing those requirements prescribed in the management directive. In this Inspection Manual it provides the deterministic criteria and risk assessments process for evaluating these types of events to make a decision as to what level of reactive inspection should be performed, and that was specifically asked earlier.

So there's a series of deterministic criteria. When something like this happens, a reactor trip, a plant event, an operational occurrence that occurs, failure of safety equipment, we first look at the deterministic criteria. If any of the deterministic criterion are met, then we evaluate further for risk insights. We do that looking at conditional core damage probability and conditional large early release fraction. And depending on the results of that additional risk evaluation, that will determine the level of inspection performed.

Any questions on that? I know there was kind of a question about that earlier.

(No response.)

MR. WARNICK: Okay. I'll continue on. So I've kind of presented to you the programs that the agency has, our policy and the implementing guidance, and I'll show you a couple of examples here for how we applied that guidance, talk through the events of what happened so you can see how the guidance applied, and why the objectives of the guidance and policy were met through our ability to do these types of inspections above just the normal baseline and performance indicator input to our Reactor Oversight Process.

First event is one I talked about earlier, it's the one Ryan talked about, the reactor trip that put River Bend Station over the threshold for their performance indicator, and it just so happened it occurred on Christmas Day. So December 25 of last year at 8:37 in the morning, River Bend Station scram'd from 85 percent power following a trip of reactor protection system motor generator set. At the time of the motor generator set trip, there was a half scram that existed on the other division due to an unrelated equipment problem. The combination of the motor generator set trip and the half scram that was already into the reactor

protection system made up the logic for our reactor trip.

As expected, the licensee notified the resident inspector. Our senior resident inspector promptly concluded his celebration activities with his young family and responded to the site. As he got there, he did what he would normally do, and that's to assess what happened, to look at plant conditions, make sure they were in a safe condition, and they were at this time, and talk to operators to kind of get some feedback as to why this was complicated and how did it happen.

As he did that, he learned, and it was revealed through the event, that the following equipment issues occurred following the initial scram. Specifically, an unexpected high reactor water level signal was received which resulted in the tripping of other reactor feedwater pumps. This is a logic associated with that. Following the reset of the high reactor water level signal, plant operators had difficulties recovering feedwater, specifically the pumps wouldn't restart when they tried to -- these are powered by MagneBlast GE breakers -- as well as the valves they were trying to operate to restore feed once they could get a pump started, started feed rate valves wouldn't respond as expected and they had difficulty

getting feedwater regulating valves open, such that they couldn't restore feedwater as promptly as they're trained to do, and as a result, level was trending down towards the low level set point, and it was complicated further by in fact receiving a low level water trip, or a Level 3 signal.

As they were approaching that level set point, they were successful, as I said, getting a pump started, getting the feedwater regulating valve open, they were starting to recover level, went below that low level set point, recover level, and restored it to the normal band.

DR. STETKAR: They never got down to Level 2?

MR. WARNICK: No.

Following the restoration of the reactor vessel water level, the plant was stabilized in shutdown condition. That's the point where our resident inspector arrived onsite. After addressing the identified equipment issues, plant startup was conducted a couple of days later by the licensee, and I point this out only because during power ascension following the startup, another feedwater pump failed to start when it was demanded. As we talked, that was a problem that happened actually during the response to this event. So there were breaker issues going on that

the licensee didn't fully understand.

MR. SKILLMAN: So it was known at that time that it was circuit breaker problems?

MR. WARNICK: It was known at the time that these GE MagneBlast breakers didn't always work when demanded, and they had actually a workaround in place to where the operator, if it failed to start, they'd go down, re-rack, rack out and re-rack in the breaker, and typically that would be enough to get it to start, and in fact, that's partially what they did in these situations to get the pumps going.

DR. SCHULTZ: Greg, were any of the complicating features following the trip connected with the half trip that had been set?

MR. WARNICK: No. That set up the conditions for the reactor scram, and again, the half trip that was in was due to another unrelated problem that was not associated with the complications.

DR. SCHULTZ: Okay. Thank you.

MR. WARNICK: So this was a significant in our mind, it was a complicated trip for the reasons kind of that I talked about related to the multiple failures of the feedwater system. As far as the pumps go, the breaker issues that we knew they had problems with. In this situation it complicated an initiating event

further.

Let's see, issues related to the licensee's operations department, their inability to control level like they're trained to in the bands between a Level 3 and a Level 8. We looked at the deterministic criteria. We satisfied deterministic criteria so we looked at it from a risk standpoint, and with the things that went on, we made the conclusion -- and you can see here that the conditional core damage probability was determined to be 1.2 times E to the minus 6, which falls into the overlap region between no inspection and a special inspection. That gives the NRC the ability to look at that, evaluate, and with management input make a decision is a special inspection appropriate. And for the reasons I listed here, we determined it was appropriate and we did do a special inspection.

DR. BLEY: Your third bullet sounds as if there was a problem with operators. Was it, or was it a hardware problem, or had you decided at that point?

MR. WARNICK: We hadn't decided at that point. We knew there were breaker problems, they didn't get the valves working the way they expected them to. We didn't fully understand that, which added to our interest in wanting to understand it better and our decision-making to do a special inspection. So as we

did that special inspection, we looked into the performance of the operators, how did it contribute to this. That inspection is actually ongoing, so the information is pre-decisional, can't really talk about the results but we are certainly considering those things to determine if there were, in fact, performance deficiencies?

DR. BLEY: Is there a preliminary report out yet?

MR. WARNICK: No. We're actually exiting with the licensee later today, so a report on this special inspection is expected to be out within the next couple of weeks.

DR. STETKAR: Are these circuit breakers uniquely associated with the feedwater pumps?

MR. WARNICK: I'm relatively new to the branch. I'm looking around to see if anybody has experience at River Bend Station. Are the GE MagneBlast breakers just with the feedwater pumps?

DR. STETKAR: I don't know what voltage it is, so I'll just say 6kv, might be 4kv, might 13. Did you look at if it's a hardware problem and they're used for power transfers at those buses in your evaluation? Have you pulled those strings?

MR. WARNICK: We did. That was all part of

the charter for the special inspection to look into those types of things: maintenance practices, review, operating experience over time, have they been incorporating operating experience to address/identify generic issues. We did have some issues of concern associated with that, but again, the conclusions that we drew are pre-decisional so I can't really offer up our conclusions at this point. But certainly those were the types of things that we looked at. As this was an input to our decision to do the special inspection, we wanted to understand it.

DR. STETKAR: My only question was that 1.2 times E to the minus six, did you only look at feedwater related issues or did you look at all issues that could be affected by breakers that might have the similar problem?

MR. LOVELESS: This is David Loveless. At the time we didn't know the extent of condition and that number only included the feedwater issue.

DR. SCHULTZ: Greg, the decision basis looks very strong with these four bullet points. If you had three of them would you have gone forward with a special inspection, two of them? Can you give an appreciation for what the tipping point was in the discussions that led to the special inspection?

MR. WARNICK: Certainly. There's deterministic criteria, there's a list of about ten questions that are asked, and you only need to satisfy one of those questions, answer yes to one of them to meet the deterministic criteria to do the risk analysis that David referred to which gives you the number, put us in the overlap region so now we're considering do we do no special inspection or do we do one. Us not fully understanding the extent of condition of the GE MagneBlast breakers, where else it may apply, the practice they had by racking out and racking in these breakers, that caused us to have concern. We wanted to understand that better, is that really a practice they should be doing or should they identify why these things aren't working, fix the problem such that they don't have to take this operator workaround action.

DR. SCHULTZ: So would you say if that one bullet alone was there you likely would have done the special inspection?

MR. WARNICK: Yes. We met the risk insight, we had enough concern that we didn't understand. It's hard to say what management would have decided, but I, as a branch chief, would have made the case to my manager that we need to get onsite to meet the objectives of Management Directive 8.3, that I pointed out, to get a

prompt understanding of the facts, found out where we can learn more as far as generic guidance and where the licensee needs to improve in these equipment and performance issues.

DR. SCHULTZ: That's fine. That gives me an appreciation for it. Thank you.

DR. BLEY: Greg, just to follow up where you started, you told us the general place you go to get the criteria for whether you do an SIT or an AIT, I know of a few cases where they went in with a special inspection and part way through they said, No, we need an augmented inspection. Instead of just the general you've got to meet some rules, can you give us a hint of what the dividing line is in terms of significance or the need for additional expertise or something that triggers jumping to the higher level inspection?

MR. WARNICK: Well, typically the first -- well, not typically but always one of the first items in a charter for any level of inspection -- in this case a special inspection -- is during the first day for the team to get there, assess the facts, talk to people, make sure we have a good understanding of the basis for our decision to do a special inspection. If we identify any information that we didn't fully understand, could be more significant, we immediately get with our SAR,

reconsider that, redo the calculation and determine if there's a need for a higher level of inspection. And actually, that's a required call at the end of the first day onsite back to the branch chief to give me the information as to that decision.

Now, the continue to look through that as they investigate. I told you this inspection is still ongoing. So it's a continuous effort that we do, we continue to look for things that we maybe didn't fully understand to see if there's a need to upgrade to provide the level of oversight appropriate for the significance of the event.

DR. BLEY: One thing I think is really important you said, you try to get there on the first day.

MR. WARNICK: Well, the first day of the onsite inspection. That may be two to three weeks after the actual event occurred.

MR. KENNEDY: Could be that day, could be in a week. A lot depends on what happened and what the licensee is doing and when is the right time for us to be onsite.

DR. BLEY: The thing I was thinking of, with the hardware you can reconstruct later. For people, even people trying to be very honest, the more time that

passes, the more we reinterpret, we build a rationalization even if we don't know we're doing it, so you get a different story as time moves on, not that people are dishonest, it's just what happens.

MR. KENNEDY: And that would be a factor, how quickly do we need to get out there to conduct interviews with the plant employees or those involved, that definitely is a factor. And don't forget, we have a resident inspector onsite, and so they are there responding to the complicated trip, they are beginning the inspection. This is just determining how many more resources we apply to inspecting this event.

MR. WARNICK: And that's an excellent point I just want to reiterate. Resident inspectors are the key to us for keeping us informed as to the timeliness, the lack of understanding that we need to acquire in terms of when we need to be onsite to conduct this inspection.

MR. SKILLMAN: Let me ask this, Greg. Was the equipment quarantined, and when it was quarantined, was there what I'm going to call a thick magnifying glass inspection of the MagneBlast breaker or breakers?

MR. WARNICK: The equipment, as I told you, they had a number of issues racking out, racking in breakers, they wouldn't start -- and they needed to do

that to get feedback to prevent getting to a Level 2 -- so certainly during the event they were operating equipment to respond to it. Once the plant was stabilized, they collected what data they could, but as I told you, they felt they addressed the issues that were out there, went to a startup just two days later, and on that startup they had another problem with the GE MagneBlast breaker.

So certainly they didn't do the level of investigation that you're alluding to, otherwise, they shouldn't have been in that scenario where they continued to have the same problem again during the startup two days later. That's in part why we went out there and wanted to understand better what the situation was.

MR. SKILLMAN: It seems to me MagneBlast breaker problems are not unique to River Bend. Industry has dealt with these for a long time, and it seemed to me that if there was a second incident of the very same type of hardware, leadership would have said timeout, we may have a common mode failure that we're dealing with her, we had better backtrack and find out what's wrong with this equipment.

This same problem happened at Perry almost at Christmastime and it was failure of the MagneBlast to

recharge. Those were 6900 volt machines but on them is a little 120 volt machine, looks like a little sewing machine, and it actually winds the spring so that when you give the command to close, the springs rack in the knife blades. So here is this big machine that's as big as a small refrigerator but on the back of it is this little teeny 120 volt little driver servo motor that actually winds up the spring that's the recharge. That's a MagneBlast problem.

So if you say it wouldn't close and it wouldn't close again, it almost sounds as though there is an underlying hardware problem that needed to have been diagnosed so they would have a root cause that would make sense. If that wasn't done, it seems like a real opportunity has been lost.

MR. WARNICK: The opportunities are there. We have expectations of corrective action programs that the licensee implements that they identify these things and do the appropriate level of evaluation to understand it and correct it. That's a big piece of what was chartered in the special inspection, to understand where they should have done better, and again, the report that will be coming out will document the conclusions that we had associated with that.

I want to talk about our next event that

occurred, the other special inspection that we did there. This special inspection was associated with an event that occurred on March 9, 2015. While shut down for a planned refueling shutdown and during the testing of the Division 1 safety related equipment, a control building chiller failed to start when required. The chiller shed from the electrical buses as expected but failed to restart and sequence onto the emergency diesel generator as designed. Since the redundant Division 1 chiller was not available, operations personnel tried to start either of the other two Division 2 chillers without success. Both of those Division 2 chillers also failed to start. The station entered their abnormal operating procedure for loss of control building ventilation due to the loss of the system function.

It's interesting to point out that just about a week earlier they were doing the same surveillance testing on the other division, on Division 2, and during that testing they had some similar failures, however, during that testing they were successful in restoring one of the chillers such that they maintained control building ventilation and there was no need to enter the abnormal operating procedure. We took this event, coupled with what had happened just a week earlier, and

felt that we needed to understand it better, such that we went into our process, Inspection Manual Chapter 0309 for the management directive, to look at the deterministic criteria.

One other thing that had us concerned is some of these failures were associated with a problem that River Bend Station was aware of. It's a known problem with NLI Masterpact breakers which are the breakers associated with the chillers and the ventilation system and the air handling units in the ventilation system. Specifically, as experienced at River Bend Station, the Masterpact circuit breaker is vulnerable to an intermittent failure mechanism under certain scenarios. Generally, the control logic is set up such that the breaker experiences briefly a simultaneous open and close signal. This dual open and close signal can create a condition where mechanical binding can impact the breaker's ability to close.

So as this surveillance is trying to find out, you do a load shed of the safety related bus, diesel starts up, comes up to rated speed and voltage, diesel powers up the bus, and this equipment cycles back on. So these Masterpact breakers got an open signal and then they were receiving a closed signal to cycle back on, and they were finding out that these breakers weren't

always cycling back on as expected. And in fact, as I mentioned, this was a known deficiency that they were aware of, felt that the likelihood of the breaker not closing back in was extremely low.

But these events during the surveillance testing revealed to the NRC that, okay, there's a higher likelihood of these not working, especially during a design basis event, that we wanted to understand better. So that was one of the deterministic criterion that was answered associated with the control building ventilation system: generic problems with the breakers causing the system not to work as designed.

Additionally, they had multiple failures of the ventilation system, as evidenced by the surveillance that was done in the February time frame, as well as this March 9 event. And finally, back to the MagneBlast breakers, this special inspection was starting as the previous special inspection was kind of wrapping up what they did, and we kind of rolled into the MagneBlast breaker continuation look. We wanted a better understanding with one of our breaker experts who was put onto this team. So because of that deterministic criteria satisfied, again, we looked at the additional risk insights and determined that the appropriate NRC response was a special inspection.

We did that special inspection, and again, both of those special inspections are ongoing, both of them are wrapping up here within the next week or two, so inspection reports documenting the results of these inspections will be issued within the coming weeks.

Finally, I just wanted to point out as is typical of all the inspections we do -- I heard mentioned earlier that was something I was very involved with -- we like to look at lessons learned, provide feedback where we can, and certainly there have been some things identified by the team where we can feed back to the program offices to see where we can learn better in the future to try and improve the agency response as well as licensee performance to eliminate these kind of significant events.

Thank you very much, and I'll answer any questions.

MR. SKILLMAN: Let me ask a question. On your slide 66 your third bullet you identified: overall adequacy of the licensee's breaker maintenance program was called into question. Did the corrective action program at River Bend point to this emerging deficiency?

MR. WARNICK: The Masterpact breaker?

MR. SKILLMAN: Yes.

MR. WARNICK: No. That bullet was primarily addressing what the first special inspection was finding, issues of concern about the maintenance program for the GE MagneBlast breakers. At this time we thought, okay, maybe there's a problem with the Masterpact breakers also in terms of their maintenance program, so we kind of rolled it in. Again, at the time of the decision-making we wanted to understand it better, and that bullet goes to our wanting to understand better the licensee's maintenance practices. As we've gone through that we've reached conclusions.

Certainly with the Masterpact there's probably available information talking about this design deficiency associated with Masterpact breakers, there's nonconformance reports with NLI, they aren't widely distributed which is one of the contributing issues here, but the information is available such that these opportunities could be there through a healthy corrective action program to identify these problems to avoid them from happening when this equipment is called upon.

MR. SKILLMAN: Greg, I think the members might be interested to read these reports when they're completed, particularly the MagneBlast because they are

used throughout industry at very high power levels, very high voltages. I'm sure other than River Bend every GE Mark 6 uses them; I think that's probably the standard chassis from that supplier. So I think members would like to see those reports.

MR. WARNICK: Absolutely. These are issued throughout but I'm sure we can have somebody arrange to make sure you're aware of when they're issued and get them to you.

MR. SKILLMAN: I would offer perhaps Kent Howard as the person you might send them to.

MR. KENNEDY: We'll make sure those get to you.

MR. SKILLMAN: Thank you, Kriss. And thank you, Greg.

MR. WARNICK: All right. Thank you very much.

MR. WALKER: Good afternoon. My name is Wayne Walker. I'm the chief for Branch A in the Division of Reactor Projects, with responsibility for Diablo Canyon. At this time I'd also like to just recognize Ryan Alexander for the help he was able to give me on preparing this presentation.

The purpose of this presentation today is to provide a brief overview of past and present activities

regarding seismic issues at Diablo Canyon, and I want to focus on the current challenges and then also look at the ongoing seism hazard reevaluations that are associated with the implementation of the Japanese lessons learned near-term task force recommendations, and also touch briefly on license renewal, and then just a current schedule and some challenges that we're currently facing.

I guess prior to you coming here we provided you some background documents so hopefully some of this won't be redundant but we did provide you with the seismic hazard reevaluation documentation and then also what we refer to at the AB or Assembly Bill 1632. That was the bill that required by that State of California to do a reevaluation of seismic hazard at Diablo and other base-loaded plants, specifically SONGS in California.

Diablo Canyon is a pre general design criteria plant. They were initially licensed with a terminology that's not exactly in line with Part 100 of the GDC criteria in Appendix A. The station has two design basis earthquakes plus a third one that's unique to Diablo Canyon. The design basis earthquake is set at .2g of peak ground acceleration. At Diablo Canyon the design earthquake is equivalent to the operating

basis earthquake, and that's probably terminology most people are more familiar with. The double design earthquake at Diablo Canyon is at .4g of peak ground acceleration, and that's equivalent to the safe shutdown earthquake which you read about in the Appendix A of Part 100.

As I discuss the next slide, you'll see Diablo Canyon has a unique earthquake that they're also designed to and they were constructed to this based on seismic information that was developed early in the 1970s. Oil company geologists identified a new fault which later became known as the Hosgri fault. Upon discovery of the fault, the licensee re-analyzed and significantly upgraded the structures, systems and components to accommodate the postulated ground motion values up to .75g from the Hosgri fault, and therefore, the Hosgri earthquake was established as a unique third design criteria for Diablo Canyon.

One other aspect that is unique to Diablo Canyon is the station has actual seismic sensors on the containment base slab, and those sensors at .3g of peak ground acceleration, there's an automatic trip associated with that for Diablo Canyon.

This next slide is somewhat busy, I won't talk about everything, but I thought it would be beneficial

just to kind of give you an overview of Diablo Canyon and what's gone on over the years. In 1968 and 1970 the initial construction permits were issued for the two units. The design earthquake and double design seismic design criteria were based on a consideration of two design basis earthquakes, and those two earthquakes were a magnitude 7.25 earthquake on what was referred to as the Nacimiento fault, which is about 20 miles from the site, and then there was another one that was a magnitude 6.75 aftershock at the site associated with a large earthquake on the San Andreas fault. However, based on the identification of the Hosgri fault, PG&E undertook several years of analysis and plant upgrades to account for the hazard, so once they discovered the Hosgri, they had to do a number of mods.

In 1977, PG&E submitted the Hosgri report to the NRC, and later that same year the Hosgri analysis was accepted by the NRC and was documented in Safety Evaluation Report 34. In 1978, that was a significant year relative to review of the Hosgri report for the NRC. We issued two supplements to the safety evaluation reports. They were supplements to Safety Evaluations Reports 7 and 8, and they documented the evaluation of the Hosgri report.

Some key statements in those SERs were as

follows. In July of 1978, the ACRS letter to the Commission noted that the applicant's analysis and tests related to the Hosgri event have been subjected to an unprecedentedly intensive and comprehensive review by the NRC staff -- and that's just a partial quote -- however, the ACRS also noted that the theory and analysis of earthquakes are in a state of active development. The committee recommends that the seismic design of Diablo Canyon be reevaluated in about ten years, taking into account applicable new information. And that's a key statement there, the reconsideration of applicable new information, and I'll talk a little bit more about that later.

In September of 1979, the Atomic Safety Licensing Board concluded the Diablo Canyon plant will be able to withstand any earthquake that can reasonably be expected to occur on the Hosgri fault. And then in November of 1984, the operating license was issued for Unit 1. In response to the ACRS recommendation in 1978 for PG&E to conduct a seismic reevaluation after approximately ten years, the license contained a license condition requiring that the licensee perform further assessments of the seismic sources and ground motions applicable to the site and beyond those considered in the development of the Hosgri event. So

this kind of tied them into a continuing evaluation process for seismic conditions.

PG&E actions to meet the license condition became the program which is often referred to as LTSP, or long-term seismic monitoring program. In July of 1988, PG&E submitted their long-term seismic program report to the NRC, which included seismic probabilistic risk assessment and a deterministic seismic margin assessment. And then in June of 1991, the NRC reviewed and accepted the results of the long-term seismic program that was documented in the supplement to Safety Evaluation Report 34, and that included a key statement, and the statement was, and I quote, "The staff notes that the seismic qualification basis for Diablo Canyon will continue to be the original design basis, design earthquake, double design earthquake, plus the Hosgri evaluation basis, along with associated analytical methods." So that's kind of the key thing that tied them into actually having three different design basis requirements.

DR. BLEY: Wayne, could I interrupt you for a second?

MR. WALKER: Sure.

DR. BLEY: This is really for the committee if you haven't followed this all the way through. The

stuff we've been seeing in the last year or two about probabilistic seismic assessment is really based on the kind of modeling that was developed during the long-term seismic program. It's pretty interesting stuff to go back and take a look at.

MR. WALKER: It's a long, long time ago they started it all.

DR. BLEY: It doesn't seem that long.

(General laughter.)

DR. RICCARDELLA: And that's basically what all the CEOS plants are going to be doing. They're not going to be updating their original design basis calculations, they're going to be doing this now.

DR. BLEY: But the way to look at those alternative fault mechanisms and the like was really laid out in this study.

MR. WALKER: Next slide, and I'm going to kind of talk about this last part also in this next slide but I'll go to the next slide and go back for you to refer to it. So just now look at a little bit more recent history. Relative to seismic analysis at Diablo Canyon there's what I kind of try to break it down into three key events, and these kind of have intersecting timelines, it's not one right after another necessarily.

But the Shoreline fault zone, in November of 2008 PG&E notified the NRC of a potential line of epicenters about one mile offshore from the plant. This became known as the Shoreline fault zone. By December 2008, using the long-term seismic program methods, PG&E completed a seismic margin assessment which demonstrated that the Shoreline fault was bounded by the Hosgri evaluations. Then in April of 2009, the NRC issued a research information letter, it was Comm RIL 0901, and this was an independent study of potential impacts and it concluded that adequate seismic margin existed for the Shoreline fault.

Then in late 2010, early 2011, PG&E completed and issued their final results of the seismic evaluation for the Shoreline report. This report included deterministic evaluations for the Shoreline and other smaller faults in the area, as well as probabilistic hazard calculations. The licensee concluded that each of the faults was bounded by the existing long-term seismic program.

Then in October of 2012, NRC issued another research information letter, and that was 2012-01, and that documented the staff's review of the Shoreline final report. The cover letter stated that the NRC concluded that the Shoreline fault was considered to be

a lesser included case of the Hosgri event and should be documented as such in the updated final safety analysis report. So even though they discovered the Shoreline fault in '08, they were still bounded by Hosgri.

And this is something we've been dealing with a little more recently in the region. In 2006, the California Assembly Bill, and this was a directed bill by the California Energy Commission to assess potential vulnerability of California's largest base-loaded power plants -- and at the time it was Diablo Canyon and San Onofre -- to a major disruption due to a seismic event or plant aging and to assess the impacts of such a disruption.

In 2008, PG&E initiated a significant assessment and reevaluation of those seismic risks based on this law and they did some significant analysis. Some of the things they did were they did onshore and offshore 2D and 3D seismic reflection studies. They only did low energy offshore.

Originally they were supposed to do high energy and they got redirected on that and they only ended up doing low energy offshore. Onshore they did some geologic and topographic mapping and they did gravity and magnetic surveys, and they also did some

additional installation of seismometers, both ocean bottom and right near the site or onsite. They continued these studies through early 2014.

And then lastly, there's the post Fukushima recommendations. As everyone here knows, in March 2011 the Fukushima event occurred and then the NRC's near-term task force was assembled. Out of that work, a request for information for licensees to reevaluate seismic and flooding hazards at their sites was issued.

And then what PG&E did is they leveraged the analysis they already had underway in that state-mandated evaluation, the Assembly Bill 1632, and they integrated that into the development of their NRC requested seismic reevaluation. So basically, they were pretty far along in doing a seismic reevaluation because of what the state had mandated in 2006.

In late 2011, PG&E committed to use the senior seismic hazard analysis committee process to perform a probabilistic seismic hazard assessment. And that's kind of been an ongoing process they've had going. I think they've had a total of six meetings, they've been public meetings, and they're at the end of that process or very near the end of that. Once they've completed the senior seismic hazard study, they'll update and replace the long-term seismic program with the senior

seismic hazard analysis.

In September of 2014, PG&E submitted this mandated report.

DR. BLEY: I'm sorry. Can I interrupt you on that one?

MR. WALKER: Sure.

DR. BLEY: I'm not completely familiar with this. In the methodology that was developed for the long-term seismic program there were places in there where expert elicitation gave probabilities for certain kinds of events. Are they keeping that same model and just reevaluating the likelihoods within that model, or are they building a whole new model?

MR. WALKER: I'm not sure I can answer that question. I believe they're using some of it, I don't know if they're using all of it or not. Ryan might know.

MR. ALEXANDER: I think the simplest answer to that it's a combination thereof, I think is the best way to describe it.

MR. SKILLMAN: Identify yourself, please.

MR. ALEXANDER: I'm sorry. Ryan Alexander, senior project engineer here in the region.

The best way that we can describe it is it's sort of a combination thereof in terms of what they're using. They're using the process that's derived in the

SSHAC process, that's an acronym that we use.

DR. BLEY: But that's the elicitation process, it's not the underlying model.

MR. ALEXANDER: No, it's not the underlying model. They then use the solicitation of that information in that process to then develop their overall model. What we understand is that that model that they develop from the process will ultimately be integrated into the overall site model and ultimately, if you will, not replace but update.

DR. RICCARDELLA: SSHAC is an expert elicitation process, it's a very structured one.

DR. BLEY: I know exactly what SSHAC is. Thank you very much.

DR. STETKAR: But it's not a geotechnical model, it's an expert elicitation.

MR. SKILLMAN: Go ahead. Let's proceed.

MR. WALKER: In September of 2014, PG&E submitted a statement report that was called the Central Coastal California Seismic Imaging Project report, and they provided that to the State of California as mandated by the law. They also provided a copy to us which was based on a commitment they had made to us when the Shoreline report came out in 2008. Basically, they said if they had new information they'd provide it to

us, so this was some additional new information they provided to us.

This report was compiled using updated data derived in part from the senior seismic hazard studies and it was a study using deterministic scenarios. While much of the information from the previous Shoreline fault report of 2011 was confirmed, some new data suggested, for example, there was a reduce slip rate on the Hosgri fault zone and the Shoreline fault zone which could indicate there is less active faults than previously believed. That was one of their conclusions. They also had a conclusion that postulated connection of the Hosgri and San Simeon faults which could result in a longer, larger but much more infrequent earthquake. There were other conclusions but those are kind of the two main ones I pulled out.

In September through December 2014, Region IV, with the support of headquarters, conducted an inspection of the licensee's operability. So we got the report, as a regulator we had to look at the operability based on that report. We did our own independent review of the report, and basically in three months we issued a report with our findings. As documented in our inspection report, we didn't identify

any issues with the licensee's operability evaluation. And again, we had lead for it in the region but with a lot of help from the seismic experts in headquarters.

Finally, in March of 2015, PG&E provided its seismic reevaluation report to the NRC. And that's the most recent of the Western U.S. plants. They were required to provide a reevaluation by March 11 and we just got that.

So this goes into the seismic reevaluation. As part of PG&E's seismic reevaluation response, the licensee developed a new ground motion response spectra. The ground motion response spectra exceeds the double design earthquake, and that's not unexpected due to the fact that we knew previously there was the Hosgri and that the Hosgri had already exceeded the double design. They identified some slight nuances, they did identify some slight exceedences above low and high frequency ranges versus the Hosgri curve, and those were at about the 1.33 hertz was the low range and 24 hertz was the high range.

Currently the headquarters staff is reviewing this submission, so we're going to look at those exceedences. At this current time, based on the long-term seismic program information, there's not an operability concern but we're looking at long term what

that means to us. Then like I said, no immediate safety concerns were identified.

Diablo Canyon is expected to conduct a seismic PRA and submit that to us by June 30 of 2017. In the case of Diablo Canyon, it will be basically an update of what they've already done because they've already done a seismic PRA, so it's not like they're going to have to go out and provide something brand new, they've already done a lot of work in this area. And the NRC staff is still evaluating the need for Diablo Canyon to provide an expedited approach submittal, and the expedited approach would be an evaluation if they are required to conduct it -- that hasn't been decided yet by us -- they would have to look at systems and components that could be used to safely shut down a plant under station blackout and the loss of alternate heat sinks. And again, that has not been decided yet.

DR. BLEY: I'm a little confused on that one. They're already going to have to do that for other reasons.

MR. WALKER: I won't speculate on it. I think the licensee doesn't think they need to do it because they feel like what they've done already is enough, is sufficient, but it will be up to NRC whether we agree with them or not and require them to do the

expedited.

DR. RICCARDELLA: Expedited over what?

MR. WALKER: What?

DR. RICCARDELLA: Aren't you talking about flex there that they'd have to do or expedited flex? I don't understand that.

MR. WALKER: Well, the way I understand it is the expedited approach would just provide an additional safety benefit because what they've already done shows they can withstand higher seismic ground motion, so the expedited would just be, I guess, something on top of what they've already done if we require them to do it.

MR. ALEXANDER: Ryan Alexander again. Officially the expedited approach -- and this has been documented in the agency documents on this before -- it's essentially, if you will, a margins analysis to verify that there's sufficient margin to continue the long-term evaluation without any intermediate modifications. And so as Wayne just mentioned, the licensee has indicated they believe that essentially the LTSP and all the stuff that they have done in the years past is sufficient to show that level of margin. The agency hasn't made a decision on that yet, and that letter that was issued just last week indicated we're still evaluating that aspect.

DR. BLEY: And that's for interim things before they finish.

MR. ALEXANDER: Correct. That is correct.

DR. BLEY: Okay. I get it now.

MR. WALKER: So current challenges we've got, as you can see there's a complicated seismic history. There have been some complex inspections that were needed. For example, when new seismic evaluations were developed for the Shoreline fault, it took over four years to do that evaluation. A number of concerns were raised during that four-year period by outside groups and also inside the NRC, and it required two comprehensive research information letters that had to be issued, so just a complexity involved in the seismic history.

And then the California mandated study and report, that took a number of months of inspection and also required not only regional but headquarters expertise. And then there's also been a large number of modifications. They replaced their reactor vessel head and the steam generators, and then when you think about the re-analysis they have to do based on three design basis earthquakes, it adds complexity to those modifications.

And then the next bullet there is just well

informed and engaged external stakeholders. Diablo Canyon has historically operated in the licensee response column, as we talked about earlier today of the Reactor Oversight Process, but for Diablo Canyon, normally a plant that's in that licensee response column for public meetings, we might just do an outreach or a poster board session, with Diablo we've historically always done Category 1 meetings due to the amount of public interest and local interest in the plant.

At Diablo there's some pretty highly informed and engaged organizations. There's the Mothers for Peace in the San Luis Obispo area; there's another group called Alliance for Nuclear Responsibility, Friends of the Earth, and Californians for Green Nuclear Power, and each one of those groups typically shows up to our public meetings and a typical meeting is between 100 to 150 people come and the meetings last usually three to four hours with about two hours for public questions usually.

DR. BLEY: Wayne, early on you mentioned that California mandated study. That doesn't have anything to do with your deliberations, does it?

MR. WALKER: It wasn't required by us at all. Is that what you're asking?

DR. BLEY: You're not involved with that in any way, are you? Does it affect your deliberations?

MR. WALKER: Well, the one thing we did do is because of the Shoreline fault, what the NRC directed the licensee was if they came up with new information they'd provide it to us, so there was some new information in the AB 1632 report, so we did look at that from an operability standpoint. But what we did was, there was a pretty narrow inspection done -- and I can get you that inspection report -- but we focused on the operability part with the, I guess, caveat that we knew they were doing the reevaluation and that we were going to take a hard look at that in the next few months. So that's kind of how it went.

So just talking about those organizations, they're not only focused on seismic aspects but also overall plant performance, so at out meetings we typically get into discussions on spent fuel pool, spent fuel cast storage, license renewal. And right now -- Ryan has been knee deep in this -- we're planning a public meeting right now, the annual assessment meeting, which will be the week of June 24 out in California, so a lot of effort goes into those meetings.

And then the last point, I guess, just on engaged stakeholders' oversight, congressional interest, we seem to get a lot of interest from the Environmental Public Works Committee and frequently

we're -- I would say almost monthly -- answering questions or assisting headquarters with answering questions of the whole gamut of the area.

And then lastly, the impact of seismic reevaluation on the current licensing basis inspections, the only thing I'd like to say on that that's just left open the possibility for further modifications and changes to the licensing basis, so there is that potential always.

And then just thought I'd talk a minute about license renewal. They did initiate the license renewal process in November of 2009. While those activities are primarily a function of the headquarters staff, our staff here in Region IV also has been actively engaged in this process, in part because of the aforementioned stakeholder interest and our activities in the license renewal inspections from the regional standpoint if renewal is issued. As noted, in November 2009 they submitted their application, however, in April 2011 PG&E asked the NRC to delay final processing of the application pending the completion of the advanced seismic study. So they knew they were doing these studies, they said we don't want a heavy review during this time, let us go off and get house in order there.

DR. BLEY: When does their current license

expire?

MR. WALKER: 2025.

And so with much of the advanced seismic work completed, that's why they again basically asked us to resume looking at our review. We sent them a letter saying we'd restart the review. There is one kind of caveat in that, though, and it's in the letter we sent back to them in April of 2015. We told them there would be no final action taken by the NRC pending final determination by the state relative to the Coastal Zone Management Act consistency review. So the state has some mandated things they're asking the licensee to do regarding cooling and what's your cooling at the plant, so that's an ongoing issues.

DR. CORRADINI: Does that supercede the EPA rule or is that part of the EPA rule for western cooling?

MR. WALKER: You're beyond my knowledge.

DR. CORRADINI: Because I thought the EPA 210 rule was for all like 1,000 or 1,100 different things, whether it be chemical plants or power plants.

MR. WALKER: I can try to look that up.

MR. KENNEDY: This is Kriss Kennedy. I have not heard EPA in this discussion, it's all focused on the state requirements from what we've heard.

MR. WALKER: So that concludes my

presentation, if you've got questions.

MR. SKILLMAN: Colleagues, any questions for Greg?

(No response.)

MR. SKILLMAN: Greg, thank you.

MR. FARNHOLTZ: My name is Tom Farnholtz. I was asked to give a presentation to you today on the component design basis inspections. I'm a branch chief here in Region IV with oversight over the component design basis inspection, along with the 10 CFR 50.59 and permanent plant mods inspection and heat sink inspections. Those are all under my branch.

We spent a lot of time on the component design basis inspection, as you may have just imagined. A component design basis inspection looks at structures, systems, components that are risk important, either safety or non-safety. The focus is on engineering and design aspects. It's a three-week long inspection, performed by six inspectors, regional and two contractors, typically.

A typical inspection has a direct inspection activity of approximately 400 hours and reviews about 15 to 25 components during a three-week period. The components are a mixture of structures, systems, components, including a large early release frequency

important samples and operating experience feedback reviews, so it covers a gamut, and it primarily focuses on engineering.

And I wanted to make a couple of salient points here while we're here. Here in Region IV we've been doing these, I think this is the third cycle now, the third triennial cycle that we're starting on and we're currently involved in now, so we've done several of these component design basis inspections at each and every site here in Region IV.

In Region IV we've had some significant findings, not so much risk significant findings as far as color goes, but findings that have proven to be very valuable to us, I think, and so I want to point out these four examples here as examples of items that were identified during CDBIs that have proven to show a weakness in a licensee's area of performance such that I believe we can make a strong case to say that we precluded a potentially more significant issue by identifying these earlier.

The Fort Calhoun external flooding mitigation inadequacy, that was identified in 2009. We were doing a CDBI at Fort Calhoun in 2009. We identified the water seals in the intake structure that were actually missing. It was a small item, we

identified it and processed it during the CDBI, but it gave us the thread to pull, and when we pulled that thread it turns out that the flood mitigation strategy at Fort Calhoun was less than adequate, and so we pursued that over the next couple of years.

In 2011, as you're probably aware, they actually did have a flood there at Fort Calhoun. The flood was significant and it was a significant event for Fort Calhoun, but because we had identified that in 2009 and a lot of work was done in the following two years, that flood was a much lesser event than it could have been.

The Comanche Peak condensate storage tank bladder vulnerability. We did a CDBI at Comanche Peak. We identified in the condensate storage tank they used a bladder on top of that tank and the bladder moves up and down with tank level. The bladder is there to control chemistry in the water in that tank. It's a non-safety function, the bladder itself is non-safety, but that condensate storage tank is the primary suction source for the auxiliary feedwater system, all three trains.

So if that bladder were to have failed -- and there were some failure mechanisms that the team had identified could potentially cause that to fail and that

bladder material to sink to the bottom of the tank and clog all three trains of AFW -- a significant event, it was a non-safety related item that could potentially affect all three trains of a safety related system.

The Waterford 3 emergency diesel generator day tank vent corrosion, this is one that we identified earlier this year. Both the alpha and bravo train day tank vents -- or diesel generator day tanks, the day tanks themselves are in the aux building but the vents associated with those tanks extend vertically and then penetrate the roof up there. The area where that vent penetrates the roof was corroding, and in fact, had corroded so much that there were actually holes in the vent and it was right at the roof level where water tends to pool.

The problem with that was that if it rained, such as in a hurricane or tropical storm or even just a heavy rainstorm, that provided a direct path for water to go into the fuel in the day tank on both trains, alpha and bravo. So a significant degradation of safety related components at Waterford not identified by the licensee but the CDBI team did identify that.

And then the last example I've got here is the Fort Calhoun CDBI, the most recent one that we did earlier this year was a major part of the

decision-making process that went into whether or not to take Fort Calhoun out of the 0350 process and put it back into the ROP process.

So based on these examples and many others over the years that we've identified, we in Region IV consider the CDBI to be a very valuable and fruitful inspection.

MR. SKILLMAN: Tom, please say more about assessment of engineering readiness. What is it that you found that was the concern?

MR. FARNHOLTZ: I'm sorry, the last part of that question?

MR. SKILLMAN: What did you find about engineering readiness that was not acceptable?

MR. FARNHOLTZ: At which one of these?

MR. SKILLMAN: The fourth bullet.

MR. FARNHOLTZ: Well, not acceptable, we actually did find it acceptable, and one of the mandates for doing the CDBI at Fort Calhoun was to come back with some assessment to provide to the 0350 panel as to whether or not they were, in fact ready to go out of the 0350 process back into the ROP from an engineering standpoint. And when we went out there, we actually did find them to be acceptable for that.

MR. SKILLMAN: So this is a positive finding.

MR. FARNHOLTZ: It's a positive finding, exactly right.

MR. SKILLMAN: I understand. Thank you.

MR. FARNHOLTZ: But it was a key piece of decision-making data that the 0350 panel was looking for.

MR. SKILLMAN: Now I understand.

DR. REMPE: But in other cases, just out of curiosity, like the corrosion, is it that they aren't doing sufficient inspections in-house that they didn't notice it, or just the same person had been there every day and didn't notice it, or what was the root cause?

MR. FARNHOLTZ: It's a combination of both. At Waterford they actually had a procedure for the system engineer responsible for that equipment to inspect accessible portions of the safety related equipment, including these vents. Well, it turns out these vents are up on a rooftop, there is a permanently installed ladder to get up onto that particular roof, there was no reason why they couldn't have gone up there, but they had over the years not done that.

There was a procedural requirement to do that but they hadn't done that. They had looked at these vents from a distance from another platform but they hadn't actually got up there and inspected these vents

up close. The CDBI team actually did do that and that's when they found the corrosion.

It's the type of thing we not only review a lot of calculations and evaluations and talk to a lot of people, but we go out in the plant and we actually look at this stuff and we find it to be very valuable. In this case it was the slow process of corrosion that was causing degradation.

MR. KENNEDY: Tom, that's a really good point on the value of the CDBI inspections. I will point out that John Dixon, sitting in the back, is actually the one that climbed up on that rooftop and laid eyes on that vent and identified the issue.

So thanks, John.

MR. FARNHOLTZ: That's right. And in fact, John helped me out with this presentation quite a bit this week, so give credit to him.

DR. BALLINGER: But this inspection had to be missing this for years.

MR. FARNHOLTZ: Yes.

DR. BALLINGER: So it somehow was overlooked?

MR. FARNHOLTZ: As it turns out, the licensee, during the reg conference associated with this particular finding, the regulatory conference that

we had for this particular finding, admitted that yes, they had been overlooking corrosion related issues at that plant for a long time.

Waterford, as you probably know, is located right on the Gulf of Mexico in Louisiana. It's a harsh environment as far as corrosion goes, and over the years they've kind of accepted corrosion as part of the deal and not making a big deal out of it.

I think one of the benefits of this particular finding was that it re-centered the licensee now to look at a corroded pipe support, for example, or corroded nuts on a body to bonnet valve or something, as a big deal. They need to write a condition report, they need to get it repaired, they need to get it re-coated, whatever it took.

MR. KENNEDY: Was this finding actually through the wall?

MR. FARNHOLTZ: Yes. In fact, here's some photographs that kind of illustrate what I'm talking about. These bottom two photographs here are the vents. It's a little hard to see, but this is a hole right here. This is a mirror actually looking back on the backside of that. That's a through wall hole right there. You can see the corrosion at the bottom of this vent, and this, of course, is the rooftop right here,

so this is where water would pool whenever it rains and then just eat into this metal. And over the years those holes opened up and now you've got a direct path for water to go into that tank and it's a straight shot down into the day tank, both trains.

DR. STETKAR: They weren't finding water in the samples in the day tank, or didn't they have a bottom sample point on the day tank?

MR. FARNHOLTZ: I don't know. John Dixon can answer that directly.

MR. DIXON: My name is John Dixon. I'm a senior inspector in the region.

To answer your question for this, the way that they assessed for water in the diesel was in accordance with their surveillance test is after the diesel had been up and running for at least an hour, then they pulled for a water sample.

DR. STETKAR: So they assumed if the diesel was running there was no water?

MR. DIXON: Effectively, yes. The other issue that presents a problem here is the suction source for the diesels on the bottom of this tank was directly on the bottom of the tank, there was no stand pipe, there was no pipe within a pipe, it was dead center on the bottom, so any water that collected in the tank went

straight down into the suction of the diesel.

MR. FARNHOLTZ: This emphasizes the value of the CDBI. Those top two photographs there are both from Fort Calhoun during the flood of 2011. You can see water intrusion there on a pull box, a cable pull box, and then this is a room in the plant where water is coming from the seal between the roof and a wall, so there was water during the flood that was actually coming into the power block at Fort Calhoun. This would have been a lot worse had we not identified this issue two years earlier.

I put these up here just to emphasize that the types of findings that we're typically finding during these CDBIs are latent issues, longstanding issues, and because we're finding them earlier, they're not becoming major issues. And so I'd like to kind of toot our own horn that way because we find that to be of great value for the CDBI.

MR. SKILLMAN: Tom, how are these inspections scheduled? How often do you conduct them on a per unit basis?

MR. FARNHOLTZ: It's a triennial inspection so once every three years on average, sometimes it's a little less, sometimes a little more. We're able to schedule them any time during the triennial period, but

typically we try to keep them to every three years. They are quite a large inspection. Three weeks onsite and a couple of weeks in between, plus the prep and the doc weeks, so we're talking six or seven weeks of footprint on these, so it's a large inspection and a large team that goes with it, but every three years.

MR. SKILLMAN: Do you risk inform your targets?

MR. FARNHOLTZ: Yes, we do.

MR. SKILLMAN: And could you explain that process, please?

MR. FARNHOLTZ: Yes. During the process of preparing for one of these inspections, the team lead and a regional SRA will go out to the site and do an information gathering trip. The raw values and the PRA type cut sets and all that are gathered during that time frame and we choose our samples based on that. It's not risk-based but it's certainly risk-informed. And we try to think a little outside the box because if it was strictly risk-based, we'd be looking at the same equipment, you know, diesel generators, AFW pumps, that sort of thing. We've already looked at that many times and the residents look at that all the time, so that gets a pretty good look.

But some of the other stuff that we look at

is a little more obscure but still important. One of the areas of sample selections that we have is called scenario-based sample selection which I kind of like that one because you pick a scenario that's identified, perhaps a main steam line breaks or something like that, and then you think, well, what components would be important for that scenario to operate, and then we will choose that as a component.

MR. SKILLMAN: You do the whole scenario from that?

MR. FARNHOLTZ: Yes. Although, in the end we boil it down to an actual component, so it really is a component design basis inspection. So we're looking at pumps, valves, breakers, relays, that kind of thing, so we're looking at what's really going to have to work during that scenario. So our latitude for choosing components is enough to where we can get to these components fairly easily, and if we have any particular concerns at a particular site, for example, a number of years ago we did a CDBI out at Diablo Canyon and there were some concerns at that time about the electrical design at Diablo Canyon, for whatever reasons there was some question about that, so we loaded that particular CDBI team up with electrical folks and we kind of emphasized that as an area of looking, more electrical

than mechanical pieces.

DR. BLEY: Looking at some of your pictures makes me think as one does a risk-informed selection, one might think about the things that are kept out of the risk models because they're passive and they're not going to fail, maybe they do.

MR. FARNHOLTZ: And you're exactly right. I feel the same way as you because I'm all for risk-informed sample selection and risk-informed ROP. I think it's a great tool for us.

DR. BLEY: But testing the assumptions of that assessment is a good thing to do.

MR. FARNHOLTZ: Yes, absolutely. We shouldn't box ourselves in on just that because if we do, we could very easily miss something.

MR. SKILLMAN: The other side of that, of course, is the licensee's system health reports and their maintenance reporting, and that ought to be a very fertile area for you to go and find what needs to be looked at.

MR. FARNHOLTZ: Yes, and that's all good stuff, and actually early on we did a couple of these CDBIs and we started to run out of safety-related, risk important, low margin components, which was the original thought on these. So we ended up expanding our

sample selection, including the scenario-based and that sort of thing, to throw a wider net and to think a little outside the box. And of course, we do emphasize site walkdowns and looking. In fact, that's how the Fort Calhoun missing seals in the intake structure, the external flooding thing started out with an inspector who was walking along the intake structure wall and noticed that there were some fire header pipes that penetrate that wall and there was no seals around there. There was a clear path for water to go from the outside directly into the intake structure, nothing to stop it, and inside that intake structure are the four safety related raw water pumps, it would have taken them all out.

DR. BLEY: Are the inspection reports that support license renewal fertile ground too for looking at other plants?

MR. FARNHOLTZ: John may have a thought on that. I don't think we've used that specifically but it's certainly an avenue of information.

MR. DIXON: This is John Dixon again.

We do have an aspect in the CDBI procedure that allows us to look at aging management programs for utilities that have entered the period of extended operation. Fort Calhoun, for example, is one of the

plants that has entered the period of extended operation, so we did look at the cable aging management program and the corrosion program as part of our component review for electrical systems and mechanical systems. So from that aspect, stuff that's been a previous part of license renewal is directly within the CDBI scope.

DR. BLEY: I like to hear that. I guess the thing I was suggesting is when we started looking for license renewals we might see phenomena that we wouldn't normally look for and it might a good thing to think about when we go and do a plant that's not at that point.

MR. FARNHOLTZ: Absolutely. Forward thinking is what we to do.

DR. BALLINGER: From the standpoint of these photos and stuff, does the licensee know ahead of time what systems are going to be inspected?

MR. FARNHOLTZ: We make the sample selections as far in advance as we can, and it is not our intent to surprise them on the day of the inspection team showing up. We provide this information to them, the final sample selection, at least a week or two in advance, and maybe even more.

DR. BALLINGER: So they knew this was going to be inspected?

MR. FARNHOLTZ: Yes, in general. You know, some of this stuff comes up through walkdowns and other things. It's not our intent to surprise or do any of that, so they know what the components are that we're going to look at.

But my point with all this was that Region IV considers the CDBI to be a very significant inspection. It is a significant inspection also from a resource point of view, and in fact, you probably heard that the industry is very interested in changing the CDBI because of the resource impact on them. So I wanted to touch on that a bit.

MR. SKILLMAN: Before you go on, so here you go down to Waterford 3 on the Mississippi River and you find corrosion at the interface between the roof and the emergency diesel generator fuel tank vents. How is that information communicated, perhaps to Monticello or to Ginna or to Indian Point?

MR. FARNHOLTZ: Of course, once a report gets issued, that report becomes a public document, and I know that there are industry groups, such as NEI, that every time we issue a report they review those reports and they provide that information to their member station. And of course, member stations can pull those reports any time they want. So it is public

information, and we're hoping and we encourage licensees wherever we go to look at previous CDBI inspection reports and see what kind of issues are being developed at that particular issue. And it's not unusual for us to identify an issue at Plant A and then go to Plant B, the very next plant, and find the very same issue. We don't like to do that but it does happen, and we were hoping that the Plant B would see that that is a vulnerability at Plant A.

DR. BALLINGER: But these inspection reports, I'm assuming they have an executive summary which would outline the key findings, so a licensee doesn't have to go through 500 pages before he figures out that the vent pipe might corrode.

MR. FARNHOLTZ: Exactly right. It's not that time consuming to look through there and do that.

MR. DIXON: This is John Dixon again.

This particular tank vent corrosion actually went out as an operating experience sample across the agency.

MR. FARNHOLTZ: Again, it's in our best interest to get the word out widely so that people can examine their own site and see if they're open to this. But yes, if there's a better way to do that, we're certainly open for that.

So the industry issued a white paper -- and by the industry, I'm talking NEI, Nuclear Energy Institute, is the spokesman for the entire nuclear industry on this subject, and so they issued a white paper back in February of this year to us proposing changes to the CDBI, and their main concern with the CDBI is the impact that it has on their engineering departments and groups and the cost of the CDBI. It is, admittedly, a high impact inspection and it does take a fair amount of time, it's three weeks onsite and there are hundreds of questions that are asked by the inspectors. And the questions are not easy and the answers to the questions require a lot of research, a lot of knowledge, and so it does take the engineering staff at the facilities away from whatever their normal duties might be to address those questions that the inspection team is asking.

And so they would like to make changes to the CDBI from the current three-week inspection that we currently have now, and so for this slide here I wanted to touch on some of the things that the industry is proposing. On April 22 of this year we had a public meeting to talk about this and understand what the industry's concerns were.

They proposed levelizing the engineering

inspections, and by that they mean taking some of the components out of the CDBI and putting them perhaps into the 50.59 permanent plant mods inspection, for example, taking some out of this one, putting it into that one, or taking some out of the CDBI inspection and putting it into the triennial heat sink inspection, and try to minimize the high impact of the CDBI and move it out.

They would also like to see a scale in some way shape or form the engineering inspection, such that if we have concerns for an engineering organization or a particular licensee, we can do a full blown CDBI, but if we don't have any specific concerns, perhaps we could scale it back and not look as deeply to a plant that doesn't have similar concerns for the engineering department.

They would also like us to give them credit for self-assessments that they might include. In other words, they would like us to give them the list of components that we would inspect perhaps six months ahead of time and then they would do a self-assessment on those components and give us a report. We would review the report and if we found it to be adequate we would give them credit for that, if we found it to be lacking in certain areas we would go and look at those areas.

That's kind of their proposal. Interesting and worthy of consideration. We did have this discussion back in April with them. Of course, we were noncommittal on what to do but we certainly wanted to understand their thoughts. We have to consider, however, the philosophy of the current ROP. Some of this stuff doesn't seem to fit, at least on the surface. Giving credit for self-assessment, for example, that historically hasn't been done because that takes away the independence factor that the NRC has to have for that process, so we're not quite sure how that would fit in.

Scaling is another aspect that we're not quite sure how that would fit in because a major premise of the ROP is that every site in the country would get a minimum baseline inspection, and of course, the CDBI is a baseline inspection, every site gets one, so how do you then scale that up or down depending on performance and still call it a baseline inspection. So we're not sure about that.

Those are all worthy of consideration but I wanted to bring all those up on the slide here just to let you know this is kind of what the industry is pushing for, and if you haven't already gotten an earful from an industry spokesman, a VP or something, you may eventually get some of that.

DR. CORRADINI: Your last bullet, is that a forum between NRC and the licensee, or is that a forum across the industry so they'll see what you're getting at other places?

MR. FARNHOLTZ: It's the latter is what they're proposing, a forum kind of a group of executives from all the industries and sharing thoughts amongst themselves.

DR. CORRADINI: Surprised they're not already doing that.

MR. FARNHOLTZ: Maybe they want to formalize it a bit or something.

DR. STETKAR: Do you have a counterproposal?

MR. FARNHOLTZ: We do, actually.

DR. STETKAR: Like an unannounced inspection?

(General laughter.)

MR. FARNHOLTZ: I'm not sure they'd go for that. We want to work with industry here if there's a better way to do these inspections. We understand that they're high impact and they're very expensive, so we don't want to discount whatever their thoughts are, so we welcome their thoughts. On the other hand, we do have a job to do and we feel that the CDBI, as it's structured right now, is delivering the goods, at least

I feel that. I think I speak for many others in the agency. There's nothing broken about the current CDBI, however, if there's a better way to do it, if there's something that would minimize or reduce the impact or reduce the cost. And on us too, this is a high impact inspection for us as well. We spend a lot of time and effort on this inspection.

And what we're doing right now is, in fact, just last night I returned from Region III and I was involved in a meeting with my counterparts from the other regions and from the program office up in headquarters, and what we're proposing to address some of this, at least, and kind of get us going in a direction of perhaps revising the CDBI, is that we're developing a new CDBI that's not radically different from the current one but is somewhat scaled back. It still looks at components and still does the deep dive vertical dive kind of inspection that we do now because we think that's a valuable thing, we want to hang on to that feature, but scaling it back from three weeks to two weeks but then adding engineering programs.

Because we know that engineering organizations do a lot more than just engineering evaluations and that sort of thing, they also have EQ commercial grade dedication, MOV/AOV testing

requirements, there's a lot of things that engineering does and there's a lot of programs that they own and are caretakers for that we either haven't looked at before or it's been many years since we have looked at them -- maintenance rule is another one.

So what we want to do, the general thinking is -- and we haven't gotten approval for this or concurrence from everybody so this is all kind of preliminary just general thinking, but the idea is to reduce the number of components and reduce the amount of time that we look at those components, using the vertical slice process, from three weeks down to two weeks, and then add these programs on as a third week, either concurrent with the other two weeks or separated by time, either way, and look at some of these programs specifically with a smaller team. The idea would be to reduce the impact on the licensee and still get what we need from this inspection, from an engineering inspection.

To test this, what we're going to do is we're going to do pilots, we're going to do two pilot inspections like this in each region, so a grand total of eight of these inspections will be performed, assuming we get permission to move forward. And then these pilots will take place either late this year or

early next year and certainly by the middle of 2016 we'll have all these pilots done. And then we'll take a lessons learned and suggestions and comments that we receive during these pilot inspections and decide does the two-week inspection actually deliver what we think it will or doesn't it.

Same way with the program inspection. The first program that we're going to do is equipment qualification, EQ. We're going to take a look at that program in great detail.

So we don't want to make any wholesale changes to the CDBI inspection procedure that's currently in place until we do these pilots because we want to make sure that whatever we do doesn't fundamentally undermine the current CDBI. So we want to go slow on this, we want to make sure that whatever we do continues to deliver what the CDBI has historically been delivering. But we also want to be sensitive to what the industry is saying, and also the ROP enhancement project that has suggested actually that we include engineering programs into the CDBI, so that's a big reason why we want to include that.

MR. SKILLMAN: Tom, I'd like to ask. When you talk about component design base inspection, those who have done design engineering and plant engineering

and STA work understand CD, component design basis, generally quite well. When you consider in lieu of design based inspection for components, program inspections, what consideration have you given to the difference in that inspection? I would assert that is a very different inspection.

MR. FARNHOLTZ: It is indeed, and we recognize that. In fact, it would no longer be a component design basis inspection, we'd probably have to change the name of it to accurately reflect what it's actually doing. The new proposed inspection would actually be more of an engineering inspection, overall engineering, to include components and design basis, but only as a part of what they're doing. So your point is well taken that what we're doing here, as a pilot now, is a significant change from historically what we've looked at. That change may be good or it may not be good. Are we currently locking ourselves into components and focusing on those at the expense of other stuff that engineering is doing? If so, maybe looking at those programs is a good thing. On the other hand, are we going to become diverted over to the program inspections and then not see some things in the component area. Those pilots should tell us that, I would think.

MR. VEGEL: This is Tony Vegel. I think we have to be very careful, because it's very important that we continue to do component design basis inspections because the reason why we started doing that is because of plants that lost control of the design basis. The D.C. Cooks, for example, they lost control of that and I think it's very important that we continue to really do the deep dive to make sure that the systems or components can perform the design part of the function.

And as we saw today, our inspections continue to identify issues in that area and I think it's important that we continue to look at that. It's a slippery slope, once you start losing control of that design basis, if you're not continuously checking it, it could quickly result in potential problems.

DR. BALLINGER: The stuff that they're proposing, it impacts you but how does it impact them with respect to fixing these kind of problems so you don't find them -- I mean, you don't have to find them, let's put it that way.

MR. FARNHOLTZ: Exactly, and the jury is still out on that. I wish I had a clean answer for that. Do we have faith that they're going to be able to identify these things on their own through

self-assessments or stuff like that.

DR. BALLINGER: But what you said was they not only knew about it, they had known about it for a long time.

MR. FARNHOLTZ: Right.

DR. BALLINGER: So self-assessment, what self-assessment?

MR. FARNHOLTZ: Exactly. I'm dubious of that, but if there's some way we can work with them on that, I think it's worth considering, but I wouldn't sign off.

DR. SCHULTZ: So Tom, in this new approach are you taking them up on the offer to perform self-assessment?

MR. FARNHOLTZ: No, not at this stage. Actually, the way I'm viewing it is we're going to do it in two stages. The first stage is what I just described, the two week and the one week. That one we can do kind of in-house because that only affects the one procedure, the 7111.21 which is the CDBI inspection procedure. That one, myself and my colleagues and the program office up in headquarters, we can revise that amongst ourselves.

The other parts of that, like the levelizing and moving stuff out of that and into the other programs

and adopting the self-assessment as a tool, those will require much larger groups of people and much more thought, I think, and so we're not tackling that at this point. I think in the next triennial cycle, which starts in 2017, we're planning on using this new revised procedure, but perhaps the triennial cycle after that, which would start in 2021 or whatever it is, down the road we could consider those longer term changes, but for right now we're not adopting that.

DR. SCHULTZ: I think that would be a reasonable tradeoff, although based on what you've shown us and what the experience base has been so far, just following up with what Ron said, industry would have to prove and demonstrate the self-assessment process that they're proposing is deep enough and thorough enough to be certain to capture those things that we are, in fact, identifying in the inspection process.

MR. FARNHOLTZ: I agree with that. If we can get them to commit to a rigorous self-assessment and then we would somehow have to inspect that, the process of self-assessment in some way.

DR. SCHULTZ: That's a given, I believe.

MR. FARNHOLTZ: So a lot of thought is going to have to go into that. That's a pretty radical change

from the existing ROP. It's not to say that it shouldn't be adopted at some point, but not today or tomorrow.

DR. BALLINGER: The poster boy -- or poster person for the self-assessment problem is Davis-Besse. Right?

MR. FARNHOLTZ: Yes, absolutely. When you find something like that, it certainly is a setback to what are the licensees doing and how effective is that. We consider our job to be the conscience of the licensee, to go out and look at these things with an independent view. Regardless of what they're doing themselves, we're going to go look at it ourselves, and if what we see matches their finding, great, if it doesn't, there's a gap, we're going to pursue that.

DR. BLEY: Tom, I've got a couple of points I'd like to ask you about on that slide. The first is I would assume -- and correct me if my assumption is wrong -- that if you go in with this alternative approach and you start to spot some problems that you would not be impeded from chasing those as far as you can. And the second part of this is I get a feeling -- but maybe it's just the way you organized the presentation -- that when you've gone in plants and found problems you tend to find a lot of related

problems, not wildly different ones so much, which would make pulling the thread make more sense.

MR. FARNHOLTZ: It does. And in fact, extent of condition, extent of cause is a big deal for us and it should be and we mandate it, in fact, for the licensee. When you find one problem, a lot of times that's just the tip of the iceberg, so you need to look at the other train, at a minimum, and perhaps similar equipment that may have a similar problem. That's a big source of our information, you know, once you find an issue like that.

MR. KENNEDY: This is Kriss Kennedy. I just want to make it clear -- I know you know this -- there's really nothing that prevents an inspector from pulling that string. So programmatically sometimes we create these inspection procedures, they provide guidance, they give you a scope of things to look at, but all our inspectors know if they find something in the area they're inspecting or even outside the area they're inspecting, someone is going to pull that string, whether it's them or they refer it to maybe the resident inspector or maybe another specialist in the region. That's a good point.

MR. FARNHOLTZ: And that is true. We work closely with the resident inspectors at the various

sites, or even if we find something that looks like maybe a potential fire issue, we would get with John Mateychick, for example, and he would put that on his list to follow up on that kind of thing. So we do act as a group and coordinate quite well.

MR. SKILLMAN: I wanted to make the point that the industry's recommendation is they would like to do self-assessments, probably like streamlining, they would like a number of enhancements that would reduce their effort, but I'd be quick to point out that in every case that I'm aware of 95003 plant or an 0350 plant, that is normally a one- to two-year journey, can be longer than that, and that journey takes that utility through an assessment of all of the programs and all of the hardware. And so I would just assert that if those owners understand under 10 CFR 50, Appendix B in maintaining their design basis, that some of the enhancements they are asking for really aren't needed. And if they fall in the 95003 or 0350, they're going to have to do everything, not just a sample.

MR. FARNHOLTZ: That's right.

MR. SKILLMAN: And so there is a tradeoff here that they need to be mighty aware of, and if they haven't learned from the 0350 people or the 95003 people, they should probably go and take some notes

because that's very, very painful and it's horribly expensive, much more than doing a thorough CDBI for three weeks.

MR. KENNEDY: You're absolutely correct. And in fact, as I was sitting in that public meeting up in Washington, D.C. on April 22 where NEI was describing their proposal, I was thinking exactly that: Be careful what you ask for because there's a lot of land mines out there that you could be stepping on right now. We want to be sensitive to that and we don't want to let me make a big mistake, but yes, you're right, the long-term ramifications of what they're asking for could be -- at least for some facilities could get ugly.

MR. SKILLMAN: Thank you.

DR. REMPE: What is the process for the final decision on whether you have a revised procedure or not? How does it go through the agency before they make that decision?

MR. FARNHOLTZ: Well, now that I'm back from Region III, we had our meeting earlier this week so we've got a marked up revision of what we think, our recommendation, I've got to brief my division director and RA for them to understand exactly what were proposing, and then they'll get with Bill Dean, director of NRR and those kind of folks, kind of talk amongst

themselves, is this something we want to do. And assuming we get the okay for that, or they may very well have comments or suggestions themselves as to, well, let's do this instead of this or this way, we certainly want to incorporate those. So it's kind of a process at the management level to make sure everybody is onboard.

DR. BALLINGER: Along the lines of what Dick was saying, agreeing to something like this without the big hammer that's available, the hammer and stick type of approach where, okay, if we do some of this, you need to be aware that if we find something that's not working, it's going go be a tough row.

MR. FARNHOLTZ: And we're not going to back off from that, I don't anticipate. And the jury is still out on going from three weeks down to two weeks, and historically in CDBI many of the issues aren't closed or aren't wrapped up or decided on until the middle of that third week because the answers to the questions are coming in. That's just the nature of the way the inspection unfolds. Now we're going to try to do that in two weeks.

There was a lot of discussion earlier this week amongst ourselves as to is that even practical, is a licensee going to be able to deliver the

answers and satisfy all the questions, even with the reduced number of samples that we're going to be doing, is that still going to be possible. We don't know the answer to that, but by doing a pilot or a couple of pilots in each region, I think that will give us that data, at least a good idea of it, and it may come out that no, two weeks just isn't practical and we'll go back to the three weeks.

Personally -- and I'm only talking on my own here -- I kind of like the three-week footprint, I like the way we're doing it now. I don't think it's broke. I recognize that it is a major impact. I often go out to the sites during that third week when the teams are wrapping up their inspection activities. And we've gotten very good at these CDBIs. Our inspectors, I wouldn't want to be on the other end of their inspection, I can tell you that. They're asking some tough questions and they're demanding real answers, not some glossy engineering judgment based thing or nothing like that. They've got to have real data, and if they don't get it the first time then they have to go back and do some more.

It's a real challenge, so I understand why the industry is pushing to change the footprint of this inspection. It is the largest team inspection that we

do in the baseline inspection program, and it is a very expensive inspection. I've heard a number of a million dollars for them to do that, so this is a line item on their budget, and in these days of tight financial markets, I understand why they want to push for that. But as you so correctly point out, the alternative might be worse than what we've got now for them.

So those are the things I wanted to hit, and I do want to emphasize that this inspection seems to be working for us. In Region IV we do consider this inspection to be of great value and has historically been of great value for us and continues to be.

Identifying both latent issues, old design engineering issues, mistakes and errors, omissions that were made many years ago, we're finding those along with current performance issues. So it's an overarching inspection that's good.

With that, I'll entertain any additional questions.

MR. SKILLMAN: Tom, I thank you very much.

To my colleagues, do you have any further questions for Tom Farnholtz?

(No response.)

MR. SKILLMAN: Tom, thank you.

MR. FARNHOLTZ: Thank you.

MR. SKILLMAN: At this point in the meeting I would like to ask if the telephone line is open. Can someone confirm that our communication is active?

OPERATOR: This is the operator, the telephone line is open.

MR. SKILLMAN: Thank you, Operator.

Before we got to the telephone line, are there any individuals in the room that would like to make a comment or ask a question, please?

(No response.)

MR. SKILLMAN: Seeing and hearing none, on the phone line, if you are out there would you please say yes, I'm here, please? Anyone at all, may I ask again if you are on the phone line would you please communicate by responding yes, I'm here.

SPEAKER ON TELEPHONE: Yes, I'm here.

MR. SKILLMAN: Okay. I thank you very much, and with that, sir, would you please make your comment. I invite you to make your comment, sir, if you wish to.

SPEAKER ON TELEPHONE: I have no comment at the moment.

MR. SKILLMAN: Yes, sir. Thank you.

Anybody else out there that would like to make a comment?

(No response.)

MR. SKILLMAN: Hearing none, thank you very much. Please close the phone line.

And Kriss, back to you.

MR. KENNEDY: Well, thanks. I just wanted to say a couple of words before you concluded the meeting.

As you can tell, we have a dedicated staff in Region IV that are passionate about what they do in their inspection activities to protect public health and safety. I think that came across today.

As I said at the beginning, it was an honor to host the committee at this meeting in our region, and I appreciate the time that you've spent with us, the dialogue and the questions and insights that you've given us. But there was one theme I wanted to touch on, and it was asked several times, how do you communicate issues to the industry, and I wanted to go through a couple of quick thoughts on that.

Internally in Region IV we have a morning safety meeting every morning and each of the division director of projects branch chiefs reports out on anything unusual or out of the ordinary that happened the day before. We have that meeting every day. And then we debrief all of our inspections, both by our DRP inspectors and by DRS inspectors, and if we identify

some issue that we think is maybe generic, we make sure that the other branch chiefs are aware of that and that they communicate that to their sites.

We do have the regulatory information summaries that if there's a generic issue that reaches a certain threshold, we'll issue that information notices. Our inspection reports are all available, publicly available, and then there are consultants that their job is to review inspection reports, and for those companies that have hired those consultants, they will report out on findings to the licensees.

And also within a fleet, obviously, if there's an issue that comes up at ANO, the fleets are fairly good about communicating those issues across, at a minimum, their fleet plants. I know that came up a couple of times. And then there's, of course, the big G, capital G, generic issue where the agency decides, in fact, we need to communicate that more broadly and more formally.

I took away one IOU. I owe you a copy of the River Bend special inspection reports. If there's any other IOUs, you can let me know now or later.

And that's all I had for closing comments. Thanks again for coming to Region IV, and you did a great job for getting in so late last night.

MR. SKILLMAN: Kriss, thank you. We're not quite wrapped up here. I need to ask my colleagues if they have any further comments, any questions, any other business they wish to conduct here.

DR. CORRADINI: No comments. Just thank Region IV individuals for putting this on. I think it was very good.

DR. RICCARDELLA: Same here, no comments.

DR. BLEY: I have a comment. I really appreciate all your presentations, but I especially appreciate getting to the regions. We don't get to see you folks very often, and from my first visit to the region, to this one, I'm always impressed with the depth of expertise and the commitment I find out here, and hearing from you guys who are very close to the plants, it's a different picture we get than we get back in Rockville. Appreciate the day very much.

MR. SKILLMAN: Our chairman, John Stetkar, any comments?

DR. STETKAR: I have nothing to add other than I certainly echo Dennis's comments. It's always a learning experience to come out here, so we appreciate that.

MR. SKILLMAN: Dr. Rempe.

DR. REMPE: I just want to add my

appreciation because it is educational for me and I appreciate it.

MR. SKILLMAN: Dr. Schultz.

DR. SCHULTZ: I too would echo the comments associated with appreciating the opportunity to be here and to listen to folks that are closer to the plants than headquarters is at some point in times.

I really want to thank you for the topic selection today. I thought what you've chosen to present, those topics were excellent in the selections, and I know they kind of come to you, but you've told us a lot about what's happening in the region as a result. And not only did I appreciate knowing about the findings, but you also talked about the process by which you found them and knowing how that process works, providing us more information for that has been very helpful.

I thought it interesting that as we focus so hard on lessons learned form Fukushima that today you talked about mostly external events and fire and floods and seismic and all of those things above, as well as a couple of what I'll call mini black swans, the day tank corrosion and the complicated reactor trip sequences and so forth. So I think we've covered a lot today and it's right on the mark, I think with regard to what the

industry is focusing on.

I just want to comment, as well, we really did have a nice opportunity to see a lot at the Palo Verde site and really appreciate that, and we know that you are interacting with that site at a very high level and appreciate that as well. Thank you.

MR. SKILLMAN: Thank you, Steve.

Another IOU, this NEI white paper, I think it's the white paper on the CDBI, we'd like to see that.

One or two other items. We are here supported by our staff. We have Dr. Edward Hackett, Chief of Staff Mark Banks, and we have other staff members with us, so I want to recognize their making an effort to come with us. They're very important to us, without them we don't get our work done. And we also are supported by a team back in Rockville that does our travel for us, so I want to acknowledge them and thank them for being a part of this business today. Thank you.

Kriss, and to your whole team, thank you very much for your hospitality, your excellent presentations, for information that's right on the mark, and my colleagues have said it all, so I appreciate it. And with that, this meeting is adjourned.

(Whereupon, at 3:00 p.m., the meeting was

concluded.)

US NRC

Region IV
Arlington, Texas

Thursday, May 21, 2015

AGENDA

10:00am	Opening Remarks – Gordon Skillman
10:05am	Region IV Welcome and Overview – Kriss Kennedy
10:25am	Operating Reactors ROP Status – Ryan Lantz
10:40am	NFPA 805 Fire Protection Inspection Implementation – John Mateychick
11:00am	Arkansas Nuclear One: Yellow Inspection Findings – Brian Tindell & David Loveless
12:00pm	Break
1:00pm	River Bend Special Inspection – Greg Warnick
1:20pm	Background and Status of Seismic Analyses and Challenges at Diablo Canyon – Wayne Walker
2:20pm	Component Design Basis Inspections – Tom Farnholtz
2:40pm	Wrap-up
2:45pm	Public Comments – Public
2:50pm	Subcommittee Discussion – Gordon Skillman
3:00pm	Adjourn – Gordon Skillman

Opening Remarks

Gordon Skillman

Region IV
Welcome & Overview

Kriss Kennedy

Region IV Fast Facts

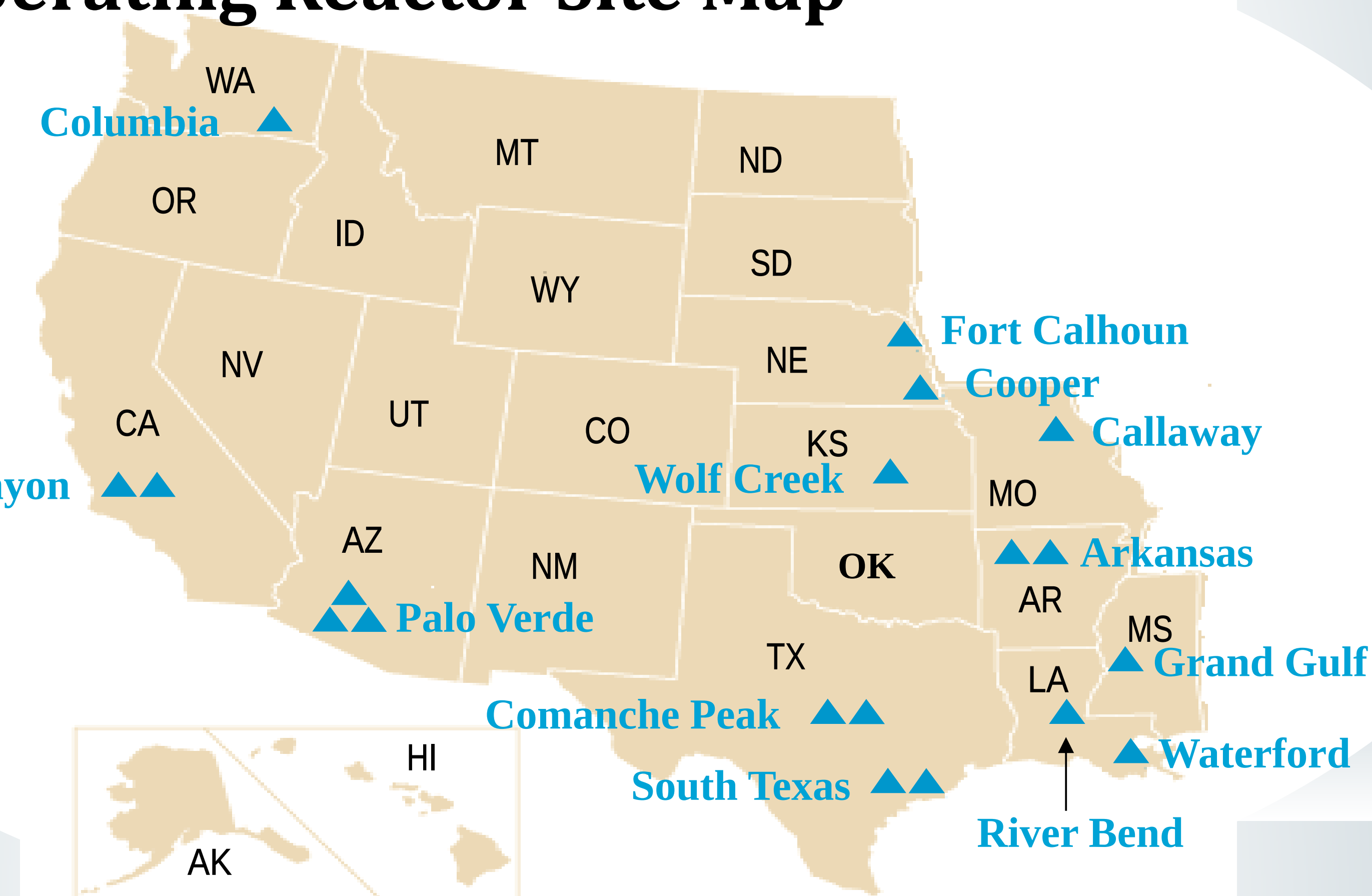
- Western U. S., ~75% of the US surface area, 5 time zones
- Reactor Program
  - 13 operating reactor sites (19 operating reactors)
  - 9 PWR sites (1 B&W/CE, 3 CE, 5 Westinghouse), 4 BWR sites (GE)
- Materials & Waste Management Programs
  - Approximately 600 materials licensees
  - U.S. Air Force Master Material License
  - 14 ISFSI's
  - Multiple active reactor and complex materials decommissioning sites
- Response Program
  - Natural phenomena impacts on licensed facilities results in team event response multiple times per year

Region IV Principal Organization Roles

- Office of the Regional Administrator
  - Overall Regional activities with the lead for enforcement, allegation, information security, state liaison, outreach, and response coordination
- Division of Nuclear Materials Safety
  - Oversight of nuclear materials licensees, including ISFSI's, uranium recovery, decommissioning, and Agreement States
- Division of Reactor Projects
  - Oversight of overall reactor program implementation, including assessment of licensee performance, and resident inspection program
- Division of Reactor Safety
  - Oversight of specialized reactor inspection program and operator licensing
- Division of Resource Management & Administration
  - Oversight of operating plan, budget, human resources, financial resources, facilities, record handling, and information technology for Arlington and the remote offices

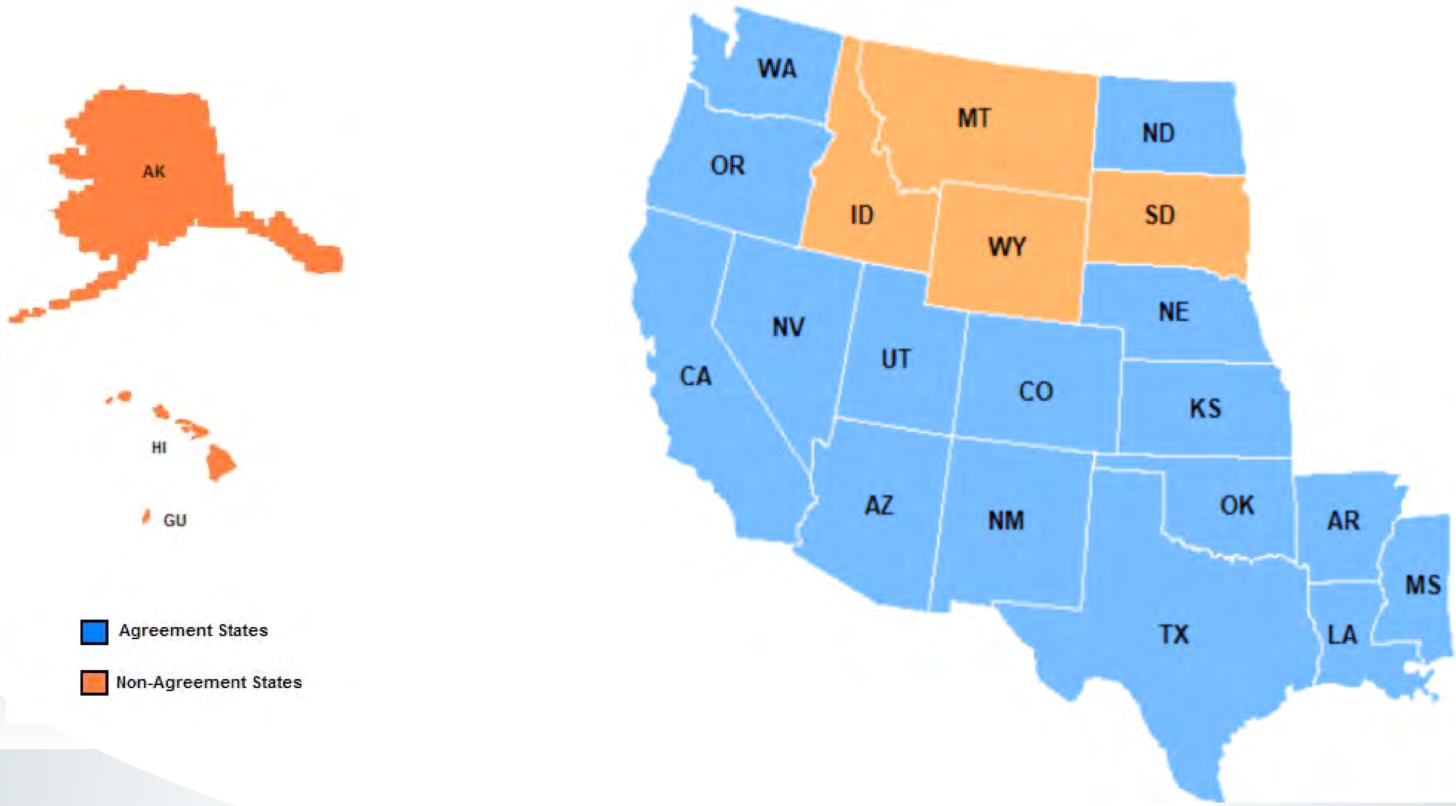
Power Reactor Program

Operating Reactor Site Map



Materials & Waste Programs

Materials Agreement States



Emergency Oversight & Response

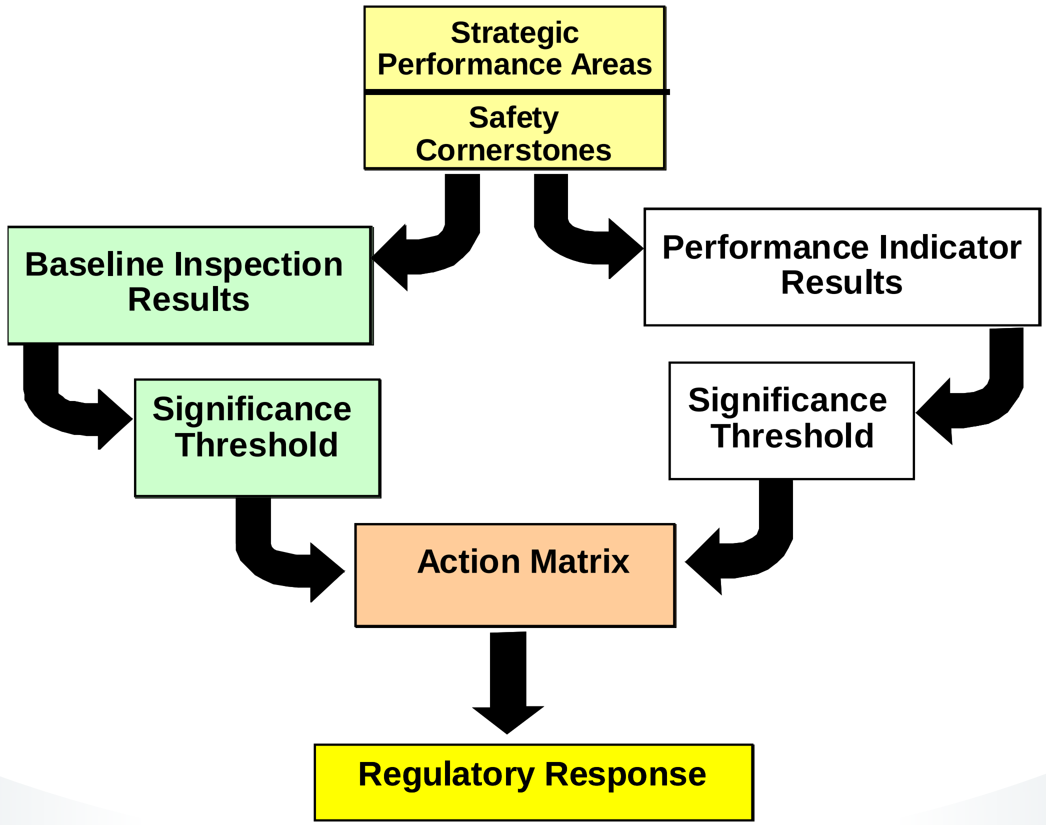
Response Coordination Branch

- Incident Response
  - Provides leadership during event response in a state-of-the-art Incident Response Center
  - Implements an enhanced outreach program with licensees and local, state, and Federal response organizations
  - Prepares for and coordinates participation in exercises with utilities and in National Level Exercises

Operating Reactors ROP Status

Ryan Lantz

ROP Flowchart



ROP Action Matrix Columns

1	2	3	4	5
Licensee Response	Regulatory Response	Degraded Cornerstone	Multiple/Repetitive Degraded Cornerstone	Unacceptable Performance

- The results of NRC inspections and licensee submitted performance indicators are used to determine the amount of regulatory oversight provided per the ROP Action Matrix

- Increasing safety significance of inputs moves the licensee to the right in the Action Matrix

- The farther to the right that a licensee falls, the greater the degree of regulatory oversight from the NRC

Region IV Overview

- 19 Operating Reactors at 13 Sites in Region IV
- Nine Sites are in the Licensee Response Column (Column 1)
- Three Column 2 Sites
- One Column 4 Site

Column 2 Sites

- Diablo Canyon; Emergency Preparedness White, effective 4Q14
- River Bend; Security Greater Than Green, White Performance Indicator, effective 2Q14
- Comanche Peak; Security Greater Than Green, effective 3Q14

Column 4 Plant

Arkansas Nuclear One, Units 1 and 2

- Moved to Column 4, from Column 3, effective 3Q14
- Yellow finding for control of contractors(June 2014)
- Yellow finding for flooding barrier deficiencies (January 2015)
- White PI for unplanned scrams
- Supplemental inspection plans being developed, pending licensee readiness

Operating Reactors
ROP Status

QUESTIONS

NFPA 805 Fire Protection Inspection Implementation

John Mateychick

First RIV NFPA 0805 Triennial Inspection

RIV Licensee Fire Protection Program Overview

- Thirteen sites in the region. Six transitioning to NFPA 805. Seven will remain Standard Review Plan sites. All older Appendix R sites are transitioning to NFPA 805.
- Seven NFPA 805 programs will have to be inspected since ANO Unit 1 is a B&W unit and ANO Unit 2 is a CE unit.
- Callaway, ANO Unit 2, Cooper, and Fort Calhoun have received their license amendments. ANO Unit 1, Diablo Canyon, and Waterford 3 will be approved before the next triennial inspection.

First RIV NFPA 0805 Triennial Inspection

- Completed inspection at Callaway last week.
- The plant analyzed 83 fire areas:
  - 28 met the deterministic requirements (NFPA 805 Section 4.2.3)
  - 55 were evaluated using the risk-informed, performance-based methodology (NFPA 805 Section 4.2.4)

Hazard Group	CDF (/yr)	LERF (/yr)
Internal Events	2.6x10-5	4.2x10-7
Fires	2.0x10-5	4.0x10-7
Seismic	2.3x10-6	Negligible
TOTAL	4.9x10-5	8.2x10-7

First RIV NFPA 0805 Triennial Inspection

Contributions to the total fire CDF:

• Main Control Room	22.63%
• Other Performance Based Fire Areas	74.26%
• Deterministically Compliant Fire Areas	3.10%

Sample Fire Areas Selected	CDF (/yr)
• Main Control Room (C-27)	2.841E-06 (22.63%)
• Control Room AC and Filtration Unit B (A-21)	2.367E-06 (18.86%)
• ESF Switchgear Room B (C-10)	1.188E-06 (9.47%)
• Reactor Trip Switchgear Room (A-27)	6.63E-08 (0.528%)

Delta in risk between full deterministic compliance and the approved program

Delta-CDF	2.2x10-6/yr	Delta-LERF	4.2x10-8/yr

First RIV NFPA 0805 Triennial Inspection

The inspection team consisted of five inspectors and a Senior Reactor Analyst. Headquarters provided a representative who was involved with approval of the new program.

- Significant preparation time was required to understand the new NFPA 805 documentation.
- To implement the new fire protection program based on a 19 page standard, the licensee estimated that 32,000 pages of documentation was developed.
- Having a Senior Reactor Analyst on the team for the initial inspection is critical.

First RIV NFPA 0805 Triennial Inspection

- For the Control Room, the focus was on the control room evacuation procedure.
  - At Callaway, this is the only fire area requiring transfer of control the remote shutdown panel (NFPA 805 Primary Control Station)
- For the other sample fire areas, the fire scenarios from the detailed fire modeling reports were walked-down along with the Recovery Actions required for two of the fire areas.

Fire Area	Fixed Ignition Scenarios	Transient Scenarios
Ventilation Room	3	3
Reactor Trip Switchgear Room	57	10
ESF Switchgear Room	64	12

First RIV NFPA 0805 Triennial Inspection

- The license condition required implementation of the items listed in the final version to the NFPA 805 Transition Report Table S-3. Those address procedure changes, process updates and training. The team selected 42 of the 74 items listed for review.

- A sample of the plant modifications associated with the new fire protection program were reviewed.

First RIV NFPA 0805 Triennial Inspection

Challenges found during the first inspection:

- Use of new techniques such as fire modeling and fire PRA combined with the number and volume of the interrelated analyses
- Confirming that the implementation items have been completed satisfactorily
- The use of different acceptance criteria in the performance-based approach versus the deterministic approach and the use of different acceptance criteria for the control room evacuation
- The use of a generic disposition statement for many Variations of Deterministic Requirements which indicated that the performance-based approach was successful but did not provide any reference to where the details supporting that conclusion were documented.

First RIV NFPA 0805 Triennial Inspection

Favorable observations during the first inspection

- Fire Modeling was performed in a conservative manner (location of fires, cable tray fill, and ventilation)
- Fire response procedures for each fire area provide the operators information necessary for responding to the potential affects of the fire in a clear and concise manner.
- Procedure for a fire in the control room provides operators more guidance as to the potential affects of the fire.

NFPA 805 Fire Protection Inspection Implementation

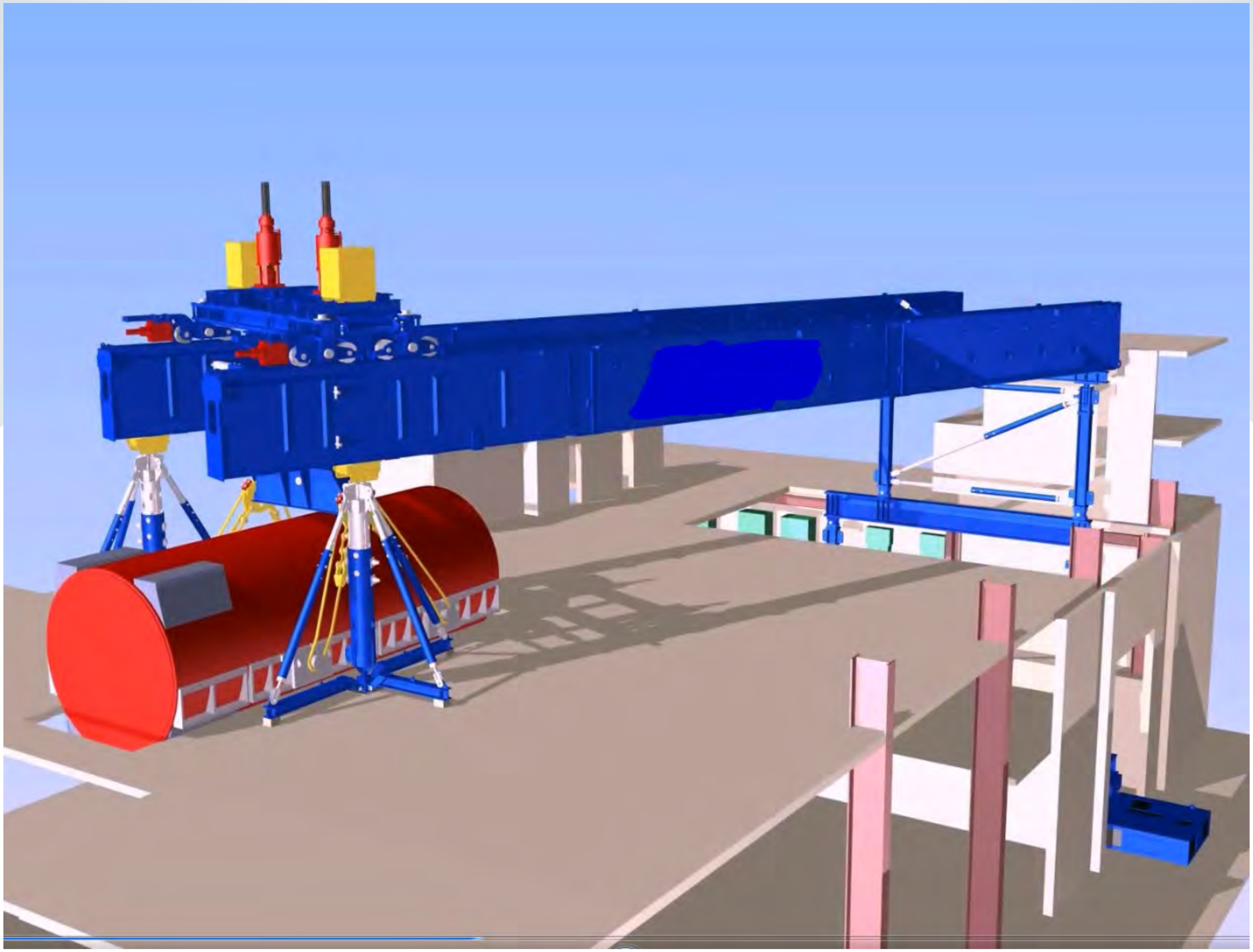
QUESTIONS

Arkansas Nuclear One: Yellow Inspections Findings

Brian Tindell

David Loveless

Arkansas Nuclear One: Stator Drop Event



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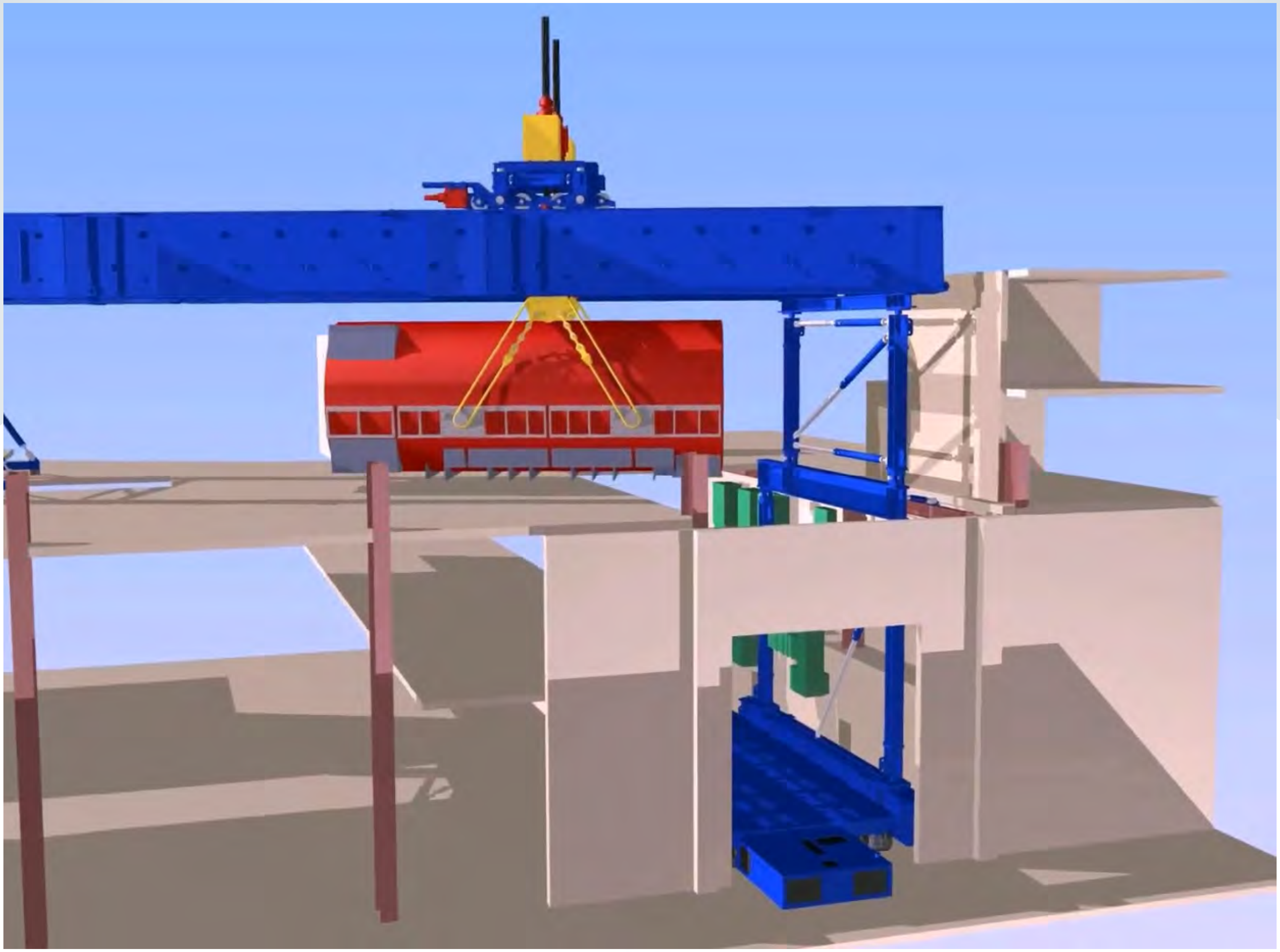
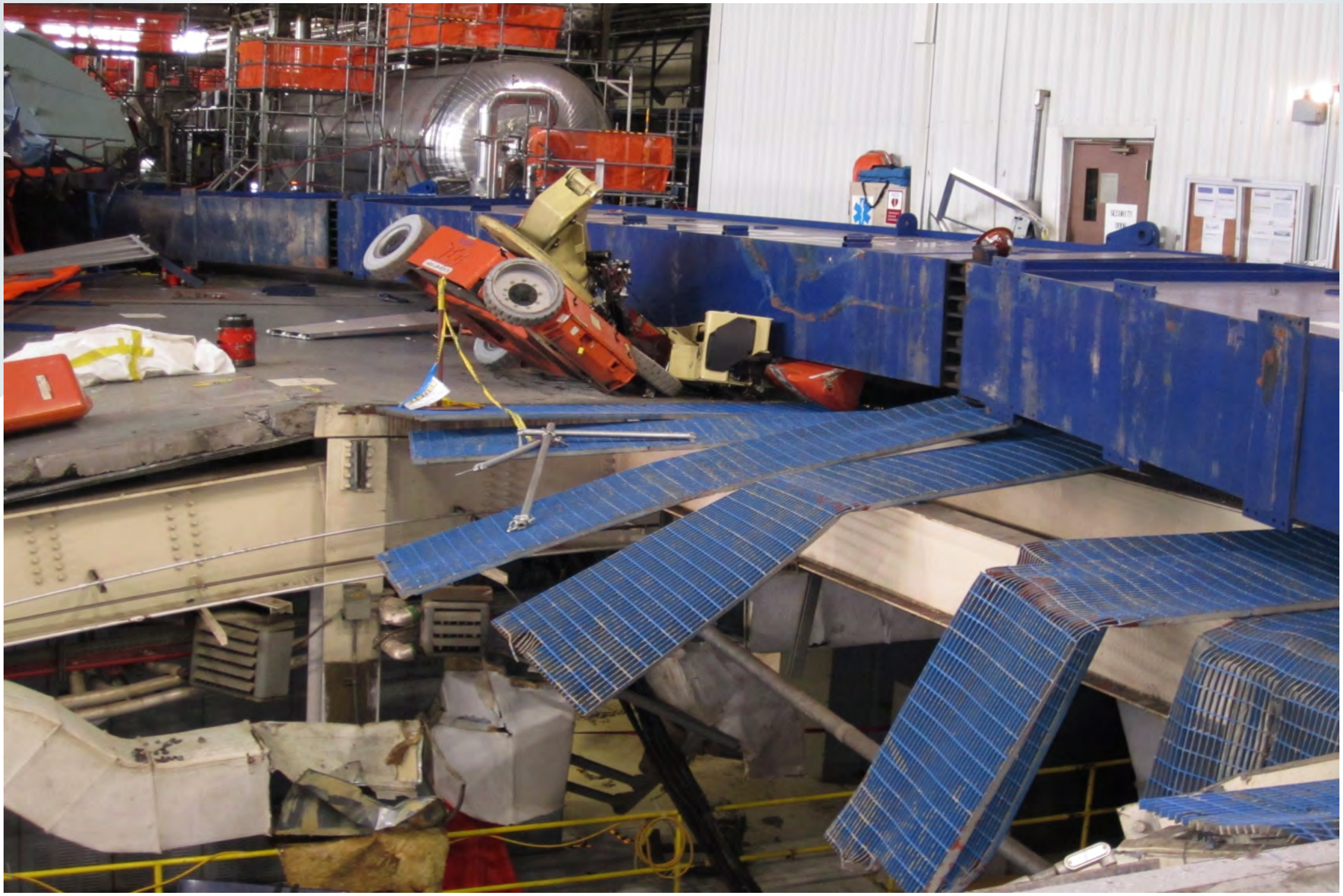




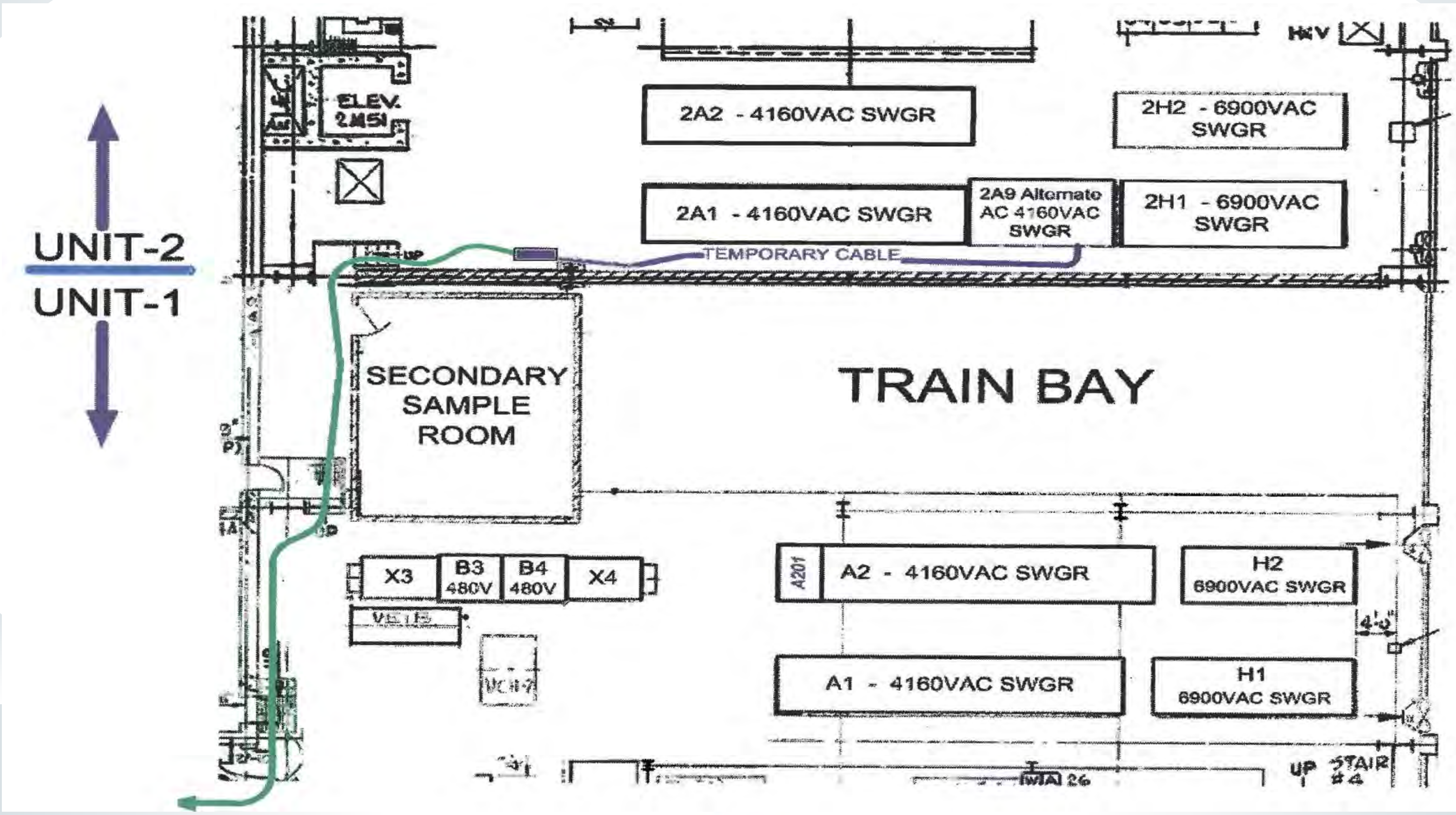

A-1
4160 VOLT
SWITCHGEAR
A-2
4160 VOLT
SWITCHGEAR

The licensee failed to perform an adequate review of the design calculation and failed to conduct a load test.

Unit 1 Plant Conditions

- Fuel in Reactor
- Pool Filled to 23 feet above active fuel
- Loss of Offsite Power
- 2 Diesel Generators in Operation
- 4.8 days to core uncovery

Electrical Damage



Unit 1 Dominant Risk

- Recovery of Shutdown Cooling
- Recovery of Offsite Power within 72 hours
- Establishing Gravity Feed to Reactor

Unit 2 Conditions

- 100 Percent Power
- Broken Fire Header
- Water Intrusion in Plant Switchgear
- Lockout of Startup Transformer 3
- Loss of Main Feedwater Regulation
- Deenergized two 6.9 kV Nonsafety Buses
- Alternate AC Diesel Generator Cable Failures

Conditions Affecting Risk

- Other Nonsafety Bus (2A2) Locked Out
  - Vital Bus Energized via Associated Diesel Generator
- Other Nonsafety Bus (2A1) Faulted
  - Nonsafety Bus 2A1 Reenergized via Alternate Breaker
  - Alternate Breaker in Wetted Area
  - Alternate Breaker Several Feet from Faulted Breaker

Unit 2 Dominant Risk

- Loss of Main Feedwater
- Postulated Failure of Emergency Feedwater
- Postulated Failure of Once-Through Cooling

Conclusions

- Unit 1: Credit for recovery yielded Yellow finding on Conditional Core Damage Probability

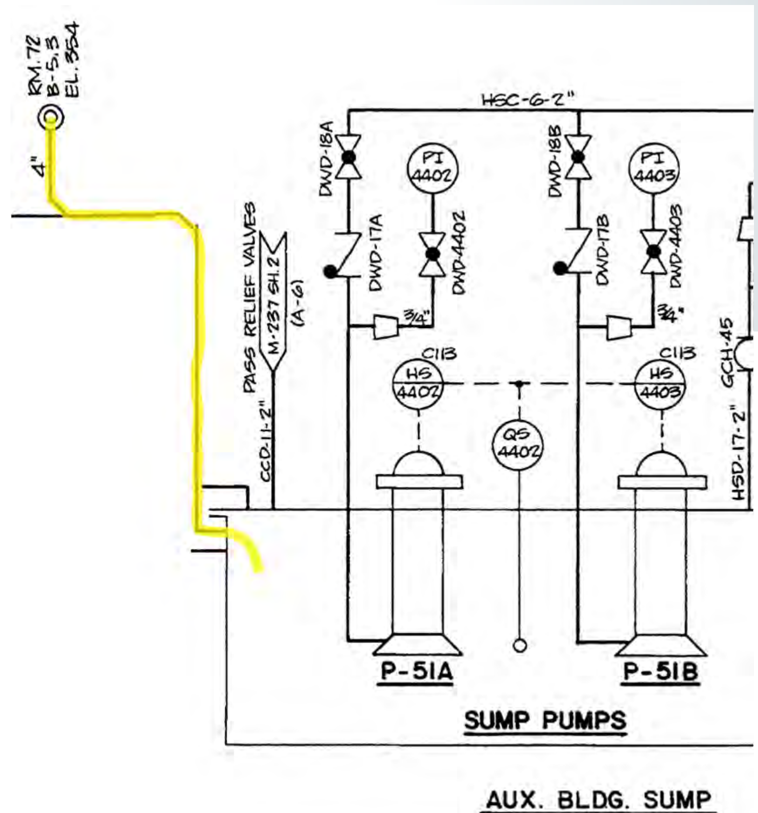
- Unit 2: Preliminary Significance Determination was valid (2.81×10^{-5})
  - Credit was Given for Nonsafety 4160 volt Bus Recovery
  - Additional Credit for AAC Diesel Generator not Significant
  - Final Significance Remained Yellow

Arkansas Nuclear One: Flooding Deficiencies

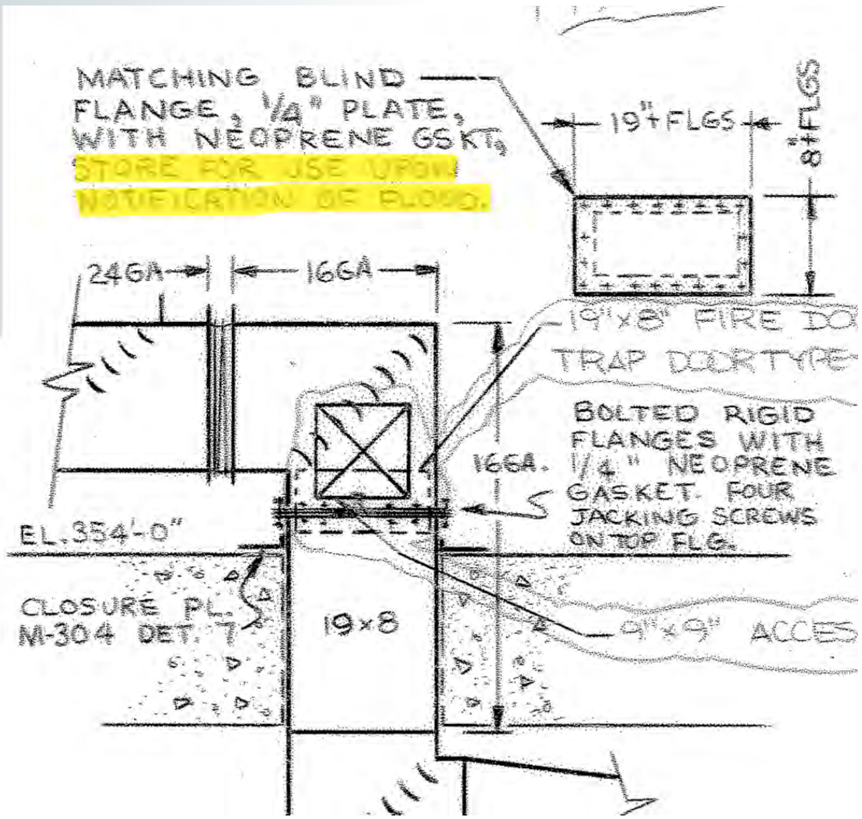

FIRE DOOR
228
CAUTION
RADIATION AREA
RADIOACTIVE MATERIAL
RADIOLOGICAL CONTROLLED AREA
RWP REQUIRED FOR ENTRY
NO EATING, SMOKING, OR CHEWING

006
H30

FLOOD
BARRIER
22LA-17
22LA-17
FLOOD SEAL



RM.72
B-5,3
EL.354
4"
HSC-6-2"
PASS RELIEF VALVES
M-237 SH.2
(A-6)
CCD-11-2"
DWD-18A
DWD-17A
PI 4402
DWD-4402
3/4"
C113
HS 4402
QS 4402
DWD-18B
DWD-17B
PI 4403
DWD-4403
HS 4403
GCH-45
HSD-17-2"
P-51A
P-51B
SUMP PUMPS
AUX. BLDG. SUMP


MATCHING BLIND FLANGE, 1/4" PLATE, WITH NEOPRENE GSKT, STORE FOR USE UPON NOTIFICATION OF FLOOD.
19" FLGS
8" FLGS
24GA
16GA
19"x8" FIRE DO
TRAP DOOR TYPE
BOLTED RIGID FLANGES WITH 1/4" NEOPRENE GASKET. FOUR JACKING SCREWS ON TOP FLG.
16GA.
EL.354'-0"
CLOSURE PL. M-304 DET. 7
19×8
9"x9" ACCES

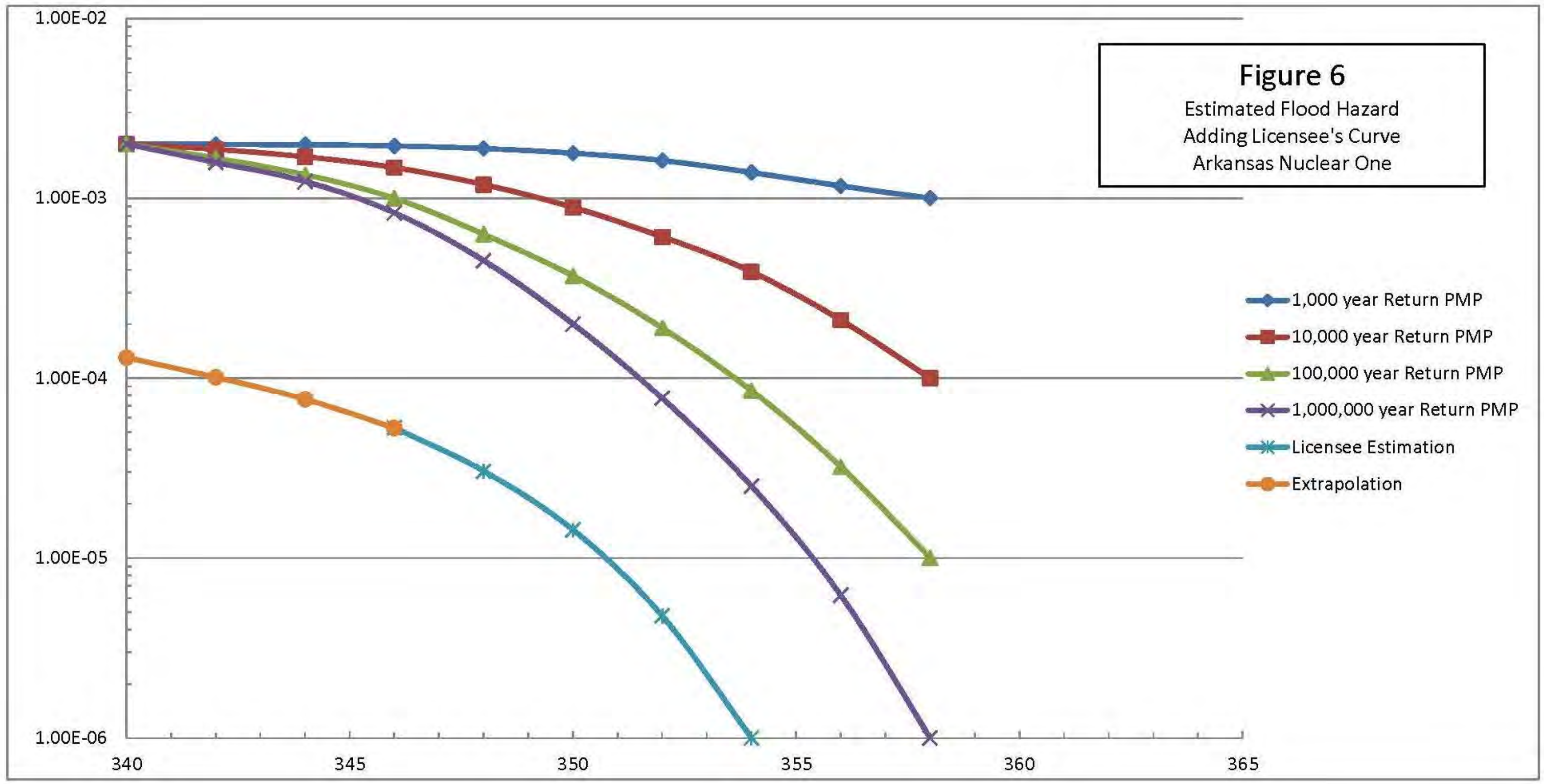

(2057-0001)


WASTE CATALYST
STORAGE TANK

The licensee failed to design, construct, and maintain the auxiliary building to protect safety-related equipment from flooding.

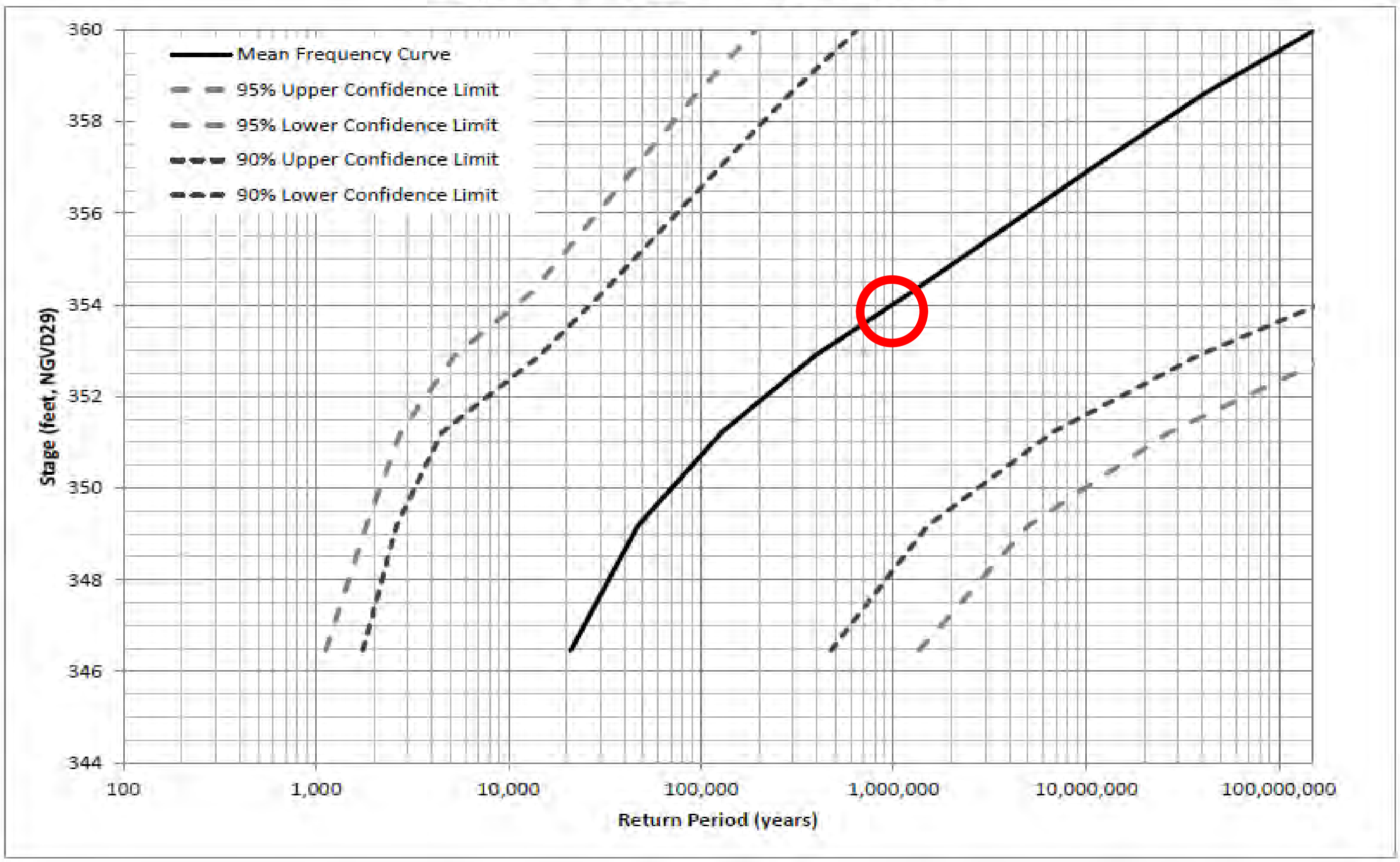
Flood Licensing Basis

Risk Assessment



Licensee's Flood Frequency

Figure 8: Stage Frequency Plot at ANO



Affected Systems

- Emergency Feedwater System - Submerged
- High Pressure Injection System – Submerged
- Spent Fuel Pool Cooling System – Submerged
- Diesel Fuel Oil Transfer Pumps – Submerged
- Decay Heat Removal System – Submerged
- Reactor Building Spray System - Submerged

Functional Recovery

- Licensee's Proposed Recovery Actions:
  - Pre-Flood Preparations protect to 2 feet above grade
  - Service Water System to Steam Generators
  - Portable pumps to Steam Generators
  - No Reactor Makeup Connections Available

Arkansas Nuclear One: Yellow Inspection Finding

QUESTIONS

Break

River Bend Special Inspections

Greg Warnick

Management Directive 8.3
NRC Incident Investigation Program

- To ensure that significant events involving reactor and materials facilities licensed by the NRC are investigated in a timely, objective, systematic, and technically sound manner; that the factual information pertaining to each event is documented; and that the cause or causes of each event are ascertained.

MD 8.3 - Objectives

- Promote public health and safety, instill public confidence, and provide for the common defense and security
- Increase the efficiency and effectiveness of NRC regulatory programs and licensee operations
- Improve regulatory oversight of licensee activities
- Ensure that Incident Investigation, Augmented Inspection, and Special Inspection Team findings are properly dispositioned

Inspection Manual Chapter 0309

- Serves as guidance for implementing the requirements prescribed in Management Directive 8.3 for operating reactors.
- Includes a detailed list of deterministic criteria that can be used on their own or in conjunction with a probabilistic risk assessment as a decision basis for implementing reactive inspections.

Unplanned Reactor Trip with Complications

- On Christmas Day 2014, at 8:37 AM, River Bend Station scrammed from 85 percent power
- An unexpected Level 8 (high) reactor water level signal was received
- Following reset of the Level 8 high reactor water level signal, complications occurred associated with the recovery of feedwater
- Operators were unable to recover feed in time to prevent a Level 3 low reactor water level trip

MD 8.3 Decision Basis

- The event included multiple failures in the feedwater system
- Involved Magne Blast circuit breaker issues which could possibly have generic implications
- Involved several issues related to the ability of operations to control reactor vessel level
- The preliminary Estimated Conditional Core Damage Probability was determined to be 1.2E-6

Loss of Control Building HVAC

- March 9, 2015, during emergency core cooling system and loss of coolant accident (ECCS/LOCA) testing of Division I, control building chiller 1C failed to start
- No other Division I chillers were available, so operations personnel attempted to start either of the Division II chillers without success
- Abnormal operating procedure for a "Loss of Control Building Ventilation," was entered due to the loss of the control building ventilation system
- Similar equipment failures occurred during Division II ECCS/LOCA testing on February 23, 2015

MD 8.3 Decision Basis

- The event included multiple failures in the control building ventilation system
- Involved repetitive failures of safety-related Masterpact breakers
- Overall adequacy of the licensee’s breaker maintenance program called into question
- The preliminary Estimated Conditional Core Damage Probability was determined to be 2.6E-6

- Inspection Status
- Feedback

River Bend Special Inspections

QUESTIONS

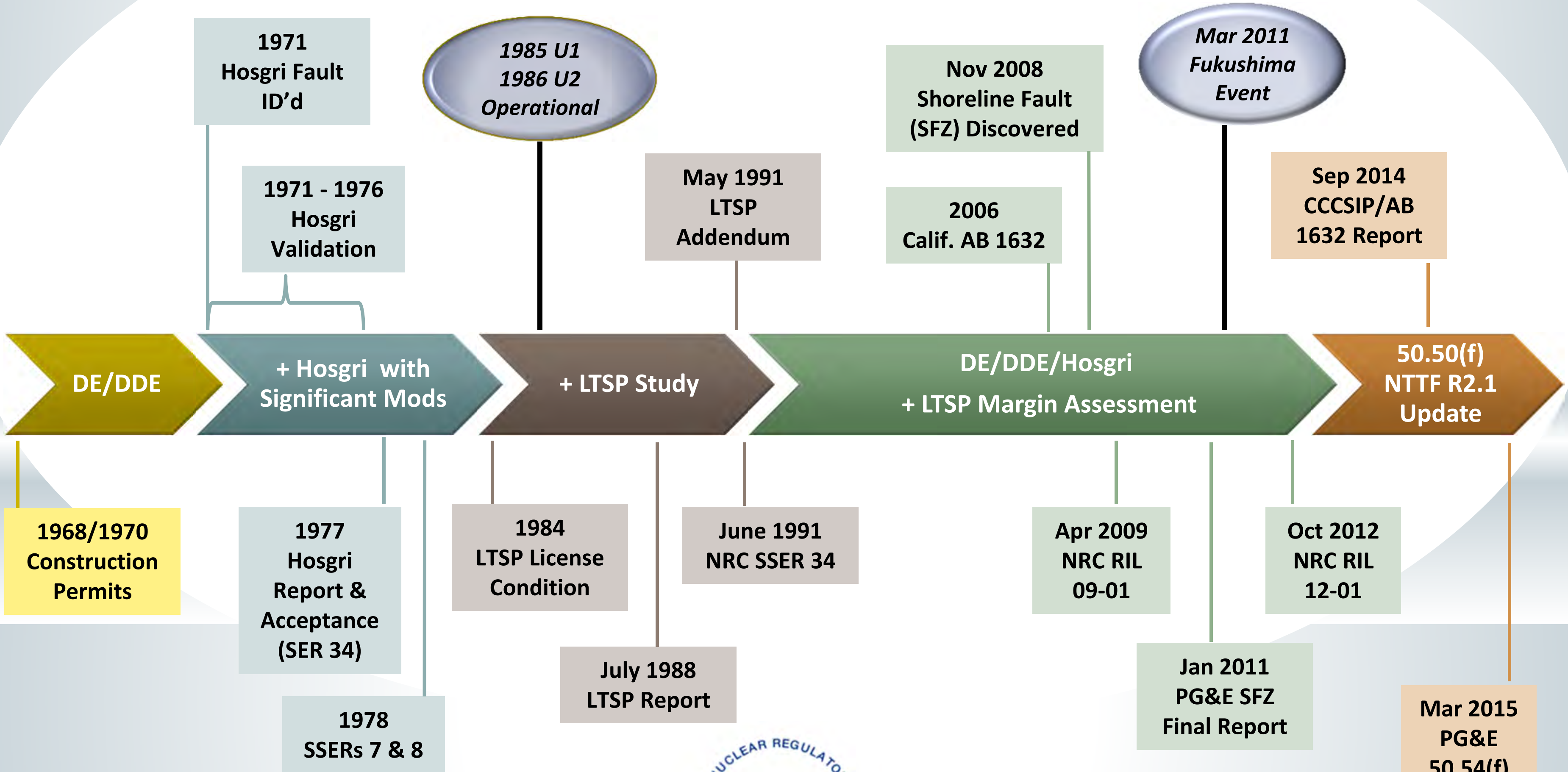
Background, Status of Seismic Analyses, and Challenges at Diablo Canyon

Wayne Walker

Current Seismic Licensing Basis

- Design Earthquake (DE) = 0.2 g Peak Ground Acceleration (PGA)
  - Equivalent to Operating Basis Earthquake
- Double Design Earthquake (DDE) = 0.4 g PGA
  - Equivalent to Safe Shutdown Earthquake
- Hosgri Earthquake (HE) = 0.75 g PGA
  - Unique to DCPP
- Reactor Protection System Reactor Trip = 0.3 g
  - 3 sensors on Containment base slab
  - Unique to DCPP

Seismic Design/Licensing History



Recent Seismic Issues (2006 – 2015)

- Shoreline Fault Zone
  - NRC Staff reviewed PG&E's Initial Shoreline report
    (Research Information Letter 09-01)
  - NRC Staff reviewed PG&E's final Shoreline report
    (Research Information Letter 12-01)
- California-mandated study and report (AB-1632/CCCSIP)
- NRC Post-Fukushima Recommendations
  - PG&E used NRC-endorsed seismic analyses peer review process (SSHAC process)
  - Seismic Re-Evaluation Submittal

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Seismic Re-Evaluation

- New Ground Motion Response Spectrum (GMRS)
  - Exceeds DDE (SSE)
  - Mostly encompassed by HE
- Under review by HQ Staff
- May 2015 Screening Letter
  - Seismic Probabilistic Risk Assessment by June 2017
  - No immediate safety issues

Current Challenges

- Complicated Seismic History = Complex Inspections
  - Shoreline Fault
  - California-mandated study and report
  - Large Component Modifications
- Well Informed and Engaged External Stakeholders
  - Enhanced Outreach & Public Meetings
  - Congressional Interest
- Impact of seismic re-evaluation on current licensing basis and inspections

License Renewal

- November 2009 – Initiated license renewal process
- April 2011 – PG&E requests “delay in final processing”
- April 2015 – NRC resumes license renewal activities

Background, Status of Seismic Analyses, and Challenges at Diablo Canyon

QUESTIONS

Component Design Basis Inspections

Tom Farnholtz

Component Design Basis Inspection Issues Identified in Region IV

- Fort Calhoun Station External Flooding Mitigation Inadequacies
- Comanche Peak Condensate Storage Tank Bladder Vulnerabilities
- Waterford Unit 3 Emergency Diesel Generator Day Tank Vent Corrosion
- Fort Calhoun Station Assessment of Engineering Readiness to Transition from 0350 Status to the ROP


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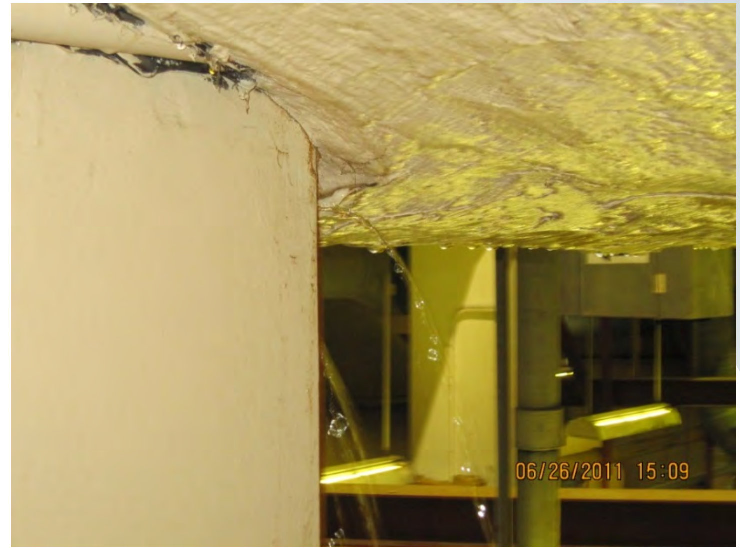
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Industry Recommendations to Enhance Efficiency and Effectiveness of Engineering and Design Inspections

- Utilize NRC's suite of engineering and design inspections to focus more on validation of design program effectiveness and provide for scaling inspections based on licensee performance
- Revise the scope of the current CDBI to reflect the full utilization of other engineering and design inspections
- Establish a framework for allocating credit for licensee self-assessment
- Establish a management forum for lessons learned

NRC Response to Industry Recommendations is a Two Phase Approach

- In the short term, pilot inspections of a revised CDBI procedure will be performed in each region in late 2015 and early 2016. Lessons learned from these pilot inspections will be incorporated into the final version of the procedure, to be used in 2017.

- In the longer term, consideration will be given to revising other engineering and design inspection procedures to further reduce the impact of the CDBI inspection by incorporating some aspects into other inspection activities. In addition to continuing to evaluate recommendations from the ROP feedback and ROP enhancement programs.

Component Design Basis Inspections

QUESTIONS

Wrap-up

Public Comments

Subcommittee Discussion

Gordon Skillman

Adjourn

Gordon Skillman