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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

+ + + + +

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

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Adjourn	

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

2 MR. SKILLMAN: The meeting will now come to order.
3 To the Region IV crew, thank you very much for permitting
4 us to come here today. We have been looking forward to
5 this meeting.
6 This meeting is a meeting of the Advisory
7 Committee and Reactor Safeguards Plant Operations and
8 Fire Protection Subcommittee. My name is Dick Skillman
9 and I'm chairman of the subcommittee.
10 ACRS members in attendance are Dr. Peter
11 Riccardella, Dr. Michael Corradini, Dr. Ron Ballinger,
12 Dr. Michael Bley, Dr. John Stetkar, Dr. Joy Rempe, and
13 Dr. Steven Schultz. The designated federal official is
14 Mike Snodderly.
15 The ACRS meets annually in one of the NRC's
16 four regions to discuss that region's oversight and
17 inspection of those facilities. The purpose of today's
18 briefing is for the Region IV staff to discuss items of
19 mutual interest, namely regional inspection and
20 operational activities. The subcommittee will gather
21 information, analyze relevant issues and facts, and
22 formulate a proposed position and action as appropriate
23 for deliberation by the full committee if needed.
24 The rules for participation in today's
25 meeting were announced as part of the notice of this

1 meeting previously published in the Federal Register on
2 May 13, 2015. The meeting will be open to public
3 attendance with the exception of portions that may be
4 closed to protect information that is proprietary, and
5 that is pursuant to 5 USC 522(b)(c)(4). We have
6 received no written comments or requests for time to
7 make oral statements.
8 A transcript of today's meeting is being kept
9 and will be made available as stated in the Federal
10 Register notice, therefore, we request that meeting
11 participants use the microphones located throughout the
12 meeting room. When addressing the subcommittee,
13 participants should first identify themselves and speak
14 with sufficient clarity and volume so that they can be
15 readily heard. A telephone bridge line has been
16 established for this meeting. To preclude
17 interruption of this meeting, I ask that you please mute
18 your electronic devices.
19 We will now proceed with the meeting, and I
20 call on Mr. Kriss Kennedy, deputy regional
21 administrator of Region IV, to make introductory
22 remarks. Thank you.
23 MR. KENNEDY: Thank you, Mr. Skillman.
24 Good morning. On behalf of Mark Dapas, the
25 Region IV regional administrator and the dedicated

1 members of the Region IV staff, I want to welcome the
2 members of the Advisory Committee on Reactor Safeguard
3 to the NRC Region IV office in Arlington, Texas.
4 My name is Kriss Kennedy. I'm the deputy
5 regional administrator in Region IV. Mark Dapas was
6 not able to be with us today. He's up at headquarters
7 participating in a Commission meeting; they're briefing
8 the Commission on the results of the agency action
9 review meeting, and I did have an opportunity to watch
10 a little bit of that this morning.
11 Region IV is excited and honored to host this
12 meeting today. We have prepared briefings on a number
13 of different topics that we hope you'll find interesting
14 and informative. We also look forward to your
15 questions and discussions on these topics.
16 I want to thank the Region IV staff for all
17 their hard work in preparing for this meeting, and I'll
18 introduce the presenters for today's meeting.
19 Although not presenting, I do want to introduce Tony
20 Vegel. Tony is the director of the Division of Reactor
21 Safety, and most recently he completed work as the
22 leader of the oversight panel for Fort Calhoun Station.
23 Ryan Lantz is the deputy director of the
24 Division of Reactor Projects.
25 John Mateychick, senior reactor inspector in

1 the Fire Protection area. John, did you raise your
2 hand? There you go.
3 And Brian Tindell. Brian is the senior
4 resident inspector at Arkansas Nuclear One.
5 David Loveless is one of the senior reactor
6 analysts in Region IV.
7 Greg Warnick is a branch chief in the Division
8 of Reactor Projects. Most recently he was the senior
9 resident inspector at San Onofre.
10 Wayne Walker is a branch chief in the Division
11 of Reactor Projects.
12 Tom Farnholtz is a branch chief in the
13 Division of Reactor Safety. And did we get all the
14 presenters? Okay, good.
15 I also want to thank the other staff members
16 who helped the presenters prepare their discussion
17 topics and their presentations, and also our IT staff
18 that helped us set this up today.
19 Before I start with just an overview of Region
20 IV, I wanted to provide a short safety briefing. We are
21 in the first floor conference room. If for some reason
22 we had to evacuate the building, we would go out the
23 front door that you came in this morning and we'd go to
24 the far end of the parking lot, assemble at the far end
25 of the parking lot towards the main road. We may get

1 a little wet today if we have to do that, but that's where
2 we would assemble.
3 If we have a need to shelter in place, the
4 staff would assemble in the interior rooms, including
5 this one, so although we don't forecast any need to do
6 that this morning, I just wanted to let you know what
7 the protocol was. The bathrooms are down the hall as
8 you leave this room to the left, just across the lobby.
9 And please let myself or any other member of
10 the Region IV staff know if you need anything or if we
11 can help you in any way during your visit today.
12 Before we begin the presentations, I'd like
13 to provide a high level overview of Region IV. So
14 Region IV licensees are in a geographic area that
15 encompasses essentially the western half of the United
16 States. Our licensees include 13 operating reactor
17 sites with 19 operating reactors and approximately 600
18 materials licensees.
19 In addition to our inspection and oversight
20 function, we maintain the capability to respond to plant
21 events and impacts from natural phenomena 24 hours a
22 day. Working in concert with response by the
23 headquarters staff, our response could include the
24 staffing of our instant response center here in the
25 Region IV office and dispatching a team from the region

1 to the affected site.

2 We have approximately 200 staff in Region IV.

3 MR. SKILLMAN: Kriss, would you go back one,

4 please?

5 MR. KENNEDY: Yes, sir.

6 MR. SKILLMAN: I see you write 13 operating

7 reactor sites and 14 ISFSIs. Is the 14th San Onofre,

8 the non-operating site, is that what that is?

9 MR. KENNEDY: I'd have to look at the

10 specific inputs to the numbers, but I think the 14th is

11 the ISFSI, independent spent filed storage

12 installation.

13 MR. SKILLMAN: Thank you, Chris.

14 DR. BALLINGER: Chris, the last bullet says

15 many times a year. Can you modify that?

16 MR. KENNEDY: Thank you. Because our sites

17 are on the Gulf, we have a lot of opportunities to

18 respond to hurricanes, and so a majority of our response

19 to natural phenomena deals with hurricanes.

20 DR. BALLINGER: And where does that start?

21 Are you talking about unusual event alerts or just when

22 the phenomena is going to occur you assemble?

23 MR. KENNEDY: About 72 hours before the onset

24 of a hurricane we will start in our monitoring mode, we

25 will bring people into the incident response center and

1 start the process of monitoring the hurricane,
2 monitoring plant response to the hurricane, and then our
3 onsite inspectors are also monitoring licensee actions
4 to prepare for the hurricane.
5 Another unique thing that we do is in
6 consideration for the onsite inspectors, we will
7 actually dispatch one or more inspectors from the
8 regional office to allow the resident inspectors to take
9 care of their own families and their property. So in
10 advance of a hurricane, we'll dispatch staff from the
11 region to fill that inspector role such that the
12 inspectors can take care of family and property.
13 We've been lucky. it's been a couple of
14 years since we had a significant hurricane that would
15 impact one of our sites, but it hasn't -- it wasn't that
16 way several years before that.
17 DR. CORRADINI: What about preparation for
18 tornado response or tornado events?
19 MR. KENNEDY: In the case of a
20 tornado -- obviously you can't predict
21 tornadoes -- licensees do have procedures for abnormal
22 weather that includes high winds, and so licensees
23 typically have some advance notice if there's a tornado
24 watch, tornado warning, and they will take actions to
25 prepare the site for that high wind event, primarily

1 making sure that there's not loose equipment in the
2 yard, that equipment is tied down or placed inside. And
3 then if there was an actual event, some damage caused
4 by the tornado, we would be in a response mode for that,
5 including response by our resident inspectors.
6 Any other questions?
7 DR. BLEY: Yeah. What is the real issue
8 regarding the Air Force Master Material License?
9 MR. KENNEDY: Well, it's not an issue. It's
10 just a program that we have responsibility for in the
11 licensing and oversight of that master materials
12 program.
13 DR. BLEY: Is this weapons material or is
14 this diagnostic material?
15 MR. KENNEDY: No, no. It's any of the
16 radioactive sources, byproducts that they may use in
17 their operations, not weapons.
18 DR. BLEY: Thank you, Kriss.
19 Again, we have about 200 staff members in
20 Region IV. In addition to the Office of Regional
21 Administrator, we have four divisions. It's fairly
22 standard from region to region. Region II is a little
23 different in that they do not have a materials division,
24 they have a fuel facilities division, and of course,
25 Region II also has the construction inspection program.

1 Division of Nuclear Materials Safety has oversight
2 for nuclear materials licensees.
3 Division of Reactor Projects, they own the
4 resident inspectors. The resident inspectors are in
5 the Division of Reactor Projects, and so the branch
6 chiefs in the Division of Reactor Projects manages the
7 inspection oversight and assessment of the plants that
8 they're responsible for.
9 Division of Reactor Safety, their inspectors
10 are located here in the region and they conduct the more
11 specialized inspections, some of which you'll hear
12 about today, including fire protection and the
13 component design basis inspection.
14 And then we have the Division of Resource
15 Management Administration that does our budgeting,
16 human resources, acquisitions, and financial
17 management.
18 This is just a quick graphic and depiction of
19 the geographic area that we have and where our reactor
20 sites are located. You were at the Palo Verde the last
21 couple of days. And then this is a depiction on the
22 materials side the states that are agreement states and
23 non-agreement states.
24 The NRC has regulatory authority for
25 materials licensees in those states that we refer to as

1 non-agreement states, and those states that have
2 assumed NRC regulatory authority for material licensees
3 under the Atomic Energy Act of 1954, we refer to those
4 as agreement states. Our area includes the western
5 half of the United States, Alaska, Hawaii and Guam, so
6 our materials inspectors conduct inspections in Guam.
7 DR. BLEY: The 600 licensees, that's just in
8 the non-agreement states?
9 MR. KENNEDY: That would be non-agreement
10 states and federal facilities in agreement states.
11 DR. BALLINGER: With the non-agreement
12 states, the yellowish group, do you have then folks that
13 travel there and do inspections?
14 MR. KENNEDY: Yes, sir, we do.
15 DR. BALLINGER: But nobody in residence?
16 Nobody -- there's no office that --
17 MR. KENNEDY: There's no office, no
18 full-time resident inspectors at those sites. I was
19 going to mention this. You know, because of the large
20 geographic area that we have, it is a challenge for both
21 materials inspectors and the Division of Reactor Safety
22 inspectors to conduct those inspections, to travel to
23 conduct those inspections. To fly to Columbia
24 Generating Station takes a day.
25 DR. STETKAR: How long does it take to get to

1 Guam?

2 (General laughter.)

3 MR. KENNEDY: Tony how often -- we go to Guam

4 once a year, and you have to factor that in. So it

5 creates a challenge but we've gotten good at it. Some

6 of these materials sites are very remote.

7 DR. CORRADINI: What interaction do you have

8 to have with the agreement states? Do you track what's

9 going on there?

10 MR. KENNEDY: We do. We provide oversight

11 of the agreement states' implementation of the

12 inspection program and we conduct periodic reviews of

13 their programs to ensure that they're consistent with

14 the NRC's programs. It's a formal review, we will send

15 people to the state offices, review their programs and

16 provide them feedback on the results of that program.

17 DR. BLEY: Have you ever run into problems

18 that they're not doing what you expect?

19 MR. KENNEDY: Yes, we have.

20 DR. BLEY: They're not licensees, so what is

21 the administrative way you deal with that?

22 MR. KENNEDY: Tony, can I get your assistance

23 on answering this question.

24 MR. VEGEL: Absolutely.

25 MR. SKILLMAN: Make sure you're at a

1 microphone, because we have to have it on a transcript.
2 MR. KENNEDY: Tony was -- prior to his
3 current position, he was a director of Division for
4 Material Safety.
5 MR. VEGEL: We have a program, Kriss talked
6 about the periodic reviews, and if we see where there's
7 gaps in alignment, we can increase the oversight by
8 increased meetings with them, and then also, every time
9 we do a review, we develop recommendations and they may
10 have to follow up on that. And we do have the option
11 of taking the program back.
12 DR. STETKAR: Has that ever happened
13 anywhere?
14 MR. VEGEL: Not that I'm aware of, but there
15 has been some, I think it was in Region II, the Georgia
16 program that came very close to that.
17 I think it would be important to note that we
18 have staff dedicated, state agreements officers, that
19 constantly communicate with the agreement states and
20 have that point of contact with the agency and what the
21 agreement states are doing, and then also it tells you
22 if there's events within the agreement states, that
23 there's communications and awareness of what the states
24 are doing in response to issues.
25 Does that help?

1 MR. KENNEDY: Thanks, Tony.

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

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

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

1 MR. KENNEDY: Yes, we do.

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

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

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

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

1 exercises, has there been evidence of specific
2 weaknesses that have emerged that are new or different
3 over the last eight to ten years? Is there something
4 new that's beginning to show itself that we hadn't
5 anticipated in the past?
6 MR. KENNEDY: It's a good question because
7 what's happened in the last ten years obviously is the
8 implementation of the hostile action based exercises
9 that licensees are now required to conduct on a periodic
10 basis. I think it's every six years they have to
11 conduct a hostile action based exercise. So that
12 actually created whole new scenarios and a whole new way
13 to interact, both with the NRC, with offsite
14 organizations and even internally, and so I think that
15 has created some new observations/findings, as we would
16 expect. And that's the purpose of the exercises is to
17 help licensees improve, help NRC improve.
18 I'm just trying to think of some of the ones
19 we've had in the last couple of exercises. Primarily
20 it's communication, command and control, how licensees
21 interact with local law enforcement who are actually
22 staffing the incident command posts and the overall
23 coordination of that response, because it's a
24 security-centric response as opposed to what we've been
25 used to in the past with our exercises which were all

1 focused on the plant and the reactor.

2 MR. SKILLMAN: Radiological.

3 MR. KENNEDY: Yes, radiological.

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

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

22 MR. KENNEDY: Without going into too much
23 detail, what I can tell you is that based on the hostile
24 action based exercises I've participated in and have
25 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

1 that possibility.

2 DR. BLEY: At least we brought it up and I

3 guess you can't talk more about it, but it was a striking

4 audit concern and the folks at that meeting were mostly

5 security folks.

6 MR. KENNEDY: I can tell you on the three or

7 four or five hostile action based exercises I've been

8 that's never come up.

9 DR. BLEY: But it has somewhere and they

10 claimed the right of law to do what they were doing, and

11 they would have created a worse situation than the bad

12 guys.

13 MR. SKILLMAN: I think that's worth hearing

14 two times. Here we all think we're doing the right

15 thing, at least in our case, that security scenario

16 unraveled very, very quickly. It was underway before

17 anybody knew what to do about it, and in that case we

18 went from a 100 percent normal operation on a beautiful

19 Sunday morning to a site area emergency because of the

20 way our EALs were written.

21 Dr. Bley has introduced this issue, but who

22 has got the right to shoot, and particularly, who has

23 got the right to stop an operator from taking important

24 action that might save the core. I think that needs

25 some ventilation. That's all I'm going to say.

1 MR. KENNEDY: I don't know the specifics of
2 that case, but based on the exercises and responses I've
3 seen, I'm confident that licensees have measures in
4 place to address that.
5 Any other questions for me?
6 (No response.)
7 MR. KENNEDY: Okay. At this point I'd like
8 to turn it over to Ryan Lantz, and Ryan is going to
9 provide an overview of the Reactor Oversight Process in
10 Region IV.
11 MR. LANTZ: Thank you, Kriss.
12 I'll just start out, I'll apologize for the
13 acronym on the slide, ROP, that is our Reactor Oversight
14 Process. It would have fit on the slide but it would
15 have looked a little cumbersome, so I'll start with that
16 apology.
17 I have two main goals this morning. I'd like
18 to talk to you a little bit about what the ROP is and
19 how it does what it does, and then I just want to cover
20 briefly what the current status of the outcome of the
21 ROP is with each of the Region IV operating reactor
22 sites.
23 So this is kind of in a nutshell what the ROP
24 is, and if you look at the very top of this
25 diagram -- we'll start at the top, of course, that's a

1 good place to start -- the goal of the Reactor Oversight
2 Process is the continuous assessment of the safety
3 status of the operating reactor plants. So by safety
4 status I mean what's going to impact, with the operation
5 of a nuclear power plant, what is going to impact public
6 health and safety. So that's what we're concerned
7 about.
8 So we divide up all those things that might
9 impact public health and safety into three strategic
10 performance areas, that first block, and those are
11 reactor safety, radiation safety, and then safeguards.
12 Then we further break those three strategic areas into
13 cornerstones of safety, and there's seven cornerstones
14 of safety. The reactor strategic area has four: it's
15 an initiating event, mitigating systems, barrier
16 integrity, and then the emergency preparedness
17 cornerstone.
18 The radiation strategic performance area has
19 two cornerstones: that's public health and safety,
20 public radiation health, and then occupational which is
21 the workers at the plant radiation safety.
22 And the safeguards area has only one
23 cornerstone and that's the security of the plant and the
24 information at the plant.
25 On both sides of the top you'll see baseline

1 inspection results and performance indicators. We
2 spend roughly, on average at each plant 2,700 hours
3 devoted to inspection, the baseline inspection program
4 at each reactor facility, at each reactor site. Those
5 inspection procedures are all public, they're all
6 visible, and we take the results of those inspections,
7 and I'll talk briefly about how significant each one of
8 the results of those inspections and the findings that
9 come out of those inspections.
10 Similarly, for the performance indicators
11 this is a voluntary program that every licensee is
12 participating in, and performance indicators set some
13 data and information that they collect and report to us
14 every quarter and they're broken up also into each one
15 of the seven cornerstones of safety. So they provide
16 a set of data every quarter, things like how many
17 unplanned reactor scrams occurred per the last 7,000
18 critical hours, how effective have their offsite sirens
19 been, what is the percentage of the releases that were
20 done outside the plant and how they compare to certain
21 limits that we have set, so what percentages.
22 DR. BLEY: Ryan, I'm pretty familiar with how
23 the left side, the inspection side part works. How the
24 right side works, especially with respect to the
25 thresholds and what they are and what happens if you

1 don't meet those, I haven't heard much about. If you
2 could expand on that just a little. I know you don't
3 have much time.
4 MR. LANTZ: Absolutely. So like I said,
5 performance indicators are all well defined, they have
6 thresholds that are all predetermined. One thing you
7 may be familiar with, the significance determination
8 process for inspection findings, there's a risk-based
9 grouping where we actually assign a risk of core damage
10 frequency, change to core damage frequency, and then
11 there's some more deterministic, like emergency
12 preparedness findings are put through a process. It's
13 not risk-based but it does relate to significance. And
14 the outcome of that is green, white, yellow or red, and
15 I think you're all fairly familiar with those terms. So
16 that's the significance determination for inspection.
17 Very similar on the performance indicator
18 side, but on that side the data is compared to
19 predetermined thresholds that are advertised, and the
20 outcome is if the performance indicator is functioning
21 like we expect, like say there's no unplanned scrams
22 during the quarter, they report a number of zero, that
23 produces a green threshold, they're in that green band.
24 If they exceed a threshold that's
25 predetermined -- and I'll give you one example,

1 unplanned scrams with complications -- they're only
2 allowed one in the time period of that assessment. If
3 there's two, then that crosses a threshold into white.
4 DR. BLEY: But it only goes to white. Do any
5 of those --
6 MR. LANTZ: No. They do go -- some do go
7 further, and I think yellow is the most for a performance
8 indicator. So the same way that reactor inspection
9 results result in green, white, yellow and red outcomes,
10 and they're related to risk to the public, performance
11 indicator results are the same way. They'll get green
12 inputs, white inputs, yellow inputs, not a red input.
13 MR. SKILLMAN: Ryan, let me just fact-check
14 my own understanding. Let's say in this operating
15 cycle you have one trip in 7,000 hours and it's a not
16 complicated trip, it's a rod drop, the plant comes down,
17 and 36 hours later you're back in power.
18 The following year you have two. One of them
19 is a very similar event, just a mild trip, the instrument
20 system has a hiccup, and then two months later after
21 you're back stabilized, you have another one, same
22 system, leading to complications, a couple of valves
23 stuck open, you drop reactor coolants and compressor
24 doesn't ignite when it should, and now you're into a
25 complicated trip. I believe that could conceivably

1 take you to a red; I don't think you're limited to a
2 yellow. I think if you line up enough pieces, STP might
3 even take you to red.
4 For instance, you had incidents up at Fort
5 Calhoun that came out red, and we're saying wait a
6 minute, what's cooking here. All I'm saying is you had
7 said as far as it goes is probably a yellow. I'm
8 challenging saying I think you can get worse than that,
9 given particular circumstances.
10 MR. LANTZ: So now the fact that there were
11 scrams, maybe there was a scram with complications as
12 you described, those would feed into the performance
13 indicator, and as I understand, there are no red
14 performance indicators. I'm looking at my body of
15 knowledge over there.
16 MR. ALEXANDER: I just looked it up to remind
17 myself, they're pretty high thresholds. This is Ryan
18 Alexander, a senior project engineer in Division of
19 Reactor Projects.
20 For example, the unplanned scrams per 7,000
21 critical hours, if you had more than 25 unplanned scrams
22 per 7,000 critical hours, yes, you could cross into red,
23 and also in the mitigating systems performance index,
24 those systems all at the one E four range of that
25 calculation can result in yellow.

1 VOICE: What about repeated events, do
2 repeated events have a special treatment?
3 MR. ALEXANDER: It depends on where they fall
4 in the time frame of that calculation in most cases.
5 MR. LANTZ: So one thing I wanted to make a
6 point, we talked about the scram, so that feeds into
7 performance indicators, the fact there was a scram,
8 there was a scram that feeds into performance
9 indicators, we don't stop at that. We need to look at
10 why did the scram occur, was there a performance
11 deficiency, so something that the licensee should have
12 been able to know, predict and prevent. And so we will
13 factor that into our inspection side and that's where
14 maybe you've only had two or three trips, but if there's
15 some significance, we'll feed that in, and you can
16 actually get up to a red flag for a performance issue
17 that occurred at the plant that they should have been
18 able to see and prevent.
19 VOICE: One last question in this area. We
20 recently had a briefing that included some folks from
21 EPRI and NEI and they were talking about what they think
22 they've come up with -- and we don't have the
23 details -- that they think is truly a leading indicator
24 that's a combination of several kinds of indicators of
25 the sort you have and some others. I wonder if you're

1 hearing about that or if you're tracking that work, or
2 if that's something that maybe is back in headquarters.
3 MR. LANTZ: That's something that I have not
4 heard about here. I will say our performance
5 indicators, they're a metric, essentially, and all
6 metrics need to reevaluated periodically to see if
7 they're measuring what we want. If we have a
8 performance indicator that is continuously green and
9 not providing any assessment of value, we should
10 reevaluate that performance indicator and re-baseline
11 that indicator.
12 DR. SCHULTZ: To summarize what I understood
13 you to say is that you have the performance indicator
14 results, they can feed directly into an action matrix
15 finding because there are thresholds associated with
16 them, but there's also a line, dotted or whatever you
17 want to call it, over to inspection or questioning
18 programs associated with the inspection side that is
19 likely also to then lead to other findings, other action
20 matrix determinations.
21 MR. LANTZ: Absolutely. As Kriss had
22 mentioned, we do have resident inspectors on the sites
23 at all times. They're observing activities day to day,
24 and if there is an event that occurs -- and this would
25 be an event -- we would want to investigate that event

1 and look for performance issues that caused the event.
2 Performance indicator is just a set of data that is
3 collected. We would definitely look at the causes and
4 potentially prosecute that as another finding.
5 DR. SCHULTZ: But that doesn't happen within
6 the performance indicator side, it needs to be coming
7 in on the inspection side.
8 MR. LANTZ: That's correct. It would come
9 on the inspection side.
10 DR. SCHULTZ: Thank you.
11 DR. BALLINGER: So in effect, those are not
12 really black and white separate. If you have performance
13 indicator results that are continuously bad that's got
14 to have resulted at some point in inspection issues.
15 MR. LANTZ: I would totally agree with that,
16 absolutely.
17 MR. SKILLMAN: One more question. The
18 significance threshold is really a product that comes
19 from your significance determination process.
20 MR. LANTZ: Correct.
21 MR. SKILLMAN: And that really is a PRA of
22 sorts.
23 MR. LANTZ: Definitely for most of the
24 reactor safety cornerstones it is based on
25 probabilistic risk assessment. That's correct.

1 MR. SKILLMAN: And so the question is how do
2 you know that tool is accurate.
3 MR. LANTZ: I would say we have our experts
4 here that talk about risks and the actors have that tool.
5 MR. SKILLMAN: We've got ours here.
6 (General laughter.)
7 MR. LANTZ: I mean, that's a good question.
8 We have to struggle with that. One of the things we can
9 do in this process -- and we do do this -- is this is
10 a very public process, we follow this process, however,
11 we are still the regulator, we still have to step back
12 after a finding is analyzed and run through our
13 significance determination process, should it really be
14 a yellow finding, should it really be. Because there's
15 consequences in the action matrix, as I'll talk briefly
16 about, for us to give that result as a final
17 determination. We have always got the ability to make
18 a deviation from what the ROP tells us we should do and
19 do what we think is the right thing. I hope that answers
20 that question.
21 MR. SKILLMAN: Thank you. Yes, sir.
22 DR. STETKAR: Let me follow up on it because
23 it's something -- and this is why I like to get feedback
24 from the folks who are actually out here trying to make
25 these determinations -- I've seen events that have

1 happened either during plant shutdown or that could
2 affect the availability of systems during plant
3 shutdown, and in many cases the PRA tools that are
4 available to the NRC don't cover those shutdown modes.
5 How do you handle in practice significance
6 determination under those conditions when you don't
7 have the calculator?
8 MR. LOVELESS: This is David Loveless,
9 senior reactor analyst.
10 It's a good thing you brought that up. We're
11 going to be talking about that.
12 DR. STETKAR: I'll wait then. Thanks. I
13 didn't look ahead. We'll wait and bring it back up.
14 Thanks.
15 MR. LANTZ: To try and move on, so action
16 matrix inputs are the green, white, yellow and red that
17 come from both sides of this graph. They go down into
18 the action matrix, and ultimately what that does is
19 tells us what we should do different than what we
20 normally do in our baseline inspection process and our
21 normal level of oversight, management oversight at the
22 particular facility.
23 So just briefly to try and catch up on time
24 because I see we're running a little bit, there's five
25 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

1 cases where there's a serious event and nobody pushes
2 real hard to come back online until everything gets
3 worked out. You're kind of de facto over here until
4 that gets straightened out, although there's never a
5 ruling that says you're out.
6 MR. LANTZ: I think you could consider that
7 but it's really not the ROP.
8 DR. BLEY: Okay, fair enough.
9 MR. LANTZ: That has to do with maybe orders
10 or confirmatory action letters where the licensee makes
11 a commitment that they will not start up until we say
12 we think it's safe for you to do so. Not really in this
13 process.
14 DR. BALLINGER: But if they do get into that
15 region, Column 5 where you can't operate -- well, you've
16 never had anybody go there so you don't really know how
17 to get somebody out of there.
18 MR. LANTZ: I sure hope we have good
19 procedures saying how we do that, but I've personally
20 never explored that arena.
21 DR. BLEY: One last thing along this area,
22 it's not part of the ROP, I guess, but after there's an
23 event and you go and take a quick look at it, are there
24 specific triggers that lead to a special investigative
25 inspection, an augmented inspection and an integrated

1 inspection?

2 MR. LANTZ: Absolutely, and Greg Warnick is

3 actually going to talk a little bit about that.

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

5 MR. LANTZ: So just quickly to give you a

6 status of where we are in Region IV with the action

7 matrix, there are 19 operating reactors at 13 sites.

8 When we assess the action matrix at one of the sites,

9 say Palo Verde, for instance, Palo Verde is a three unit

10 site, but if any one of those units fell into an elevated

11 column in the action matrix, the site is considered to

12 be at that. So there are nine sites in Column 1, there's

13 three in Column 2, and there's only one in Column 4 and

14 it's the only one in the nation right now.

15 So just quickly, Diablo Canyon is one of the

16 sites in Column 2. They had an inspection finding in

17 the emergency preparedness cornerstone which was white,

18 and that was effective in that quarter. River Bend and

19 Comanche Peak both essentially got into that from

20 security cornerstone findings that were greater than

21 green and we don't in a public forum advertise what that

22 level actually is. River Bend also had a white

23 performance indicator and that was in unplanned scrams

24 with complications. Since those are two different

25 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

1 inspection last week at Callaway. That plant had 83
2 fire areas, 28 remain in deterministic analysis, the
3 other 55 were analyzed in the
4 performance-based/risk-based methodology. The table
5 on the slide is out of the safety evaluation report for
6 the unit. It's an easy way to give you some perspective
7 how significant the contribution of fires are to overall
8 plant risk.
9 DR. STETKAR: That table, John, you said 55
10 areas were evaluated by NFPA, so you have numbers for
11 those 55. Twenty-eight met deterministic
12 requirements. The risk from those 28 isn't zero, it
13 just wasn't calculated. The core damage frequency from
14 fires being two times ten to the minus five, how does
15 that relate to the real core damage frequency from
16 fires.
17 MR. MATEYCHICK: I'm not the SRA who was on
18 the inspection, but in their fire PRA summary report
19 they do -- on this slide you'll see the deterministic
20 compliance areas do have a very small risk contribution
21 to the overall plant risk. There's the plant risk for
22 fires in those areas and there's the delta risk between
23 a fully compliant program and a risk-based program.
24 At Callaway, the main contributor, its
25 highest hitter is the control room, as we would expect.

1 Then almost three-quarters of the risk comes from the
2 other risk-based areas; there's very little risk from
3 the deterministically compliant areas.
4 DR. STETKAR: The truth is we don't know. I
5 mean, we might like to think because they're
6 deterministically compliant the risk is really low, but
7 we don't know if we haven't looked.
8 MR. MATEYCHICK: In deterministic space in
9 the old programs, you assumed all will have burned up
10 but you also assume that all systems and components were
11 in operation and nothing was subject to a random
12 failure. In the fire PRA space you have factors in
13 there for auto service equipment and random failures,
14 so even though they're deterministically compliant,
15 there's still some contribution in the fire PRAs.
16 DR. STETKAR: I think I see what you're
17 saying. You're saying in their PRAs, even thought they
18 didn't full evaluate those fires, they have some pieces
19 of it showing up.
20 MR. MATEYCHICK: They still know which
21 systems and components are being used in those fire
22 areas, so they still have factored into their fire PRA.
23 Now, remember, we have a sample size of one because this
24 was our first plant.
25 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.

1 Our inspection team had five inspectors and
2 a senior reactor analyst, and of course, I also sent out
3 a representative who has been involved in the review and
4 approval of these programs. We spent significant
5 amount of time in preparations trying to get familiar
6 with all the new documentation to understand the new
7 program.
8 Callaway reported to us that to implement
9 this new standard that has 19 pages of text they
10 generated 32,000 pages of documentation. Having a
11 senior reactor analyst with us was critical since so
12 much of this is risk-informed.
13 VOICE: I'm unfamiliar with any of this so
14 I'm just watching Stetkar and Bley asking questions, but
15 32,000 pages of documentation?
16 MR. MATEYCHICK: Yes. There is a table
17 dealing with circuit analysis of cable routing that has
18 over 6,700 pages
19 DR. REMPE: Could you say that a little
20 louder? There was something with circuit analysis I
21 couldn't quite hear.
22 MR. MATEYCHICK: I said there's a table that
23 summarizes some of the circuit analysis work and it has
24 over 6,700 pages.
25 DR. STETKAR: Did you have anyone from

1 headquarters on this inspection?

2 MR. MATEYCHICK: Yes. We had a

3 representative with us to help us through it and an

4 interface with headquarters if we had questions.

5 Our sample areas. For the control room we

6 focused on the control room evacuation procedure and the

7 analyses that back up that timeline and response to any

8 plant transients. At Callaway this is the only fire

9 area where that would not be detected from the control

10 room, and now what was their remote panel is the only

11 primary control station in the new NFPA 805 terminology.

12 The other sample fire area, we locked the

13 areas down, we looked at the detailed fire modeling

14 reports, we used the circuit analysis for those areas,

15 also looked at operator actions that have to be done

16 outside of the control room which are now recovery

17 actions of the new programs.

18 The table below shows you the number of fixed

19 emission source fire scenarios and transient

20 scenarios --

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

22 MR. MATEYCHICK: The bottom table is the

23 summary of the fire modeling that was done under the

24 risk-based approach for these programs for these fire

25 areas. Fixed emission sources and transient

1 scenarios. We logged these down, compared the results
2 to the physical configurations.
3 Since this was the first inspection of the
4 program, we also looked at a large sample of the items
5 they were supposed to implement during the transition.
6 This table is referenced in the license condition that
7 they had a time period to implement these items. We
8 selected 42 out of the 74. There were also seven
9 modifications that they take credit for in the new
10 program. We looked at a sample of those modifications.
11 DR. STETKAR: John, do you have some examples
12 of the modifications that Callaway installed as a result
13 of this?
14 MR. MATEYCHICK: Yes. They added
15 additional control power fusing to many of their control
16 circuits. They added some additional isolation and
17 transfer switches to isolate the control circuits
18 between the main control room and motor control centers
19 that take local control of valves. There's some cable
20 rerouting. They also took credit in the options for
21 shutting down the plant and incorporating the PRA. The
22 non-safety grade auxiliary feedwater pump they
23 installed for a different purpose, and also now include
24 the station blackout diesels in the program.
25 DR. STETKAR: I know some plants have made

1 decisions to install so-called incipient fire
2 detection.
3 MR. MATEYCHICK: No incipient at this unit.
4 DR. STETKAR: Okay. Thank you.
5 MR. MATEYCHICK: Let's go to the challenges
6 we had during our first inspection.
7 DR. BLEY: Let me just ask you a little
8 different question, John. When you go out to do the
9 inspection, after you've reviewed all their
10 documentation to some extent at least before you go, how
11 do you decide what areas to look at? Did you look at
12 any of the areas that they concluded were not
13 significant and see if you agreed with that?
14 MR. MATEYCHICK: Yes, as a matter of fact, we
15 did. See the reactor trip switchgear room, that is very
16 low significance compared to the others, but because
17 we're familiar with that area and we know there are alpha
18 and bravo trans circuits through there that aren't
19 deterministic to compliance, we were interested to see
20 how that was resolved to generate such a low number for
21 that area. We picked the main control room and the
22 ventilation room were the top two areas. The ESF
23 switchgear room that was number 9 or 10, we went to that
24 reactor trip switchgear room to understand why that is
25 such low risk significance.

1 DR. BLEY: Do the residents help you in that
2 process to decide what areas to look at?
3 MR. MATEYCHICK: No. We did this, we used
4 our past experience reviewing the summary report from
5 the fire PRA which lists the top fire areas and fire
6 scenarios and just our past experience with post-fire
7 safe shutdown.
8 DR. BLEY: The only reason I brought that up
9 is I would think that being more familiar with some
10 details of the plant that they might have raised some
11 issues that would be helpful. But you didn't do that.
12 That's okay.
13 MR. MATEYCHICK: No. More familiar with
14 details of the plant but not post-fire safe shutdown
15 analysis.
16 The challenges we had was working through the
17 new techniques for fire modeling, fire PRA, just the
18 sheer volume and number of documents involved. We did
19 spend a lot of time confirming that the implementation
20 items were completed satisfactorily, and there the SRA
21 was critical since many of these implementation items
22 were changes to methodology in fire PRA. We used
23 different acceptance criteria before the
24 performance-based approach and the old deterministic
25 approach, and also we treat control room evacuation

1 somewhat differently in plant response compared to the
2 old programs so we had to work through that.
3 DR. BLEY: Can you elaborate on that a little
4 bit? We've heard that you believe the numbers that the
5 control room was at the top of the heap.
6 MR. MATEYCHICK: It's always fire
7 significant.
8 DR. BLEY: Well, but you say use of different
9 acceptance criteria for the control room evacuation.
10 That's what I was curious about.
11 MR. MATEYCHICK: Appendix R and it's
12 mimicked as a specific set of requirements for alternate
13 shutdown and dedicated shutdown. Appendix R, Section
14 3(g)(3) and 3(l) basically are control room specific in
15 the older plants where there's only one cable splitting
16 room, you might also have to evacuate for a fire there.
17 There's no distinct requirements in NFPA 805 for a
18 control room evacuation scenario, it's just used the
19 overall performance-based, risk-based.
20 DR. BLEY: It does mention habitability.
21 MR. MATEYCHICK: You have to have the ability
22 to have a safe shutdown path for every area in the plant,
23 but there are no special requirements for the control
24 room. They did the fire modeling a little differently
25 and we're satisfied that they worked their way through

1 the control room and they addressed all potential issues
2 and had a sound control room evacuation procedure.
3 One thing we did have an issue with is that
4 these amendment requests in the transition reports that
5 are submitted to get them did use a generic disposition
6 statement for risk-based issues. Each variation for a
7 deterministic requirement has to be resolved and
8 addressed in performance-based analysis and they keep
9 using a statement that essentially says the fire area
10 had problems under deterministic criteria, we applied
11 the risk-informed performance-based criteria and we
12 were successful. The risks, the defense in depth, the
13 safety margins are acceptable. Doesn't give you a clue
14 if it was detailed circuit analysis, fire modeling, fire
15 PRA numbers, use of recovery actions. The trail to the
16 right place in those 30,000-plus pages of documentation
17 is sometimes difficult to follow but we did work through
18 that.
19 DR. SCHULTZ: John, you mentioned you've got
20 these four bullets here and this is the first
21 inspection, you've got several more to come. Are you
22 concerned that you're going to run into the same four
23 major challenges with the other inspections? And if
24 so, how are you getting the word out as to what you found
25 here? Is there an activity that's transmitting,

1 communicating the results of this inspection to the
2 other sites that are using the technique with their
3 applications?
4 MR. MATEYCHICK: Their applications are in.
5 They're in the review process so we're not going to get
6 changes to their documentation here, we'll just be
7 talking to them up front that we're going to need even
8 more extensive support from their side of the inspection
9 to help guide us through here effectually.
10 DR. SCHULTZ: But using this to indicate
11 these were the problems we found here and when we come
12 to do your inspection perhaps you can help us through
13 in a different way and just highlight these things and
14 prepare yourselves for addressing these issues.
15 MR. MATEYCHICK: We'll be talking to them
16 well in advance of our inspections. And the fire
17 protection people from all the regions we'll have a
18 seminar once or twice a year and we'll compare our notes
19 and what we've found, what is a worthwhile technique and
20 what is just not effective use of our time.
21 DR. SCHULTZ: You said twice a year the
22 regions get together?
23 MR. MATEYCHICK: Once or twice a year.
24 DR. SCHULTZ: Because Region II has done more
25 inspections. Right?

1 MR. MATEYCHICK: They've done more
2 inspections, Region III has done a few, I don't recall
3 if Region I has done their first yet. We actually had
4 a meeting up in Region III last fall, I believe it was,
5 where we had headquarters and Region II people talking
6 to what to look at and how things are structured. These
7 programs may look a little different from site to site
8 depending on the contractors that are used to develop
9 the program, the documents may be structured a little
10 differently, but all the basic concepts we expect to see
11 at each site.
12 MR. SKILLMAN: John, let me ask you this.
13 You've been doing fire inspections for a long, long
14 time. This is not an area that I'm particularly
15 familiar with so I may be more objective because I don't
16 have any skin in the game, but it sounds to me like when
17 a licensee says by golly, we're going to do NFPA 805,
18 they've just signed up for a bag of worms. And I'm
19 wondering has the level of safety really increased, or
20 is this just a humongous smokescreen that doesn't really
21 give a significant increase in nuclear safety? It's a
22 loaded question.
23 MR. MATEYCHICK: Go back to that room we
24 picked that was of low safety significance but we know
25 it didn't meet deterministic requirements, there's

1 alpha train circuits in there which we had assumed were
2 burned up under the old bow ramp. Looking at the detail
3 work that was done under the new program, it confirmed
4 that there is no fire int that room which would damage
5 that stack of cable trays. All that equipment is
6 available to the operators in the control room, they can
7 shut down the plant using the alpha train from the
8 control room. So it confirmed that area is actually
9 safer than we would have given it credit to be under
10 deterministic rules.
11 DR. CORRADINI: Can I ask this question
12 differently? Again, since I don't follow this. I
13 wouldn't use the word smokescreen but is there a story
14 that's told here that you as an inspector or your
15 colleagues are doing that makes it more understandable?
16 Because I'm still back at 32,000 pages. I'm concerned
17 that I can't understand what I'm getting which makes the
18 inspection all that more complex or problematic.
19 MR. MATEYCHICK: Under the old program we
20 talked about having one train of equipment necessary to
21 get the hot shut down free from fire damage. Under the
22 new program we are looking at having one success path
23 of equipment available to get the plant into a safe and
24 stable condition. We're still looking at the plant
25 systems, we're still looking at the components, we're

1 looking at the cabling that supports them, the power
2 supplies, so we're getting to the same bottom line: for
3 each and every fire area is there a set of equipment that
4 will keep the plant in a safe condition. So we focus
5 on that in each fire area, and all of the rest of this
6 is supporting documentation.
7 DR. CORRADINI: I didn't hear that.
8 MR. MATEYCHICK: All the rest of these
9 analyses are supporting documentation that document
10 that.
11 DR. CORRADINI: So to go back to Steve's
12 question, so given these four things, given the
13 conversations between the regions, do you feel that the
14 next set of inspections are going to go easier for your,
15 that they know what you're looking for, or is it going
16 to be just the same thing all over again? That's what
17 I thought Steve was kind of worried about.
18 MR. MATEYCHICK: We know that we're going to
19 have to talk to the other licensees and line up that
20 additional support pretty much on an inspector with a
21 counterpart kind of basis in order to work through all
22 this because now we have the traditional fire protection
23 people, operations people, electrical people, fire PRA
24 people, the fire modeling person, there's must more
25 people to interface with, more documentation to work

1 your way through.

2 And an extra complicating factor for Callaway

3 was the only one of our licensees who performed their

4 modifications at risk before their license amendment

5 requests were approved. All the rest of our licensees

6 are not going to have all of their modifications done

7 during their first triennial under the new program. So

8 we'll have the extra complication of saying: Okay, you

9 have all these variations for deterministic

10 requirements, these modifications were going correct,

11 they're not finished, these are outstanding, so what was

12 your review and results of reviewing those for

13 establishing compensatory measures to have acceptable

14 safety until the modifications are done? So there's an

15 extra complication.

16 Last slide is what we found that was good. We

17 spent a significant amount of time looking at the fire

18 modeling, we were pleased that they were still in what

19 we believe is a very conservative manner, so if

20 anything, the number of circuits impacted by any given

21 fire is going to be a little overstated than reality

22 would dictate.

23 The fire response procedures the operators

24 use, they have a separate attachment in that procedure

25 for each and every fire area, and we're very pleased with

1 the amount of information and the structure of it. It
2 tells them what trains of which systems are available
3 to conduct the shutdown, it tells them what their
4 reliable instrumentation is, their specific actions to
5 take in response to the fire for the reactor operator
6 in the control room and the safe shutdown operator out
7 in the plant to perform recovery actions. Operations
8 people are very pleased with the final product they have
9 to work with in case a fire does occur.
10 DR. BLEY: Can I ask you a question about
11 that, John? I'm familiar with a number of fire
12 procedures in plants that have been there a long time,
13 but I'm hearing about some that are now in some sense
14 integrated with EEOP so even if you're in an EEOP, when
15 you're called off to the fire that the fire response
16 procedures pick up all the things that are in the EEOP
17 so you're only in one procedure. Are these written that
18 way or is this more the kind I've seen in the past?
19 MR. MATEYCHICK: No. That was not generally
20 what we found. The control room evacuation is so much
21 outside the box of a normal shutdown that they have
22 unique complete stand-alone procedures.
23 DR. BLEY: Okay. For that condition.
24 MR. MATEYCHICK: For that condition. All
25 the rest you use your normal post-trip plant procedures,

1 EEOPs in parallel with a fire response procedure.

2 DR. BLEY: Okay. Thanks.

3 DR. SCHULTZ: John, with regard to the first

4 bullet there, have we got covered -- when you make

5 conservative assumptions and analyses, you run the risk

6 of masking the right decisions that should be made when

7 you're comparing one potential course of action versus

8 another. You make conservative assumptions here, you

9 make other conservative assumptions there, and you get

10 the wrong answer compared to if you did a best estimate

11 analysis in both places. Is there a concern that that's

12 happening?

13 MR. MATEYCHICK: No, because this was all

14 done on a fire area basis. It's what's in that fire area

15 that could potentially be damaged, so saying that one

16 or two in additional balance might spuriously operate

17 doesn't impact the risk numbers in other parts of the

18 plant, it doesn't divert resources. Like I said, 83

19 fire areas, this is all done in the individual fire area,

20 each one has to have a safe shutdown capability.

21 DR. SCHULTZ: If I'm trying to decide where

22 should I put resources to improve the plant's capability

23 to respond to fire, I might come up with the wrong choice

24 of area.

25 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

1 event. On March 31, 2013, ANO Unit 1 was in a refueling
2 outage and was replacing their main generator stator due
3 to it being at its end of life. They had contracted out
4 that project, as well as the contractor had
5 subcontracted to an experienced and well known heavy
6 lift expert to move the stator. So the main generator
7 stator was one million pounds, and the way that they were
8 going to move this out of the turbine building is they
9 designed a system with two rails and a trolley. They
10 were going to pick it up, trolley it over to what we call
11 the train bay -- this is the train bay here -- put it
12 onto a vehicle down here in the train bay and move it
13 out of the turbine building.
14 DR. BLEY: This is the old stator going out?
15 MR. TINDELL: That's correct.
16 This is a picture of that day, March 31. This
17 s while they were picking the stator up and trolleying
18 it out, and of course, they lifted it slowly, did not
19 see any issues with the crane during the initial lift,
20 and began to trolley it. And this is the configuration
21 that the crane actually failed in, so as you can imagine,
22 the majority of the static vertical load was on the
23 tripods over here during the initial lift, and as they
24 trolleyed the load over, the vertical load transferred
25 to these columns here.

1 So when the engineer designed this custom
2 rig, he treated these columns individually for column
3 buckling and these columns individually for column
4 buckling, but failed to look at the column buckling for
5 the entire height of this column. And so this column
6 actually failed from static column buckling load, and
7 when that happened the stator fell, impacted the turbine
8 building deck here, and then rolled down into the train
9 bay.
10 This is a picture after the event. You can
11 see the massive floor deformation from the stator
12 impacting the floor here. The crane actually fell over
13 too and caused substantial damage to both units as well.
14 This resulted in an loss of offsite power to Unit 1. The
15 operators immediately restored shutdown cooling to that
16 unit because it was in a refueling outage after the
17 emergency diesels powered the safety buses back up.
18 DR. RICCARDELLA: Brian, could you point out
19 where the control rooms are?
20 MR. TINDELL: This is the entrance to the
21 control rooms here. This is what they call an
22 extension. This is not the safety related portion of the
23 control rooms but this is the normal entrance and exit
24 to the control rooms so the operators had to use an
25 alternate entrance and exit during the event.

1 VOICE: What caused the loss of offsite
2 power?
3 MR. TINDELL: We'll get to this here, I've
4 got a slide next. But this floor is over the non-vital
5 switchgear and when that floor deformed it actually
6 crushed the non-vital switchgear which is their normal
7 offsite power source to the safety buses.
8 Unit 2 was operating at the time, they had a
9 reactor trip, and there was a crushed fire main in the
10 train bay that actually sprayed equipment and caused a
11 fault in their non-vital switchgear, again, non-safety
12 related, but that resulted in a loss of one offsite power
13 source and also a loss of instrument air which
14 complicated that trip.
15 So this is the Unit 1 non-vital, again,
16 non-safety related switchgear. It was underneath the
17 floor so the stator drop impacted above and it deformed
18 that floor about three feet and it came down so much that
19 it crushed the cubicles for the non-vital switchgear and
20 resulted in a fault so they completely lost offsite
21 power and non-vital power.
22 VOICE: No fires.
23 MR. TINDELL: There was no fire. There was
24 an electrical fault on Unit 2 due to water intrusion.
25 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

1 crane be adequate for the load and that a load test be
2 performed. Now, the licensee has taken extensive
3 corrective actions in their heavy load program, but we
4 have had some challenges in that the initial Arkansas
5 Nuclear One root cause only looked at the contractor's
6 activities and what their contribution was to the event
7 and did not find any fault with their own actions.
8 And it's critical here that the licensee is
9 responsible for licensed activities at the site, so the
10 NRC actually came in and identified this performance
11 deficiency and drove licensee actions to address their
12 own performance issues. Now, subsequent to this when
13 we issued the yellow finding, ANO did initiate a second
14 root cause that has found fault with their own
15 performance and they are addressing that at this time.
16 DR. RICCARDELLA: Is the design calculation
17 a 10 CFR Appendix B violation?
18 MR. TINDELL: Well, the heavy load program is
19 a safety related program and the performance deficiency
20 we just talked about was an Appendix B violation, so we
21 determined that although it was not directly related to
22 safety equipment, it affected safety equipment, so it
23 was under the Appendix B program.
24 DR. RICCARDELLA: And it was Appendix B
25 violation by the contractor? The contractor did that?

1 MR. TINDELL: Well, as I said before, ANO was
2 responsible for all licensed activities at the site so
3 it was a violation against ANO, not the contractor.
4 DR. SCHULTZ: But you're saying that ANO did
5 not take responsibility at the outset.
6 MR. TINDELL: That's correct.
7 DR. SCHULTZ: How did that impact your
8 finding related to the event?
9 MR. TINDELL: Well, the NRC had to come in and
10 do the inspection to determine ANO's responsibility,
11 and we did that.
12 DR. SCHULTZ: But both the NRC and the
13 licensee should have known that it was their
14 responsibility. How did they feel they could shed that
15 responsibility?
16 MR. TINDELL: Well, there is a little bit of
17 complication. A man actually died during the stator
18 drop and there's some ongoing litigation. There is
19 some sensitivity to pointing fingers at who's at fault,
20 but still we expect the licensee to understand and
21 evaluate and address their performance issues and that
22 was not done here.
23 DR. STETKAR: Had the licensee -- you
24 mentioned heavy load drop program and I'm somewhat
25 familiar but not very familiar with how one conducts

1 those analyses in terms of scoping in the things that
2 they need to look at. People look at polar cranes,
3 people look at things that are in safety related areas.
4 Had ANO actively excluded cranes in the turbine building
5 from their heavy load drop analyses? I mean, this was
6 a temporary crane but I'm thinking about the main
7 turbine building crane.
8 MR. TINDELL: So this performance deficiency
9 here is related to their own procedures. Their own
10 procedures had a requirement to review the design
11 calculation and that a load test be performed in
12 accordance with the calculation, so it was done, it was
13 just done inadequately.
14 DR. REMPE: Is that limited to just the heavy
15 load activities, or are there other different types of
16 activities where they're supposed to be performing
17 reviews of design calculations for work done at the
18 site, and did this evaluation go beyond the heavy load
19 program?
20 MR. TINDELL: At this time they're taking a
21 broad look at programs and how they affect equipment.
22 Those types of design reviews, decision-making is a
23 critical piece of what went wrong here. Verification
24 of assumptions, and the licensee has taken a good scrub
25 at those performance issues, and then our inspections

1 will come in and look at and confirm that they did a good
2 scrub of those as well. Does that answer your question?
3 DR. REMPE: Yes. I'm just thinking of other
4 examples where if they're procuring something or other
5 things that they need to look at too and review.
6 MR. TINDELL: Absolutely, and that's why I
7 wanted to bring home the point that although they've
8 fixed the issues with the heavy load program, those
9 calculations, these performance issues may be broader
10 than that and that's why we're going to take a good scrub
11 of those.
12 DR. RICCARDELLA: I'm chairing an ACRS
13 lessons learned activity on the San Onofre steam
14 generator issue, and one of our concerns is that in that
15 case the licensee failed to enforce an Appendix B QA
16 program on his vendor, and this would seem to be very
17 similar. The person who did that calculation, if this
18 is under Appendix B, there should have been a vendor QA
19 on that.
20 MR. TINDELL: There were definitely some
21 vendor issues as well, that person that designed it, but
22 as far as the NRC is concerned, we hold the licensee
23 responsible for those actions. I can't say much about
24 this but I will say that we are looking at the
25 contractor's contribution to that.

1 DR. RICCARDELLA: You know, I think the
2 lessons learned for the NRC is to somehow confirm that
3 the licensee is enforcing Appendix B QA requirements on
4 his vendors.
5 MR. TINDELL: Yes, sir. That's absolutely
6 something we'll look at in the supplemental inspection.
7 The supplemental inspection does a great job of asking
8 those questions that are maybe one or two levels deeper
9 than what we typically look at in an inspection to find
10 those kind of contributions to the event.
11 MR. SKILLMAN: Brian, did the NRC produce an
12 information bulletin or some type of formal
13 communication to the industry that says: Heads up.
14 Here is a case where a man died, the utility was
15 depending on the capability of the contractor -- they
16 probably signed a contract and put all the liability on
17 Bigge, that's what I'd guess -- each licensee has a
18 heavy loads program, each of those programs is an
19 Appendix B program, beware, you own the accountability
20 no matter what happens.
21 MR. TINDELL: There's actually been several
22 events recently in the industry. I think Crystal River
23 Containment, San Onofre is another example, and this is
24 another example.
25 MR. SKILLMAN: But I'm asking if the NRC has

1 turned on the spotlight and said, Hey, we are keen on
2 top of this, here are a couple of examples, and those
3 of you who have licenses beware. I'm asking if there's
4 been a formal communication to industry.
5 MR. TINDELL: I believe there has, I can't
6 remember exactly what it was, though. I'm looking at
7 Ryan; he was my branch chief at the time.
8 (General laughter.)
9 MR. SKILLMAN: INPO puts out SOERs, and by
10 golly, if you're at a plant and an SOER comes in, it's
11 resource time, you've got jobs to do, you've got work
12 you've got to get done.
13 MR. LANTZ: The NRC does have the vendor
14 branch, they look at the activities that our quality
15 vendors do undertake. In the case of San Onofre it's
16 not a strong bite but there was a notice of
17 non-conformance issued to that vendor, Mitsubishi Heavy
18 Industries, for their essentially failures in the
19 design of the generators. I don't know if that's going
20 to occur with Bigge, if that's still processing. Brian
21 mentioned the litigation so there's some complicating
22 factors there as well.
23 VOICE: But did we put out a risk?
24 MR. LANTZ: That I do not know.
25 MR. SKILLMAN: It seems to me that that's the

1 real question.

2 MR. VEGEL: Let me check into that to see did

3 we put a regulatory issue or bulletin or generic letter

4 or anything like that. Let me check on that.

5 MR. SKILLMAN: Tony, thank you.

6 DR. STETKAR: But the key is not just focus

7 to the drop of that stator, to the broader issue.

8 MR. SKILLMAN: The broader issue is the

9 licensee owns the accountability for what happens on the

10 licensee's site, period. That's what you're saying.

11 I think we all agree with that. But in this

12 environment, this financial environment, we are well

13 aware that the economic pressures are so great that

14 these utilities will sign a contract to have somebody

15 else do for them, therefore, avoid having to spend their

16 own personnel resources and this is the kind of thing

17 that can happen unless that activity is very carefully

18 engineered and controlled.

19 Tony, let us know.

20 DR. RICCARDELLA: But in the case of San

21 Onofre, there's no way the licensee had the technical

22 capability to perform the necessary reviews of that

23 calculation. What he needed to do was ensure that the

24 vendor had the proper quality assurance program in

25 place, and he didn't do that.

1 MR. SKILLMAN: In this particular case it's
2 a heavy load program that is, in my view, very well
3 understood throughout the industry, and Bigge has done
4 this work at other sites so this is not new.
5 DR. RICCARDELLA: But under Appendix B that
6 buckling calculation should have been subject to an
7 independent review by a third party, and I would think
8 that somebody would admit that the independent review
9 wouldn't have missed that.
10 DR. BALLINGER: Either that, or they just
11 didn't consider the double height. In other words, the
12 buckling calculation was done on one set, and so nobody
13 realized or missed or something.
14 VOICE: The question is were the proper
15 reviews done, was it done within the organization that
16 did the work, was it done as an oversight. Most
17 licensees will do oversight work on the vendor programs
18 in spite of the fact that they may or may not have that
19 regulatory responsibility. In addition, though, there
20 is an extent of condition issue here that needs to be
21 examined as well.
22 MR. TINDELL: The only other thing I didn't
23 mention. You did mention INPO. INPO did put out an
24 SOER for the industry to look at oversight of projects
25 and contractors like that, and it did take those three

1 examples I talked about into account. The NRC has had
2 a lot of visibility on that too. I know that Mark was
3 actually talking to the Commission today about that very
4 issue. We'll get the exacts about what we issued,
5 though.
6 MR. SKILLMAN: Thank you, Brian. I would
7 ask, you started a little late, if you can move ahead
8 and maybe finish not too many minute past noontime, that
9 would be very good for us. Thank you.
10 MR. LOVELESS: Good morning. I'm David
11 Loveless.
12 At the time of the stator drop, the units were
13 in different configurations and they were differently
14 impacted by the event, therefore, the risk we had was
15 calculated separately for each unit, so I'll go a little
16 bit into each unit.
17 Unit 1 was shut down with the reactor coolant
18 system open, fuel was in the reactor and the refueling
19 pool was filled for fuel movement. The impact to the
20 stator on the turbine deck crushed non-vital buses
21 causing a complete loss of offsite power. The damage
22 was so extensive that it took months to recover offsite
23 power via normal plant process equipment. Both
24 emergency diesel generators did start and provide power
25 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

1 the Unit 1 auxiliary building and caused flooding, but
2 also a large amount of water made it onto this deck here,
3 and as we'll discuss later, the incoming power supply
4 to this bus to Alpha 1 faulted from the water and caused
5 an explosion and the failure of that start transformer.
6 One of the questions you asked was how do we
7 calculate shutdown risk. We have multiple tools for
8 calculating shutdown risk. The simplest we have
9 screening tools and some simplified PRA type models
10 that's in our inspection manual Chapter 0609, Appendix
11 Golf. That appendix handles screening check sheets for
12 both PWRs and BWRs that go through and screen out issues
13 that are not risk significant because of what occurred,
14 and those would all be determined to be green. It also
15 provides event trees that can be used by the SRA to look
16 at rough calculations, order-of-magnitude estimates.
17 In the most cases those are used only to determine that
18 a finding would be of very low safety significance.
19 Beyond those tools we do have SPAR models
20 which are PRA models that have shutdown capabilities for
21 at least one of each of the large block reactor designs,
22 one for a three-loop Westinghouse, one for a four-loop
23 Westinghouse, one for a BWR-6, that sort of thing. Now,
24 those are unique to a specific unit in the industry, but
25 because shutdown risk is mostly driven by operator

1 action, those can relatively easily be modeled or
2 modified to look at a specific site that the model was
3 not written for.
4 DR. STETKAR: You really think that's true?
5 MR. LOVELESS: Yes. I'm not saying that
6 it's as good as having a unique PRA.
7 DR. STETKAR: I would really caution you on
8 stretching that assumption too far, because every plant
9 that I've ever looked at -- and I've probably done about
10 eight shutdown risk assessments -- they all have unique
11 problems.
12 If you only look at mid-loop operation in one
13 particular plant operating state, you might have some
14 insights, but be careful about making those broad
15 assumptions based on one simplified model for a
16 particular plant, especially during shutdown.
17 DR. BLEY: Just one more aside on that.
18 Plants handle their maintenance activities during
19 shutdown differently, and take out whole hunks of the
20 plant for maintenance, and if you don't do that on a
21 plant specific basis, you can be missing a lot. On the
22 other hand, you can focus on where the problems might
23 be.
24 DR. STETKAR: Electric power supplies, for
25 example, might not be too bad, but many of the other

1 subtle things that can and do happen, it's dangerous to
2 extrapolate.
3 MR. LOVELESS: Absolutely. And don't get me
4 wrong, I don't pull an off-the-shelf model and go push
5 a button and say here's the answer. We do large amounts
6 of work in determining the exact plant configuration.
7 Brian will attest that I spend large amounts
8 of time asking him to do additional inspections and to
9 make sure we understand the configuration of the plant.
10 Usually at this level we have plant visits where I'll
11 go out and my headquarters counterparts will go out to
12 the site and hand over hand walk down the critical
13 portions that the models help us to determine what they
14 are.
15 DR. STETKAR: Let me -- for example, the good
16 news at ANO is that neither one of the diesels on Unit
17 1 were out of service for maintenance; they weren't
18 apart in pieces on the floor, so therefore, you made the
19 observation that both diesels started and that the Unit
20 1 dominant risk is shown as recovery of offsite power
21 within 72 hours.
22 Suppose that event had occurred when one of
23 the diesels was apart in pieces in the floor, how would
24 your risk metrics have changed when you pushed that
25 button? You don't have to answer that question.

1 That's our whole point about looking at plant
2 configuration management. Extrapolating generically
3 can lead you to sometimes excessively conservative
4 results and sometimes optimistic results just because
5 when the event happened the plant happened to be in a
6 good configuration.
7 MR. LOVELESS: And I think, unfortunately,
8 at times our program does drive us to provide some of
9 that luck in the calculations we do. We looked at
10 potential; the models would show a potential that that
11 equipment was out of service or failed, but in the case
12 where it actually was out of service there would be a
13 detriment provided into the model for that so we would
14 show that in the way we did our risk analysis.
15
16 All that aside, in this particular case this
17 was unique enough of a circumstance that we did develop
18 our own model specific to the configuration of this
19 plant, specific to what happened. PRA models don't
20 model large chunks of equipment crushed -- well, that's
21 not -- you know, they model random failure of this
22 component, and so whenever there's large impacts to the
23 plant, we tend to have to make adjustments and/or
24 completely new models for that.
25 Was there another question?

1 DR. BALLINGER: We spent the last couple of
2 days in Palo Verde where there was a number of
3 presentations where the emphasis was on using risk
4 methods -- I'm probably not using the right
5 terminology -- to try to make sure that during
6 maintenance they're never above green. Now, did the
7 licensee ever do anything beforehand, before this
8 operation, to sort of make an assessment of if A happens,
9 this is a problem, so therefore we need to make sure that
10 A doesn't happen?
11 MR. LOVELESS: There is a
12 requirement -- I'll start there -- in (a)(4) of our
13 maintenance rule that requires licensees to look at
14 their maintenance configurations and determine what the
15 added risk is for the configuration therein.
16 Unfortunately, in this case the vast majority of the
17 people and the mindset of those that were doing risk
18 evaluations for the outage at ANO was that this stator
19 couldn't drop, and so there wasn't an analysis of what
20 would happen if we dropped this stator.
21 DR. BALLINGER: So is there a lesson learned
22 here that gets transmitted out to the rest of the fleet?
23 MR. LOVELESS: We have talked about that many
24 times and with my counterparts. I can't make any 4-0
25 statements but I would be surprised if we did not find

1 those type of risk analyses at other plants in the
2 future.
3 DR. RICCARDELLA: Also, considering where
4 we've been on this trip earlier, in your opinion if the
5 flex equipment or the flex procedures had been in place
6 here, would it have been helpful in reducing the risk
7 after this event?
8 DR. BLEY: If you included them in your
9 model, of course.
10 DR. RICCARDELLA: Well, I mean, if you had
11 the situation like John said where you only had one
12 diesel and had some returns there you'd have had that
13 equipment to maintain power.
14 MR. LOVELESS: I think for the Unit 1 risk
15 flex would have been a benefit to have because it would
16 have direct lineups into the refueling pool and that was
17 what they were missing.
18 DR. RICCARDELLA: It's good to know that that
19 $2 billion spent would have actually done some good.
20 MR. SKILLMAN: I'm going to ask you to pick
21 up the pace, if I may, please.
22 MR. LOVELESS: Sure. Any other questions?
23 MR. SKILLMAN: Colleagues, let's let the
24 gentleman proceed.
25 MR. LOVELESS: Okay. Unit 2 was at 100

1 percent power, the stator dropped and caused the reactor
2 trip, water from the broken fire main caused an
3 explosion in the supply breaker that resulted in a
4 lockout of the startup transformer 3. One of the two
5 power sources from offsite power was that startup
6 transformer 3, so they lost that. One of the non-vital
7 buses was provided by startup transformer 2, the other
8 non-vital bus was locked out because of limitations of
9 startup transformer 2, and it was provided by its
10 associated emergency diesel generator.
11 Also, I did note here on the slide that the
12 alternate AC diesel generator for the site had those
13 cables pulled out. Turns out there's questions about
14 whether that source would have been available in Unit
15 2 or not. The licensee seems to believe it would have
16 been but the mindset of the operators was that there was
17 damage and that they could not use that source.
18 One point that I wanted to make, the 2 Alpha
19 2 bus was energized by its associated diesel generator.
20 2 Alpha 1 bus had the explosion in its supply breaker
21 that locked out startup transformer 3. It was
22 re-energized by an alternate breaker. Now, that
23 breaker was two cubicles away from the breaker that
24 faulted; it was also in the same area that was wetted
25 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

1 that far into it.

2 In this case the SPAR models don't model

3 offsite power from the switch yard into the plant very

4 well. They're low failure probability equipment and it

5 assumes that if we have a source of offsite power that

6 it's at the vital bus. So we had to do some significant

7 modifications and use several surrogates in the

8 evaluation of the Unit 2 risk. As I show, the dominant

9 risk here, about 90 percent of the risk was the loss of

10 main feedwater with a postulated failure of emergency

11 feedwater and then failure of operators to establish

12 once through cooling.

13 Any questions on Unit 2?

14 (No response.)

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

16 MR. KENNEDY: I think the recommendation,

17 where we're at in the timeline now, I guess we'll just

18 offer it up as a choice, do we want to talk about the

19 flooding portion of the ANO discussion or would you like

20 to defer that?

21 MR. SKILLMAN: I would recommend we move from

22 that portion to page 52, flood licensing basis. And I'm

23 going to suggest you started with a minus fifteen, if

24 you can catch us up at minus ten that would be good. If

25 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

1 that we have from various experts on what the frequency
2 of a probable maximum flood might be.
3 DR. CORRADINI: What's the exact feet in the
4 horizontal scale?
5 MR. LOVELESS: This is elevation above mean
6 sea level, feet above mean sea level. Just for
7 reference, the site elevation is about 354, normal river
8 elevation is between 336 and 338.
9 DR. CORRADINI: So 354 is what, the site
10 elevation?
11 MR. LOVELESS: The site elevation. That's
12 the elevation of safety related structures.
13 DR. CORRADINI: All of those are above 354.
14 MR. LOVELESS: I guess the major message here
15 is that we have 75 years worth of river data on the
16 Arkansas River showing what levels might be and we have
17 a very wide potential range of what a flood hazard might
18 look like when you get out into the more rare events.
19 DR. CORRADINI: We've been pressing research
20 to give us this kind of probabilistic data and we've been
21 told it's impossible to do that for flooding. What kind
22 of an expert process was used to develop that set of
23 curves?
24 MR. LOVELESS: These end points characterize
25 the range of what a group of experts determined was the

1 likelihood of a probable maximum flood, and the probable
2 maximum flood previously defined at ANO was 358 feet.
3 DR. CORRADINI: So it was an expert
4 elicitation process.
5 MR. LOVELESS: That's what it was.
6 DR. RICCARDELLA: Maybe I'm still not there.
7 So the X axis is site elevation above sea level, the Y
8 axis is probability?
9 MR. LOVELESS: The Y axis is the frequency of
10 exceedence. This is water level for flood elevation
11 and this is frequence of exceedence per year.
12 DR. CORRADINI: And the lower curve, the one
13 that says extrapolation, what is that?
14 MR. LOVELESS: If you look here at ten to the
15 minus four, that's the frequency that you will exceed
16 358 in any given year.
17 DR. CORRADINI: And then the green, the
18 purple and the blue are just composited into the red?
19 The one with the red squares is a composite of the other
20 three? That's what I'm trying to understand.
21 MR. LOVELESS: Each of these represents
22 a -- the whole package represents the range that the
23 expert elicitation came out with. We had experts that
24 said this point is at ten to the minus six, we had experts
25 that said this point is at ten to the minus three.

1 DR. STETKAR: If I could help. I think
2 everybody sets the PMP at 358. Right?
3 MR. LOVELESS: All of these experts.
4 DR. STETKAR: Set the PMP flood level at 358.
5 MR. LOVELESS: 358 is the designed PMP at the
6 Arkansas.
7 DR. STETKAR: And if I ask Joe, Joe says,
8 well, I think that's going to happen once in a million
9 years, and if I ask Mary, Mary says I think that's going
10 to happen once in ten thousand years.
11 DR. CORRADINI: So these are four different
12 Y estimates but all the same X estimate.
13 DR. STETKAR: I believe that's the case.
14 DR. BALLINGER: But you mentioned the Army
15 Corps of Engineers somewhere in this conversation a
16 little while back. What was their role?
17 MR. LOVELESS: The Army Corps of Engineers
18 provided that point right there, that's the 500-year
19 flood. That's as far as the Army Corps of Engineers
20 calls credible in flood analysis.
21 DR. BALLINGER: And so research and
22 regulatory experts that drew the rest of the curves?
23 MR. LOVELESS: They provided the end points.
24 DR. CORRADINI: And that lower curve that
25 says extrapolation.

1 MR. LOVELESS: Well, I haven't got to that.
2 This blue portion here is what the licensee provided us
3 and the licensee did a number of things. The first
4 thing they did was they redefined what their probable
5 maximum flood was for the site. Then they used a number
6 of methods to come up with this curve. The only reason
7 for the extrapolation backwards was to show that the
8 licensee's curve didn't converge with the 500-year
9 flood which was one of the reasons that we questioned
10 their curve initially. I am going to show their curve
11 here in a minute for a different reason.
12 Do we have any other questions on this?
13 DR. BALLINGER: So what you're saying is the
14 Corps supplied one number, the licensee chose another
15 number, and that was it.
16 MR. LOVELESS: That's true. But the main
17 purpose of looking at this is you can ask a whole bunch
18 of experts, ask the licensee, and you get a very wide
19 range of what the flood hazard might look like at that
20 site.
21 DR. BLEY: And the only thing I still don't
22 understand is the expert elicitation that did those top
23 four curves, whose experts were they? Did you guys do
24 that, did the licensee, who did those?
25 MR. LOVELESS: It was came out of a

1 conference that included the USGS and agency personnel,
2 I believe the Corps was there, and it was not specific
3 to ANO, it was specific to a probable maximum flood.
4 The goal was to say, okay, what is the frequency of a
5 probable maximum flood because a probably maximum flood
6 is a deterministically calculated number.
7 DR. REMPE: But even though the conference
8 was not specific to ANO, it was that site all the experts
9 looked at?
10 MR. LOVELESS: No. We simply took that
11 site --
12 DR. STETKAR: David, let me see if I can
13 understand, though. You said that this was a
14 conference that people said what is the
15 probability -- I'll use that term -- of a probable
16 maximum flood. Is that like saying the probability of
17 a Styrofoam cup -- in other words, without telling
18 people a particular site or just saying what would you
19 think the probable maximum flood probability would be?
20 In a generic sense, regardless of the site, regardless
21 of the hydrology, what question were they asked at this
22 conference?
23 MR. LOVELESS: The probable maximum flood is
24 deterministically calculated but it uses probabilistic
25 information.

1 DR. STETKAR: But my silly analogy is I can
2 call this thing a Styrofoam cup, but taken out of context
3 it doesn't mean anything unless I say probable maximum
4 flood at a particular location.
5 DR. BLEY: I'm not sure even the analogy
6 helps, but for me what would help is what question were
7 those guys asked.
8 DR. STETKAR: Were they asked probable
9 maximum flood on the Arkansas River at the location of
10 the ANO plant?
11 MR. LOVELESS: No, they were not.
12 DR. STETKAR: Or were they told there is a
13 probable maximum flood of 358 feet, what's the
14 probability of that without knowing anything else?
15 MR. LOVELESS: No. They were asked if you
16 use industry standards at any location -- it wasn't even
17 nuclear site -- any location in the U.S. and you use the
18 deterministic methods and the probabilistic type data
19 that you collect to calculate a probable maximum flood,
20 how frequent is that flood.
21 DR. CORRADINI: So can I try it a different
22 way? You're saying that they basically put a
23 probability number regardless of site or location based
24 on data.
25 MR. LOVELESS: Given that you have a specific

1 method, given that you have a specific type of data that
2 you pull in, that that data has a probabilistic nature
3 to it.
4 DR. STETKAR: But site independent.
5 MR. LOVELESS: Right.
6 DR. REMPE: You've been given the 358.
7 DR. STETKAR: So this would be the
8 uncertainty and the frequency of a probable maximum
9 flood at Palo Verde.
10 DR. BLEY: Anywhere. If I understand what
11 he's said to us, he said, You guys know or you think you
12 know how the probable maximum flood is calculated.
13 Given that if one has been calculated, what is the
14 frequency of that flood. But it was that general is
15 what it sounds like.
16 MR. LOVELESS: The fundamental problem is we
17 have 75 years' worth of data and we're trying to
18 extrapolate it out into the 10,000 year, 100,000 year
19 and million year flood, and we can't do it. It's
20 exactly that you're saying. That's what our point is,
21 we can't do it, none of these are valid curves.
22 DR. STETKAR: But David, this type of
23 comparison now, I'd question why are those top four
24 curves at all relevant to ANO. Why are we looking at
25 this comparison for ANO? I don't understand what went

1 into the licensee's calculation but why is it relevant
2 to ANO?
3 MR. LOVELESS: The two things that make this
4 relevant to ANO is that it starts with the 500-year
5 flood.
6 DR. STETKAR: And that is the Army's estimate
7 for that point on the Arkansas River.
8 MR. LOVELESS: Correct. And it ends with
9 the probable maximum flood over a range --
10 DR. STETKAR: From what I've heard, I have
11 absolutely no confidence or understanding on anything
12 to the right-hand side of the Y axis.
13 MR. LOVELESS: And that's what I was trying
14 to tell you is I don't either.
15 DR. SCHULTZ: All it does, John, as I see it,
16 there's one point that the Corps of Engineers calculated
17 over on the axis, then there's four points that are on
18 the right-hand side, one is at ten to the minus three,
19 ten to the minus four, ten to the minus five, ten to the
20 minus six, happens to match up with 358.
21 DR. RICCARDELLA: No. 358 is a solid point
22 from somewhere. Right?
23 MR. LOVELESS: 358 is a site specific
24 calculated probable maximum flood.
25 DR. STETKAR: But the experts who estimated

1 those four numbers weren't given 358, they were just
2 saying if you use generic methods for determining
3 something called a probable flood --
4 DR. SCHULTZ: And I'm questioning whether
5 this chart is trying to represent expert elicitation at
6 all. All I see is that there's one point there, four
7 points there, ten to the minus two, three, four, five,
8 six, and lining up and compared to what the licensee has
9 calculated, that's all that's doing.
10 DR. STETKAR: But my point is that the
11 right-hand -- the points in between are irrelevant
12 because I don't think anybody actually calculated.
13 See, I have two points: you have a vertical slice at
14 358, you have a vertical slice at 340, the Corps
15 calculated a number of 340. Some other people were
16 asked to estimate something about what they thought the
17 frequency of something called a probable maximum flood
18 on a generic basis might be, and this curve is somehow
19 trying to relate that to a number that was calculated
20 by the Corps for that site.
21 DR. SCHULTZ: Well, I know that's what we
22 heard earlier but I'm not sure that's the case with this
23 curve.
24 DR. BALLINGER: But the 358 is their design
25 basis, ANO's design basis? Where did the 358 come from?

1 MR. LOVELESS: It is the probable maximum
2 flood that was calculated for their licensing basis when
3 they were licensed.
4 DR. BALLINGER: So that's their license.
5 Right?
6 MR. LOVELESS: Well, they have a slightly
7 higher licensed flood, but that's the probable maximum
8 flood.
9 DR. BLEY: I think he's going to get to that
10 question in a second, but I have one more about this.
11 Given what we just all think we understand, that we have
12 one point on the left, four points on the right, you
13 sketched in these multi-colored curves just to connect
14 them back to that original point.
15 MR. LOVELESS: Correct.
16 DR. CORRADINI: Just so everybody gets it,
17 let me repeat it. So the Corps' number is on the 340
18 axis, and who computed the 358?
19 MR. LOVELESS: That was a probable maximum
20 flood came from a combination of the Corps and the USGS.
21 DR. CORRADINI: So the Corps computed both
22 the 340 and the 358.
23 MR. LOVELESS: Well, the Corps computed the
24 340 was at the 500-year flood. The Corps computed that
25 the probable maximum flood was 358. The problem is we

1 don't know what the frequency of a probable maximum
2 flood is.
3 DR. RICCARDELLA: And the Corps doesn't
4 assign that.
5 DR. CORRADINI: But you know precisely how
6 358 was calculated?
7 MR. LOVELESS: We know how it was calculated.
8 Correct. Very specific methods that were used to
9 calculate that number.
10 DR. RICCARDELLA: But the experts who came up
11 with these probabilities also knew how the 358 was
12 calculated.
13 MR. LOVELESS: Correct. They weren't
14 looking at the 358, they were looking at the process.
15 They said, If you follow this process, what will the
16 probability of the resulting number be for any site?
17 DR. BLEY: And my last question on this
18 chart -- and I'm sorry that we're dragging this
19 out -- at this conference were there four individuals
20 or did they have like four little subgroups, or are these
21 four points things that came out of some kind of joint
22 process?
23 MR. LOVELESS: You're beyond my area.
24 DR. BLEY: Is there a paper or something?
25 MR. LOVELESS: There were a number of papers

1 that were written in the area. You can't find a paper
2 that has these four points.
3 DR. BLEY: Where did you find them?
4 MR. LOVELESS: Well, we have several papers
5 that showed the ranges of numbers that were given, and
6 this was the range.
7 DR. REMPE: So I think I sort of understand
8 what you've done here, but the fact that the licensee
9 has a much different curve, could it not be because of
10 specific -- in some cases specific insights related to
11 their site that would make them have more knowledge and
12 maybe we should believe their curve a bit more?
13 MR. LOVELESS: There are a couple of
14 different things to answer that. I guess the first
15 thing I'll tell you, again, is that they went in and
16 recalculated this 358 and said, Well, we believe this
17 number is really 353-1/2.
18 DR. BLEY: Based on the same process.
19 MR. LOVELESS: Well, they used a new process.
20 DR. BLEY: But that was ANO.
21 MR. LOVELESS: Yes. We haven't reviewed it
22 or evaluated it and determined that's appropriate, and
23 then they used a very river specific model to show that
24 curve.
25 DR. BLEY: And when you say they used a new

1 process, is that a new Corps of Engineers process or some
2 new process that they invented?
3 MR. LOVELESS: This is a new process that
4 their contractor invented.
5 DR. STETKAR: And one more thing from me on
6 these curves -- we'll let you get to it
7 eventually -- you show what I'll characterize the
8 blue-orange curve and you said they recalculated, they
9 did something to redefine their probable maximum flood
10 at 353-1/2 or something. Tell me more about the blue
11 curve. Who calculated the blue curve or more than one
12 point? I know how the E to the minus six, at I'll call
13 it 354 -- I don't know how it was calculated but I
14 understand that somebody did that. What's the rest of
15 the blue curve? And this is from their submittal?
16 MR. LOVELESS: This is a draft of their
17 submittal.
18 DR. BALLINGER: So is this to re-analyze the
19 flooding hazard? Is that what we're talking about
20 here?
21 MR. LOVELESS: Yes.
22 DR. BALLINGER: So that's the Fukushima
23 mandated.
24 MR. LOVELESS: Right.
25 DR. BLEY: And they have uncertainty bounds.

1 MR. LOVELESS: The primary thing I want to
2 show here is most of our parameters in a PRA have error
3 factors in the three to five range, some items we end
4 up with the error factor on the order of a single order
5 of magnitude.
6 DR. BLEY: So error factor means uncertainty
7 this way.
8 MR. LOVELESS: It's our uncertainty bounds,
9 yes.
10 In this case, if we take the point that we're
11 of interest in, we have over five orders of magnitude
12 of data uncertainty. There is no modeling uncertainty
13 in this.
14 DR. BLEY: Their curve they claim is based on
15 data or is it judgment?
16 MR. LOVELESS: Well, it's based on their
17 extrapolation of data.
18 DR. BLEY: Of data, but it's data based.
19 MR. LOVELESS: Remember, all of this,
20 anything we do in flooding is an extrapolation of
21 whatever the data set we had, and for the Arkansas River
22 at ANO, that data set is 75 years worth of data. And
23 we're trying to extrapolate out it into here they've got
24 a million, 10 million, 100 million years.
25 Now, for all your digging to try to find out

1 what this data meant, what it meant to us was that we
2 couldn't come up with a valid flood hazard for ANO.
3 Because of that, a significant enforcement review
4 planning panel, what we call SERP, has determined that
5 we should use our Inspection Manual 0609, Appendix M,
6 which is a qualitative approach to significance
7 determination process. We say that we do not have the
8 tools, we don't have the data, we don't have whatever
9 to use significance determination to give a risk-based
10 answer to the risk of a performance finding.
11 Appendix M asks us to do two things. First
12 thing it asks us to do is, if we can, develop a
13 qualitative and quantitative upper bound. So we looked
14 at what is the upper bound using the licensees here and
15 95 percent upper confidence intervals and upper bound,
16 got about 11,000-year return period which is like
17 somewhere around two E minus five per year, and that's
18 at the flood elevation of concern which was anything
19 above 354.
20 DR. CORRADINI: So return period means?
21 MR. LOVELESS: It's the inverse of the
22 frequency of exceedence. It's supposed to be for the
23 public to say, okay, how often do we expect to see this
24 type of flood. We expect to see one every 10,000 years,
25 that's return period.

1 DR. BALLINGER: So you guys really went after
2 it as good as you could. That's what you came up with,
3 that's the best you could do in terms of you couldn't
4 determine it.
5 MR. LOVELESS: And that was an upper bound.
6 We went and said, okay, this is as high as it can be.
7 Actually, our quantitative upper bound was above ten to
8 the minus four and we used some qualitative factors we
9 knew under the process and estimated that the upper
10 bound was below one times ten to the minus four.
11 DR. BALLINGER: What I'm trying to get at
12 fill in the blank, Plant X -- everybody is going to have
13 to do this -- are they going to be faced with the same
14 kind of issues that you had here?
15 MR. LOVELESS: We've done this either ten or
16 eleven times over the last five or six years and we've
17 run into the same issues every time.
18 DR. BALLINGER: But for different plants.
19 MR. LOVELESS: For different plants, yes.
20 DR. BLEY: Although nobody believes those
21 pictures on the previous page, the uncertainty bounds
22 are kind of like what these folks developed from very
23 different starting points.
24 MR. LOVELESS: Absolutely. We don't
25 believe the curves because they're extrapolations, and

1 there's uncertainties that are amazingly large.

2 DR. RICCARDELLA: But looking at that

3 previous slide, your number is more like the mean of that

4 series of curves. Right? You go to 354 and you look

5 at those four curves up above, the number that you were

6 using, like ten to the minus four, it was like the mean

7 of those curves, isn't it? You said two times ten to

8 the minus five, so it's near the bottom curve.

9 MR. LOVELESS: Well, two times ten to the

10 minus five was the licensee's upper bound. Our upper

11 bound would have been this point here. But we looked

12 at a number of qualitative factors and determined that

13 it was somewhere below this.

14 DR. BALLINGER: The 500-year flood from the

15 Corps is actually uncertain.

16 MR. LOVELESS: Correct. A lot less

17 uncertain than this.

18 DR. BALLINGER: I mean, the point where you

19 started the extrapolation is actually uncertain.

20 MR. LOVELESS: True, true.

21 So after you have an upper bound and decide

22 it can't go any higher than this, our Appendix M process

23 has us look at the defense in depth that's remaining

24 after the performance deficiency. So if we had this

25 flood we looked at what would fail at ANO. Well, here

1 we go: emergency feedwater, high pressure injections,
2 spent fuel pool cooling, diesel fuel oil, decay heap
3 removal. Essentially we failed all feedwater to the
4 steam generators and all makeup to the reactor.
5 DR. BLEY: And what level was this at?
6 MR. LOVELESS: This is just above 354.
7 DR. BLEY: So even regardless of where they
8 calculated their PMP or all this other stuff, for what
9 they calculated, they aren't protected.
10 MR. LOVELESS: Right. They are protected to
11 their design. That's the problem we started with.
12 They're supposed to be protected to 361 and we found that
13 they couldn't protect the plant to flood something just
14 above 354.
15 DR. BLEY: But this is based on this
16 re-analyzed flood pageant.
17 DR. BALLINGER: The original was 358.
18 MR. LOVELESS: The flood hazard and all has
19 to do with the frequency of the flood. I'm saying if
20 there's a flood to 354, we would lose all of that. If
21 you go back through the pictures that we skipped
22 through, there were holes that the aux building was a
23 sieve.
24 DR. BLEY: Ron's question wasn't about
25 probabilities or anything, this doesn't have anything

1 to do with recalculated. The original probable maximum
2 flood, the requirement was 361.
3 MR. LOVELESS: Correct.
4 DR. BLEY: That's something above their
5 original PMP. The design basis for plants in this
6 region was the PMP plus a flood-induced failure of the
7 upstream dam.
8 DR. BALLINGER: So you're saying that the
9 original design basis was wrong. They calculated a
10 number. Their building wasn't built to survive what
11 they said it was designed for.
12 MR. LOVELESS: No. We're saying that they
13 had -- we skipped over --
14 VOICE: We skipped over the very first part
15 of this, so what we found was performance deficiencies,
16 we found inadequate flooding seals, so that's what got
17 us into a performance deficiency.
18 MR. ALEXANDER: If I could. I'm Ryan
19 Alexander and I was on the inspection team. The
20 performance deficiency was revealed during the stator
21 drop and the flood on the fire water went to the aux
22 building and showed up places that it shouldn't have
23 been which got us looking at their flood protection
24 measures.
25 DR. RICCARDELLA: But if they had all those

1 sealed and everything proper they would have been able
2 to survive to 361.
3 MR. LOVELESS: Right. They should have been
4 able to survive a 361 foot flood, and they are today.
5 DR. RICCARDELLA: They've fixed all that
6 stuff.
7 MR. LOVELESS: Right. Licensing came in
8 during a regulatory conference and discussed a number
9 of things that they thought should reduce the risk.
10 They said that they would have time; if a flood was
11 imminent, they would know it and they would be able to
12 prepare the plant for that flood. They showed a number
13 of methods, including inflatable water berms, sandbags
14 and sheet metal on doors to raise the elevation that the
15 site could take about two feet which any increase in a
16 flood decreases risk.
17 They also came in and their service water
18 system is above the flood grade of concern and they
19 indicated that they would be able to provide water to
20 the steam generators through their service water
21 system. They had portable pumps from their B5B
22 equipment; they indicated pathways that they could get
23 water to the steam generators using that. They also
24 showed a method that they could go into containment and
25 use the safety injection tanks to make up to the reactor.

1 DR. RICCARDELLA: None of those deficiencies
2 you found in the inspections, just skimming through
3 them, appear to have been due to the stator drop, they
4 were preexisting.
5 MR. LOVELESS: Correct. The only reason the
6 stator drop is tied to the flooding is it revealed that
7 they had a problem with flooding. Water into the train
8 bay that should have stayed in the train bay or gone out
9 the door went into the auxiliary building, and it was
10 a lot of water that went into the auxiliary building.
11 In an after conference inspection, Brian and
12 his team found that a number of the methods that the
13 licensee said that they would have would not have worked
14 during the specific timelines of a flood, they wouldn't
15 have been able to get water into the steam generators,
16 and/or called into question how well those would be, and
17 so they got very little credit for that. In the final
18 analysis we determined that it was a high safety
19 significance, or yellow.
20 DR. SCHULTZ: So you said they got very
21 little credit for it. I think they ought to be
22 penalized if they come forward and say: Well, we could
23 have done these things. And then you look and find that
24 they couldn't have done those things. I'm sure further
25 discussions were held as a result.

1 DR. BLEY: Is there any reason to believe all
2 the deficiencies you found are unique to one plant? Are
3 we nosing around anywhere else? I mean, we haven't
4 looked for this for a long time.
5 MR. LOVELESS: Well, like I said, this is
6 either the tenth or eleventh flood issue that we've had,
7 the first one being one I worked on which was Fort
8 Calhoun back in 2011 which was before the Fukushima.
9 All the rest of them were discovered as part of the
10 walk-downs and/or the agency's review of the
11 walk-downs. So at ANO, one of the biggest concerns was
12 that their initial walk-downs did not find a lot of these
13 problems.
14 DR. SCHULTZ: So this is in the process of
15 gradually getting corrected is what you're saying.
16 MR. LOVELESS: Yes, for the industry.
17 DR. BLEY: So what elevation did they design
18 their flex equipment to?
19 MR. LOVELESS: I don't have the answer to
20 that.
21 MR. SKILLMAN: Colleagues, we really have
22 run out of time. Any other final questions before we
23 break?
24 (No response.)
25 MR. SKILLMAN: I'm going to take a 35-minute

1 break. Let's come back at five minutes after 1:00 on
2 that clock.
3 (A recess was taken.)
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25 A F T E R N O O N S E S S I O N

1 MR. SKILLMAN: We are now back in session,
2 and I welcome Greg.
3 Greg, go ahead.
4 MR. WARNICK: Good afternoon. My name is
5 Greg Warnick. I'm a branch chief, Branch C here in the
6 region. I'm responsible for some of the boiling water
7 reactors in the region and today we're going to talk
8 about the River Bend Station, GEBWR6, where we've had
9 a couple of events over the last several months that had
10 us do special inspections.
11 There were some questions earlier about the
12 NRC's incident investigation program that Ryan talked
13 to, as well as some questions about our performance
14 indicators and what additional inspections could we do.
15 This is an exact example actually referring to River
16 Bend Station that you were asking about earlier. River
17 Bend Station had a reactor trip in December of last year.
18 That was actually the additional input for a complicated
19 reactor trip that put them into the white band for the
20 performance indicator that is one of the reasons why
21 they're in Column 2 of the action matrix.
22 Well, in addition to the input from the
23 performance indicator, we also apply our reactive
24 inspection program to see if there's more information
25 we need to go out and look at to evaluate performance,

1 to see what lessons learned, what the licensee needs to
2 be addressing. So we're going to talk about those
3 things today.
4 So our NRC Incident Investigation Program is
5 defined or outlined in Management Directive 8.3.
6 Management Directive 8.3 is the agency policy for
7 ensuring that significant events that involve reactor
8 and materials facilities are investigated in a timely,
9 objective, systematic and technically sound manner.
10 And like I was just talking about, for a reactor trip
11 to happen, complicated reactor trip, there could be some
12 things that happened during that trip that we need to
13 go out and investigate in a little more timely fashion
14 to understand better such that performance issues can
15 be addressed in a more timely manner.
16 The objectives of the management directive
17 are here. I'm going to focus on the third bullet there
18 to kind of drive the point to illustrate why we did the
19 inspections at River Bend Station, and specifically it
20 helps the NRC increase the efficiency and effectiveness
21 of our regulatory programs and licensee operations by
22 the prompt dissemination of the facts, conditions,
23 circumstances and causes of significant events and the
24 identification of appropriate followup actions.
25 The management directive talks about three

1 different types of inspections, and they were asked
2 about earlier. Our lowest level of reactive
3 inspections is a special inspection, next is the
4 augmented inspection, and finally for those higher
5 significance events we have incident investigations.
6 The NRC's guidance that we have is our NRC
7 Inspection Manual Chapter 0309. That's the guidance to
8 the regional staff for implementing those requirements
9 prescribed in the management directive. In this
10 Inspection Manual it provides the deterministic
11 criteria and risk assessments process for evaluating
12 these types of events to make a decision as to what level
13 of reactive inspection should be performed, and that was
14 specifically asked earlier.
15 So there's a series of deterministic
16 criteria. When something like this happens, a reactor
17 trip, a plant event, an operational occurrence that
18 occurs, failure of safety equipment, we first look at
19 the deterministic criteria. If any of the
20 deterministic criterion are met, then we evaluate
21 further for risk insights. We do that looking at
22 conditional core damage probability and conditional
23 large early release fraction. And depending on the
24 results of that additional risk evaluation, that will
25 determine the level of inspection performed.

1 Any questions on that? I know there was kind
2 of a question about that earlier.
3 (No response.)
4 MR. WARNICK: Okay. I'll continue on. So
5 I've kind of presented to you the programs that the
6 agency has, our policy and the implementing guidance,
7 and I'll show you a couple of examples here for how we
8 applied that guidance, talk through the events of what
9 happened so you can see how the guidance applied, and
10 why the objectives of the guidance and policy were met
11 through our ability to do these types of inspections
12 above just the normal baseline and performance
13 indicator input to our Reactor Oversight Process.
14 First event is one I talked about earlier,
15 it's the one Ryan talked about, the reactor trip that
16 put River Bend Station over the threshold for their
17 performance indicator, and it just so happened it
18 occurred on Christmas Day. So December 25 of last year
19 at 8:37 in the morning, River Bend Station scram'd from
20 85 percent power following a trip of reactor protection
21 system motor generator set. At the time of the motor
22 generator set trip, there was a half scram that existed
23 on the other division due to an unrelated equipment
24 problem. The combination of the motor generator set
25 trip and the half scram that was already into the reactor

1 protection system made up the logic for our reactor
2 trip.
3 As expected, the licensee notified the
4 resident inspector. Our senior resident inspector
5 promptly concluded his celebration activities with his
6 young family and responded to the site. As he got
7 there, he did what he would normally do, and that's to
8 assess what happened, to look at plant conditions, make
9 sure they were in a safe condition, and they were at this
10 time, and talk to operators to kind of get some feedback
11 as to why this was complicated and how did it happen.
12 As he did that, he learned, and it was
13 revealed through the event, that the following
14 equipment issues occurred following the initial scram.
15 Specifically, an unexpected high reactor water level
16 signal was received which resulted in the tripping of
17 other reactor feedwater pumps. This is a logic
18 associated with that. Following the reset of the high
19 reactor water level signal, plant operators had
20 difficulties recovering feedwater, specifically the
21 pumps wouldn't restart when they tried to -- these are
22 powered by MagneBlast GE breakers -- as well as the
23 valves they were trying to operate to restore feed once
24 they could get a pump started, started feed rate valves
25 wouldn't respond as expected and they had difficulty

1 getting feedwater regulating valves open, such that
2 they couldn't restore feedwater as promptly as they're
3 trained to do, and as a result, level was trending down
4 towards the low level set point, and it was complicated
5 further by in fact receiving a low level water trip, or
6 a Level 3 signal.
7 As they were approaching that level set
8 point, they were successful, as I said, getting a pump
9 started, getting the feedwater regulating valve open,
10 they were starting to recover level, went below that low
11 level set point, recover level, and restored it to the
12 normal band.
13 DR. STETKAR: They never got down to Level 2?
14 MR. WARNICK: No.
15 Following the restoration of the reactor
16 vessel water level, the plant was stabilized in shutdown
17 condition. That's the point where our resident
18 inspector arrived onsite. After addressing the
19 identified equipment issues, plant startup was
20 conducted a couple of days later by the licensee, and
21 I point this out only because during power ascension
22 following the startup, another feedwater pump failed to
23 start when it was demanded. As we talked, that was a
24 problem that happened actually during the response to
25 this event. So there were breaker issues going on that

1 the licensee didn't fully understand.

2 MR. SKILLMAN: So it was known at that time

3 that it was circuit breaker problems?

4 MR. WARNICK: It was known at the time that

5 these GE MagneBlast breakers didn't always work when

6 demanded, and they had actually a workaround in place

7 to where the operator, if it failed to start, they'd go

8 down, re-rack, rack out and re-rack in the breaker, and

9 typically that would be enough to get it to start, and

10 in fact, that's partially what they did in these

11 situations to get the pumps going.

12 DR. SCHULTZ: Greg, were any of the

13 complicating features following the trip connected with

14 the half trip that had been set?

15 MR. WARNICK: No. That set up the

16 conditions for the reactor scram, and again, the half

17 trip that was in was due to another unrelated problem

18 that was not associated with the complications.

19 DR. SCHULTZ: Okay. Thank you.

20 MR. WARNICK: So this was a significant in

21 our mind, it was a complicated trip for the reasons kind

22 of that I talked about related to the multiple failures

23 of the feedwater system. As far as the pumps go, the

24 breaker issues that we knew they had problems with. In

25 this situation it complicated an initiating event

1 further.

2 Let's see, issues related to the licensee's

3 operations department, their inability to control level

4 like they're trained to in the bands between a Level 3

5 and a Level 8. We looked at the deterministic criteria.

6 We satisfied deterministic criteria so we looked at it

7 from a risk standpoint, and with the things that went

8 on, we made the conclusion -- and you can see here that

9 the conditional core damage probability was determined

10 to be 1.2 times E to the minus 6, which falls into the

11 overlap region between no inspection and a special

12 inspection. That gives the NRC the ability to look at

13 that, evaluate, and with management input make a

14 decision is a special inspection appropriate. And for

15 the reasons I listed here, we determined it was

16 appropriate and we did do a special inspection.

17 DR. BLEY: Your third bullet sounds as if

18 there was a problem with operators. Was it, or was it

19 a hardware problem, or had you decided at that point?

20 MR. WARNICK: We hadn't decided at that

21 point. We knew there were breaker problems, they

22 didn't get the valves working the way they expected them

23 to. We didn't fully understand that, which added to our

24 interest in wanting to understand it better and our

25 decision-making to do a special inspection. So as we

1 did that special inspection, we looked into the
2 performance of the operators, how did it contribute to
3 this. That inspection is actually ongoing, so the
4 information is pre-decisional, can't really talk about
5 the results but we are certainly considering those
6 things to determine if there were, in fact, performance
7 deficiencies?
8 DR. BLEY: Is there a preliminary report out
9 yet?
10 MR. WARNICK: No. We're actually exiting
11 with the licensee later today, so a report on this
12 special inspection is expected to be out within the next
13 couple of weeks.
14 DR. STETKAR: Are these circuit breakers
15 uniquely associated with the feedwater pumps?
16 MR. WARNICK: I'm relatively new to the
17 branch. I'm looking around to see if anybody has
18 experience at River Bend Station. Are the GE
19 MagneBlast breakers just with the feedwater pumps?
20 DR. STETKAR: I don't know what voltage it
21 is, so I'll just say 6kv, might be 4kv, might 13. Did
22 you look at if it's a hardware problem and they're used
23 for power transfers at those buses in your evaluation?
24 Have you pulled those strings?
25 MR. WARNICK: We did. That was all part of

1 the charter for the special inspection to look into
2 those types of things: maintenance practices, review,
3 operating experience over time, have they been
4 incorporating operating experience to address/identify
5 generic issues. We did have some issues of concern
6 associated with that, but again, the conclusions that
7 we drew are pre-decisional so I can't really offer up
8 our conclusions at this point. But certainly those
9 were the types of things that we looked at. As this was
10 an input to our decision to do the special inspection,
11 we wanted to understand it.
12 DR. STETKAR: My only question was that 1.2
13 times E to the minus six, did you only look at feedwater
14 related issues or did you look at all issues that could
15 be affected by breakers that might have the similar
16 problem?
17 MR. LOVELESS: This is David Loveless. At
18 the time we didn't know the extent of condition and that
19 number only included the feedwater issue.
20 DR. SCHULTZ: Greg, the decision basis looks
21 very strong with these four bullet points. If you had
22 three of them would you have gone forward with a special
23 inspection, two of them? Can you give an appreciation
24 for what the tipping point was in the discussions that
25 led to the special inspection?

1 MR. WARNICK: Certainly. There's
2 deterministic criteria, there's a list of about ten
3 questions that are asked, and you only need to satisfy
4 one of those questions, answer yes to one of them to meet
5 the deterministic criteria to do the risk analysis that
6 David referred to which gives you the number, put us in
7 the overlap region so now we're considering do we do no
8 special inspection or do we do one. Us not fully
9 understanding the extent of condition of the GE
10 MagneBlast breakers, where else it may apply, the
11 practice they had by racking out and racking in these
12 breakers, that caused us to have concern. We wanted to
13 understand that better, is that really a practice they
14 should be doing or should they identify why these things
15 aren't working, fix the problem such that they don't
16 have to take this operator workaround action.
17 DR. SCHULTZ: So would you say if that one
18 bullet alone was there you likely would have done the
19 special inspection?
20 MR. WARNICK: Yes. We met the risk insight,
21 we had enough concern that we didn't understand. It's
22 hard to say what management would have decided, but I,
23 as a branch chief, would have made the case to my manager
24 that we need to get onsite to meet the objectives of
25 Management Directive 8.3, that I pointed out, to get a

1 prompt understanding of the facts, found out where we
2 can learn more as far as generic guidance and where the
3 licensee needs to improve in these equipment and
4 performance issues.
5 DR. SCHULTZ: That's fine. That gives me an
6 appreciation for it. Thank you.
7 DR. BLEY: Greg, just to follow up where you
8 started, you told us the general place you go to get the
9 criteria for whether you do an SIT or an AIT, I know of
10 a few cases where they went in with a special inspection
11 and part way through they said, No, we need an augmented
12 inspection. Instead of just the general you've got to
13 meet some rules, can you give us a hint of what the
14 dividing line is in terms of significance or the need
15 for additional expertise or something that triggers
16 jumping to the higher level inspection?
17 MR. WARNICK: Well, typically the
18 first -- well, not typically but always one of the first
19 items in a charter for any level of inspection -- in this
20 case a special inspection -- is during the first day for
21 the team to get there, assess the facts, talk to people,
22 make sure we have a good understanding of the basis for
23 our decision to do a special inspection. If we identify
24 any information that we didn't fully understand, could
25 be more significant, we immediately get with our SAR,

1 reconsider that, redo the calculation and determine if
2 there's a need for a higher level of inspection. And
3 actually, that's a required call at the end of the first
4 day onsite back to the branch chief to give me the
5 information as to that decision.
6 Now, the continue to look through that as they
7 investigate. I told you this inspection is still
8 ongoing. So it's a continuous effort that we do, we
9 continue to look for things that we maybe didn't fully
10 understand to see if there's a need to upgrade to provide
11 the level of oversight appropriate for the significance
12 of the event.
13 DR. BLEY: One thing I think is really
14 important you said, you try to get there on the first
15 day.
16 MR. WARNICK: Well, the first day of the
17 onsite inspection. That may be two to three weeks after
18 the actual event occurred.
19 MR. KENNEDY: Could be that day, could be in
20 a week. A lot depends on what happened and what the
21 licensee is doing and when is the right time for us to
22 be onsite.
23 DR. BLEY: The thing I was thinking of, with
24 the hardware you can reconstruct later. For people,
25 even people trying to be very honest, the more time that

1 passes, the more we reinterpret, we build a
2 rationalization even if we don't know we're doing it,
3 so you get a different story as time moves on, not that
4 people are dishonest, it's just what happens.
5 MR. KENNEDY: And that would be a factor, how
6 quickly do we need to get out there to conduct interviews
7 with the plant employees or those involved, that
8 definitely is a factor. And don't forget, we have a
9 resident inspector onsite, and so they are there
10 responding to the complicated trip, they are beginning
11 the inspection. This is just determining how many more
12 resources we apply to inspecting this event.
13 MR. WARNICK: And that's an excellent point
14 I just want to reiterate. Resident inspectors are the
15 key to us for keeping us informed as to the timeliness,
16 the lack of understanding that we need to acquire in
17 terms of when we need to be onsite to conduct this
18 inspection.
19 MR. SKILLMAN: Let me ask this, Greg. Was
20 the equipment quarantined, and when it was quarantined,
21 was there what I'm going to call a thick magnifying glass
22 inspection of the MagneBlast breaker or breakers?
23 MR. WARNICK: The equipment, as I told you,
24 they had a number of issues racking out, racking in
25 breakers, they wouldn't start -- and they needed to do

1 that to get feedback to prevent getting to a Level
2 2 -- so certainly during the event they were operating
3 equipment to respond to it. Once the plant was
4 stabilized, they collected what data they could, but as
5 I told you, they felt they addressed the issues that were
6 out there, went to a startup just two days later, and
7 on that startup they had another problem with the GE
8 MagneBlast breaker.
9 So certainly they didn't do the level of
10 investigation that you're alluding to, otherwise, they
11 shouldn't have been in that scenario where they
12 continued to have the same problem again during the
13 startup two days later. That's in part why we went out
14 there and wanted to understand better what the situation
15 was.
16 MR. SKILLMAN: It seems to me MagneBlast
17 breaker problems are not unique to River Bend.
18 Industry has dealt with these for a long time, and it
19 seemed to me that if there was a second incident of the
20 very same type of hardware, leadership would have said
21 timeout, we may have a common mode failure that we're
22 dealing with her, we had better backtrack and find out
23 what's wrong with this equipment.
24 This same problem happened at Perry almost at
25 Christmastime and it was failure of the MagneBlast to

1 recharge. Those were 6900 volt machines but on them is
2 a little 120 volt machine, looks like a little sewing
3 machine, and it actually winds the spring so that when
4 you give the command to close, the springs rack in the
5 knife blades. So here is this big machine that's as big
6 as a small refrigerator but on the back of it is this
7 little teeny 120 volt little driver servo motor that
8 actually winds up the spring that's the recharge.
9 That's a MagneBlast problem.
10 So if you say it wouldn't close and it
11 wouldn't close again, it almost sounds as though there
12 is an underlying hardware problem that needed to have
13 been diagnosed so they would have a root cause that would
14 make sense. If that wasn't done, it seems like a real
15 opportunity has been lost.
16 MR. WARNICK: The opportunities are there.
17 We have expectations of corrective action programs that
18 the licensee implements that they identify these things
19 and do the appropriate level of evaluation to understand
20 it and correct it. That's a big piece of what was
21 chartered in the special inspection, to understand
22 where they should have done better, and again, the
23 report that will be coming out will document the
24 conclusions that we had associated with that.
25 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

1 felt that we needed to understand it better, such that
2 we went into our process, Inspection Manual Chapter 0309
3 for the management directive, to look at the
4 deterministic criteria.
5 One other thing that had us concerned is some
6 of these failures were associated with a problem that
7 River Bend Station was aware of. It's a known problem
8 with NLI Masterpact breakers which are the breakers
9 associated with the chillers and the ventilation system
10 and the air handling units in the ventilation system.
11 Specifically, as experienced at River Bend Station, the
12 Masterpact circuit breaker is vulnerable to an
13 intermittent failure mechanism under certain
14 scenarios. Generally, the control logic is set up such
15 that the breaker experiences briefly a simultaneous
16 open and close signal. This dual open and close signal
17 can create a condition where mechanical binding can
18 impact the breaker's ability to close.
19 So as this surveillance is trying to find out,
20 you do a load shed of the safety related bus, diesel
21 starts up, comes up to rated speed and voltage, diesel
22 powers up the bus, and this equipment cycles back on.
23 So these Masterpact breakers got an open signal and then
24 they were receiving a closed signal to cycle back on,
25 and they were finding out that these breakers weren't

1 always cycling back on as expected. And in fact, as I
2 mentioned, this was a known deficiency that they were
3 aware of, felt that the likelihood of the breaker not
4 closing back in was extremely low.
5 But these events during the surveillance
6 testing revealed to the NRC that, okay, there's a higher
7 likelihood of these not working, especially during a
8 design basis event, that we wanted to understand better.
9 So that was one of the deterministic criterion that was
10 answered associated with the control building
11 ventilation system: generic problems with the
12 breakers causing the system not to work as designed.
13 Additionally, they had multiple failures of
14 the ventilation system, as evidenced by the
15 surveillance that was done in the February time frame,
16 as well as this March 9 event. And finally, back to the
17 MagneBlast breakers, this special inspection was
18 starting as the previous special inspection was kind of
19 wrapping up what they did, and we kind of rolled into
20 the MagneBlast breaker continuation look. We wanted a
21 better understanding with one of our breaker experts who
22 was put onto this team. So because of that
23 deterministic criteria satisfied, again, we looked at
24 the additional risk insights and determined that the
25 appropriate NRC response was a special inspection.

1 We did that special inspection, and again,
2 both of those special inspections are ongoing, both of
3 them are wrapping up here within the next week or two,
4 so inspection reports documenting the results of these
5 inspections will be issued within the coming weeks.
6 Finally, I just wanted to point out as is
7 typical of all the inspections we do -- I heard
8 mentioned earlier that was something I was very involved
9 with -- we like to look at lessons learned, provide
10 feedback where we can, and certainly there have been
11 some things identified by the team where we can feed back
12 to the program offices to see where we can learn better
13 in the future to try and improve the agency response as
14 well as licensee performance to eliminate these kind of
15 significant events.
16 Thank you very much, and I'll answer any
17 questions.
18 MR. SKILLMAN: Let me ask a question. On
19 your slide 66 your third bullet you identified:
20 overall adequacy of the licensee's breaker maintenance
21 program was called into question. Did the corrective
22 action program at River Bend point to this emerging
23 deficiency?
24 MR. WARNICK: The Masterpact breaker?
25 MR. SKILLMAN: Yes.

1 MR. WARNICK: No. That bullet was primarily
2 addressing what the first special inspection was
3 finding, issues of concern about the maintenance
4 program for the GE MagneBlast breakers. At this time
5 we thought, okay, maybe there's a problem with the
6 Masterpact breakers also in terms of their maintenance
7 program, so we kind of rolled it in. Again, at the time
8 of the decision-making we wanted to understand it
9 better, and that bullet goes to our wanting to
10 understand better the licensee's maintenance
11 practices. As we've gone through that we've reached
12 conclusions.
13 Certainly with the Masterpact there's
14 probably available information talking about this
15 design deficiency associated with Masterpact breakers,
16 there's nonconformance reports with NLI, they aren't
17 widely distributed which is one of the contributing
18 issues here, but the information is available such that
19 these opportunities could be there through a healthy
20 corrective action program to identify these problems to
21 avoid them from happening when this equipment is called
22 upon.
23 MR. SKILLMAN: Greg, I think the members
24 might be interested to read these reports when they're
25 completed, particularly the MagneBlast because they are

1 used throughout industry at very high power levels, very
2 high voltages. I'm sure other than River Bend every GE
3 Mark 6 uses them; I think that's probably the standard
4 chassis from that supplier. So I think members would
5 like to see those reports.
6 MR. WARNICK: Absolutely. These are issued
7 throughout but I'm sure we can have somebody arrange to
8 make sure you're aware of when they're issued and get
9 them to you.
10 MR. SKILLMAN: I would offer perhaps Kent
11 Howard as the person you might send them to.
12 MR. KENNEDY: We'll make sure those get to
13 you.
14 MR. SKILLMAN: Thank you, Kriss. And thank
15 you, Greg.
16 MR. WARNICK: All right. Thank you very
17 much.
18 MR. WALKER: Good afternoon. My name is
19 Wayne Walker. I'm the chief for Branch A in the
20 Division of Reactor Projects, with responsibility for
21 Diablo Canyon. At this time I'd also like to just
22 recognize Ryan Alexander for the help he was able to give
23 me on preparing this presentation.
24 The purpose of this presentation today is to
25 provide a brief overview of past and present activities

1 regarding seismic issues at Diablo Canyon, and I want
2 to focus on the current challenges and then also look
3 at the ongoing seism hazard reevaluations that are
4 associated with the implementation of the Japanese
5 lessons learned near-term task force recommendations,
6 and also touch briefly on license renewal, and then just
7 a current schedule and some challenges that we're
8 currently facing.
9 I guess prior to you coming here we provided
10 you some background documents so hopefully some of this
11 won't be redundant but we did provide you with the
12 seismic hazard reevaluation documentation and then also
13 what we refer to at the AB or Assembly Bill 1632. That
14 was the bill that required by that State of California
15 to do a reevaluation of seismic hazard at Diablo and
16 other base-loaded plants, specifically SONGS in
17 California.
18 Diablo Canyon is a pre general design
19 criteria plant. They were initially licensed with a
20 terminology that's not exactly in line with Part 100 of
21 the GDC criteria in Appendix A. The station has two
22 design basis earthquakes plus a third one that's unique
23 to Diablo Canyon. The design basis earthquake is set
24 at .2g of peak ground acceleration. At Diablo Canyon
25 the design earthquake is equivalent to the operating

1 basis earthquake, and that's probably terminology most
2 people are more familiar with. The double design
3 earthquake at Diablo Canyon is at .4g of peak ground
4 acceleration, and that's equivalent to the safe
5 shutdown earthquake which you read about in the Appendix
6 A of Part 100.
7 As I discuss the next slide, you'll see Diablo
8 Canyon has a unique earthquake that they're also
9 designed to and they were constructed to this based on
10 seismic information that was developed early in the
11 1970s. Oil company geologists identified a new fault
12 which later became known as the Hosgri fault. Upon
13 discovery of the fault, the licensee re-analyzed and
14 significantly upgraded the structures, systems and
15 components to accommodate the postulated ground motion
16 values up to .75g from the Hosgri fault, and therefore,
17 the Hosgri earthquake was established as a unique third
18 design criteria for Diablo Canyon.
19 One other aspect that is unique to Diablo
20 Canyon is the station has actual seismic sensors on the
21 containment base slab, and those sensors at .3g of peak
22 ground acceleration, there's an automatic trip
23 associated with that for Diablo Canyon.
24 This next slide is somewhat busy, I won't talk
25 about everything, but I thought it would be beneficial

1 just to kind of give you an overview of Diablo Canyon
2 and what's gone on over the years. In 1968 and 1970 the
3 initial construction permits were issued for the two
4 units. The design earthquake and double design seismic
5 design criteria were based on a consideration of two
6 design basis earthquakes, and those two earthquakes
7 were a magnitude 7.25 earthquake on what was referred
8 to as the Nacimiento fault, which is about 20 miles from
9 the site, and then there was another one that was a
10 magnitude 6.75 aftershock at the site associated with
11 a large earthquake on the San Andreas fault. However,
12 based on the identification of the Hosgri fault, PG&E
13 undertook several years of analysis and plant upgrades
14 to account for the hazard, so once they discovered the
15 Hosgri, they had to do a number of mods.
16 In 1977, PG&E submitted the Hosgri report to
17 the NRC, and later that same year the Hosgri analysis
18 was accepted by the NRC and was documented in Safety
19 Evaluation Report 34. In 1978, that was a significant
20 year relative to review of the Hosgri report for the NRC.
21 We issued two supplements to the safety evaluation
22 reports. They were supplements to Safety Evaluations
23 Reports 7 and 8, and they documented the evaluation of
24 the Hosgri report.
25 Some key statements in those SERs were as

1 follows. In July of 1978, the ACRS letter to the
2 Commission noted that the applicant's analysis and
3 tests related to the Hosgri event have been subjected
4 to an unprecedentedly intensive and comprehensive
5 review by the NRC staff -- and that's just a partial
6 quote -- however, the ACRS also noted that the theory
7 and analysis of earthquakes are in a state of active
8 development. The committee recommends that the
9 seismic design of Diablo Canyon be reevaluated in about
10 ten years, taking into account applicable new
11 information. And that's a key statement there, the
12 reconsideration of applicable new information, and I'll
13 talk a little bit more about that later.
14 In September of 1979, the Atomic Safety
15 Licensing Board concluded the Diablo Canyon plant will
16 be able to withstand any earthquake that can reasonably
17 be expected to occur on the Hosgri fault. And then in
18 November of 1984, the operating license was issued for
19 Unit 1. In response to the ACRS recommendation in 1978
20 for PG&E to conduct a seismic reevaluation after
21 approximately ten years, the license contained a
22 license condition requiring that the licensee perform
23 further assessments of the seismic sources and ground
24 motions applicable to the site and beyond those
25 considered in the development of the Hosgri event. So

1 this kind of tied them into a continuing evaluation
2 process for seismic conditions.
3 PG&E actions to meet the license condition
4 became the program which is often referred to as LTSP,
5 or long-term seismic monitoring program. In July of
6 1988, PG&E submitted their long-term seismic program
7 report to the NRC, which included seismic probabilistic
8 risk assessment and a deterministic seismic margin
9 assessment. And then in June of 1991, the NRC reviewed
10 and accepted the results of the long-term seismic
11 program that was documented in the supplement to Safety
12 Evaluation Report 34, and that included a key statement,
13 and the statement was, and I quote, "The staff notes that
14 the seismic qualification basis for Diablo Canyon will
15 continue to be the original design basis, design
16 earthquake, double design earthquake, plus the Hosgri
17 evaluation basis, along with associated analytical
18 methods." So that's kind of the key thing that tied
19 them into actually having three different design basis
20 requirements.
21 DR. BLEY: Wayne, could I interrupt you for
22 a second?
23 MR. WALKER: Sure.
24 DR. BLEY: This is really for the committee
25 if you haven't followed this all the way through. The

1 stuff we've been seeing in the last year or two about
2 probabilistic seismic assessment is really based on the
3 kind of modeling that was developed during the long-term
4 seismic program. It's pretty interesting stuff to go
5 back and take a look at.
6 MR. WALKER: It's a long, long time ago they
7 started it all.
8 DR. BLEY: It doesn't seem that long.
9 (General laughter.)
10 DR. RICCARDELLA: And that's basically what
11 all the CEOS plants are going to be doing. They're not
12 going to be updating their original design basis
13 calculations, they're going to be doing this now.
14 DR. BLEY: But the way to look at those
15 alternative fault mechanisms and the like was really
16 laid out in this study.
17 MR. WALKER: Next slide, and I'm going to
18 kind of talk about this last part also in this next slide
19 but I'll go to the next slide and go back for you to refer
20 to it. So just now look at a little bit more recent
21 history. Relative to seismic analysis at Diablo Canyon
22 there's what I kind of try to break it down into three
23 key events, and these kind of have intersecting
24 timelines, it's not one right after another
25 necessarily.

1 But the Shoreline fault zone, in November of
2 2008 PG&E notified the NRC of a potential line of
3 epicenters about one mile offshore from the plant.
4 This became known as the Shoreline fault zone. By
5 December 2008, using the long-term seismic program
6 methods, PG&E completed a seismic margin assessment
7 which demonstrated that the Shoreline fault was bounded
8 by the Hosgri evaluations. Then in April of 2009, the
9 NRC issued a research information letter, it was Comm
10 RIL 0901, and this was an independent study of potential
11 impacts and it concluded that adequate seismic margin
12 existed for the Shoreline fault.
13 Then in late 2010, early 2011, PG&E completed
14 and issued their final results of the seismic evaluation
15 for the Shoreline report. This report included
16 deterministic evaluations for the Shoreline and other
17 smaller faults in the area, as well as probabilistic
18 hazard calculations. The licensee concluded that each
19 of the faults was bounded by the existing long-term
20 seismic program.
21 Then in October of 2012, NRC issued another
22 research information letter, and that was 2012-01, and
23 that documented the staff's review of the Shoreline
24 final report. The cover letter stated that the NRC
25 concluded that the Shoreline fault was considered to be

1 a lesser included case of the Hosgri event and should
2 be documented as such in the updated final safety
3 analysis report. So even though they discovered the
4 Shoreline fault in '08, they were still bounded by
5 Hosgri.
6 And this is something we've been dealing with
7 a little more recently in the region. In 2006, the
8 California Assembly Bill, and this was a directed bill
9 by the California Energy Commission to assess potential
10 vulnerability of California's largest base-loaded
11 power plants -- and at the time it was Diablo Canyon and
12 San Onofre -- to a major disruption due to a seismic
13 event or plant aging and to assess the impacts of such
14 a disruption.
15 In 2008, PG&E initiated a significant
16 assessment and reevaluation of those seismic risks
17 based on this law and they did some significant
18 analysis. Some of the things they did were they did
19 onshore and offshore 2D and 3D seismic reflection
20 studies. They only did low energy offshore.
21 Originally they were supposed to do high
22 energy and they got redirected on that and they only
23 ended up doing low energy offshore. Onshore they did
24 some geologic and topographic mapping and they did
25 gravity and magnetic surveys, and they also did some

1 additional installation of seismometers, both ocean
2 bottom and right near the site or onsite. They
3 continued these studies through early 2014.
4 And then lastly, there's the post Fukushima
5 recommendations. As everyone here knows, in March 2011
6 the Fukushima event occurred and then the NRC's
7 near-term task force was assembled. Out of that work,
8 a request for information for licensees to reevaluate
9 seismic and flooding hazards at their sites was issued.
10 And then what PG&E did is they leveraged the
11 analysis they already had underway in that
12 state-mandated evaluation, the Assembly Bill 1632, and
13 they integrated that into the development of their NRC
14 requested seismic reevaluation. So basically, they
15 were pretty far along in doing a seismic reevaluation
16 because of what the state had mandated in 2006.
17 In late 2011, PG&E committed to use the senior
18 seismic hazard analysis committee process to perform a
19 probabilistic seismic hazard assessment. And that's
20 kind of been an ongoing process they've had going. I
21 think they've had a total of six meetings, they've been
22 public meetings, and they're at the end of that process
23 or very near the end of that. Once they've completed
24 the senior seismic hazard study, they'll update and
25 replace the long-term seismic program with the senior

1 seismic hazard analysis.

2 In September of 2014, PG&E submitted this

3 mandated report.

4 DR. BLEY: I'm sorry. Can I interrupt you on

5 that one?

6 MR. WALKER: Sure.

7 DR. BLEY: I'm not completely familiar with

8 this. In the methodology that was developed for the

9 long-term seismic program there were places in there

10 where expert elicitation gave probabilities for certain

11 kinds of events. Are they keeping that same model and

12 just reevaluating the likelihoods within that model, or

13 are they building a whole new model?

14 MR. WALKER: I'm not sure I can answer that

15 question. I believe they're using some of it, I don't

16 know if they're using all of it or not. Ryan might know.

17 MR. ALEXANDER: I think the simplest answer

18 to that it's a combination thereof, I think is the best

19 way to describe it.

20 MR. SKILLMAN: Identify yourself, please.

21 MR. ALEXANDER: I'm sorry. Ryan Alexander,

22 senior project engineer here in the region.

23 The best way that we can describe it is it's

24 sort of a combination thereof in terms of what they're

25 using. They're using the process that's derived in the

1 SSHAC process, that's an acronym that we use.
2 DR. BLEY: But that's the elicitation
3 process, it's not the underlying model.
4 MR. ALEXANDER: No, it's not the underlying
5 model. They then use the solicitation of that
6 information in that process to then develop their
7 overall model. What we understand is that that model
8 that they develop from the process will ultimately be
9 integrated into the overall site model and ultimately,
10 if you will, not replace but update.
11 DR. RICCARDELLA: SSHAC is an expert
12 elicitation process, it's a very structured one.
13 DR. BLEY: I know exactly what SSHAC is.
14 Thank you very much.
15 DR. STETKAR: But it's not a geotechnical
16 model, it's an expert elicitation.
17 MR. SKILLMAN: Go ahead. Let's proceed.
18 MR. WALKER: In September of 2014, PG&E
19 submitted a statement report that was called the Central
20 Coastal California Seismic Imaging Project report, and
21 they provided that to the State of California as
22 mandated by the law. They also provided a copy to us
23 which was based on a commitment they had made to us when
24 the Shoreline report came out in 2008. Basically, they
25 said if they had new information they'd provide it to

1 us, so this was some additional new information they
2 provided to us.
3 This report was compiled using updated data
4 derived in part from the senior seismic hazard studies
5 and it was a study using deterministic scenarios.
6 While much of the information from the previous
7 Shoreline fault report of 2011 was confirmed, some new
8 data suggested, for example, there was a reduce slip
9 rate on the Hosgri fault zone and the Shoreline fault
10 zone which could indicate there is less active faults
11 than previously believed. That was one of their
12 conclusions. They also had a conclusion that
13 postulated connection of the Hosgri and San Simeon
14 faults which could result in a longer, larger but much
15 more infrequent earthquake. There were other
16 conclusions but those are kind of the two main ones I
17 pulled out.
18 In September through December 2014, Region
19 IV, with the support of headquarters, conducted an
20 inspection of the licensee's operability. So we got
21 the report, as a regulator we had to look at the
22 operability based on that report. We did our own
23 independent review of the report, and basically in three
24 months we issued a report with our findings. As
25 documented in our inspection report, we didn't identify

1 any issues with the licensee's operability evaluation.
2 And again, we had lead for it in the region but with a
3 lot of help from the seismic experts in headquarters.
4 Finally, in March of 2015, PG&E provided its
5 seismic reevaluation report to the NRC. And that's the
6 most recent of the Western U.S. plants. They were
7 required to provide a reevaluation by March 11 and we
8 just got that.
9 So this goes into the seismic reevaluation.
10 As part of PG&E's seismic reevaluation response, the
11 licensee developed a new ground motion response
12 spectra. The ground motion response spectra exceeds
13 the double design earthquake, and that's not unexpected
14 due to the fact that we knew previously there was the
15 Hosgri and that the Hosgri had already exceeded the
16 double design. They identified some slight nuances,
17 they did identify some slight exceedences above low and
18 high frequency ranges versus the Hosgri curve, and those
19 were at about the 1.33 hertz was the low range and 24
20 hertz was the high range.
21 Currently the headquarters staff is
22 reviewing this submission, so we're going to look at
23 those exceedences. At this current time, based on the
24 long-term seismic program information, there's not an
25 operability concern but we're looking at long term what

1 that means to us. Then like I said, no immediate safety
2 concerns were identified.
3 Diablo Canyon is expected to conduct a
4 seismic PRA and submit that to us by June 30 of 2017.
5 In the case of Diablo Canyon, it will be basically an
6 update of what they've already done because they've
7 already done a seismic PRA, so it's not like they're
8 going to have to go out and provide something brand new,
9 they've already done a lot of work in this area. And
10 the NRC staff is still evaluating the need for Diablo
11 Canyon to provide an expedited approach submittal, and
12 the expedited approach would be an evaluation if they
13 are required to conduct it -- that hasn't been decided
14 yet by us -- they would have to look at systems and
15 components that could be used to safely shut down a plant
16 under station blackout and the loss of alternate heat
17 sinks. And again, that has not been decided yet.
18 DR. BLEY: I'm a little confused on that one.
19 They're already going to have to do that for other
20 reasons.
21 MR. WALKER: I won't speculate on it. I
22 think the licensee doesn't think they need to do it
23 because they feel like what they've done already is
24 enough, is sufficient, but it will be up to NRC whether
25 we agree with them or not and require them to do the

1 expedited.

2 DR. RICCARDELLA: Expedited over what?

3 MR. WALKER: What?

4 DR. RICCARDELLA: Aren't you talking about

5 flex there that they'd have to do or expedited flex? I

6 don't understand that.

7 MR. WALKER: Well, the way I understand it is

8 the expedited approach would just provide an additional

9 safety benefit because what they've already done shows

10 they can withstand higher seismic ground motion, so the

11 expedited would just be, I guess, something on top of

12 what they've already done if we require them to do it.

13 MR. ALEXANDER: Ryan Alexander again.

14 Officially the expedited approach -- and this has been

15 documented in the agency documents on this

16 before -- it's essentially, if you will, a margins

17 analysis to verify that there's sufficient margin to

18 continue the long-term evaluation without any

19 intermediate modifications. And so as Wayne just

20 mentioned, the licensee has indicated they believe that

21 essentially the LTSP and all the stuff that they have

22 done in the years past is sufficient to show that level

23 of margin. The agency hasn't made a decision on that

24 yet, and that letter that was issued just last week

25 indicated we're still evaluating that aspect.

1 DR. BLEY: And that's for interim things
2 before they finish.
3 MR. ALEXANDER: Correct. That is correct.
4 DR. BLEY: Okay. I get it now.
5 MR. WALKER: So current challenges we've
6 got, as you can see there's a complicated seismic
7 history. There have been some complex inspections that
8 were needed. For example, when new seismic evaluations
9 were developed for the Shoreline fault, it took over
10 four years to do that evaluation. A number of concerns
11 were raised during that four-year period by outside
12 groups and also inside the NRC, and it required two
13 comprehensive research information letters that had to
14 be issued, so just a complexity involved in the seismic
15 history.
16 And then the California mandated study and
17 report, that took a number of months of inspection and
18 also required not only regional but headquarters
19 expertise. And then there's also been a large number
20 of modifications. They replaced their reactor vessel
21 head and the steam generators, and then when you think
22 about the re-analysis they have to do based on three
23 design basis earthquakes, it adds complexity to those
24 modifications.
25 And then the next bullet there is just well

1 informed and engaged external stakeholders. Diablo
2 Canyon has historically operated in the licensee
3 response column, as we talked about earlier today of the
4 Reactor Oversight Process, but for Diablo Canyon,
5 normally a plant that's in that licensee response column
6 for public meetings, we might just do an outreach or a
7 poster board session, with Diablo we've historically
8 always done Category 1 meetings due to the amount of
9 public interest and local interest in the plant.
10 At Diablo there's some pretty highly informed
11 and engaged organizations. There's the Mothers for
12 Peace in the San Luis Obispo area; there's another group
13 called Alliance for Nuclear Responsibility, Friends of
14 the Earth, and Californians for Green Nuclear Power, and
15 each one of those groups typically shows up to our public
16 meetings and a typical meeting is between 100 to 150
17 people come and the meetings last usually three to four
18 hours with about two hours for public questions usually.
19 DR. BLEY: Wayne, early on you mentioned that
20 California mandated study. That doesn't have anything
21 to do with your deliberations, does it?
22 MR. WALKER: It wasn't required by us at all.
23 Is that what you're asking?
24 DR. BLEY: You're not involved with that in
25 any way, are you? Does it affect your deliberations?

1 MR. WALKER: Well, the one thing we did do is
2 because of the Shoreline fault, what the NRC directed
3 the licensee was if they came up with new information
4 they'd provide it to us, so there was some new
5 information in the AB 1632 report, so we did look at that
6 from an operability standpoint. But what we did was,
7 there was a pretty narrow inspection done -- and I can
8 get you that inspection report -- but we focused on the
9 operability part with the, I guess, caveat that we knew
10 they were doing the reevaluation and that we were going
11 to take a hard look at that in the next few months. So
12 that's kind of how it went.
13 So just talking about those organizations,
14 they're not only focused on seismic aspects but also
15 overall plant performance, so at out meetings we
16 typically get into discussions on spent fuel pool, spent
17 fuel cast storage, license renewal. And right
18 now -- Ryan has been knee deep in this -- we're planning
19 a public meeting right now, the annual assessment
20 meeting, which will be the week of June 24 out in
21 California, so a lot of effort goes into those meetings.
22 And then the last point, I guess, just on
23 engaged stakeholders' oversight, congressional
24 interest, we seem to get a lot of interest from the
25 Environmental Public Works Committee and frequently

1 we're -- I would say almost monthly -- answering
2 questions or assisting headquarters with answering
3 questions of the whole gamut of the area.
4 And then lastly, the impact of seismic
5 reevaluation on the current licensing basis
6 inspections, the only thing I'd like to say on that
7 that's just left open the possibility for further
8 modifications and changes to the licensing basis, so
9 there is that potential always.
10 And then just thought I'd talk a minute about
11 license renewal. They did initiate the license renewal
12 process in November of 2009. While those activities
13 are primarily a function of the headquarters staff, our
14 staff here in Region IV also has been actively engaged
15 in this process, in part because of the aforementioned
16 stakeholder interest and our activities in the license
17 renewal inspections from the regional standpoint if
18 renewal is issued. As noted, in November 2009 they
19 submitted their application, however, in April 2011
20 PG&E asked the NRC to delay final processing of the
21 application pending the completion of the advanced
22 seismic study. So they knew they were doing these
23 studies, they said we don't want a heavy review during
24 this time, let us go off and get house in order there.
25 DR. BLEY: When does their current license

1 expire?

2 MR. WALKER: 2025.

3 And so with much of the advanced seismic work

4 completed, that's why they again basically asked us to

5 resume looking at our review. We sent them a letter

6 saying we'd restart the review. There is one kind of

7 caveat in that, though, and it's in the letter we sent

8 back to them in April of 2015. We told them there would

9 be no final action taken by the NRC pending final

10 determination by the state relative to the Coastal Zone

11 Management Act consistency review. So the state has

12 some mandated things they're asking the licensee to do

13 regarding cooling and what's your cooling at the plant,

14 so that's an ongoing issues.

15 DR. CORRADINI: Does that supercede the EPA

16 rule or is that part of the EPA rule for western cooling?

17 MR. WALKER: You're beyond my knowledge.

18 DR. CORRADINI: Because I thought the EPA 210

19 rule was for all like 1,000 or 1,100 different things,

20 whether it be chemical plants or power plants.

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

22 MR. KENNEDY: This is Kriss Kennedy. I have

23 not heard EPA in this discussion, it's all focused on

24 the state requirements from what we've heard.

25 MR. WALKER: So that concludes my

1 presentation, if you've got questions.

2 MR. SKILLMAN: Colleagues, any questions for

3 Greg?

4 (No response.)

5 MR. SKILLMAN: Greg, thank you.

6 MR. FARNHOLTZ: My name is Tom Farnholtz. I

7 was asked to give a presentation to you today on the

8 component design basis inspections. I'm a branch chief

9 here in Region IV with oversight over the component

10 design basis inspection, along with the 10 CFR 50.59 and

11 permanent plant mods inspection and heat sink

12 inspections. Those are all under my branch.

13 We spent a lot of time on the component design

14 basis inspection, as you may have just imagined. A

15 component design basis inspection looks at structures,

16 systems, components that are risk important, either

17 safety or non-safety. The focus is on engineering and

18 design aspects. It's a three-week long inspection,

19 performed by six inspectors, regional and two

20 contractors, typically.

21 A typical inspection has a direct inspection

22 activity of approximately 400 hours and reviews about

23 15 to 25 components during a three-week period. The

24 components are a mixture of structures, systems,

25 components, including a large early release frequency

1 important samples and operating experience feedback
2 reviews, so it covers a gamut, and it primarily focuses
3 on engineering.
4 And I wanted to make a couple of salient
5 points here while we're here. Here in Region IV we've
6 been doing these, I think this is the third cycle now,
7 the third triennial cycle that we're starting on and
8 we're currently involved in now, so we've done several
9 of these component design basis inspections at each and
10 every site here in Region IV.
11 In Region IV we've had some significant
12 findings, not so much risk significant findings as far
13 as color goes, but findings that have proven to be very
14 valuable to us, I think, and so I want to point out these
15 four examples here as examples of items that were
16 identified during CDBIs that have proven to show a
17 weakness in a licensee's area of performance such that
18 I believe we can make a strong case to say that we
19 precluded a potentially more significant issue by
20 identifying these earlier.
21 The Fort Calhoun external flooding
22 mitigation inadequacy, that was identified in 2009. We
23 were doing a CDBI at Fort Calhoun in 2009. We
24 identified the water seals in the intake structure that
25 were actually missing. It was a small item, we

1 identified it and processed it during the CDBI, but it
2 gave us the thread to pull, and when we pulled that
3 thread it turns out that the flood mitigation strategy
4 at Fort Calhoun was less than adequate, and so we pursued
5 that over the next couple of years.
6 In 2011, as you're probably aware, they
7 actually did have a flood there at Fort Calhoun. The
8 flood was significant and it was a significant event for
9 Fort Calhoun, but because we had identified that in 2009
10 and a lot of work was done in the following two years,
11 that flood was a much lesser event than it could have
12 been.
13 The Comanche Peak condensate storage tank
14 bladder vulnerability. We did a CDBI at Comanche Peak.
15 We identified in the condensate storage tank they used
16 a bladder on top of that tank and the bladder moves up
17 and down with tank level. The bladder is there to
18 control chemistry in the water in that tank. It's a
19 non-safety function, the bladder itself is non-safety,
20 but that condensate storage tank is the primary suction
21 source for the auxiliary feedwater system, all three
22 trains.
23 So if that bladder were to have failed -- and
24 there were some failure mechanisms that the team had
25 identified could potentially cause that to fail and that

1 bladder material to sink to the bottom of the tank and
2 clog all three trains of AFW -- a significant event, it
3 was a non-safety related item that could potentially
4 affect all three trains of a safety related system.
5 The Waterford 3 emergency diesel generator
6 day tank vent corrosion, this is one that we identified
7 earlier this year. Both the alpha and bravo train day
8 tank vents -- or diesel generator day tanks, the day
9 tanks themselves are in the aux building but the vents
10 associated with those tanks extend vertically and then
11 penetrate the roof up there. The area where that vent
12 penetrates the roof was corroding, and in fact, had
13 corroded so much that there were actually holes in the
14 vent and it was right at the roof level where water tends
15 to pool.
16 The problem with that was that if it rained,
17 such as in a hurricane or tropical storm or even just
18 a heavy rainstorm, that provided a direct path for water
19 to go into the fuel in the day tank on both trains, alpha
20 and bravo. So a significant degradation of safety
21 related components at Waterford not identified by the
22 licensee but the CDBI team did identify that.
23 And then the last example I've got here is the
24 Fort Calhoun CDBI, the most recent one that we did
25 earlier this year was a major part of the

1 decision-making process that went into whether or not
2 to take Fort Calhoun out of the 0350 process and put it
3 back into the ROP process.
4 So based on these examples and many others
5 over the years that we've identified, we in Region IV
6 consider the CDBI to be a very valuable and fruitful
7 inspection.
8 MR. SKILLMAN: Tom, please say more about
9 assessment of engineering readiness. What is it that
10 you found that was the concern?
11 MR. FARNHOLTZ: I'm sorry, the last part of
12 that question?
13 MR. SKILLMAN: What did you find about
14 engineering readiness that was not acceptable?
15 MR. FARNHOLTZ: At which one of these?
16 MR. SKILLMAN: The fourth bullet.
17 MR. FARNHOLTZ: Well, not acceptable, we
18 actually did find it acceptable, and one of the mandates
19 for doing the CDBI at Fort Calhoun was to come back with
20 some assessment to provide to the 0350 panel as to
21 whether or not they were, in fact ready to go out of the
22 0350 process back into the ROP from an engineering
23 standpoint. And when we went out there, we actually did
24 find them to be acceptable for that.
25 MR. SKILLMAN: So this is a positive finding.

1 MR. FARNHOLTZ: It's a positive finding,
2 exactly right.
3 MR. SKILLMAN: I understand. Thank you.
4 MR. FARNHOLTZ: But it was a key piece of
5 decision-making data that the 0350 panel was looking
6 for.
7 MR. SKILLMAN: Now I understand.
8 DR. REMPE: But in other cases, just out of
9 curiosity, like the corrosion, is it that they aren't
10 doing sufficient inspections in-house that they didn't
11 notice it, or just the same person had been there every
12 day and didn't notice it, or what was the root cause?
13 MR. FARNHOLTZ: It's a combination of both.
14 At Waterford they actually had a procedure for the
15 system engineer responsible for that equipment to
16 inspect accessible portions of the safety related
17 equipment, including these vents. Well, it turns out
18 these vents are up on a rooftop, there is a permanently
19 installed ladder to get up onto that particular roof,
20 there was no reason why they couldn't have gone up there,
21 but they had over the years not done that.
22 There was a procedural requirement to do that
23 but they hadn't done that. They had looked at these
24 vents from a distance from another platform but they
25 hadn't actually got up there and inspected these vents

1 up close. The CDBI team actually did do that and that's
2 when they found the corrosion.
3 It's the type of thing we not only review a
4 lot of calculations and evaluations and talk to a lot
5 of people, but we go out in the plant and we actually
6 look at this stuff and we find it to be very valuable.
7 In this case it was the slow process of corrosion that
8 was causing degradation.
9 MR. KENNEDY: Tom, that's a really good point
10 on the value of the CDBI inspections. I will point out
11 that John Dixon, sitting in the back, is actually the
12 one that climbed up on that rooftop and laid eyes on that
13 vent and identified the issue.
14 So thanks, John.
15 MR. FARNHOLTZ: That's right. And in fact,
16 John helped me out with this presentation quite a bit
17 this week, so give credit to him.
18 DR. BALLINGER: But this inspection had to be
19 missing this for years.
20 MR. FARNHOLTZ: Yes.
21 DR. BALLINGER: So it somehow was
22 overlooked?
23 MR. FARNHOLTZ: As it turns out, the
24 licensee, during the reg conference associated with
25 this particular finding, the regulatory conference that

1 we had for this particular finding, admitted that yes,
2 they had been overlooking corrosion related issues at
3 that plant for a long time.
4 Waterford, as you probably know, is located
5 right on the Gulf of Mexico in Louisiana. It's a harsh
6 environment as far as corrosion goes, and over the years
7 they've kind of accepted corrosion as part of the deal
8 and not making a big deal out of it.
9 I think one of the benefits of this particular
10 finding was that it re-centered the licensee now to look
11 at a corroded pipe support, for example, or corroded
12 nuts on a body to bonnet valve or something, as a big
13 deal. They need to write a condition report, they need
14 to get it repaired, they need to get it re-coated,
15 whatever it took.
16 MR. KENNEDY: Was this finding actually
17 through the wall?
18 MR. FARNHOLTZ: Yes. In fact, here's some
19 photographs that kind of illustrate what I'm talking
20 about. These bottom two photographs here are the
21 vents. It's a little hard to see, but this is a hole
22 right here. This is a mirror actually looking back on
23 the backside of that. That's a through wall hole right
24 there. You can see the corrosion at the bottom of this
25 vent, and this, of course, is the rooftop right here,

1 so this is where water would pool whenever it rains and
2 then just eat into this metal. And over the years those
3 holes opened up and now you've got a direct path for
4 water to go into that tank and it's a straight shot down
5 into the day tank, both trains.
6 DR. STETKAR: They weren't finding water in
7 the samples in the day tank, or didn't they have a bottom
8 sample point on the day tank?
9 MR. FARNHOLTZ: I don't know. John Dixon
10 can answer that directly.
11 MR. DIXON: My name is John Dixon. I'm a
12 senior inspector in the region.
13 To answer your question for this, the way that
14 they assessed for water in the diesel was in accordance
15 with their surveillance test is after the diesel had
16 been up and running for at least an hour, then they
17 pulled for a water sample.
18 DR. STETKAR: So they assumed if the diesel
19 was running there was no water?
20 MR. DIXON: Effectively, yes. The other
21 issue that presents a problem here is the suction source
22 for the diesels on the bottom of this tank was directly
23 on the bottom of the tank, there was no stand pipe, there
24 was no pipe within a pipe, it was dead center on the
25 bottom, so any water that collected in the tank went

1 straight down into the suction of the diesel.

2 MR. FARNHOLTZ: This emphasizes the value of

3 the CDBI. Those top two photographs there are both from

4 Fort Calhoun during the flood of 2011. You can see

5 water intrusion there on a pull box, a cable pull box,

6 and then this is a room in the plant where water is coming

7 from the seal between the roof and a wall, so there was

8 water during the flood that was actually coming into the

9 power block at Fort Calhoun. This would have been a lot

10 worse had we not identified this issue two years

11 earlier.

12 I put these up here just to emphasize that the

13 types of findings that we're typically finding during

14 these CDBIs are latent issues, longstanding issues, and

15 because we're finding them earlier, they're not

16 becoming major issues. And so I'd like to kind of toot

17 our own horn that way because we find that to be of great

18 value for the CDBI.

19 MR. SKILLMAN: Tom, how are these

20 inspections scheduled? How often do you conduct them

21 on a per unit basis?

22 MR. FARNHOLTZ: It's a triennial inspection

23 so once every three years on average, sometimes it's a

24 little less, sometimes a little more. We're able to

25 schedule them any time during the triennial period, but

1 typically we try to keep them to every three years. They
2 are quite a large inspection. Three weeks onsite and
3 a couple of weeks in between, plus the prep and the doc
4 weeks, so we're talking six or seven weeks of footprint
5 on these, so it's a large inspection and a large team
6 that goes with it, but every three years.
7 MR. SKILLMAN: Do you risk inform your
8 targets?
9 MR. FARNHOLTZ: Yes, we do.
10 MR. SKILLMAN: And could you explain that
11 process, please?
12 MR. FARNHOLTZ: Yes. During the process of
13 preparing for one of these inspections, the team lead
14 and a regional SRA will go out to the site and do an
15 information gathering trip. The raw values and the PRA
16 type cut sets and all that are gathered during that time
17 frame and we choose our samples based on that. It's not
18 risk-based but it's certainly risk-informed. And we
19 try to think a little outside the box because if it was
20 strictly risk-based, we'd be looking at the same
21 equipment, you know, diesel generators, AFW pumps, that
22 sort of thing. We've already looked at that many times
23 and the residents look at that all the time, so that gets
24 a pretty good look.
25 But some of the other stuff that we look at

1 is a little more obscure but still important. One of
2 the areas of sample selections that we have is called
3 scenario-based sample selection which I kind of like
4 that one because you pick a scenario that's identified,
5 perhaps a main steam line breaks or something like that,
6 and then you think, well, what components would be
7 important for that scenario to operate, and then we will
8 choose that as a component.
9 MR. SKILLMAN: You do the whole scenario from
10 that?
11 MR. FARNHOLTZ: Yes. Although, in the end
12 we boil it down to an actual component, so it really is
13 a component design basis inspection. So we're looking
14 at pumps, valves, breakers, relays, that kind of thing,
15 so we're looking at what's really going to have to work
16 during that scenario. So our latitude for choosing
17 components is enough to where we can get to these
18 components fairly easily, and if we have any particular
19 concerns at a particular site, for example, a number of
20 years ago we did a CDBI out at Diablo Canyon and there
21 were some concerns at that time about the electrical
22 design at Diablo Canyon, for whatever reasons there was
23 some question about that, so we loaded that particular
24 CDBI team up with electrical folks and we kind of
25 emphasized that as an area of looking, more electrical

1 than mechanical pieces.

2 DR. BLEY: Looking at some of your pictures

3 makes me think as one does a risk-informed selection,

4 one might think about the things that are kept out of

5 the risk models because they're passive and they're not

6 going to fail, maybe they do.

7 MR. FARNHOLTZ: And you're exactly right. I

8 feel the same way as you because I'm all for

9 risk-informed sample selection and risk-informed ROP.

10 I think it's a great tool for us.

11 DR. BLEY: But testing the assumptions of

12 that assessment is a good thing to do.

13 MR. FARNHOLTZ: Yes, absolutely. We

14 shouldn't box ourselves in on just that because if we

15 do, we could very easily miss something.

16 MR. SKILLMAN: The other side of that, of

17 course, is the licensee's system health reports and

18 their maintenance reporting, and that ought to be a very

19 fertile area for you to go and find what needs to be

20 looked at.

21 MR. FARNHOLTZ: Yes, and that's all good

22 stuff, and actually early on we did a couple of these

23 CDBIs and we started to run out of safety-related, risk

24 important, low margin components, which was the

25 original thought on these. So we ended up expanding our

1 sample selection, including the scenario-based and that
2 sort of thing, to throw a wider net and to think a little
3 outside the box. And of course, we do emphasize site
4 walkdowns and looking. In fact, that's how the Fort
5 Calhoun missing seals in the intake structure, the
6 external flooding thing started out with an inspector
7 who was walking along the intake structure wall and
8 noticed that there were some fire header pipes that
9 penetrate that wall and there was no seals around there.
10 There was a clear path for water to go from the outside
11 directly into the intake structure, nothing to stop it,
12 and inside that intake structure are the four safety
13 related raw water pumps, it would have taken them all
14 out.
15 DR. BLEY: Are the inspection reports that
16 support license renewal fertile ground too for looking
17 at other plants?
18 MR. FARNHOLTZ: John may have a thought on
19 that. I don't think we've used that specifically but
20 it's certainly an avenue of information.
21 MR. DIXON: This is John Dixon again.
22 We do have an aspect in the CDBI procedure
23 that allows us to look at aging management programs for
24 utilities that have entered the period of extended
25 operation. Fort Calhoun, for example, is one of the

1 plants that has entered the period of extended
2 operation, so we did look at the cable aging management
3 program and the corrosion program as part of our
4 component review for electrical systems and mechanical
5 systems. So from that aspect, stuff that's been a
6 previous part of license renewal is directly within the
7 CDBI scope.
8 DR. BLEY: I like to hear that. I guess the
9 thing I was suggesting is when we started looking for
10 license renewals we might see phenomena that we wouldn't
11 normally look for and it might a good thing to think
12 about when we go and do a plant that's not at that point.
13 MR. FARNHOLTZ: Absolutely. Forward
14 thinking is what we to do.
15 DR. BALLINGER: From the standpoint of these
16 photos and stuff, does the licensee know ahead of time
17 what systems are going to be inspected?
18 MR. FARNHOLTZ: We make the sample
19 selections as far in advance as we can, and it is not
20 our intent to surprise them on the day of the inspection
21 team showing up. We provide this information to them,
22 the final sample selection, at least a week or two in
23 advance, and maybe even more.
24 DR. BALLINGER: So they knew this was going
25 to be inspected?

1 MR. FARNHOLTZ: Yes, in general. You know,
2 some of this stuff comes up through walkdowns and other
3 things. It's not our intent to surprise or do any of
4 that, so they know what the components are that we're
5 going to look at.
6 But my point with all this was that Region IV
7 considers the CDBI to be a very significant inspection.
8 It is a significant inspection also from a resource
9 point of view, and in fact, you probably heard that the
10 industry is very interested in changing the CDBI because
11 of the resource impact on them. So I wanted to touch
12 on that a bit.
13 MR. SKILLMAN: Before you go on, so here you
14 go down to Waterford 3 on the Mississippi River and you
15 find corrosion at the interface between the roof and the
16 emergency diesel generator fuel tank vents. How is
17 that information communicated, perhaps to Monticello or
18 to Ginna or to Indian Point?
19 MR. FARNHOLTZ: Of course, once a report gets
20 issued, that report becomes a public document, and I
21 know that there are industry groups, such as NEI, that
22 every time we issue a report they review those reports
23 and they provide that information to their member
24 station. And of course, member stations can pull those
25 reports any time they want. So it is public

1 information, and we're hoping and we encourage
2 licensees wherever we go to look at previous CDBI
3 inspection reports and see what kind of issues are being
4 developed at that particular issue. And it's not
5 unusual for us to identify an issue at Plant A and then
6 go to Plant B, the very next plant, and find the very
7 same issue. We don't like to do that but it does happen,
8 and we were hoping that the Plant B would see that that
9 is a vulnerability at Plant A.
10 DR. BALLINGER: But these inspection
11 reports, I'm assuming they have an executive summary
12 which would outline the key findings, so a licensee
13 doesn't have to go through 500 pages before he figures
14 out that the vent pipe might corrode.
15 MR. FARNHOLTZ: Exactly right. It's not
16 that time consuming to look through there and do that.
17 MR. DIXON: This is John Dixon again.
18 This particular tank vent corrosion actually
19 went out as an operating experience sample across the
20 agency.
21 MR. FARNHOLTZ: Again, it's in our best
22 interest to get the word out widely so that people can
23 examine their own site and see if they're open to this.
24 But yes, if there's a better way to do that, we're
25 certainly open for that.

1 So the industry issued a white paper -- and
2 by the industry, I'm talking NEI, Nuclear Energy
3 Institute, is the spokesman for the entire nuclear
4 industry on this subject, and so they issued a white
5 paper back in February of this year to us proposing
6 changes to the CDBI, and their main concern with the CDBI
7 is the impact that it has on their engineering
8 departments and groups and the cost of the CDBI. It is,
9 admittedly, a high impact inspection and it does take
10 a fair amount of time, it's three weeks onsite and there
11 are hundreds of questions that are asked by the
12 inspectors. And the questions are not easy and the
13 answers to the questions require a lot of research, a
14 lot of knowledge, and so it does take the engineering
15 staff at the facilities away from whatever their normal
16 duties might be to address those questions that the
17 inspection team is asking.
18 And so they would like to make changes to the
19 CDBI from the current three-week inspection that we
20 currently have now, and so for this slide here I wanted
21 to touch on some of the things that the industry is
22 proposing. On April 22 of this year we had a public
23 meeting to talk about this and understand what the
24 industry's concerns were.
25 They proposed levelizing the engineering

1 inspections, and by that they mean taking some of the
2 components out of the CDBI and putting them perhaps into
3 the 50.59 permanent plant mods inspection, for example,
4 taking some out of this one, putting it into that one,
5 or taking some out of the CDBI inspection and putting
6 it into the triennial heat sink inspection, and try to
7 minimize the high impact of the CDBI and move it out.
8 They would also like to see a scale in some
9 way shape or form the engineering inspection, such that
10 if we have concerns for an engineering organization or
11 a particular licensee, we can do a full blown CDBI, but
12 if we don't have any specific concerns, perhaps we could
13 scale it back and not look as deeply to a plant that
14 doesn't have similar concerns for the engineering
15 department.
16 They would also like us to give them credit
17 for self-assessments that they might include. In other
18 words, they would like us to give them the list of
19 components that we would inspect perhaps six months
20 ahead of time and then they would do a self-assessment
21 on those components and give us a report. We would
22 review the report and if we found it to be adequate we
23 would give them credit for that, if we found it to be
24 lacking in certain areas we would go and look at those
25 areas.

1 That's kind of their proposal. Interesting
2 and worthy of consideration. We did have this
3 discussion back in April with them. Of course, we were
4 noncommittal on what to do but we certainly wanted to
5 understand their thoughts. We have to consider,
6 however, the philosophy of the current ROP. Some of
7 this stuff doesn't seem to fit, at least on the surface.
8 Giving credit for self-assessment, for example, that
9 historically hasn't been done because that takes away
10 the independence factor that the NRC has to have for that
11 process, so we're not quite sure how that would fit in.
12 Scaling is another aspect that we're not
13 quite sure how that would fit in because a major premise
14 of the ROP is that every site in the country would get
15 a minimum baseline inspection, and of course, the CDBI
16 is a baseline inspection, every site gets one, so how
17 do you then scale that up or down depending on
18 performance and still call it a baseline inspection.
19 So we're not sure about that.
20 Those are all worthy of consideration but I
21 wanted to bring all those up on the slide here just to
22 let you know this is kind of what the industry is pushing
23 for, and if you haven't already gotten an earful from
24 an industry spokesman, a VP or something, you may
25 eventually get some of that.

1 DR. CORRADINI: Your last bullet, is that a
2 forum between NRC and the licensee, or is that a forum
3 across the industry so they'll see what you're getting
4 at other places?
5 MR. FARNHOLTZ: It's the latter is what
6 they're proposing, a forum kind of a group of executives
7 from all the industries and sharing thoughts amongst
8 themselves.
9 DR. CORRADINI: Surprised they're not
10 already doing that.
11 MR. FARNHOLTZ: Maybe they want to formalize
12 it a bit or something.
13 DR. STETKAR: Do you have a counterproposal?
14 MR. FARNHOLTZ: We do, actually.
15 DR. STETKAR: Like an unannounced
16 inspection?
17 (General laughter.)
18 MR. FARNHOLTZ: I'm not sure they'd go for
19 that. We want to work with industry here if there's a
20 better way to do these inspections. We understand that
21 they're high impact and they're very expensive, so we
22 don't want to discount whatever their thoughts are, so
23 we welcome their thoughts. On the other hand, we do
24 have a job to do and we feel that the CDBI, as it's
25 structured right now, is delivering the goods, at least

1 I feel that. I think I speak for many others in the
2 agency. There's nothing broken about the current CDBI,
3 however, if there's a better way to do it, if there's
4 something that would minimize or reduce the impact or
5 reduce the cost. And on us too, this is a high impact
6 inspection for us as well. We spend a lot of time and
7 effort on this inspection.
8 And what we're doing right now is, in fact,
9 just last night I returned from Region III and I was
10 involved in a meeting with my counterparts from the
11 other regions and from the program office up in
12 headquarters, and what we're proposing to address some
13 of this, at least, and kind of get us going in a direction
14 of perhaps revising the CDBI, is that we're developing
15 a new CDBI that's not radically different from the
16 current one but is somewhat scaled back. It still looks
17 at components and still does the deep dive vertical dive
18 kind of inspection that we do now because we think that's
19 a valuable thing, we want to hang on to that feature,
20 but scaling it back from three weeks to two weeks but
21 then adding engineering programs.
22 Because we know that engineering
23 organizations do a lot more than just engineering
24 evaluations and that sort of thing, they also have EQ
25 commercial grade dedication, MOV/AOV testing

1 requirements, there's a lot of things that engineering
2 does and there's a lot of programs that they own and are
3 caretakers for that we either haven't looked at before
4 or it's been many years since we have looked at
5 them -- maintenance rule is another one.
6 So what we want to do, the general thinking
7 is -- and we haven't gotten approval for this or
8 concurrence from everybody so this is all kind of
9 preliminary just general thinking, but the idea is to
10 reduce the number of components and reduce the amount
11 of time that we look at those components, using the
12 vertical slice process, from three weeks down to two
13 weeks, and then add these programs on as a third week,
14 either concurrent with the other two weeks or separated
15 by time, either way, and look at some of these programs
16 specifically with a smaller team. The idea would be to
17 reduce the impact on the licensee and still get what we
18 need from this inspection, from an engineering
19 inspection.
20 To test this, what we're going to do is we're
21 going to do pilots, we're going to do two pilot
22 inspections like this in each region, so a grand total
23 of eight of these inspections will be performed,
24 assuming we get permission to move forward. And then
25 these pilots will take place either late this year or

1 early next year and certainly by the middle of 2016 we'll
2 have all these pilots done. And then we'll take a
3 lessons learned and suggestions and comments that we
4 receive during these pilot inspections and decide does
5 the two-week inspection actually deliver what we think
6 it will or doesn't it.
7 Same way with the program inspection. The
8 first program that we're going to do is equipment
9 qualification, EQ. We're going to take a look at that
10 program in great detail.
11 So we don't want to make any wholesale changes
12 to the CDBI inspection procedure that's currently in
13 place until we do these pilots because we want to make
14 sure that whatever we do doesn't fundamentally
15 undermine the current CDBI. So we want to go slow on
16 this, we want to make sure that whatever we do continues
17 to deliver what the CDBI has historically been
18 delivering. But we also want to be sensitive to what
19 the industry is saying, and also the ROP enhancement
20 project that has suggested actually that we include
21 engineering programs into the CDBI, so that's a big
22 reason why we want to include that.
23 MR. SKILLMAN: Tom, I'd like to ask. When
24 you talk about component design base inspection, those
25 who have done design engineering and plant engineering

1 and STA work understand CD, component design basis,
2 generally quite well. When you consider in lieu of
3 design based inspection for components, program
4 inspections, what consideration have you given to the
5 difference in that inspection? I would assert that is
6 a very different inspection.
7 MR. FARNHOLTZ: It is indeed, and we
8 recognize that. In fact, it would no longer be a
9 component design basis inspection, we'd probably have
10 to change the name of it to accurately reflect what it's
11 actually doing. The new proposed inspection would
12 actually be more of an engineering inspection, overall
13 engineering, to include components and design basis,
14 but only as a part of what they're doing. So your point
15 is well taken that what we're doing here, as a pilot now,
16 is a significant change from historically what we've
17 looked at. That change may be good or it may not be
18 good. Are we currently locking ourselves into
19 components and focusing on those at the expense of other
20 stuff that engineering is doing? If so, maybe looking
21 at those programs is a good thing. On the other hand,
22 are we going to become diverted over to the program
23 inspections and then not see some things in the
24 component area. Those pilots should tell us that, I
25 would think.

1 MR. VEGEL: This is Tony Vegel. I think we
2 have to be very careful, because it's very important
3 that we continue to do component design basis
4 inspections because the reason why we started doing that
5 is because of plants that lost control of the design
6 basis. The D.C. Cooks, for example, they lost control
7 of that and I think it's very important that we continue
8 to really do the deep dive to make sure that the systems
9 or components can perform the design part of the
10 function.
11 And as we saw today, our inspections continue
12 to identify issues in that area and I think it's
13 important that we continue to look at that. It's a
14 slippery slope, once you start losing control of that
15 design basis, if you're not continuously checking it,
16 it could quickly result in potential problems.
17 DR. BALLINGER: The stuff that they're
18 proposing, it impacts you but how does it impact them
19 with respect to fixing these kind of problems so you
20 don't find them -- I mean, you don't have to find them,
21 let's put it that way.
22 MR. FARNHOLTZ: Exactly, and the jury is
23 still out on that. I wish I had a clean answer for that.
24 Do we have faith that they're going to be able to
25 identify these things on their own through

1 self-assessments or stuff like that.

2 DR. BALLINGER: But what you said was they

3 not only knew about it, they had known about it for a

4 long time.

5 MR. FARNHOLTZ: Right.

6 DR. BALLINGER: So self-assessment, what

7 self-assessment?

8 MR. FARNHOLTZ: Exactly. I'm dubious of

9 that, but if there's some way we can work with them on

10 that, I think it's worth considering, but I wouldn't

11 sign off.

12 DR. SCHULTZ: So Tom, in this new approach

13 are you taking them up on the offer to perform

14 self-assessment?

15 MR. FARNHOLTZ: No, not at this stage.

16 Actually, the way I'm viewing it is we're going to do

17 it in two stages. The first stage is what I just

18 described, the two week and the one week. That one we

19 can do kind of in-house because that only affects the

20 one procedure, the 7111.21 which is the CDBI inspection

21 procedure. That one, myself and my colleagues and the

22 program office up in headquarters, we can revise that

23 amongst ourselves.

24 The other parts of that, like the levelizing

25 and moving stuff out of that and into the other programs

1 and adopting the self-assessment as a tool, those will
2 require much larger groups of people and much more
3 thought, I think, and so we're not tackling that at this
4 point. I think in the next triennial cycle, which
5 starts in 2017, we're planning on using this new revised
6 procedure, but perhaps the triennial cycle after that,
7 which would start in 2021 or whatever it is, down the
8 road we could consider those longer term changes, but
9 for right now we're not adopting that.
10 DR. SCHULTZ: I think that would be a
11 reasonable tradeoff, although based on what you've
12 shown us and what the experience base has been so far,
13 just following up with what Ron said, industry would
14 have to prove and demonstrate the self-assessment
15 process that they're proposing is deep enough and
16 thorough enough to be certain to capture those things
17 that we are, in fact, identifying in the inspection
18 process.
19 MR. FARNHOLTZ: I agree with that. If we can
20 get them to commit to a rigorous self-assessment and
21 then we would somehow have to inspect that, the process
22 of self-assessment in some way.
23 DR. SCHULTZ: That's a given, I believe.
24 MR. FARNHOLTZ: So a lot of thought is going
25 to have to go into that. That's a pretty radical change

1 from the existing ROP. It's not to say that it
2 shouldn't be adopted at some point, but not today or
3 tomorrow.
4 DR. BALLINGER: The poster boy -- or poster
5 person for the self-assessment problem is Davis-Besse.
6 Right?
7 MR. FARNHOLTZ: Yes, absolutely. When you
8 find something like that, it certainly is a setback to
9 what are the licensees doing and how effective is that.
10 We consider our job to be the conscience of the licensee,
11 to go out and look at these things with an independent
12 view. Regardless of what they're doing themselves,
13 we're going to go look at it ourselves, and if what we
14 see matches their finding, great, if it doesn't, there's
15 a gap, we're going to pursue that.
16 DR. BLEY: Tom, I've got a couple of points
17 I'd like to ask you about on that slide. The first is
18 I would assume -- and correct me if my assumption is
19 wrong -- that if you go in with this alternative
20 approach and you start to spot some problems that you
21 would not be impeded from chasing those as far as you
22 can. And the second part of this is I get a
23 feeling -- but maybe it's just the way you organized the
24 presentation -- that when you've gone in plants and
25 found problems you tend to find a lot of related

1 problems, not wildly different ones so much, which would
2 make pulling the thread make more sense.
3 MR. FARNHOLTZ: It does. And in fact,
4 extent of condition, extent of cause is a big deal for
5 us and it should be and we mandate it, in fact, for the
6 licensee. When you find one problem, a lot of times
7 that's just the tip of the iceberg, so you need to look
8 at the other train, at a minimum, and perhaps similar
9 equipment that may have a similar problem. That's a big
10 source of our information, you know, once you find an
11 issue like that.
12 MR. KENNEDY: This is Kriss Kennedy. I just
13 want to make it clear -- I know you know this -- there's
14 really nothing that prevents an inspector from pulling
15 that string. So programmatically sometimes we create
16 these inspection procedures, they provide guidance,
17 they give you a scope of things to look at, but all our
18 inspectors know if they find something in the area
19 they're inspecting or even outside the area they're
20 inspecting, someone is going to pull that string,
21 whether it's them or they refer it to maybe the resident
22 inspector or maybe another specialist in the region.
23 That's a good point.
24 MR. FARNHOLTZ: And that is true. We work
25 closely with the resident inspectors at the various

1 sites, or even if we find something that looks like maybe
2 a potential fire issue, we would get with John
3 Mateychick, for example, and he would put that on his
4 list to follow up on that kind of thing. So we do act
5 as a group and coordinate quite well.
6 MR. SKILLMAN: I wanted to make the point
7 that the industry's recommendation is they would like
8 to do self-assessments, probably like streamlining,
9 they would like a number of enhancements that would
10 reduce their effort, but I'd be quick to point out that
11 in every case that I'm aware of 95003 plant or an 0350
12 plant, that is normally a one- to two-year journey, can
13 be longer than that, and that journey takes that utility
14 through an assessment of all of the programs and all of
15 the hardware. And so I would just assert that if those
16 owners understand under 10 CFR 50, Appendix B in
17 maintaining their design basis, that some of the
18 enhancements they are asking for really aren't needed.
19 And if they fall in the 95003 or 0350, they're going to
20 have to do everything, not just a sample.
21 MR. FARNHOLTZ: That's right.
22 MR. SKILLMAN: And so there is a tradeoff
23 here that they need to be mighty aware of, and if they
24 haven't learned from the 0350 people or the 95003
25 people, they should probably go and take some notes

1 because that's very, very painful and it's horribly
2 expensive, much more than doing a thorough CDBI for
3 three weeks.
4 MR. KENNEDY: You're absolutely correct.
5 And in fact, as I was sitting in that public meeting up
6 in Washington, D.C. on April 22 where NEI was describing
7 their proposal, I was thinking exactly that: Be
8 careful what you ask for because there's a lot of land
9 mines out there that you could be stepping on right now.
10 We want to be sensitive to that and we don't want to let
11 me make a big mistake, but yes, you're right, the
12 long-term ramifications of what they're asking for
13 could be -- at least for some facilities could get ugly.
14 MR. SKILLMAN: Thank you.
15 DR. REMPE: What is the process for the final
16 decision on whether you have a revised procedure or not?
17 How does it go through the agency before they make that
18 decision?
19 MR. FARNHOLTZ: Well, now that I'm back from
20 Region III, we had our meeting earlier this week so we've
21 got a marked up revision of what we think, our
22 recommendation, I've got to brief my division director
23 and RA for them to understand exactly what were
24 proposing, and then they'll get with Bill Dean, director
25 of NRR and those kind of folks, kind of talk amongst

1 themselves, is this something we want to do. And
2 assuming we get the okay for that, or they may very well
3 have comments or suggestions themselves as to, well,
4 let's do this instead of this or this way, we certainly
5 want to incorporate those. So it's kind of a process
6 at the management level to make sure everybody is
7 onboard.
8 DR. BALLINGER: Along the lines of what Dick
9 was saying, agreeing to something like this without the
10 big hammer that's available, the hammer and stick type
11 of approach where, okay, if we do some of this, you need
12 to be aware that if we find something that's not working,
13 it's going go be a tough row.
14 MR. FARNHOLTZ: And we're not going to back
15 off from that, I don't anticipate. And the jury is
16 still out on going from three weeks down to two weeks,
17 and historically in CDBI many of the issues aren't
18 closed or aren't wrapped up or decided on until the
19 middle of that third week because the answers to the
20 questions are coming in. That's just the nature of the
21 way the inspection unfolds. Now we're going to try to
22 do that in two weeks.
23 There was a lot of discussion earlier
24 this week amongst ourselves as to is that even
25 practical, is a licensee going to be able to deliver the

1 answers and satisfy all the questions, even with the
2 reduced number of samples that we're going to be doing,
3 is that still going to be possible. We don't know the
4 answer to that, but by doing a pilot or a couple of pilots
5 in each region, I think that will give us that data, at
6 least a good idea of it, and it may come out that no,
7 two weeks just isn't practical and we'll go back to the
8 three weeks.
9 Personally -- and I'm only talking on my own
10 here -- I kind of like the three-week footprint, I like
11 the way we're doing it now. I don't think it's broke.
12 I recognize that it is a major impact. I often go out
13 to the sites during that third week when the teams are
14 wrapping up their inspection activities. And we've
15 gotten very good at these CDBIs. Our inspectors, I
16 wouldn't want to be on the other end of their inspection,
17 I can tell you that. They're asking some tough
18 questions and they're demanding real answers, not some
19 glossy engineering judgment based thing or nothing like
20 that. They've got to have real data, and if they don't
21 get it the first time then they have to go back and do
22 some more.
23 It's a real challenge, so I understand why the
24 industry is pushing to change the footprint of this
25 inspection. It is the largest team inspection that we

1 do in the baseline inspection program, and it is a very
2 expensive inspection. I've heard a number of a million
3 dollars for them to do that, so this is a line item on
4 their budget, and in these days of tight financial
5 markets, I understand why they want to push for that.
6 But as you so correctly point out, the alternative might
7 be worse than what we've got now for them.
8 So those are the things I wanted to hit, and
9 I do want to emphasize that this inspection seems to be
10 working for us. In Region IV we do consider this
11 inspection to be of great value and has historically
12 been of great value for us and continues to be.
13 Identifying both latent issues, old design
14 engineering issues, mistakes and errors, omissions that
15 were made many years ago, we're finding those along with
16 current performance issues. So it's an overarching
17 inspection that's good.
18 With that, I'll entertain any additional
19 questions.
20 MR. SKILLMAN: Tom, I thank you very much.
21 To my colleagues, do you have any further
22 questions for Tom Farnholtz?
23 (No response.)
24 MR. SKILLMAN: Tom, thank you.
25 MR. FARNHOLTZ: Thank you.

1 MR. SKILLMAN: At this point in the meeting
2 I would like to ask if the telephone line is open. Can
3 someone confirm that our communication is active?
4 OPERATOR: This is the operator, the
5 telephone line is open.
6 MR. SKILLMAN: Thank you, Operator.
7 Before we got to the telephone line, are there
8 any individuals in the room that would like to make a
9 comment or ask a question, please?
10 (No response.)
11 MR. SKILLMAN: Seeing and hearing none, on
12 the phone line, if you are out there would you please
13 say yes, I'm here, please? Anyone at all, may I ask
14 again if you are on the phone line would you please
15 communicate by responding yes, I'm here.
16 SPEAKER ON TELEPHONE: Yes, I'm here.
17 MR. SKILLMAN: Okay. I thank you very much,
18 and with that, sir, would you please make your comment.
19 I invite you to make your comment, sir, if you wish to.
20 SPEAKER ON TELEPHONE: I have no comment at
21 the moment.
22 MR. SKILLMAN: Yes, sir. Thank you.
23 Anybody else out there that would like to make
24 a comment?
25 (No response.)

1 MR. SKILLMAN: Hearing none, thank you very
2 much. Please close the phone line.
3 And Kriss, back to you.
4 MR. KENNEDY: Well, thanks. I just wanted
5 to say a couple of words before you concluded the
6 meeting.
7 As you can tell, we have a dedicated staff in
8 Region IV that are passionate about what they do in their
9 inspection activities to protect public health and
10 safety. I think that came across today.
11 As I said at the beginning, it was an honor
12 to host the committee at this meeting in our region, and
13 I appreciate the time that you've spent with us, the
14 dialogue and the questions and insights that you've
15 given us. But there was one theme I wanted to touch on,
16 and it was asked several times, how do you communicate
17 issues to the industry, and I wanted to go through a
18 couple of quick thoughts on that.
19 Internally in Region IV we have a morning
20 safety meeting every morning and each of the division
21 director of projects branch chiefs reports out on
22 anything unusual or out of the ordinary that happened
23 the day before. We have that meeting every day. And
24 then we debrief all of our inspections, both by our DRP
25 inspectors and by DRS inspectors, and if we identify

1 some issue that we think is maybe generic, we make sure
2 that the other branch chiefs are aware of that and that
3 they communicate that to their sites.
4 We do have the regulatory information
5 summaries that if there's a generic issue that reaches
6 a certain threshold, we'll issue that information
7 notices. Our inspection reports are all available,
8 publicly available, and then there are consultants that
9 their job is to review inspection reports, and for those
10 companies that have hired those consultants, they will
11 report out on findings to the licensees.
12 And also within a fleet, obviously, if
13 there's an issue that comes up at ANO, the fleets are
14 fairly good about communicating those issues across, at
15 a minimum, their fleet plants. I know that came up a
16 couple of times. And then there's, of course, the big
17 G, capital G, generic issue where the agency decides,
18 in fact, we need to communicate that more broadly and
19 more formally.
20 I took away one IOU. I owe you a copy of the
21 River Bend special inspection reports. If there's any
22 other IOUs, you can let me know now or later.
23 And that's all I had for closing comments.
24 Thanks again for coming to Region IV, and you did a great
25 job for getting in so late last night.

1 MR. SKILLMAN: Kriss, thank you. We're not
2 quite wrapped up here. I need to ask my colleagues if
3 they have any further comments, any questions, any other
4 business they wish to conduct here.
5 DR. CORRADINI: No comments. Just thank
6 Region IV individuals for putting this on. I think it
7 was very good.
8 DR. RICCARDELLA: Same here, no comments.
9 DR. BLEY: I have a comment. I really
10 appreciate all your presentations, but I especially
11 appreciate getting to the regions. We don't get to see
12 you folks very often, and from my first visit to the
13 region, to this one, I'm always impressed with the depth
14 of expertise and the commitment I find out here, and
15 hearing from you guys who are very close to the plants,
16 it's a different picture we get than we get back in
17 Rockville. Appreciate the day very much.
18 MR. SKILLMAN: Our chairman, John Stetkar,
19 any comments?
20 DR. STETKAR: I have nothing to add other
21 than I certainly echo Dennis's comments. It's always a
22 learning experience to come out here, so we appreciate
23 that.
24 MR. SKILLMAN: Dr. Rempe.
25 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

1 industry is focusing on.

2 I just want to comment, as well, we really did

3 have a nice opportunity to see a lot at the Palo Verde

4 site and really appreciate that, and we know that you

5 are interacting with that site at a very high level and

6 appreciate that as well. Thank you.

7 MR. SKILLMAN: Thank you, Steve.

8 Another IOU, this NEI white paper, I think

9 it's the white paper on the CDBI, we'd like to see that.

10 One or two other items. We are here

11 supported by our staff. We have Dr. Edward Hackett,

12 Chief of Staff Mark Banks, and we have other staff

13 members with us, so I want to recognize their making an

14 effort to come with us. They're very important to us,

15 without them we don't get our work done. And we also

16 are supported by a team back in Rockville that does our

17 travel for us, so I want to acknowledge them and thank

18 them for being a part of this business today. Thank

19 you.

20 Kriss, and to your whole team, thank you very

21 much for your hospitality, your excellent

22 presentations, for information that's right on the

23 mark, and my colleagues have said it all, so I appreciate

24 it. And with that, this meeting is adjourned.

25 (Whereupon, at 3:00 p.m., the meeting was

1 concluded.)

2

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

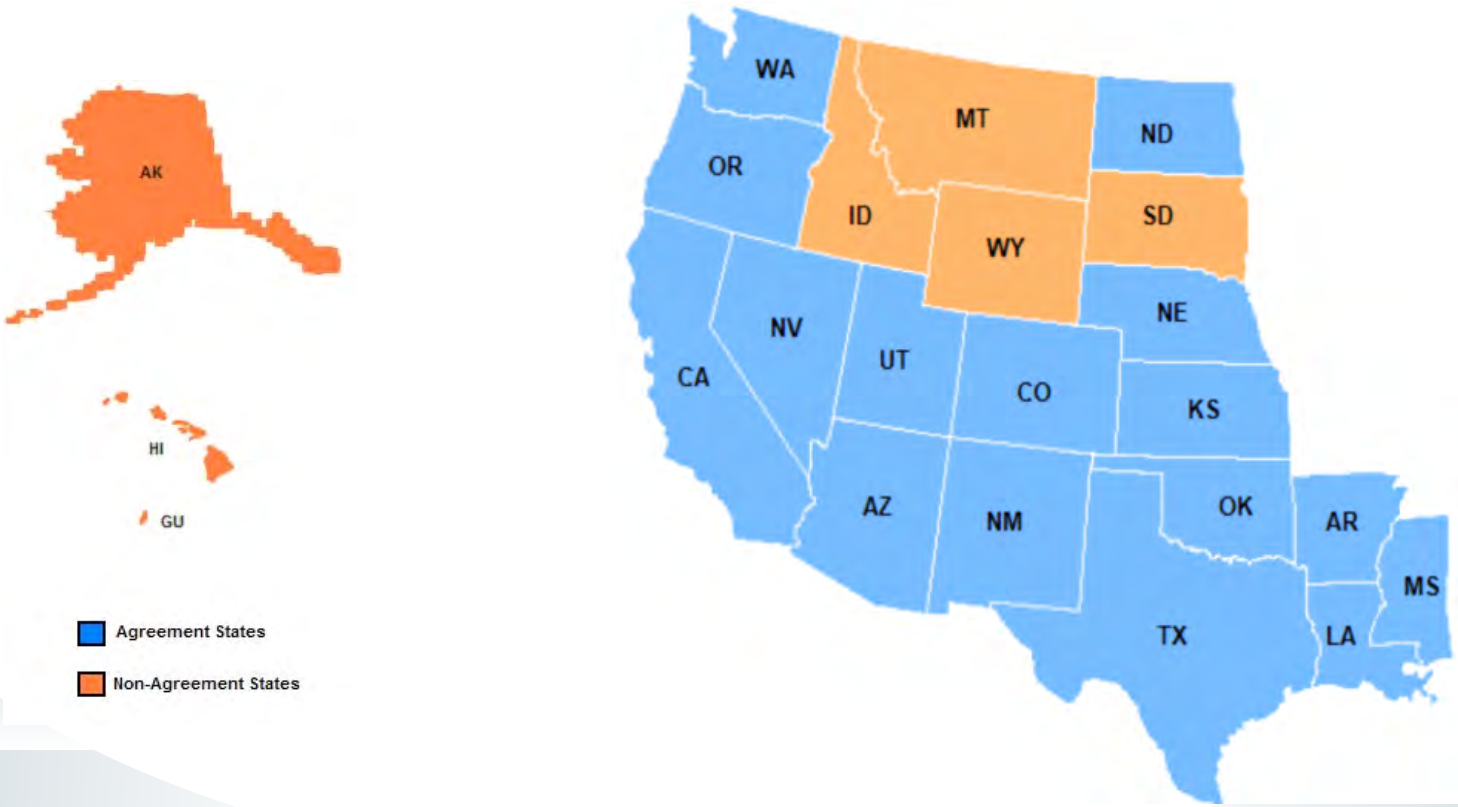
- Office of the Regional Administrator
  - Overall Regional activities with the lead for enforcement, allegation, information security, state liaison, outreach, and response coordination
- Division of Nuclear Materials Safety
  - Oversight of nuclear materials licensees, including ISFSI's, uranium recovery, 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

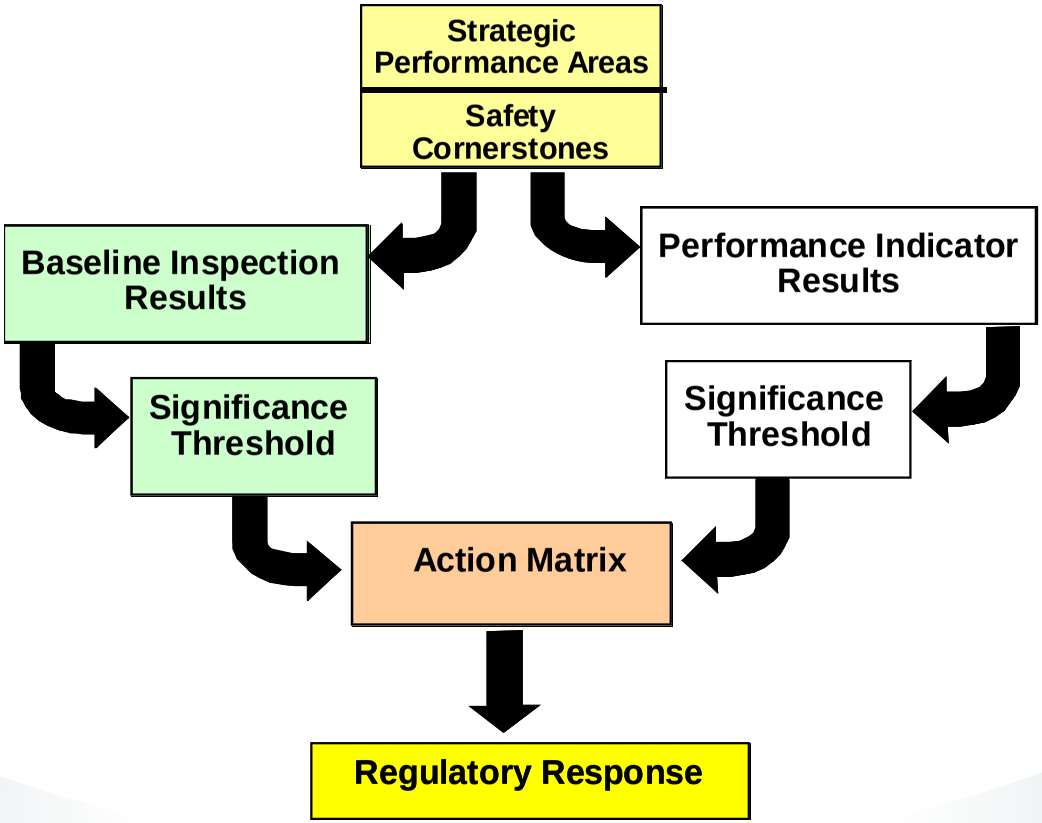
Response Coordination Branch

- 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

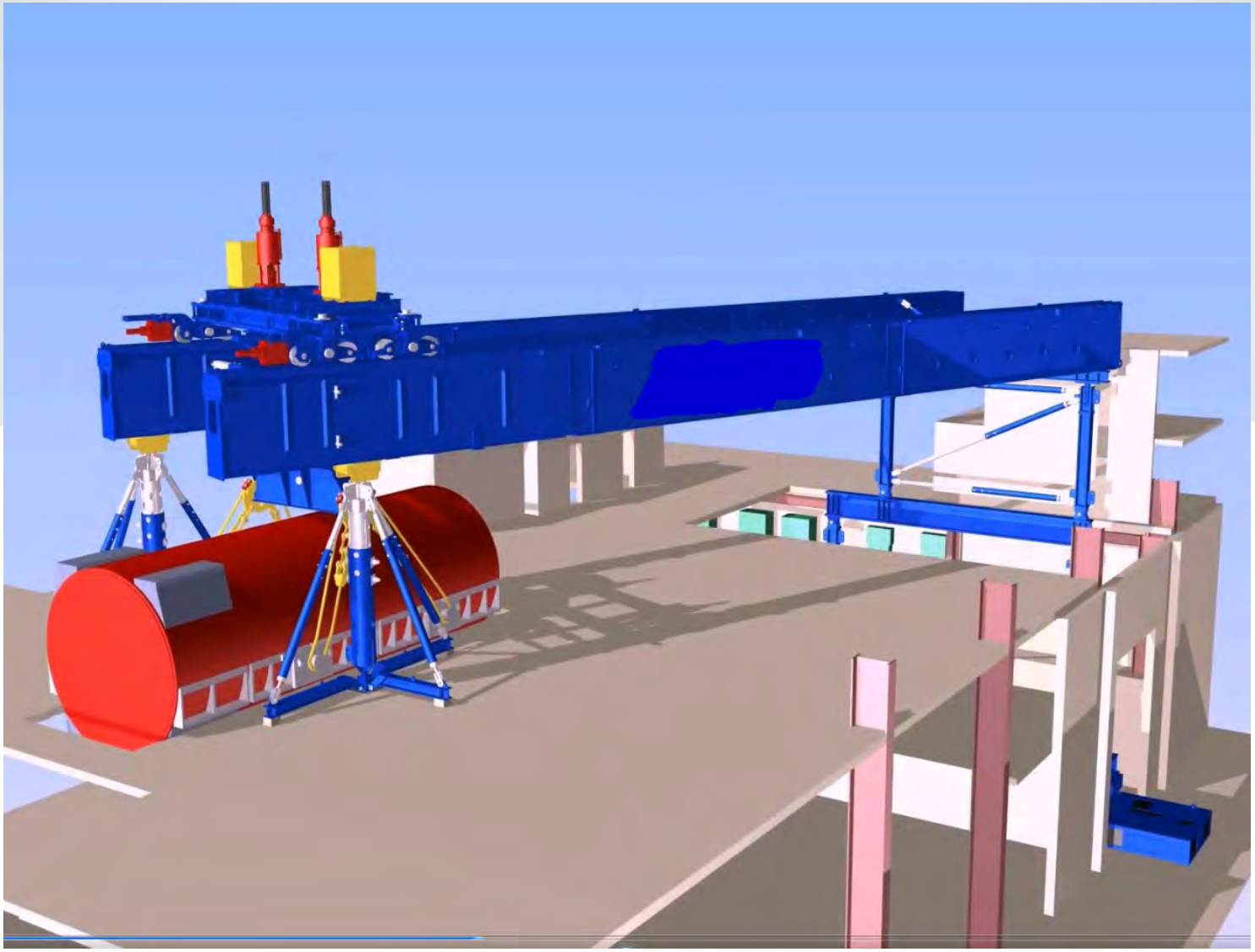
QUESTIONS

Arkansas Nuclear One: Yellow Inspections Findings

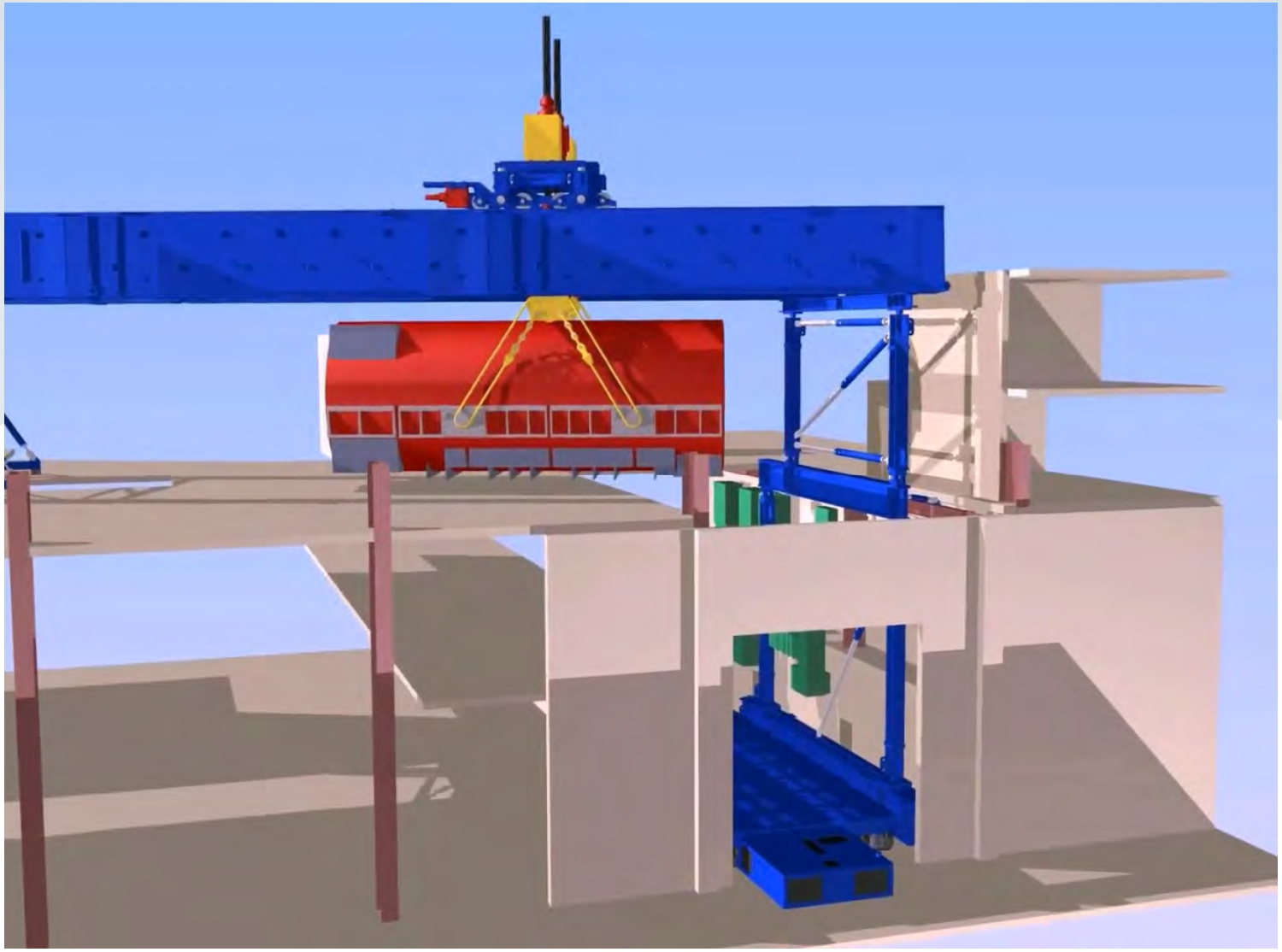
Brian Tindell

David Loveless

Arkansas Nuclear One: Stator Drop Event



BIGGE
BIGGE
BIGGE
BIGGE
CAUTION



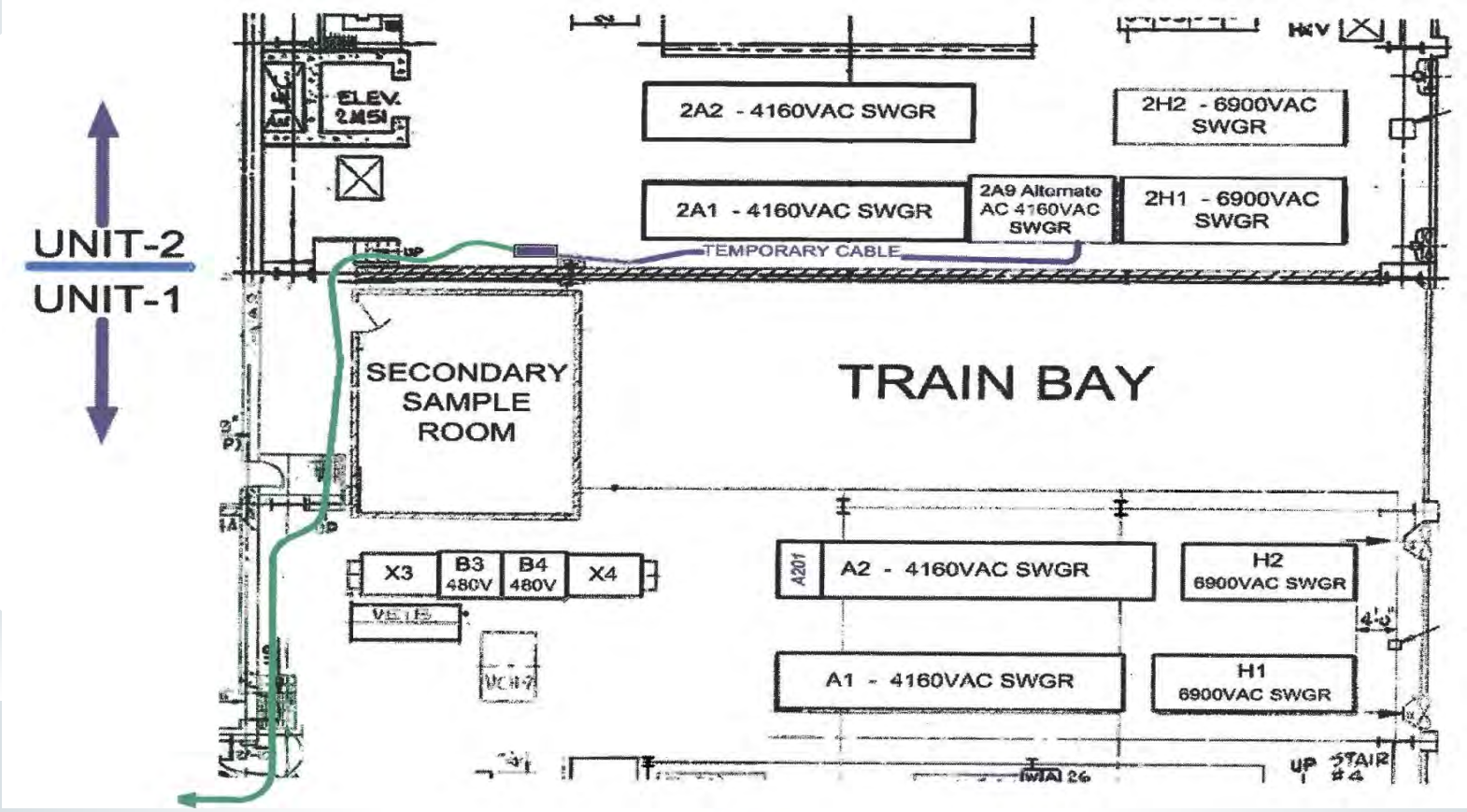
A-1
4160 VOLT
SWITCHGEAR
A-2
4160 VOLT
SWITCHGEAR

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

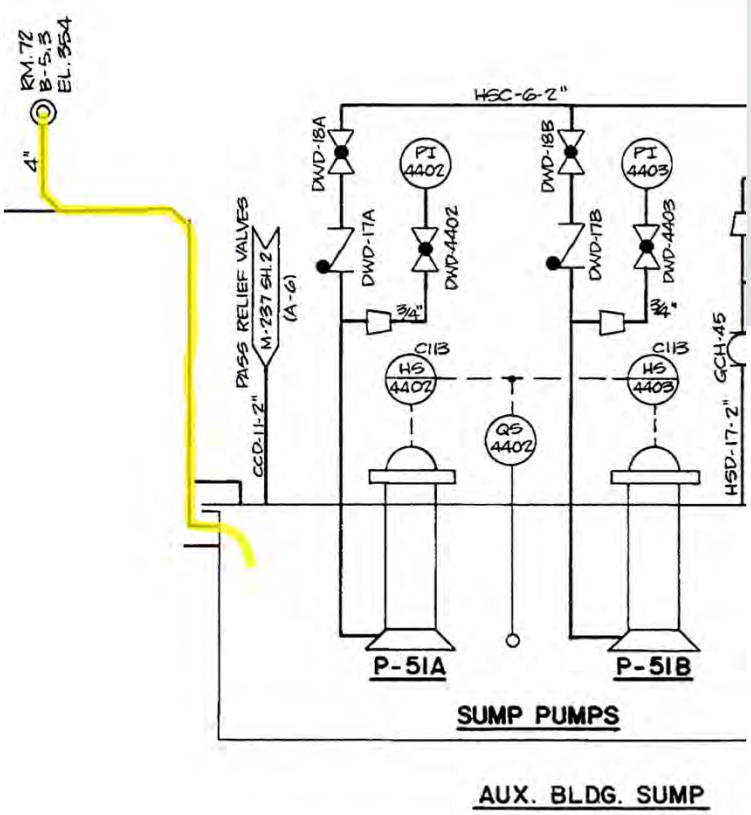
- Unit 1: Credit for recovery yielded Yellow finding on Conditional Core Damage Probability

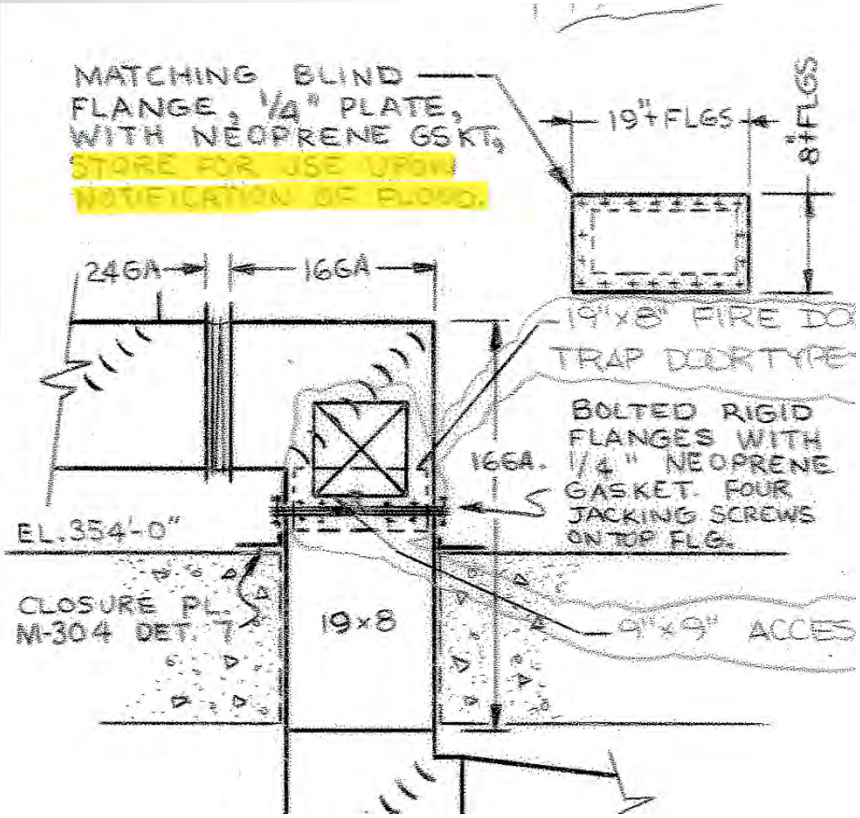
- Unit 2: Preliminary Significance Determination was valid (2.81×10^{-5})
  - Credit was Given for Nonsafety 4160 volt Bus Recovery
  - Additional Credit for AAC Diesel Generator not Significant
  - Final Significance Remained Yellow

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

FLOOD
BARRIER
22LA-17
22LA-17
FLOOD SEAL


RM.72
B-5.3
EL.354
4"
HSC-6-2"
DWD-18A
DWD-17A
DWD-4402
PI
4402
3/4"
DWD-18B
DWD-17B
DWD-4403
PI
4403
3/4"
PASS RELIEF VALVES
M-237 SH.2
(A-6)
CCD-11-2"
C113
HS
4402
C113
HS
4403
QS
4402
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
19x8
9"x9" ACCES

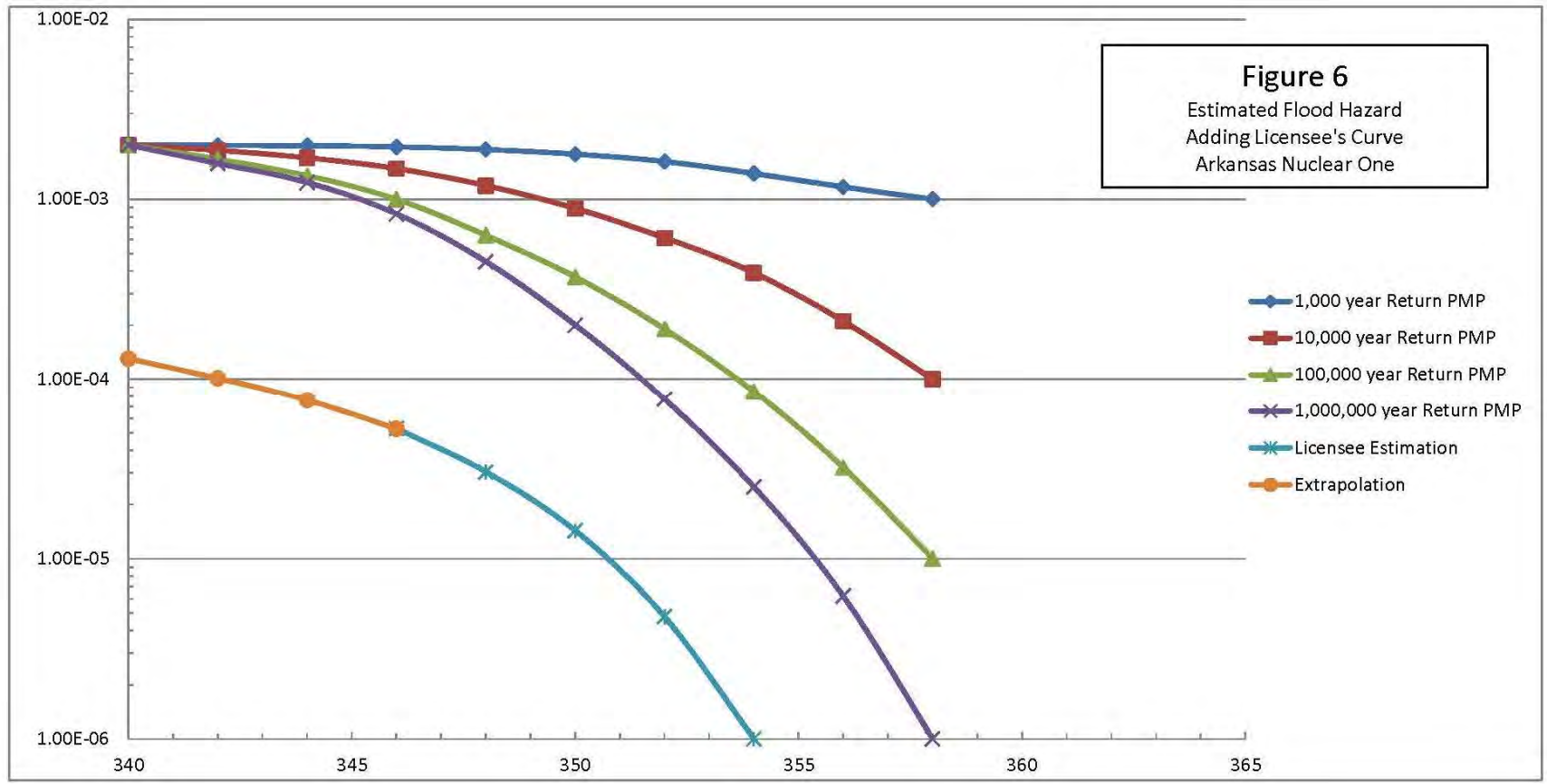
(2057-0001)

WASTE CATALYST
STORAGE TANK

The licensee failed to design, construct, and maintain the auxiliary building to protect safety-related equipment from flooding.

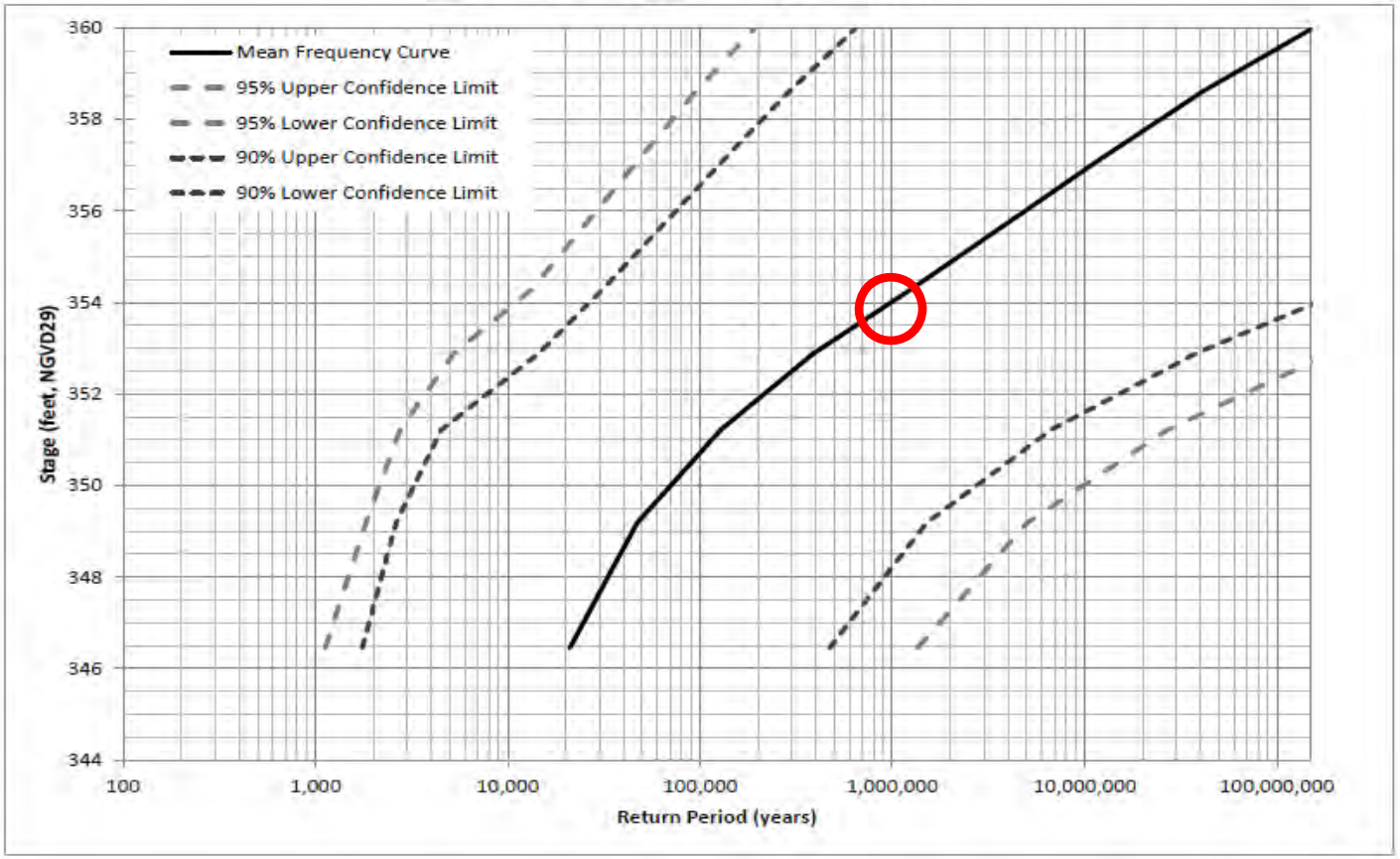
Flood Licensing Basis

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

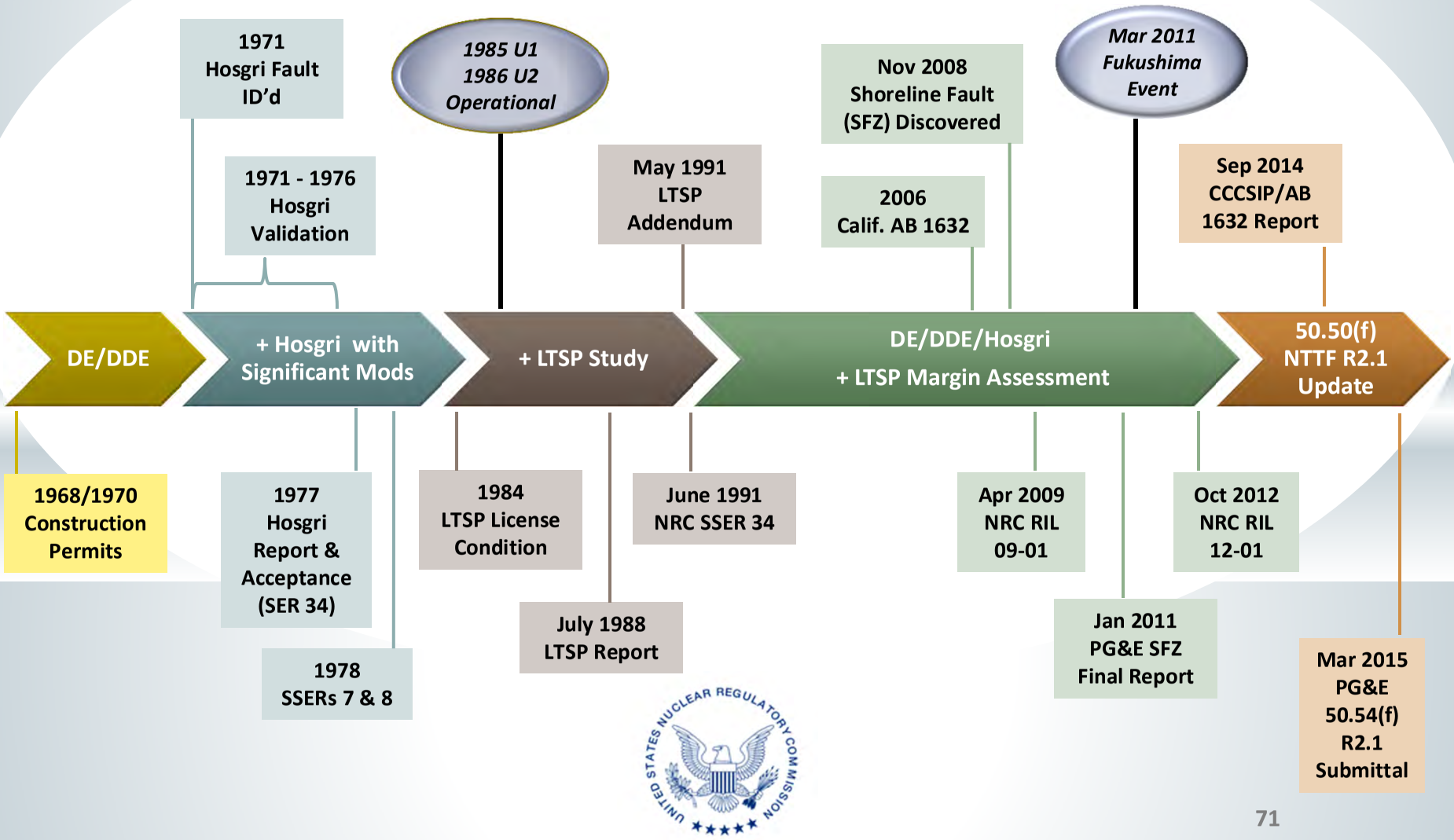
Background, Status of Seismic Analyses, and Challenges at Diablo Canyon

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

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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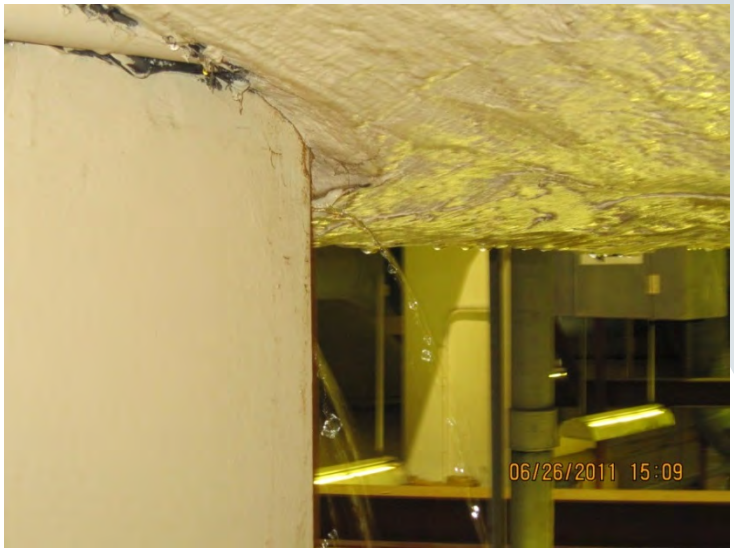
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Industry Recommendations to Enhance Efficiency and Effectiveness of Engineering and Design Inspections

- 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