UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

August 22, 2014

MEMORANDUM TO: ACRS Members

FROM: Mark L. Banks, Senior Staff Engineer ***/RA/***
Technical Support Branch

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE MEETING – REGION III VISIT, JULY 24, 2014, LISLE, ILLINOIS

The minutes for the subject meeting were certified on August 20, 2014, as the official record of the proceedings of that meeting. A copy of the certified minutes is attached.

Attachment: Certification Letter
Minutes
Meeting Transcript

cc w/o Attachment: E. Hackett
C. Santos

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, DC 20555 - 0001

August 20, 2014

MEMORANDUM TO: Mark L. Banks, Senior Staff Engineer
Technical Support Branch, ACRS

FROM: Gordon R. Skillman, Chairman
Plant Operations and Fire Protection Subcommittee

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE MEETING – REGION III VISIT, JULY 24, 2014, LISLE, ILLINOIS

I hereby certify, to the best of my knowledge and belief, that the minutes of the subject meeting on July 24, 2014, are an accurate record of the proceedings for that meeting.

/RA/

Mr. Gordon R. Skillman, Chairman Date: August 20, 2014
Plant Operations and Fire Protection Subcommittee

Certified on: August 20, 2014
Certified by: Gordon Skillman

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE MEETING MINUTES

REGION III VISIT
JULY 24, 2014
LISLE, ILLINOIS

INTRODUCTION

The Advisory Committee on Reactor Safeguards (ACRS) Plant Operations and Fire Protection Subcommittee met at the Region III Headquarters of the U.S. Nuclear Regulatory Commission (NRC), located at 2443 Warrenville Road, Suite 210, Lisle, Illinois, on July 24, 2014. The Subcommittee was briefed by NRC Region III staff. Region III briefings discussed items of mutual interest, namely Regional inspection and operational activities (see meeting agenda below for specific briefing topics).

The meeting convened at 8:30 AM and adjourned at 12:00 PM. The meeting was open to the public. No written comments were received from members of the public related to this meeting. No oral comments were received from members of the public during this meeting.

ATTENDEES

ACRS Members
Gordon Skillman (Chairman)
John Stetkar
Stephen Schultz
Michael Corradini
Harold Ray
Joy Rempe
Michael Ryan
Ronald Ballinger
ACRS Staff
Mark Banks (DFO)
NRC Region III Presenters
Cynthia Pederson
Anne Boland
Bob Daley
Atif Shaikh
James Neurauter
Julio Lara
Rhex Edwards
Billy Dickson
NRC Region III Staff
John Jandovitz
Raymond Ng
Brent Boston
Stuart Sheldon
Ken Riemer
Mohammed Shuaibi
Ken Nicely
Sarah Anderson
Eric Duncan
Laura Smith
John Lewandowski
Mel Holmberg
Don Krause
Jackie Wojewoda
Chuck Jackel

A table of significant issues discussed during the meeting is provided below, as a guide to the attached transcript.

AGENDA

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

PLANT OPERATIONS AND FIRE PROTECTION SUBCOMMITTEE

REGION III VISIT

LISLE, ILLINOIS
JULY 24, 2014

Cognizant Staff Engineer/DFO: Mark L. Banks
Email: mark.banks@nrc.gov
Phone #: (301) 415-3718

Topics	Presenters	Time
Opening Remarks	Gordon Skillman, ACRS	8:30 am – 8:35 am
Region III Welcome and Overview	Cynthia Pederson	8:35 am – 8:55 am
Reactor Oversight Process	Anne Boland	8:55 am – 9:10 am
Technical Issues of Interest	Bob Daley	9:10 am – 9:40 am
Davis-Besse Steam Generator Replacement Inspection	Atif Shaikh Jim Neurauter	9:40 am – 10:15 am
Fukushima Initiatives	Julio Lara	10:15 am – 10:35 am
Break		10:35 am – 10:50 am
Kewaunee Decommissioning	Rhex Edwards	10:50 am – 11:10 am
Inspection of Industry Voluntary Initiatives	Billy Dickson Atif Shaikh	11:10 am – 11:40 am
Wrap-up		11:40 am – 11:45 am
Public Comments	Public	11:45 am – 11:50 pm
Subcommittee Discussion	Gordon Skillman, ACRS	11:50 am – 12:00 pm
Adjourn	Gordon Skillman, ACRS	12:00 pm

Significant issues from ACRS July 24, 2014
Plant Operations and Fire Protection Region III Subcommittee Meeting
Issues linked to location in attached meeting transcript

SIGNIFICANT ISSUES	
Issue	Reference Pages in Transcript
Inspection Manual Chapter (IMC) 95001 or 95002 decision process (Skillman)	8-9
Decommissioning questions (Corradini)	10-13
Fukushima-related flooding walkdowns (Skillman, Corradini)	21-24
Cross cutting issues? (Corradini)	26-27
Duane Arnold safety-related cable conduits filled with water (Stetkar, Schultz, Skillman)	32-45
Reactor Oversight Process (ROP) risk significance discussion (Stetkar)	46-49
Operability discussion – proven operable vs. proven inoperable (Ray)	49-56
Cable aging – insulation and jacket degradation and damage (Ballinger)	66-68
Steam generator replacement operating experience reviewed prior to Region inspection of Davis-Besse steam generator replacement (Stetkar)	79-81
Questions regarding use of low resistance carbon steel inlet support plates in replacement steam generators at Davis-Besse (Ballinger, Corradini)	83-86
Question regarding the cause of the Davis-Besse shield building flaw – issue with the licensee's process or issue with codes and standards (Skillman)	98-101
Did the Region perform a self-evaluation to find out why it accepted the Davis-Besse flawed shield building condition (Stetkar)	101-103
Discussion regarding uncoated rebar in the Davis-Besse shield building (Ballinger)	118-119
Discussion regarding "interim" mitigating strategies that may change if eventually the design basis seismic level changes (Corradini)	123-125
Discussion regarding Kewaunee decommissioning emergency planning violations in spite of previous industry experience (Shultz)	138-140
Alignment of NEI 09-14 (Ground Water Protection Voluntary Initiative) and GALL [Generic Aging Lessons Learned Report], Revision 2 (Stetkar)	156-157

DOCUMENTS PROVIDED TO THE COMMITTEE

1. U.S. NRC, “Annual Assessment Letter for Palisades Nuclear Plant,” March 4, 2014 (ML14063A276)

Fukushima Near-Term Task Force Items

2. U.S. NRC, Request for Information, “Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3, and 9.3, of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident,” March 12, 2012 (ML12056A046)

Seismic Walkdowns

3. Electric Power Research Institute, Report 1025286, “Seismic Walkdown Guidance – For Resolution of Fukushima Near-Term Task Force Recommendation 2.3: Seismic,” Draft Revision 7, May 2012 (ML12164A751)
4. U.S. NRC, Staff Assessment, “Palisades Nuclear Plant – Staff Assessment of the Seismic Walkdown Report Supporting Implementation of Near-Term Task Force Recommendation 2.3 Related to the Fukushima Dai-ichi Nuclear Power Plant Accident,” May 22, 2014 (ML14105A372)
5. Palisades, “Seismic Walkdown Report – Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding the Seismic Aspects of Recommendation 2.3 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident,” November 27, 2012 (ML12334A093)

Flooding Walkdowns

6. Nuclear Energy Institute, NEI 12-07, “Guidelines for Performing Verification Walkdowns of Plant Flood Protection Features,” May 2012 (ML12144A401)
7. Palisades, “Update to Response to NRC 10 CFR 50.54(f) Request for Information Regarding Near-Term Task Force Recommendation 2.3, Flooding – Review of Available Physical Margin Assessments,” January 30, 2014 (ML14034A168)
8. Palisades, “Flooding Walkdown Report – Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding the Flooding Aspects of Recommendation 2.3 of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident,” November 27, 2012 (ML12332A377)
9. U.S. NRC, Staff Assessment, “Palisades Nuclear Plant – Staff Assessment of the Flooding Walkdown Report Supporting Implementation of Near-Term Task Force Recommendation 2.3 Related to the Fukushima Dai-ichi Nuclear Power Plant Accident,” June 17, 2014 (ML14128A569)

Mitigating Strategies

10. U.S. NRC, Interim Staff Guidance JLD-ISG-2012-01, “Compliance with Order EA-12-049, Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events,” August 29, 2012 (ML12229A174)

11. U.S. NRC, Order EA-12-049, “Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events,” March 12, 2012 (ML12054A7350)
12. Nuclear Energy Institute, NEI 12-06, “Diverse and Flexible Coping Strategies (FLEX) Implementation Guide,” August 2012 (ML12242A378)
13. U.S. NRC, Bulletin 2011-01, “Mitigating Strategies,” May 11, 2011 (ML111250360)
14. U.S. NRC, “Palisades Nuclear Plant – Closeout of Bulletin 2011-01, “Mitigating Strategies”,” August 7, 2012 (ML12209A218)
15. U.S. NRC, “Palisades Nuclear Plant – Interim Staff Evaluation Regarding Overall Integrated Plan in Response to Order EA-12-049 (Mitigation Strategies),” February 10, 2014 (ML13365A264)
16. U.S. NRC, “Nuclear Regulatory Commission Audits of Licensee Responses to Mitigation Strategies Order EA-12-049,” August 28, 2013 (ML13234A503)
17. Palisades, “Palisades Nuclear Plant Second Six-Month Status Report in Response to March 12, 2012 Commission Order Modifying Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events (Order Number EA-12-049),” February 28, 2014 (ML14059A078)
18. Palisades, “30-Day Response to NRC Bulletin 2011-01, Mitigating Strategies,” June 10, 2011 (ML111640451)
19. Palisades, “60-Day Response to NRC Bulletin 2011-01, Mitigating Strategies,” July 8, 2011 (ML111890270)
20. Palisades, “Overall Integrated Plan in Response to March 12, 2012 Commission Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events (Order Number EA-12-049),” February 28, 2013 (ML13060A361)

Safety Injection Refueling Water Tank (SIRWT) Leakage

21. U.S. NRC, Confirmatory Action Letter, “Confirmatory Action Letter – Palisades Nuclear Plant Commitments to Address Safety Injection Refueling Water Tank and Control Room Concrete Support Structure Leakage,” July 17, 2012 (ML12199A409)
22. U.S. NRC, Confirmatory Action Letter, “Confirmatory Action Letter (CAL) Revision 1 – Palisades Nuclear Plant Commitments to Address Safety Injection Refueling Water Tank (SIRWT) and Control Room Concrete Support Structure Leakage,” June 26, 2013 (ML13177A280)
23. Palisades, “Confirmatory Action Letter – Palisades Nuclear Plant Revisions to Address Commitments to Address Safety Injection Refueling Water Tank and Control Room Concrete Support Structure Leakage,” June 30, 2013 (ML13171A219)
24. Palisades “Safety Injection Refueling Water Tank Leakage and Corrective Actions,” July 12, 2012 (ML12194A573)
25. U.S. NRC, “Palisades Nuclear Plant – Closure of Confirmatory Action Letter, Revision 1, June 20, 2014 (ML14171A628)

Control Rod Drive Mechanism (CRDM) Housings

26. Palisades, License Event Report 2012-001-00, “Degraded Condition due to Control Rod Drive Mechanism Housing Assembly Crack,” October 11, 2012 (ML12285A320)
27. Palisades, License Event Report 2014-002-00, “Degraded Condition due to Crack Indications in Control Rod Drive Mechanism Housing Assemblies,” March 27, 2014 (ML14086A626)
28. U.S. NRC, Special Inspection Report, “Palisades Nuclear Plant – NRC Special Inspection Team (SIT) Report 05000255/2012012,” October 17, 2012 (ML12291A806)
29. Alley, D., *et al*, “Leak in Control Rod Drive Mechanism Housing, Palisades Nuclear Plant,” January 30, 2014 (ML14030A368)

Reactor Vessel Foreign Material

30. U.S. NRC, “2014 Palisades Communication Plan – Reactor Vessel Foreign Material,” March 18, 2014 (ML14077A234)

Pressurized Thermal Shock (PTS)

31. Palisades, “Updated Palisades Nuclear Plant Reactor Vessel Fluence Evaluation,” June 25, 2013 (ML13176A412)
32. Palisades, “Palisades Nuclear Plant 10 CFR 50 Appendix G Equivalent Margins Analysis,” October 21, 2013 (ML13295A448)
33. U.S. NRC, “Palisades Nuclear Plant – Updated Reactor Vessel Fluence Evaluation Supporting a Revised Pressurized Thermal Shock Screening Criteria Limit,” December 18, 2013 (ML13346A136)
34. Westinghouse, WCAP-15353-Supplement 2-NP, “Palisades Reactor Pressure Vessel Fluence Evaluation,” July 2011 (ML13295A450)
35. Westinghouse, WCAP-17403-NP, Revision 1, “Palisades Nuclear Power Plant Extended Beltline Reactor Vessel Integrity Evaluation,” January 2013 (ML13295A449)
36. Westinghouse, WCAP-17651-NP, “Palisades Nuclear Power Plant Reactor Vessel Equivalent Margins Analysis,” February 2013 (ML13295A451)

GSI-191 / Generic Letter 2004-02

37. Palisades, “Schedule for Generic Safety Issue – 191 Resolution,” December 18, 2013 (ML13353A567)
38. U.S. NRC, SECY-12-0093, “Closure Options for Generic Safety Issue – 191, Assessment of Debris Accumulation on Pressurized-Water Reactor Sump Performance,” July 9, 2012 (ML121310648)
39. U.S. NRC, SRM-SECY-10-0113, “Staff Requirements – SECY-10-0113 – Closure Options for Generic Safety Issue – 191, Assessment of Debris Accumulation on Pressurized-Water Reactor Sump Performance,” December 23, 2010 (ML101820212)

Region III Special Inspections – FY 2014

40. U.S. NRC, Special Inspection Report, “Clinton Power Station NRC Special Inspection Team Report 05000461/2013009,” January 31, 2014 (ML14031A463)

Recent Palisades Inspection Reports

41. U.S. NRC, Inspection Report, “Palisades Nuclear Plant Integrated Inspection Report 05000255/2013002,” May 14, 2013 (ML13134A329)
42. U.S. NRC, Inspection Report, “Palisades Nuclear Plant – NRC Integrated Inspection Report 05000255/2013003,” August 6, 2013 (ML13219B114)
43. U.S. NRC, Inspection Report, “Palisades Nuclear Plant – NRC Integrated Inspection Report 05000255/2013004,” November 13, 2013 (ML13318A079)
44. U.S. NRC, Inspection Report, “Palisades Nuclear Plant – NRC Integrated Inspection Report 05000255/2013005 and Exercise of Enforcement Discretion,” February 12, 2014 (ML14043A507)
45. U.S. NRC, Inspection Report, “Palisades Nuclear Plant Integrated Inspection Report 05000255/2014002,” May 7, 2014 (ML14127A543)
46. U.S. NRC, Inspection Report, “Palisades Nuclear Plant – Problem Identification and Resolution Focused Inspection Report 05000255/2014009,” March 6, 2014 (ML14127A543)
47. U.S. NRC, Inspection Report, “Palisades Nuclear Plant – Problem Identification and Resolution Inspection Report 05000255/2014007,” June 20, 2014 (ML14171A394)
48. U.S. NRC, Inspection Report, “Palisades Nuclear Plant – NRC Supplemental Inspection Report 05000255/2012011; and Assessment Follow-up Letter,” November 9, 2012 (ML12314A304)

Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

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Docket Number: (n/a)

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Date: July 24, 2014

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BEFORE THE NUCLEAR REGULATORY COMMISSION

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ACRS PLANT OPERATIONS AND FIRE PROTECTION

SUBCOMMITTEE

\+ + + + +

THURSDAY

July 24, 2014

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2443 WARRENVILLE ROAD, SUITE 210

LISLE, ILLINOIS 60532

PRESENT:

JOHN W. STETKAR, ACRS CHAIRMAN

HAROLD RAY, ACRS VICE CHAIRMAN

RONALD BALLINGER, ACRS MEMBER

MIKE RYAN, ACRS MEMBER

DICK SKILLMAN, ACRS MEMBER

STEVE SCHULTZ, ACRS MEMBER

MIKE CORRADINI, ACRS MEMBER

CYNTHIA PEDERSON, REGIONAL ADMINISTRATOR

REGION III

ANNE BOLAND, DIRECTOR DIVISION OF REACTOR

PROJECTS

KEN O'BRIEN, DEPUTY DIRECTOR DIVISION OF REACTOR PROJECTS

JULIO LARA, TSS TEAM LEADER

ATIF SHAIKH, SENIOR REACTOR INSPECTOR

JIM NEURAUTER, SENIOR REACTOR INSPECTOR

RHEX EDWARDS, REACTOR INSPECTOR

BOB DALEY, ENGINEERING BRANCH CHIEF

BILLY DICKSON, BRANCH CHIEF

P R O C E E D I N G S

(8:33 a.m.)

MR. SKILLMAN: Good morning. This meeting will now come to order. This is a meeting of the Advisory Committee on Reactor Safeguards, Plant Operations and Fire Protection Subcommittee. I'm Dick Skillman. I'm chairman of the subcommittee. ACRS members in attendance today are Steve Schultz, Harold Ray; Harold is the vice chairman of the ACRS, John Stetkar, on my left, chairman of the ACRS, Mike Ryan, Ron Ballinger and Mike Corradini. The designated federal official is Mark Banks.

The ACRS meets annually with one of the NRC's four regions to discuss their oversight and inspection of NRC licensed facilities. The purpose of today's briefing is for the Region III staff to discuss items of mutual interest, namely regional inspection and operational activities.

The subcommittee will gather information, analyze relevant issues and facts, and formulate a proposed position and action as appropriate for deliberation by the full committee, if needed. The

rules for participation in today's meeting were announced as part of the notice of this meeting previously published in the federal register on June 18, 2014.

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

A transcript of today's meeting is being kept, and will be made available as stated in the federal register notes. Therefore, we request that meeting participants use the microphones located throughout the meeting room when addressing the subcommittee. Participants should first identify themselves and speak with sufficient clarity and volume so that they can be heard.

A telephone bridge line has been established for this meeting. To preclude interruption of this meeting, we ask you to please mute your individual telephones during presentation and discussion. We will now proceed with the meeting, and I call on Ms. Cindy Pederson, Regional Administrator,

NRC Region III to make introductory remarks. Thank you.

MS. PEDERSON: Thank you, and good morning to everyone. It's a pleasure to be host to the ACRS subcommittee this morning, and I also understand you had a good visit yesterday at Palisades. So, hopefully, your two days will be very fruitful, and we'll be happy to answer your questions as we go on this morning.

I wanted to just quickly introduce the NRC staff at the table. We'll hear from many more during the morning. And so, we have Julio Lara at my far left, who helped to organize today's session. And we have Anne Boland, the Director of the Division of Reactor Projects and Bob Daley, one of our engineering branch chiefs. And I would like to take just a second to check. Do we have anyone on the telephone with us this morning? Hearing no one, okay, thank you.

Just one small bit of safety focus for our meeting this morning as far as if we do have the need to evacuate the facility, we have exit doors to my right and left, and also to your right and left behind you that you would exit through and go to our stairwell and proceed downstairs and out into the parking lot.

Certainly, there would be NRC folks from Region III that would be helping you in identifying those exit pathways, but I just did want to make note of that.

Let's just quickly talk about a little bit of the agenda, and did someone just join on the telephone? Hello? Anyone on the phone? Maybe someone dropped off. The agenda, and you all have, I believe, a copy in front of you as well, but for those in the audience, we've got a number of topics that we're going to be discussing this morning.

I'm going to start with just a very general overview of Region III operations, and then we'll go to the particular technical topics that you requested and we're happy to discuss with you this morning. And we'll take a break, mid-morning, as well. At any time if you desire, Mr. Skillman, to take another break, just give us a signal and we can make that happen, too.

MR. SKILLMAN: Thank you.

MS. PEDERSON: Just quickly an overview of Region III. As you know, in your many regional visits, our focus is on implementation of the inspection program for the operating reactors. But we also have a number of other activities; our dry cask storage inspection, air conditioning inspections. And we do

materials licensing and inspection out of this region.

We certainly have the operator licensing examiner program, and public affairs and government liaison. So we do the broad gambit of regional operations. We do not, however, do fuel oversight or construction, as they are centralized in Region II. But we have all the other functions. As far as our inspection staff, we have approximately 92 qualified reactor inspectors. And in addition to that, we do have our materials inspectors and our operator examiners.

Just very briefly, the last year or year-and-a-half, we've been quite active with supplemental inspections, in addition to our routine baseline inspection. We've done a number of 95001 and 95002 inspections, and those certainly are extra emphasis for us for plants that have exhibited performance issues. And so we have more planned yet for this year, as well. It's been rather active for us with plants in column three of the oversight matrix, and Ann's going to discuss that a little bit more in detail than these slides.

MR. SKILLMAN: If I could ask this question.

MS. PEDERSON: Certainly.

MR. SKILLMAN: When the regional identifies a plant that is stumbling, what is the precision with which a decision is made to invoke, you know, the inspection manual Chapter 95001 or 95002? Is that a very predictable, precise process, or is that very, very --

MS. PEDERSON: It's very, I'll tell you, it's technical and it's well formulated through our reactor oversight process. Anytime we identify a finding, we have an assessment process we utilize to determine its significance. If the significance is greater than green, green being the lowest; green, white, yellow and red, if it's anything beyond the green level, we then involve more offices, including property and reactors. We get the NRR or NSIR if their flaw is a security or EP related issue, and the office of enforcement.

So the process involves more people with a higher significance. And then, if we determine it is white, that automatically has us to the 95001 and supplemental inspection. If it's a yellow, 95002. And we have a precise process through our ROP, reactor oversight process, that defines that. So, from a

formulation standpoint, it's pretty rigorous.

The place that probably the must judgment, if you will, is involved in assessing the significance in the first place. We have a lot of guidance to help us with questions that drive us to coming to that conclusion. But that is where we tend to us more of the engineering judgment, as an example.

MR. SKILLMAN: So, if I can repeat back, it's really driven by the SDP that drives the color.

MS. PEDERSON: Yes, yes.

MR. SKILLMAN: The color then, drives the --

MS. PEDERSON: It drives the inspection, correct.

MR. SKILLMAN: Thank you.

MS. PEDERSON: Sure. And just I wanted to, briefly, I know it's not the focus, but I just wanted to briefly mention our nuclear materials program. Now, this is not materials as in metallurgical or material science; radioactive materials. And we use that word, materials, often in the region to mean the radioactive materials portion. And we do have a very, a large group of support right there where we have about 1,100 licensees that we license and inspect in this

region.

But focusing a bit more on the reactors, your area of focus. We do have 15 operating facilities in this region, and you'll see the states listed there. We now have 23 operating reactors, 12 of which are pressurized water reactors, 11 of those units are boiling water reactors.

We have 19 dry cask storage facilities, 17 of which are co-located at operating reactors or decommissioned reactors, and then we have two stand-alone facilities that we oversee. One is the wet storage at GE-Morris, and the other is dry cask in the former facility at Big Rock Point.

We also have three decommissioned reactors in SAFSTOR in Zion, La Crosse and Kewaunee. And then we have a number of complex decommissioning sites that were what we would call nuclear material sites that we also oversee and inspect.

MR. CORRADINI: Can I ask a question about the last part?

MS. PEDERSON: Certainly.

MR. CORRADINI: So you make a point about saying complex. The Michigan reactor is complex because it's on campus, or because of the other things

that are going on inside what was the containment?

MS. PEDERSON: No we have, there's a gradation of materials programs, as you certainly are aware. We have some very simple programs that are small, maybe industrial or small medical facilities. A research reactor would be a larger, more complex site, from just kind of the gradation of how they do it.

MR. CORRADINI: Okay.

MS. PEDERSON: There's nothing specific that would say A, B or C, --

MR. CORRADINI: Okay, I just didn't understand.

MS. PEDERSON: -- it's just more of the size and the kinds of activities. In this case, the research reactor, there would have been by-product material licenses intermingled with that, and production as well.

MR. CORRADINI: Has that been concluded? Because it shut down a good 10, some years ago.

MS. PEDERSON: It's very near. It's in the stage of final surveying and review is my understanding.

MR. CORRADINI: That's fine. I just was curious what it meant.

MS. PEDERSON: I got thumbs up. Yes, I got that right now.

MR. CORRADINI: All right, thank you.

MS. PEDERSON: So it's near, very near, yes.

MR. CORRADINI: And since I have a bias, is Kewaunee going to go into the same SAFSTOR as La Crosse, or a different end point?

MS. PEDERSON: They'll, Kewaunee is, has accelerated their fuel movement portion. So they expect to have their fuel into dry casks by 2016, by the end of 2016. And so, they will then stretch out and go into SAFSTOR, so there will be a similar period. I think what's a bit different between La Crosse and Kewaunee is Kewaunee is much more rapidly getting their fuel into dry casks than La Crosse did. La Crosse now has all of theirs in dry casks.

MR. CORRADINI: Sure, sure.

MS. PEDERSON: But it took them quite a while longer.

MR. CORRADINI: But if I remember the geography, do they have a dry cask pad? I thought they were using the beach, or am I remembering incorrectly? Does Kewaunee have a dry cask pad that's right next to

the plant, or across the road in a different location?

MS. PEDERSON: I think it's just right next to the plant. Rhex, yes?

MR. EDWARDS: That's correct.

MS. PEDERSON: Thanks Rhex.

MR. CORRADINI: Okay.

MS. PEDERSON: Yes, it's right next to the plant.

MR. CORRADINI: Thank you.

MS. PEDERSON: All right. Just looking at it from a map, just a brief representation of where the plants, operating plants are here in Region III. And just breaking it up, just a small note on this representation of jurisdiction, Missouri is Region III's state for oversight of materials facilities. However, the Callaway plant, which operates in Missouri, is overseen by Region IV.

So Missouri is a state of dual jurisdiction. We like to claim Missouri, and that's in the map we gave you on this one.

MR. CORRADINI: There's no fight, though?

MS. PEDERSON: No, no.

MR. CORRADINI: There's no border wars or anything like that.

MS. PEDERSON: No, no, nothing to be drawn from that. It was just a number of years ago we divvied up the reactors so each of the regions have a more comparable number for oversight. Just a few highlights, more details will be provided on these issues. But we already actually mentioned Kewaunee. That is a new decommissioned site for us, because they relatively recently shut down and went into permanent non-operational status.

And so, we are kind of the lead for the other ones that are going to follow; places like Songs and Crystal River. Region III is working very closely with our headquarters counterpart offices to re-invigorate, I'll say, the inspection program for decommissioning. And, certainly, there's a lot of activities going on in the licensing area and with NLR regarding extensions and so forth, because our rule making has not kept up with the state of affairs in decommissioning.

As I'm sure you know, it went to the commission some number of years ago to proceed with rule making. The decision, at that time, is there wasn't a need to do it. And then, 9/11 happened and a lot of our resources were diverted elsewhere. And rule

making has not happened yet. And so, that's actively just being discussed on when is the appropriate time to pursue rule making for these transitional things that are transitioning early from operating status to decommissioned status.

MR. SKILLMAN: I would like to ask this question regarding Kewaunee. Here's a plant that was operating successfully 18 months ago. The announcement was made that that plant would be taken out of service, and that action and the process that follows really was a key thing for the community. My question is in the weeks and months that have transpired between the announcement and where Kewaunee is today, what involvement by the NRC has been in the community? And what is the observation at the NRC regarding the community's response to the announcement that will take this plant out of service?

MS. PEDERSON: The reaction from the community that we've observed is mostly focused on financial and economical issues. Certainly, it is an impact to the local community from a loss of jobs and the loss of taxes. So that seems to be the focus. Not, we haven't been inundated with concerns about the safety of decommissioning or any of that type of area

of safety, which is really our focus. It's been more on this financial and economic side. And we're, later we'll have one of our experts up to also talk with you about decommissioning of Kewaunee.

MR. CORRADINI: So it may be you'll delay this one to your expert. But there's some recent press that I'm sure you're aware of, and I just take it as recent press. But I'm curious about calls to sell and re-license, which I think is complex. So, we would wait for that one?

MS. PEDERSON: Well, I can give you, I can give you a perspective on that. Yes, there has been a lot of play in the press regarding RGA wanting to purchase and operate the plant. They have not approached the NRC to have a discussion about licensing of that facility, to my knowledge, based on the latest check-in I had with that. So they've not come to the NRC to inquire.

We are looking, internally, as to if they did how would that proceed. Actually, I got some late breaking news this morning that OGC is examining that issue currently. So, right now, there's nothing, there's no, there's nothing before us to act upon. But it's certainly getting a lot of press.

MR. CORRADINI: Okay. Thank you.

MS. PEDERSON: Sure.

MS. BOLAND: Cindy?

MS. PEDERSON: Yes.

MS. BOLAND: If I could just add one thing, and I know we're going to have a special presentation on this. But when Kewaunee went into decommissioning and made their announcement and submitted, you know, their intentions and plans, we did hold meetings in the community where we discussed the NRC's oversight and the NRC's process and what the regulatory framework would be as the facility reached these various stages.

So we've had several opportunities to have that direct interaction. As well as our end-of-cycle meetings that we hold in the area for Point Beach, does attract some constituency from Kewaunee, and we're always prepared, you know, to engage and answer those questions.

MR. CORRADINI: I was just wondering if there was outrage, if there was a lot of turbulence, if there was a new group of anti-whatever showed up that you had never seen before. I was just curious.

MS. PEDERSON: Yeah, we've not been getting that type of input.

MR. CORRADINI: Okay.

MS. PEDERSON: And also, we're going to talk more today about steam generator replacements. We've had two of those recently, Davis-Besse and Prairie Island which are big efforts and more discussion to follow on that. I would just note, I mentioned our three plants that are in column three of the action matrix, Monticello, Point Beach and Duane Arnold.

And lastly, just to acknowledge that you'll be hearing some very interesting emergent technical issues that we're dealing with coming up very soon, after I stop talking. Just a quick summary of where we are on license renewal. I know that's certainly something that you folks are engaged in at ACRS.

And this is just a quick articulation of which plants are currently operating in their beyond 40-year time period, their period of extended operation and a couple that have been renewed that soon will be. And then, this is the last listing of those that are yet to be renewed. All the plants in Region III that are currently operating are expected to be in their extended period while they request extension of their

license.

And that was the broad overview I was going to cover. Any questions for me at this time? I'll be sticking around, also. So I'll be happy to answer any questions you may have. All right, Anne.

MR. SKILLMAN: Thank you.

MS. BOLAND: Okay, I think we need to pass the mouse and microphone.

MS. PEDERSON: Anne, maybe we should switch. I don't know that the cord is long enough on that one.

MS. BOLAND: Okay.

MS. PEDERSON: All the cords, I think, are on that side.

MS. BOLAND: Excellent. Again, my name is Anne Boland. I'm the Director of the Division of Reactor Projects. And really what I wanted to do was, before we transitioned over to Bob Daley who's going to talk about some emergent technical issues that I think will be of particular interest, I just want to kind of give you a sense of where the Region III fleet, if you will, stands relative to the ROP, and the action matrix and to give you a perspective on overall licensing performance.

So again, I'm was going to go over just a general action matrix summary, talk about the Kewaunee plant that we haven't discussed the cost-cutting issues. And then just, in addition, there's lots of changes going on in the ROP. Lots of external and internal inputs on perspectives on how we can improve the program. And we've been very engaged in those processes, and just wanted to give you a sense of that.

This is an overview of the action matrix summary for Region III as it sits today. And you'll see that we have three units in column three of the action matrix. So that means that those sites have had either multiple white findings or have had a single yellow finding. And then we have four units that currently remain in column two, which means that there was one white input to the action matrix.

Each of these, for varying reasons, and I think they are described in detail on the slides for you. They vary. Some of them involve exceeding the threshold for performance indicator, that would be like for Clinton and Prairie Island. The Fermi plant, which is in column two, that issue was associated with security. And the remaining, well, and then with the column three plants, Duane Arnold, Monticello and one

of the Point Beach units, again we have multiple findings that key this.

But I guess if I was going to highlight one thing for you that has been a, has generated multiple inputs to the action matrix for changes is flooding. The region, over the last year or so, has had three greater than green findings associated with our follow-up initial Fukushima walkdown. And those three sites are Monticello, Point Beach, and the third one that's not represented on the slide is Dresden.

Dresden was in column two, but they have since had a 95001 inspection, and have cleared and returned back to column one. So our inspections relative to that TI were very fruitful in improving plant safety relative to the flooding analysis. And really, what we found at a high level, is either the strategies were inadequate or the procedures could not be executed in the time frame that was needed to mitigate and protect the plant so that it wouldn't flood.

MR. SKILLMAN: Anne, in that regard, for those plants where there were findings that were discovered by the Fukushima flooding walkdowns, can you give us an idea of what the CEF benefit was as a

consequence of addressing the finding? By how much did the overall safety improve?

MS. BOLAND: The overall risk profile improved. I don't know that I can speak to that exact number. I will say that the degraded condition for two of the plants was in the 10 minus six range, as we worked it through our SDP. And then, for Monticello, it was yellow which put it in the 10 minus five range.

So corrective actions were taken to address those, but the overall enhancement in the risk profile, we'll need to take a question to follow-up. I don't think we have any risk folks in the audience. But if you'd like that we'll respond to you to at the next break.

MR. SKILLMAN: I do, and it gets to what do we really do if that work and the actions that came out the Fukushima walkdowns, we were very deeply involved in that. Did we really make a difference, or are we just taking a thin slice out of the pie?

MS. BOLAND: I would offer at a high level, major difference.

MR. SKILLMAN: I think so. But I'd like --

MS. BOLAND: We think your plant changes

were required to either make, completely redo the flooding strategy, or to shore up the current.

MR. SKILLMAN: Really do something that was big.

MS. BOLAND: Correct. Physical changes were required in barriers and in strategy.

MR. CORRADINI: So if we could take two examples, and maybe it's not for this time now, because I know that you have a number of issues. But if you take Dresden, which had an issue, corrected it either by procedures or changes, and Monticello, which is still in the middle of it, from a process standpoint, is it that you now go back, look at those, inspect, and have them go through a drill to show they can do it in the allotted time with their procedures, and then they come off of the column? Or how does it work to exit where they are to back into the good graces of you guys?

MS. BOLAND: Excellent question. When we have a finding, we certainly go through the assessment process. The licensee is required to take the corrective actions. Then our action matrix dictates the level of inspection that we do. So when he is at more of a significant finding. We would do a follow-up inspection, and we would verify the accuracy of the

licensee's corrective action.

How we go about doing that could involve what you suggest, or it could involve other techniques. But we would look at the actual, have they restored compliance. And then, secondarily, have they, whatever the root cause of that original concern was, have they addressed the root cause and extent of condition or extent of cost.

So it is a broader look, and when you're in column one, you would get a 95001 inspection. That inspection is about a week long. Sometimes it's a two-person week, depending on the scope and the nature of the inspection.

If it's a more risk significant finding, or there's more, multiple inputs, which would put them into column three, you would get a much more intrusive inspection, 95002 inspection, which is about a 250-hour or more inspection. Multiple weeks, multiple people on it.

MR. CORRADINI: Okay, thank you.

MS. PEDERSON: And, Anne, if I can just add one more thing. We've been talking certainly about Region III's flooding findings. The other regions also have had findings based on their flooding walkdown

post Fukushima. Ginna, Watts Bar, Sequoyah and TMI.

MR. SCHULTZ: I have a question. What we're shown here, between Point Beach 1 and Point Beach 2 was the same descriptions related to the action matrix column but they're in different columns. Can you explain the difference?

MS. BOLAND: Yes. For Point Beach, the risk profile is different between the two units we had assessed for flooding. But then, there was also a second input to the action matrix having to do with their turbine driven oxygenating water system. And that was only applicable to one unit.

MR. SCHULTZ: Thank you.

MS. BOLAND: All right, so that's really kind of, I just wanted to give you a broad overview and we will have Mr. Skillman, follow-up on your question related to those changes.

MR. SKILLMAN: Thank you.

MS. BOLAND: The next slide is really just an overview of really what we just talked about. The execution of the supplemental inspection program is in addition to our normal baseline. It's a substantial effort. And for us, we've had, this year we will have executed four 95002 inspections. So stacking that in

addition to our normal work is quite challenging. But we do like to do those promptly to get out and verify corrective actions and understand how the issue is being solved.

We do work with the other regions when needed for cross fertilization, and also to help with staffing, as well. And then, I noted here that Monticello does have an open substantive cross cutting issue in the area of documentation. And that is the only Region III site and the only site in the country at the moment that does have a substantive cross cutting issue. So when we do our supplemental inspection, we will be looking at that area in more depth. And then, lastly, I just wanted to, again give you a --

MR. CORRADINI: Just, sorry, I'm not familiar with all these, what does that mean, H7 open substantive cross cutting issue?

MS. BOLAND: Whenever we identify an NRC finding under the ROP analysis system, green, white, yellow, red, the staff assesses what safety culture action caused that to occur. And, as we go through our assessment process under the ROP, we evaluate the trend of, you know, have there been a number of issues in a certain key performance area. Or have there been a

number of issues in corrective action. And if they meet a certain threshold, they we decide do we need to identify a substantive cross cutting issues.

And the basis for that is just not numbers, that's the objective piece. But we make an assessment of, does the licensee really understand the issue, and have they put in corrective actions to improve it.

MR. CORRADINI: Okay.

MS. BOLAND: And if not, we open up the issue to look at it further.

MR. SCHULTZ: What specifically is, can you expand on the finding related to documentation?

MS. BOLAND: There were multiple findings that had some input relevant to documentation, and I don't have that complete list here. But they had to have had at least four, and one of them was the flooding finding; that they had inadequate procedures. And that's, generally, what the documentation feeds into, is adequacy of procedures and assessments. Okay, any more questions on the ROP?

Relative to improvement initiatives, I'm sure the group here has understood that there's a number of ongoing efforts relative to assessing the ROP. Those include the ROP enhancement project, which is a

staff driven periodic review of the ROP. The ROP reliability effort, which also is a staff driven effort to look at consistencies across the regions and how we disposition inspection findings and other areas of oversight.

And then we've had some external drivers, if you will, that have caused us to look at various recommendations for the ROP, including a report by the Government Accountability Office, which looked at regional differences in application of the ROP. So we've been very engaged in that relative to the ROP enhancement.

We, at Region III, had the lead in the engineering area, and this work is still in progress. But we're really looking at how, how we can better target the procedures to get at certain things like operating experience, or to add flexibility to the program so that we, instead of for example, doing one particular review quarterly, we give the inspectors flexibility to do it four times within a year, whenever the appropriate time is. So that they can focus on, if they get an activity in progress or a risk taking activity that might be in front of them. So just adding some program flexibilities. And we've also --

MR. SKILLMAN: Anne, before you leave that subject, how do the licensees respond to that notion?

MS. BOLAND: We do engage the licensees as we go through the ROP changes. And I don't know, we had a series of public meetings in headquarters where we walked through with all external stakeholders, what their thoughts were, and got input. So they're aware, and I'm not sure. Gary, I look to you. I don't think in that area they had any significant pushback?

MR. SHEAR: No, nothing substantial.

MR. SKILLMAN: I can imagine a licensee would say well, you don't want to watch me while I'm operating normal, you want to watch me while I maybe stumble.

MS. BOLAND: Exactly.

MR. SKILLMAN: And I would rather have you watch me when I know you're going to be watching me, outside normal.

MS. BOLAND: Right, and we'd rather see the other.

MR. SKILLMAN: Yeah, I understand that. So that's my curiosity how a licensee might respond to that.

MS. BOLAND: Right. And on the, you know,

we have a very healthy, I would say, engagement with the utilities and other external stakeholders any time we make a change to the ROP. So there is that dialogue, ongoing dialogue.

MR. SKILLMAN: Thank you.

MS. BOLAND: We've been, like I said, a leader for the effort on engineering procedure enhancements. We've also taken a very active role in incorporating aspects of license renewal with an agent management program into our existing procedures. Just for, to institutionalize that process beyond the normal license renewal inspection process.

MR. SKILLMAN: Please say more about that. The members on the committee here are very engaged in this idea about life beyond 60, and how that is perceived. But also, the practical consequences of approaching what will be the license renewal amendment for the 61st year to the 80th year. So please speak to us a little bit about the view you might have or whether your people know what they're doing there.

MS. BOLAND: From the subsequent renewal, we have been engaged in working groups to feed in an inspection experience and our regional insights into both the policy efforts relating to any potential

revision of the law, so we have been engaged there.

The other aspect that I was referencing here was really the, integrating license renewal into our normal operating reactor inspection program such that, for example, when a piece of equipment fails that we're highlighting to the inspector consider whether this piece of equipment or this activity should be covered by the aging management program. So we've been trying to integrate and feed into that.

MR. SKILLMAN: Thank you.

MS. BOLAND: Stu, I would call, do you have anything you want to add in that regard?

MR. SHELDON: No, I have nothing.

MS. BOLAND: Stu's our lead, for license renewal here. Okay? All right. And then the last area is, we already touched on substantive cross cutting issues. I would just say there is a working group established to evaluate the efficacy, if you will, of substantive cross cutting issues, and whether or not they are influential in predicting, or whether they're leading indicators of licensee performance. Or whether they're effective in changing licensee performance.

And so, we're currently evaluating that,

and really looking at that process from beginning to end to see if changes need to be made and when it ages out. So I guess that would be all I would have, unless you have any further questions.

MR. SKILLMAN: Thank you.

MS. BOLAND: Okay, I'm going to turn it over to Bob Daley.

MR. DALEY: I'll start here. The first issue I want to talk to you about, and it deals with submerged cables in the Duane Arnold Energy Center. Just to give you a little background and context. My name is Bob Daley. I'm an engineering branch chief. I have the electrical engineering folks. I also have cyber security, fire protection and Mod 50.59.

October of 2012, the licensee discovered that they had some problems with their emergency diesel control cabling and that it was in a conduit filled with water. The way that they found this was because they had instrumentation that was behaving erratically. So they went ahead and they opened up the conduit, and found out that there was water in it. The root cause for the issue, they attributed it to a insulation issues, however there was actually no proof of there being insulation problems with it. The one thing that

is a fact is that the cables were under water.

They went ahead and replaced all the water, replaced, I'm sorry, replaced all the cable. Got as much water out of the conduits as they could, put new cables. But, as of today, I think those same, the new cables are still under water.

Because of this, we knew that there, we were also, we're also kind of in contact with the licensee and with the resident staff, and we knew that they're coming up with new issues associated with the other, there being other conduits under water. So, as the owner of Mod 50.59 inspection, I decided to send out a couple, a specialty staffed inspection team. Send them out to the site to actually look at these issues, looking at the modification that they did, replacing the cable and then having to have them go back and look at some of these other problems that they found, and how they were dealing with them.

MR. STETKAR: Bob, just for clarification, because I couldn't find it anywhere on the slides, I'm assuming these were underground or buried conduits.

MR. DALEY: Yes. A portion of them are, or portions of them were, they're between like the

reactor building and the auxiliary building.

MR. STETKAR: But these weren't conduits inside a building, were they?

MR. DALEY: Well, yes they were, yes.

MR. STETKAR: They were?

MR. DALEY: Yes.

MR. STETKAR: Okay.

MR. DALEY: They're not, they're not what you're thinking is they go off to a transformer --

MR. STETKAR: I'm talking about, you know, there's been a lot of concern about underground conduits or underground cables becoming wet. Were these underground? I'm trying to get my hands around how this could happen as late as October, 2012, given regulatory focus on this issue and the industry theoretical focus on this issue.

MR. DALEY: Yes, they are below ground level, but they are in the plant.

MR. STETKAR: They're inside the building?

MR. DALEY: They are actually inside the building.

MR. STETKAR: Okay. I wanted to make sure, I wanted to make that real clear.

MR. CORRADINI: So it's like Building X, Building Y?

MR. DALEY: Correct.

MR. CORRADINI: Not a parking lot or open tarmac?

MR. DALEY: That is correct.

MR. STETKAR: They're not in underground ducts?

MR. DALEY: That is correct.

MR. STETKAR: Okay, thank you.

MR. DALEY: The, what we found when we sent the modification, Mod 50.59 inspection team out was that there were numerous conduits filled with water. And the way the licensee dispositioned those cables immediately was that they did an evaluation to qualify the cables for submergence.

Well, if anybody who has a certain amount of history on submerged cables, they're a special animal. I mean, they're the type of things you use in the English Channel. You know, you pump in, put gas into it and make sure that you, you get oil in it to keep water out. I don't know of a single plant, and I've got a lot of experience. I don't know of a single plant in the country that has cables that are qualified

for submergence, for complete submergence in water.

So, the regional inspectors challenged the licensee. We challenged them on that evaluation, so the licensee now went back to the drawing board, we also challenged them, then, on the corrective actions to date. Because, as far as we could see, they still had cables under water. They hadn't gotten all the water out of the conduits. And our concerns, primarily, are on the wetting of the cables.

There's two things, if you look at the results of the summary report for the generic letter of 2007 01, one of the things that NRR has proposed is that the way you can resolve this issue is by drying out the conduit, drying out the cables, and doing some type of accelerated testing program. Testing the cables, making sure they're performing well.

MR. SKILLMAN: Before you go further, the way you present bullet two, my interpretation is there had to have been a modification prior to October, 2012, where they actually changed out those cables. So, is that bullet communicating that they did a mod and that they approved the mod under 50.59 and said it's not a licensing requirement. So they took out the original installed plant and put in this new cable.

MR. DALEY: You said prior to 2012. I think you mean 2013, correct?

MR. SKILLMAN: No, prior to 2012, because in 2012 they found the conduit. You did your inspection in 2013, and you found those same cables to be under water.

MR. DALEY: Correct. The, what they did, they didn't do a mod before 2012. And after 2012 what they did was they went ahead and replaced all the cables in that conduit.

MR. SKILLMAN: Now I understand.

MR. DALEY: Okay.

MR. SKILLMAN: And they did that under 50.59.

MR. DALEY: They did that under the modification process, and their screening of 50.59. I don't know whether they graduates to a 50.59 or not, but they never really solved the cable wetting issue.

MR. SKILLMAN: What it is, apparently from that second slide, is they chose to use cables that they thought they could qualify submergence for, and they used those cables and they ended up wet again.

MR. DALEY: Right. Well, their cable submergence evaluation was really for all, pretty much

all the cable in the plant. I think primarily, they have Carent cable. Now, does that answer your question?

MR. SKILLMAN: It does, thank you.

MR. DALEY: So the result of the Mod 50.59 inspection is we issued two non-tech violations, two were verbal, it's Criterion 16 for corrective actions. Another one was a criterion three --

MR. SKILLMAN: Design.

MR. DALEY: Correct, because it's safety related cable, and safety related cable was used in an application that shouldn't have been. It was under water.

MR. STETKAR: Bob, let me interrupt you because we're going to be talking about cables. Do you have any idea, anybody know where the water's coming from?

MR. DALEY: I think it's coming from the ground. I mean, they originally had a, they had a speculation that it could have been coming from the drains. But they, they, there might be some wishful thinking in that. I mean, they went ahead and they shut off their drains, you know, closed them up. And the conduit's still backed up with water, so it's coming

from somewhere, and it isn't coming from the drains. So it must be coming from the ground.

MR. STETKAR: So theoretically, if it's ground water, unless the ground water profile has changed, this condition has existed since day one?

MR. DALEY: That's hard to say. The conduits could have been intact. They might not have had a lot of ground water in it for years. But we know now that they have got to have a major problem with the water, I mean it's in a number of cables that are underground.

MR. STETKAR: Okay, thanks.

MR. SCHULTZ: Bob, what was the timing here? Is it October, 2012 licensing fines, then there must have been, between October, 2012 and September, 2013, an extent of condition evaluation. So, in terms of finding these additional cables that were filled with water, the conduit was filled with water, when did that happen? Did they find that soon after October, 2012, and then go into this project to qualify cables for submergence? Is that what you believe you found?

MR. DALEY: I think what they, essentially what happened, I'd like to say that they did all of them right away, but they didn't. And that's part of the

problem that we're seeing here. They found more cable, you know, the found more, they started going through and doing inspections and they found other conduits that were filled with water. And there was indication that conduits were filled with water, I found a picture of it.

But you can see the cables going into the wall, and you'll have like a fire penetration, you know a penetration plug on there. And the, and you can see the water from some of them. Some of them are probably just holding the water in, but some of them you can actually see, visibly see water coming out of them. So you know there's water in there.

So they might have gone to those, some of the ones that had, some of the ones that they could actually see the water in and for safety's sake checked them out. It's, it's has an added, there's added complexity to it because they have, you know, you have two sides to any of these conduits, right. One side is like in the turbine building, and the other side is in the reactor building, or it might be in between the reactor building and the auxiliary building.

And opening up certain conduits compromises their secondary containment integrity.

So it becomes kind of an issue, an iffy issue from an operability perspective, whether online or not, some of that's probably due to the lack of margin for secondary containment, which they probably closed it off a little bit, but it is what it is. I don't know if I answered your question though.

MR. SCHULTZ: That's fine. Perhaps we'd understand it better if you'd describe the non-cited violations in more detail, the two that were issued in September, 2013.

MR. DALEY: Well, one of them was a Criterion 16 and it had to do with cable, the cables, they had actually seen that the cable was in water. They had gone through and opened similar, when I said they opened one of the conduit ends, and drained it of water to the best of their ability. Put a borescope down and they found out that there was still water in this area because of the different slopes of the conduit.

So they couldn't get it all out. They also found that there was like mud that had kind of encapsulated over the cables. So they couldn't get any farther with the borescope. And then, they didn't want to open the other end, as well, because of operability

issues with the plant online. So we gave them a Criterion XVI on that issue because we felt that they hadn't, they hadn't got rid of all the water. They really hadn't addressed the issue for that conduit.

The second issue, and I can't remember the cable itself, the cable, if I'm not mistaken, was a Criterion III. Here's part of the problem with submerged cable issues. If they're not safety-related cable, you don't have a real in with Appendix B, the Appendix B clause is safety-related equipment.

So a lot of this stuff, like you said is out in the parking lot, right. And a lot of it is not, it might be very important to safety, but it's not safety related, so begin this, where do you write the, what do you write the violation on, right? But we had a lot safety related cables in there so we gave a violation on Criterion III, which basically says that for safety-related cabling, all of these, none of these cables are qualified for submergence and they're operating in a submerged environment. Therefore, the design, the application doesn't meet the design. So that's kind of a quick description of the NCV's.

MR. SCHULTZ: Thank you.

MR. DALEY: Sure. Knowing the problems

that we had in September, 2013, we talked to the licensee. Told them that we were less than pleased with the status so far of the cable wetting issue. And I went ahead and set up, worked with our division of reactor projects, and set up for another inspector, an electrical inspector to go out to the site in April to see where they were at on resolving some of these issues, knowing full well that they might not resolve them all until the operating system was fixed in the fall, October time frame.

When he did the additional inspection follow-up, he found a lot of problems. Basically, I wanted him to do a status check of where they're at. Now, the licensee, to their credit, they started taking it a lot more seriously. They assigned a dedicated engineer to the issue of wetted cables. They also put together a plan to go out and check conduits based on safety, the safety significance of the conduits. And also, to ultimately, get to all these conduits and see how big the problem is, see if they can get, how much water they could get out of them.

They did do that. But on the other side of the coin, there were a lot of cables that still had water, and they're still refilling up. So at that

point in time, we have not exited that issue yet, but we've debriefed it with the licensee. We've done a couple debriefs, but we plan to give them a cited violation on Criterion XVI for the corrective action program. The last time we gave them a non-cited; this time we gave them cited. So we're escalating our actions.

Some of the conduits that are known to have cables in water, as you can see on the slides, there are a number of safety-related systems here, very risk significant, very safety significant. And, as I said, fire seals show signs of water. As of a month-and-a-half to two months ago, there were at least nine conduits that still had not yet been opened. So, to the extent we still don't know the full extent of how many problems they have.

They've done limited testing. They've done testing, they don't have shields on these cables, so they're trying to do CDR testing which is more common, a test that they can't do, but they can do Megger testing on them. The cables that they've tested, for the most part, are found out as operable. They've had, I think, one low rating on an instrument cable, which they've replaced. That was about a year ago, maybe a

little more.

They also have a, just recently, well I'll get into that in my last, last piece.

MR. SKILLMAN: So, if I interpret what you just said accurately, they've done operability determinations on each of these instances, and in each instance except one, they've found operable. And on one, they found some form of degradation and they replaced or resolved it.

MR. DALEY: Correct.

MR. STETKAR: Just, you mentioned Megger testing. They've only done Megger testing?

MR. DALEY: That is all they've done so far.

MR. STETKAR: That doesn't tell you anything about the condition. If the insulation has failed, the cable will fail. It doesn't tell you anything about degrading.

MR. DALEY: If the leakage dried out.

MR. STETKAR: It's a leakage test.

MR. DALEY: It is what it is. It's better than nothing, unless you really got a drop in voltage, and then you'll ruin it.

MR. STETKAR: Well, but I mean, anyway

that's the problem with the testing that they've done.

MR. DALEY: And they've done that, I think based, primarily based on safety significance. They've done all their 4160. Any 4160 cable they find underneath water, they've done a Megger test on. And then, they've done SAM for any type of controls cabling.

So the next step is to go ahead and do an exit meeting for the cited violation, enforce the issue. The risk determination has resulted in a green, but that's due to a nuance in the SDP, because there's a statement on page one that says if you have an operability, if you don't have an operability issue, it goes into the green category.

MR. STETKAR: Now I get to ask the question I was going to ask after you stopped talking. But I have to ask it now. We heard earlier that several plants, units are in the column three because of risk significant findings in the, I think I heard numbers thrown around 10 to minus 5, 10 to minus 6. They were said very quickly. I'm kind of disappointed we don't have any risk experts in the large audience here today.

And yet this thing, where we're seen degradation of three trains of 4KV for RHR standby diesels, HPCI standby transformers has a green finding?

How is that determined through the risk significance determination process? Because true, no cables failed. True, no flooding ever occurred. It seems to me very strange that those two, in comparison, that the flooding should be so important to risk. And this known condition should be so insignificant to risk. So I'm really curious how your risk folks make those determinations.

MR. DALEY: Your, probably a better way of saying it, you pattern my frustration, as well.

MR. STETKAR: Okay. And that's, the reason I ask the question is we've had some discussions about the reactor oversight process in some of our meetings. We, generally, don't get involved in it very much. And we're, certainly some subset of the committee, especially the PRA folks, have been very interested in practice, in terms of how these risk insights or risk metrics are applied in practice during the oversight process, and the significance determination.

Now, and this seems to be, the contrast between the significance that's assigned to a flooding and the insignificance that's assigned to this condition, seems to be indicative of, perhaps, at least

some inconsistency. So that's why I'm trying to probe a little bit from your perspective. Because we don't, we don't have feedback from the regions.

MR. DALEY: Well, one thing just to take note of is that, you know, right now we haven't actually decided yet, so it is pre-decision.

MR. STETKAR: Okay.

MR. DALEY: So there will be a final determination. And we are having meetings amongst ourselves trying to make sense of some of the information that we have. You have, there's a couple different pieces. You got a Phase I that takes, for this type of issue, it's hard to punch a hole in an operability determination, because you're postulating at what could happen, right?

So you have that one statement that takes operability and put you into the green category. But then you get into another, you get into another pickle with a, even if you go into a Phase II, you start getting into an issue with okay, how do we accumulate, what type of data do we use, and where is that data, and what's good data and what's not bad as far as failure rates due to water.

MR. STETKAR: And yet, somehow you must

have projected some flooding frequency to determine that 10 to the minus 5, 10 to the minus 6 that was quickly thrown around. And I know doggone well people don't know how to do that. And yet, apparently, it's done.

MR. RAY: Can I just interrupt, John? You're probabilistic with a simple deterministic kind of question. Why is that something that's outside its design basis, in the case of this cabling, isn't inoperable unless it's proven to be operable? Why is the assumption seemingly made that we have to prove inoperability, and in the absence of that, it's operable?

MS. BOLAND: It's, correct, it doesn't meet its design, but it hasn't been concluded that it's inoperable.

MR. RAY: But you just said what I said.

MS. BOLAND: So that's great.

MR. RAY: Which is you are, this is something the ACRS needs to observe. We assume something's operable when it's outside its design until it's proven inoperable. Is that really what you want to say to us?

MS. BOLAND: Ken, maybe you can answer.

MR. O'BRIEN: Ken O'Brien, I'm currently

the deputy director for reactor projects, and in a week I'll be the director of reactor safety. If I could go to your question a little bit. The licensee has to have methodologies to identify the equipment their relying upon is operable. Anytime they have an indication of potential inoperability, they're require to evaluate that.

So they have to have positive indication to begin with that it is operable. And then they have to have information after that if they have a belief that it's inoperable or potentially inoperable and go at it. In the case of the wetted cables, while the design is not for the cables to be in a wetted environment, putting them in a wetted environment, I'll take the extreme example, for one second, does not preclude their ability to continue to operate and to function.

Putting them in that environment for 10 minutes does not, necessarily, preclude them from being able to perform their intended function. The agency focuses on the ability to do its intended function. What Bob has raised here is a very, very good issue. It’s they're in a condition that they weren't designed for, that we know has the potential, over some period

of time, to address it, to degrade that position to take it to inoperability.

What he's trying to do through his inspection technique is to identify one, that these conditions exist. Two, that the licensee's taking corrective actions to resolve it, and resolve it before it results in inoperability, or degrading conditions. That it's testing to try and identify it. You identify there's difficulties in doing that because of the way the system's set up.

And Bob indicated one of the things the agency's considering is we rely upon the licensee's corrective action program to address non-conforming conditions, they're required to. So we gave them a violation. We expected them to address it. As Bob indicated to you right now, we don't believe that they're addressing it was comprehensive and inclusive to ensure and preclude an inoperability showing up.

MR. RAY: In the meantime, however, you are assuming it's operable and it's --

MR. O'BRIEN: In the meantime, well it's not assuming, in the meantime, the licensee has demonstrated information that it is operable.

MR. RAY: All right, oh really?

MR. O'BRIEN: That's correct.

MR. RAY: I see. All right, well, then that's, I think goes back to an earlier question here as to whether we agree with that. But that's not the purpose of this discussion. I think your statement on the record is what we're looking for. As it describes how you look at it, which I guess implies to me that the agency doesn't make an operability determination absent the licensee's doing so.

MR. O'BRIEN: I probably would, I'd probably disagree with that statement in the sense that I believe that it's the licensee has a license to operate. We're here in charge of evaluating, being should they operate within that license. We have the ability to identify when we believe the licensee's conclusions are incorrect and to challenge on that.

And when we believe licensee has made an incorrect decision, we have tool to enforce, a whole tool chest of enforcement activities available to us, including orders to shut them down when we feel they're incorrect. So I --

MR. RAY: How are you disagreeing with what I said?

MR. O'BRIEN: You said that we don't make

an operability evaluation.

MR. RAY: That's what I said.

MR. O'BRIEN: If we believe the licensee's operability eval is incorrect, I mean, we believe we've evaluated technically that these are wrong, and they don't come to that same conclusion, we can take enforcement action. Which is based upon our belief and our assessment.

MR. RAY: I understand all of that. But the issue remains, I guess, and we should stop this now, that it's still an open question in my mind as to how we decide, as an agency, that we will determine that something which is outside its design basis is inoperable, putting the burden of proof for it to be operable on the licensee. But, until that occurs, it's inoperable.

MR. O'BRIEN: I'm not sure I caught the last part of that.

MR. RAY: Okay. In other words, it has to do with where the burden of responsibility is. And I know you've addressed that to some degree, and I don't want to prolong the discussion here now. But it does go to the question of when things, not just these cables, are outside their design, are we assuming,

until proven otherwise, that they remain operable? And that seems to be the case here, but I don't want to pursue it further. I don't want to get into an argument back and forth.

MR. O'BRIEN: If I can offer just one clarifying point. It was the word “assume” that you used. We require there to be objective evidence. The objective evidence goes back to an original testing, an original surveillance. But that can be called into question by the current conditions that are out there. And I think that's what Bob is doing with the staff.

MR. RAY: Well, I understand, but the testing took place over a period of time. There's a question as to whether the testing really shows operability or not and so forth. But let's not pursue it here.

MS. BOLAND: And on the risk question, you know as Bob indicated I think in his remarks. There have been discussions given to the point on, you know, we have an STP, we have a process. But, you know, to get through the first decision point it is, you know, is the equipment operable or not. And, but there has to, you know, internal questions, right, as to should we look at this for other risk drivers.

But currently our process would have us look at it as, you know, a particular way, but I know that there have been questions asked in that regard, and we'll continue to pursue those

MR. O'BRIEN: And just to follow one more aspect, part of what you point out here with the process when the licensee identifies a degrading condition and they expect to correct it. We instruct them to correct it and return it to the way it's supposed to be. In a case where we find that it isn't, as Bob indicated, we'll go back and look and evaluate were they're original corrective actions reasonable, and should they have done something different.

In a case where we feel that there needs to be more focus on that, we're considering that on the cited violations as far as them just finding it and bringing it to us, and us going back to them or evaluating that perspective. In the case, for example, a condition that reoccurs, part of the thing that the agency would look at is, is the licensee's corrective action sufficient over a period of time to make sure it's adequate.

Give you an example, historically, where a licensee did something over a period of time. And

every time they came back to it, it wasn't adequate. You would then expect them to shorten the duration of time that they're looking at it, and make sure that, the surveillance is supposed to prove two things.

One, that it was previously operable and able to perform its function. And two, that the duration between surveillances is sufficient. So that when you come back and test it a second time, it'll still be operable and able to perform its function.

Where they come back and they don't find it being able to perform its function, we expect them to take corrective action, and probably shorten that surveillance frequency so they can better understand the duration of the issue. Does that make sense?

MR. SKILLMAN: I think this has been a healthy discussion. But you're right, it's kind of hard to put a finger on the issue, to Harold's point, guilty until proven innocent or innocent until proven guilty is one that everybody listened to, because it has to do with how they do their job, how quickly they take action to return something to its pristine condition.

So, and I think another takeaway for everybody is how do you think about flooding? Do you

really think about the river coming up 50 feet? Do you talk about three gallons of water that affects the cable? It could be that three gallons of water that gets to the cable are actually more of a significant incident than the river coming in, depending on where your plant's located.

So it's good fact that everybody is standing by; it's a good discussion. Let's end it and keep on going.

MS. BOLAND: Okay thanks.

MR. DALEY: Okay, and just a reminder of time, so I'll go through my next piece. Really I did test this at 15 minutes.

MR. STETKAR: What you didn't do is anticipate the typical ACRS exchange.

MR. DALEY: That's all right, that's all right. Let me go ahead and, the next issue I want to talk about is the cable tray fire at Quad Cities nuclear plant. I actually have a flip chart here. I made sure I drew some stuff beforehand, but I'm a terrible drawer.

At Quad Cities, they had a steam leak. They're coming up out of an outage. They're starting up the plant. They had a steam leak in the heater bay, heater bay of the plant. And when the steam leak

occurred, they knew that they were having a steam leak. They sent operators down and saw there was a steam leak. They sent operators down several times to see the status of the area.

About a half hour into the steam leak, they actually had a fault on the 120 volt AC cable. Now, when talk 120 volt AC, but that's really low voltage, how are you going to see the fault on that? This is kind of a special deal. It's heating an instrumentation bus, four arc cable. It had, it normally had about 50 to 150 amps running through it.

The way the actual cable tray was, cable trays were, plugged, you have the top cable tray. You have several of these four arc cables going this way and down. And then you have a lower cable tray, now just imagine these filled up all the way to the brim with cables on top of it all. These were actually right at the bottom of the cable tray.

So what happened was 120 volt AC cable faulted. So you had a fault to this stanchion it's got to fault something. It faulted to the stanchion, took out the stanchion, they lost a stanchion and a half took out a whole bunch of these other cables with it. But at least five of the 120 volt AC cables were right there

and I call it a potpourri of cables.

They had, Quad Cities is a big plant, built similar, I say similar to a coal plant only because they have very little separation. They had 120 volt AC grounded. They had 120 volt AC ungrounded for the CPD. They had 41, they had 14160 cable in there. They had 120 volt AC in there. You had the whole plethora of cables in this cable tray.

So once you get something that actually faults, now you're talking about PVC jacketed cable. PVC has a, had a burning at low temperature. Well, you start getting arcing and you're talking about massive content, so a fire started in here. You had, what essentially happened is you had two cables that both fed different, were different feeds to the same instrumentation bus and both of these were damaged and arcing to each other.

So just imagine an arc welder kind of going zap, zap, zap, zap. And it just, this kept on for about two minutes. Kept on going back, kept on, these cables just, the two cables just kept on going back, dancing more and more and more dripping hot copper onto the lower tray area, cable tray here.

It kept on going back, back, back until it

hit a stanchion where there was enough conductor, enough metal to it, you know, and it all, you're basically going to be able to ground it, but there's enough metal on here, so it actually got a hard ground, okay?

Now, you could ask why, why did it take so long to take on the breaker? The licensee did look at the, at the setting on the breaker, found the breaker was set properly. The truth of the matter is I'm on a, sat on an expert panel for cable failures up at, it's called the PERC panel that research combined every NRC panel, about eight people. And we looked at a bunch of cable fire tests. One of them was a desiree, a desiree testing on DC cables.

We found, possibly the exact same thing, because we found that the fuses for the DC control cabling, they did not pop during this testing. And our view was that the fuses were so high, and the arcing, and you know, arcing is not like a hard ground. You get a lot of resistance in and arc, and it cleared, right?

So you never, if you're familiar with a circuit breaker, you'll have an instantaneous setting which is very high and you'd never clear that. Then

you have a timed over current setting and you'd never clear that either just because of the characteristics of arcing.

But, as all this was going on, this cable tray started burning up. They had a lot more faulting, a lot more, basically, kind of, the fire kind of regenerating itself. On the bottom, you have this hot copper, which essentially caused the PVC on the bottom tray to start on fire, as well. So now you have this on fire and this on fire, as well. The major damage coming on the, on the upper cable tray.

Ultimately, after a little, a certain amount of time, there's a suppression system, there's actually a suppression head that went off right above it. And, ultimately, that put out the fire. But, because of the obstruction, this one obstructing the second cable tray, it took a while.

So if you actually went down and actually looked at the damage, what you would see is you'd see a whole bunch of damage like right here. Tons of damage, major damage being done here where the arcing was. But the damage here, after the fire, extended all the way across, much farther than this area.

MR. STETKAR: And you actually had cable

damage in the lower tray? Or was it just insulation?

MR. DALEY: Absolutely. Yeah, we had to get jackets all the way off, I'm not quite --

MR. STETKAR: Is the insulation damaged, or is it just the jackets?

MR. DALEY: No, insulation and jackets.

MR. STETKAR: Okay, thanks.

MR. DALEY: On the other tray, you had severed cables, open circuits, everything you can think of. So, okay let me go to the next, to the next slide. Some of the things that came out of this event that, well one thing I do want to talk about. You may ask how, why would this thing fault during, when people are not electrically developed, well, I don't want to get into that, Bob and somebody.

MR. STETKAR: Anyway.

MR. DALEY: What ended up happening, if you have a pre-existing fault in a cable, let's just say this the conductor.

MR. STETKAR: Don't worry about insulting our intelligence. You'd have to bend pretty doggone low to do that.

MR. DALEY: The four arc cable, the four arc cable and cables in question were single conductor

cables, okay, you can have a, there's all kind of cables out there. You can have 12 conductors in a cable. And the twelve conductors would all be surrounded by a jacket.

But each conductor will have an insulation layer on it, and the insulation layer is to actually, you know, reduce the voltage from whatever it is here to zero on the other side. The jacket is there, and this where it kind of becomes, the jacket over time, there's been kind of an ignorance of what the jacket's there for.

A lot of people think that the jackets are for insulation purposes, to protect it. But it's also there to protect itself from the environment. This kind of comes into play with cable wetting as well. If you have an intact jacket, you don't have water getting into the insulation in the beginning, okay.

So, now the truth be told that this jacket's intact, and the actual insulation's intact. If you act speedily about this, you shouldn't get fault at all. Everything should just go on its own, and probably would have, but if you had some type of fault, some type of defect in the cable itself, then what could end up happening is over, with it just sitting here,

that defect was just over there, which is a pretty good distance, you get water in that, now you've got a conductor in it and you're going to get flash over. And that's what you have here, flash over from the ground and that would cause the arc.

So a couple things that I found that are a little different on this, this like I said, when I first saw the pictures of the cable trays, my statement was I see it, I've seen the look, and I go do cable testing, it actually fiber cables testing I've seen with that.

Bottom line is, first of all, we never, in the past we never assumed there was zero probability that a fire would start in a cable tray. Well, this did start in a cable tray. Also, we never assumed the cable tray, the fire would go to the cable tray alone, it was either go up or just stay put, that didn't happen here.

Arcing faults and over current protection have proved something to us from the expert panel that, you know what, you're not going to, necessarily, clear these faults right away. Also, it proved that open circuits will happen during a fire. We had a lot of discussion, and the industry takes for granted that

fact.

Protective relaying, I think I kind of talked about that. And the last thing that I just, I think comes out of this that I think is very important is with our aging management, we really don't talk about the jackets. But in this area, if you look at the jackets, the jackets are charred. They're charred because it's a high temperature area, and there's, a lot of them are cracked. Well you know, if you got, like I said, if you have an intact jacket, this isn't going to happen.

You know, I mean, it's possible you can get seepage into the jacket. There's that possibility. But most likely that isn't going to happen, because you have, and they have intact insulation, as well. The root cause for the event was actually a bad, inadequate bend radius going across that. That's the root cause.

There's a number of factors here. One factor is you got a four-arc cable and that's got other cables on top of it and you were going to get it to seep over to the wire rack. Part of the reason is because it depressed the cables, increased the possibility of a fault. Bend radiuses are normally the type of things or concepts that comes from initial cable pull, doing

their initial cable pull. But it's not, this is hanging at an area where there is a certain amount of tension down here that you will get in the cable.

You also had a lot of, you had years of the cable jackets being heated up and breaking apart, as well. Which, once that happens, you also have the possibility of the insulation degrading and that is really the end of this presentation and unless you can think of any questions.

MR. BALLINGER: So what you're saying is, is that, from an aging management point of view, there's an incipient problem here in the sense that the jacket could be intact, but the interior insulation could be degraded in some way, which would make it inoperable as soon as the jacket gets penetrated in some way.

MR. DALEY: That is correct. For the bend radius that we talked about, like bend radius and compression facts on cables, yes you can have a problem with the insulation. That jacket may be fully, for instance, let's assume, because we don't know this. You know, all that cable, it's all gone, so all we're doing is just postulating right now, right.

But at the, it's easier for me to come over here and talk about it. If I have a, if I have a bend

radius originally when, let's say when I pulled this thing, he jacket may be fully intact, but you might have, you know, have a void in the insulation. You might have put it under some type of, kind of a stress that weakened the insulation at some point there in the, there in the plant.

Also, if you've just got this hanging stress on it, ultimately, that could weaken the insulation over time, as well. Or these compression effects from the four arc cable. Because I do not that in the NC code, they say that you shouldn't put 4 arc, you shouldn't have other cables on top. So yeah, you can have these things in there and you can have these defects. And over time, that could be a problem.

It might not be a problem on day one because you have an intact jacket, everything's going to work properly. But now you add into the mix water, for instance, and that suddenly causes a problem. Now, the truth of the matter is the water, because like over here the water accelerated the fault. But if you have a defect in your insulation at some time, you're probably going to get a fault then, at some point in time.

MR. STETKAR: I've got to say it, like water turning.

MR. DALEY: Like water turning, correct.

MR. BALLINGER: But would they find this by Megger or something like that? In other words, I'm looking to the aging management issue.

MR. DALEY: No. That's the other point by the way, because I'm not sure there's a lot of testing that's necessarily going to find these certain things. There are certain things I could find if, there are, there's a plethora of, and I like this word plethora, but a plethora of testing out there. You've got partial discharge testing. You have timed runs, I mean, anomaly testing, we have a lot of different testing that tests for different things. The Meggers test, with the Meggers test is a form for want of a better term, it's more of a gross system test.

MR. SCHULTZ: Bob, I appreciate the detailed technical evaluation you've done, and the presentation today. My question is general, and that is are you satisfied with the sharing of this information within the industry and within the agency?

MR. DALEY: I think Quad Cities plans on sharing this within the industry itself. Sharing the information that they extracted from this fire. They had, we had a technical debrief and as I say, they were

going to do a follow-up with us and I've already talked to the operating experience, the operating experience folks at the NRR called me and I talked to them.

And I'm constantly talking to some research guys from the Central office and NRR, but like every other case we have had discussions on this. Now the question is what do we do with some of this information going forward.

MR. SCHULTZ: Thank you.

MR. SKILLMAN: Paul, do you have any questions?

MR. STETKAR: Just one quick one. Is, I don't remember, because I don't remember much. Is Quad Cities and NFP 805 plant?

MR. DALEY: They are not.

MR. STETKAR: They are not. Okay.

MR. SKILLMAN: Ladies and gentlemen, I would like to suggest that this next module could be fairly lengthy. There's a lot of information. So I propose a 15-minute break beginning now. You guys have to return in 15 minutes, please, but we are adjourned.

(Off the record.)

MR. SKILLMAN: We've got one minute. The meeting is now back in session. I would like to make

an announcement and a request. We have a sign-in sheet by the door to my right. And when you attend an ACRS meeting, it's FRN, you are asked to please sign that sign-in sheet. So may I ask those of you who have not done so already to please sign in. With that, back to you, please.

MR. SHAIKH: Good morning everyone. Glad everyone's back and they're refreshed from the break, and ready to proceed with the next presentation. So this presentation is about the Davis-Besse steam generator replacement inspection, which concluded earlier this month, on July 2nd to be exact. That was the inspection date.

And to begin with, I'd just like to introduce myself. My name is Atif Shaikh. I am senior reactor inspector. I was the lead for this steam generator replacement inspection. And to my right I have Jim Neurauter. He's another senior reactor inspector, and also one of the team members on this large inspection. Jim's primary role for this inspection was structural reviews on modifications, large core piping and et cetera.

So to begin with, I'd like to go into just the overview of the replacement steam generators at

Davis-Besse. What we see here is a pictorial of what are once-through steam generators. And this is the design at Davis-Besse. And, typically, I think these slides are in some type of pause. Okay. So what you see on your left-hand side is a schematic of the Babcock and Wilcox once-through steam generator at Zion.

This was used for the replacement steam generators at Davis-Besse. And these replacement steam generators are each 75 feet tall and 13 feet in diameter. Just to give you a physical sense of how large these components are, the replacement weight was 465 tons; that's dry weight. And that's a reduction of about 100 tons compared to the original steam generators at Davis-Besse.

The replacement steam generators use thermally treated alloy-690 material, as opposed to the alloy-600. And alloy-690 has actually more resistant, corrosion resistance. Next slide. Here is an actual picture of the Davis-Besse replacement steam generators. So, the team and myself were able to go out, and during our prep weeks, when we did the entrance exam back in December of 2013, for the steam generator replacement inspection.

And what you see over here is, you see these

replacement steam generators are one-piece steam generators. So they were brought onsite as one piece, and they were put inside containment, and installed as one piece, as opposed to two pieces that the needed to be welded together. We're having a little difficulty here with the presentation. It keeps, I have it on pause, okay.

So, basically, that's just a picture of the steam generators that were, and these steam generators were housed in the interim storage facility onsite. Can we go to the next slide, please.

And then I'd like to talk about the inspection objectives. So, as I mentioned, this inspection began in December, 2013, and it just recently concluded this month. The objective of this inspection, which was done in accordance with inspection procedure 50001; it's an infrequently performed inspection, was to verify that engineering evaluations and design changes are in conformance with the facility license, applicable codes and regulations.

And that the removal and replacement activities maintain nuclear and radiological safety in accordance with Federal regulations and industry codes

and standards, and that the post-installation test program is implemented in compliance with our codes and regulations. Next slide, please, Julio.

Some of the major inspection activities that were associated with this replacement inspection included a design and planning phase, which involves the review of these engineering evaluations, the design changes, which in the case of David-Besse, specifically refer to engineering and changes packages, mods that were physically implemented out in the field facilitating this steam generator replacement. And operating experience evaluation which, given our experience most recently, was very heavy emphasis from the Region perspective with regards to operating experience.

MR. SKILLMAN: And can you expand that discussion, please?

MR. SHAIKH: With regard to operating experience, I actually have a few slides that will talk about operating experience that I have for this.

MR. SKILLMAN: Thank you.

MR. SHAIKH: But --

MR. SKILLMAN: All right, happy to wait.

MR. SHAIKH: I appreciate it. And then,

another inspection activity, major activity was steam generator lifting and rigging. Again, this was another chance to, that we saw fit to incorporate operating experience out there given the qualifications that focus on nuclear with regards to the shatter problem.

Well, I'll just keep talking through the slides while they figure out the order, if you can go back one slide back, please. That's fine.

The other aspect of the major inspection activities includes radiological protection program controls. It is a very large outage. There is, they have many workers onsite, including temporary contract workers. And although it involves the transportation and eventual removal of contaminated steam generators onsite through the protected area, so radiation protection programs were verified by our radiation protection and inspector who was onsite during the course of this outage to determine what people might need in their plans.

Security considerations as well. A temporary opening was made in not only the protected area through the fence, but also the shield building to the containment vessel. So our security inspector

was onsite to ensure that we had implemented adequate compensatory measures for these temporary openings. Can we move to the next slide, please Julio.

Continuation with the major inspection activities, we now go to the second stage, which is the steam generator removal and replacement. So this refers to the actual cutting, welding and non-destructive examination. So this would be cutting away the reactor cooling system or RCS piping from the existing steam generators, and welding on RCS piping to the new steam generators, the replacement steam generators and then post-welding, non-destructive examinations that takes place after this cutting and welding activities.

That, of in itself, involves a plethora of activity, the non-destructive examinations. They include quality metric examinations, which is ultrasonic, surface examinations, visual examinations. And that is followed by pre-service examination before the reactor, the reactor pipe can actually start up.

Lifting and rigging activities, as I mention before, involve lifting and rigging from not only the outside, which involved the outside lifting

systems to take the steam generators from the storage facility up to the shield building, and then transport them through the containment opening into the containment, through the shield building opening into the containment vessel.

And once they were inside the containment, the steam generators were maneuvered using a puller-crane. Because that, of in itself, was a very large evolution given the size of these steam generators. And again, as I mentioned, the containment opening, we'll talk in more detail about the containment opening and some of the issues we had. And, as I already discussed, radiation protection controls implementation.

And, finally, we did, the final aspect of this inspection, major inspection activity, which includes the post-installation testing. This, the testing program and implementation, once the steam generators have been installed, and the plant is ready to start up. These are some of the secondary type, post-installation secondary type testing that takes place. Our resident inspectors are onsite surveying the work, they were there to observe some of this testing in accordance with the site's procedures.

MR. SKILLMAN: Before you proceed, that fourth bullet on the first group, radiation protection controls implementation, can you give us an idea of the radiation levels, that is MR per hour or so many feet of the expended steam generated as they were literally dragged out of the building?

MR. SHAIKH: I actually, yeah, I'll refer that question to Billy Dickson. One of his staff members were, was on the inspection team as our radiation protection specialist.

MR. DICKSON: I don't have detailed information on the actual dose rates associated with the steam generator move. But there were several instances where we saw one R, one to two R in grinding for the operations. The licensee did put the appropriate controls in place and air monitors. But specific information on dose rates I don't have at this point.

MR. SKILLMAN: And we don't need, I don't need follow-up. I was just curious whether it was 10 to 15 R per hour or 100 or 200 MR an hour or two liters. I was just curious after all of those years of experience with those generators, approximately what the radiation levels were as these old generators were

removed from their shield building and containment.

MR. DICKSON: I think I can actually get you that information before the end of this meeting.

MR. SKILLMAN: Thank you. I'd be curious. Please proceed.

MR. SHAIKH: Thanks. And this goes to now we're going to talk about the operating experience that I discussed earlier. So, essentially, the inspectors wanted to incorporate operating experience into this inspection, and we also have the licensee who addressed to us the operating that they have evaluated with regards to specifically, San Onofre Nuclear Generating Station and their steam generator experience, Oconee and Three Mile Island.

What you'll notice between these three plants, Oconee and TMI both involve Babcock and Wilcox once-through steam generators, and SONGS, San Onofre, involves re-circulated steam generators; two completely different designs. So the ones, Oconee and TMI steam generator experience is somewhat more applicable to the Davis-Besse once-through steam generators as opposed to the experience at SONGS.

But, nonetheless, we reviewed the operating experience whether there's any relevance

associated with the Davis-Besse steam generators, and also asked the licensee to address specific questions on how, some of the issues that they had with their replacement steam generators would not affect the Davis-Besse design for the replacement steam generators.

And I can get a little more into detail if you'd like with regards to the operating specifically with that.

MR. STETKAR: It's kind of interesting to me that you focused on SONGS and not the vast majority of other plants that have also replaced steam generators. Could you expand on why SONGS? Because the steam generators are, obviously, the designs are entirely different.

MR. SHAIKH: Right. And that's an excellent question, which is why we also focused on Oconee and TMI.

MR. STETKAR: But many other plants have replaced steam generators. So my question is why didn't you also focus on the operating experience from all of those other plants? Why SONGS?

MR. SHAIKH: That's an excellent question. The reason we focused, not necessarily on

SONGS, but I'm going to focus upon Oconee and TMI --

MR. STETKAR: No, I see SONGS up there, so I'm asking you why you focused on SONGS and not all of the other Westinghouse plants that have replaced steam generators. There have been many Westinghouse plants that have replaced steam generators.

MR. SHAIKH: Right.

MR. STETKAR: They've cut holes in containments. They've moved heavy loads.

MR. SHAIKH: Right.

MR. STETKAR: They've done welding and cutting.

MR. SHAIKH: Correct.

MR. STETKAR: So why didn't you focus on the operating experience from those plants? Why did you focus on SONGS? That's why I'm asking.

MR. SHAIKH: Okay. I understand your question now. The reason why we focused attention on SONGS, which is a particular re-circulating steam generator, was due to the particular mechanism that resulted in the degradation of SONGS, which was in plane vibration of the steam generator tubes due to the elastic instability.

And one of the things that, one of the

outputs that came out of the analysis post SONG's degradation was that industry had not, necessarily, taken into account in plane vibration. And that's something that we wanted to take a look at that. Are licensees now incorporating that lesson learned, whether it be a once-through steam generator or a re-circulating steam generator with regards to in plane vibration and how it can affect elastic instability.

MR. STETKAR: Thanks. That's a fair answer.

MR. SHAIKH: So, more specifically, we tried to understand developments of Oconee and Three Mile Island with regards to Davis-Besse. Both Oconee and TMI, again, Babcock and Wilcox designed once-through steam generators, so the correlation is therefore an apples to apples comparison.

One of the things that came out of the Oconee experience was that the tube degradation involved loose tube in the tube support holes. And the tube support holes are, essentially, they're tube support plates that are arranged up to the height of the steam generator at different levels and the tubes go through these tube support plates, and there's holes through which these tubes go.

Davis-Besse addressed that concern by employing a somewhat more tight, dynamic set up, so the tubes are not in contact with the tube support plate, and there's an offset between the tube support plate arrangement. So you don't, necessarily, have to, you have tighter contact, actually, in the Davis-Besse steam generators, as opposed to what you have in the Oconee steam generators.

But when there is some vibration, you get less threading between the tubes and tube support plates. So that was one lesson learned that Davis-Besse incorporated into their Babcock and Wilcox design for the once-through steam generators.

For TMI's tube degradation, what was observed as part of the operating experience was that a greater than optimum number of unrestrained free span between the tube support plates. In total, the TMI once-through generators had 15 tube support plates. Davis-Besse actually has 16 tube support plates. So what that, essentially, does, it reduces the effectiveness between each tube support plate, and you now have less free span in which the tubes can actually vibrate and cause this threading or degradation from the outside and your tubes.

MR. BALLINGER: Excuse me. I have a question.

MR. SHAIKH: Yes.

MR. BALLINGER: I just noticed this, and I probably should have noticed it a long time ago. But this diagram of the steam generators is a low-resistance carbon steel tapered inlet support plate. Carbon steel.

MR. SHAIKH: Right.

MR. BALLINGER: Is that true?

MR. SHAIKH: This is?

MR. BALLINGER: The first diagram there. Page 20.

MR. SHAIKH: Got it. Okay. So where are you looking at that?

MR. BALLINGER: It says low resistance carbon steel tapered inlet support plates.

MR. SHAIKH: That is correct. This once-through steam generator diagram is actually taken from the Davis-Besse steam generator replacement itself.

MR. BALLINGER: Okay, I hope we're not reinventing, or re, we're not going to be subject to history. That's what caused denting in the previous

earlier steam generator steam tubing designs.

MR. SHAIKH: What specific ones are you referring to?

MR. BALLINGER: Well, all of them. There's a bunch. Carbon steel support plates.

MR. SHAIKH: Okay.

MR. BALLINGER: The newer steam generators, at least the Westinghouse ones that Westinghouse makes definitely are not using carbon steel support plates.

MR. SHAIKH: Okay. And I can actually follow-up with you on that.

MR. BALLINGER: That would be great. I'd be curious to know their reason.

MR. SHAIKH: Oh, most definitely.

MR. BALLINGER: I mean, at the zero silence treatment, you know, their chemistry is different because of the once-through steam generator. But --

MR. CORRADINI: I guess in response to this issue, but I'm, so I'm going to say this and then, I'm still not sure, in this case, if this is a, is this considered a safety issue? Or is this you're following to make sure they follow ASME code in terms of how they

do their re-design and re-installation?

MR. SHAIKH: What this inspection is going on to do is make sure that the licensee is implementing, not only their own procedures, but obviously what the industry codes and standards are, it includes the ASME code when they actually do the installation of these steam generators. So it's not in response to any safety concern.

MR. CORRADINI: Okay, I didn't think so. I just wanted to make sure.

MR. SHAIKH: Absolutely. That's one question.

MR. CORRADINI: So that if I take you back to where we took you off track when you say you went from 15 to 16, that's a design change. Does it fit within the code, the allowable code standards? That's what, I guess, would be the comparison line?

MR. SHAIKH: Does the change from 15 to 16 --

MR. CORRADINI: Does it all just fit within the design standard, I guess, is what I'm asking?

MR. SHAIKH: We're going to ask the licensee if it fits in that evaluation which the inspectors reviewed.

MR. CORRADINI: Okay.

MR. SHAIKH: When they made changes from the original steam generators to the replacement steam generators, and if there were any significant changes. Now, if anything, the use, the going to 16 tube support plates is actually a new and more conservative variation, as opposed to going with fewer tube support plates. And that's one of the criteria's also that we're making to understand what the licensees are going to accomplish at this time.

MR. CORRADINI: And then, just to finish it with Ron's question, within ASME, what Ron just said, I was a bit surprised, too. But I didn't know. Is that still within the ASME standards allowed to do carbon steel? That's what I want to know.

MR. BALLINGER: You can use whatever you want. Whether it's prudent or not, that's a different story.

MR. CORRADINI: Okay, fine.

MR. SHAIKH: Great. And that's actually a good point. I mean, the licensee can make whatever modifications they need to for these replacement steam generators, and that's why we review them so we would understand.

MR. CORRADINI: Okay. Thank you.

MR. SHAIKH: Where we're at.

MR. SKILLMAN: But let me ask this, you opened a subject, did 50.59 and it seems to me that there can be an attitude, this is like or like, this has all been a part, when you change the number of tube support plates, you're actually changing the dynamic differential pressure on the steam liner. I mean, you've got 13,130 tubes, approximately, connected to the support plate in the B&W steam generator you feed inside, down goes through the tube tunnel and it doubles down to share the tube support plate.

You've got another increment to help you, and so the question is when you reviewed 50.59, did you also review the accident analysis for a main steam line break? I mean, you had to tell the field the extra tube support plate provides in terms of trying to pull the tube on or off on the double feed, of having that one extra tube support plate, it's a double feed, is that steam going to flash and you're faced with B plumbing. So in the 50.59 review, what could you use to get to the main steam line break impact on the internal steam generator?

MR. SHAIKH: What you're referring to is,

basically, the secondary site analysis with regard to the main steam line break.

MR. SKILLMAN: It is?

MR. SHAIKH: And what we did was we were in discussion with NRR with regards to any licensee or bend radius breaks that were occurring for David-Besse with regards to certain aspects of the steam generator replacement. And secondary site volume was one of the consideration, including the main steam line break. So some of the accident analysis was actually done by headquarters and NRR concurring with our steam generator based on inspection.

So it's not something that we particularly looked at in terms of a main steam line break accident analysis to change the differential pressures and how that affects the secondary site, but that was something that was looked at from the headquarters side. So we coordinated very closely with headquarters and NRR staff. Just wanted to make sure we weren't duplicating efforts.

But that was something that was addressed by them. So I can't speak to specifics of that. But I can definitely when we get back, get, follow-up with you on that.

MR. SKILLMAN: I'd be curious whether or not headquarter's evaluation had a close look at whether that flow was supported by --

MR. BALLINGER: There's another comment I had with, if I recall the very early B&W once-through steam generators had a problem where they set up a standing wave, in effect, in the steam pipe outlet. And that caused excessive vibrations feeding back into the steam generator. I'm assuming that what the design, made sure that that was not an issue. Because they now have different support plates, and a whole different design.

MR. SHAIKH: Right.

MR. BALLINGER: Whether or not that sort of natural frequency of the system is not such that we run into trouble there.

MR. SHAIKH: Right. For the HFC specifically, we tried to stick to the original steam generator design as much as possible. And they did not experience any issues with resonant or retaining waves being created, and the tubes vibrating or oscillating too excessively displace it.

In addition, the inspectors ourselves looked at flowing through vibration analysis that

Davis-Besse produced for its replacement steam generators, and basically one of the coefficients that they use is the possible velocity divided by critical velocity and that generated the fluid elastic disability ratio. So the fluid elastic disability ratio shall be less than one in order to preclude any event of fluid elastic instability causing tube degradation.

In the case of Davis-Besse for their fluid use vibration analysis for the replacement steam generators, they were always under the ratio of one. In fact, the most limiting condition was right around .81. So it's still less than one, so it should, theoretically, preclude the event of fluid elastic instability from causing excessive tube degradation vibration.

One other aspect I wanted to talk about on the topic of operating experience is that, as an entity, as a whole, we have pockets of higher understanding and specific skills. Some reside at headquarters, some within the region. So what we tried to do for this inspection, and also as Cindy alluded to earlier, in the earlier slide, there was a Prairie Island inspection that preceded the Davis-Besse steam

generator replacement inspection.

Is that we reached out to NRR to understand if there were any short-term lessons learned that we can incorporate in the quick turnaround for our inspection numbers. And these were lessons learned that, perhaps, we can incorporate from the SONGS steam generator issues. And also, if there's any good practices that we can incorporate from other regions that have implemented steam generator replacements recently to understand the differences.

So we reached out to headquarters and NRR. And we also reached out to Region IV to understand if there's something that, outside of inspection procedure 50001, or perhaps within it, we can do differently. So, in that healthy dialogue some recommendations did come from NRR, which included, obviously, paying closer scrutiny to 50.59 evaluations to understand if the licensee had adequately dispositioned not only its screenings, but the evaluations if it did screen and then it required an evaluation.

And ask the questions with regards to those changes that may have warranted the licensee to perhaps consider a license amendment request, but rather they

went with the evaluation. And there were, you know, cases where the licensee thought they could go, they might need a license amendment request, but it was an evaluation, or vice versa.

So we paid closer scrutiny to those. We also paid closer scrutiny to any minority deltas or differences between what the licensee envisioned as their actual design of the new Besse steam generators and what was actually delivered to them. Because during the course of this designing and fabrication of the steam generators, was constant dialogue between the licensee and their vendor.

And one of the lessons that came out of SONGS was that there was considerable dialogue between Mitsubishi and San Onofre with regards to the design of the steam generators. And then there were changes made during the course of the process. So we wanted to understand if that was applicable for both steam generators that we replaced here at both Prairie Island and Davis-Besse. So we paid close attention to that, as well.

And so I just wanted to highlight that there was good cooperation with not only headquarters staff, but other regional staff to understand if we

needed to incorporate lessons learned and good practices moving forward.

Now I'd like to discuss some of the issues that were identified during the course of this inspection. The reason we have these particular two issues up there is that these two issues resulted in enforcement action. And we recently just issued the report for Davis-Besse. That report number is 2013-010. So that's, again that would be 05000346 2013-010, and the report was issued yesterday and made available in-house.

And in that report you'll find the details of these two particular findings and non-cited violations. So I'll just briefly discuss both the void and the rebar damage. So, essentially, in order to accommodate the steam generators to be removed from the containment vessel and new steam generators go in, the licensee constructed a temporary access opening in the shield building.

And the shield building is a freestanding structure. It's a concrete structure. And there's approximately a four foot or so annulus and then after that you have your containment, that metallic containment vessel here. So, basically, the temporary

access opening that was constructed in the shield building involved a hydro demolition process in which high jets of water are used to blast away concrete.

In the shield building, would be approximately 30 inches in depth is the shield building and during the course of that hydro demolition, the licensee identified that there was a void. And this void was approximately 25 feet in length, and with a 12 foot mouth opening, and 24 inches in maximum depth, at it's maximum location, as determined by the licensee.

So one of the questions that we asked was, with regards to the operability of the shield building given the existing of this void. The licensee performed a task operability evaluation to determine whether the shield building could perform it's intended design functions given the existence of this void, because the void was actually due to restoration that took place in 2011.

If you remember, in 2011, the reactor vessel head was replaced, and another shield building opening construction was made and new concrete was poured. This current opening, or the current opening in 2014 was encompassed within that 2011 shield

building opening. And I actually have a schematic that actually highlights that.

So you see here the 2011 replacement opening. And then you see the 2014 steam generator opening, and it's encompassed within the 2011. So basically, this opening will be freshly poured concrete in 2011 so new concrete, and the licensee didn't find the void. So the void was present since the 2011 restoration of the shield building.

Upon further evaluations by the NRC inspectors, it was identified that the licensee did identify this void in 2011, and they did repair this void. But they did not completely repair the void, because the licensee did not, basically, chase the void to the backside of the shield building wall to determine if the void had, indeed, been adequately repaired.

And therefore, we approached this issue with concern, as not only a performance deficiency but a violation of NEC Criteria 16 corrective action for the licensee's failure to correct a condition adverse to quality. So it's not that the licensee did not identify it. They identified it, but they did not correct the void as they should have completely repaired the void.

MR. CORRADINI: So, just so I understand, so the big square is the original opening. The green square is where they put the RPV head through. The brown square is where they currently cut it in '14. Where's the void in relation to the overlap?

MR. SHAIKH: Excellent. So the void is right up here towards the top of the shield building. The shield building opening, sorry. So the void is right up here. And it was 25 feet in length, and approximately 24 inches at it's maximum depth. Because the voiding was non-linear so at it's maximum depth they were able to identify it was 24 inches.

MR. CORRADINI: Okay, so the brown is actually where they put in the '11 opening?

MR. SHAIKH: No.

MR. CORRADINI: We're trying to understand all those zeroes.

MS. PEDERSON: The little green edge around the brown that represents the 2011 opening.

MR. CORRADINI: Ahhhh.

MR. SHAIKH: Do you see that dotted line?

MS. PEDERSON: The little green edge.

MR. SHAIKH: Yes.

MR. CORRADINI: They went through the

same, they went through the same hole?

MR. SHAIKH: Exactly, through the same hole, but smaller than the 2011 hole. So it's encompassed within the 2011 hole.

MR. CORRADINI: And the void is sitting on the periphery or through the --

MR. SHAIKH: The void is sitting, primarily at the top.

MR. CORRADINI: Okay, that's what I was trying to, I'm trying to understand where it was.

MR. SHAIKH: Exactly. By extending out from the inside surface of the shield building in depth.

MR. CORRADINI: About 24 inches at it's max.

MR. SHAIKH: That is correct.

MR. CORRADINI: And the function that is weakened is missile protection, external missile protection?

MR. SHAIKH: That's one of the functions.

MR. NEURAUTER: The shield building has three functions. One is shielding. Another one is control and release of radiation into the atmosphere during an accident through the system. And protection from environmental lode, earthquake, tornados.

MR. CORRADINI: So it actually has a filtering function besides missile protection?

MR. NEURAUTER: In case of an accident.

MR. CORRADINI: So it's just shield in terms
of --

MR. NEURAUTER: There's a shielding function --

MR. CORRADINI: All right, I got it. Thank you very much.

MR. SKILLMAN: Let me ask this, you mentioned that you issued a violation because yes they did identify the flaw, but they didn't chase it to its end. Would another plant that might find a flaw today chase to the end, or, and the reason I ask is is this an ASCI code issue, or licensee may have done what they thought was sufficient.

That they didn't do what was sufficient because there's an inadequacy in the code? Or was it an adequacy of their judgment as to how far to proceed?

MR. SHAIKH: Right.

MR. SKILLMAN: In other words, could another utility fall into the same situation unknowingly?

MR. SHAIKH: Right. No, and those are great questions. Essentially, what the licensee also did, as part of this, and I wanted to mention was that they performed an apparent cause evaluation to understand why they ended up in this situation to begin with. And one of the things that they identified was that the direct cause of why they were not able to repair this was lack of flowable concrete.

So it was actually, they wanted us to look at it from a high level perspective. The quality control issue was actually the actual concrete pour itself. That the concrete was not able to penetrate the entire depth of the void that was identified in 2011. Now, as part of that repair, which is essentially corrective action, the expectation, the requirement is that the licensee repair that condition or correct that condition that affects quality.

What the licensee did in this particular case was they removed the forms, and the forms are put in place to pour the concrete. So they removed the forms from the outside surface, inspected the surface, and did not find a flaw, a void. Excellent. You now go to the back side and remove the forms to understanding if whether your concrete penetrated, and

you do not have a void back there.

And they knew that the void extended all the way back there. But they did not remove that form. They left those forms in place in 2011. It was an engineer decision, well before the outage even began, to leave the forms in place. It was a permanent modification. Inspectors actually reviewed that modification, as well, during this current outage.

And the licensee, so that's where we challenged them on their lack of questioning attitude with regard to was this a conservative decision to, although you intended to leave the forms back in place now that you realized you do have a condition adverse to quality that may potentially reach to the outside, perhaps you remove these permanent forms to understand you have rectified the issue, and the proceed forward.

So this was something where we had had, this is the cross cutting aspect that we identified underlying the actual performance deficiency. That was lack of a questioning attitude. Not using conservative bias when making the decision to not remove the forms and inspect. Because, in hindsight which is always 20/20, had they removed these forms, they would have identified that they did not adequately

seal this void and would have fixed it.

MS. PEDERSON: It was an execution issue, right?

MR. SHAIKH: Correct.

MR. STETKAR: And did the region perform a similar self-evaluation to find out why you accepted that condition?

MR. SHAIKH: Did, I'm sorry I didn't hear you.

MR. STETKAR: Did the region inspectors perform a similar self-evaluation to understand why you accepted that condition, and didn't also have the similar questioning attitude about the forms being left in place, and what they might hide?

MR. SHAIKH: We did look at our processes to understand if there's some things that we can do differently to ensure that the licensee has adequately restored the shield building. And, in this particular case, not only repaired the void, but when they actually plotted outage or they're coming out of the outage through restore the shield building.

And that included to verify, visually, by performing inspections of the outside and inside surface of the shield building to understand that there

are not any voids present. And both Jim and myself actually towards the annulus and the outside of the shield building. And I can show some of the pictures that we took that show not only the void area that was repaired, but the surface conditions --

MR. STETKAR: I understand what you're doing now to make sure that you have confidence. What I'm asking is how did it get past you back in 2011 when you, essentially, said you inspected and accepted what they were doing?

MS. PEDERSON: Let me state the peace of that. As you know, our sampling, our inspection process is a sample-based process. And we have reflected upon this, but we have not, we did not conclude that we made an error in not identifying this at that point. We certainly could have had an opportunity to select and look at that in more depth, but we, we made a selection based upon the information available and what we think the appropriate priorities are.

So, could we have learned something different? One could probably say yes. But we have to make judgments on our expenditure of resources, and we try to prioritize what we think is our most bang for

the buck, if you will. So, yes, we've reflected upon the missed opportunity.

MR. STETKAR: Thanks.

MR. BALLINGER: Back up one more step, though. On what basis did they allow, how did they justify leaving the form in place in the first place?

MR. NEURAUTER: They justified leaving the form in place by analysis. They, when they put the modification for the reactor vessel head replacement, they originally were going to do that as part of the steam generator replacement. They had cracking issues in the reactor vessel head. So they accelerated the pace of modifying the head. And they did that in 2011.

Originally, they were going to do it as part of the steam generator replacement, so they had, they knew they had to make another construction opening in the shield building. So they left the forms in place as a glass shield, during the hyper demolition, so it was an engineering decision to leave that form in place. They didn't, they can't analyze that.

MR. BALLINGER: But, so they were eventually going to take that form out?

MR. NEURAUTER: They were eventually going to take the form out, after they did the access

construction opening. The form comes down. That's when they identified that there was a void on the --

MR. BALLINGER: Okay, so they weren't going to leave that form in there --

MR. NEURAUTER: No, no, not totally, no. And as you'll see in this slide, the form is gone.

MR. SHAIKH: Right. That's what I just wanted to clarify. There are no forms at Davis-Besse anymore, on the inside or the outside surface. And, as Jim alluded to, the whole point was for them to leave the forms in place to, as, to protect the containment vessel from this hydro demolition process.

MR. CORRADINI: So, I have to ask this. It's just, so besides pointing fingers, that's all past. So, with the form in place, is missile protection increased and is shielding increased? Was that included in the calculation, by leaving it in place?

MR. NEURAUTER: The, when they did their operability evaluation to demonstrate that the shield building with the void was fully functional, they didn't take credit for the vessel shield. They could have, but they did not.

MR. CORRADINI: Okay, got it.

MR. SCHULTZ: So, as I understand it now from what you just said, in terms of their evaluation, they did an evaluation before the repair that the void, in place, the backing forms would be adequate. And then they proceeded with the repair, and based on what was found out, the repair was incomplete.

MR. SHAIKH: No. Just a difference in the time line. So the evaluation that we're talking about, the operability evaluation, that was done during this recent outage. So once they identified that a void is present currently, and that this void has been present since the 2011 shield building restoration, they performed a task operability to understand whether it would have, was capable of performing the design function during the time the plant was operating with that void present.

MR. SCHULTZ: Understood.

MR. SHAIKH: Back in 2011, when they first identified the void during the restoration process, they didn't do an evaluation because it was simply go repair the void and make sure the concrete seals the void, and that's what they did.

MR. SCHULTZ: I understand. Thank you.

MR. SKILLMAN: Let's pick up the pace.

We've got about 30 slides left, and we've got on the counter 15 minutes.

MR. SHAIKH: Absolutely. I appreciate that. And this is just a picture showing the annulus site and up here where you see some of this area, that's where the void was, and the void was repaired at that area. So we were up on the scaffolding ensuring that no void was present.

The other issue that I wanted to talk about was rebar. That's the shield building rebar that was damaged during the hydro demolition process in constructing this shield building opening. Over here you see some of these vertical rebar that run along the span of the shield building opening. And the have been sheared off on these ends.

And there's a few more pictures. Here's another rebar that hadn't completely sheared off, but you see it's broken. It's basically just hanging on for its dear life. And here's a horizontal bar where, again, a rebar has been sheared off. Now, this was unexpected during the creation of this temporary shield building opening.

So the licensee needed to understand exactly what was at play here. What was the mechanism

behind why this, why these rebars failed during the hydro demolition process. One of the things that the licensee did was, again, they did an apparent cause evaluation to understand the causes surrounding the failure of the rebars.

We included laboratory testing that was done up in Cleveland and I flew up and observed some of this tests in progress. This was metallurgical analysis to understand what the mechanism was for this failure. And what the, essentially, found was that it was a fatigue cracking that resulted in the failure of the rebar.

In total, 57 locations were damaged, some of them, like I said, were actually sheared off, others cracked but left in place. And others were actually bent. And the T-crack bending was caused due to the high stress, low cycle cyclic loading induced by this hydro demolition process.

At the end of the day, when this robot latches onto the shield building from the outside, you have a dual jet head that is spinning at high RPMs and blasting high pressure water, up to 20,000 PSI. So at any given point, we'll see a periodic pulsing force, and that causes the bending back and forth of the rebar

that's running vertically along the length of the shield building opening, and horizontally, as well.

When you have rebar that's restrained, either imbedded in concrete or imbedded at what these are, these are mechanical couplers that, basically, couple together two sections of rebar, bunching them together. Not sliced, but actually joined together. It acts as another restraint point.

So, considering a stress riser, if you will, so you have rebar that's restrained at one point. You have high cycle, I'm sorry, high stress, low cycle, coupled with extremely low temperatures. This was done in February, in the Midwest. So we had a pretty healthy winter here this past winter season.

And the fact that you had these long lengths of rebar running across the span of the shield building. Those were the contributing factors. And the direct factor was, again, the high stress, low cycle of fatigue that caused it, along with that addition of that coupler.

MR. SCHULTZ: Did they do hydro demolition in 2011?

MR. SHAIKH: So, yes they did in 2011. But what they did different in 2011 is they took the

hydro demolition up to a certain point. After that point, they lightly chipped away the concrete, so as to not expose the rest of the shield, the rebar lattice structure, if you will, to the hydro demolition process itself.

Now, typical industry guidance and operating experience will show that hydro demolition is not supposed to damage the rebar, even if you hydro demolition all the way through, it's not supposed to damage the rebar or cause it to crack or fail in this fashion.

But what the licensee attributed it to, main contributing factors were not only the very cold temperatures that were experienced, but also the fact that you had these mechanical couplers that, basically, take two pieces of rebar, and they apply a mechanical load, and crimp them if you will, to hold them in place.

So that acts as a stress riser. So this is why, when you look at all these pictures, you will see it broke right at the interface of the mechanical coupler to where the mechanical coupler and the rebar extends out into the shield building opening. The actual mechanism, fatigue cracking, was identified using scanning electron microscopy, I was able to

observe some of that testing in progress over there and some of the SDF images that the licensee was able to share with us. And all of these results bled into the licensee's apparent cause evaluation.

Now, moving forward, what I wanted to talk a little bit about was the performance deficiency, the non-cited violation, and the finding we, the inspectors identified due to this rebar damage. In order to qualify the rebar, once the licensee knew that they may have potentially damaged all the rebar that was in the opening, we know 57 locations were actually damaged. But others could have been potentially damaged.

The licensee did a non-descriptive examination that included ultrasonic examination, scanned from one end of the, from each end of the rebar, going 24 inches straight into the rebar. So this is zero degree transference shooting straight in looking for flaws originating from the outside of the rebar.

And this was one method of evaluating whether the existing rebar can be left in place and new rebar attached to it, and the shield building can be returned to service. Or whether the rebar has to be taken out and chipped away, and completely removed and new rebar put in. So this was very critical to the

safety related structure. And we need to have assurance that the licensee has adequately qualified each section of rebar.

So I was actually out there while they were performing some of the field ultrasonic examination. And I identified performance deficiency in that the licensee had not considered near field limitations when using this ultrasonic technique. Essentially, the licensee had not calculated the near field distance, which is different on the frequency, the diameter of the rebar, and also the velocity of sound in this particular material, which is carbon steel.

So because the licensee hadn't calculated that, by my calculations it was approximately three inches. So approximately three inches or rebar section the data was unreliable in the sense the licensee could not definitively state whether there was a flaw in that area, or whether there wasn't. And that would be key, because that's where they would be coupling the new rebar and moving onwards with the shield building.

So the licensee entered that into the corrective action program. And what came out of it is that the licensee performed a magnetic particle

examination from zero to five inches of each rebar end to qualify whether there were any existing, to understand if there were any flaws in that first few inches of the rebar.

So that was the, and the non-cited violation was Appendix B, Criteria 9 controls special processes. So that was identified out in the field while we were observing the licensee performing the routine examination. And then, I have a few more pictures.

So that concludes the steam generator replacement inspection with regards to the inspection activities and the issues that we encountered and that resulted in enforcement decisions on our part. And as I mentioned earlier, that inspection report has been issued at the --

MR. SCHULTZ: With the in field testing that was done, what did they find? What were the findings? Did they have to remove all the rebar?

MR. SHAIKH: Right. The in field testing, what the licensee found is there were a number of rebar locations that did not meet the acceptance criteria for the ultrasonic testing. So those rebars were actually removed and replaced. Other rebar that

did not, that passed the ultrasonic, the volumetric examination. But physically, appearance-wise, did a visual examination, they seemed a little out of shape, a little bit bent because the steam generator movement itself damaged some of the rebar that was sticking out. So they removed those rebars, as well.

So, in total, the licensee did remove a number of, replace a number of rebar sections, and others were left in place. I don't have the exact number with me as to how may rebar sections were replaced, but I can definitely get that for you.

MR. SCHULTZ: This is fine. Thank you.

MR. SHAIKH: And now what I'm going to do is I'm going to turn it over to Jim Neurauter, my colleague here, to discuss the shield building laminar cracking. This was a previous issue.

MR. NEURAUTER: At Davis-Besse there's an item of extreme interest especially with the public, shield building laminar cracking which was identified during the project to replace the vacuous head. And during the fabrication of the construction -- the direct cause of the laminar cracking was determined to be an integrated effect of moisture content, wind speed, temperature, and duration from the blizzard that

happened in 1978. And the root cause was determined to be that the design specification for the construction of the shield building did not specify an application of an exterior sealant for moisture.

The contributing causes were determined to be the inherent stress concentration at the outer rebar in the shoulder area. The shield building was constructed with an architectural flute that gave some definition. There were eight flutes and two shoulders on the side of each flute. And I'll have a detail of that later on.

The second contributing cause was that the shoulder design did not include sufficient radial reinforcement in the shoulder region. And another contributing cause, there's a list of them, close rebar space less than six inches which contributed to crack propagation outside the, typically, the outside shoulder region. Once they cracked, they had to share.

Here's an actual picture of the 2011 construction opening with the hydro demolition. Up at the top you can see a crack, right there, that's the laminar crack. It's not visible from the surface, so it's sub-surface laminar cracking. It's been determined that laminar cracking is, basically, all 16

shoulders. And if you look at the left side, you can see the closely spaced rebar that certain portions of the shield building.

This is another picture, and two things, you can see the blast shield that, essentially, had formed the construction opening. This is the blast shield that in place to protect the containment vessel. And up on top you can see where the licensee did some further demolition right there.

They originally had thought that if they chipped away, they would arrest the crack. They had chipped away on the left side and the bottom of the construction opening, and a crack actually dissipated. But once they started going up, the crack did not dissipate. And then they had to do further exploration into the extent of the condition. Originally, they had postulated that the cracking was just due to the hydro demolition process at some point.

Here's a detail, structural detail of the flute and shoulders. The flute and shoulders were part of the continuous form. So they did not do the shell first, and then add the architectural flutes. So it was quite a continuous form. So there was no cold joint to cause a crack foundation.

And if you can see the little red line. That is, that is the typical profile of the laminar cracking. It follows the outside map of the rebar, and of importance is that it doesn't go into the interior of the core. It stays outside of that, outside the rebar. And also, you can see the depiction of the radial hooks. There's only one of them, and that contributed to the laminar cracking.

Had there been more radial reinforcement to resist the radial stresses when the water froze during the blizzard of '78, it would have been able to resist cracking.

Originally, the root cause postulated the cracks to be due to the one-time event; the blizzard of '78. And the cracks were stable. And the licensee, in 2012, put on a protective coating, moisture barrier from the outside. So if they ever got another similar to the blizzard of '78, there wouldn't be further crack propagation.

And also to validate that assumption or that theory, the licensee was doing regular inspections of the cores. They had about 80 cores to divine the extent of the laminar cracking. And they monitored those cores for any evidence of crack growth. In 2012,

they did not. But in 2013, they did further inspections. And in 2013, they changed their cores and had better resolution and the had an articulated head, and so they identified evidence of crack growth.

When they did further examination, of 15 cases of indications of crack growth, they were able to, based on the cores, state this is prior crack growth; that the core had broken, was actually an original crack. But in many cases, they could not explain it away.

So they did a further study, and the licensee, in response to a request for information from our license renewal headquarters, they indicated that the direct cause of the crack propagation is due to ice wedging. And there's three conditions that you need for crack propagation; pre-existing crack, saturated water at the crack tip, and a freezing cycle to cause the crack growth.

A contributing cause was the application of the coating that prevented the water from leaving the wall. So, they put the coating on in 2012, and there was moisture inside the wall of the shield building. And that vibrated to the crack tip, and once they made that cold, freezing temperatures that formed

ice and caused the crack to propagate.

The licensee's proposed corrective action is to monitor the core bores for crack growth. But they have concluded it's not feasible to arrest the crack, get rid of the water, and to prevent freezing. So right now they're going to monitor the crack conditions, and evaluate crack growth.

MR. BALLINGER: This rebar is uncoated.

MR. NEURAUTER: The rebar is uncoated.

MR. BALLINGER: It's uncoated and there's water in there. Is there any issue related to water getting to the rebar? If that happens, they've got a much bigger problem than just laminar cracking.

MR. NEURAUTER: When they did, when they did the core borings, they didn't see any evidence of rebar degradation.

MR. BALLINGER: Yet.

MR. NEURAUTER: They did some, they did rebar. So they --

MR. BALLINGER: I mean, they are getting heavy, they are getting moisture that far in, past the rebar, past the first layer of rebar. Right? There's two layers of rebar in there?

MR. NEURAUTER: There's, there's, in the

shoulders, there's rebar in the outer portion.

MR. BALLINGER: Right.

MR. NEURAUTER: That's just for the shoulder. But the rebar that's taken credit in the design calculation is that, in the shell.

MR. BALLINGER: Right. But those, that laminar cracking is right at the rebar.

MR. NEURAUTER: It is at the rebar, yes. They have performed a lot of testing on the cores. And they did not find evidence of degrading rebar.

MR. BALLINGER: But is this part, the issue of corrosion, possible corrosion related to the rebar part of an aging management program going forward? Because this is going to corrode.

MR. NEURAUTER: I, I, I'm not sure. They're still developing the aging management program.

MR. BALLINGER: Okay.

MR. SHAIKH: And with that slide, that concludes Jim's presentation on laminar cracking. Are there any questions for Jim or myself for either of the presentations?

MR. SKILLMAN: Let us move swiftly. We could run out of time and we have a lot of distance to cover.

MR. LARA: And so it is, sir. Well mine is nowhere near as interesting as the discussion you just heard. Nonetheless, we did want to communicate and share with the ACRS subcommittee. I have a brief status of where the agency region is when it's planning for the various activities to do with post-Fukushima inspections.

First slide, the first slide, just in summary, represents the number of inspections that the regions have been involved with respect to performing inspections following the Fukushima accident. I would just follow that it was made clear to the regional staff and our inspectors shortly after the Fukushima accident from our senior leadership within the agency that our inspectors are refocused on operations safety of the current operating facilities.

And as time has progressed since the accident, more work is coming forward to the region, and we are making a concerted effort to bring our inspection staff up to speed with respect to the content of the various orders and the forthcoming inspection evidence coming our way.

Our second slide here reflects a summation of the summary that Anne Boland and Cindy Pederson had

talked about with respect to the overall findings with respect to, primarily, flooding. Nine greater than green findings across the country. Regional III certainly had, several yellow finding and Point Beach is one, and Dresden as well, so a lot of effort across the country. And for your reference, we've provided here a summation of the deficiencies with respect to the flooding walkdowns.

The last slide is, this kind of reflects what I just said a few minutes ago; that it is, a lot of the work now is coming to the regions. Certainly a lot of licensing work, submittals that are going back and forth between the licensees and the NRR staff. In terms of the reviewing licensee submittal for spent fuel pool level instrumentation order, mitigation strategies orders, hide and bend is upcoming. The first quarter was just stated recently.

So given that there's a lot of correspondence, a lot of licensing work, the work that's coming out to the region is primarily dealing with spent fuel pool instrumentation and mitigating strategies. NRR has begun the process of performing site audits. We at Region III have assigned our resident inspectors to assist the NRR in providing the

onsite insight as to plant performance, the design of the facilities, location of equipment that would be relied upon to mitigate potential events.

And on the right-hand side, I've provided a date that we currently no with respect to the audits that are going on now, so a lot of work our way. Certainly we are involved in that, the regions work very closely. We have periodic phone calls to address questions from the regions and our inspectors. So, we're on our way.

MR. SCHULTZ: Is there added support planned from the region staff to the resident inspectors for these particular inspections?

MR. LARA: Yes. Yes. That's, one of the things that we have on our page here at site is the distribution of the resource inspection, the specialties, the expertise that are needed to perform these inspections. The spent fuel pool level instrumentation mitigation strategies, these are my own personal thoughts, that's kind of more geared towards the residents.

Once we get to the event, that design, the analysis, and that's I think where we'll certainly look again to achieve, that's again with the engineering

group, so we're going inspection by inspection and we're trying to figure out where the resources are.

MR. CORRADINI: So we were at Palisades, and we got in a discussion with the licensee that was interesting. And it involved, they're dealing with mitigating strategies. They're using a basis for their design of their mitigating strategies.

And we came back and asked questions about, given that there is some sort of we'll call it design basis. But that design basis, in some sense, is kind of an interim design, because there's going to be a chance of, essentially, a different seismic level that will be applied.

What's the process that you guys are going through relative to what they plan for? Is there a margin so that they don't have to go back and re-design after they go through all the effort of procuring, purchasing, planning, et cetera?

MS. PEDERSON: That's currently an issue that's being discussed between industry and NRR predominantly. There's a recognition that there are those two tracks, one being mitigating strategies that are ongoing and in the current re-evaluation process.

MR. CORRADINI: Yeah.

MS. PEDERSON: Do that's recognized as an industry issue. And we don't have a solution yet for that. But NRR has been, they're looking at a couple of different options and trying to, they're trying to deal with that. And they're --

MR. CORRADINI: So regions watching what NRR is doing essentially?

MS. PEDERSON: In this case, yes.

MR. CORRADINI: The only reason I bring it up is that, at least it's my impression, my colleagues would probably tell me I've got it wrong. But at least my impression was yesterday with the licensee is that I think they're aware of it, and they're concerned. But they're, they see the current goal and they're going there. The worry, at least I have, is that isn't the goal we're going to end up with.

And so there's going to be an awful lot of what worries me is in the audit, the iteration, and excuse my English, wasted time and effort with no benefit.

MS. PEDERSON: And that is front and focus of everyone.

MR. CORRADINI: Okay.

MS. PEDERSON: That is recognized, but we

don't have a solution yet.

MR. LARA: And hopefully when it gets to Palisades, they talk about their --

MR. CORRADINI: Well, we saw that. They also showed us their current plans for their, their, I don't want to call it, I think of it a little red wagon, but basically, they're pumping and they're associated --

MR. LARA: And just so you know, this afternoon, we have another poster that may refresh your memory in terms of the technology that is available. With that, that summarizes our presentation.

MR. SKILLMAN: One question. I see the dates for the spent fuel pool level instrumentation completion and mitigating strategies completions. The audits are simply a review of work in process?

MR. LARA: It's primarily a review to understand the correspondence and submittal that's being provided so NRR can kind of put their eyes on it and really assess the completeness of the information that's being provided, the location of equipment, where is the instrumentation that's in place. So that that can then inform the final safety evaluation that will come back to the licensee and we in turn then will take

that as input for our further inspections for compliance.

MS. PEDERSON: NRR is utilizing that to be more efficient than going and forth with requests for information.

MR. SKILLMAN: Thank you.

MR. LARA: And with that, I'll turn it over to Rhex Edwards who talk about the Kewaunee decommissioning.

MR. SKILLMAN: Let me make a comment here. We have a scheduled break on the agenda. I am going to claim that our break an hour ago wasn't a break. I'm going to ask those who might need to exit for a minute or two to please do so. But let's keep the hammer down, okay.

MR. EDWARDS: I understand. Good morning. My name is Rhex Edwards. I am a reactor inspector in the division of nuclear safety Region III. I'll be discussing Kewaunee in addition to the decommissioning of the reactor. Kewaunee is a single unit in keeping with what was the announced plan to begin operation in 1974, and has currently ceased operation in 2013, last year.

The site is proceeding into safe storage.

So their focus now is on safe storage of spent fuel that's onsite as well as preparing for decommissioning activities. And that's a shared focus that the NRC has, as well, as we're inspecting those storage facilities in ultimate preparation for decommissioning. They have the majority of fuel in the spent fuel pool still. They do have an ISFSI just north of the planning site, the affected area. They are currently are using a horizontal cask design and are expanding that as you see, in 2016 to use a vertical cask design to completely unload the pool to the casks instead of --

As the plant transitions, there's always a focus on safety as there always has been. But now there's a more specific focus on spent fuel pools as I mentioned. And the NRC in wanting to share that same objective and maintain the focus. But there's certain decisions, certain challenges that have to be looked at, and I'll start with regulation.

The site must meet all regulations, but the risks associated with the decommissioned plants are less than that when they were operating. So the regulations that apply to an operating plant may not be essential to public health and safety as is

transitions to decommissioned. And now the process has limited automatic reductions in regulatory requirements. So the licensee has options to pursue to reduce regulatory requirements to the appropriate level for, in certain instances in the plant. And that's done through the exception process or the licensing process.

Now, for equipment and personnel, the same is true. An operating plant needs less equipment, less personnel, and that goes along with the accidents, as well. There's fewer accidents and scenarios that apply. So they systematically go through a process of reducing equipment to get that right balance, as well as assuring that the drive by staff insures these are followed.

And then, finally, there's an insurance that they must have that they have adequate funding for decommissioning. They also have a financial responsibility to ensure that they have funding available for safe storage of fuel for however period of time they need to. So there's a balance. They need to balance the right mixtures of regulations appropriate in the circumstances with the right equipment, the right planning, the right personnel to

ensure safe storage while preserving the funding that they do have.

This slide here shows a quick snapshot of the efforts that are ongoing in the past year, and it highlights those, the decisions that I mentioned on the previous slide. At the top corner there is the regulatory challenges that their decisions have been made, and their path or time line to get through success there. Modifications for equipment is shown at the bottom. And again, the instance he's showing down there, a rough schedule. This only shows out to 2014, so if there is a campaign in progress at the station that will be expanded in 2016.

When looking at equipment, the licensee starts with what equipment is necessary for safe storage of spent fuel. And it's not easy. And they look at abandoning that equipment, some tables for example are no longer needed. They can abandon that. Same would be true about speed water, safe detentions, now they go and look at remaining equipment that's present and see what could possibly be modified to reduce operating costs or efficiency of operations.

And they've done that through, there's electrical distribution system either make it more

flexible or reduce output or in the case of service water pumps, they no longer need the original full flow of the pumps, and the reduce the capacity of the pumps.

And then the other examples that are shown here. But our main theme in the short term is the spent fuel pool, and make-up supplies, and power distribution equipment for supplying the components, the spent fuel pumps are there and these generators are still there onsite. A lot of instrumentation there. In many cases, they're actually using the existing level --

MR. CORRADINI: What about staffing? How many people are onsite, including security?

MR. EDWARDS: There's presently about 200 or so. Those numbers are dwindling down. There following all of the safe score staffing now at 140, closer to 175 here and there.

MR. CORRADINI: Thank you.

MR. EDWARDS: Now a major driver for personnel is emergency preparedness. This provides a good example of staffing. When the plant shut down, the emergency plan at shutdown was the same one of the operating reactor. And that goes, that takes all of the possible actions of an operating reactor, and all the possible staffing requirements for that emergency

plan.

They have responsibility, they must ensure public health and safety for all the possible accidents that could occur at the plant. But the Part 50 requirements in place are for operating reactors, so it may not be applicable to their current configurations. So they have options. They can pursue exemptions or license amendments. And the threshold that they need has essentially proved that those requirements don't provide a substantial contribution to public health and safety.

One example that they have is they performed an analysis that shows 90 days following shutdown a design basis accident, spent fuel pool accident could not exceed protective action guidelines recommendations at the site area boundary. Another example would be a beyond design basis event 17 months after shutdown would also not exceed protective action guidelines recommendations at the site area boundary.

So with that knowledge, they know they must still maintain an onsite emergency response capability. But the need for an offsite response capability is no longer seen as a possibility through their analysis. So they're requesting exemptions.

And the select portions of 50.47, specifically for that offsite emergency response plan has been proposed to the Commission for exemption.

Then, ultimately, they go to the permanently defueled emergency plan. They have exemptions approved. There's a licensed member in place that would, essentially, keep it to an onsite emergency plan and the highest classification levels are show there with an alert.

MR. SCHULTZ: Rhex, so we can understand the schedule here, and you don't have to go back to the chart, I think you'd know it. But, for example, there's a box for the EP exemption that shows a date of the end of July. And is that their exemption request that's expected, and then that will be reviewed? Is that what that means?

MR. EDWARDS: Correct. They originally requested the end of July.

MR. SCHULTZ: They requested that it be approved by end of July, or they request, or they're making an exemption request around this time?

MR. EDWARDS: The exemption request came in last year

MR. SCHULTZ: It's already in.

MR. EDWARDS: And they requested approval for July.

MR. SCHULTZ: Okay.

MR. EDWARDS: Then the actual analysis implementation date wouldn't be until October of 2014, and that's 17 months after shutdown. That was the basis.

MR. SCHULTZ: Understood.

MR. EDWARDS: And that's really the back down that they want for the --

MR. SCHULTZ: And that same is true with these boxes, then, that show time line milestones for security, for example. Those are end points that the licensee has requested.

MR. EDWARDS: That's correct.

MR. SCHULTZ: Okay, thank you.

MR. EDWARDS: And that's a working chart that they continue to update periodically.

MS. PEDERSON: Rhex, if I remember correctly, the EP exemption proposals with the commission currently and where there going.

MR. EDWARDS: That's correct.

MR. SCHULTZ: Thank you.

MS. PEDERSON: It's near the very end of

the process.

MR. STETKAR: Rhex, I have to ask, apparently there's some, I'm not familiar with this so, you said that some consideration of beyond design basis events determines this 17-month time window. What extent of beyond design basis event?

MR. EDWARDS: They've analyzed several different scenarios.

MR. STETKAR: Drain the fuel pool?

MR. EDWARDS: Complete drain down.

MR. STETKAR: Okay, that's good enough.

MR. EDWARDS: And I'll just highlight two different analyses that were performed. One's is no air cooling considered, as well as air cooling considered.

MR. STETKAR: Okay, thanks.

MR. EDWARDS: Some challenges we've seen inspections face. The site can make changes to their plan so long as they follow the process under regulatory 50.54(q), and that it also does not reduce the effectiveness of the emergency plan. We did see two instances we're going to talk about.

One example where two issues were we found a reduction in effectiveness and issued a non-cited

violation, and also because of those changes. There's a staffing analysis that shows those folks that are on shift and assigned emergency response responsibilities, that they don't have some duty assigned them that would preclude them from doing their emergency response role. And that staffing analysis was now updated following some changes. Other personnel that they considered, security staffing, operations staffing for emergency operations, as well as you know, the fire protection.

Regarding regulation, as the plant conducts operations, certain operations will automatically create regulatory change. An obvious example of that is the permanent cessation of operation and removal of fuel from the reactor. But there are limited regulations that change, as I mentioned.

As the changes occur, that keeps in motion our inspection oversight for the reactor. We maintain a resident inspector onsite for a period of time. And then, usually within six to 12 months that resident inspector comes back to the region, or the responsibilities come back to the region, and we transition to a different chapter for inspections.

Throughout this process, we do maintain

public outreach. There is no set frequency following some certain public meetings that have occurred, or as events are occurring we're sensitive in the region to the public's needs and interests. So we're maintaining that, and have had a couple opportunities to engage with the public, as well.

And it's not so much that inspection oversight drive licensing basis, but if that licensing basis changes through exemptions and amendments and such, that then gets our inspection oversight program back in motion again. The fact that there's this, the inner working relationships follow.

The current process that we're following is based on past precedents where plants have shut down in the '90's. And that there has been significant events that have occurred since then; 9/11, Fukushima, of course. And the regulatory landscape has changed significantly since that time. So we are looking at our own processes to find inefficiency or improve upon incidents that we have.

So the respective offices shown here are working together to transition working group with short term goals of increasing effectiveness of the existing process through resolving the challenges that come up

in coordination. And then the long-term goal to improve the regulatory process. And the group will maintain guidance for policy changes.

And with that, if you have any additional questions for me?

MR. SKILLMAN: Rhex, I have one. And maybe it's more of a question of common sense and practicality versus regulation. It's certainly non-essential. But I watched, in my career, when they pulled the plug in Midland, the TVA pulled the plug in Bellefonte and those plants became cannibalized in three months.

What I mean by that is others came in and took equipment, the working equipment, non-working equipment, water pumps and safety rating instrumentation. And in six to eight months what had been a very viable, in the case of the Midland plant, became a wasteland and Bellefonte has never been able to recover.

Is there any protection in place to prevent Kewaunee from becoming cannibalized prematurely? I recognize it's an economic decision from the owner. But it seems like common sense ought to apply, at least in some degree.

MR. EDWARDS: They have not put any, any such a plan in place as you described. They are selling off equipment and pieces are being removed for scrap or for other purposes. So there's not a foreseeable future of the operation of Kewaunee, so they are focused on safe storage and decommissioning and finding places for this equipment.

MR. SCHULTZ: Rhex, there's two non-cited violations associated with the emergency planning. It just strikes me that, with regard to the previous decommissioning activities that these are not new issues. I don't understand why the licensee would not have understood the expectations associated with eliminating positions, response time analysis and so forth.

These have come up before in other decommissioning projects. And it doesn't seem as if they followed lessons learned associated with previous experience. And I'm wondering if we're watching this as carefully as we need to in terms of other issues. It's done here. They missed it. But it's certainly an indication that decommissioning lessons learned aren't being, weren't being followed adequately.

MR. EDWARDS: And I agree that the, in

principle, the issues are very simple to understand where they went wrong. In reality, it was a very complex understanding of each side’s point of view of the regulatory guides that were out there. Ultimately, the safety significance of these issues was very small.

One example where they reduced staffing, they eliminated the core assessment position for this plant. That's a reasonable thing to do based on the current configuration of the plant, however, they didn't follow the process of assessing prevention effectiveness from the NRC approved emergency plan, which was based on an operating reactor. So, at the end of the day, it just became I'd say an interpretation of the NRC guidance that's out there.

MR. SCHULTZ: Okay, so an opportunity to improve the guidance then.

MR. EDWARDS: Perhaps.

MR. SCHULTZ: And as you have that shown as what you're looking to do going forward, going forward in future processes.

MR. EDWARDS: We at the NRC believe the guidance was clear. Obviously, there's a different perspective, and the other side of that coin is that

the operator does not, so that's something that has been reviewed by this improvement group so certainly that's a consideration.

MR. SCHULTZ: Thank you.

MR. SKILLMAN: Colleagues, any questions? Okay, we're on to the next topic.

MR. DICKSON: Good morning. My name is Billy Dickson. I am the branch chief, for L50 emergency response branch here in the region. Along with other things, we're responsible for conducting the inspections associated with the public and occupation radiation double core zone, LOROP, for the plants within Region III.

As the leaks were identified at different power plants in the U.S., including this region, the nuclear reactor industry begins to adopt a voluntary initiative to help protect ground water. Today I'm going to briefly discuss the GI, ground water initiative, ground water protection initiative, the completion of NRC's temporary structures associated with the ground water protection initiative, and the inspection activity that going on today to ensure that the ground water protection initiative is still being implemented.

The ground water protection initiative was born under NEI 07-07. It identified actions to improve licensees' response to leak emergencies, leaks and spills that may make it to the subsurface below the water, water around the plant. The voluntary initiative contained three major affirmative actions. The first action was to respond to the ground water protection plan.

Also, the second was to improve communications with certain stakeholders. And the third item was to perform program oversight under the auspices of NEI. Within the NEI 07-07, there are 11 different program objectives developed to address these three major program issues. There are 42 program elements to address those 11 program objectives.

In 2008, the NRC issued TI 173 industry ground water protection initiative to assess ground water protection programs to determine whether or not NEI 07-07 had been implemented at these sites. The NRC inspectors visited sites between August, 2008 and 2010, and used the TI to determine whether ground water protection initiative contained all the 42 elements discussed in NEI 07-07.

The licensee had to demonstrate to the

inspectors that the program elements were present in their program. At the end of this effort, NRC performed an evaluation of the results of the TI. And across the industry, about 92 percent of the program elements of the voluntary initiative were implemented. About 60 percent of power plants had implemented all of the 42 program elements. In other words, the projections were met, while 40 percent of the plants were rated incomplete in at least one of 42 program elements of NEI 07-07.

The program objectives that were most often not met were development of remediation process, the completion of a site risk assessment, or systems components onsite to develop a program that allowed NEI to implement self-assessments in the establishment of the program for --

Between 2011 and December, between November, 2011 and December, 2012, the NRC repeated its assessment at sites with five or more program elements not met. This inspection or assessment was done under TI 2515/85. We called it follow-up on the industry ground water protection initiative. There were a total of 14 sites across the nation involved in this assessment.

There were two sites here in Region III. They were Kewaunee and Perry. The region, following the assessment, determined that all the ground water protection objectives were implemented at both of these sites.

Nationwide, the assessment determined that nuclear power plants licensees, except for Fitzpatrick, Cooper and Waterford, had completed implementation of the ground water protection initiative. Those issues were put in the licensees' corrective action program, and they are being assessed by our normal inspection program.

In addressing the ongoing inspection activities to ensure continued implementation of the NEI 07-07, the NRC continues to conduct inspections at all the different power plants to check for gaps in implementing the voluntary initiative and ensure that the trends we've currently seen over the last six years are continued. These inspections are done through NRC inspection procedure 711246 and in particular, Section 06.

And it looks at the licensee's implementation or remediation process too, there are again 11 objectives that we focus on. At that point,

I'm going to end my presentation for questions.

MR. SCHULTZ: I have one. Thank you for your presentation, a very thorough description. The inspection program, as it continues, can you describe a little bit more about that. You've mentioned a lot of open items that were still in play, and went back and looked at those that were greater than five. But there's a lot of plants that must have been less than five.

And is there sufficient inspection focused on this going forward to assure that implementation is complete? Enough time has passed so that implementation of the industry initiative should be complete.

MR. DICKSON: As I mentioned earlier, there are three sites across the nation that actually have, that during the TI-185, that didn't meet the program objectives of at least one. Again, the licensees have put those issues in their corrective action program. There are issues surrounding hydrology, mapping, site characterization.

And from what I understand in talking to other branch chiefs in other regions, the licensees are actively seeking private independent consultants to

come in and do mapping, to take a look at the site, the site topology, to understand ground water flow at this point.

So the industry, from what I understand, we do attend a number of the ground water protection initiative conferences, the industry is taking this very seriously. And again, from the regulatory standpoint, the ground water planning group, we did implement some changes to Subpart F of the CFR Part 20. A change that has made the licensee actually take a look at several issues associated with ground water protection, and to put that as part of its normal program.

Also, there is a change associated with 14.6, Part 20, 14.6, which is decommissioning planning, that requires licensees to develop processes and programs, while operating, to help minimize contamination onsite. So, and that's done through, the industry has accepted that the licensee, as long as you implement NEI 07-07 process and program, that you will, you will have actually completed that, or met that requirement.

MR. SCHULTZ: Thank you. Good example of how the process should work. Thank you.

MR. RYAN: One other interesting link to geohydrology has always been the training of the geohydrologist is I just need one more pull, one right here and I'll be all set. And then there's another gap. And, you know, there's kind of a process of filling those gaps in over relatively long periods of time, like a few years, and sometimes a decade or so.

MR. DICKSON: That's right.

MR. RYAN: Has that kind of thinking, you know, been integrated into the plans to coach the developing and executing?

MR. DICKSON: Yes. Well, part of the NEI ground water protection initiative is a continuing risk assessment at the sites based on what's found through the survey process. And the licensee, in their processes and procedures, may have to have corrective actions to assess through those. And if they have to go out to do other bores or wells, it's supposed to be built in their process to do that. And that analysis should be onsite, and we could review this issue.

MR. RYAN: Okay, thanks. That's helpful. I encourage that, because it kind of keeps the licensee on track, keeps you well informed so that the decision making is, you know, a mutual thing. It's not

something that, you know, is separate, one or the other.

MR. SKILLMAN: Billy, there's another set of slides on the TI-182. Okay, Billy, thank you.

MR. SHAIKH: So, I'm going to talk about to this slide with regards to NEI 09-14. That's the industry initiative for buried piping and for underground piping tanks. And, essentially, the purpose or the goal of this NEI 09-14 is to provide reasonable assurance of structural and leakage integrity of buried piping and underground piping, as well as tanks that are underground or below grade.

And, essentially, in a letter dated November 20, 2009, to the then EDO Bill Borchardt, NEI wrote a letter and stated that all the chief operating officers at power plants voted to approve this initiative 09-14, and this initiative is a formal commitment by the companies to meet the requirements of this initiative.

At the end of the day, the initiative is fairly straightforward. It involves procedure and oversight, development of procedures and oversight programs for buried piping at facilities, as well as the risk ranking of those buried piping systems, including the tanks.

And one caution that I would draw, or a caveat associated with risk ranking is this is not, necessarily, a risk as in Delta CDF or core damage frequency, but this is risk also from a financial perspective and from an optics perspective, from a public relations perspective.

Having underground pipes or buried piping that may contain licensed radioactive fluid not, necessarily, corresponding to safe reactor shutdown. But nonetheless, it has licensed material. So a leak from there has that aspect associated with it. So all that was tied into their risk algorithm, if you will, to determine which piping systems are more susceptible, and therefore they would end up in high risk. And risk was determined based on consequence times the product that we buried.

The other aspect associated with this initiative after risk ranking, and this is in methodical order, so it's procedures and oversight first. Then you have the risk ranking. And then, after that, you have the inspection plan itself. So this is the plan that outlines which piping systems, which tanks will be inspected and when. So it's a timetable.

And the fourth one is the plan implementation itself. So this is the use of various technology, whether it be ground penetrating radar or it be measuring electrical potentials in the ground itself for piping that's in contact with soil, or visual examinations for piping that's in cases and vaults. So that's the actual implementation of the plan to determine whether there's any gross degradation of piping and if these can be identified.

The last one is active management plan. So now that you have the procedures, you've done your risk ranking. Based on your risk ranking, you've taken your most susceptible piping systems and tanks, and you've implemented an inspection plan, and actually performed the inspections.

You now have direct data, and also indirect data. The direct data refers to actual excavations, and the indirect data is should you use ground penetrating radar to examine whether there's any degradation of the coating on the pipe. Using that data, you now make an assessment of your piping system to understand how long can these piping systems stay in service before I can experience, say a through wall leak or a gross degradation?

And a lot of these piping systems were usually designed as -- systems. Because a lot of them are not safety related piping systems. Actually, the vast majority of underground or buried piping is not safety related. There are cases where it is safety related, I think such as safety related service water piping that, at certain plants, unfortunately, is actually below grade and exposed to soil.

So that the text of the initiative in a nutshell. It's a five-step process, if you will. And what TI-182, temporary instruction 182 deems to achieve is, basically, it's a fact finding temporary instruction. Where the inspectors are going out to the sites, and they're performing these inspections in accordance with these five tasks that are outlined in the initiative to determine whether the licensee actually has procedures and oversight or programs in place for buried piping and tanks.

Do they have risk ranking completed? And the risk ranking was mostly done using proprietary software that FRE came up with in response to this industry initiative that, basically, ranks the piping according to some of the factors that I've talked about for risk. And also, whether the licensee has an

inspection plan. We review that inspection plan to determine when they're doing certain examinations, if those examinations have been conducted, and for certain activities, we were actually able to observe some of these in-field examinations as they took place.

And also, whether the licensee was implementing the plan, as I stated, and were they actually performing these inspections or was it simply we will do it, but we don't know if they actually did it.

And then, after management plans, basically, this is end of life calculations the licensee does using industry acceptance criteria. That if I do identify that I have a defects in my pipe or my coating, how long, how many years can I go before I need to replace that? What flaw am I willing to accept in my buried piping, given it's risk ranking, and how long can its service life be?

So the inspectors looked at that in two phases, Phase I and Phase II, in accordance with TI-182. Phase I was simply to understand that the skeleton or the framework for this buried piping initiative was there and those five industry objectives were in place from a programmatic standpoint.

And Phase II was more thorough and detailed, where we actually went out and we reviewed the risk ranking process, the risk ranking methodology to understand that the licensee was appropriately risk ranking piping systems. For example, did they inadvertently leave out safety related service water as high risk or at low risk or medium risk.

So perhaps, maybe from a financial standpoint or an AR standpoint, if they needed to move it from a medium risk. But from a safety related standpoint, it should be high risk. But, and on the flip side, you can, to understand are there any piping systems that contain licensed radioactive material that's not necessary for plant shutdown, and it may not have financial consequences for the licensee or large consequences.

But because a gross degradation of that pipe can result in radioactive material released to the public. Therefore, it should have been a high risk. So that's something we looked at. We looked at their risk rank to understand that it made sense based on the risk ranking methodology.

And up there you see a summary of our TI-182; 15 Region III sites, Kewaunee being the

exception. We only completed Phase I at Kewaunee, and then they announced that they were decommissioning, so the study was not completed there. TI-182 samples are complete for each site. There was one deviation, I believe it's Palisades. And that was Palisades' failure to meet an inspection plan milestone.

So if you go back to the objectives I talked about, you need to have procedures and oversight, checkmark, risk ranking, checkmark, inspection plan. The licensee did not meet the milestone outlined in the initiative that they should have a plan by this date. And they followed their process, the NEI outlined process for submitting a deviation.

So this was a deviation not in the NRC's terminology, if you will, but a deviation as described in the NEI initiative with regards to not being able to meet a milestone. The one thing I'd like to point out is that even that mediation we do take into consideration.

Because at the end of the day, the purpose of this was a fact finding mission that staff and NRR would use and correlate all this information or compile it from all the regions to provide a response back to the commission on how well this initiative was working.

And that, ultimately, factors into the decision making down the road. Whether this needs to be a rule making space, or is this can the industry govern itself from an initiative standpoint? Is the initiative working? Are they regulating themselves using their own initiative and performing the inspections as needed, accordingly?

So it does serve as a data point for the staff to use at headquarters. And again, the overall assessment of the Region III plants is that the NEI 09-14 industry initiative concerning buried piping and tanks is effective in examining potential risks for such systems, and implementing mitigation techniques to minimize opportunities for leakage.

And what I mean by implementing mitigation techniques. A lot of these licensees did not have adequately mapped out topography of their sites to understand where exactly these buried piping systems are going. And when they mapped it out, when they hired contractors to map it out, they were puzzled, as well.

They're like oh wow, we did not know that we had buried piping over there. Because a lot of these pipings were capped and left in place since the time of construction. They had no purpose, but

nonetheless, it's there. And in certain cases they found systems that correlate with other piping systems that went over and also local utility piping systems that overlapped with the licensee.

So it served a purpose in the licensee being able to accurately map the underground piping systems, and also risk rank them, and employing mitigation techniques. When the licensee got out of protection, the licensee, most licensees started off with that. But, over time, a lot of them do not pay attention to that annual test, and they degraded a lot. A lot of annual tests were, basically, depleted.

So now licensees are putting in effort to replace annual tests to raise their protection system back up, install new rectifier stations so that the CP is actually working, because one of the best measures for preventive maintenance is to not have the degradation in the first place.

So it did serve its purpose, at least from a Region III perspective, when we look back at the sites, that the sites do understand the purpose behind the initiative, and they are taking actions necessary to beef up, if you will, preventive measures at their site to make sure that there's no structural,

occurrence of structural and leakage integrity is minimized.

MR. STETKAR: Atif, let me ask you a quick question.

MR. SHAIKH: Yes.

MR. STETKAR: I'd like a quick answer.

MR. SHAIKH: Sure.

MR. STETKAR: How well does the current revision of NEI 09-14, which I'm not familiar with, align with the recommendations in GALL Rev 2 regarding inspections, reliability of tectonic protection, et cetera? Just, is it in lockstep with it, or do you know the answer to that?

MR. SHAIKH: I actually don't know the answer to this.

MR. STETKAR: Thank you. That's good enough. That bothers me, because neither you nor Palisades could answer that question.

MR. SKILLMAN: And we're depending on GALL 2 for license extension, particularly for SLR.

MS. PEDERSON: Let's get back to --

MR. STETKAR: That, it just, Cindy, it bothers me.

MS. PEDERSON: No, I understand.

MR. STETKAR: Because neither you nor the licensee, when I asked the question, could answer the question. And, as Dick mentioned, GALL Rev 2 is being committed to in terms of license renewal going forward, people in the process now. Some of the people who were renewed under GALL Rev 1 have recognized the problem of buried piping, and have committed to GALL Rev 2. But, apparently, there's a lot of people out there who don't pay any attention to that.

MS. PEDERSON: I appreciate the question. I'm hopeful somebody that is not in the room right at the moment knows the answer to that. But we should educate ourselves, as well. Thank you for the question.

MR. SKILLMAN: Cindy, Region III, everybody, thank you. Let me ask my colleagues, any further questions? Okay. Is the telephone line open?

MS. PEDERSON: Yes.

MR. SKILLMAN: This is Dick Skillman. I'm part of the ACRS. I'm chairman of the subcommittee, and I'm asking if there are any public comments from anyone that is on the telephone line, please. Is anyone out there? If so, would you please signify by just identifying that you are there.

Hearing none, to the audience, are there any members of the public that would like to make a comment, please? Hearing none, we have no further comments from the ACRS. Any comments from Region III, please.

MS. PEDERSON: I would just like to thank you all for coming out. It's not very often that we get a chance to chat with you folks, and we do appreciate the opportunity. So I hope these two days that you've been visiting in our area met your objectives, done what you wanted to accomplish here. And we appreciate you being here. Thank you very much for coming.

MR. SKILLMAN: And we thank you, too, for your warm invitation and for the provision that you made for us today. Thank you. With that, this meeting is adjourned.

(Whereupon, at 12:00 p.m., the meeting was adjourned.)

Region III Welcome and Overview

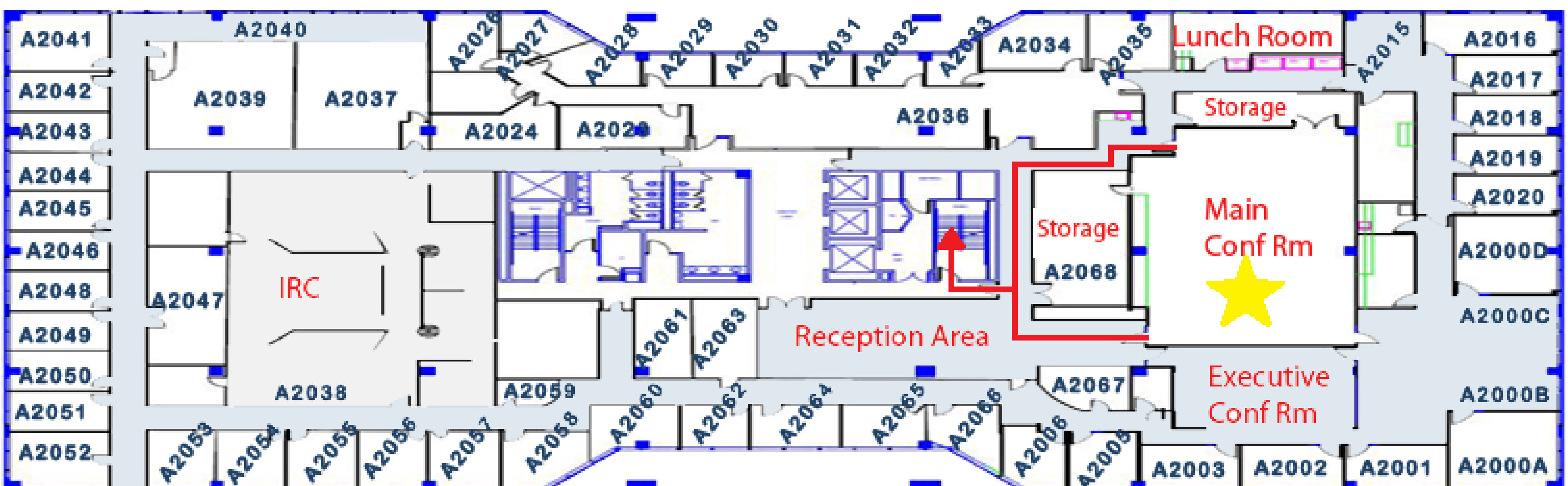
July 24, 2014

Cynthia Pederson
Regional Administrator
Region III

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

Introduction

- Safety (exit routes in red in event of an alarm)
- Security
- Meeting is being transcribed for public record (Category 1)
- Teleconference attendance



Agenda

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Topics	Presenters
Opening Remarks	Gordon Skillman, ACRS
Region III Welcome and Overview	Cynthia Pederson
Reactor Oversight Process	Anne Boland
Technical Issues of Interest	Bob Daley
Davis-Besse Steam Generator Replacement Inspection	Atif Shaikh Jim Neurauter
Fukushima Initiatives	Julio Lara
Break	
Kewaunee Decommissioning	Rhex Edwards
Inspection of Industry Voluntary Initiatives	Billy Dickson Atif Shaikh
Wrap-up	
Public Comments	Public
Subcommittee Discussion	Gordon Skillman, ACRS
Adjourn	Gordon Skillman, ACRS

Overview of Region III

U.S.NRC
United States Nuclear Regulatory Commission
Protecting People and the Environment

- **Mission –** Oversight of operating nuclear reactors, ISFSIs, decommissioning reactors in SAFSTOR, reactors in active decommissioning, Materials licensees, Master Materials License, and complex materials decommissioning sites to ensure adequate protection of the public health and safety and the environment.

- **Who we are –** 218 total staff in Region III (92 Qualified Inspectors)

- **What we do –**

  Reactor Inspections
  - Baseline Inspections – average 2300 hours per site
  - In 2013 5 Supplemental (4 – 95001 & 1 – 95002) and 2 Reactive Inspections
  - In 2013 responded to 3 Notice of Unusual Events
  - In 2014 5 Supplemental (3 – 95001 & 2 – 95002) and 1 Reactive Inspection
  - In 2014 responded to 2 Notice of Unusual Events and 2 ALERTS

  Nuclear Materials Program
  - 400 Inspections and 800 Licensing Actions (FY2013)
  - Department of Veterans Affairs Master Material License (MML)
  - Oversight for Agreement States

Region III Data
Number and Type of Licensees

- **15 Nuclear Reactor Sites (IL, IA, MI, MN, OH, WI)**
  - 23 operating reactors
    - 12 PWRs (9 W, 1 CE, 1 B&W)
    - 11 BWR (7 Mark-I, 2 Mark-2, and 2 Mark-3)
- **1100 Materials Licensees**
- **19 ISFSIs**
  - 17 located on reactor sites/decommissioning reactor sites
  - 2 stand-alone (GE-Morris, Big Rock Point)
- **3 Decommissioning Reactors in SAFSTOR**
- **Complex Decommissioning Activities**
  - 5 complex materials sites
  - 1 Research/Test reactor (University of Michigan)

Reactor Safety
Where We Regulate

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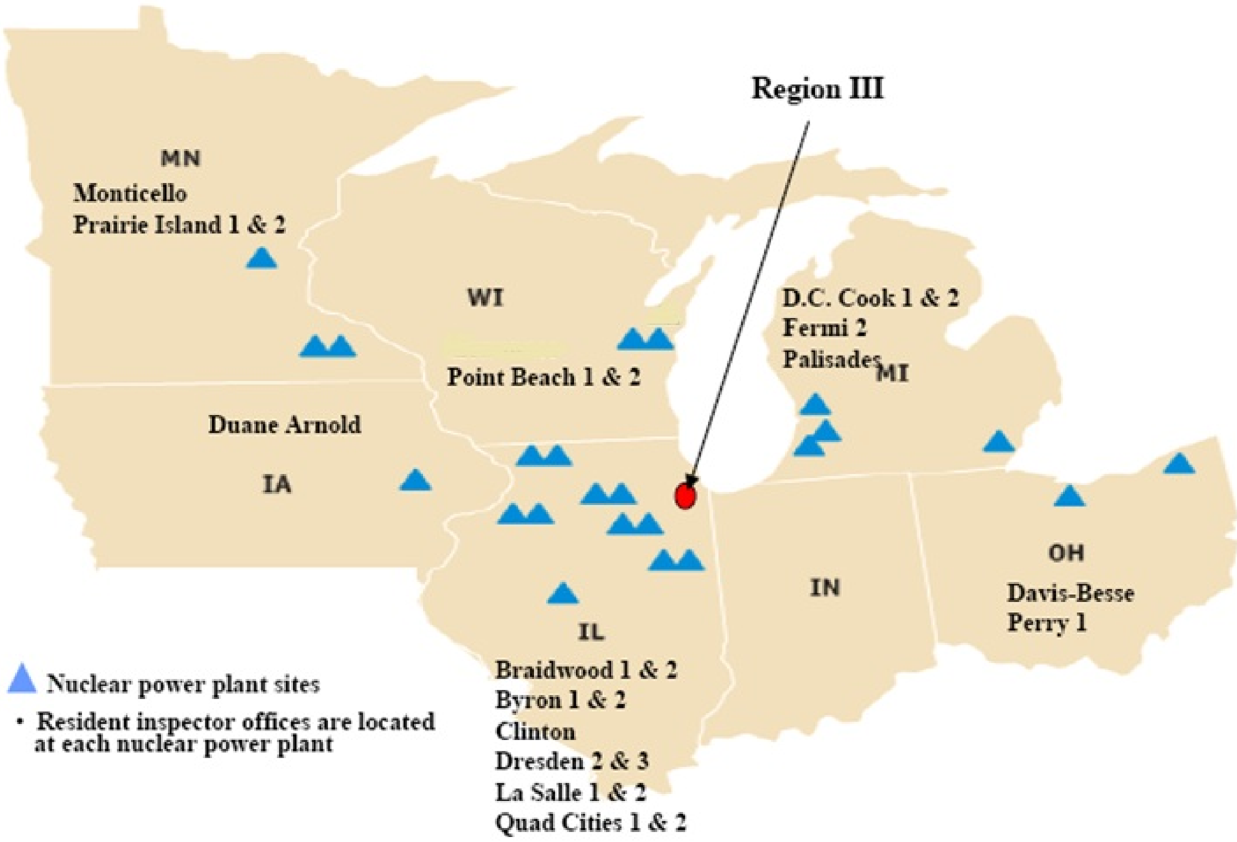

Materials Safety Where We Regulate

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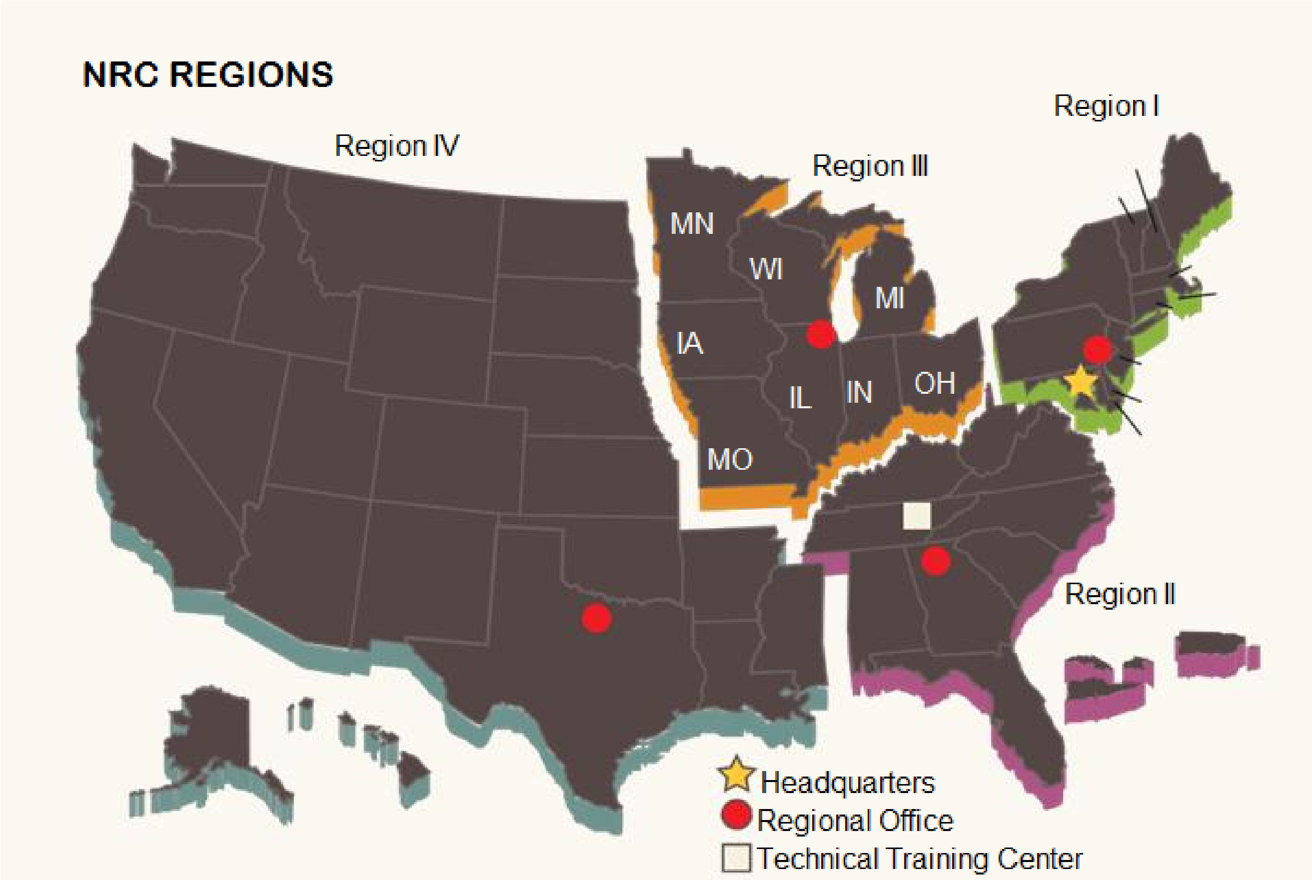

Agreement States: Illinois, Iowa, Minnesota, Ohio, Wisconsin

Challenging Region III Plant Activities

- Kewaunee – new decommissioning site
- Davis-Besse/Prairie Island – new steam generators
- Action Matrix Column 3 plants – Monticello, Duane Arnold, and Point Beach
- Emergent Technical Issues

Region III License Renewal (LR) Summary

13 Reactor Units were granted renewed licenses

- Operating beyond 40 years:
  - Dresden 2 & 3
  - Duane Arnold
  - Monticello
  - Palisades
  - Point Beach 1 & 2
  - Prairie Island 1
  - Quad Cities 1 & 2
- Renewed but not in Period of Extended Operations:
  - Prairie Island 2
  - D.C. Cook 1 & 2

R-III LR Summary

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10 Reactor Units without renewed licenses

- Application received:
  - Davis-Besse
    - (Inspections Complete)
  - Braidwood 1 & 2
    - (Inspections Late Summer 2014)
  - Byron 1& 2
    - (Inspections Late Summer 2014)
  - Fermi
    - (Inspections Spring 2015)

- Anticipated Applications:
  - LaSalle 1 & 2
    - (1st Quarter 2015)
  - Perry
    - (September 2015)
  - Clinton
    - (1st Quarter 2017)

Questions?

Reactor Oversight Process

Anne Boland
Director
Division of Reactor Projects

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Agenda

- Action Matrix Summary
- Substantive Cross Cutting Issues
- Reactor Oversight Process Improvement Initiatives

Action Matrix Summary

As of 7/17/2014

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Reactor Unit	Action Matrix Column
Clinton	Regulatory Response Column Clinton is in Column 2 because of a white performance indicator in the Initiating Events (IE) Cornerstone due to unplanned scrams originating in 4Q2013. (95001 inspection in progress)
Duane Arnold	Degraded Cornerstone Column Duane Arnold is in Column 3 because of 2 white findings in the Mitigating Systems Cornerstone due to a RCIC turbine overspeed trip and an 'A' standby diesel generator lube oil heat exchanger gasket failure originating in 3Q13. (95002 inspection in progress)
Fermi 2	Regulatory Response Column Fermi is in Column 2 because of a greater-than-green finding in the Security Cornerstone originating in 1Q2014. Awaiting licensee notification of readiness for IP95001 supplemental inspection.
Monticello	Degraded Cornerstone Column Monticello is in Column 3 because of a Yellow finding in the Mitigating Systems Cornerstone due to failure to maintain an adequate flood plan consistent with design requirements originating in 2Q2013. Awaiting licensee notification of readiness for IP95002 supplemental inspection.
Point Beach 1	Degraded Cornerstone Column Point Beach 1 is in Column 3 because of a white finding in the Mitigating Systems Cornerstone due to failure to establish an adequate procedure to implement wave run-up design features originating in 1Q2013. Awaiting licensee notification of readiness for second IP95002 supplemental inspection.
Point Beach 2	Regulatory Response Column Point Beach 2 is in Column 2 because of a white finding in the Mitigating Systems Cornerstone due to failure to establish an adequate procedure to implement wave run-up design features originating in 1Q2013. Awaiting licensee notification of readiness for second IP95002 supplemental inspection.
Prairie Island 2	Regulatory Response Column Prairie Island 2 is in Column 2 because of a white performance indicator in the Mitigating Systems Cornerstone due to the emergency AC power system originating in 4Q2012. IP95001 supplemental inspection scheduled.

Action Matrix Summary

As of 6/7/2013

All other Region III plants are in the Licensee Response Column

Monticello - Open Substantive Cross Cutting Issue “H7, "Documentation“, (opened as of 2013 End-of-Cycle Assessment)

Significant effort to accomplish program Supplemental inspections in 2014

Reactor Oversight Process (ROP) Improvement Initiatives

Active Involvement in Various ROP Activities

- ROP Enhancement Project

  Incorporate aging management program implementation in existing inspection procedures and developing training

- ROP Reliability Effort

- Government Accountability Office Report: "Analysis of Regional Differences and Improved Access to Information Could Strengthen NRC Oversight"

- Active Participation in Subsequent Renewal

- Substantive Cross Cutting Issues

Questions?

Technical Issues of Interest

Bob Daley
Engineering Branch Chief
Division of Reactor Safety

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Submerged Cables for Safety Related Equipment at Duane Arnold Energy Center

- October 2012 – Licensee finds emergency diesel generator control cabling in conduit filled with water

- September 2013 – Modification/10CFR50.59 inspection
  - Numerous conduits filled with water
  - Licensee originally performed evaluation to qualify cables for submergence
  - Challenged by regional electrical engineering inspectors
  - Challenged corrective actions to date
  - Concerns centered on continuous wetting of cables.
  - Two Non-Cited Violations issued

- April 2014 – additional inspection followup

Summary of Affected Cables

- Conduits that are known by the licensee have cables in water today are:
  - Standby Transformer 4KV Cables
  - A, B and C Trains of RHR 4KV Power Cables
  - A SBDG Low voltage control and 480VAC Cables
  - B SBDG 4KV Power Cables
  - HPCI Low voltage control cables
- Fire seals on Secondary Containment show signs of water on more than listed above
- Nine Conduits that contain Safety-Related cables have not been inspected yet
- Current, limited testing reveals operable components
- Next steps – risk determination, enforcement, exit meeting

Cable Tray Fire at Quad Cities Nuclear Plant

- Steam leak from gland seal system in heater bay
- Half hour after steam leak, 120 VAC cable faulted, causing fire
- Multiple cables faulted, increasing spread of fire
- Continuous faulting caused copper to drip on lower cable tray starting fire in lower tray
- Fire ultimately extinguished by fire suppression system

Cable Tray Fire at Quad Cities Nuclear Plant

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- Old ideas on fires that need revisiting
  - Fire starting in cable tray
  - Fire spread to cable trays below
  - Arcing faults and overcurrent protection
  - Open circuits during a fire
- Protective Relaying
  - Arcing produces less current than hard faults
  - This phenomenon also seen during DC testing with high amperage fuses. Postulated as high resistance arcing by Expert Panel
- Aging Management – Jackets may be important after all

Questions?

Davis-Besse Steam Generator Replacement Inspection

Atif Shaikh, Senior Reactor Inspector
Jim Neurauter, Senior Reactor Inspector
Division of Reactor Safety

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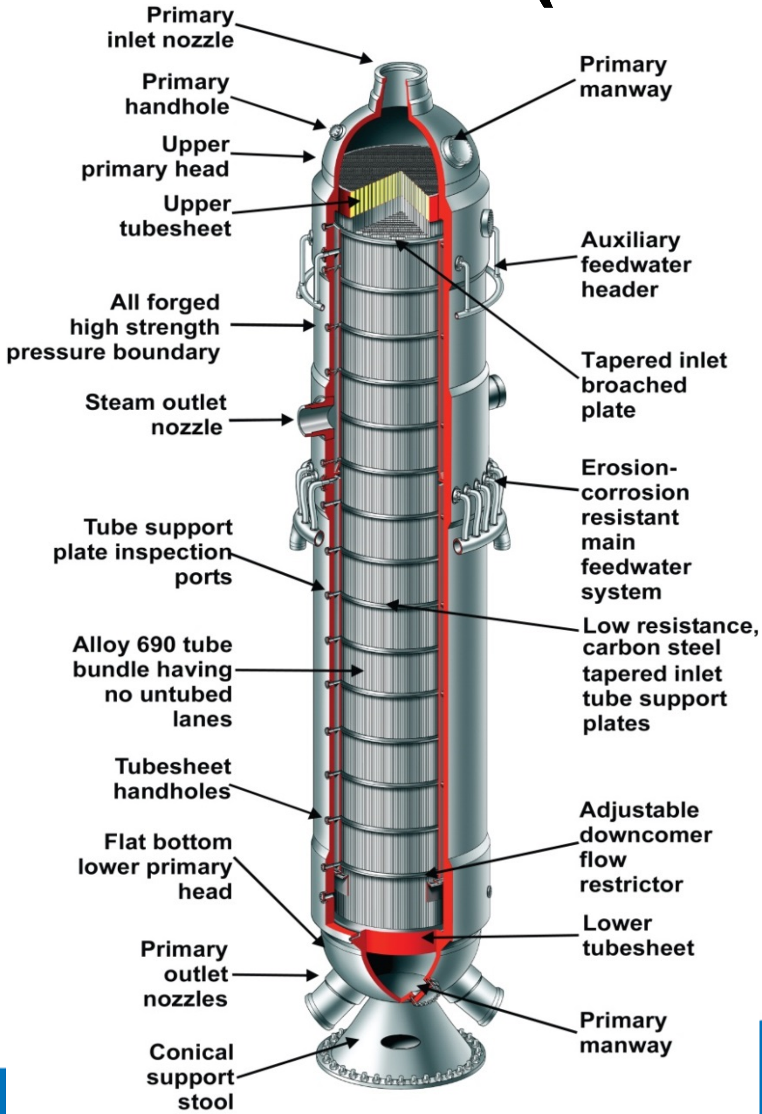
Once-Through Steam Generators (OTSG) - Overview



- Replacement OTSGS are each ≈ 75 feet tall and ≈ 13 feet in diameter
- Replacement OTSG Weight = 465 Tons (Dry)
- Replacement OTSG tubes are made from thermally treated Alloy-690 material providing increased corrosion resistance

Davis Besse SG

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Inspection Objectives

Verify that:

- Engineering evaluations and design changes are in conformance with facility license, codes, regulations
- Removal and replacement activities maintain nuclear and radiological safety in accordance with Federal regulations and industry codes & standards
- Post-installation test program implementation is in compliance with applicable codes and regulations

Major Inspection Activities

Design and Planning

- Engineering evaluations, design changes, modifications, and operating experience evaluation
- Steam Generator lifting and rigging
- Radiation Protection program: controls, planning, and preparations
- Security considerations – affected barriers

Major Inspection Activities

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<u>Steam Generator Removal / Replacement</u>

- Cutting, welding / non-destructive examinations
- Lifting / rigging activities
- Containment opening
- Radiation protection controls implementation

<u>Post-installation Testing</u>

- Testing program and implementation

Operating Experience

- SONGS, Oconee and TMI SG replacements OpEx were reviewed by inspectors for relevance

- Licensee was specifically asked to address OpEx applicability of SONGS, Oconee and TMI to Davis-Besse replacement SGs

- Oconee SGs are most similar to Davis-Besse replacement SGs

Significant Issues During Inspection

- Shield Building (SB) Void Identified During Creation of 2014 Construction Opening

- SB Rebar Damage During Creation of 2014 Construction Opening

Shield Building Opening

- New construction opening in SB was cut through new concrete poured in 2012 to accommodate transfer of SGs into and out of containment

- This opening was completely encompassed by the 2011 Reactor Pressure Vessel Head replacement opening

- Void and rebar damage were identified during creation of construction opening

Shield Building Opening

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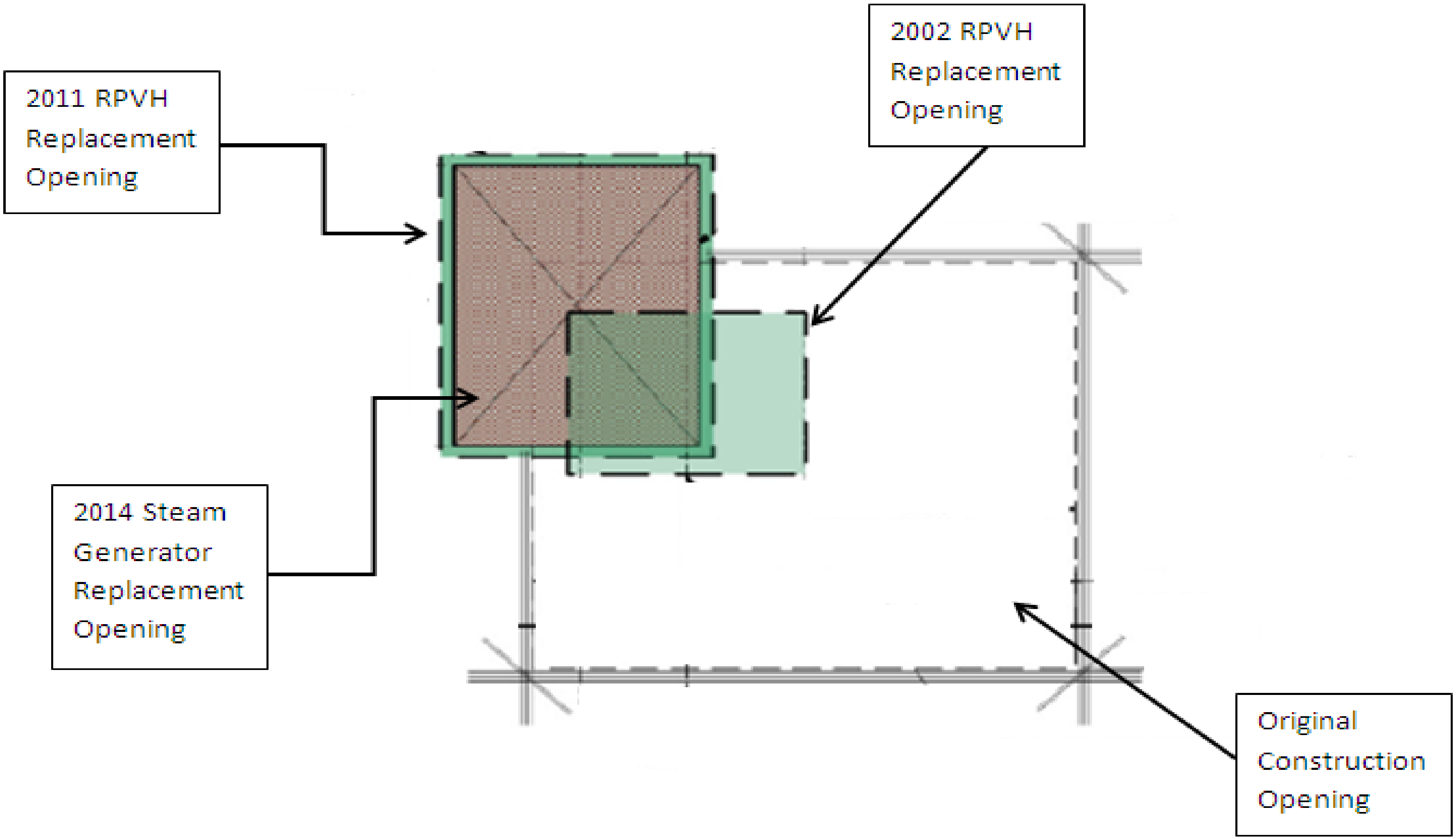
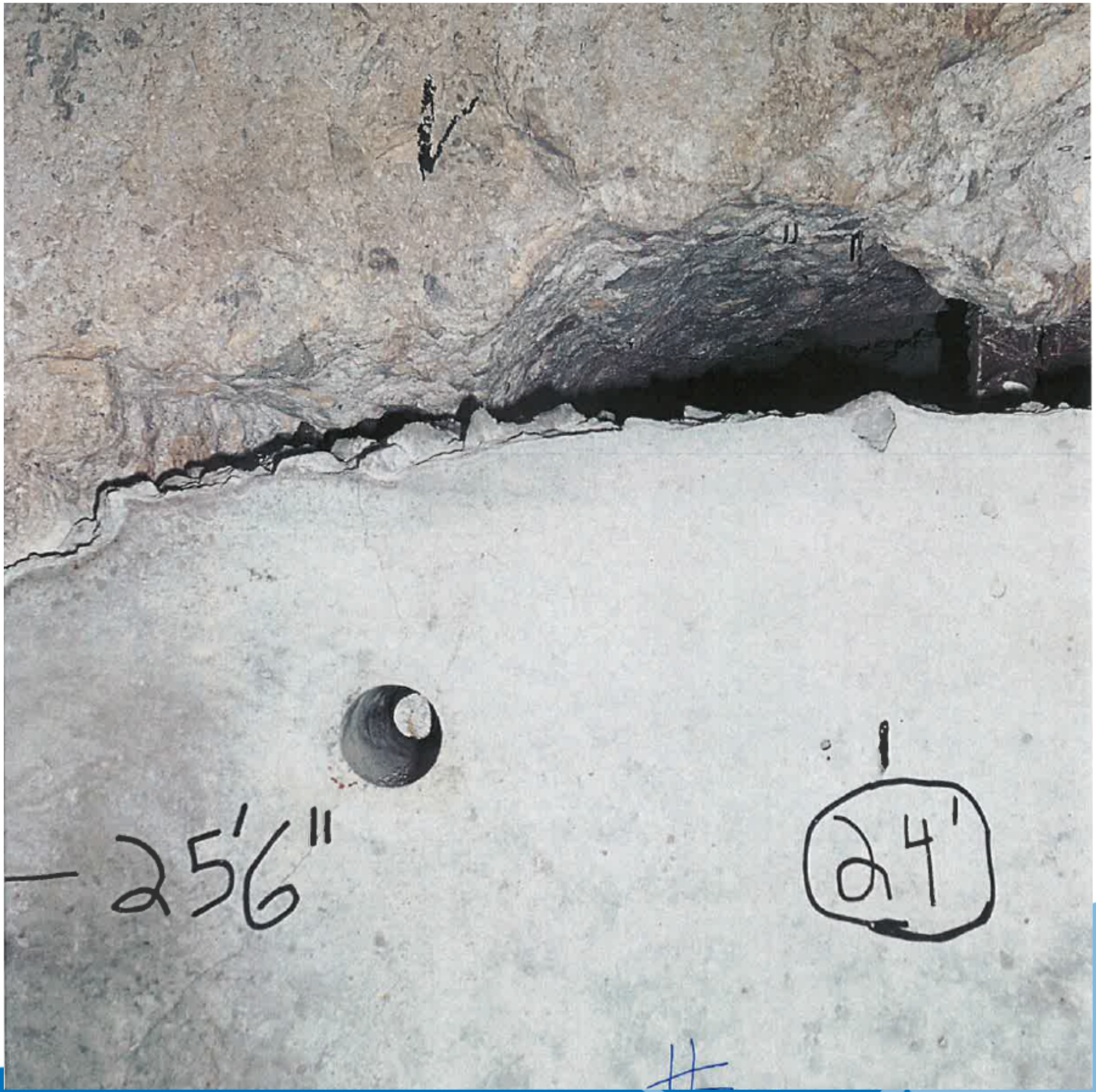


SB 2014 Opening Void



Void Post Restoration

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SB 2014 Opening Rebar Damage

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SB Laminar Cracking

Direct Cause:

- Integrated effect of moisture content, wind speed, temperature, and duration from blizzard of 1978

Root Cause:

- Design specification for construction did not specify application of exterior sealant from moisture

SB Laminar Cracking

Contributing Cause 1:

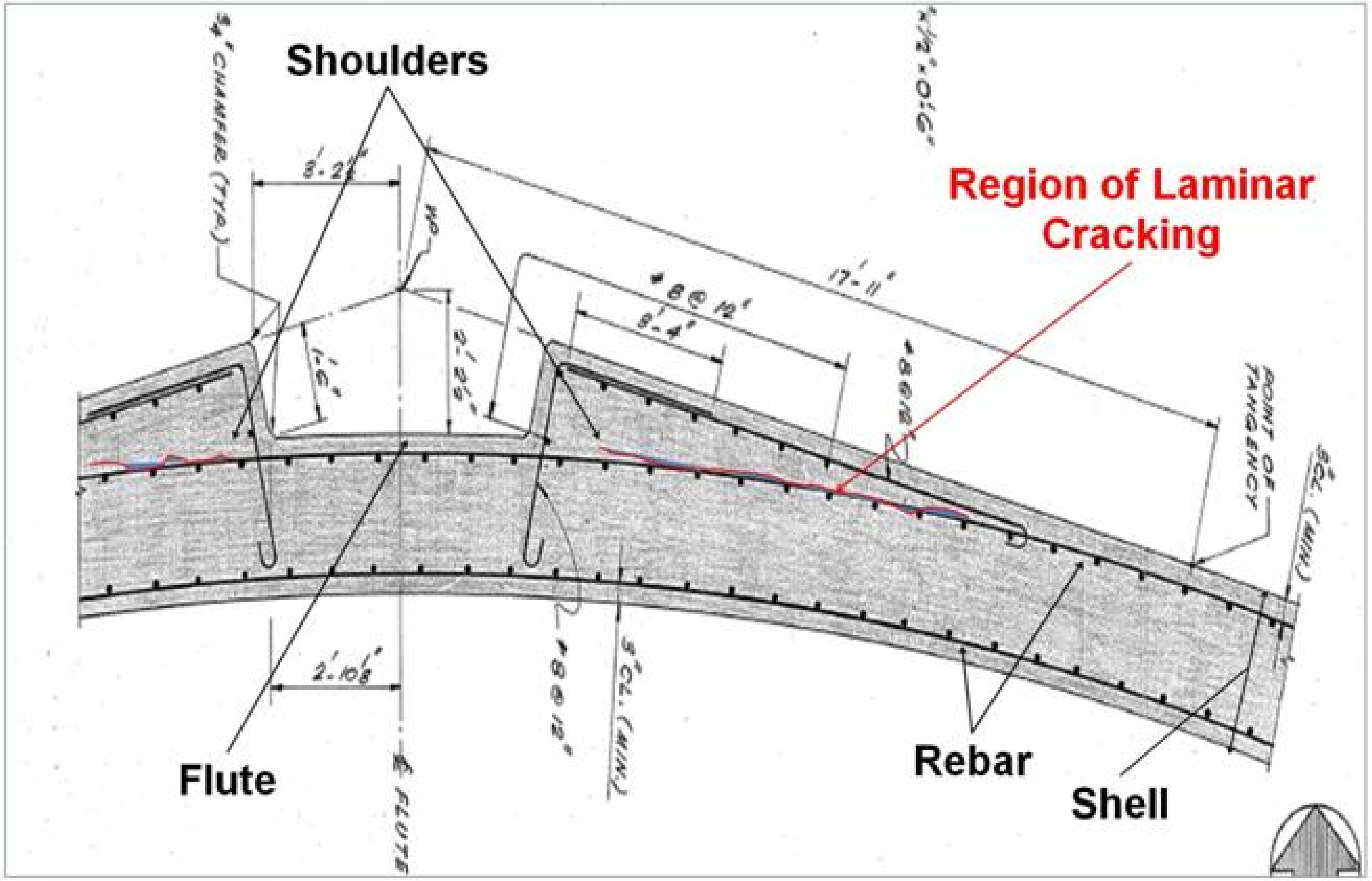
- Inherent stress concentration at outer rebar in shoulder

Contributing Cause 2:

- Shoulder design did not include sufficient radial reinforcement in shoulder region

Contributing Cause 3:

- Rebar spacing ≤ 6” contributed to crack propagation outside shoulder region


Shoulders
Region of Laminar Cracking
Flute
Rebar
Shell

Laminar Crack Propagation

Direct Cause:

- Ice-Wedging
  - Pre-existing Crack
  - Saturated Water in Crack
  - Freezing Cycles

Contributing Cause:

- Application of Coating Prevented Water from Leaving Wall

Corrective Action:

- Monitor Existing Core Bores for Crack Growth

Questions?

Fukushima Initiatives

Julio Lara
TSS Team Leader
Division of Reactor Projects

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Post-Fukushima Inspections

- NRC Regional inspectors completed Temporary Instruction (TI) inspections
  - 2515/183, “Followup to the Fukushima Daiichi Fuel Damage Event”
  - 2515/184, “Availability and Readiness Inspection of Severe Accident Management Guidelines (SAMGs)”
  - TI 2515/187 (flooding walkdowns) and TI 2515/188 (seismic walkdowns)
  - TI 2515/190 (flood hazard reevaluations and interim protection measures)
  - TI 2515/191 is drafted for public comment: Areas: Mitigating Strategies, Spent Fuel Pool Instrumentation, Emergency Planning Staffing & Communications

TI 2515/187 INSPECTION OF NEAR-TERM TASK FORCE RECOMMENDATION 2.3 FLOODING WALKDOWNS

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- From 2012 through 2014, nine greater-than-Green findings were identified related to plant's vulnerability to external flooding.
- Majority of the findings were identified as a result of licensee flooding walkdowns directed by the NRC as a follow-up to the Fukushima Lessons Learned Task Force report.
- The findings noted deficiencies in three broad areas:
  - Inadequate seals that would allow flood waters into safety-related spaces.
  - Procedurally directed actions that could not be accomplished in the time allotted by the final safety analysis report (FSAR) for design basis flooding events.
  - Incomplete procedures that did not provide sufficient direction to prevent core damage during design basis flooding events.

Near-Term Activities

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2014 Mitigation Strategies/Spent Fuel Pool (SFP) Level Instrumentation Audits

Site	SFP Level Instrumentation Completion Date	Mitigation Strategies Completion Date	Onsite Audit Date
Byron	4Q 2014	Unit 1: September 2015 Unit 2: October 2014	August 2014
D.C. Cook	February 2015	Unit 1: November 2014 Unit 2: April 2015	June 2014
Braidwood	2Q 2015	Unit 1: April 2015 Unit 2: October 2015	October 2014
Monticello	April 2015	April 2015	November 2014
Perry	Spring 2015	March 2015	December 2014

Questions?

Kewaunee Decommissioning

Rhex Edwards
Reactor Inspector
Division of Nuclear Materials Safety

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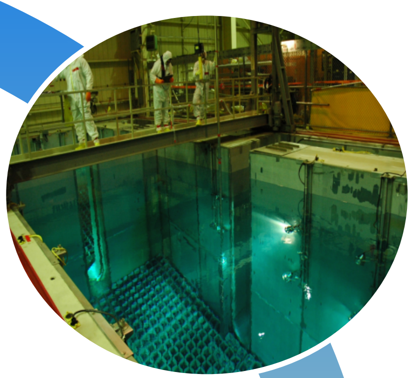
FOCUS

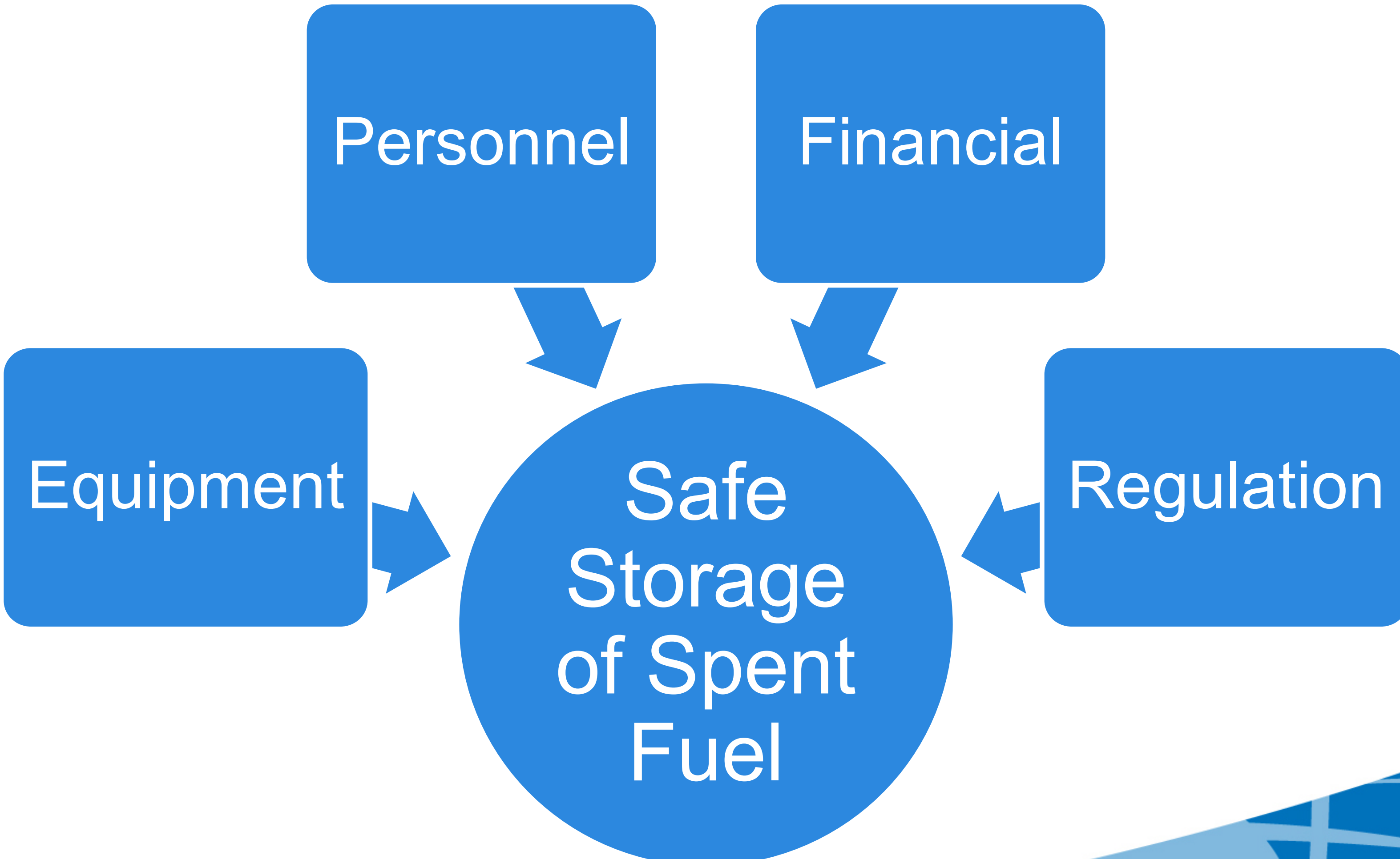
Safe Storage of Spent Fuel



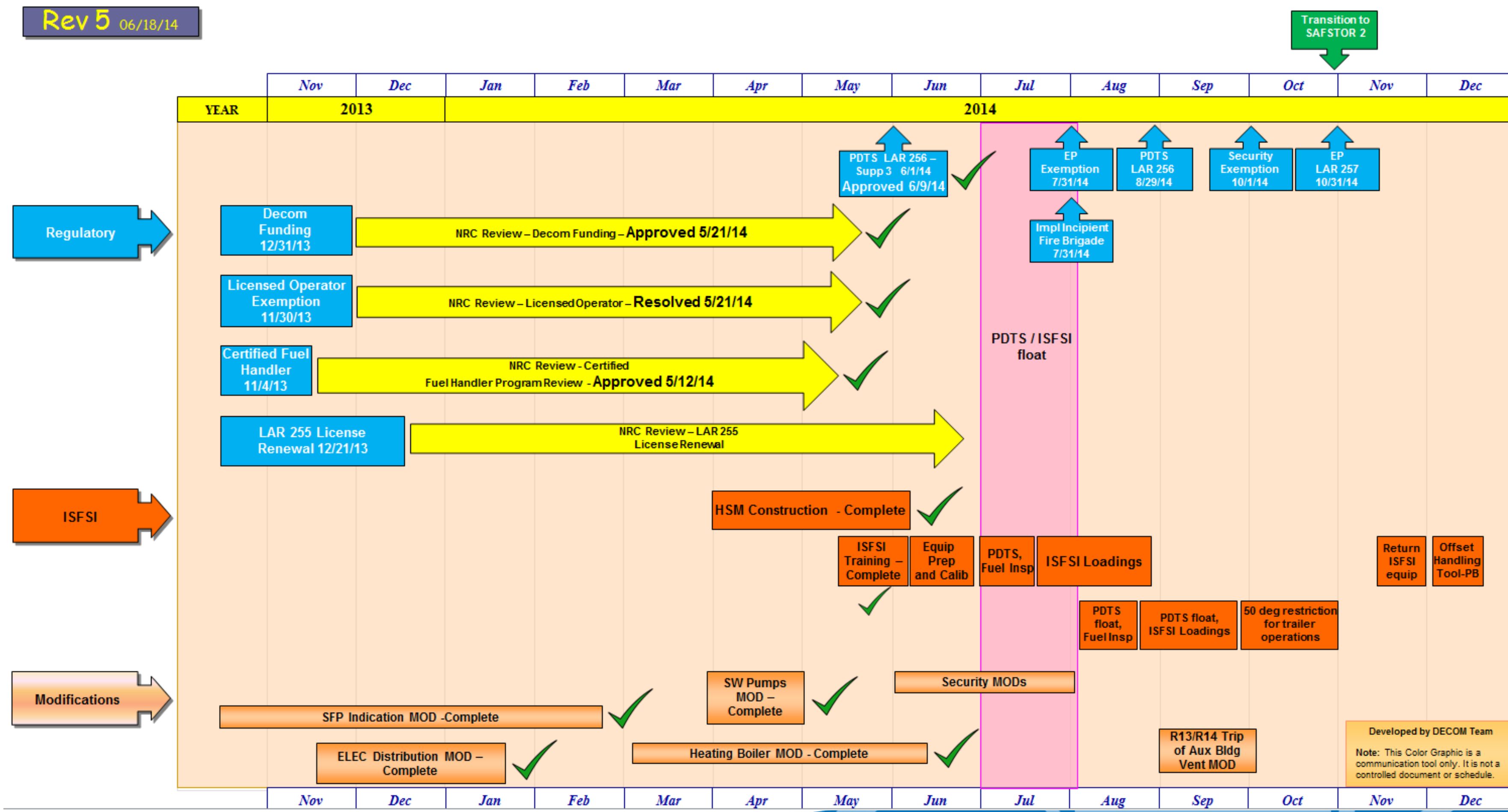
Spent Fuel Pool

ISFSI

CHALLENGES


Personnel
Financial
Equipment
Safe Storage of Spent Fuel
Regulation

2014 Timeline KPS Decommissioning



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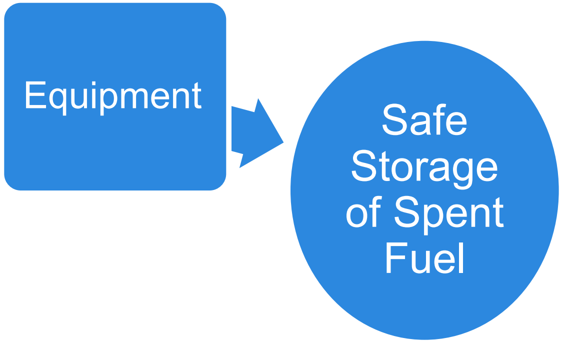
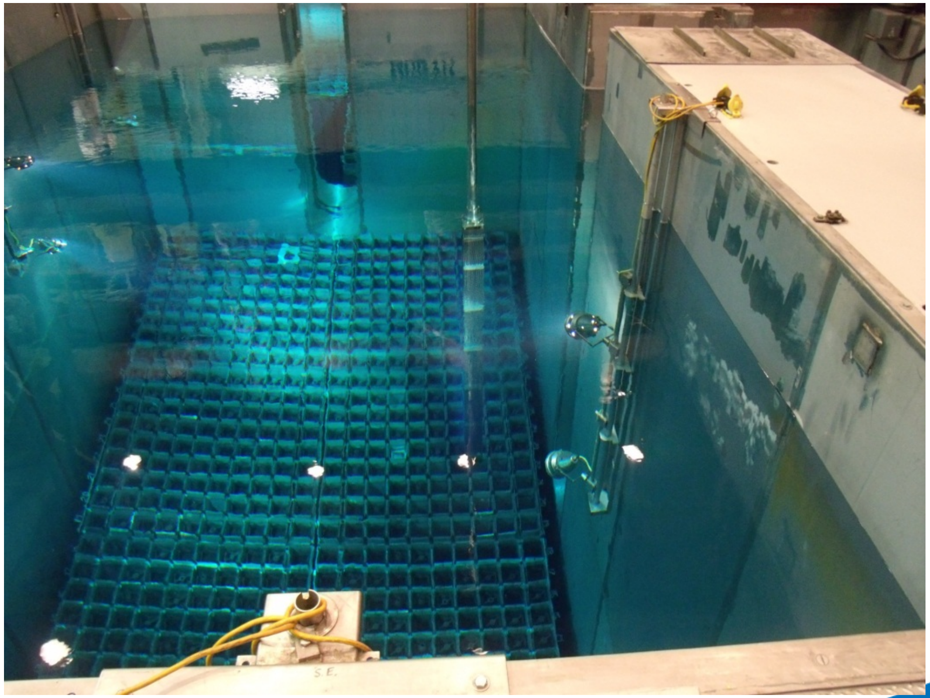


<u>Abandon:</u> Equipment not necessary for fuel management or decommissioning

<u>Equipment Modifications:</u>
- Electrical Distribution
- Service Water Pumps
- Heating Boiler
- Remote Alarm Capabilities
- Security Equipment

<u>Maintaining:</u>



Emergency Preparedness

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Personnel → Safe Storage of Spent Fuel

Current Emergency Plan:
- Operating Reactor
- NEI 99-01 Revision 4

Proposed Exemptions
- Select portions of 50.47 and Appendix E
- Contribution to public health and safety

Permanently Defueled Emergency Plan
- NEI 99-01 Revision 6
- Classification Levels:
  - Unusual Event
  - Alert

<u>Challenges:</u>
- Changes to Emergency Plan under 50.54q
- Two Recent NCVs:
  - Elimination of position & response time changes
  - Staffing analysis

Personnel

Safe Storage of Spent Fuel

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Other Personnel:

- Security
- Operations Staffing
- Fire Protection

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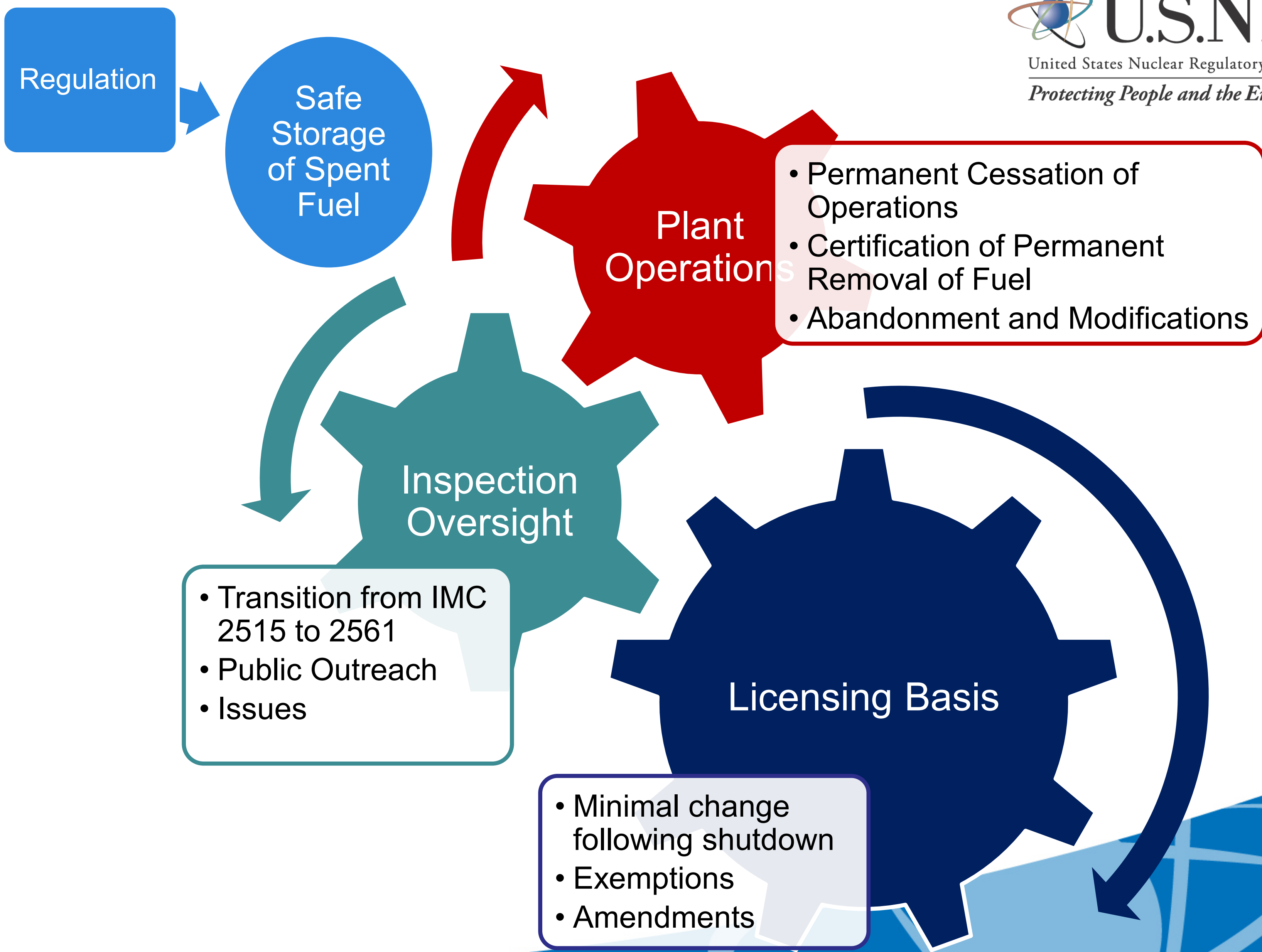

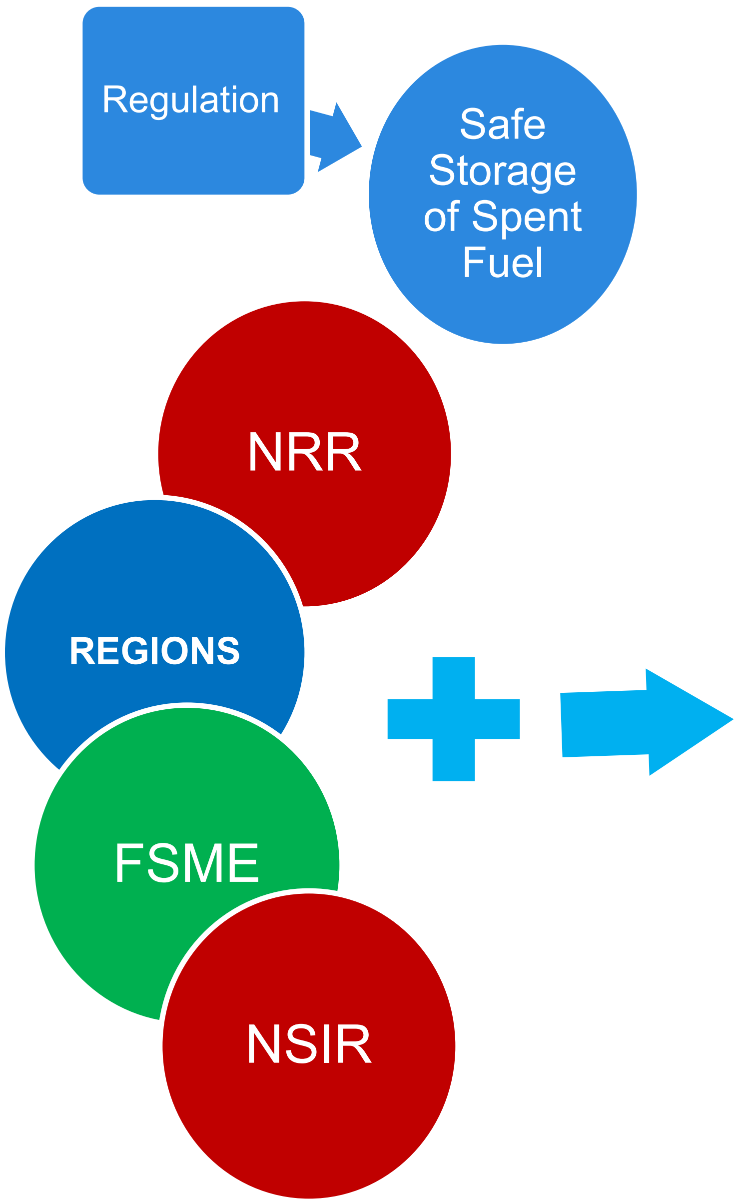

- Short Term – Increase effectiveness of existing process
- Long Term – Recommend regulatory changes to improve process

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Safe Storage of Spent Fuel

Questions?

Inspection of Industry Voluntary Initiatives

July 24, 2014

Billy Dickson, Branch Chief
Atif Shaikh, Senior Reactor Inspector

Division of Reactor Safety

U.S.NRC
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Ground Water Protection Initiative TI-185

- 2 R-III sites lacked full implementation of the industry's ground water protection initiative (Kewaunee and Perry)
- TI-185 samples complete for these sites
- All ground water protection objectives were implemented at both sites

The NRC continues to inspect implementation of the voluntary industry initiative for ground water protection at all sites through the reactor oversight process baseline inspection program (IP 71124.06 Radioactive Gaseous and Liquid Effluent Treatment).

Buried Piping
TI-182

- 15 R-III sites (PWRs and BWRs)
- TI-182 samples complete for each site
- 1 Deviation at Palisades

Overall assessment of R-III plants is that the NEI 09-14 industry initiative concerning buried piping and tanks is effective in examining potential risks for such systems and implementing mitigation techniques to minimize opportunities for leakage

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Questions?