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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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629TH MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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WEDNESDAY

NOVEMBER 4, 2015

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ROCKVILLE, MARYLAND

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The Advisory Committee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., John W. Stetkar, Chairman, presiding.

COMMITTEE MEMBERS:

JOHN W. STETKAR, Chairman

DENNIS C. BLEY, Vice Chairman

MICHAEL L. CORRADINI, Member-at-Large

RONALD G. BALLINGER, Member

CHARLES H. BROWN, JR. Member

DANA A. POWERS, Member

HAROLD B. RAY, Member

JOY REMPE, Member

PETER RICCARDELLA, Member
STEPHEN P. SCHULTZ, Member
GORDON R. SKILLMAN, Member

DESIGNATED FEDERAL OFFICIALS:

KENT L. HOWARD, SR.
MICHAEL SNODDERLY

ALSO PRESENT:

VICTORIA ANDERSON, NEI
DENNIS BLAKELY, FENOC
BRIAN BOLES, FENOC
KEN BYRD, FENOC
CHONG CHIU, FENOC
PHYLLIS CLARK, NRR/DLR/RPB1
CLIFF CUSTER, FENOC
STEVE DORT, FENOC
RICHARD DUDLEY, NRR/DPR/PRMB
RAYMOND FINE, PWR Owners Group
JOE GIITTER, NRR/DRA
TRENT HENLINE, FENOC
ACE HOFFMAN *
JON HOOK, FENOC
KEVIN KAMPS, Beyond Nuclear
MARVIN LEWIS *

JOHN MONNINGER, NRO/DSRA

JAVEED MUNSHI, FENOC

JAMES NEURAUTER, R-III/DRS/EB1

RICK PLASSE, NRR/DLR/RPB1

BOB RISHEL, BWR Owners' Group

GEORGE THOMAS, NRR

*Present via telephone

A G E N D A

P R O C E E D I N G S

8:34 a.m.

CHAIR STETKAR: The meeting will now come to order. This is the 629th meeting of the Advisory Committee on Reactor Safeguards. During today's meeting, the Committee will consider the following: Risk management regulatory framework, Davis-Besse nuclear power station license renewal and preparation of ACRS reports.

This meeting is being conducted in accordance with the provisions of the Federal Advisory Committee Act. Mr. Michael Snodderly is the Designated Federal Official for the initial portion of the meeting. We've received no written comments. Actually, that's not true. We have received written comments, and we have received requests to make an oral statement from a member of the public regarding today's sessions.

There will be a phone bridge line. To preclude interruption of the meeting, the phone will be placed in a listen-in mode during the presentations and Committee discussion. I'll remind you all to please check your communications devices and silence them please. A transcript of portions of the meeting is being kept and it is requested that the speakers use one of the microphones, identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

I also want to make folks aware that theoretically, this is the first meeting of the ACRS that will be webcast, with the ability to view our presentation slides on the web.

Those of you out there on the bridge line who may want to do that, can dial into the -- or connect through the NRC's Public Meeting website and click on the link, I've been told, and it should work. It doesn't call our office and harass them.

With that, unless any of the members have any comments that you'd like to make. The first item on our agenda for today is the Risk Management Regulatory Framework, and I'll lead us through that session.

CHAIR STETKAR: We've had numerous meetings on this topic over the last oh three years or more. It's a long and arduous process that started with the Risk Management Task Force being assembled in really 2011, just before the Fukushima accident. It was linked somewhat to the Near Term Task Force Recommendation 1, and is now coming to some sort of closure, I think.

I don't want to steal too much of the staff's thunder, so I'll turn it over to Joe Giitter of the staff, who will make some introductory remarks. Joe?

MR. GIITTER: Okay, good morning. Today you're going to hear a short presentation from the staff on several options that were considered for the Risk Management Regulatory Framework.

These options include the full implementation of the regulatory framework discussed in NUREG-2150, an optional voluntary approach that would allow licensees to risk-inform certain aspects of the current deterministic requirements, and finally an option to advance risk-informed decision-making without making changes to the current framework.

As the Chairman Stetkar mentioned, there have been a number of public meetings and opportunities for public input, and input from our stakeholders on the different approaches. As you know, the Risk Management Regulatory Framework envisioned in NUREG-2150 was not something to be implemented in a matter of months, but rather a vision for the future, 15 years or more from now.

While the recommendations of the staff are influenced by the current reality facing the NRC and the industry, which is admittedly near-term focus, they also support sustaining and increasing risk-informed decision-making within the agency.

It is imperative in the current environment of declining resources that we focus our attention on issues of greatest safety significance. As you will hear later this morning, we are actively leverage risk insights to become a more effective and efficient regulator.

Finally, I want to recognize all of the hard work and dedication that the staff has put into this effort. In particular, I want to recognize Dick Dudley, who has put off his retirement to help us develop the SECY paper. So with that, I'm going to turn it over to Dick.

MR. DUDLEY: Thanks Joe. On Slide 2 is an outline, if I show it, of the presentation that we'll be giving you today. First, I'll talk about the background of the effort and our next steps. Then I will go through the RMRF, Risk Management Regulatory Framework SECY paper. It has four sections.

Section 1 is on RMRF implementation options for power reactors, the three options that Joe discussed with you. Section 2 is a reevaluation of Near Term Task Force Recommendation 1, Improvement

Activities 1 and 2 that was deferred to this RMRF effort by the Commission. Section 3 is a discussion of an agency-wide risk management policy statement.

After that, I will briefly discuss changes that were made to the SECY paper during the office concurrence process, and then finally I will discuss Section 4 just briefly on the interrelationships between the risk-informed -- ongoing risk-informed activities for nuclear power reactors.

After that, Joe Giitter will begin a discussion of the Risk Informed Steering Committee oversight activities. I just want to point out that there are four sections to the paper. Sections 1, 2 and 4 apply only to power reactor safety, and only Section 3 is applicable on an agency-wide basis to all program areas.

As Chairman Stetkar said, there's been a long history behind this, and we've had a significant level of public interaction on the NUREG-2150 RMRF. We've held four public meetings. We've had five ACRS Subcommittee meetings. I believe I counted right. I know we've had three written public comment periods and we released white papers in November 2013 and May 2015.

We met with the Reliability and PRA

Subcommittee most recently on October 19th, where we discussed our draft final RMRF SECY paper. We're meeting with the full Committee today with the purpose of receiving an ACRS letter some time around mid-November.

Our response to that ACRS letter will be delivered in December, and I hope to bundle all the letters together in the RMRF SECY and provide it to the Commission by December 18th, 2015. On Slide 4, as Joe said, we considered three options.

I'm going to give them in a different order, but Option 1 was maintain the current regulatory framework; Option 2 was to implement a voluntary alternative licensing basis that would be done on a plant-specific basis; and Option 3 would be to implement the approach recommended in NUREG-2150.

Discussing Option 1 in a little more detail, Option 1 would be no extensive revision to our current regulatory framework. We believe that the current regulatory framework meets the four criteria in NUREG-2150 for what they characterized as a Risk Management Regulatory Framework, and that it has a mission and objective, and the goal -- the goal we would utilize --

The goal is to provide sufficient risk-informed and performance-based protections to ensure risks are acceptably low. We can use the Commission's safety goal policy statement and subsidiary risk metrics to do that, and decision-making processes that include monitoring and feedback, and we have those in -- this is all for power reactors. We have those in LIC-504 and in Regulatory Guide 1.174.

Power reactor Option 2 is to maintain the existing generic regulatory structure, but we would then write a rule and this rule would allow licensees who choose to upgrade their PRAs to apply for NRC approval of a risk-informed alternative licensing basis.

Now under this licensing basis, licensees could select a plant-specific set of compliance issues or design changes or things they wanted to change that their PRA show are of low risk significance. For these, they'd be allowed to deviate from certain of the current deterministic requirements, but with the condition that they would mitigate all known plant-specific risk vulnerabilities that would meet NRC specified criteria.

So this could potentially bring a currently unregulated event that for some reason was a risk outlier at a specific facility. It could bring that into its licensing basis. The rule would also require mandatory monitoring and feedback, to make sure that the changes in risk were acceptable throughout the lifetime of the facility.

Now we were not able to develop implementation details for this approach, and there are substantial implementation uncertainties with it, and they're listed here. We'd have to review the power reactor regulations and decide which of the rules are amenable to risk-informing or which are not.

We'd have to determine the minimum scope and technical accuracy of a suitable PRA. Would that include certification or review of the PRA? We don't know. We'd have to determine the selection and scope of permissible design changes, and the processes for staff review of those design changes.

We'd have to determine reporting, documentation requirements and then the whole effort would have to be structured in a way as to ensure transparency, both to the NRC and to the public of the process that the licensee was using to maintain risk acceptably low at his facility, because facilities of starting with seemingly identical designs could evolve and look different from one another over time under this approach.

CHAIR STETKAR: Dick?

MR. DUDLEY: Yes.

CHAIR STETKAR: If I -- if this option were invoked, and I were a new plant licensee, whether that's an SMR or maybe even the next generation of plants, this would allow me to voluntarily come in and use a risk-informed basis for my entire licensing basis, would it not?

MR. DUDLEY: I would hope that -- I can't really speak.

CHAIR STETKAR: I mean that's perhaps a bit too strong when I say the entire licensing basis, but it would certainly open that door to those types of applicants, wouldn't it?

MR. DUDLEY: I mean I think it's true, that this approach would be more useful for new reactor designs than it would be for these current plants that are already built for the -- and in accordance with the criteria that were established, you know, some 30 or more years ago.

CHAIR STETKAR: Yeah, yeah. Okay, thank you.

MEMBER SCHULTZ: But it would seem that what you've outlined is what implementation details would be necessary to move forward with the alternative, that in fact the expectation associated with that long list of things that would need to be done is that you're looking for the process to, if you will, totally change to a risk-informed regulatory framework for that licensee, and that that could be used, should be used for their licensing approach moving forward.

I mean it's a very daunting list of implementation details that have not been developed.

MR. DUDLEY: Yeah, that's correct.

MEMBER SCHULTZ: Therefore, one would assume that the benefit, the product would in fact be that allowance, in terms of the regulatory approach following satisfying all the implementation requirements.

MR. DUDLEY: I'm not sure I understand -- is there a question or --

MEMBER SCHULTZ: Well, I'm trying to understand -- you set up to say the implementation details are as such, and that the expectation is that the approach will be for a licensee to mitigate all known plant-specific vulnerabilities meeting NRC specified criteria yet to be determined.

So if one were to jump all of those

hurdles, one would expect there would be a substantial benefit at the end.

MR. DUDLEY: Well, it would -- it works both ways, and so once we set the risk criteria, if that brings in an unregulated event, then that event would be regulated and the risk will be mitigated. But it would also go other ways and allow licensees to remove certain protections that exist now by the deterministic regulations, that show -- that are shown by the PRA to not be risk-significant.

So the -- it would really work both ways, and the net change in safety could be none.

MEMBER CORRADINI: But so just to ask these --

MR. DUDLEY: By the way, it would be more economical for licensees.

MEMBER CORRADINI: So can I ask Steve's question differently? So Option 2, you list all the things that have got to be done. So are there practical technical questions that are taking this route now? The one that comes to mind is GSI-191. Certain plant licensees are going to approach this from a risk-informed process.

So instead of trying to sit down and change the whole regulatory framework in Option 2, are there certain technical issues that are being pursued this way that staff is already addressing?

MR. GIITTER: I can address that Dick, if you want.

MEMBER CORRADINI: Yes.

MR. GIITTER: Yeah. We do have some examples, and I just wanted to comment on something Dick said. I don't think that safety would be neutral. I think safety would be improved, because you're looking at -- with this approach, because you're not focusing on those things that are compliance issues of a low safety-significant issue, and you're addressing vulnerabilities that aren't currently addressed.

So I want to just be on the record to make sure that I think this is -- this would result in improvement in safety.

MR. DUDLEY: We really don't know, and so yeah, we don't know.

MR. GIITTER: Well, but I think theoretically anyway that's -- that would be the result.

MEMBER CORRADINI: Well, the reason I asked my question, I guess, is just repeating Steve's question a little differently, is that from a process standpoint, it seems to me this is attractive if there are certain technical issues that are already out there that in current plants --

MR. GIITTER: So we do have -- I'll give you some examples. Probably the biggest example is NFPA-805. About half the fleet went from a deterministic, prescriptive requirement --

MEMBER CORRADINI: That's a good example?

MR. GIITTER: They came out, you know, and --

CHAIR STETKAR: It's an example.

MR. GIITTER: But the other example is 50.69, you know. When we looked at the Vogtle pilot and then prior to that the South Texas exemption for 50.69, the categorization of safety-related structure systems and components, we found that 75 percent of systems, SSCs that were originally considered to be safety-related were in fact that important to safety, when you look at it from a risk perspective.

But there were also systems, for example like RCIC and the BWR and other examples of non-safety related systems that were actually pretty important to safety. So it's looking at the list of SSCs that were determined based on a very stylized accident, design-basis accident. With a risk perspective, you see they don't necessarily match up.

So the treatment requirements for those previously -- the 75 percent of the safety-related SSCs could be different and, you know, I've heard anecdotally from South Texas and Vogtle that, you know, saving of millions of dollars a year in how they treat those safety-related SSCs.

CHAIR STETKAR: I also look at what's been done for some of the new reactor design certifications, where there's a bit of analogy here, where the concept of regulatory treatment of non-safety systems that are important to safety falls within this kind of intermediate range.

So things that do not meet the traditional criteria for the designation of safety-related mean they're not absolutely required to meet the deterministic criteria for mitigation of design basis accidents.

But the risk assessments indeed do show that they're important to safety, and there's -- there are now in place various monitoring and treatment mechanisms for those that are not as stringent as, for example, technical specifications.

But in many cases, in practice have many of the same types of practical implications on the way people operate the systems and monitor them in the plant. So there is sort of this notion building, I think among the industry and the staff, of some sort of comfort with the use of risk information to more finely focus, if I can call it that, on the equipment and the systems that are shown to be, at least through the risk assessment, important.

Those words "important to safety" rather than strictly safety-related, according to the traditional licensing definitions of that term.

MR. DUDLEY: On Slide 7, because of these implementation uncertainties, the staff held a public meeting on July 29th, specifically on Option 2, to try to discuss in more detail these implementation issues. The staff presented additional details on Option 2, and thoughts and approach for what it might take to develop a suitable PRA.

The industry stakeholders at that meeting were still concerned about the lack of implementation details on Option 2, and they said without further information on these areas of uncertainty, that they could not assess the safety benefits and the costs of Option 2.

Because they couldn't do that with the information before them, industry said it was not able to support the approach until we developed more details.

MEMBER CORRADINI: Are there -- so let me just go back to topical areas, and I'll keep on coming back to GSI-191. Are there particular attributes of what currently is being considered with that as an example, with certain plants thinking they want to essentially approach it that way, that could be generalized?

MR. DUDLEY: GSI-191 is being looked at in 50.46(c) for long term cooling on the debris issue. So there is a risk-informed alternative included in the draft --

MEMBER CORRADINI: Draft final?

MR. DUDLEY: --of 50.46(c).

MEMBER CORRADINI: Okay.

MR. DUDLEY: So and 50.46(a) on risk-informed ECCS five years ago, also has a risk-informed alternative for emergency core cooling, and that would be reconsidered by the staff after RMRF is completed.

MEMBER CORRADINI: Well but I guess --

MR. DUDLEY: After the Commission decision.

MEMBER CORRADINI: Yeah. But I guess what I'm asking is so you have these examples. Are there actually some examples that are common, so that you see a common framework could develop from what already as ad hoc has occurred or is occurring?

MR. DUDLEY: You know, these are pretty specific applications. I'm not sure that -- well, maybe Joe will answer that.

MEMBER CORRADINI: But let me -- I mean you guys are much more adept at the process part of this. But it just strikes me that if this one, based on whatever slide you just left, the stakeholders are not in favor of it, conversely are there attributes in what it's already being applied to that can be generalized that actually develops an ad hoc approach to this.

So that if the next one pops up, it ought to have certain attributes that are similar to the past ones so you don't re, you know, re-earth and go through all, a lot of wasted effort?

MR. DUDLEY: I think we do that naturally, but Joe.

MR. GIITTER: Yes. No, I would agree. That's something that, you know, we don't necessarily want to adopt exactly what we did before, because I mean I could use NFPA-805 as an example. We learned a lot of lessons from NFPA-805.

So you know, we're a learning organization and -- well, I'll talk a little bit about that when I talk about the Risk-Informed Steering Committee. But yeah, I mean there are certain attributes that are common to all of these, and I think would be included or would be considered if we were to try to implement Option 2.

MEMBER CORRADINI: Does -- well, we can ask industry that. Okay, fine. Thank you.

MR. DUDLEY: On Slide 8, I discuss power reactor Option 3 to implement the NUREG-2150 recommended RMRF. Under that recommended approach by the Risk Management Task Force, we would issue a regulation that requires all operating reactors to upgrade their PRAs to specify criteria, and then they would develop a plant-specific licensing basis, based on their plant-specific risk profiles.

They would have to meet NRC specified risk management objectives. But we would also have to develop enhanced criteria for determining adequacy of non-risk factors, such as defense indepth and safety margins. We have to have better criteria for these non-risk factors, or this would become a risk-based approach and not a risk-informed approach, which is the NRC's policy.

So based on the risk profile, licensees would implement a plant-specific licensing basis by determining on their own how they want to meet the risk objective, ensure the necessary protections are there, demonstrate the adequacy of the non-risk factors, establish a risk-informed decision-making process and a monitoring and feedback process.

CHAIR STETKAR: But to be clear for the members who weren't at the Subcommittee meetings, the functional difference between Option 2 and Option 3 is Option 3 would be required for all licensees, required for all licensees.

MR. DUDLEY: Right, that's the difference.

CHAIR STETKAR: Whereas Option 2 --

MR. DUDLEY: Option 2 is voluntary.

CHAIR STETKAR: Is functionally the same, but it's voluntary.

MR. DUDLEY: Well, the scope of the PRA for Option 3 might be larger, I think. Option 2 a licensee, based on their desired design changes, might be able to limit the scope of the PRA.

CHAIR STETKAR: Okay.

MR. DUDLEY: So the difference is one is mandatory, one is voluntary, and depending on what design changes the plant would choose, the scope of the PRA might be different.

CHAIR STETKAR: Thanks. Thanks for the clarification.

MR. DUDLEY: So on Slide 9, I discuss the written public comments we got on these three options for power reactors. On Option 1, maintain the current framework. Four commenters specifically addressed Option 1, and all four of the commenters that addressed Option 1 supported maintaining the current regulatory framework.

On Option 2, the voluntary alternative risk-informed licensing basis, three commenters addressed Option 2 specifically, and all three again expressed some level of interest, but said the NRC hadn't developed sufficient implementation details to analyze costs and benefits.

Option 3 was specifically addressed by two commenters, and neither of those commenters supported Option 3 for currently operating power reactors. One commenter said the approach was simply not viable, and another thought even though there is insufficient information, in that commenter's judgment they believed Option 3 was unlikely to be justifiable for the current fleet of operating reactors.

So what was the staff's conclusion? The

staff concluded that we should not pursue Option 2 at the present time, because industry and staff do not have the resources to develop and support the approach. We determined that we should not pursue Option 3 for the operating reactor fleet, because the modest potential safety benefits are unlikely to justify the substantial implementation costs.

Therefore the staff, for -- under Section 1 of the paper, RMRF options for nuclear power reactor safety, recommends Option 1, to maintain the current regulatory framework. We want to emphasize that Option 1 is not a do-nothing approach. All ongoing and planned risk-informed initiatives will continue, and the staff will continue to make incremental risk-informed regulatory improvements whenever appropriate.

By making these incremental improvements, we're maybe moving closer to a point that we could reduce some of these implementation uncertainties of Option 2. So we may get to a point where we can then -- Option 2 becomes less of a daunting challenge.

Okay. Section 2 of the paper is different. It addresses a reevaluation of two improvement activities recommended by the staff in Near Term Task Force Recommendation 1. Improvement Activity 1 was to establish a new design basis extension category of events and regulatory requirements.

And the staff has determined that creating a new design basis extension category is not necessary. Instead, what the staff intends to do is to develop clear internal rulemaking guidance to make sure that all new regulations, and specifically regulations that are in the beyond design basis area, specify all of the necessary regulatory attributes that are needed.

That would include quality assurance requirements, treatment requirements, sorry. Quality assurance, treatment, sorry. This is embarrassing. It will -- I'll come back to that. I'm really disappointed. Okay, reporting requirements, change processes. That's right. The change process in 50.59 only applies to design basis requirements. You would need to develop your own change process for beyond design basis requirements.

So there are six or seven different regulatory attributes that are necessary to be addressed for beyond design basis requirements, that are not necessarily required to be addressed for design basis requirements.

Now Improvement Activity 2 is to develop criteria for -- a definition and criteria for determining the adequacy of defense indepth. While this effort could potentially succeed and we believe it could potentially succeed in establishing predictable objective criteria for adequacy of defense indepth, the resources for developing these criteria would be substantial.

We estimated six FTE over a period of three to four years in the SECY 13-0132 on Recommendation 1. We also note that it's possible that after having spent these resources, the staff might be unable to establish predictable objective criteria that were found acceptable to the Commission.

So given the current environment, as Joe was discussing, the staff recommends that the NRC should not undertake the defense indepth activity at the present time. That does not mean we recommend against never undertaking it, and in fact defense indepth criteria developing a better definition and criteria was supported by a number of public and industry commenters.

So this is an activity that is -- it has some stakeholder support, but at the present time we think would be -- resources are insufficient to undertake it. We will, however, go forward to update the defense indepth guidance in Reg Guide 1.174 that was directed by the Commission in the SECY paper on containment accident pressure.

MEMBER CORRADINI: So can I summarize what I hear here, at least for Activity 1? So Activity 1 basically says there will be no gray zone. There will be a black zone and a white zone, and if we come up with an issue that was beyond design basis, we're going to stick it inside the design basis with a special -- with a special event.

MR. DUDLEY: I don't think so.

MEMBER CORRADINI: My example is already you have special events. That was SBO. We've added to them FLEX. We have a hydrogen rule. All these things were considered beyond design basis and now they've been pulled in based on experience and judgment. But there shall not be a gray zone. That's how I read Activity 1.

MR. DUDLEY: No. I'm trying to find the right slide. Hold on. Here it is. Okay. There is the gray zone. All right. You can see the top three boxes, the green box, the yellow box and the blue box. That's the design basis. That's what we understand. That's what we note Appendix B applies to that. We have clear existing criteria for all the regulatory attributes for the -- for design basis requirements in these three boxes.

But yet we have additional regulations that exceed the design basis. Some of them are for adequate protection and some of them are cost-justified substantial safety increases. So those regulations exist in this space, which is currently undefined.

The category, the Recommendation 1 was to well, let's invent a category and call them design basis extension. Well what's the utility of that? Well, it tells you that you need to specify the regulatory attributes for all of those rules.

Well, if I tell all the rulemakers in the rulemaking guidance that hey, if I'm beyond these three boxes, that I have to specify all those regulatory attributes in a rule, then the intent of that category is satisfied, just by us knowing how to make better rules.

MEMBER CORRADINI: Okay.

MR. DUDLEY: And we don't officially name it.

MEMBER CORRADINI: That's subtle enough. So again --

MR. DUDLEY: It's there by default.

(Simultaneous speaking.)

MEMBER CORRADINI: But I guess I'm -- but I guess I'm -- the way I read Activity 1 is we've done it in an ad hoc manner. There is no reason to go back and reevaluate it, that some things may fall in and somethings may fall out.

MR. DUDLEY: Well, I think everything that's not within the design basis by default is in this gray area, and some of those rules that we -- when we initially started writing beyond design basis requirements, I think the ATWS rule might have been the first one.

I think it said that the shunt trip breakers had to be reliable, and that was it. That was all that they -- those were the only regulatory parameters specified. What does reliable mean, and you know, and what if they wanted to change that design? 50.59 doesn't apply to beyond design basis requirements.

So over time, we started to add more and more regulatory attributes when we would write our next beyond design basis rule. We still haven't gotten it right. I think the aircraft impact rule I can't remember. It might have been quality assurance that it left out.

But you know, we're getting better and better. On the mitigating systems rule, knowing the full list of regulatory attributes, when we issue that rule it should be the first rule that we will issue that satisfies all of these regulatory attributes, and it will indeed have its own regulatory change process that would allow licensees to make changes to this -- to the beyond design basis requirements that they're committing to under the mitigating systems for the beyond design basis events rule.

MEMBER CORRADINI: Okay.

MEMBER RAY: When you use the term "rule," you mean to do that deliberately and not -- because there are of course a lot many things in the hierarchy of guidance, in the staff guidance and regulatory guidance and so on and so forth. But at this point, you're talking just rules.

MR. DUDLEY: This is -- it will be actually in the rule language for the mitigating systems rule. There will be a change process for --

MEMBER RAY: But I think this figure is helpful, very helpful actually. But again, we're just -- you're talking about rules. That's what we're talking about now and not --

MR. DUDLEY: Just about rules, yeah. Just about -- when you write a regulation, that's why we can do it by putting it in the rulemaking guidance for power reactors. We have LIC-300. That's where we'll put it.

MEMBER RAY: And there's a presumption that rules are the basis for everything else we do I guess here.

MR. DUDLEY: Yes.

MEMBER RAY: Yeah.

MEMBER RICCARDELLA: Are there design basis, beyond design basis considerations or events that we have to address that aren't covered by rules?

MR. DUDLEY: Well, some things are voluntary --

MEMBER RICCARDELLA: Well no. The example that comes to mind is the seismic upgrades, the 2.1 activities. Is there going to be a rule addressing this?

MR. DUDLEY: I can't speak to that. I really don't know. I think there are going to be rules, but I'm not knowledgeable about how that's going on.

MR. GIITTER: But currently those are being done under 50.54(f), as you're aware.

MEMBER CORRADINI: Which is an order.

MR. GIITTER: So what the regulatory footprint would be beyond that, I think, is still undetermined.

MEMBER CORRADINI: So to modify Harold's question, it's rules and orders. So what you just said is an order. So it will be done, period.

MR. DUDLEY: Right.

MEMBER CORRADINI: So okay.

MR. DUDLEY: Well actually the rulemaking guidance may not apply to an order, but it would certainly be good practice if we did.

MEMBER RICCARDELLA: To have these regulatory attributes that you listed?

MR. DUDLEY: Yes.

MEMBER RICCARDELLA: Yeah. Thank you.

MEMBER CORRADINI: But I'm sorry that I'm -- so on a particular issue, I get it. But when you start giving me these colored zones, in the colored zones there that are either adequate protection or cost justified, I write down the ones that I remember. ATWS, SBO, FLEX, EDMGs.

I'm sorry? Oh and sorry, Reactivity-Initiated Accident, RIAs. There are a list of these things that fall somewhere in the gray?

MR. DUDLEY: Yes, there are. Yeah, and I

think --

MEMBER CORRADINI: What I'm trying to understand, the staff's view is there's no reason to look at the various colors of gray again. They're there, we understand them, no need to regularize them, no safety benefit.

MR. DUDLEY: No. They're also different that, you know, if you threw them all in the gray box and said these are the requirements for the stuff in the gray, then it might not be right, because each rule has a different level of specificity, a different level of risk associated with it.

We're just saying that when you're in that gray area or exceeding the design basis, there are many additional regulatory parameters the rule should address for it to be full and complete.

MEMBER CORRADINI: I understand, okay.

MR. DUDLEY: And we're not telling you -- in this guidance it won't tell the rulemakers what those parameters should be, you know, what the level of quality assurance could be. It just says you're going to have to decide in the rule.

Otherwise, when we issued all those other rules that weren't complete, we had to work it all out with guidance and it was kind of messy. We need to write a rule that's clear and specific, and we're going to just do that by specifying these regulatory attributes in the rulemaking guidance. Let's see, where I am?

MEMBER RAY: This is what we sometimes call process. We don't like to dwell on it, but it is important, to spend some time on it.

MR. DUDLEY: Yes, yeah.

MEMBER CORRADINI: So last question, then the Chairman told me that I have to be quiet. So is there any activity inside the staff that one could evaluate this decision based on a Level 3 PRA, like the Level 3 PRA activity?

In other words, can one almost use the activity that you're undergoing now to actually see the various colors of gray and see if they were there and if they weren't there how to assess risk?

MR. GIITTER: It's a hypothetical question because --

MEMBER CORRADINI: I know it is but --

MR. GIITTER: We don't really have a lot of plants out there at Level 3 PRAs. But certainly --

MEMBER CORRADINI: Say the last part, I'm sorry?

MR. GIITTER: I said there's not a lot of plants that have a Level 3 PRA.

(Simultaneous speaking.)

MEMBER CORRADINI: Yeah. But staff is doing a specific activity.

MR. GIITTER: Okay. Yeah, I think you could. I think the question you're asking is could I take what I know about the risk of a plant and compare it to the chart that Dick had up, and decide, you know, for that particular plant anyway whether something that was beyond design basis or design basis, where it stacked up in terms of relative risk. Yeah, certainly you could do that.

MEMBER CORRADINI: So instead of -- so my interpretation of the staff's opinion here is it isn't worth the effort. It is what it is right now, various levels of gray. There are rules or orders and we just live with it, and to go back and re-analyze it generically is a lot of work for little benefit.

But if you already have an activity where you're actually looking at it in detail, it seems to me this would be an interesting pilot to actually see where all this stuff stacks up.

MR. DUDLEY: Okay.

MEMBER CORRADINI: I have to be quiet.

CHAIR STETKAR: No, and for the record, I didn't tell you you have to be quiet. We have ample time this morning for a fulsome discussion of this issue. So please continue if you feel that you have something pertinent to add.

(Off mic comment.)

CHAIR STETKAR: No. This is not up to vote.

(Off mic comment.)

MR. DUDLEY: Okay. So that's -- those improvement activities constitute Section 2 of the paper. Section 3 of the paper again is the only section that applies on an agency-wide basis. So it applies to all program areas. It also applies to both radiological safety and common defense and security.

We believe that an agency-wide risk management policy statement could potentially improve and make more consistent the regulatory framework used for all program areas. That was in the Risk Management Task Force report.

I mean I think it's true. It's perhaps debatable, but I believe it's clearly in the Risk Management Task Force report. The NRC requested public comments on two different draft example policy statements. We issued one in November of 2013 and we issued another in May of 2015.

The public comments on both of those draft example policy statements were generally not supportive, and on the most recent draft, only one of ten commenters supported an agency-wide risk management policy statement.

Generally, the reasons for not supporting one were that the commenters believed that NRC can appropriately risk-inform its regulations under the current policy and guidance, that you don't need to establish an agency-wide policy statement before you can go and risk inform individual programs.

There were also concerns expressed about the use of NRC and licensee resources to do this, to try to get a one-size-fits-all policy statement that would apply across all program areas, and would that be useful. To have it apply to everything, it might have to be at such a high level that it might not really be useful or very insightful.

The staff's evaluation is that we agree with the public commenters, that NRC programs can be appropriately risk-informed without an agency-wide risk management policy statement. We believe it would not be appropriate to divert NRC and licensee resources to work on such a policy statement, and therefore the staff recommends against developing a agency-wide policy statement. Are there any questions on Section 3 of the paper?

And you'll be hearing or you were given a non-concurrence by one of the members on the working group, that the agency-wide policy statement is one of the elements of that non-concurrence.

So I was also asked to tell you what changes. When I met with the Subcommittee on October 19th, the paper was an office concurrence, and I was also asked then to tell them what did we change as a result of office concurrence. You can -- the most significant changes are shown in the changes to our recommendations.

The text in red is added text as a result of office concurrence. So Recommendation 1 is maintain the existing regulatory framework and we made it clearer, throughout the paper, that this is for the nuclear power reactor safety program area. So there were a number of additional changes made throughout the text of the paper, to make clear that when we say maintain the existing framework, we mean for nuclear power reactor safety only.

But we also added, and I'm just going to read this, that the NRC will continue its long-held commitment to the defense indepth concept, to the regulation of nuclear reactor issues beyond the traditional design basis events where appropriate, and to the inclusion of the defense indepth concept as the central component of risk-informed regulation.

Although we're not recommending going forward today to develop the definition and criteria for defense indepth, we added these words to make it very clear that we're not going backwards either. We maintain our long-held commitment to defense indepth.

In Recommendation 2, the recommendation is to refrain from developing an over-arching agency-wide risk management policy statement. But we also added language that ongoing staff activities to implement risk-informed approaches within NRC program areas will continue to move forward, and are not impacted by the staff's recommendation against developing an overarching agency-wide risk management policy statement.

There was some concern that some might think that if we say don't do an agency-wide statement, that might mean that other offices that are working on risk informing things other than nuclear power reactor safety, that that would affect their ongoing efforts. We want to make it clear that no, those efforts can and should proceed.

The last section of the paper, the Commission asked to explain the interrelationships between a number of ongoing risk-informed initiatives for nuclear power reactor safety. That was in the SRM on SECY 13-0132.

We've done that in Section 4 of the SECY paper, where we've listed the risk-informed initiatives that we're aware of and we've tried to explain how they're related to one another.

So that completes my presentation. Next, Joe Giitter is going to talk about the Risk-Informed Steering Committee and how it does forward-looking planning actions. Joe.

CHAIR STETKAR: Thanks Dick.

MR. DUDLEY: Sure.

CHAIR STETKAR: Before we let you off the hook, do any of the members have any other questions for Dick, on the material we've heard about? If not, Joe you're up.

MR. GIITTER: Okay. I'm just going to talk from here. I just have one slide. I wanted to point out, this should be in quotes, but this comes right out of the charter for the Risk-Informed Steering Committee, and one of the taskings or one of the charter items is to provide strategic direction to the NRC staff, to advance the use of risk-informed decision-making in all aspects of our -- how we regulate in licensing oversight, rulemaking, other regulatory areas. So pretty broad direction.

As I'll talk about in just a minute though, I think the focus right now of the Risk-Informed Steering Committee, although it is forward-focused in a number of areas, I think the primary focus is to remove some of the obstacles to risk-informed decision-making, and I'll talk a little bit about those.

The chairman of the Risk-Informed Steering Committee is the office director of NRR, Bill Dean, and we have representatives or other members or deputy office directors from the offices, as you see up there, Research, NMSS, NSER, NRO and we also have a regional -- a Region I regional administrator to have regional representation.

So the focus so far of the Risk-Informed Steering Committee is to deal with some of what are viewed as obstacles to future risk-informed decision-making. Probably the biggest focus area coming out of NPFA-805 was PRA technical adequacy.

One of the issues, and I know we've talked to the ACRS about this before, with NFPA-805 was the peer review process that was envisioned didn't exactly work out the way that people expected it to. Those are my words. But I'll give you an example. When fire PRAs were developed by licensees, typically by contractors, they used new methods, and the new methods were methods that the NRC had never seen before.

In some cases, they used the screening methods in NUREG CR 6850, but in many cases they felt those were too conservative, so they used new methods. The peer review would come in and in the process of identifying facts and observations, they would note the new methods.

They would turn the facts and observations over to the licensee. So when NRC received an application, one of the things they would do is go out and do an audit, and one of the things they noted was that a lot of the facts and observations weren't closed out. A number of RAIs we had pertained to the licensees, you know, with the steps they had taken to close out some of the facts and observations.

In many cases, the facts and observations that were open related to these new methods. So the NRC found itself during the NFPA-805 review of trying to resolve the new methods initially as part of the individual licensing reviews, and then in parallel. So some of the changes that are being proposed under this PRA technical adequacy is just to develop a vetting panel, and then the vetting panel would include some NRC membership on it.

It ultimately would decide when there's a new method, what is the appropriate process for dealing with that new method, and that could be a wide range of things. Something as substantial as going to a separate EPRI panel, if it's a very complicated or technically detailed method, to the possibility that it's a method that's well-established, but perhaps not widely used in the nuclear industry.

So the vetting panel, I think, is one step to address the new methods issue. The other one is to provide better direction on closing out the F&Os. So those are some issues that are being addressed under technical adequacy.

Another area is the treatment of uncertainties and decision-making. We had working groups, by the way, for PRA -- we have working groups for PRA technical adequacy and for treatment of uncertainties, and there's white papers that the NRC has been reviewing that industry has prepared.

I think we're, you know, we've had a

number of public meetings to address these. So I think we're pretty close on both of these. Treatment of uncertainties, we already came and addressed the ACRS Subcommittee on reliability and PRA on the work going on and for that particular working group. That issue has largely to do with the fact that when you're looking at the risk contribution from different initiators, you're going to have different uncertainties associated with that.

So for example, with internal events, you're going to have, you know, a much narrow band of uncertainties than you might with an external event like flooding or seismic, where there's a great deal of uncertainty in the frequency.

So how do you deal with that in an integrated decision-making process? You don't just add those initiators together and say well this is the total risk of the plant, because the uncertainties associated with those different initiators varies widely. So that's what the working group number two is looking at.

Another area that the Risk-Informed Steering Committee is looking at is how do we provide PRA credit for mitigating strategies? There are a number of licensees that are making changes to their

PRA models to model FLEX. So the question is how do we do that? What are the -- we need to make sure that whatever we do it's consistent.

So that's an effort that's currently ongoing right now with the Risk-Informed Steering Committee. Then the last thing I listed here, and these aren't all the things the Risk-Informed Steering Committee is looking at, but these are just examples. The last one is RMRF, and we did brief the Risk-Informed Steering Committee on the recommendations of the RMRF and received their feedback and comments.

So again, I think these are all short-term focused areas. But they're viewed as things that we need to address now, and that will set the stage, I think, for being able to think further into the future, once we've removed -- once some of these obstacles to risk-informed decision-making are addressed.

MEMBER SCHULTZ: Joe, what I've heard in your discussions and see on the slide is that what the Committee has been working on is kind of the tools of the process, and improving the way things are done. Was there established at any point a goal or an objective, a long-term focus for where the Committee intends to go? A risk management regulatory framework might have been that, but in concluding that we're going to go with Option 1, to say well, we'll just move forward and do what we have been doing, it seems to negate the opportunity to have some structure.

In other words, we're kind of working on the tools, on the plumbing and a little bit of electrical, but we don't seem to have a picture of what the house is going to look like when we're all done. It would be helpful.

MR. GIITTER: Yeah, no. I think that's a fair statement. I mean they are looking right now at the tools, if you will. But there is a recognition, as stated in the charter, that they are to provide strategic direction of -- let me use an example -- of what, how we see risk playing a role in the future.

So we're doing that not -- I wouldn't say at a visionary level necessarily, but we're doing that more at a tactical or maybe somewhat strategic level. An example of that is a current focus within NRR. We spent a lot of time and energy on compliance issues of very low safety significance as measured by risk.

So one of the things that we're looking at is how do we -- early on in the process, let's say a CDBI inspection uncovers non-compliance. How do we bring risk insights into evaluating the significance of that early on? If we can bring risk insights into evaluating the significance of that early on, it can save us from spending a lot of resources, if it turns out that that particular issue is of low safety significance.

But right now, compliance equals safety, and it doesn't matter whether it's a low safety significant item or something, you know, that's highly safety significant. We treat everything the same. So what we're trying to do is to take a measured approach and to work smarter using risk as a tool, if you will, for doing that, for making those decisions.

MEMBER SCHULTZ: It seems like a start, but I appreciate the comment back. Thank you.

MEMBER CORRADINI: So can I ask it slightly differently His house analogy is great. I want to write that one down. So today you have a three bedroom home, a tract home and you have 100, plus or minus, depending who's up and down and closing and not closing.

You have 100 tract homes that look approximately the same. Some three bedroom split level, some three bedroom ranch style, and there's no reason to go in and rethink about how you're going to architecturally change these, but you can do them little by little, as you said plumbing, whatever.

So are there any new homes on the market that actually could benefit from this? So new plants, or is NuScale and mPower so similar to current things there's no benefit there?

MR. GIITTER: Do you want me to try to comment on that?

MEMBER CORRADINI: And then I'm going to ask you something else about, since you had the workshop with DOE on September 1st, and everybody was all over you about your regulatory process for advance plants, and there's going to be another activity this week again on that, I'm curious on how you're looking forward to the new home designs?

MR. GIITTER: I don't know if we have anybody from NRO here, but I can give you -- this is my own personal observation, because early in my career, I worked on the licensing of a liquid metal fast breeder reactor. It was my job to go through NUREG-0800, the Standard Review Plan, and to show how it applied or didn't apply to this particular design.

Personally, I feel strongly that looking at, especially Gen IV reactors, we can't adopt the current paradigm of light water reactors. I think it's an opportunity to take a fresh look, and I had some discussions with Mike Mayfield. We have a statement in the SECY paper that talks about possibly using something like an RMR type framework, you know, for these types of reactors.

It doesn't say you can't use a current framework, but personally I think it takes more effort and more work and, you know, now that we have a clean slate, why not look at that as an opportunity. But that's my personal view, and I want to make it clear I'm not speaking for NRO.

MEMBER CORRADINI: So looking down the pike, this is not the right time to start that, or is it a matter of resources that it's inappropriate to use current resources on licensing fees to do it? I'm looking for --

So I'm totally in process mode now. But it strikes me that if you're saying I've got the current 100 plants and things ad hoc are perfectly fine, if I look down the road, do I want to do something for the next things that I'm expecting to have to deal with now, and is it simply a matter of resources that we can't do it now?

CHAIR STETKAR: I didn't see John was here. John.

MR. MONNINGER: Good morning. This is

John Monninger from the staff. I'm the director of the Division of Safety Systems and Risk Assessment in NRO. We are doing various activities to hopefully improve the regulatory framework for advanced reactors and SMRs. I think it depends a lot about the different categories of plants you're talking about.

One of the activities underway for the Gen IV reactors is a re-look at the GDC, the general design criteria. The Department of Energy submitted a report earlier this year and we're going through the GDC and looking at which of those GDC apply to the advanced reactor designs, what should be modified and what should potentially be added.

When you look at something like the SMRs, for example, most likely the closest design coming in would be the NuScale design, to a large extent they're proposing to follow the current approach. Each applicant with their submittal with their application, they are to propose GDC that are applicable to their plant.

The GDC in effect were developed in the 70's, based upon the experience at that time. So NuScale has come in and they've defined certain technical issues that they believe they need departures from or, I guess in a similar manner, the staff is looking at the NuScale design to see whether it introduces any new policy issues associated with their design.

So there is some activities underway, but I wouldn't say a significant amount is not underway.

MEMBER CORRADINI: So John, since you're there, so is it a matter of if there were resources there to think of the future for the Gen IV, it would be worth doing, or it's just too early?

MR. MONNINGER: So I think one of the big issues for the advanced reactors is resources, and you know, how much can the agency plan for the future not quite sure whether the future will occur or not. You know, there are quite a few small corporations out there interested in advanced reactors and talking advanced reactors, but it's very difficult to know, you know, which direction it will ultimately go.

MEMBER CORRADINI: Okay, thank you.

CHAIR STETKAR: Anything else for Dick or Joe? If not, I'd like to thank the staff for providing us a good overview of the paper, and next up we're going to hear from the owners groups.

They have several comments and had some quite interesting material at our Subcommittee meeting. So we felt it would be good for the full

Committee to hear from them. I don't know which one is -- apparently the Pressurized Water Owners Group is up first. So I'll call them up.

MR. FINE: Good morning. My name is Raymond Fine. I'm lead supervisor of PRA at FirstEnergy Nuclear Operating Company, and I'm also the vice chair of the Risk Management Committee for the PRA Owners Group. I'll be presenting today on the PWR perspective and Bob Rishel will be presenting from the BWR perspective, and then Victoria will finish up.

So overview. We have the current state, successful applications, challenges and recommended path forward. The current state is we have a tremendous number of applications and guidance through the Reg Guides, through Reg Guide 1.200, through peer review activities, and everything that is working currently in process to allow us to get into the more advanced risk-informed applications.

And all of this framework that's currently in place we've worked very hard to create the game, so we know what we have to play to get to the goal. So these set the criteria for how we move forward, and then we have to get our management and staff and everybody moving in that direction, and that's a tremendous amount of momentum.

So the successful applications that we do now and many plants are going after are surveillance frequency control program, risk-informed completion times, 50.69 maintenance rule, MSPI and so forth, and as we develop new and advanced models, we'll start asking for more things. It's the unknown unknowns that we don't know what we're going to ask for next.

But we'll keep asking and we'll keep moving. You know, we'll talk about a couple, like you know, now that we have FLEX, we're going to start going after FLEX and then we'll go after the next thing when it comes up. So this is an evolving process that we're working on.

You know, we have challenges, but none of our challenges are insurmountable. All these challenges are the natural progression and natural learning process that we go through with the staff and our own management. You know, we have PRA technical adequacy, treatment of uncertainty, incorporation of FLEX, risk aggregation, all these the staff just discussed.

All of these we're moving forward on through the Risk Committee, and none of these were on our radar a few years ago. They're on our radar now. So you know, as we evolve, we learn more, the more we change, the more we adapt and everybody learns.

We have -- wrong way. So our recommended path forward, because we have so much invested in this and we need regulatory certainty and stability to move forward, we recommend that they stay on the path that we're on right now.

You know, I should say, you know, me and many of my peers are change agents. PRA is very much about change and adapting and learning and growing, and you know. So we're not saying that staying the current path is not change. We absolutely want change. It's just we want controlled change, predictable change, something we can manage, not just throw out everything and start over, you know.

That's too much change and everything will stop with that change. So we have a significant effort that's already been extended by both us and the NRC. The current framework is well understood. We're leveraging existing lessons learned and improving, and we continue to improve.

Now the 10 C.F.R. 50.46(a), risk-informed emergency core cooling and so forth, these are all evolutionary, revolutionary ways of looking at things. So you know, we continue to challenge and you know, even though we today don't know what we want to do next, we will continue to move forward, because that's what we do.

So in conclusion, the PWR Owners Group endorses the staff's recommendations in the draft SECY paper, to maintain the current regulatory framework. The NTTF Recommendation 1 improvement activities, development of an overarching agency-wide policy statement is not needed.

We think the current policy statement is sufficient, and the PWR Owners Group will continue to work with the staff and ensure appropriate methods are available to develop, implement and regulate risk-informed applications and risk-informed regulation. So much faster than the last time, but --

CHAIR STETKAR: That was efficient.

(Laughter.)

MR. FINE: Well you wanted it faster so --

CHAIR STETKAR: I don't know. We're actually very -- we're well ahead of schedule. So we don't need to rush through this.

MEMBER CORRADINI: So can I ask the same question I asked of the staff relative to a Level 3 PRA. So are there Level 3 PRAs that are within the PWR Owners Group that you've actually used as a way to gauge all of these various individual risk-informed activities, or current things that are beyond the design base? Well, I'll say this wrong. That are kind of extensions into the beyond the design base, ATWS, Station Blackout, etcetera, that the various risk, if you were to risk categorize them as to which one improves the most, which one improves the less in terms of safety?

MR. FINE: The only example we have undergoing right now is Vogtle. Just we're piloting it with the NRC.

MEMBER CORRADINI: Would that be an interesting activity to at least -- I'm looking for -- I can't come up with the right word. I want to just say "categorize," but essentially rank order some of the things that are being required by order or rule and see how much it really improves safety? Or what things you could drop because it doesn't?

MR. FINE: I don't see how Level 3, because we haven't really learned a lot about it yet. But I don't see how Level 3 is going to help with that. Level 3 could help with like e-plan or something like that, you know, risk informing that whole process.

What we do currently with Level 2 PRAs with external hazards gives much more information than a Level 3 would give. So if we were --

MEMBER CORRADINI: So going back to that then, if that gives you more information, is there some example of where the industry or at least the owners group has looked into this and decided how these things all kind of are prioritized in terms of --

MR. FINE: I'm going to let Victoria answer.

MS. ANDERSON: So I believe this can be a start about the prioritization initiative, that both the NRC and the industry took on together. So I mean I think that's sort of --

CHAIR STETKAR: Yes, we have.

MS. ANDERSON: Probably more than you wanted to. But I think that's sort of where that kind of work would be going on, and I didn't work very closely with that. But I believe that didn't call for a Level 3 PRA. That was just using existing risk information, and people were, would -- they would be able to use that guidance to help prioritize activities.

MR. RISHEL: Bob Rishel from BWR Owners Group and Duke Energy. I would just add that the BWR Owners Group does have a plan on the books to go forward with both Level 2 and Level 3, to try and provide some tools of our members on how to do that. Just personally, you know, Duke Energy does use Level 2 on the fringes, I would say.

But you know, when we start talking about Level 2, the uncertainty really starts to climb, much moreso than LER. So that is one issue that is sort of worth thinking about when we think about Level 2 and then subsequently Level 3. What the uncertainties in that are tend to get even larger.

CHAIR STETKAR: Victoria, just for the public record in this meeting, we not only have heard about the risk prioritization; we wrote a letter on it March 11th of this year. So we're -- ACRS is on the record on that issue.

MS. ANDERSON: Okay. I was fairly certain you had heard a lot about it.

CHAIR STETKAR: Yeah, we have. Yeah.

MR. RISHEL: So I'm Bob Rishel from Duke Energy and the BWR Owners Group, and I'm the chairman of the Informed -- Risk-Informed Regulation Committee. So we'll discuss where the BWR Owners Group with PRA and where we're going in the near term, and future applications that we would like to see the NRC pursue.

Mr. Giitter talked a lot about -- go back

-- about the technical adequacy. We'll talk about that and the peer reviews and then we'll talk about our Option 2s and 3s. So BWR Owners Group is -- supports the continual evolution incremental approach. Licensees are continuing to develop new hazard models, and it's mostly driven by business need more than anything else.

You know, there's a need there, so or a concern. So currently like that of Fukushima, there's a flooding, external flooding PRA work; there's seismic PRA work going on, which will then also feed into all the applications. Then companies are making decisions about whether they need to -- even though they're not required by the order to do those things, whether they think those are beneficial for them for whatever risk applications they may be having.

I would -- I'd add that model maintenance is a continual process, and model upgrades have to be done as part of the evolution going on. Many of the plants, as a result of both the order and for other reasons, are making plant design changes. Some of them are relatively significant changes, added capabilities, be it diesel driven cooling pumps that are permanently installed and permanently installed additional diesels are the typical things that are being done.

But I would add that PRA model development and maintenance, the cost of this to our -- to an individual utility has grown quite a bit. 805 is another very large cost burden to maintain that model.

MEMBER SCHULTZ: Bob, before you go forward, I want to get an appreciation for what you've said the owners group's activity is. Is it -- has the owners group taken on a common process that is being established for BWR licensees, that is effective in coordinating what individual licensees are doing and transferring knowledge from one licensee to the other in the applications?

MR. RISHEL: There's a lot of information-sharing between licensees.

MEMBER SCHULTZ: Is that done through the owners group or is it done through their own devices?

MR. RISHEL: It's both. The owners group is trying to facilitate it. We're developing databases on what -- so that everybody can look at each other's models and compare how do I stack up? Why is Limerick this way and I seem to be an outlier? Make sure I understand what the -- in many cases the design issues are that might be driving those, or is it go back to is there a methodology being used that

I'm not using or I could learn from.

The other part is we took an effort on this past year, to try and see what we can do about fire PRAs, to try and cut down the effort on what's required, to try and get at the meat of what the fire PRA should tell them.

Now that's probably not good enough for a 805 submittal, but it might be good enough for risk applications, and we're continuing that on with the seismic effort, to see if there's something that we can put out there as a template on how to get to it.

MEMBER SCHULTZ: The owners group is acting as a facilitator?

MR. RISHEL: Yes.

MEMBER SCHULTZ: As well as a librarian?

MR. RISHEL: As well as setting up a -- correct.

MR. FINE: This is Ray Fine. Plus we work with EPRI and NEI. So if it's R&D that generic all, for example like high frequency relay testing, well then EPRI will take that as a lead, and then we'll feed off of that and then share amongst each other what we did.

So like on my seismic PRAs, I've done three and we're pretty much done. We're just wrapping up, and the -- all of my notebooks, template. It is an industry template. I've shared it with everyone, including vendors, so that everybody has a template to work by, on how to do these seismic PRAs, because it is a very complex project.

And so as I progress through each of my plants, I developed this template and then I said okay guys, now follow this and you'll be at least 50 percent there. So and then that also allows us to have better consistency in peer review; it allows us to have better consistency in the application and the submittal, because we all did it pretty much the same way.

Granted, I was a rock site, Vogtle was a soil site. They were doing the template with us. But as these sites change, they'll be uniqueness in them. But the general concept of what is there, where to find it, it's all going to be the same.

MEMBER SCHULTZ: Is the PWR Owners Group also have the focus for lessons learned in fire PRA, for example?

MR. FINE: Yes, yes. Very much so, and we worked with EPRI and NEI very closely, and the Risk Committee for that matter. Fire is hot topic, so everybody stays very tight on that. Yeah.

MR. RISHEL: No pun intended.

MEMBER SCHULTZ: I wish I had a snare drum.

MR. FINE: But even on seismic, yeah we -- all these different new things that we're doing, even regarding FLEX and PRA, that now has both BWR and PWR. I'm on that committee and we have multiple people, plus EPRI is on the committee. All these people that need to be in the room are in the room, and we do it as a unified effort.

MR. RISHEL: I would be remiss. EPRI also has a very, and we've been pushing them, a robust effort on knowledge-sharing on a specific topic. HRA is probably the biggest one with uncertainty coming up, and just the generic, you know, how-to is also EPRI holds the workshops quite frequently across the country.

We've had two in Charlotte in the past two months, with various utilities coming in to Charlotte and getting essentially a week seminar on various actions or technical knowledge.

MEMBER SCHULTZ: One reason that I'm pursuing this is every time fire PRA is mentioned, there's a big groan in the room that comes forward. Again, unless we're learning those lessons and not only learning them but figuring out ways to apply them to these additional initiatives going forward, we're going to be in the same place.

MR. FINE: Oh absolutely, yes. We were worried about that when we moved forward on seismic, because we're like well if seismic goes the way fire went, this is going to be a very bad day. But luckily everybody's learned from that experience, and we're not doing that. So seismic seems to be moving much smoother, with much more agreement than fire did.

MEMBER SCHULTZ: Thank you.

MR. RISHEL: So I mentioned fire. So there it is. Fire PRA, there are concerns with the over-conservatism and we also have similar concerns with seismic, especially in the fragility analysis area. We are working with EPRI to try and improve those state of knowledge. These conservatisms do impact our ability to use our PRAs in some sort of licensing action or a tech spec action.

MEMBER SCHULTZ: Is that because the uncertainties are so large or we don't know how to handle the uncertainty in the analysis?

MR. RISHEL: I think it's three things. One is the uncertainties are large, and we tend to default to the high for the uncertainty.

MEMBER SCHULTZ: The treatment of uncertainty.

MR. RISHEL: The treatment, and we are -- currently we're adding them up. So we're adding the uncertainty of seismic with uncertainty of fire and coming up with a number. Those are the two major drivers of the issue.

VICE CHAIR BLEY: Why do you live with a plant estimate at the high end, when you have the uncertainty distribution? You don't know how to handle them?

MR. RISHEL: Well, let's take fire, for example. So in fire, much of the uncertainty is in the fire itself. We can do the uncertainty distribution of the event trees, of the circuit failures.

But when we start talking about non-suppression probabilities, detection time, fire growth, those are very uncertain. So there's two ways to handle that. One is to chop up the fire scenarios into small pieces and that can be done, and then you add it up.

Of course a lot of it, a lot of the fire would drop off the table, as it doesn't leave the cabinet. It doesn't do any damage other than the component itself. But if I try and put that into a probability distribution, that gets very complicated very quickly. So our probability distribution for fire is somewhat limited by the ability to do that.

VICE CHAIR BLEY: I mean all those curves you're using were put together either from data or from expert groups that the industry and NRC participated in. It's not that they're artificial; it's that that's the best people could do. You have tools for --

MR. RISHEL: We do have tools --

VICE CHAIR BLEY: --for working with that. I mean it's not surprising if you just take the high ends of everything that you get an answer you don't like a whole lot.

MR. RISHEL: Correct, and part of it is in some cases, there is schedule pressure, you know, under fire, especially under 805. It was get done and okay, I don't like the answer. How can I improve my uncertainty, reduce my uncertainty?

CHAIR STETKAR: But Bob, modern computer codes, I can push a button a propagate uncertainties faster than you can tell me it takes too much time to do that.

MR. FINE: It's not that simple. This is

Ray Fine.

CHAIR STETKAR: It isn't?

MR. FINE: No. There isn't --

CHAIR STETKAR: No, it's not. But I've seen people do it.

MR. FINE: Well no. It's the fact that you have a combination of deterministic input and probabilistic input, and some of that is inherent in the actual model building. So when you put together, you know, I can give a different example taking the seismic route. If you look at how we calculate the fragility of a component, you start with the structure. Then you get to its particular location. You propagate into the component itself, and then you calculate a fragility.

All of those can be all based on probabilities, or you can actually do deterministic math. The thing is that whether you use separation of variables, which is the probabilistic method or CDFM, which is the deterministic method, you get about the same answer, okay. But all of them have inherent built-in conservatism.

For example, you know, when we do the fragility analysis on the structure, and we're looking at how the steel moves and the concrete moves, well civil engineers built in a lot of safety factor in those numbers, okay, in some cases a factor of five or ten.

It's really difficult to back-calculate to what the median is, because they didn't actually give you the median number. They gave you a number that, with a fairly good certainty, it won't fail.

MEMBER CORRADINI: It met the code.

MR. FINE: Yes, because it met the code, right. So nobody knows what the actual failure of that beam is or where it's going to break. They built it to the code, okay.

So the -- and each time you take -- you know, first I view the building. Then I go to the frame that the structure is sitting on or the component is sitting on. Then I go to the component itself. Each one of those compounding conservatisms has that inherent deterministic bound in it, plus the probabilistic bound in it.

The only part we're really tracking is the probabilistic part. So we don't know how to undo and get to realism on the actual when does this thing fail, you know, and that's the hard part. It's bounded by at least a factor of five.

MEMBER CORRADINI: So you're saying

there's an inherent conservatism because if I follow code in all the building of the components, there's no way to unravel that as to what the actual failure, where the actual failure might be compared to where the code is satisfied?

MR. FINE: That's correct.

MEMBER RAY: Yes, but the conservatism is there for a purpose.

MR. FINE: Correct.

MEMBER CORRADINI: No, I understand that conservatism is there for a purpose, because you make darn sure it doesn't fail.

MR. FINE: But will it fail in real space is the question.

MEMBER RAY: You make darn sure it doesn't fail because of uncertainties in your design.

MEMBER CORRADINI: Well, but the moment -- so I think Harold was going where I was going to ask. So the moment you start unraveling and say well the code is conservative, then you have to take care of all the uncertainties of the manufacturing of that component and all those uncertainties. Unless I'm off base, I don't think you really want to go there, because that's a rat's nest.

MR. FINE: Exactly, and that's what Bob's saying, is that there comes a point where tracking the uncertainty becomes impossible.

MR. RISHEL: And I would -- I would just add, at least in fire, that you know, we're working on the uncertainty. So NUREG-2178 was out with heat release rates. So that gives us an opportunity to go back and revisit a lot of issues, and try and remove some more of that uncertainty.

VICE CHAIR BLEY: I'm glad you said that, because earlier, you're right. You were under time pressure to get things done and you had to take, get there. Over the next few years, you'll have time to do some of those things more carefully --

(Simultaneous speaking.)

VICE CHAIR BLEY: --and I think that's an important point.

MR. RISHEL: Many plants have either put a plan on the table to go start that or there's a few actually that have started using it.

VICE CHAIR BLEY: And that time pressure came from a lot of sources, some here, some out there. Eventually, it came to a head.

MR. RISHEL: Some were self-induced.

MR. FINE: Yeah. But that's the natural evolution of PRA, because our internal events PRA started out fairly simplistic, with a lot of more uncertainty than they have today, and we over the last 20 years have brought them into something that makes pretty good sense.

Fire's going to take about that long to make it make sense, and seismic and all them the same way. So --

MR. RISHEL: So the other point I wanted to make was development of new methods is slow, and hopefully the Risk-Informed Steering Committee will help streamline that process. If somebody comes up with a new method, we can get that through some process that has some -- a surety of outcome in some reasonable amount of time.

So the current plans are for the BWR Owners Group is, I'd say generically and there could be some outliers here or there, but is to continue with the current approach of essentially Option 1.

So plan submittals here in the near term, we've got some risk-informed surveillance frequency programs coming up being submitted, completion time for the 4b tech spec. A number of members have indicated they'll be submitting license applications, and of course the 15 year Appendix J will be submitted as the plants come up to essentially the need date.

When they need that application, they'll submit it.

So going forward, some areas we would sort of like to see; this sort of comes out a little bit maybe out of Option 2 is tech spec completion time for containment isolation valves, 50.69, which is available but really no BWR is in the pool yet, and use of PRA for SPAR. I think that's an area we would also like to see.

So on peer reviews, so we're trying to incorporate NRC feedback on peer reviews for technical adequacy.

VICE CHAIR BLEY: Bob, Bob?

MR. RISHEL: Yeah.

VICE CHAIR BLEY: Before you read that last line, that was passing kind of fast, there was some discussion about this. It seemed in the subcommittee it was a more complex issue. I mean there are some people who really like that idea of licensing PRA as a SPAR model. I think we heard there are others out in the industry who have reasons they're not so sure they like it. Can you provide the Committee a little more background on that?

MR. RISHEL: So you're correct. It's a split, and it's more in favor of than against. I give you that.

VICE CHAIR BLEY: At least for the BWRs. I don't know --

(Simultaneous speaking.)

MR. RISHEL: For the BWRs, right. I'm not speaking for the P's. You know, as I said at the Subcommittee meeting, we have provided the regulator all of our models, all of the notebooks, all of the fault trees, you know, and actually we just sent --

CHAIR STETKAR: Bob, just for the record, when you say "we," does that mean Duke?

MR. RISHEL: Duke Energy.

CHAIR STETKAR: Okay, thank you.

MR. RISHEL: I'm sorry. I mean yeah. For the record, Duke Energy has sent to the Region II, and we just provided an update to one of the plants that had an update provided to the -- and so far, the interchange has been -- has been beneficial for both sides, that they have that information available. I don't think they're running the models, you know, trying to solve it, some issue on this.

But they are using information to get insights into so what is it -- so what is it that's applicable to whatever issue is that we're missing, that they don't understand or has changed since the last time. And frankly there's been turnover in the

SRAs. That's another area that, you know, is -- and they need to understand the plants too. So that's another tool for them.

VICE CHAIR BLEY: Okay. I just wonder for the record. Ray, do you want to add anything to this discussion?

MR. FINE: Well, from the PWR perspective, we would do it on a plant by plant basis. They don't believe in wholesale sharing the models.

But I do know of my particular -- one of my plants I will have to share with the staff here soon, because of the number of changes we've made, that if we were to go into an STP following our spring outage, it would get really interesting, because our answers would be totally different.

So it's on a case-by-case basis, and right now we don't currently plan on sharing.

VICE CHAIR BLEY: Okay, thank you.

MS. ANDERSON: And NEI's actually leading a tabletop study on the potential to share licensee PRAs with the NRC, to eliminate the need for the SPAR models. That tabletop setting I think is starting at the beginning of next month, and we have some volunteer plants to work on that. So I think if we go through this tabletop study and then maybe eventually a pilot, that might help alleviate some of the concerns that people have and that might help us move towards using licensee PRAs instead of the SPAR models.

MR. FINE: And we are involved with this.

VICE CHAIR BLEY: Okay, good. Thank you.

MEMBER SCHULTZ: I think that's very encouraging. It would be nice to go through the significance determination process in a way where the discussion is not about the modeling, but about the results associated with the inputs only, and not trying to determine whether -- whose model is correct or not.

It takes a lot of time and a lot of effort and it would be nice to eliminate that piece. So I'm glad it's moving forward with some demonstration projects as well.

MR. RISHEL: So back on the peer reviewed technical adequacy. So the BWR Owners Group is putting greater emphasis on the peer-review team leader being a leader, rather than being a super technical expert but leading a team. We introduced a training program for those folks, specifically on the standard, what does that requirement meet, what are some of the OEs that have been seen in the past, where people have either defaulted, you know, too conservatively or too much towards you didn't do it the way I do it, so it's wrong, and much more emphasis on the consensus of the team rather than individual person and the rest of the team just acquiescing to whatever that person's view is.

Also, the licensee ownership of being ready. That's been an issue in the past sometimes, where the licensees, again under some pressure to have a peer review, probably should not have undergone a peer review at that point in time. So a lot more effort on pushback on being ready, meaning that their model has been churned enough, that they've looked at the uncertainties and issues enough that they've tried to remove some of the uncertainty in there.

As a matter of fact, we just had one ownership, owners group, excuse me, one plant that was supposed to have a peer review this week as a matter of fact, be pushed out into second quarter next year.

MEMBER SCHULTZ: Bob, in the process of trying to develop an approach where the review team works as a team rather than a group of individuals, do you do that by -- has that been done or accomplished by direction to the team, or have you developed some processes that make the team work as a team?

MR. RISHEL: Well we've -- the process, the closest we have to process is we put together a little training package for the team, on what the expectations are. It's not so much on technical, but the expectations of your team. Here's what we expect of you, and they hold that pretty early on, once the team is formed and before they start reviewing anything.

Then you know, we come back with the team leader and make sure he understands that, and going forward we're talking about what to do next, to try and circle back and see how this is working.

MEMBER SCHULTZ: What I was looking for was whether you had an issue resolution process associated with it at this point.

MR. RISHEL: Yeah. We do have --

MR. FINE: We do. It's actually Victoria runs an NEI task force for peer reviews and peer review leads. So both me and Bob are on it and quite a few other people are on it, including the vendors who could potentially be leads and so forth.

So it's a fairly large group of people. When we identify issues, we hash it out, work it out and say okay, well this is what we need to do to improve that. And we're kind of going through a sea change, because we experienced what we did with NFPA-805.

Now that wasn't just modeling challenges. That was also peer review challenges, because a whole lot of models went through peer reviews very quickly, and it was getting the right people in the room at the right time, the right leads and you know. It was extremely challenging to have the right people there for some of these.

And so the, you know, and seismic will be no different, because the population of people who can do that is even smaller. So it's going to -- we're trying to get all of our programs such that, you know, we can adapt to these things and be ready for them and prepare for them, instead of just getting run over by them.

So you know, the requirements of 30 days prior to you will have, and the team will be assembled at least by this date and the lead will be a lead and not an actual reviewer of any particular supporting requirement or high level requirement, and all these little rules that we're putting in place.

These are all fairly recently, in the last year, okay, and we're feeling them out as we go, seeing if it works. So we've only had a couple of peer reviews so far where the lead is truly an independent lead who's, you know, roving. But I've been in peer reviews where the lead did do that. A contractor led one of them is a utility guy and it worked really well. So we said why don't we try it on more?

So there's things like this that we're constantly evolving on. But we do it as an industry. It's not just the B's. Everybody does it together the same, because of the need to ensure consistency.

MR. RISHEL: I do have a slide, I think.

MEMBER BROWN: But before you --

MR. RISHEL: But we do have -- I'll cover it now because of the question. With NEI, there is a peer review task force, and issues come up and they're brought to the task force, and it is sort in its infancy now. But the task force is also going okay, so this is what good looks like. The licensee does something that looks like this; that's what the standard is looking for.

You can always do more, but this is the minimum of what the effort should be in that we've done, what, two of those.

MR. FINE: Well, all of my PRAs are on the new process.

MR. RISHEL: So far, but there's more to come. So we are bringing things forward. But it is a bit like herding cats, I'll say, on getting a consensus.

MEMBER BROWN: Yes sir. Your comment that greater emphasis on peer review team leader being a leader, and then I've listened to the rest of discussion. But I hope I don't get the flavor that when you say you want somebody who's "comes out, he's got this great management training and leadership skills because he's been through leadership training."

But if he doesn't have a fundamental understanding of PRA itself, while he may not be a reviewer -- I agree the leader shouldn't be -- I think that's a good idea, should not be a reviewer so he can overview everything. But he really does need a fundamental understanding.

MR. RISHEL: I'll say we're not using folks that don't know anything about PRA.

MEMBER BROWN: Thank you. That's all I wanted to make sure.

MS. ANDERSON: They still have the qualification requirements.

MR. RISHEL: They still have to be on the peer review team. They've still got to meet the PRA reviewer quals.

MR. FINE: So this individual doesn't have to be per se the technical --

MEMBER BROWN: I'm not arguing with that. But if he can't talk across the board and understand what the team would bring to, you know, to the table, then it's difficult to meld those guys together and make sure you get a valid result.

MR. FINE: He has to speak the language.

MR. RISHEL: So exactly. So what we were finding was is that the team leads were typically the heaviest, as far as PRA knowledge goes, and they would be totally immersed in the technical and not paying attention to what everybody else is doing. So extract him from that, come in and provide some oversight on whatever, exactly what you're talking about.

And as far as new reviewers, we have instituted a working observer, where an individual that has been working in PRA for some number of years, but hasn't participated in a peer review before, rather than throw him into the fire right away, have him participate, do work but he's not -- he's not an official member, but is part of a training process so he understands what's going on.

MR. FINE: Right, and just to amplify on

that a little more, the working observer will be somewhat specific. So if you want to do peer review on a seismic PRA, then you're a working observer on a seismic PRA just like on a fire PRA, because I don't have the skill set for fire PRA. Even though I've managed the development of fire PRAs, I don't go on those, because they're very complex.

But I have guys that do that, okay. But I wouldn't send one of those guys on the seismic PRA review because he wouldn't know what he's looking at. So you're being trained to that type of model.

MR. RISHEL: Next slide, Ray. So for the BWR Owners Group, you know, one of the issues that staff brought up and we share is that a week on site is not much time. So part of that was the expectation that the peer review team look at at least 40 percent of it before they show up on site, and have a stack of questions or issues for the -- to provide the host on what's -- on something they discovered in part of their review.

We've also seen licensees follow up with a follow-up peer review, to try and see if they've resolved F&Os and get a sort of second view. Okay, I had a peer review. They had these F&Os. I think I did the work, bring in another team to pass judgment on that work. That has picked up speed in the owners groups. Like I said, the industry task force looking for some technical resolution of one issue or other. We talked about it earlier.

So then with the gap on technical adequacy, so part of it is there is limited resources. These folks take a long time to train up and so it is a small group. In peer reviews, the objective criteria in trying to get consistency, you know.

The worse case is like I had two peer reviews, this is from Duke Energy. One was a strength and the other was a not met, and it was exactly the same approach in both cases. Two different peer reviewers. So that kind of, you know, makes us pull our hair out and circle back.

But it is an individual and then, you know, as the licensee we have to go back and resolve what the -- what we think the right answer is. So going forward for like using the PRA, one of the questions we have as the owners group is if the staff members start passing judgment on technical elements in, you know, that's something we would need to work out for reviews, is whose opinion counts so to speak.

Also going forward with Option 2 and 3 is, you know, the question about we have these -- the projected benefits, but if we don't have a fixed time line on resolving all of the -- either the technical issues or the process issues, the time lines stretch out and we'll never achieve the benefit of an Option 2 or 3.

MEMBER CORRADINI: Can I ask a question of both owners group representatives? So if you did a survey of your membership, how does the membership come down in terms of Option 2? In other words, is it 95 percent of all the owner group members think that Option 2 just really is not appropriate, or is there a relatively large split that finds on a case-by-case basis there might be some benefit?

MR. RISHEL: So we're probably -- we're probably the 95 percent no and maybe a five percent, I would say, maybe. I wouldn't even say a yes.

VICE CHAIR BLEY: In concept, or in terms of the way it was presented in the SECY paper?

MR. RISHEL: In concept.

VICE CHAIR BLEY: In concept.

MR. RISHEL: You know, I guess kind of step back of where the fleets are at.

MEMBER CORRADINI: And this is -- it's based on resource or based on there's no safety benefit?

MR. RISHEL: It's based on --

MEMBER CORRADINI: Well I should say the opinion thereof.

MR. RISHEL: The opinion thereof of the cost to get there and two is a question about whether, what the benefit would be. Where is the payoff at the end?

MR. FINE: I would agree. The P's are pretty much at the same place. There was a lot of uncertainty programmatic wise in the bullets in Option 2 and 3, and you don't really know where it's going to go. But you know, when you say something like oh, we would like to do certified PRAs.

Well, you're talking about completely redoing the entire process and we've got to start over again? Seriously. Yeah, that's not going to work, you know. But could we talk with a different way to do it? Probably, you know. I think it would be beneficial for all of us.

VICE CHAIR BLEY: That's kind of what I meant by hidden concept.

MR. FINE: Yeah. Not in the flavor that it was sold to us, you know. We would change it.

MR. RISHEL: I would hazard an opinion that fire, 805 fire is the elephant that sticks over this.

VICE CHAIR BLEY: In terms of it gave everybody a bad taste or --

MR. RISHEL: It gave everybody a bad taste. The costs were astronomically much higher than anybody projected.

MR. FINE: It showed us how -- it showed us how, you know, when you don't have regulatory certainty moving forward, the cost will go exponential. Because we started out thinking five to ten million dollars to do a fire PRA. But then because of issues with methods and approvals and other things, we're at 50, 60 million per unit and counting, and we're not even implemented yet.

So that's why we're like no, we don't need any uncertainty at all right now. If you want us to keep moving forward and show safety benefit and improve the safety of the plants, we need some, you know, like when you want us to go after 4b tech specs or 50.69 because it will focus us better on the things that matter most, you know, and we agree. We want to go do that.

But if the staff or anybody starts changing those rules midstream, which we're discussing right now, yeah. A lot of people are going to stop, because it's just too uncertain, too much money. And so, you know, there's quite a few plants. You know, even though Bob gave you a list of plants that are moving forward, he has a similar list.

These are the plants that want to move forward and want to submit. But all of them are saying "but we want to see what happens in the current submittals before we decide we're going to go."

MR. RISHEL: Yeah. We're not spending that much on 805.

CHAIR STETKAR: It makes me sad that I'm not a contractor anymore.

MR. FINE: It made a lot of contractors very wealthy.

CHAIR STETKAR: You could buy a few extra shirts for that.

EE I can't say anything.

(Laughter.)

MR. RISHEL: So that's our concerns, those three bullets with Option 2 and 3, and that's pretty much why the BWR Owners Group wants to sort of back up the staff's position of keeping forward where we're going, keeping -- progressing forward. If there's areas where we can improve the technical adequacy and review process, you know, we would do those things.

I know we got a recent letter with some issues and questions that provide feedback to the staff on peer reviews. So I already started my conclusion here, and again, the elephant in the room is fire PRA. It has become a large consumer of resources.

I would just say for Duke Energy, just not even revising the model, but just keeping up with the plant is 4 FTE for the Duke Energy fleet.

MEMBER CORRADINI: So let me ask the question differently, since this is how you've ended it. Are there lessons learned from the fire PRA that you don't want to ever do again on any risk-informed topic, and does the NRC staff agree with it? In other words, are there attributes that have come out of this behavior that you never want to see revisited, and have you talked it out with the staff?

MR. RISHEL: Yeah. So I don't know if the staff agrees, but I think we attempted to do a pilot, two pilots with fire and they weren't as good of a pilot. The problem, I think the problem was the rest of the industry was right behind them, and there wasn't enough time to really swallow what came out of that.

CHAIR STETKAR: Bob for the record, there was an attempt to do a pilot back in 2005, and nobody -- the industry didn't support it. So when you say "pilots," there were the first on the record submittals of the process that had not been actually tested in a real world pilot application.

MR. RISHEL: Yeah, and so to get back to the question, correct, I think. So they really weren't pilots. So going forward, we do need to pilot things. So we just finished up a pilot of a low power shutdown for a BWR, and we have a laundry list of things that we think ought to be changed before anybody goes forward and uses that document.

MEMBER CORRADINI: Is part of it -- well I mean I don't really -- this is not my area of expertise. But is part of it lack of experience of the managers of the project that allowed too many details in when they didn't need to be there?

MR. FINE: I wouldn't say that. I would say that, you know, 68.50 in general had a lot of steps in it that weren't really well thought out, and when somebody actually started putting it all together and adding it all up and it started not making any sense, everybody was like well what do we do now, and that's when we got into this whole methodology. How do we make this make more sense, because we know what we're getting right now doesn't make any sense.

And then we got -- but we're in a lesson learned kind of scenario, where the staff really hadn't been involved in methodology before then. Now they wanted to be involved in methodology. Then, you know -- before they just took what we did and now it doesn't go like that.

There's a whole lot of things that changed in and amongst just doing it, you know, and you know, so one of the things we did with seismic different than fire was when the pilots, which were my plants and Vogtle, got done, completely done, peer reviewed, everything, lessons learned, had lots of workshops, had a good year or so for people to digest and understand before the others started moving forward.

MS. ANDERSON: So I think the two major lessons learned we took from the fire PRA and 805 experience, and the first was that we need to have some level of staff involvement and NRC staff understanding of the methods that are being used, because I think we didn't necessarily have that with fire PRA, and that held up the licensing applications.

The other major lesson learned is that we need to have a clear understanding of the level of realism of the PRAs that are supporting licensing applications before the licensing applications go in. That was where we wound up with a lot of problems and time pressure and inability to solve the methods problems in 805, was that all these applications were due and the fire PRAs were not yet ready to support an application like that.

MR. FINE: We were committed to a date without the ability to truly make it right.

MR. RISHEL: I would agree with all that.

MEMBER CORRADINI: Thank you.

MR. RISHEL: So we'll continue to work on technical adequacy and work with the various owners groups to improve the peer review process, and I think we'd support continuing on with Option 1. So I don't have any other points to make.

CHAIR STETKAR: Anything more for Bob? If not, Victoria, you're up.

MS. ANDERSON: Victoria Anderson with NEI. I'm going to present on the industry comments on the draft SECY on the RMRF. Before I get into our specific presentation, I'm going to talk a little bit about sort of the vision that the RISC has, because the question came up and the question I think that was posed earlier was well, is the RISC really working to a larger vision, or are we just working on tools and maybe --

CHAIR STETKAR: Victoria, before -- for clarity for the members, we heard earlier about the NRC staff's RISC.

MS. ANDERSON: Right.

CHAIR STETKAR: You're going to talk about the industry's RISC.

MS. ANDERSON: The industry RISC.

CHAIR STETKAR: There are two RISCs.

MS. ANDERSON: Yep.

CHAIR STETKAR: Who talk to one another.

MS. ANDERSON: Yep, and we talk to each other and work together and so far have not had major disagreements on where we need to be moving forward. But I think the question that was posed was maybe the Risk Management Regulatory Framework would have been some sort of visionary change that maybe the RISC should have been looking for.

And I think, you know, right now we are doing a lot of work on sort of those tools. But we did spend some time on the overall vision back when we formed the two risk-informed steering committees. I just want to talk about that for a little bit.

I mean I think the overall vision and purpose of the Risk-Informed Steering Committees is to maximize the use of risk information and regulation. Underpinning that, you know, other parts of that vision are that we'll have a deliberate approach to PRA development, maintenance and applications. So we don't go off developing models that will sit on a shelf or models that won't help us run the plants better; that we have a seamless risk-informed licensing process. That's a nicer way of saying we don't want to repeat NFPA-805.

I think, you know, outside of risk-informed licensing, we want to have an increased use of PRA in all regulatory activities, as well as a more predictable use of PRA in regulatory activities and plant operations. So these things like inspections, the significance determination process and just day-to-day decision-making at the plants.

So those are sort of the visions that we're looking at, and we say well, what's stopping us from getting to this vision? What's getting in our way, and we did actually -- you know, it was almost two years ago now. We said if we could rewrite the PRA policy statement, what would we make it say to make things better?

And when we looked at the policy statement, we said there's really nothing that's missing there. There's no need for a new enabling rule. The things that are getting in our way are tools and culture. So that's why we've been focusing on those things. But I think they are supporting that larger vision.

So now I'll go ahead and start on the presentation. So what you're going to notice throughout the slides is that we do agree with the staff's recommendation throughout. The first recommendation, to maintain the current framework and continue to make improvements. Based on what I just said about the risk-informed steering committees and our vision and how we've been progressing, you know, we agree with that.

There are a lot of efforts underway to improve things, and we didn't think that any kind of large-scale policy statement change or rulemaking was really necessary to support improvement.

So the specific Option 2, the plant-specific regulatory framework, the staff agreed with our comments that the approach need not be pursued. We didn't really find any licensees that would want to implement it, as was described in the papers we had seen. So if no licensees are going to use it, given how much the staff has on their plate, it's really not worth it to go and develop something like that. So we agree with the staff recommendation in the draft SECY there.

I think we already talked about the design basis extension category and where the staff landed on that. We also agreed with the staff that there's no need for a design basis extension category.

With respect to defense indepth, we also agree that the right place is in Reg Guide 1.174. We don't think a policy statement is really necessary there. Reg Guide 1.174 has been sufficient. We can enhance the discussion in there to provide additional guidance, but we don't think a policy statement would really do much.

As far as an overarching policy statement on the risk management approach, we think the existing PRA policy statement does enough. So we agree with the staff recommendation to not work on an overarching agency-wide policy statement.

So our conclusion, if it hasn't been clear so far, we agree with the staff's recommendations in the SECY paper, and we are going to continue to work with the staff, both through the Risk-Informed Steering Committee and on specific initiatives, to make sure that the right methods and guidance are available to support that vision that we have for maximizing the use of risk information and regulation.

MEMBER CORRADINI: So I have a question about non-currently operating plants like the SMRs.

MS. ANDERSON: Okay.

MEMBER CORRADINI: There's no need for any of this for the SMRs from your perspective?

MS. ANDERSON: So what we noted with the SMRs is that there's nothing -- there isn't a need for an enabling rule or a change to the policy statement to pursue the use of risk information in the design and construction of the SMRs. There isn't anything that really needs to be changed at a policy level to support that.

I do know the SMR designers are doing a lot of integrated PRA development in design, where they're doing sort of an iterative process and using the risk information throughout. There's absolutely nothing in the current regulatory framework that stops them from doing that.

MEMBER CORRADINI: So if they have to take on a particular topic and risk-inform it, they can do it on a case-by-case basis and there's no need for any of the Option 2 activities?

MS. ANDERSON: Right. That's what we

noticed here. For example, they're doing -- they're using some risk information to support changes to emergency planning. It's not really a traditional risk-informed application, but that's something that they're doing just under normal processes.

MEMBER CORRADINI: Okay.

MR. FINE: So there's even nothing under the current process that would prevent me from doing for 50.69, 5b and 4b all in one submittal, you know, or going after one of those but saying in my submittal I want to be my PRA reviewed for all. They can do that too.

MEMBER CORRADINI: I guess where I was going with this was if you don't want to relive the fire PRA activity, you think that you can handle it by these steering committees on individual issues or general attributes, without having to do some of the activities under Option 2?

MS. ANDERSON: Right. I don't think that Option 2 is really necessary. I mean I think if you look at the current policy statement and the current regulatory guidance, it says we should use PRAs that are realistic, you know, and that was one of the major sticking points with fire PRAs.

So I think it's a matter of getting back to the overarching policy statement and the vision that we have, and making sure that we're really following it.

MEMBER CORRADINI: Okay. So now if I move on to non-light water reactors and NEI now has a working group in that area, is that not correct?

MS. ANDERSON: Yes, we do.

MEMBER CORRADINI: So what's the view there?

MS. ANDERSON: They had some interest in the concept of a risk managed regulatory framework. But again when we talked to them, they also agreed, you know, well it doesn't seem like there's really anything in the current rules or the current policy statements that's prohibiting us from doing what we want to do.

MEMBER CORRADINI: So but okay. So you're telling me I could do it on a case-by-case basis there, because I've done it in the past and at least until I approach it and nothing looks like it's broken, that I can't use the current --

MS. ANDERSON: Right.

MEMBER CORRADINI: Right. But I guess I hear different things from different parts of the industry. Are we back to resource issue, which is current plant shouldn't pay for it, or that it really, from a technical standpoint, that it makes no sense to take Option 2 attributes or activities for advanced reactors?

MS. ANDERSON: I think the advanced reactors, I think the design isn't that really far enough along in what they're planning with their regulatory strategies, to say for sure that they would use an Option 2 type framework either way.

MEMBER CORRADINI: Okay. So let me pushback. So we just went through NGNP, and when all is said and done, we were in this room and staff came in and said we don't know enough. We'll invent a maximum credible accident that may not be physical, but it's definitely maximum credible, and the DOE, who was representing the industry group said well, we don't necessarily agree with that.

But and we have our risk analysis or their -- I'll call it their mini-PRA. I can't even call it a PRA. We'll call it a mini-PRA and historical stuff, and there was a rift. It seems to me that's almost like a lesson learned, that if I go down the path of pick your favorite peanut butter reactor, chunky, creamy, and you go down this path, you're going to -- we're going to stumble over the same path again unless we address it now.

You think there's enough there without doing Option 2 attributes, that we could just go down that path again?

MS. ANDERSON: I mean I think -- well, avoid going down the same path, but I think we can do that without pursuing something like Option 2, and that is what it sounded like the advanced reactors agreed with.

MEMBER CORRADINI: Okay, all right.

MEMBER REMPE: During the subcommittee meeting, I guess actually Michael was the presenter rather than you.

MS. ANDERSON: Yes.

MEMBER REMPE: But my notes indicated that there was a discussion about any plants being interested in Option 2, and my notes indicated that they said absolutely no at this time. They needed some nearer term wins and in fact the staff had said they weren't going to be pursuing defining more details, you just won't have that regulatory certainty.

I kind of got that a little bit from the BWR presentation, but I didn't see that today. Is that still the message?

MS. ANDERSON: Yep, that's still the case, yes.

MEMBER REMPE: Okay, thanks.

MS. ANDERSON: I think we'd just say 95 percent of the plants say no, because we're PRA people and we never want to say it's absolutely 100 percent for sure.

(Laughter.)

CHAIR STETKAR: Any other questions for the industry?

MEMBER CORRADINI: Yeah, I guess I'm still bugged by all this, because I went through the advanced reactor stuff with DOE helping industry and it went nowhere after ten years. So I'm still bothered. So is it resources or is it safety benefit? I'm struggling with don't go down an Option 2 path with current reactors. I understand the logic.

So now if I switched the target to an SMR, I switched the target to a non-LWR, is it still the same thing? There's no safety benefit and not enough resources, or if we had the resources, there actually would be some safety benefit?

MS. ANDERSON: I think the concept is more that the resources could be used to reach the same safety -- you could get the same safety benefit for less of a resource investment under the current regulatory framework, under the current approaches that are available. I think that's the perception.

MEMBER CORRADINI: Okay.

MEMBER RAY: Well Mike there's -- you posed two choices there. There's a third choice that has to be evaluated which is not a safety benefit, but an economic benefit.

MEMBER CORRADINI: Well okay.

MEMBER RAY: All right, and whether there's an economic benefit or not is also part of the calculus that any new reactor vendor has to engage in. In order to do that, you have to know well in the absence of PRA, what am I going to be faced with? That's where you get into the do loop.

In other words, you don't want to commit as a vendor to doing an analysis that doesn't provide any obvious safety benefit, unless it also provides you an economic outcome benefit.

MEMBER CORRADINI: Right.

MEMBER RAY: And that's where I think the hangup exists, more than whether it's a safety benefit or not.

MEMBER CORRADINI: So maybe we're -- the Chairman will tell us to be quiet, but since we're in discussion mode, it just strikes me that after -- since I attended all these meetings and it was frustrating with the NGNP, nobody looks at that as a lessons learned and say okay, how could we have done that better, whether it be for safety or for economics and for what I'll call certainty in the process, that we could learn better because we're going to get another one of these, because it seems that a lot of venture capitalists, whether they're on some sort of Kool-Aid trip or in reality want to do it.

So again, the staff is going to get beaten up about not being precise. Industry is going to proceed with some of these things and there could be a lot of money wasted and going nowhere again. It just strikes me that at least the NGNP is something that can be looked at as a way to essentially improve on it. But I think you're right. It could be economic as well as safety.

MEMBER RAY: Well, it's going to be economic in my judgment. Again, the question that the proponent of a new design is going ask themselves is what if I don't do it? Or what's the consequence of not engaging in full scope PRA as opposed to the benefit, economic benefit that I would obtain from doing it?

I don't think the driver is I'm going to improve safety by doing it, from a vendor's perspective, because the vendor's already presumably comfortable with the idea that this concept has got advantages that warrant moving forward.

The thing that they don't know is well, where is it going to prove to me -- prove to be an advantage by doing the analysis, and I would use NGNP as an example of that. You just -- how is this going to benefit me? Well, I don't know, because I don't know what I have to do in the absence of it, from the standpoint of EPZ or whatever you're talking about.

MR. FINE: Plus in this particular case, you have no owner involved yet. It's all just vendor. The owner's still going to come in and --

MEMBER RAY: That's another debate that we have over dinner often.

(Simultaneous speaking.)

MEMBER RAY: But you're right, yes. Getting an owner engaged makes a big difference as well, but right now, he and I are just talking with --

MEMBER CORRADINI: I mean under the assumption there's a vendor and there's a potential owner, because there is that other stumbling block.

MEMBER REMPE: And you seem to not want to mention the Cheyenne example, where they --

MEMBER CORRADINI: But Cheyenne is good nuclear. Cheyenne is not bad nuclear.

MEMBER REMPE: Yeah. Well again, they went through a different process with inadequate detail, and they are moving forward.

CHAIR STETKAR: Remember, that's just a construction permit, so they don't have to have the same --

MEMBER REMPE: I know, but maybe that's not bad --

CHAIR STETKAR: --they don't face the same issues.

MEMBER REMPE: But then that's not a bad way to go when you don't have the detail.

MEMBER CORRADINI: Well, I mean again we're debating.

MEMBER REMPE: Hypotheticals.

MEMBER CORRADINI: --off topic a bit, but it is not a commercial reactor. It's not a power reactor. It's essentially being treated as a research reactor in terms of licensing. It's a different beast. The only reason I'm going to NGNP --

MEMBER REMPE: Then what would be a different beast?

MEMBER CORRADINI: The only reason I'm going back to the NGNP, there was a lot of industry activity on now good it was because of this and that. There were actually risk numbers advanced as to why it's safer or could be more economic. When all came to past, there was this chasm between staff and DOE, and I just see -- or and DOE and the industry consortium, and all I see is this is going to happen again unless some parts of Option 2 aren't addressed.

MS. ANDERSON: I mean I'm not sure if that chasm existed because there wasn't some sort of enabling rule or framework out there, or if it was because there was a cultural difference and maybe some sort of miscommunication on how risk could be used to improve the process.

MEMBER CORRADINI: So without a framework, there will still remain a culture difference, wouldn't there?

MS. ANDERSON: Or we could try to fix the cultural differences, which is one of the things that the Risk-Informed Steering Committee is trying to do, is try to address the cultural differences and the lack of tools.

MEMBER CORRADINI: Yeah. Well, there's enough cultural differences in the world. Eventually you come to a peace agreement with rules.

MS. ANDERSON: Right.

MEMBER CORRADINI: That you have to follow. Otherwise, the cultural difference remains.

MR. RISHEL: You know what -- this is Bob Rishel. I would just, you know, maybe that would be the value of Option 2, would be it would bridge -- it would force the culture to change.

MEMBER CORRADINI: Well, I would be totally honest on the record, that it strikes me it's a resource issue. If industry didn't have to dive into their essentially revenues for it, but actually was looking forward on some sort of advanced reactor and on simultaneously on the NRC side it wasn't a fee-based approach.

It strikes me with those resources, there might be some benefit to do this. But I sense that there's a resource underpinning here. On a level of where I want to spend my resources, this is low on the totem pole.

CHAIR STETKAR: I'm going to have to interject here, because we do have a schedule and --

MEMBER CORRADINI: Well, you didn't stop me before.

CHAIR STETKAR: No, I know. I need to let the discussion play out until we start repeating too many things. So anything else for the industry?

(No response.)

CHAIR STETKAR: Okay. If not, we do have Mary Drouin on the line, and I want to make sure we get the line opened up, because she has been patiently waiting out there. She wants to make a statement. While we're getting the line opened up, for the record we do have written material from Mary.

It will be entered into the record of the meeting, so that it will be on the meeting record, discussing her non-concurrence on the staff's SECY paper. But with that background, Mary would like to have the opportunity to give us a little bit of oral background and perspectives on her non-concurrence.

But I'm hearing popping and crackling. Mary, if they're out there, could you just let us know that you're there?

(No response.)

CHAIR STETKAR: And we're not hearing that. So we're going to wait and get the actual line open.

(Pause.)

CHAIR STETKAR: I'm told the line is open. Mary, are you there?

(Pause.)

CHAIR STETKAR: Hmm. So --

MR. SNODDERLY: John, this is Mike Snodderly, ACRS staff. What I'd like to suggest is that, as you said, we're going to have this document that was emailed to us by Mary entered into the record.

It will be part of the transcript and put into ADAMS. If someone from the public would like a copy of the email, please you can either phone me at 301-415-2241 or at mrs1@nrc.gov, and I'll forward you the email. But eventually it will be put into ADAMS this week and will be referenced in our --

CHAIR STETKAR: Okay. Thanks Mike. I appreciate that. While we're -- we're going to see if we can perhaps contact Mary on the side, to see if she's available. While we're doing that, let me take the opportunity to ask is there anyone, members of the public in the room who would like to make a statement? If so, come up to the mic and do so.

(No response.)

CHAIR STETKAR: And since we have, I think, the bridge line open, if there are members of the public on the bridge line, could you just someone say hello to confirm that indeed the line is open?

(No response.)

CHAIR STETKAR: Okay. Silence is always questionable.

MR. SNODDERLY: It's open.

CHAIR STETKAR: I've been told the bridge line is open, so I'm assuming there is no one out there.

MR. SNODDERLY: She's not available for about five minutes.

(Pause.)

CHAIR STETKAR: Okay. Mary is temporarily unavailable. So as Mike Snodderly said, we certainly will enter her written comments into the record. They're rather complete. I've scanned through them. So they will be on the meeting record and, as Mike said, available to the public.

With that, I'd like to ask if there are any other member comments?

VICE CHAIR BLEY: I have a question. Was there any -- has there been any resolution to --

CHAIR STETKAR: I don't know. I think we'll have to -- I don't believe so. But for the non-concurrence, I don't believe so.

VICE CHAIR BLEY: Any resolution at all to the non-concurrence, or it's just standing by itself?

MR. DUDLEY: It was just received at seven o'clock this morning.

VICE CHAIR BLEY: Oh, this morning. Okay.

CHAIR STETKAR: Yeah. It's very recent.

VICE CHAIR BLEY: I didn't know.

MR. DUDLEY: It's been partially read.

VICE CHAIR BLEY: Okay, fair enough.

CHAIR STETKAR: Any other comments or questions for the staff or the industry? If not, we are recessed until one o'clock this afternoon.

(Whereupon, the above-entitled matter went off the record at 10:54 a.m. and then resumed.)

CHAIRMAN STETKAR: We are back in session. The topic for this afternoon is the Davis-Besse Nuclear Power Station license renewal, and Harold Ray will lead us through this session. Harold?

MEMBER RAY: Thank you, John. In reviewing the application for license renewal at Davis-Besse we'll be hearing obviously from the applicant and also from our Division of License Renewal.

There is a bridge line, as we just heard, in service. It's going to remain in a listen-in mode until we end the meeting today when it will be open for any comments from members of the public. Also, we've received a request to address the Committee by someone present in the audience. He and anyone else who wishes to do so may make comments on the record at the end.

As we will seen in timelines that are to be presented, the Davis-Besse license renewal application was submitted in 2010 and the License Renewal Subcommittee first met to review the SER with open items two years later in 2012. We met again in September of this year to review the final SER and Supplement 1 to that SER which had been issued a month prior in August of this year.

The discussion at our first Subcommittee meeting including questions concerning the potential for groundwater on the exterior of the containment pressure vessel and refueling canal leakage on the interior to cause corrosion of the steel pressure vessel. This was addressed at our second Subcommittee meeting and now by the Aging Management Program and it will be addressed later here today.

Following our second Subcommittee meeting the applicant provided on the LRA docket for our review the calculations and analyses which had been performed concerning the effect of concrete cracking on the strength of the shield building. We needed to perform this review in order to evaluate the adequacy of the Shield Building Aging Management Program. The applicant also provided on the docket a letter further describing the margin between the cracking, which is expected to exist at the start of the period of extended operation and that which has been conservatively assumed in the calculation of its effects. We appreciate the clarification provided since the assessment of any Aging Management Program needs to understand the margins which do exist.

Also following our second Subcommittee meeting the applicant submitted an amendment to the LRA which elaborates on the use of nondestructive testing to monitor the extent of the concrete cracking. Again, this is important relative to assuring that margin is maintained between the cracking which exists and that which has been assumed in the analyses.

Finally, the staff and we, including our consultant Dr. Shack, have separately reviewed the analysis used by the applicant to demonstrate the effect of the concrete cracking on the ability of the shield building to perform its intended functions and the applicant will submit an amendment to include this analysis in the current license.

We will now proceed and I call on Jane Marshall to begin.

MS. MARSHALL: Okay. Thank you, Mr. Ray. As stated, I'm Jane Marshall. I'm the Deputy Director for the Division of License Renewal and members of my Management Team with me here today at the table are Yoira Diaz-Sanabria. She is Branch Chief of Project Branch 1. In the audience we have additional branch chiefs Dennis Morey, Brian Wittick, James Danna and Steve Bloom. Also in the audience joining us today from Region III is Jim Neurauter. He is the lead inspector from Region III who led the shield building laminar cracking inspections.

The staff's presentation on the Davis-Besse Safety Evaluation Report will be given by the safety project manager, Rick Plasse, who will be joined at the presentation table by another one of our safety project managers, Phyllis Clark. We also have in the audience with us today a number of staff members from NRC, and those who add comments or answer questions during the presentations will introduce themselves at that time.

As you know, the last time we met with the ACRS Subcommittee was on September 23rd of 2015 when we discussed the resolutions for the open items that were documented in the final SER that was issued in September of 2013 and in Supplement 1 to that SER which was issued in August of 2015.

Rick Plasse will provide an overview and background of the staff's safety review on the Davis-Besse license renewal application and will go into more details on the resolution of the open items during his presentation.

At this time I'd like to turn the presentation over to FirstEnergy and the site vice president Brian Boles to introduce his team and give their presentation.

MR. BOLES: Thank you. Good afternoon. My name is Brian Boles. I'm the site vice president at Davis-Besse. We have an agenda that we will run through today. I'll provide the introductions, we'll cover some of the background -- sorry. Should I start over?

My name is Brian Boles. I'm the site vice president at Davis-Besse. Today I'll provide some introductions, we'll cover some of the background information of Davis-Besse, we'll cover our license renewal application description, closure of the previously mentioned open items, we'll talk about our containment vessel inspections and then we'll have a summary and closing remarks at the end.

I'd like to introduce the team that we have here today. Along with myself, to my left is Ken Byrd. He's the director of site engineering. And to Ken's left is Cliff Custer. He is the fleet project manager for our license renewal effort and Steve Dort is our Davis-Besse site project coordinator. We also have a number of our License Renewal Core Team members seated in the room here over to my right, and a fairly large contingent of our Aging Management Program owners and subject matter experts are also seated in the room.

With that, what I'd like to do is turn our presentation material over to Ken who will cover most of this material, and then we'll also be introducing another member of our team that will cover some of the details. Ken?

MR. BYRD: Okay. If you could go to the next slide.

CHAIRMAN STETKAR: Yes, just remember turn your mics on when you speak; turn them off when you don't. It helps our transcript.

MR. BYRD: Okay. So first of all, I'll provide a little background on Davis-Besse, our site and location.

So, we're on the southwestern shore of Lake Erie. We're in Ottawa County. It's in Ohio. We're about between 20 to 30 miles east of Toledo, and Toledo is the nearest metropolitan area to the site. The site is a 954-acre site, and of that site 733 acres are wildlife refuge and marshland and that's leased to the U.S. Government.

Could you go to the next slide, please? Okay. We're a pressurized water reactor. Davis-Besse is a Babcock & Wilcox designed nuclear steam supply system. The one unique feature, or one of our unique features, we're a raised-loop design. The raised loop design is unique and it provides improved natural circulation over the previous designs. Bechtel was our construction management. And our operating license expires on April 22 of 2017.

So I'll talk very briefly here about some of our recent improvements. And there's many things we've done. I just selected a few of the really high-level ones for this slide. But just to cover a few other things we've done just within the last year, in our last outage we put in digital electrohydraulic control. Eliminates single point vulnerabilities. Provides us with improved monitoring capability.

We replaced our turbine plant cooling

water heat exchangers and turbine plant cooling water valves. It improves our thermal performance, gives us better isolation.

We modified a major project over an extended period of time. We modified our switchyard. Added in three new breakers, added in a new offsite line. That significantly improves our operational flexibility and our reliability for loss of offsite power.

We replaced our reactor coolant pump seal vent piping with flexible hoses for all four of our reactor coolant pumps. This reduces our susceptibility to high-cycle fatigue in the socket welds in that piping. On our last outage we replaced about 1,000 feet of service water piping, and that's part of a multi-outage project we have to replace all of our small service water piping. That would be piping under six inches. And that will improve our capability of that piping.

And as we speak right now, we're in the process of replacing the second of our two station air compressors. So we're just improving the reliability of those components.

Moving on to the more larger items, which I put on the slide here, we did in our -- in 2011 we replaced our reactor head. Our new head has got alloy 690 control rod drive mechanism tubes making it less susceptible to primary water stress corrosion cracking. Picture in the center there is our new head going through the shield building.

In our outage we conducted in the spring of 2014 -- we replaced both of our once through steam generators. We also replaced a portion of our reactor coolant system hot legs. Again, this eliminated the alloy 600. Our new tubes are alloy 690 making us less susceptible to stress corrosion cracking.

And then finally, the picture I have on the right there, that's a picture of our new emergency feedwater facility under construction. That construction is going on right now. And that's a project that we initiated in response to two programs. One is the National Fire Protection Association 805 and the other is our FLEX. This provides us with our Phase 1, the initial response in FLEX. It also significantly improves our fire core damage frequency and that assists us in our NFPA 805.

What we're going to have here is a 290,000-gallon tank. We'll have a diesel-driven feedwater pump which would be equivalent to our current auxiliary feedwater pump. Similar head and similar flow. And when we get this completed that will be an automatic start. This provides us with a lot of benefits. Of course this will all be seismic. It will be missile-protected. Benefits we'll get. We'll get a significant improvement in our core damage frequency for fire, about two orders of magnitude. And it will also provide us with a pretty good benefit to our online core damage frequency.

So that's a very brief kind of outline of some of the things that we have going on for long-term site improvements at Davis-Besse.

At this point now I'll turn it over to Cliff to talk about some of the details of our license renewal application.

MR. CUSTER: Thank you, Ken. My name is Cliff Custer. I'm the fleet project manager for license renewal.

So the application was developed to GALL Rev 1, but was reviewed to GALL Rev 2 due to the changes in the initiation of GALL Rev 2. It was developed by a core team of AREVA and the FENOC Core Team. Site review and concurrence were involved in the documents that went into the application and we had industry peer review prior to submittal. There are 44 Aging Management Programs, 13 of which are new and 31 of which are existing programs. We ended up with 55 license renewal commitments.

Next slide, please. So this is a timeline of the application evolution. We began the project in 2008. We submitted in August of 2010. Our sufficiency review was in October of 2010. And to a large degree our audits occurred in 2011. You'll notice on the bottom of the slide we had an event occur which we'll talk about later. The shield building crack was observed in October of 2011. But moving forward we had a draft safety evaluation report that was issued in 2012. Our first Subcommittee meeting was in September of 2012 and the final SER occurred in 2013. Our Supplemental SER was originated in August of this year, and of course our second Subcommittee meeting was September of this year.

Next slide, please. So in the earlier safety evaluation we had four open items. They were addressed and closed in the September 2013 safety evaluation. They were related to operating experience, reactor vessel neutron embrittlement, pressure-temperature limits, and of course the shield building.

So different individuals will now talk to that issue. Next slide, please, Steve. So I'll have

Trent Henline speak to the operating experience and how we've closed that open item.

MR. HENLINE: Trent Henline, license renewal implementation project manager.

So, in December of 2012 we updated both our Corrective Action Program and our Operating Experience Program to allow for an aging management evaluation check box. What we do with this is we allow the normal course of evolution evaluation for those two processes to take place. And independently we evaluate these particular instances in accordance with the Aging Management Program to determine if we are appropriately addressing the items that may have been identified independently.

So we use this as an opportunity to review external operating experience, internal operating experience, NRC guidance, including revisions to the GALL, or the generic aging lessons learned, as well as vendor technical information that we may get through our normal processes. This process has proven to be effective. We have identified over 500 items that have been considered for aging management evaluation and we're confident that this process will be successful through the period of extended operation.

MR. CUSTER: To discuss the next two open items I'll ask Dennis Blakely, subject matter expert, to discuss how we closed the reactor vessel neutron embrittlement and pressure-temperature limits open item.

Please go ahead, Dennis.

MR. BLAKELY: Good afternoon. My name is Dennis Blakely and I'm the reactor engineering supervisor at Davis-Besse and also the reactor vessel Aging Management Program owner.

We had two open items related to the reactor vessel as a result of our license renewal application. The first had to do with the upper shelf energy evaluations done for the vessel. Initially we used a generic value of 70 foot-pounds for that upper shelf energy evaluation. That would be the initial upper shelf energy. That was based on a mean value for similar type weld materials because we do not have material data for all the welds in the reactor vessel. That was considered statistically non-conservative since half of the values lie below the mean for that material data.

We evaluated the consequences of utilizing initial upper shelf energy that would bound the lowest data available and found that that would result in values less than 50 foot-pounds. 10 CFR 50 Appendix

G requires the final upper shelf energy to remain above 50 foot-pounds or requires the licensee to provide equivalent margins analysis to demonstrate that there's still adequate margins against fracture if the value is determined to be below 50 foot-pounds.

FirstEnergy conservatively decided to perform evaluations for all the reactor vessel welds utilizing equivalent margins analysis to ensure that we do have adequate margin to safety for the vessel. The results of those analyses demonstrated that we do retain adequate margin and the information was provided to the NRC staff. They reviewed it and closed the open item based on those analyses.

Next slide, please? The other issue with the reactor vessel aging had to do with the methodology utilized to develop the pressure-temperature limit curves at the plant and also sought assurance that we had considered all the reactor vessel materials as well as the ferritic materials that constitute the reactor coolant system when developing those pressure-temperature limits.

We do utilize 10 CFR 50 Appendix G and Regulatory Guide 1.99 Revision 2 methodologies in developing our pressure-temperature limit curves. We also use the methodologies described in the topical report BAW-10046, which has been approved by the NRC. That topical report details how the other ferritic materials in the reactor coolant system and the reactor vessel are considered within the development of the pressure-temperature limit curves. With the amount of fluents that the reactor vessel has received and will receive during the period of extended operation the reactor vessel beltline material is controlling for the plant at this point in time.

Any questions, please?

(No audible response)

MR. BLAKELY: Thank you.

MR. CUSTER: Moving on, I'd like to turn the discussion of the shield building now over to Ken and follow through with that discussion.

MR. BYRD: Thanks, Cliff. So for our discussion of the shield building I'm going to have our design engineering manager Jon Hook come up to the front table here. And just to introduce Jon, Jon is our design engineering manager. He is a civil engineer with over 40 years of experience in engineering design, also a member of the EPRI Concrete Technical Oversight Committee. So we are very fortunate to have Jon as our lead for the shield building activity over the last four years.

I also wanted to introduce a couple other people who are here and are going to be supporting us in our discussion of the shield building. Over on the side table we have Dr. Chong Chiu. Dr. Chiu is the founder of Performance Improvement International. PII is internationally recognized for their root cause analysis and investigations.

We did engage Dr. Chiu and his organization immediately back in November of 2011 when he first identified this condition. They did perform the initial root cause that we had conducted on the shield building. Later when we identified additional cracking, as Jon will describe as we walk through the events that occurred, we reengaged Dr. Chiu's organization. They conducted the second root cause as well on the propagation of cracking. And then finally we engaged Dr. Chiu to investigate the condition of the shield building with regards to relative humidity and our expectations with regards to how that condition would develop. So Dr. Chiu was involved in many of the different aspects of our investigations.

The other individual I want to introduce is Dr. Javeed Munshi. Dr. Munshi is a senior principal engineer and Bechtel Fellow. He has over 25 years experience in design and construction of concrete structures. Dr. Munshi is chair of the ASME Code Committee for Concrete Containment. He's also a member of the American Concrete Institute Code Committee for Nuclear Concrete Structures. He's a fellow of the American Concrete Institute, fellow of the American Society of Civil Engineers and fellow of the Structural Engineering Institute.

We brought Dr. Munshi in as part of our initial team back in October of 2011 when we first identified we had laminar cracking. He was involved in the initial investigations and assisted us in performing the analysis that was required to determine we had the functionality of the shield building prior to restarting. Dr. Munshi was also involved in the formulation of our testing program we did at Kansas and Purdue University as well as in the evaluation of those test results. And then finally, Dr. Munshi and his organization were involved or actually performed the design basis analysis which we are using to move forward based on the Purdue and Kansas analyses.

So what we're going to talk about here, really our intent here is to describe the Aging Management Program that we have to ensure that the shield building maintains its functions throughout our period of extended operation, recognizing this is a complicated topic. We've been at this for four years and had a lot of activity. So in order to make sure that we can coherently describe this, first we're going to describe the initial condition, where we are in the shield building.

Mr. Hook here is going to walk through a timeline and attempt to in a brief period of time bring us all up to speed with the various activities that we've performed with regards to the shield building. Then we'll get into a more detailed description of our monitoring program and our basis for concluding the shield building conditions acceptable.

So at this point I'll turn it over to Jon Hook.

MR. HOOK: Thank you, Ken. As Ken indicated, my name is Jon Hook. I am the design engineering manager at Davis-Besse.

Next slide, please. So I'd like to start off with some basic information on our shield building to get everyone familiar with the structure. The shield building is a reinforced concrete structure. It's independent of our containment vessel and there's a four-and-a-half-foot annular between the two. Although the shield building and containment are independent, they do share the same foundation. The shield building design function is to provide biological shielding, provide protection of the containment vessel and it provides an extra barrier for defense-in-depth against a release during an accident.

Next slide. Our shield building has what we call shoulders. So if you look at the upper left-hand part there, you'll see 16 projections sticking out of the cross-section of our shoulder. Those are shoulder areas. They serve no structural purposes and are only there for architectural reasons. Now if you look at the upper right, that is a picture of one of our shoulders and you'll notice that it terminates right above the aux building roof. The lower left is a section of our shoulder area where were first identified laminar crack. A laminar crack was located along the outer matte rebar shown here in red. And the picture on the lower right is a picture of one of the cracks inside our core bore. That crack has a crack width of 5,000th an inch, about the size or thickness of a single sheet of paper, and the cracks are very tight.

Next slide, please. Now I'd like to go over the major activities associated with the shield building. In October of 2011 --

VICE CHAIR BLEY: Jon?

MR. HOOK: Yes?

VICE CHAIR BLEY: Just from that last picture the cracks that you found are all in the shoulder area?

MR. HOOK: No, that was the initial condition just in the shoulder areas.

VICE CHAIR BLEY: Okay.

MR. HOOK: But we did find cracking at two other areas, the top 20 feet and then around the main steam line penetration areas. And I'll get into that.

VICE CHAIR BLEY: Okay. Thanks.

MR. HOOK: Okay. So a laminar crack was first identified when we provided an opening in the shield building to replace our reactor head. We formed a team of experts that Ken mentioned, Bechtel Power and Performance Improvement International engineers, and we did perform impulse response mapping and we did core bores to confirm the results and also to locate the crack. If you're not familiar with impulse response, that is a nondestructive examination technique very similar to ground penetrating radar where you take a calibrated mallet and you strike the building and then you record the amount of energy brought back. Based on this investigation laminar cracking is located along the outer matte of the main reinforcing steel. It's assumed to occur in all our shoulders, the top 20 feet of the shield building and near the two main steam line penetrations.

In November of 2011, prior to starting the plant up, we performed two analyses to show that the shield building meets its designed function. We took no credit for the rebar lap splice in the areas of laminar cracking. These calculations were reviewed by the NRC prior to restart. We also did a seismic two-over-one analysis to address the effect of the shoulder separating from the shield building during a seismic event. These analyses show that we have a very high margin of safety, well over four times required by the code.

In May of 2012 we --

MEMBER RAY: Jon, just to make sure everybody understands what you just said, you're, really if understood you, talking about the potential for spalling when you're talking about the shoulder areas.

MR. HOOK: Well, it's more than just spalling. It's the whole shoulder falling off, yes.

MEMBER RAY: Well, all right. The

shoulder coming off.

MR. HOOK: Right.

MEMBER RAY: That's what I call spalling.

MR. HOOK: All right.

MEMBER RAY: But in any event -- and that's what you meant by the margin you just referred to?

MR. HOOK: That is correct.

MEMBER RAY: Because there are other margins in here and we have to sort of keep track as we go along. Okay. Thanks.

MR. HOOK: Correct. No, right, the four times margin was associated with the shoulders --

MEMBER RAY: Yes.

MR. HOOK: -- separating.

MEMBER RAY: Shoulders separating. We'll use that term. Okay.

MR. HOOK: Okay. Thank you.

In May of 2012 we completed our root cause. This was led by Performance Improvement International. Through extensive investigation, testing and analysis the root cause was determined to be wind-driven rain that saturated the concrete followed by a sudden drop to near-zero temperatures. This resulting in freezing the water and cracking the concrete. Contributing causes were the reinforcing steel configuration in the shoulder areas, stress concentrations associated with the shoulder areas and high density of rebar spacing in the top 20 feet and near the main steam line penetration areas. This root cause --

MEMBER RAY: Jon, let me interrupt you again, because you used a phrase there that triggers the point I want to make.

We've seen this attributed to a particular event in 1978. You didn't do that. Was it your intent to say this could have happened over a longer period than that one event?

MR. HOOK: This was a singular event --

MEMBER RAY: Okay.

MR. HOOK: -- as a result of the blizzard of 1978.

MEMBER RAY: Because it was 33 years until you discovered it, it's that gap that I'm wanting to make sure you intend to refer to. Okay.

MR. HOOK: Right. Right. Correct. This happened much earlier on in the life of the plant.

MEMBER RAY: Okay.

MR. HOOK: Thank you.

MEMBER SKILLMAN: Jon, how do you know

that it was that single event that began this course of events?

MR. HOOK: Okay. What I'd like to do is refer to Dr. Chiu who did the evaluation.

MEMBER SKILLMAN: Please. Yes, sir. Please.

MR. HOOK: Dr. Chiu?

DR. CHIU: Yes, this is Chong Chiu. As indicated, we did an analysis, a root cause analysis. What we did is we started with 45 failure modes including everything we know about concrete failures. So by process of elimination -- we first of course -- through thermal cycling we find out that stress is very low. And then through other mechanisms we do a core bore and analyze what's the data? We find out there's only one mechanism can occur with that large stress. Was a single shock, because all the crack has no I call the ridges. No sign of propagation. All the fractured surface is very smooth. It's like one force, very big force.

So with that we start looking at all the -- I call it weather or climate events through the construction, through the operation of the plant. So we identify only two events that can have that problem, can cause that issue, or this force. Is '77 and '78. So analyze the two events. We find out '77, the water is not enough. That's just so -- the rain is not as heavy as '78 and therefore not enough water are impregnated into the concrete. Therefore, upon freezing the stress is so low, low enough not to cause the one single shock can cause the crack. So only by process of elimination we only have '78 as only possibility can cause that event.

MEMBER SKILLMAN: Okay. Thank you.

MR. HOOK: And this root cause was --

MEMBER RICCARDELLA: Excuse me.

MR. HOOK: Okay. Sure.

MEMBER RICCARDELLA: Can we go back to the previous slide?

Given the root cause I guess I'm somewhat surprised at the location of the crack as it approaches the shoulder. Why would it be in the second rebar layer as opposed to the first one that's closer to the surface?

MR. HOOK: So there is stress concentrations in there as a result of the shoulder configuration. So there's some locked in additional stresses that are there.

PARTICIPANT: Dr. Chiu's analysis. Do you want to have him describe that?

MR. HOOK: Yes. And, okay, Dr. Chiu, that's consistent with your analysis that you did on your modeling that you did?

DR. CHIU: Yes, exactly. That location is very unique because it's have two edges. We have water impregnated into the concrete from two sides. Then you freeze up and cause the expansion. You can generate a very large stress in the second point. That's why it start cracking at that point.

MEMBER RICCARDELLA: The other edge you're referring to is the flute?

DR. CHIU: Yes, flute. Two edge. You see that --

MEMBER RICCARDELLA: Yes.

DR. CHIU: -- corner? Yes.

MEMBER RICCARDELLA: Yes.

MEMBER RAY: The stress explanation I think also applies to the upper region where it's in between the shoulders.

DR. CHIU: I miss your point, sir.

MEMBER RAY: I believe the explanation having to do with the high stress area applies also to the upper region where it goes across the barrel section between the shoulders.

DR. CHIU: Yes, I think.

MEMBER RAY: Speak up.

DR. CHIU: Yes, sir.

MEMBER RAY: All right. I'm just trying to get a consistent explanation on the table here. And if I'm mistaken, please tell me, but that's what I understood to be the case.

MR. HOOK: Right, so in addition to the stresses that are up there, the top 20 feet is unique in the fact that we have a high density of rebar. We have No. 11 rebar spaced at six inches on center. So that's unique to that area. And that's the same configuration that's around the main steam line penetration area, too. So there's a little different rebar configuration there compared to what's in the shoulder area. But it has to do with stresses as well.

Okay. So the first root cause was reviewed by the NRC in a special inspection.

Going on to July 2012, we did complete our rebar test at Purdue University and the University of Kansas. These independent tests show that near design capacity is achieved for cracks that are significantly wider than we see on our shield building, and portions of these tests were witnessed by both FirstEnergy and the NRC individuals.

In August of 2012 we completed our first annual inspections with no identified issues. Also, in October of 2012 we completed the coating of the shield building exterior. The root cause identified high winds and driving rain with near-zero temperatures that caused the crack. The only practical item that we could control would be the ability to coat the shield building to prevent water from penetrating the concrete.

In August of 2013 we established the design-based calculation that addresses the current condition of the shield building. This calculation also incorporated the rebar test results from Purdue and Kansas University, and this calculation was also the subject to a special NRC inspection.

Also in August of 2013 we completed our second monitoring campaign. It was during this campaign when we first identified crack propagation. As a result, we inspected all 80 core bores and performed impulse response testing to establish the condition of laminar crack.

Yes?

CHAIRMAN STETKAR: Let me interrupt you. If anybody has your microphones on, if you're not speaking, please turn them off. We have some folks on the bridge line who are complaining that they can't hear because of rustling of papers and whatnot.

MR. HOOK: Okay.

PARTICIPANT: Can people on the phone mute their phones?

CHAIRMAN STETKAR: I don't know what that means, Glen.

PARTICIPANT: No, ask the people on the phones to --

CHAIRMAN STETKAR: People on the phones out there, also if you're listening in, please mute your phones so that we don't get cross-talk among people who are connected through the bridge line. If you could do that so all of you can hear.

Now, Dennis?

VICE CHAIR BLEY: Jon --

MR. HOOK: Okay. Continuing with --

VICE CHAIR BLEY: Jon, I had a question before he --

MR. HOOK: All right.

VICE CHAIR BLEY: -- shut me up. What kind of coatings did you use? And on concrete how long do these hold up? Do you have to do this routinely in the future?

MR. HOOK: So, what we applied was the

primer coat and then two top coats. And it was done by Sherwin-Williams, but I forget the actual number. But it's designed for high wind penetrating water, so it is a very good seal. It's part of our Aging Management Program. We perform this inspection every five years to make sure the coating system is intact, and also we will re-coat the shield building in 15. It has a 20-year life. We'll re-coat it in 15 years.

VICE CHAIR BLEY: Thank you.

MR. HOOK: Okay. So as a result of identifying crack propagation we inspected all 80 core bores and performed impulse response testing to establish the condition of the crack. We established a Root Cause Team. This again was led by Performance Improvement International. And based on their investigation of the crack surface and analysis ice wedging was determined to be the cause.

Three things are needed for ice wedging. You need an existing crack, high concrete humidity and freezing temperature that would result in collection of water in the cracked area, freeze and then expand to propagate the crack. This root cause was also subject to a special NRC inspection.

MEMBER SKILLMAN: Jon, let me ask this, and this is primarily for the record: You had a root cause in 2012.

MR. HOOK: Correct.

MEMBER SKILLMAN: Then we got to do another root cause.

MR. HOOK: Correct.

MEMBER SKILLMAN: So for those of us who came out of Corrective Action Programs and how strong are your corrective actions and how strong are your root causes and have you really gotten to the bottom of the issue? Why was a second root cause needed, please?

MR. HOOK: So there are two separate phenomena that occurred, and I'll let Dr. Chiu go into detail on those.

MEMBER SKILLMAN: Thank you.

DR. CHIU: Yes, This is Chong Chiu. The second root cause was initiated because the crack propagation at the bottom. What result of that analysis has shown, one of the contributing factor which didn't exist before is the paint. When you paint the concrete, you change the temperature profile such that the water will be driven from inside of the containment or shield building toward the outside. And also at the bottom the water through gravity will accumulate at the bottom. So as the paint solve the problem of a blizzard but do cause the water redistributed inside the containment, which was a phenomenon, was not in existence before. So therefore, the second root cause has to be initiated.

MEMBER SKILLMAN: Thank you.

MR. HOOK: Also, just to add on what Dr. Chiu was saying, that we did do a core bore in the area of a new crack propagation and its cracked surface is significantly different than all the other core bores that we had. All the other core bores were very smooth. This one was step cracked towards -- is a different phenomenon, and there's evidence of that.

MEMBER SKILLMAN: Okay. Thank you, Jon.

MR. HOOK: In May of 2015 we performed a series of analyses to establish the limit of crack propagation. These analyses show that we have significant margin over 20 years at the current crack growth rate before we reach a limit where additional analysis may be required.

And in August of 2015 performance improvement completed a series of evaluations and tests to show that the shield building relative humidity trend is declining and that the shield building will dry out to an acceptable level within two to eight years. And then just --

MEMBER RAY: Jon, I just want to underscore something you said. You said it accurately. I said it earlier also. But to be sure everyone understands. The margin we are referring to is the margin to the conservative assumptions in the calculations that have been done --

MR. HOOK: That's right.

MEMBER RAY: -- to demonstrate functionality. It's not the margin to building failure, but --

MR. HOOK: Oh, no, not by any means. There's more steps to follow that we could do.

MEMBER RAY: But you made a conservative assumption, you've done calculations and it's the margin to those assumptions that we're talking about.

MR. HOOK: That is correct.

MEMBER RAY: All right.

MEMBER RICCARDELLA: Excuse me. Would you mind if we went ahead a couple of slides? I always believe a picture is worth 1,000 words. Could we go to page 19, slide 19 where you have the results of the IR mapping?

Yes, just so I can understand, the pink in this region, is that the 2011 cracking or the 2013 cracking profile?

MR. HOOK: The pink area that you're seeing, that is the 2011-12 composite.

MEMBER RICCARDELLA: Okay.

MR. HOOK: So that is the baseline of the shield building.

MEMBER RICCARDELLA: Okay. But could we get kind of just an estimate of how much the incremental growth was in 2013 on this picture? I mean, is it just the thickness of the line or something?

MR. BYRD: I think on slide 60 we can demonstrate that in a specific area. There we go.

MR. HOOK: So what you see on this slide is the -- we did an IR map, impulse response, on the left. That was done in 2012. And then you can see it again in 2013 and then 2015. For your point of reference the green line is the same point in each of those three slides.

MEMBER RICCARDELLA: Okay.

MR. HOOK: So you can see at the bottom there's a little bulge where we're getting crack propagation. It's not the whole area that's cracking. It's just a few areas that are there.

MEMBER RICCARDELLA: Okay. So if you tried to draw that on this page 19, it would hardly even show up. Is that what you're --

MR. HOOK: That's is correct.

MEMBER RICCARDELLA: Okay.

MR. HOOK: That is correct.

MEMBER RICCARDELLA: Thank you.

MR. HOOK: Okay.

MR. DORT: Ken, what number were we on? The timeline?

MR. HOOK: We're on the timeline slide, which is --

MR. DORT: What number?

MR. HOOK: -- 16.

MR. DORT: Thank you.

MR. HOOK: Okay. August of 2015 is Performance Improvement -- we talked about the drying out rate. Then October of 2015, just last month, we revised our Aging Monitoring Plan to address several issues. We will increase our sample size to 28 core bores that will bound the leading edges that we have identified. Our impulse response testing is now a requirement whenever we find crack propagation in lieu of it being an option. And we'll perform selected impulse response testing in 2016 and in 2018 in areas not adjacent to core bores.

VICE CHAIR BLEY: So just so I understand, see if what I understand is correct, in response to the propagation and the moisture issue you're not doing any particular AMP other than monitoring and seeing that it continues to dry out?

MR. HOOK: That is correct at this time.

VICE CHAIR BLEY: And not propagate --

MR. HOOK: It's based on the significant margin that we have in the --

(Simultaneous speaking)

VICE CHAIR BLEY: Okay. That's what I thought I heard. Thank you.

MR. HOOK: Okay. Slide 17, please? Our Shield Building Monitoring Program consists of 28 core bores. Fourteen of these core bores are located approximately two feet from the existing crack areas that we are monitoring for crack propagation. We are monitoring areas of known cracking in the top 20 feet of the shield building, in our shoulder areas and the main steam line penetration areas. Specifically 6 of the 14 are located in shoulders where we have not seen crack propagation. Four of the fourteen are located in shoulders where we have seen and we are monitoring for crack propagation. Three of the fourteen are located in the top 20 feet of the shield building, and one of these we are monitoring for crack propagation.

And one is also in a main steam line penetration. And in a couple slides I'll go over and show you exactly where these core bores are located.

Next slide, please. We're also monitoring 14 crack locations to assess any changes in crack characteristics. Specifically, three are on the top 20 feet of the shield building, nine are in the shoulder areas and one is in the main steam line penetration area.

Our frequency for inspection is yearly inspections as long as we note changes. If there are no changes noted, then we'll increase our frequency to every other year. And the location of laminar cracking is well understood based on the impulse response map, which we address all the entire building.

Next slide. So this is the impulse response map for the entire exterior surface of the shield building all laid out on a flat piece of paper here. A couple things I want to point out. At the bottom, the two red circles, the zero azimuth, that's north and the 180 that's due south. The red circles on top, those are the flute areas. Each flute has 2 shoulders, so a total of 16. Over 60,000 individual impulse response readings were taken to make this map.

The magenta areas are portions of the shield building where high mobility is located which would indicate areas of laminar cracking. This map also shows the location of the auxiliary building. We also took impulse response mapping in that area as well. This map shows all 28 core bore locations that we are monitoring. Fourteen of these core bores are located immediately adjacent to areas of known cracks. Specifically, they are nine black dots. If you see those, the nine black circles there. They are immediately adjacent to existing cracks where we are not seeing crack propagation. We have five black triangles. Those are immediately adjacent to areas where we have seen and we are monitoring for crack propagation.

MEMBER RAY: Jon, I don't think you have done this. Describe the core bore a little more descriptively. How big is it? How deep is it? There's 80 of them. You've picked these 28.

MR. HOOK: The core bores range from two inches in diameter to four inches in diameter, depending upon if we were just going to inspections or we wanted to extract a sample for concrete testing. And the core bores go into the building past the outside matte rebar so we can locate the area of laminar cracking. Does that answer your question?

MEMBER RAY: Yes, I think so.

MR. HOOK: Okay. Thank you.

And then we have 14 green dots on there. The green dots have little X marks in front of those as well. Those are the 14 areas where we are monitoring for changes in crack characteristics. We are monitoring all 12 shoulders as well as the top of the shield building and the main steam line penetration areas.

Next slide, please. We have revised our Shield Building Monitoring Program to address the Subcommittee's comment on using impulse response as a requirement versus an option. We are now required to perform impulse response mapping whenever crack propagation is noted. This will also help us characterize the crack. We also revised the program to perform selected impulse responses in 2016 and in 2018. We will perform impulse response mapping at two locations in the areas known for cracking, but not in the near vicinity of core bores. We will monitor those for any changes in the area of leading edges. We are also performing impulse response mapping on two locations in areas currently not containing laminar cracking and away from core bores to establish cracking has not expanded into these areas as well.

Next slide, please. Our Shield Building Monitoring Program consists of 28 core bores which represent areas of cracking: the top 20 feet of the shield building, in the shoulder areas and main steam line penetration areas. The extent of cracking is well understood based on the impulse response map. In the examination of 80 core bores that represents the entire surface.

Laboratory tests and evaluations suggest that crack propagation will decrease as the shield building dries out. The shield building is a heavily reinforced concrete structure with significant margin in both the structural calculation and in the percent of allowable cracking. This margin provides ample time before any limits are met. Our monitoring program scope and frequency is appropriate for the identified condition.

With that, that's the conclusion I have on the shield building pending any questions.

MEMBER RAY: Jon, I don't think you've talked about what is the importance of a crack relative to strength, the issue of overlap, shear load transfer and so on. Can you make some comments about that, why the testing at the university is applicable and --

MR. HOOK: What I'd like to do is defer that one to Dr. Javeed who's been involved with both the testing and the analysis.

MEMBER RAY: That's fine.

MR. HOOK: Dr. Javeed?

DR. MUNSHI: Thank you, Jon. My name is Javeed Munshi. I have been involved with the shield building evaluation since 2011.

VICE CHAIR BLEY: Could you speak a little closer to the mic, please?

DR. MUNSHI: Sure.

VICE CHAIR BLEY: Thanks.

DR. MUNSHI: My name is Javeed Munshi. I have been involved with the evaluation of the Davis-Besse shield building since 2011. Very early on when we got involved with the cracking we recognized it's a unique type of cracking that has not been seen in the industry before, and in fact no information existed at that time to really address it as to what it means to the structural integrity. So we started a very elaborate investigation program, hired two of the main experts in the industry; namely Dr. Sozen at Purdue and Dr. Darwin, who is right now the leading expert in bond and transfer of force from rebar to concrete.

So with the help of those two experts we recognized that the only issue we have is where the rebar -- that this is what the rebar looks like in the shield building. It's a No. 11 bar. It's a very heavy bar and it has these lugs. If you see them here. These lugs, they way it works is that when this bar goes into tension -- that's the primary function of the bar. When it goes to tension these lugs bear against the concrete.

So the only question that actually the professors and we came to is that what we have is wherever we have the lap, wherever the bars lap is where we have the weak points in the shield building. So we went into that process of investigating through testing as to what does this mean to the building, because there was no prior information on this issue.

So we tested at two different places, 12 samples in one place, 6 samples in another place, independent processes. So we came to the conclusion that because of the fact which we sort of intuitively knew from structural engineering basics is that if you look at the lug, the lug is about seven times the size of the crack width that we actually saw. So if you think about a crack width that is one-sixth of the lug size, you expect that this bar will continue to develop the force and transfer the force from rebar to concrete and vice-versa.

So that's what we found in the test. We actually found that even after we have a crack that size, it's not really going to affect much in terms of structural integrity or serviceability of the structure. So that's the phenomena we came to understand. And it has been recognized now that -- we have actually done two different places with two experts and they feel very comfortable, as we do, me personally with the experience I have with concrete structures, that this building has the structural capacity to withstand its designed function.

Did I answer your question, sir?

MEMBER RAY: Yes, that was a good explanation. I guess one other thing, at least my understanding, is though, notwithstanding that explanation, the crack width present anyway is limited to 0.13 inches. If it exceeds that amount, then you have to reestablish what's acceptable. Is that correct?

MR. HOOK: The 13 thousandths that we're talking about, that is in our Aging Management Program, and that was based upon the original value that we identified. And that's the threshold where we identified in the condition report -- if we see anything greater than 0.13, we identify it in the condition report and we evaluate it. Since then though the professors have come back and given us a significantly larger value.

And, Javeed, Dr. Munshi, you want to talk about that?

DR. MUNSHI: Right. So --

MEMBER RAY: Yes, because I think now we're going beyond anything I've seen so far in terms of -- this would be how you disposition, if I understand you correctly, something that exceeded 13 thousandths of an inch?

MR. HOOK: Correct.

MEMBER RAY: All right. Go ahead.

DR. MUNSHI: So when we did the two test programs, the two different universities, we were not looking for exactly the crack widths per se. What we were looking for is if you have laminar crack in the plane of the bar would the rebar be able to do its intended function? And the answer was yes, it would.

Then when we started looking at the readings as to what was the crack width before we actually recycled the force back to develop the full force in the -- in essence what we did is we pre-cracked the beam to a particular laminar crack and then we reloaded it. And we proved that even after you have a crack you can reload it back to its full capacity. Then we started looking at the numbers as to what were the numbers that we actually saw before we reloaded it? In fact, the numbers were quite high, sometimes 0.06 to even sometimes larger numbers.

But, so from a testing point of view there is no limit that says it has to be 0.013. In fact, the crack width limit can be much higher than what it is -- what's being observed at the current state.

MEMBER RAY: Okay. Well, we just want to understand how you would respond to identification of a larger crack width. Is there anything more you want to say about that?

MR. HOOK: No, we keep track of that in our calculations. We have a calculation process that we identify that. And the value right now in the calc is 0.02, or 20 thousandths of an inch. That's the value that's in our calc. That's what we've got from both professors. They were very comfortable in giving that conservative upper limit. And as Dr. Munshi has indicated, test results show significantly wider cracks, but for conservatism right now our threshold is 20 thousandths.

MEMBER RAY: Thank you.

MEMBER RICCARDELLA: Could I ask a question of Dr. Munshi, please?

My understanding is that the testing was done predominantly monotonic loading up to some max load. Would you comment on the applicability of that type of testing to some of the service loads like seismic, which are dynamic loads?

DR. MUNSHI: Sure. So when we design the building, the building is typically designed for a code like ACI 318 in this case or 307, the chimney code, for example, in this case. So the inherent requirement in those two codes is that it's based on the requirement that the --

CHAIRMAN STETKAR: Dr. Munshi, make sure you speak into the microphone --

DR. MUNSHI: Yes, sir.

CHAIRMAN STETKAR: -- so that we pick you up on the transcript.

DR. MUNSHI: Okay. So the requirement in those two, or the expectation in those two codes is based on monotonic testing. And since this is not in a high seismic region like for example in California where you would have to look at cyclic behavior of the building, in this case it's really not a big issue in terms of what we expect. So in essence the monotonic testing is the fundamental testing that is done on any rebar. It's only when we go into expecting inelastic excursions into any system. In this case we don't expect any inelastic excursions because the seismic force is relatively low. If it was a building in California, for example, then, yes, you get into those cycles and then -- but they have required detailing in those codes for those buildings. But in this case it's not applicable, I think.

MEMBER RICCARDELLA: Thank you.

VICE CHAIR BLEY: I had a question from Dr. Chiu's explanation of the high stresses in the shoulder region where the first cracks were found. My first thought was, gee, if we didn't have this architectural fancy work, you wouldn't have had the problem. But you also said you found it in other areas as well. So is that first idea true or is it that it could have happened anywhere?

MR. HOOK: It we didn't have the shoulders, then we wouldn't have laminar cracking behind the shoulder areas. That is --

(Simultaneous speaking)

VICE CHAIR BLEY: But you also found it

somewhere else?

MR. HOOK: We also found it up at the top 20 feet and outside the shoulder areas. And as a result of that it's -- is high density of rebar. Again, we had a No. 11 bar, which is like almost one-and-a-half inches in diameter spaced six inches apart.

VICE CHAIR BLEY: Wow. Okay.

MR. HOOK: So it's a very highly congested area.

VICE CHAIR BLEY: Thank you.

MR. HOOK: Okay. Ken, I think -- any other questions on the shield building?

(No audible response)

MR. HOOK: Okay.

MR. BYRD: Okay. If there's no further questions on the shield building, we'll move forward to containment vessel inspections. And for this part of the discussion I'm going to call again on Mr. Hook to lead the discussion through this.

MR. HOOK: Okay. Thank you. So the other item I would like to talk about is the results of our containment vessel inspections. During our earlier ACRS Subcommittee meeting in 2012 several questions were asked about the containment vessel sand pocket area in the bottom of the containment vessel, specifically groundwater seeping into the sand pocket area and how this would affect the exterior surface of the containment vessel. And the other item was borated water storage, or borated water from the refueling canal would migrate through the concrete and be entrapped on the inside of the containment vessel.

We addressed both of these issues in our 18th refueling outage last year. This slide shows a general orientation of the shield building and the containment vessel with respect to these two issues. The red circles on the left and right is the location of the sand pocket area, and the lower red circle represents the bottom inside surface of the containment vessel.

Next slide, please. This is a sketch of the cross-section of the sand pocket which is identified by the upper red circle there. That's pointing to the sand pocket. The sand pocket is a tapered notch in the foundation approximately 4½ feet deep, 15 inches wide at the top. The sand pocket surface is sloped away from the containment vessel. Right there, yes, at the containment vessel. And it drains to two drains in the area. This will prevent any standing water from being in contact with the containment vessel.

To address the effects of groundwater on the containment vessel we inspected five separate areas at the bottom of the sand pocket. Each of these had nine individual readings for a total of 45 readings. All UT readings at and below the ground surface were greater than the specified mill tolerance of 1.49 inches. The nominal thickness of the containment vessel is 1.5.

Next slide, please.

CHAIRMAN STETKAR: Now, that inspection tells you that at least in the accessible area of the sand pocket you haven't seen any degradation. What about the inaccessible area?

MR. HOOK: I'll address that in a minute.

CHAIRMAN STETKAR: Okay.

MR. HOOK: The very, very next slide as well.

CHAIRMAN STETKAR: Okay.

MR. HOOK: Okay. The other concern was associated with the borated water leaking from the refueling canal, migrating through the concrete and resting at the bottom of the containment vessel interior. A core bore was located as close to the containment centerline as possible using ALARA practices. We performed a visual inspection in this area and we also took a UT reading of the containment vessel thickness. The inspection results showed no presence of water on the inside surface of the containment vessel and the UT readings were above the 1.5 nominal thickness value. So these inspections not only confirmed that there are no effects of the containment vessel from the borated water for the refueling canal, but this UT test also shows there is no effect on the containment vessel from the groundwater under -- from the outside.

So the answer to your question, we took another UT reading at the very, very bottom, and that's inaccessible. And it also showed we got full nominal thickness there.

CHAIRMAN STETKAR: Okay. And that's -- it's hard to see on this, but that location is well below the average groundwater water.

MR. HOOK: Yes. Yes.

CHAIRMAN STETKAR: So if the exterior is constantly wetted, you'd see any evidence of corrosion?

MR. HOOK: Oh, correct. The sand pocket area is about like seven feet below the groundwater table. The dead center bottom of the containment vessel is maybe 15-20 feet.

CHAIRMAN STETKAR: Okay. Good. Thank you.

MEMBER RAY: Is there a provision in the Aging Management Program to repeat this at any point?

MR. HOOK: No, there's not. This was a one-time inspection to prove we don't have a concern. Correct me if I'm wrong.

MR. DORT: This is Steve Dort, the site project coordinator. We had a commitment that had two parts. The first part was to perform an inspection prior to the period of extended operation. The second one is conditional. If we find that we have continued leakage from the spent fuel pool, we will perform another core bore and examination of the inner surface in --

MEMBER RAY: Okay. I thought there was something out there.

MR. DORT: -- 2020.

MEMBER RAY: Yes, all right. So it's directed toward continued leakage on the interior surface resulting in wetting of the interior?

MR. DORT: Correct. But it also tell us whether we're seeing degradation from the external.

MEMBER RAY: Yes, understood, but in the absence of any continued leakage, then we're not going to find out anything further about the outside. Just to be clear.

CHAIRMAN STETKAR: Steve or Jon, do you monitor the drains from the sand pocket area?

MR. HOOK: Every outage we monitor the drain.

CHAIRMAN STETKAR: When you say "monitor" you --

MR. HOOK: Sorry. The access to the annulus is only during an outage, so when we go in there and do our inspection, that's one of the things we look at is making sure the drains are free-flowing.

CHAIRMAN STETKAR: Are free-flowing?

MR. HOOK: Yes.

CHAIRMAN STETKAR: Okay. When I said "monitor," I meant verify somehow that they're indeed free-flowing.

MR. HOOK: Correct.

MEMBER RICCARDELLA: And has there been prior leakage in the refueling canal, or is that just a hypothetical consideration?

MR. HOOK: I'd like to turn that one over to Trent Henline. He's the project manager for that project.

MR. HENLINE: Trent Henline, license

renewal implementation manager. If you could go to backup slides 32 and 33, Steve?

So we have a history or we had a history of refueling canal leakage this past outage in the spring of 2014. We mitigated everything that penetrated our liner in the entire refueling canal. That was over 75 penetrations. If you look at the picture here, in the upper left-hand corner is a picture of our upender support plates. You can see the shims below the plate as well as the bolting that goes down through the liner. On the bottom right hand is post-mitigation. We used new technology, silicone technology that utilizes a two-part silicone with stainless steel plates to protect the particular areas.

So what we did after we mitigated and filled the refueling canal to reload the fuel, we had live monitoring in three particular areas where we noted leakage. Of those areas we did not see any leakage with one exception. With one exception we saw a brief amount of water that came through a cold joint in the concrete, formed about one cup of puddle, dried up and disappeared despite the refueling canal continuing to be filled.

So what we are fairly confident happened was the water that was put into the refueling canal during the filling stage was trapped between the liner and the concrete. When we filled the pool back up, it pushed that water out that was trapped after mitigation. And we have a scheduled follow-up inspection this upcoming outage to confirm that we did 100 percent mitigate the refueling canal leakage.

MEMBER RICCARDELLA: Thank you.

MR. HOOK: With that, I would like to then turn it over back to Mr. Ken Byrd.

MR. BYRD: Okay. Unless there's any further questions, we will continue with our closing remarks. So I'll turn it over to Brian Boles.

MR. BOLES: Okay. Well, appreciate the opportunity to be before the Committee today. As you heard today, we had a large number of improvements that we've made to our station. We did briefly discuss the closure of our four open items based on operating experience, the reactor vessel neutron embrittlement issue, pressure-temperature limits and our shield building. We also provided an update on the containment vessel inspections. That was at the request of a previous Committee meeting.

And, Mr. Chairman, that's all we have from a presentation perspective today.

MEMBER RAY: Yes, I just want to confirm you still, as you said at the Subcommittee, are intending at some point to submit an amendment to the license to include the analyses that were used.

MR. BYRD: That's correct. We will be submitting a license amendment for our shield building.

MEMBER RAY: A shield building analysis methodology. That's right.

Okay. Anything else from members?

MEMBER REMPE: Where is the coating as a commitment? The second re-coating after 15 years, is that part of the license amendment or is that part of the aging management?

MR. HOOK: That is included in our Shield Building Aging Management Program.

MEMBER REMPE: Thank you.

MEMBER RAY: If there's nothing else from members, we will give the staff a chance.

John, when do you want to take a break? It's your --

CHAIRMAN STETKAR: You're in charge.

MEMBER RAY: Well, we've been one hour into this. We'll see how far the staff goes. We may take a break during the staff presentation, depending on how long it takes. But one hour is too soon, I think, having come back from lunch.

Okay, Rick. The floor is yours.

MR. PLASSE: Okay. Good afternoon, Chairman Stetkar, Mr. Ray, and members of the ACRS. My name is Rick Plasse. I'm the license renewal project manager for the Davis-Besse license renewal safety review. We are here today to discuss the review of the Davis-Besse license renewal application as documented in the SER which was issued September 2013 and the Supplemental SER which was issued in August of 2015.

Joining me here at the table is Phyllis Clark, DLR Safety Project Manager, who'll be running the slides, Mr. Jim Neurauter from Region III. The senior reactor inspector is with us today in the audience. And seated in the audience are the members of the tech staff who participated in the review of the license renewal application and conducted the onsite audits.

Next slide. This slide I'll skip over. The applicant pretty much covered this in detail. And I'll go to the next slide on safety review results.

The SER with open items was issued in July of 2012 and the first Subcommittee was held on

September 19th of 2012. There were four open items, which we've discussed earlier, that we will also discuss on operating experience, pressure-temperature limits, upper shelf energy and the shield building laminar cracking. There were no other open items or confirmatory items. The final SER was issued in September 2013 and a supplement to the SER was issued, as I stated, in August 2015, which closed the four items. A second License Renewal Subcommittee was held September 23rd of 2015.

Next slide. The operating experience open item, B.1.4-1. During the review of Davis-Besse's Operating Experience Program the staff issued ISG-2011-05, titled "Ongoing Review of Operating Experience." The open item was identified to determine how Davis-Besse addressed the recommended framework for operating experience review activities in the ISG. To address the ISG and the open item the applicant provided additional information to describe how it will enhance its current AMPs or develop new AMPs based on plant-specific and industry operating experience when necessary to ensure that age-related degradation is managed during the term of the renewed operating license.

A couple examples of those program

attributes were that Davis-Besse would screen all incoming OE for age-related degradation, they included an aging flag in both the Corrective Action Program and the OE Programs, and the Corrective Action Program be used to revised or develop new AMPs based on applicable OE evaluations.

Any questions on that slide?

(No audible response)

MR. PLASSE: Next slide.

MEMBER POWERS: I don't understand how operating experience -- say something happens and they find it, when do they decide they need a new AMP versus putting an additional piece of paper into an existing AMP?

MR. PLASSE: I would let them speak to their program, if someone wants to speak to that. They'd use their Corrective Action Program to identify the issue. And then go ahead and explain what you would do.

MR. HENLINE: Trent Henline, implementation manager. So historically the Corrective Action Program would address the issue specifically. So if we found a piece of pipe that was rusted, essentially depending on the safety significance of the pipe we would fix it and close the evaluation. The difference here is that we would check the aging management evaluation box which would kick off a separate evaluation in or program. So we would continue the condition report evaluation that addresses the immediate issue and how we're going to resolve that particular condition.

Then a separate evaluation is provided by the Aging Management Program to determine if the inspection frequency, the inspection type is adequate and the Aging Management Program continues to address whatever particular conditioning or aging mechanisms that we're trying to manage is adequate. We have had examples where we have revised Aging Management Programs as a result of this process, so we believe that it continues to be effective.

MEMBER POWERS: So the baseline response is to augment existing AMPs and it takes something very special to cause you to create a new AMP?

MR. HENLINE: Yes, that's correct.

MEMBER POWERS: How special is special?

MR. HENLINE: So for example, our Small Bore Piping Program was intended to be a one-time inspection program. We did the full scope of that one-time inspection program and during the destructive analysis we did identify cracking in socket welds, small bore socket welds. So as a result of our aging management evaluation we looked at that and determined that a one-time program was not adequate, so we are in the process of developing an ongoing program that will last through the extended period of operation.

MEMBER POWERS: Excellent example. Thank you.

MR. HENLINE: You're welcome.

MR. PLASSE: Any other questions on the Operating Experience Program?

(No audible response)

MR. PLASSE: Next slide. Okay. Open Item 4.2-1 concerning reactor vessel neutron embrittlement. For Davis-Besse the applicant performed updated 60-year upper shelf energy calculations for the reactor vessel shell, nozzle and weld components in the beltline region of the vessel. The staff determined that the applicant did not have sufficient plant-specific un-irradiated upper shelf data for those reactor vessel beltline welds that were fabricated using Linde 8 weld flux materials. Under this open item the staff required the applicant to submit an equivalent margins analysis basis for accepting the upper shelf energy values for these reactor vessel weld materials.

To close the open item the applicant sufficiently demonstrated that the equivalent margins analysis basis is given in specific NRC-approved Babcock & Wilcox reports. The EMA basis was reviewed by the staff and found to be a valid basis for accepting the Davis-Besse upper shelf energy TLA under the requirements of 54.21(c)(1)(ii) and for the extended period of extended operation. This Open Item 4.2-1 has been closed by the tech staff.

MEMBER RAY: Ron, you had a chance to look at this I believe. Did you?

MEMBER BALLINGER: Yes, I did a couple times. It's consistent.

MR. PLASSE: Okay. Next slide considers Open Item 4.2.4-1, pressure-temperature, P-T, limits. The open item is associated with a potential issue that the methods in the B&W report 10046, Rev 2 for generating P-T limits may not be conservative if stresses for reactor vessel non-beltline near geometric discontinuities would cause those components to be the limiting components for P-T limit calculations.

The applicant resolved and closed the open item by demonstrating that the methodology in Babcock & Wilcox Topical Report 10046A, Rev 2 appropriately accounts for impacts of stress and tensities for non-beltline components including those near geometric discontinuities. Thus, the applicant was able to demonstrate that the approved methodology in BAW-10046 remains valid for generating P-T limits that will be needed for the period of extended operation and this forms an acceptable basis for accepting the P-T limits TLA in accordance with 10 CFR 54.21(c)(1)(iii) and demonstrating that the P-T limit update basis is valid to manage by analysis loss of fracture toughness in the reactor vessel.

Do you have any questions for the staff on the TLAs and these open items?

(No audible response)

MR. PLASSE: Okay. Go to the next slide. This slide gives the safety review results. Following the closure of all the open items, the final SER was issued in September 2013. In total, there's 44 Aging Management Programs which were reviewed. This includes 43 programs which were reviewed by the staff during the initial safety review of the license renewal application. After the final SER was issued, one additional new plant-specific program to manage service level III coatings and linings was submitted for review to address recent industry operating experience. The table here summarizes the final staff disposition of the 44 Aging Management Programs.

Any questions?

MEMBER RAY: Let me say Charlie wasn't able to attend the Subcommittee meeting, but he did review in his area, which the members are well acquainted with and found them satisfactory.

MR. PLASSE: Okay. Thank you. Go to the next slide. This slide here is what's the framework of the supplement that was issued in August of 2015. The first sub-bullet in this list, the applicant updated its Reactor Vessels Internals AMP and submitted the Reactor Vessel Internal Inspection Plan for NRC approval in late April of 2015.

The staff found the Reactor Internals AMP and the Reactor Vessels Internal Inspection Program to be acceptable because: (A) for internals conforming to the generic design in MRP-227-A the applicant will be implementing the approved protocols in MRP-227-A; and (B) for components deviating from the generic design the applicant appropriately adjusted the AMP in the Reactor Vessel Internal Inspection Program in a manner that was found to be acceptable to the staff. Thus, the prior commitment for this AMP in the final FSER was closed in the supplement.

Other noted items. For the steam generator replacement the design modification results in some changes to the list of analyses that conform to the definition of TLA for 10 CFR 54.3(a). This resulted in changes to a number of metal fatigue or cyclical flaw evaluation TLAs for specific steam generator components or auxiliary feedwater system components. The staff found the TLA's changes to be acceptable based on the new steam generator design, the updated evaluations of the TLAs were appropriately accounted for and the updates of Section 4.3 and Section 4.7 subsections in the Supplemental SER.

Does the Committee have any further questions for the staff on any of these updates and TLAs in the supplement?

(No audible response)

MR. PLASSE: Okay. With that, we'll move to the last open item. Our slides are focused on the actual aging program for the shield building. On the first slide, as the applicant noted, hairline laminar cracking was discovered in the fall of 2011 in multiple locations adjacent to the outer horizontal reinforcement of the cylindrical shell primarily in the flute shoulder regions with some cracking outside the flute shoulder in the top 20 feet and around the main steam penetrations. The applicant determined and characterized the extent of condition by ND testing using an impulse response technique and core boring. Although the root cause determined the initial cracking was an event driven by extreme environmental conditions during the Blizzard of '78, the NRC staff was concerned that the degradation could grow and potentially affect the safety function, the primarily structural concerning being effects on the rebar bond capacity adjacent to the cracks.

To address this the applicant submitted a plant-specific AMP, the Shield Building Monitoring Program, to monitor and manage aging effects of the laminar cracking through the period of extended operation. Also, the applicant applied an exterior protective coating in October 2012 as a preventive corrective action to reduce future moisture ingress.

The Shield Building Monitoring Program was updated by letter October 6th of 2015 following the second ACRS Subcommittee meeting as a plant-specific prevention and condition monitoring program to manage aging effects. Example: propagation on the shield building laminar cracking. The program supplements the structure's monitoring program. The preventive aspect is the application of the coating.

The scope of the program includes the concrete and reinforcing steel of the shield building's cylindrical wall and exterior concrete coatings on the shield building.

The program uses periodic visual inspections using a borescope of the interior surfaces of a representative sample of core bore holes, currently a minimum of 28 selected from the 80 existing core bore holes, to monitor the shield building for changes in existing laminar cracks and/or new indications of laminar cracks.

Visual inspections using borescope are appropriate because it can measure crack width and depth from the surface. The detection of laminar crack propagation during baseline inspections in the fall of 2013 and 2015 provides evidence that visual inspections are effective. The AMP will supplement visual inspections with ND techniques; i.e., the impulse response testing, noting that impulse response testing can detect the presence of cracking but cannot measure crack width or depth.

The updated AMP by letter dated October 6th will use IR for updating extent of condition in areas where propagation is indicated in leading edge core bores for a minimum of 100 square feet around the bores of observed propagation. Additionally, IR will be performed in four randomly selected 100-square-foot grids each during 2016 and 2018 inspections, two grids in areas of known cracking leading edge bores to confirm extent of crack propagation and two grids in areas with no previously known cracking away from the core bores to detect new or expanded cracking.

The program also conducts opportunistic visual inspections or rebar near laminar cracks for corrosion indications when exposed for some reason.

The coatings are visually inspected for loss of effective at an interval of five years and the coatings will be reapplied every 15 years.

Inspections under the program are conducted and the results are evaluated by personnel meeting quantification requirements of ACI Report 349.3R Chapter 7.

Any questions on the program?

MEMBER SKILLMAN: Rick, yes, Dick Skillman. My question to you is this: Did you witness the coating of the building a couple years ago?

MR. PLASSE: I was not on this project a couple years ago. We do have the region. The question is did someone in the NRC inspect the application of the coatings on the building?

CHAIRMAN STETKAR: You have to come up to the microphone. Identify yourself, please.

MR. NEURAUTER: Hi, I'm Jim Neurauter, Region III inspector. The region has resident inspectors on site and they oversaw the application of the coating to the shield building. That was one of the follow-up items that we were monitoring.

MR. PLASSE: Thank you.

CHAIRMAN STETKAR: Thank you.

MR. PLASSE: Any questions on the program?

(No audible response)

MR. PLASSE: Okay. We'll go to the operating experience of crack propagation slide. The operating experience program element includes provisions to evaluate and incorporate future plant-specific operation experience such as inspection findings, and industry operating experience is applicable and necessary.

During baseline inspections of core bores conducted during August and September of 2013 the applicant discovered indications of limited laminar crack propagation in 8 of the total of 80 core holes inspected. The applicant's apparent cause evaluation characterized this 2013 plant-specific operating experience to be the result of an ice wedging mechanism which is the freezing and expansion of trapped water at the tip of preexisting laminar cracks. Crack propagation was also detected in the recent 2015 inspection.

The applicant increased the representative core hole sample size for future inspections from the previous 20 to 23 following the 2013 inspection and to 28 following the 2015 inspection, which now includes 5 leading edge monitoring bores to identify changes in the limits of cracking in areas of observed crack propagation. The adequacy of the sample size and location of the inspection core bores will be discussed in the next slide.

The applicant also increased the inspection frequency since the observed propagation is not considered passive. The inspection interval will be annual for the years 2015 through 2018, then increase to two years 2018 through 2026, and four years thereafter, which is acceptable because the inspection interval is progressively increased only if no aging effects; i.e., indications of new cracking and/or propagation of existing laminar cracks are identified. Changes to the inspection schedule, sample size and the locations and parameters monitored will be evaluated if aging effects are identified.

The annual inspection frequency for the initial years is acceptable because it will include a complete winter between inspections, which is the likely time of propagation. And the AMP also conducts additional impulse response testing around core bores observed crack propagation to confirm and update the extent of propagation.

Any questions on the operating experience of crack propagation?

(No audible response)

MR. PLASSE: Next slide. Adequacy of sample size and distribution. The minimum representative sample size of 28 core holes to be inspected in different regions of the shield building and their distribution is acceptable because they include 14 crack core holes that cover 9 of 10 flute shoulders with highest prevalence of cracking, the upper 20 feet of the shield building and at main steam penetrations, which are areas with cracking outside shoulders in a range of observed crack widths including maximum observed crack widths.

They include 14 un-cracked core holes, but located near areas of known cracking providing ability to monitor crack propagation which include 5 bores that define the leading edge of recent observed crack propagation. And the program includes provisions for expansion of sample, consideration of past evidence of crack propagation and choosing inspection locations and for addition of new core holes for inspection if needed to bound crack propagation limits. Further, each representative core bore in the sample provides information regarding crack characteristics with depth and planar limit which help monitor maximum crack width and/or planar propagation.

The staff notes that the sample consists of core holes that define maximum observed crack widths as well as planar propagation limits. Therefore, the program includes appropriate monitoring and trending of the limiting crack width parameter as well as planar limit to effectively detect aging effects of potential crack propagation on the bond capacity of the adjacent rebar, which is the primary structural concern related to laminar cracking.

MEMBER RAY: Rick, at this point let me stop you and say you heard the dialogue, I presume, that we had about, well, what is the limit? It's now 13. Now 20 is the point at which further assessment is required. Staff's satisfied with the current setup on that? Because there isn't any particular limit specified beyond which the cracks would be considered to render the rebar non-functional.

MR. THOMAS: Yes, this is George Thomas. And, Rick, if you move to the next slide --

MR. PLASSE: Okay.

MR. THOMAS: -- we have the acceptance criteria for the program.

MEMBER RAY: So I was anticipating the comment. But in any event, that's the question that I'm trying to get to is is there a limit to the crack width beyond which you don't count the rebar any longer, or is that to be determined in the future?

MR. PLASSE: Let me go through the slide. Okay. The governing acceptance criteria for the core hole inspection results against which need for corrective actions is evaluated in a Corrective Action Program -- I'm on the right slide, right?

MR. THOMAS: Yes.

MR. PLASSE: Okay. In the qualitative criteria that the crack remains passive; that is, no discernible changes in existing laminar cracking and no new crack indications. However, quantitative criteria with defined limits for crack width and planar limits are also included. Note that the qualitative criteria controls because it bounds the quantitative criteria. The quantitative criteria was included in an RAI response January 28th of 2015 to provide an indication of the crack width and planar limit conditions that can be considered bounded by the calculation of record, calculation CSS 99.20-63.

The applicant completed inspections and analysis of the currently observed laminar cracking and propagation in the shield building in accordance with guidance in Section 5.3, Conditions Requiring Further Evaluation, of ACI 349.3R, which included large-scale beam testing at Purdue University and the University of Kansas on the impact of observed laminar cracking on rebar lap splice capacity and new analysis and design calculations based on which the applicant concluded that the as-found condition is acceptable after evaluation.

However, such is the condition is not passive, the laminar crack will be subject to increased frequency monitoring until determined to be passive and continued ongoing monitoring during the PEO by the Shield Building Monitoring Program. Thus, if the acceptance criteria is not met, the condition will be evaluated in the FENOC Corrective Action Program pursuant to 10 CFR 50 Appendix B using the evaluation criteria hierarchy in Chapter 5 of ACI

Report 349.3R. And the next slide shows the hierarch.

MEMBER RAY: Well, wait a minute. Let's just --

MR. PLASSE: Okay.

MEMBER RAY: -- stay since it's got 13 thousandths there and --

MR. PLASSE: Okay.

MEMBER RAY: -- we heard it's not 20.

MR. THOMAS: Right. The numbers, the quantitative numbers given here were provided in response to an RAI in January of 2018. And since then --

MEMBER RAY: January of when?

MR. THOMAS: January of 2015. I'm sorry. Since then the applicant has further refined their calculations and my understanding is that limit could be 0.02 inches.

MEMBER RAY: Well --

CHAIRMAN STETKAR: Well, but --

MEMBER RAY: Go ahead, John.

CHAIRMAN STETKAR: Now I'm confused. We have a slide in front of us here in writing that says 0.013. So what's the staff's evaluation based on?

MR. THOMAS: Well, as I said, the qualitative criteria, if it exceeds 0.013, or any discernable change in the crack characteristics, that will be entered in the Corrective Action Program and evaluated and necessary actions taken in that.

CHAIRMAN STETKAR: Okay, I guess.

MEMBER RAY: Well, yes --

CHAIRMAN STETKAR: I hear what you're saying.

MEMBER RAY: I think what we need to do at this point -- it's 2:30. This is not a very good way to leave this point. And so we're going to take a break and when we come back I would like you to be prepared to give a more clear statement as to what your evaluation is based on. Is it a value of crack width which is to be determined as acceptable by the applicant under their Appendix B Corrective Action Program, but we don't know what that -- it's not a fixed value, or is it, as I had read previously and as the slide suggests, a number not to be exceeded? Which is it? And rather than answer me right now, I'd like you to think about your answer and then we'll resume after taking a break. Okay?

MR. THOMAS: Okay.

MEMBER RAY: So we'll recess for 15 minutes, come back at a quarter to 3:00. Is that all right?

(Whereupon, the above-entitled matter went off the record at 2:33 p.m. and resumed at 2:47 p.m.)

CHAIR STETKAR: Okay. We're back in session. Back to you, Harold.

MEMBER RAY: All right. Thank you very much.

I hope everybody had a break that they needed. And with that, we'll resume back to you, Rick.

MR. PLASSE: Yes. There's a correction on this slide.

Under "Quantitative," -- the first bullet, "Current Observed Maximum Width," that is the trigger point where they would use a corrective action program based on test results -- the .013.

In the 2015 inspection this summer, they did have a location that was .016 inch. And the way it's explained is the trigger point gets to anything exceeding that measurement of .013, it will go into the corrective action program and then will be evaluated.

And you are correct. The calculation of record is .02.

With that, I'll turn it over to George and he can talk about the various criteria here -- the qualitative and quantitative.

MEMBER RAY: Okay.

Before George speaks though, will you revise this for the record -- this slide? Or how do you want to handle it?

Otherwise, I'd like you to be very precise about what the change is that you would make in it. You can either revise it, I believe, or you can say it should be changed in whatever way you want to change it.

MR. PLASSE: I can provide for the record a revised slide to strike what's in parentheses. And the correct width does not exceed .013 is the criteria.

MEMBER RAY: Don't you want to say is the criteria for something?

MEMBER BROWN: For subsequent re-evaluation or --

MEMBER RAY: I'm just trying to understand the slide at this point. And I think I'd ask you before we adjourn for the day to describe exactly how the slide should read so that then we can look back on it as a matter of record.

MR. PLASSE: Can I recommend that when I'm finishing up that you work with Sam and management?

MEMBER RAY: Okay. Whatever you want to do. Don't worry. We won't close the record until you can do that.

MR. PLASSE: I'll do a revised slide at the end of the meeting.

MEMBER RAY: This is something I want to be sure we understand staff position.

And I will ask the Applicant, since this was sort of a comment in passing earlier, to be precise. They've asked to have another minute for a different reason. I'll ask them to also say precisely what it was that they are intending so that we don't get into a situation in which we're not understanding each other.

MR. PLASSE: Yes. So as I stated earlier, in the upper bullets, any change to any existing crack width or planar size, they'll write up a corrective action report and evaluate any new indication of new cracking -- any crack width that is above the trigger point of .013. And that will start the corrective action review and the evaluation criteria of ACI 349.3R.

And for the record, they did have an indication of .016 inch that they evaluated from the 2015 review. But still, the trigger point going forward is still .013 inch.

MEMBER RAY: All right. Well, I want to hear the same thing from the Applicant. But we'll do that later.

George, you wanted to make a comment?

MR. THOMAS: Yes. Just clarifying.

What you see on the slide is the criteria in the AMP. And if any of these conditions -- whether qualitative or quantitative -- is exceeded, that'll trigger a condition report in the Applicant's corrective action program. And it will be evaluated against the calculations of record and any other further evaluation that needs to be done.

MEMBER RAY: Well, all right. But perhaps it's best the Applicant then explain how larger crack widths would be expected to be dispositioned.

But we'll let them do that. Okay?

MR. PLASSE: Do you want to do that now?

MEMBER RAY: No.

MR. PLASSE: No? Okay.

Okay. The next slide shows the 349 evaluation hierarchy -- the evaluation procedure from ACI 349.3R applied to the shield building.

Note that if there are indications of discernible changes in the cracking, the cracks are observed not passive and the condition is considered exceeding the second tier criteria. And therefore, the condition is considered in need of further technical evaluation.

The further technical evaluation and the calculations of record -- CRRCR 99.20-63 and 69 -- determined the condition was acceptable for structure adequacy. However, the condition of recently observed propagation in 2013 and 2015 is considered not passive. So they're still in the option at the bottom of the figure -- monitor increased frequency.

So it'd be --

MEMBER RAY: Well, that's one of the options at the bottom. Repair and replace is two other options.

MR. PLASSE: Well, right. But the one that they're using is the monitor increased frequency --

MR. THOMAS: At this time.

MR. PLASSE: -- at this time.

MR. THOMAS: At this time.

MEMBER RAY: George, did you want to say more?

MR. THOMAS: No. I just want to say that at this time of the three options, they determined monitor increased frequency. That's the appropriate --

MEMBER RAY: And the staff has accepted that?

MR. THOMAS: Yes.

MR. PLASSE: Okay. And the next slide.

To summarize, the staff finds the shield building monitoring program AMP acceptable because laminar cracks are inspected at a one-year interval and this interval will not be progressively incremented to two to four years unless cracks become passive.

A representative sample of no less than 28 core bores will be inspected at every inspection to effectively monitor crack width and planar limit. A total of 80 existing bores are available for inspection if samples need to be expanded.

The use of visual inspections and impulse response testing can effectively detect changes in laminar cracking, crack width, planar limit or new indications.

Inspection findings will be evaluated by qualified personnel using the evaluation procedure in ACI 349.3R, which is recommended by the GALL Report for evaluation of concrete structures.

And the acceptance criteria of a crack being not passive would trigger further evaluation under the corrective action program if inspection findings indicate discernible changes in the cracks. Thus, the AMP will effectively collect and evaluate laminar crack monitoring data periodically against acceptance criteria that will lead to further evaluation in the corrective action program to ensure that intended functions of the shield building are maintained.

Next slide.

Based on the AMP attributes discussed in the previous slides, the staff concludes that through implementation of the AMP, the Applicant will be able to adequately monitor the cracks, perform structural evaluations and take corrective actions as necessary in a timely manner prior to loss of intended function.

Based on the review, the staff concludes that there is reasonable assurance that the shield building monitoring program will adequately manage aging effects of the laminar cracking such that intended functions of the shield building will be maintained consistent with the current licensing basis during the period of extended operation.

And the shield building item is closed.

The open item -- staff evaluation -- is documented both in the SER and the Supplemental SER Section 3.0.3.3.9.

In conclusion, on the basis of its review, the staff concludes that the requirements of 10 CFR 54.29(a) have been met for the renewal of Davis-Besse License.

This concludes our staff presentation, and now we'd be available for any further questions from the Committee.

MEMBER RAY: Okay. There were a couple of things mentioned -- one, at the Subcommittee meeting and one here today -- that I don't know that the staff has commented on or may not have any comment on.

One of them was the implications, if any, for crack growth of cyclic loading. And here, we'd be talking about seismic.

Has there been any evaluation by the staff of that? It was characterized as well in California. It would be different than it is in Ohio. And cyclic loading isn't expected to be such as to result in crack propagation.

Has the staff considered that, do you know, Rick? Or is there anybody who can speak to that?

MR. THOMAS: This is George Thomas.

The staff has not evaluated that because our scope of review has been limited to aging management. And a seismic SSC event is a one-time rare event that's --

MEMBER RAY: Well, it goes to the adequacy of margin. The margins here are substantial.

MR. THOMAS: Right.

MEMBER RAY: And if the margins were very small, one might say well, we need to be aware of that as part of the aging management program.

MR. THOMAS: Right.

MEMBER RAY: That's the implication for license renewal if there is any. I'm not saying there needs to be any. I'm just saying that it was a comment that was made earlier.

It's something that we thought about during the course of our review. And I just wondered if the staff had given it any consideration.

Jim?

MR. NEURAUTER: Yes. Jim Neurauter.

As you know, the licensee or the Applicant here needs to put in a license amendment for the shield building to re-establish to the design basis. And they have a structural calculation that they have prepared that they believe adequately addresses the design basis.

They have not submitted this application at this point in time. So staff has not reviewed it with respect to margins. It really is a margin issue as to what staff will accept.

So until that review has taken place and staff has issued its SER with the appropriate margins that they feel are safe, it's premature.

MEMBER RAY: That's fine. I understand it, and that's fine.

Like I say, the comment has been made. It was a consideration. And I just wondered if you had anything to offer.

MR. NEURAUTER: Well, yes.

MEMBER RAY: And you've answered the question. Thanks.

MR. NEURAUTER: Okay. Thank you.

MEMBER RAY: The other issue that we also discussed was a spalling. The Applicant had addressed that very early on in the Subcommittee meeting and touched on it again today. But I don't recall seeing anything in the staff review and discussion, and I wondered if you had any comment on spalling, either in the shoulder area where there are large chunks -- and maybe you don't call it spalling but separation possible -- and also in the region of high up where there's laminar cracking in between the shoulder areas where the thinner sections might be subject to spalling failure.

Is that anything that the staff has discussed and I just missed it, or not?

Then, Rick, I guess you should be in charge here.

MR. PLASSE: I mean, the plant's operating today. It's operable. And a lot of these form the basis in 9118 space in the corrective action program.

And Jim, can you explain the items that you guys have looked at to consider?

MR. NEURAUTER: Well, we asked the question. Because it's the seal building is operable if nonconforming, why is it safe to operate your plant today? And right now, we have determined the licensee has reasonable assurance that the plant is safe. That's different than licensing basis.

Now, when staff looks at their evaluations as to why they believe this concrete won't fall off and there's adequacy of rebar to hold it in place, again, it's premature.

MEMBER RAY: Okay. Well, again, I was

exploring just not from the standpoint of whether there was anything that was of concern today. But if we're looking at the aging management program and changes in the current condition would lead to the possibility of a failure such as a spalling, the assessment that one might reach is that the rebar on the shoulders precludes a large failure and the tornado design for the areas in between the shoulders assures that there's not going to be any damage to safety-related structure systems and equipment if their failure is in between the shoulder areas. That's one way to consider it.

You guys haven't looked at it yet, and that's fine.

MR. NEURAUTER: If it was perfected round without shoulders on it, that's what they evaluated in their design basis -- that thickness of concrete --

MEMBER RAY: Right.

MR. NEURAUTER: -- for tornado missile.

So if just the shoulders --

MEMBER RAY: I'm talking about the spalling piece being smaller in size than a tornado-induced missile striking a piece of the adjacent structure systems and components. That was what I was --

MR. NEURAUTER: Again, right now, they believe the concrete is going to stay up on the shield building.

MEMBER RAY: Okay.

MR. NEURAUTER: And there hasn't been an evaluation of a chunk of concrete hitting the ops building.

MEMBER RAY: Okay.

MR. NEURAUTER: Okay?

MEMBER RAY: All right. Well, I just wanted to be sure because I hadn't seen anything discussed on either of those two items.

MR. NEURAUTER: And neither have I.

MEMBER RAY: Okay. Fine. Thank you.

Okay, Rick, anything more from you?

MR. PLASSE: Any other questions for the staff?

MEMBER RAY: All right. Well, then we'll ask if there are any questions from Members for the staff.

We will give the Applicant an opportunity to come back and address a couple of items that have come up since they left the front. And then we'll go to members of the public.

But do Members of the Committee have any questions of the staff?

(No audible response.)

MEMBER RAY: Hearing none, thank you, Rick.

MEMBER RAY: Okay. The Applicant has informed me that they would like to clarify a point related to the -- what do you call it -- the sand?

MR. HENLINE: Sand pocket.

MEMBER RAY: Sand pocket. Thank you.

And the other question I would pose to you here is if you have anything to add to the dialogue that we had about the 13/1000s and what role does that play, and has it been superseded by 20/1000s now and that sort of thing. I'd like to get anything further that you want to say on that score on the record.

MR. HENLINE: Trent Henline, Implementation Manager.

I'm going to clarify the sand pocket question.

The question was asked were the inspections that we did in the spring of 2014 were the last inspections that we're going to do of the containment vessel in the sand pocket area. And the answer to that question is no, we have a commitment. It's Commitment Number 35 in the license renewal application commitments to repeat the inspections that we completed in the spring of 2014 by December 31st of 2025. So we will do that inspection again to confirm that there is no ongoing degradation.

But I just wanted to clarify that point.

MEMBER RAY: Thank you. It makes me feel so much better.

CHAIR STETKAR: That's inspection from the exterior in the accessible area of the sand pocket?

MR. HENLINE: That's correct.

CHAIR STETKAR: Okay.

MR. HENLINE: That's the five locations where we did the nine points at each location.

CHAIR STETKAR: Okay. Thank you.

MEMBER RAY: I thought there was something on that score, but then I thought I was mistaken.

Okay. I would ask the Applicant if there's anything they can offer to us further. And frankly, let me just be clear about what I think can benefit from clarification.

The 13/1000s, I think -- and this is a long history so it's understandable -- appeared as a limit on crack width. But it wasn't clear what was going to happen after that if it was exceeded.

We understand it has been exceeded, and we understand further that perhaps it's now become a different number -- 20/1000s.

But we'd like to understand okay, what is the number and what happens afterward. Is there any limitation other than I suppose the university testing results would serve as a limitation on crack width? Or something. Just tell us how -- because crack width is very important. It's at least as important as the growth in the area of the laminar cracking. And we'd like to understand how you're going to manage that as part of the aging management program.

MR. HOOK: Okay. Again, I'm Jon Hook.

And you are correct. The crack width is an important parameter.

And so, originally it was .13, and now the current criteria is .020 -- 20/1000s.

MR. BYRD: You might direct them why we started with .13 just to get the history.

That was the widest crack we initially identified. And I think we can help you understand where we're at.

So why don't you start there?

MR. HOOK: Right.

Initially, when we first came up with or first identified laminar cracking, that was the widest crack -- 13/1000s. So that was in our program. That would be a threshold which we would take action to make sure nothing exceeded that.

So since then, we wanted to increase margin in our crack width. So we went back to the professors. Both of them independently looked at their test results and the crack sizes that they saw. Again, they saw crack sizes over 30/1000s of an inch for stresses higher than what we see in our shield building in the rebar. So they are both very comfortable in establishing a conservative level of 20/1000s of an inch. So that is right now in our calculation as an acceptance criteria.

Both professors have indicated we can go beyond that. But what they would like to do is do another series of tests to more specifically monitor that because that wasn't one of the conditions that they were looking for. They just happened to record all that information. So they believe in some cases significantly more.

So we're in the process of in the very early stages of communicating with both Purdue to do additional testing to expand even beyond 20/1000s. But right now, our design calculations have a limit of 20/1000s.

MEMBER RAY: Okay. And that seems to me, if I understand it correctly, similar to the same approach taken with regard to the aerial extent which is there's conservatively established aerial extent. There's margin to that presently.

MR. HOOK: That's correct.

MEMBER RAY: But that aerial extent could then be subject to increasing based on whatever analysis is appropriate at the time if you approached it.

MR. HOOK: That is a true statement. Yes.

MEMBER RAY: All right.

Pete, do you have anything you want to ask about this width issue?

MEMBER RICCARDELLA: No.

MEMBER BALLINGER: Well, I do.

MEMBER RAY: All right.

MEMBER BALLINGER: If you see the largest crack is .016?

MR. BYRD: That's correct.

MEMBER BALLINGER: If you see some later on at .02, that implies crack propagation, does it not?

So presumably, you would see that as part of the IR stuff -- other inspections. No?

MR. BYRD: Not IR.

MR. HOOK: We would see it as part of our -- we do core bore inspections. As part of our visual core bore inspections, we would be able to see that.

MEMBER RICCARDELLA: Just to clarify, impulse response won't give you a crack width.

MEMBER BALLINGER: It won't give you a crack width, but if you see crack widths that have increased by the way from .013 to .02, does that not imply that cracks have propagated?

MR. HOOK: That would be an indication that potentially the crack is widening -- or not widening, but extending.

MEMBER BALLINGER: Extent.

MR. HOOK: Correct.

MEMBER BALLINGER: And so that would be picked up by the IR -- yes, the extension which --

MEMBER RAY: But Ron, I don't think we can be certain of that. I know Pete wanted to make a point.

In other words, we can't be certain that increasing width necessarily means aerial propagation.

MEMBER RICCARDELLA: That's right. It's not even conceivable that the width could grow without the area increasing.

MR. BYRD: That is correct.

MEMBER BALLINGER: Okay. I'm just trying to think of a double way of seeing things.

MEMBER RAY: No, I understand. I think everybody would concede that it's likely that the aerial extent would grow at the same time the width increased. But I don't know that anybody can say it necessarily would.

MR. NEURAUTER: Jon, just for point of clarification, both you and the staff's presentation, your presentation to the staff's presentation had within it a description of what would happen at the other end of the spectrum -- that is if the cracks become passive. But it's not clear to me. What are the criteria there for assuring that the cracks are passive before the program is changed -- the inspection program interval is changed?

MR. HOOK: The program is if we see any change at all, then we'll continue to do yearly inspections. If we do our yearly inspections and we see no change at all -- none -- in either width or extent, then we would increase our inspection frequency to every other year.

MR. NEURAUTER: And that's if you see it in any given year?

MR. HOOK: Yes.

MR. NEURAUTER: Just one time and then you would increase to two years?

MR. HOOK: Right.

Then the next time if we saw a change, then we would go back to every year again.

MR. NEURAUTER: Okay. Thank you.

MEMBER RAY: Okay. That's very responsive. And I appreciate your clarifying the situation for us.

While you're still there, does anybody -- any Member -- have a question for these two gentlemen? If not, thank you very much.

MEMBER SKILLMAN: Yes. Let me ask one.

In the write-up on the AMP on your choice of number of holes, you originally had 12. You added nine to 21. And then you went from 21 to 28.

Just in a nutshell, what drove the deltas?

MR. HOOK: Twelve was established because originally the root cause says the cracks are passive. And so 12 was just a sample size to validate it's prudent to make sure that what the assumption made in the root cause was appropriate.

So we didn't have as large a sample, but those samples were still representative of all the areas -- the top and the solars and the main steamline penetration.

But when we did find a laminar crack -- and that's when we increased the sample size to 21. Since then, we've also increased it again because we get crack propagation. And sometimes we increase the sample size because we want to maintain that leading edge on a crack. So we'll add additional core bores because we know where the leading edge is and we're adding more core bores. And that's why this last time we moved it up to 28 because we're tracking those five median edges.

MR. BYRD: So we aren't eliminating any core bores. As it expands, we just keep adding.

So it will probably expand beyond 28 if propagation continues.

MEMBER SKILLMAN: Thank you, Jon. Ken, thank you.

MEMBER RICCARDELLA: But is it fair to say that the original sample of 12 did detect the propagation?

MR. HOOK: That's correct. That is correct. Yes. It's a true statement.

MEMBER RAY: Okay. Thank you so much.

Now stand by for anything further that we might need you for. I'm sure you will.

The next step was we've been informed that there is I believe a member of the audience -- at least one -- who would wish to make a comment to the Committee at this time. And if that's correct, I see Kent has gone to seek the person who's asked to make a comment to us. We'll invite you to come forward to the microphone, please. We'll try and make sure that the microphone is working fully. Thank you.

Yes. Hi. Let's just take a second and see if the microphone is on and you're close enough to it.

Okay. If you'll just please introduce yourself and then proceed. Thank you.

MR. KAMPS: Thank you, Subcommittee Chairman and Chairman and Members for this opportunity to speak.

My name is Kevin Kamps with Beyond Nuclear where I serve as Radioactive Waste Watchdog. And I'm also on the Board of Directors for Don't Waste Michigan which is the state-wide watchdog organization.

Both groups -- in addition, there are others -- are official intervenors against the 20-year license extension at Davis-Besse. And we have been since December 27th of 2010. That's when we filed our intervention.

But as was stated today, the cracking did not come to light until October 10th of 2011. And we then began to file a series of cracking contentions in the Atomic Safety and Licensing Board proceeding. Our first one was filed on January 10th of 2012.

So I only got the materials some hours ago. So it's difficult to try to wrap your head around all this and present a cogent response. But some of the concerns that come to mind just kind of follow along with that chronology I already laid out.

We protested the confirmatory action letter of December 2, 2011, which NRC staff issued allowing this reactor to re-start just a few days later. And it was some six months later after the NRC regional administrator refused to provide documents. In early January of 2012, there was a large public meeting held at Camp Perry just down the road from Davis-Besse. Some 300 people attended.

Documents were not available to the public. We had to FOIA those documents. It took six months and a threat of a law suit against the NRC FOIA staff to finally get those documents in hand. That was in June of 2012.

And it was then that we began to realize how rushed the re-start decision had been, how many unanswered questions there were. And even on the public face of the documents, the confirmatory action letter, Davis-Besse was allowed to operate until February 28th of 2012 without a root cause analysis in place, without an extent of condition for the cracking, without a corrective action plan.

Then there was what we called the snow job of 2012. That was the blizzard of 1978 route cause report that came out on February 28th of 2012.

Obviously, it was far from good enough. The NRC staff issued a large number of requests for additional information which led to a second revised root cause report that came out in May of 2012. And I think this was all included in our various filings to the Atomic Safety and Licensing Board which were ignored, in short.

There were 27 potential root causes that the NRC requests for additional information identified. And I listed some off the top of my head that I recalled. One was a top down water flow mechanism due to cracking that existed at the dome as far back as August of 1976. Pre-operational.

Another area of potential root cause was the fact that the shield building construction began in the early 1970s was not completed until the mid- to late 1970s. There were a number of years where there was no dome on the shield building. It was open to the elements. There were no number of additional years where the side of the shield building had the initial construction opening -- a very large-scale opening.

So all of these were potential water infiltration pathways. Multiple winters where the inside face of the shield building was exposed to the elements, not just the outside face. As was mentioned by Dr. Chiu -- if I have his name correct -- from PII, the blizzard of 1977 was another potential root cause, not just the blizzard of 1978. The list was 27 long for potential root causes.

We raised the issue synergisms between various potential root causes. Again ignored by NRC staff which opposed us at every time in our license intervention. Certainly ignored by the company. Ignored by the Atomic Safety and Licensing Board.

Lo and behold, August/September 2013, the cracking is growing. So we had been blocked in our intervention because our intervention contents had to be aging related. Up until that point -- we're now talking the better part of two years -- for lack of aging relatedness.

Well, now it's aging-related. It was not until July of 2014 that the full apparent cause evaluation was published by First Energy. So there was no explanation. Now this is root cause number three for the cracking. What could not possibly have happened, this all took place over a three-day period in 1978. There will be no cracking growth. That's not possible. Get lost.

Well, July of 2014, a full apparent cause evaluation root cause number three, ice-wedging crack propagation. Where did that come from? Well, it came from what we called the whitewash of 2012 -- the August to October application of a weather sealant 40 years too late on the exterior face of the shield building.

As Congressman Kucinich said in late 2011, everyone in Northern Ohio knows you have to paint your porch. Well, apparently Bechtel, First Energy's predecessor companies, back in the late 1960s decided that a weather sealant was not needed on the exterior of this building, which was odd because weather sealant was applied to other buildings on site.

When asked about that disconnect, First

Energy's only response was the other buildings appeared splotchy. It was an aesthetic reason that they did weather sealant on those buildings. So one of the single most safety significant buildings at the Davis-Besse site was not weather sealed for decades.

Well, in various exchanges with the NRC and with the company back in 2012, especially leading up to the white wash of August to October, warnings were issued by concerned members of the public. What are the unintended consequences of the weather sealant 40 years too late?

And wouldn't you know there was a big one? It locked the water in the walls. And what was really objectionable -- and I guess a part of this gets to the character of this company -- was that from early 2012 until July of 2014, First Energy knew full well that they had water locked in the walls. After the weather sealant was applied -- they knew they had water in the walls before that in early 2012 -- after the weather sealant was applied in August to October, they had now locked that water in the walls preventing its evaporation out. And hence, the ice wedging crack propagation which warnings had been issued that there could be unintended consequences to this white wash.

So this ad hoc response to this very

significant safety concern at Davis-Besse obviously thus far for the past four or five years has not gone very well. The NRC staff seems willing to sign off on First Energy's position at any turn to allow not only current operations but extended operations.

Based on the September 23rd Subcommittee meeting -- I mean, the importance of impulse response testing, which is something we've raised since January of 2012 -- to get an idea of where things are at -- I mean, referring to the old impulse response mapping from years ago now, that is obsolete. And new impulse response mapping of a comprehensive nature -- not just random selections of the shield building -- should be required. It should not be an option. It should be required.

Another example today of kind of making it up as you go along is this .013 versus .016 versus .020 versus .030, it seems like the road is being constructed as you go.

Another major issue that I've not heard addressed is corrosion of the rebar itself. Obviously you've got severe and worsening cracking. And I think that the figure for how bad the cracking is, each freeze-thaw free cycle should be mentioned on the record. According to the full apparent cause evaluation of July 2014, it's a 0.4 to 0.7 growth of cracking with every single freeze at this site which is quite disturbing.

At the Subcommittee meeting in September as well, it was very disconcerting to hear the extended discussion which I've not heard today thus far about the potential for spalling -- as it's been referred to -- exterior chunks of shield building concrete falling off most significantly onto safety-significant systems, structures and components.

The auxiliary building was mentioned by First Energy itself in September. The borated water storage tank -- there are other safety-related systems, structures and components down below.

And this is for 20 more years. So that's the big concern.

Another big concern we have is the loss of current licensing basis and design basis. And I mentioned the FOIA response that we didn't get for six months despite the ongoing licensing proceeding we were engaged in. That was a major conundrum for NRC staff at the time in October and November of 2011. How can this reactor be allowed to operate without a design basis or current licensing basis in place?

In August of 2012, there was a public

meeting held at Oak Harbor High School where the company -- and again, back at Camp Perry in January of 2012 -- we were promised that current licensing basis and design basis would be re-established. It became very clear from the FOIA response how significant that loss was in NRC decision making, although the reactor was operating from December on.

And then at the meeting in August of 2012, we were promised a plan to re-establish current licensing basis and design basis by December of 2012. Here we are it's November of 2015 and the plan seems to be a license amendment to re-establish this.

So what's really hard for the public to understand is how this reactor has been allowed to operate this whole time, how this license extension proceeding has been allowed to get to this point where if you look at the schedule, there's this meeting, there's the Director of NRR's sign off and then there's the Commission sign off. There are three check boxes left before a 20-year license extension is approved by this Agency despite this issue of cracking and other issues. This isn't the only issue.

And so, there have been broken promises -- very serious ones. Our members who live downwind and downstream, not only Ohio but in Michigan and also in

Ontario and beyond, are most concerned about this issue.

As I mentioned in September, our organizations are also appealing the NRC's Nuclear Waste Confidence policy at the second-highest court in the land -- the D.C. Circuit Court of Appeals. So this challenge against the license extension continues.

And we continue to assert that this reactor should be retired as planned on Earth Day 2017. There are way too many problems, way too many risks, way too many unanswered questions.

Thank you.

MEMBER RAY: Thank you, sir.

Is there anyone else in the audience who would wish to make a comment?

(No audible response.)

MEMBER RAY: Could we make sure the phone line is open, please, Kent?

While we're waiting for that to occur, the results of our meeting here today will be a letter at this session of the full committee, at least proposed for consideration.

The phone line appears now to be open. And I would ask for any comments from any member of the public who's on the phone line.

Is there anyone who would like to make a comment?

(No audible response.)

MEMBER RAY: Is there anyone on the phone line that could at least identify that it's open as it sounds like it must be.

MR. HOFFMAN: I'd like to make a comment if you can hear me.

MEMBER RAY: I can hear you. We all can.

Your name, please? And then proceed.

MR. HOFFMAN: Yes. Thank you.

My name is Ace Hoffman. And the comment is that I was first of all not able to hear a lot of it because there was cross talk on the phone line that might have driven a few people away.

But from material that I heard at the beginning, the utility went into great detail about various parts that they replaced. A new reactor's going to talk about $20 billion. And I don't think they were talking about anything near that kind of money. Putting a replacement part can often cost a lot more than putting the same part into a new reactor. So I don't think the utility, based on what they were saying, is replacing more than five percent or maybe ten percent of the reactor. So I don't think that emphasis was appropriate.

And also, we seem to be at the tail end of a lot of replacement projects that have gone on. I hope these should have been considered as not worth doing if they're going to retire the reactor in 2017 or maybe even a little earlier because they would prefer to save money. This is the wrong way to do business to get yourself all set up for something and then you have all the inertia to get the NRC to approve it.

I understand there were 500 items that were adjusted. And that sounds like a lot, but I think it's only a small percentage.

And that's it. That's all of my comments for now. Thank you.

MEMBER RAY: Yes, sir. Thank you.

MR. LEWIS: My name --

MEMBER RAY: Marvin?

MR. LEWIS: Yes. Thank you.

MEMBER RAY: Go ahead.

MR. LEWIS: Marvin Lewis.

And look, my undergrad degree is in metallurgical engineering. And I've also been a bench chemist and I've also run a concrete lab. So between a concrete lab and an undergraduate degree, I think I can talk on concrete and I can talk on rebar.

And one of the things I can talk on is they're quite different and they love to separate. And when you get a temperature change, the -- well, it can withstand a heck of a lot more than the concrete which means everyday you're getting a little closer to where a wall's going to fall in.

And the second thing is it makes me wonder about the telephones on site. If you can't get your telephones working right at the NRC, how the heck are you going to get the telephones right -- working right at the site.

CHAIR STETKAR: Mr. Lewis? Mr. Lewis, this is John Stetkar.

It's not a problem here. It's a problem with cross talk among people in the public who are talking on their phones on a common line. It is not a problem with our phone system here at NRC.

MR. LEWIS: Well, I'm listening to your phone system at the NRC on this phone here, and I was having a problem. I don't know how that separates one problem from another, but I'm sure you do and I'm sure you'll go down on site and make sure their phones are working.

Thank you very much for allowing me to make my comment.

MEMBER RAY: Are there any other members of the public on the phone line at present who would like to make a comment?

(No audible response.)

MEMBER RAY: Hearing none then, let's go ahead and close the line to end the popping and cracking and I'll turn it back to you, John.

CHAIR STETKAR: Thank you very much, Harold.

Any final comments by any of the members?

(No audible response.)

CHAIR STETKAR: If not, we re-scheduling --

MEMBER RAY: Excuse me a second. I just saw that maybe Rick wanted to make a comment here. He was walking toward the table.

Pardon me. I'm sorry.

CHAIR STETKAR: Okay.

MR. PLASSE: Yes. If we could refer back to slide 12.

MEMBER RAY: We need your slide operator there.

MR. PLASSE: This slide was to show the

acceptance criteria for the program.

And the acceptance criteria is still crack width does not exceed .013 inches. The confusion was added with in parentheses, current observed maximum width which we're going to strike from the slide.

That was factual when we got the RAIs which we used to evaluate the program back in January of 2015. Subsequent to that, they have done a 2015 inspection, and evidently they had an item of greater than that trigger point which they evaluated in the corrective action program which is where they are today.

So the correction will simply be to strike what's in parentheses on that slide. And I'll provide that slide to Kent.

MEMBER RAY: All right? We understand you've modified or corrected the slide accordingly.

Any questions for Rick?

(No audible response.)

MEMBER RAY: Once again, I'll turn it back to you, John.

CHAIR STETKAR: You're sure?

MEMBER RAY: No, I'm not. But I'll -- we'll try it anyway.

CHAIR STETKAR: I'll try to leap in here

quickly then.

Thanks to everyone. Thanks to First Energy, the staff. Thanks to the public, by the way.

And thanks for bearing with us. Members of the public out there, I know that we had problems on the bridge line. I apologize for that. Things are beyond our control with cross talk out there.

With that, we are recessed until -- we'll be off the record until tomorrow morning.

(Whereupon, the above-entitled matter went off the record at 3:33 p.m.)

INDUSTRY COMMENTS ON DRAFT SECY "RECOMMENDATIONS ON ISSUES RELATED TO IMPLEMENTATION OF A RISK MANAGEMENT REGULATORY FRAMEWORK"

Victoria Anderson
Senior Project Manager, NEI

I. Path Forward for enhancing risk management approach

- Staff Evaluation and Recommendation in draft SECY
  - Existing policy statements on safety goals and use of PRA along with guidance and experience have established most key aspects of RMRF for nuclear power reactor safety program area.
  - Staff recommendation: Maintain current framework and continue to make improvements on incremental basis.
  - Industry agrees with this recommendation.
    - Utilize Risk Informed Steering Committee (RISC) to expand the use of risk-informed decision making.

I. Path Forward for enhancing risk management approach

- Consideration of Alternatives
  - Plant Specific regulatory framework
    - The Staff agrees with public commenters that this approach should not be implemented for currently operating reactors
    - Industry does not find this to be a viable option.
    - Industry agrees with Staff recommendation in draft SECY

II. Re-evaluation of Improvement Activity 1 from Fukushima Near-Term Task Force Recommendation 1

- Improvement Activity 1: Establish Design-Basis Extension Category
  - Rulemaking guidance provides consistency in specifying necessary regulatory "attributes" (performance goals, treatment requirements, documentation requirements, change processes, and reporting requirements) whenever new regulations (both design-basis and beyond design-basis) are developed.
  - Staff recommends that a new category of events should not be established at this time.
  - Industry agrees with Staff recommendation in draft SECY.

II. Re-evaluation of Improvement Activity 2 from Fukushima Near-Term Task Force Recommendation 1

- Improvement Activity 2: Establish Commission Expectations for Defense-in-Depth
  - Staff recommends that a defense-in-depth policy statement is not needed. This is consistent with the industry's comments.
  - Staff intends to complete a previous effort to modify the guidance on defense-in-depth in RG 1.174.
  - The industry agrees with the Staff recommendation that a defense-in-depth policy statement is not needed and supports the revision of guidance documents (e.g., RG 1.174) to ensure consistent application of defense-in-depth in regulatory decisions.

III. Consideration of an overarching policy statement on using the Risk Management Approach

- NRC staff recommends not to develop an overarching agency-wide policy statement.
- Industry Comment:

  Accomplishing this across the entire agency in a coordinated, consistent manner would appear to be an extremely challenging task for the NRC that will require a long period of time, inter-agency coordination, and perhaps a dilution of methodological approaches to satisfy all of the agency's desires.
- Industry agrees with the staff recommendation not to develop an overarching agency-wide policy statement.

Conclusions

- The industry agrees with the staff's recommendations in the draft SECY paper.
- Will continue to work with the staff to ensure appropriate methods and guidance are available to develop, and implement risk-informed applications.

November 3, 2015

Author: **Mary Drouin**

Subject: **Staff SECY Paper Entitled "**Recommendations On Issues Related To Implementation Of A Risk Management Regulatory Framework"

Basis for Non-Concurrence:

The SECY on the Risk Management Regulatory Framework (RMRF) recommends that an Agency-wide Policy Statement on an RMRF should not be developed. This decision is inconsistent with establishing a sound agency-wide basis for increasing the use of risk insights into NRC's regulatory decision-making. Existing Policy Statements provide some of the visionary guidance for the use of risk (i.e., the PRA Policy Statement and the Safety Goal Policy Statement), but fall short in providing a holistic framework under which NRC processes could be enhanced in the long-term to increase the use of risk insights in a consistent and predictable way. As such, I believe the decision should be changed to recommend that the staff develop an Agency-wide RMRF policy statement for Commission approval that provides a high level, visionary statement towards which all of the program offices could work towards as resources permit.

The SECY paper also states that the "staff believes that developing a policy statement on defense-in-depth for nuclear power reactor safety is unnecessary, and that further efforts to develop a definition of and criteria for determining adequacy of defense in depth should not be pursued at the present time." This decision is inconsistent with the NRC's strategic goals and NRC's endeavor to have a predictable and stable regulatory process. As such, I believe the decision should be changed to recommend that the staff develop a single, formal definition for defense-in-depth and develop associated guidance for determining adequacy of defense-in-depth.

Background

In 2012, under Commissioner Apostolakis, the results from the Risk Management Task Force (RMTF) study (NUREG-2150) were published. On June 14, 2012, the NRC Chairman issued a tasking memorandum that directed the NRC staff to "… review NUREG-2150 and provide a paper to the Commission that would identify options and make recommendations, including the potential development of a Commission policy statement."

I do not believe the staff paper to the Commission has been responsive to the tasking memorandum. My issues are discussed below.

As stated in the SECY paper regarding NUREG-2150, "The report [NUREG-2150] provides findings and recommendations in two categories. The first category addresses strategic, agency-wide issues, and recommends that '[t]he NRC should formally adopt the proposed Risk

Management Regulatory Framework through a Commission Policy Statement.' The second category addresses what changes could be made in specific regulatory program areas (e.g., power reactors, nuclear materials) in the next several years to support implementation of the risk management regulatory framework." Moreover, the goal of the RMRF study was to "develop a strategic vision and options for adopting a more comprehensive, holistic, risk-informed and performance-based regulatory approach for reactors…." The staff limited its evaluation to a reactor perspective rather than assessing the merits of the study from an agency-wide, holistic perspective. Because of this limitation, I believe that observations and insights provided in the study were not fully understood or appreciated.

The paper asserts that the Safety Goal and PRA policy statements with other regulatory guidance "have established most of the key aspects of an RMRF for the nuclear power ***reactor safety*** [emphasis added] program area." First, the insights from the RMRF study were from an agency-wide, holistic perspective and not a reactor safety perspective. Consequently, the insights and benefits from the study were truly not considered. The paper does not address, as stated in NURE-2150, the patchwork of regulatory requirements that have been created as a result of addressing problems on a case-by-case basis for many years. Second, the paper, in a footnote, argues that the existing nuclear power reactor safety regulatory framework has similar elements that include a mission, objective, goal, and decision-making process. I believe this is a misleading statement. The NRC does have a formal mission as stated in the Atomic Energy Act, however, while the NRC does try and practice the stated objective and goal, it is not implemented through a formal program or policy. The Safety Goal policy statement has served the agency well, however, it is not equivalent to an agency-wide risk management policy statement. The PRA policy statement (which has also served the agency well) also is more of a sub-element of a risk management regulatory framework. The increased use of PRA in regulatory activities is not the same as risk management. Risk management is a higher level concept; the PRA policy statement is policy that addresses one element in how to implement a risk management framework. Managing risk uses insights from various risk analyses and not every program office activity is amenable to gaining insights from a PRA. There are other approaches to gain risk insights than just from a PRA.

I believe the characterization of the public comments is misleading. The staff did receive negative feedback, but it is important to read the bases for their comments. It is clear that the intent, purpose, etc. of a proposed policy statement provided to the public was not clear to stakeholders which I believe was a major reason for their negative reaction. At the public meetings, the intent, etc. were discussed. Given a clearer explanation of the intent of the policy statement and that stakeholder input would be solicited throughout the process, the staff received positive feedback. NRC policy statements are powerful tools. They communicate to the staff and to our stakeholder the Commission policy, "this is how we do business." They serve as the catalyst and basis for many of our regulatory programs and decisions. The Safety Goal and PRA policy statement are not substitutes or equivalent to a risk management policy statement.

I disagree with the statement in the paper regarding defense-in-depth. The staff states that "the defense-in-depth philosophy is already well-established in the regulations and existing Commission policy statement." Only the term and not the meaning of defense-in-depth is well established; there is not a solid, consistent understanding of defense-in-depth or how defense-in-depth is implemented. There is a long litany of examples to illustrate (which was demonstrated in the limited historical review and evaluation attached to SECY-13-132 as Enclosure 3). For example, there are several places in the NRC literature (e.g., Commission White paper, regulation, regulatory guide, NRC glossary) where defense-in-depth is defined, each different. The Commission should have a single formal definition, and it should not be left to individuals to pick and choose the definition. While it is true that the Commission has been able to make regulatory decisions without a formal definition or guidance, the staff has and continues to struggle with defense-in-depth. This struggle was very clearly articulated at the 2015 RIC conference in Dr. Uhle's presentation on defense-in-depth. Defense-in-depth is a major issue recognized in the international community; there have been and continue to be major dialogue on this topic. It is an issue that other regulatory entities have and continue to struggle with. Defense-in-depth is key to ensure that the NRC is achieving its mission. Our decision-making would be much more efficient and effective if we had a solid, common understanding of defense-in-depth.

I do not agree that the staff would be unable to establish "predictable, objective criteria acceptable to the Commission." There has been a tremendous amount of work in this area which does indicate that "predictable and objective criteria" in the form of guidance can be developed; it would not be "prescriptive," nor would it need to be. There are also examples where such an argument was used to not move forward. For example, the Systematic Assessment of Licensee Performance (SALP) process was criticized because it was too judgmental and inconsistent from Region to Region. It was heavily argued that "predictable and objective criteria" could not be developed. However, the existing Reactor Oversight Process, while not perfect, is far more predictable, using objective criteria that is a vast improvement over SALP.

I believe that the resource evaluation is misleading. I do not believe it appropriately factors in the resource savings that will be realized by having a definition and guidance for determining defense-in-depth adequacy. The development of a definition and adequacy guidance should start at high level that cuts across the entire agency. With this high level guidance, each program office can then expand to suit their unique needs. In this manner, we have a consistent and holistic approach which reinforces our strategic goals and is in line with our principles of good regulation.

PWROG
PWR Owners Group

Global Expertise • One Voice

Direction of Risk-Informed Regulatory Framework

K. Raymond Fine (FirstEnergy Nuclear Operating Co.)
Vice-Chair, Risk Management Committee

November 4, 2015

Overview

- Current State
- Successful Applications
- Challenges
- Recommended Path Forward/Conclusions

Current State

- Current NRC Policy Statements, combined with industry and NRC experience, have established a workable structure for risk-informed applications
  - RG 1.174
  - RG 1.175
  - RG 1.176
  - RG 1.177
  - RG 1.178
- RG 1.200 defines an acceptable way to assess PRA technical adequacy using the ASME/ANS PRA Standard
- PRA Peer Review process independently assesses PRA technical adequacy
  - NEI PRA Peer Review Task Force is addressing:
    - Enhancements for reviewer qualifications
    - PRA Peer Review consistency

Successful Applications

- Industry and NRC have developed successful applications under the current regulatory framework
  - Surveillance Frequency Control Program (TSTF-425)
  - Risk-Informed Completion Times (TSTF-505)
  - 10 CFR 50.69 Special Treatment Rule
  - Maintenance Rule
  - Mitigating Systems Performance Index (MSPI)
  - Integrated Containment Leak Rate Testing

Challenges

- Challenges being addressed by industry and NRC Risk-Informed Steering Committees (RISCs):
  - PRA Technical Adequacy
    - Acceptance of new methods
    - Closure of Peer Review findings
    - PRA Peer Reviewer qualifications
  - Treatment of Uncertainty
    - Training for decision-makers
    - NUREG-1855 update
  - Incorporation of FLEX in risk-informed decision-making
    - Maximize safety benefits
    - Quantitative and qualitative assessments
    - Avoid unintended consequences
    - Enhanced guidance and pilots
  - Risk Metric Aggregation
    - PWROG pilot of EPRI 3002003116 (*Risk Aggregation for Risk-Informed Decision-Making*) in 2016

Recommended Path Forward

- The PWROG agrees with the NRC staff to continue to pursue incremental improvements in current regulatory framework
  - A clear case has not been made that a new regulatory framework would be cost beneficial
  - Significant effort has been expended by both the industry and NRC
  - The current framework is well understood and has been used successfully
  - Leverage existing lessons-learned to improved the efficiency of the NRC risk-informed application review process
  - Improve consistency in licensee submittals and NRC reviews
  - Finalize 10 CFR 50.46a (Risk-Informed Emergency Core Cooling System)

Conclusions

- The PWROG endorses the staff's recommendations in the draft SECY paper:
  - Maintain the NRC's current regulatory framework
  - NTTF Recommendation 1 Improvement Activities
    - A new category of events should be not established
    - A defense-in-depth policy statement is not needed
  - Development of an over-arching agency-wide policy statement is not needed
- The PWROG will continue to work with the staff to ensure appropriate methods are available to develop, implement, and regulate risk-informed applications and risk-informed regulations

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Staff Recommendations Regarding a Risk Management Regulatory Framework

ACRS Meeting

November 4, 2015

Outline of NRC Staff Presentation on Risk Management Regulatory Framework (RMRF)

- Background and Next Steps
- RMRF SECY paper
  - I. RMRF implementation options for power reactors
  - II. Re-evaluation of Improvement Activities 1 and 2
  - III. Agency-wide risk management policy statement
    - Changes made to paper during office concurrence
  - IV. Interrelationships between risk-informed activities
- Discussion of Risk-Informed Steering Committee oversight activities

Background and Next Steps

- Significant level of public interaction on NUREG-2150 RMRF activities
  - 4 public meetings
  - 5 meetings with ACRS subcommittee
  - 3 written public comment periods
- White papers released in November 2013 and May 2015
- Met with Reliability and PRA subcommittee to discuss draft RMRF SECY paper on October 19, 2015
  - Staff positions were supported by industry stakeholders
- Full committee meeting today
- ACRS letter mid-November
- Staff response to ACRS letter mid-December
- RMRF SECY due to Commission by December 18, 2015

Section I. RMRF Implementation Options for Power Reactors

Staff Considered 3 options:

1. Maintain current regulatory framework
2. Voluntary alternative risk-informed plant-specific licensing basis
3. NUREG-2150 recommended approach

Power Reactor Option 1 – Maintain Current Framework

- No extensive revision of NRC's regulatory framework
- The current power reactor regulatory framework meets the RMRF criteria in NUREG-2150
  1. Mission – Public health and safety; common defense and security; protect the environment
  2. Objective – Manage the risks via current regulations, guidance, and oversight (including defense-in-depth, safety margins, single failure criterion, fail-safe design, reactor oversight program, etc.)
  3. Goal – Provide sufficient risk-informed and performance-based protections to ensure risks are acceptably low (utilizing Commission's Safety Goal Policy Statement and subsidiary risk metrics)
  4. Decisionmaking Process that includes monitoring and feedback (e.g., LIC-504, "Integrated Risk-Informed Decision-Making Process for Emergent Issues;" Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis;" Generic Issues Program; Operating Experience Program; Accident Sequence Precursor Program; Industry Trends Program, etc.)

Power Reactor Option 2 – Risk-Informed Alternative Licensing Basis

- Maintain existing generic regulatory structure
- Issue rule allowing licensees who upgrade PRAs to apply for approval of a risk-informed alternative licensing basis
  - Licensees allowed to select a plant-specific set of design changes/compliance issues of low risk-significance that would deviate from current deterministic requirements **and** must mitigate all known plant-specific risk vulnerabilities meeting NRC-specified criteria
  - Mandatory monitoring and feedback (as described in RG 1.174) to ensure changes in risk remain acceptable throughout the lifetime of the facility
- Staff has not developed implementation details for this approach -- implementation uncertainties:
  - Review all power reactor regulations and develop list of rules amenable to risk-informing under Option 2
  - Minimum scope/technical accuracy of "suitable" PRA for entry into the alternative approach
  - Certification/review of PRA
  - Selection and scope of permissible design changes
  - Process for staff review of design changes
  - Reporting and documentation requirements
  - Ensure transparency (NRC and public) of process

Public Meeting on RMRF Option 2
July 29, 2015

- Staff presentation
  - Additional details on Option 2
  - Thoughts/approach for “suitable” PRA
- Industry stakeholders still concerned about the lack of implementation details on Option 2
  - Industry stakeholders said that without explicit details of how the Option 2 process would work, it is very difficult to assess safety benefits and costs
  - Industry would not support the approach without more details

Power Reactor Option 3 – Plant-Specific RMRF from NUREG-2150

- Issue regulation requiring PRAs and plant-specific licensing basis based on:
  - Plant-specific risk profiles
  - NRC-specified risk management objective
  - Enhanced criteria for determining adequacy of non-risk factors (defense-in-depth, safety margins, etc.)
- Based on the risk profile, licensees would implement the plant-specific licensing basis by:
  - Determining how the risk objective is met
  - Ensuring that the necessary protections are in place to meet the risk management goal
  - Demonstrating the adequacy of non-risk factors (defense-in-depth, safety margins, etc.)
  - Establishing the risk-informed decision-making process
  - Establishing the monitoring/feedback and reporting process

Written Public Comments on RMRF Options for Power Reactors

Option 1 - Maintain Current Regulatory Framework

- Four commenters addressed Option 1. All four recommended maintaining the current regulatory framework.

Option 2 – Voluntary Alternative Risk-Informed Licensing Basis

- Three commenters addressed Option 2. All three expressed some level of interest but said the NRC had not developed sufficient implementation details to enable commenters to analyze potential costs and benefits.

Option 3 – NUREG-2150 recommended approach

- Two commenters addressed Option 3. Neither supported Option 3 for currently operating reactors.
  - Approach was not viable
  - Although insufficient implementation details had been provided to evaluate its safety and cost benefits, Option 3 is unlikely to be justifiable for the current fleet of operating reactors

Section I. RMRF Implementation Options for Power Reactors - Staff Recommendation

Staff Conclusion:

- Do not pursue Option 2 at present time because industry and staff do not have resources to develop/support
- Do not pursue Option 3 for operating reactor fleet because modest potential safety benefits are unlikely to justify substantial implementation costs
- **Staff recommends Option 1** -- maintain current framework
  - Not a "do nothing" approach
  - All ongoing and planned risk-informed initiatives would continue
  - Staff will continue to make incremental risk-informed regulatory improvements whenever appropriate

Section II. Staff Re-evaluation of NTTF Recommendation 1 Improvement Activities 1 and 2

Activty 1 – New design-basis extension category:

- Staff determined that creating new design-basis extension category is not necessary.
- Instead, staff will develop clear internal rulemaking guidance to ensure that new regulations properly specify all regulatory attributes necessary for requirements that exceed the existing design basis.

Activity 2 – Criteria for adequacy of defense in depth:

- While this effort could potentially succeed in establishing predictable, objective criteria for determining the adequacy of defense in depth for power reactor safety, the estimated resource requirements (6.3 FTE over a period of 3 to 4 years) are significant.
- It is possible that after spending these resources, the staff would be unable to establish predictable, objective criteria acceptable to the Commission.
- Based on current resource limitations, the staff recommends that the NRC should not undertake this activity at the present time.
- Staff will update defense-in-depth guidance in RG 1.174 as directed by Commission in SECY-11-0014 on Containment Accident Pressure

Section III. Agency-wide Risk Management Policy Statement

- An agency-wide risk management policy statement could potentially improve and make more consistent the regulatory framework used for all program areas
- NRC requested public comments on two draft example policy statements (November 2013 and May 2015)
- Public comments were generally not supportive
  - On May 2015 draft, 1 of 10 commenters supported an agency-wide risk management policy statement
    - NRC programs can be appropriately risk-informed under the current policy and guidance
    - Use of NRC and licensee resources

<u>Staff Evaluation</u>:

- Staff agrees with public commenters that NRC programs can be appropriately risk-informed without an agency-wide risk management policy statement
- Staff believes that it would not be appropriate to divert NRC and licensee resources away from more safety-significant activities
- Staff recommends **against** developing an agency-wide policy statement

Office Concurrence Changes to RMRF SECY Paper

SUMMARY OF RECOMMENDATIONS:

The NRC staff recommends that the Commission direct the staff to:

1. Maintain the existing regulatory framework for the nuclear power reactor safety program area. The NRC will continue its long-held commitment to the defense-in-depth concept; to the regulation of nuclear reactor issues beyond the traditional design-basis events, where appropriate; and to the inclusion of the defense-in-depth concept as an essential component of risk-informed regulation. All ongoing and planned risk-informed initiatives to enhance the existing regulatory framework would continue.

2. Refrain from developing an overarching, agencywide risk management policy statement. Ongoing staff activities to implement risk-informed approaches within NRC program areas will continue to move forward and are not impacted by the staff's recommendation against developing an overarching, agencywide risk management policy statement.

Section IV. Interrelationships Between Ongoing Risk-Informed Initiatives

- In its SRM on SECY-13-0132 on Near-Term Task Force Recommendation 1, the Commission directed the staff to provide a "description of any interrelationships of ongoing risk-informed initiatives"
- Section IV of the SECY explains the interrelationships between ongoing risk-informed power reactor safety initiatives

Risk-Informed Steering Committee Oversight

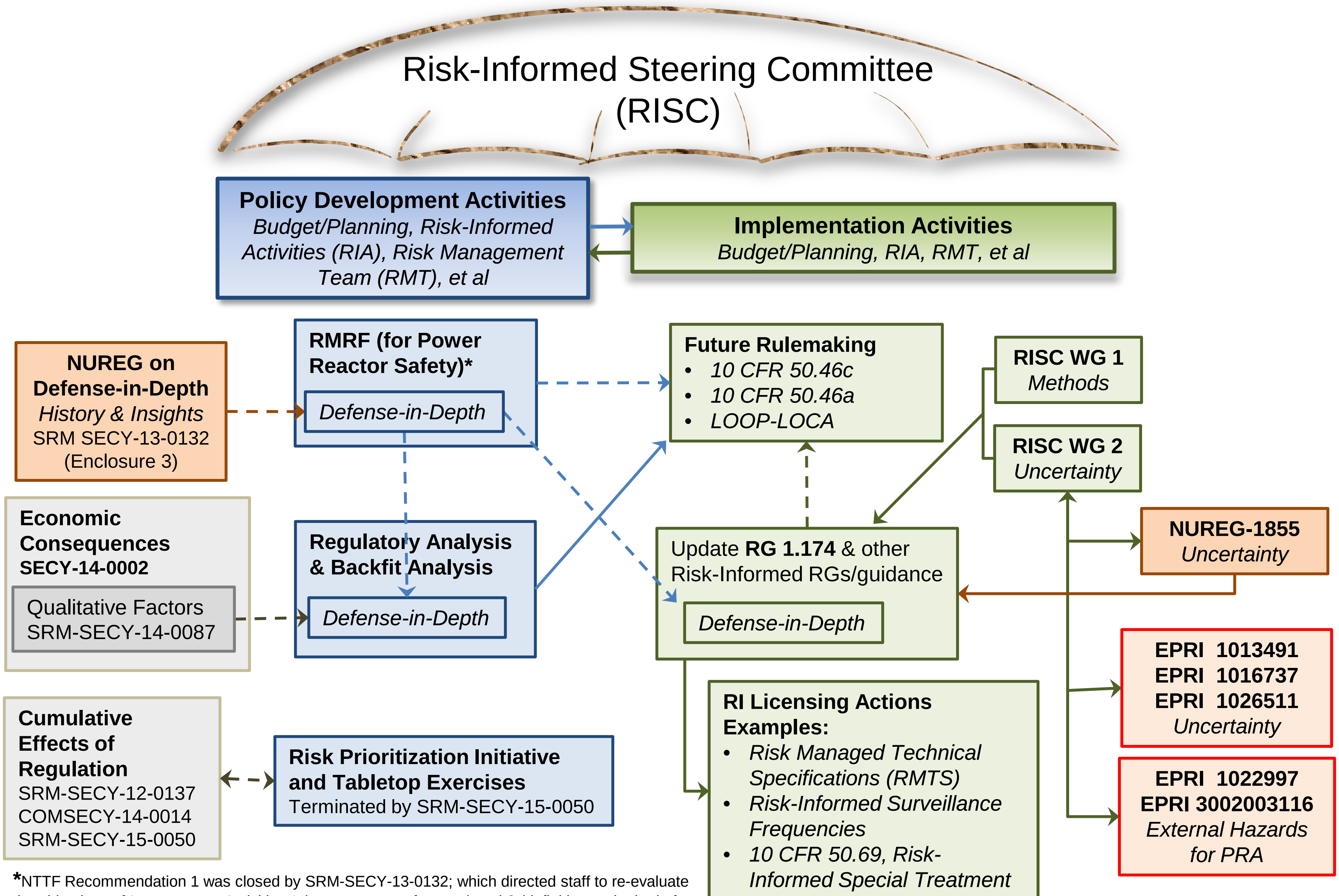
- **RISC Charter:**
  - Provide ***strategic*** direction to the NRC staff to advance the use of risk-informed decision-making in licensing, oversight, rulemaking and other regulatory areas ….”

- **RISC Membership:**
  - Chair, Director NRR
  - Members: Deputy Office Directors from RES, NMSS, NSIR, NRO and RI RA

- **RISC Focus (to date):**
  - PRA Technical Adequacy
  - Treatment of Uncertainty in Decision Making
  - PRA Credit for Mitigating Strategies
  - RMRF

Backup Slides

Inter-relationships Between Ongoing Risk-informed Activities



*NTTF Recommendation 1 was closed by SRM-SECY-13-0132; which directed staff to re-evaluate the objectives of Improvement Activities 1 (new category of events) and 2 (definition and criteria for defense-in-depth (DID)) as part of RMRF-related implementation activities.

Section I. RMRF Implementation Options for Power Reactors - Staff Recommendation

Generation IV reactor designs:

- The staff believes that the adoption of a risk-informed regulatory framework, similar in concept to an RMRF, would provide the greatest benefit for new reactor designs that employ non-traditional technologies (e.g., Generation IV designs). The staff will continue to engage stakeholders interested in pursuing such a risk-informed framework.

Agency-wide Risk Management Policy Statement

- Organization of Agreement States provided comments:
  - Policy statement would be a useful way to provide the Commission's expectations for a Risk Management Regulatory Framework
  - "We cannot state or endorse the concept that there is a general understanding [in the radioactive materials program] of the terms *risk-informed* and *defense-in-depth*."
  - "[A] risk management approach is already being performed with our current regulatory system and IMPEP [Integrated Materials Performance Evaluation Program] process" to ensure adequate protection of public health and safety
  - Policy statement should say to "review current [risks and practices] and provide recommendations for enhancement."

NUREG-2150 Hierarchy and Structured Decision-making Process

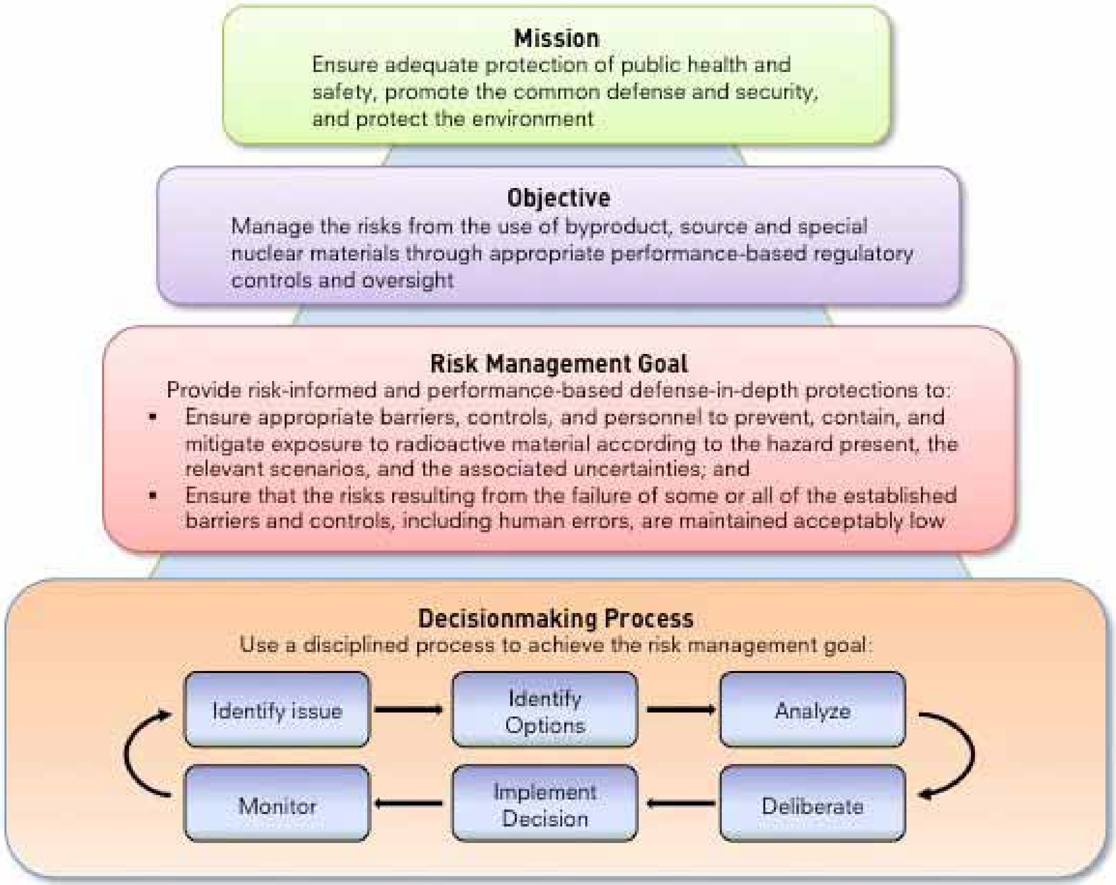
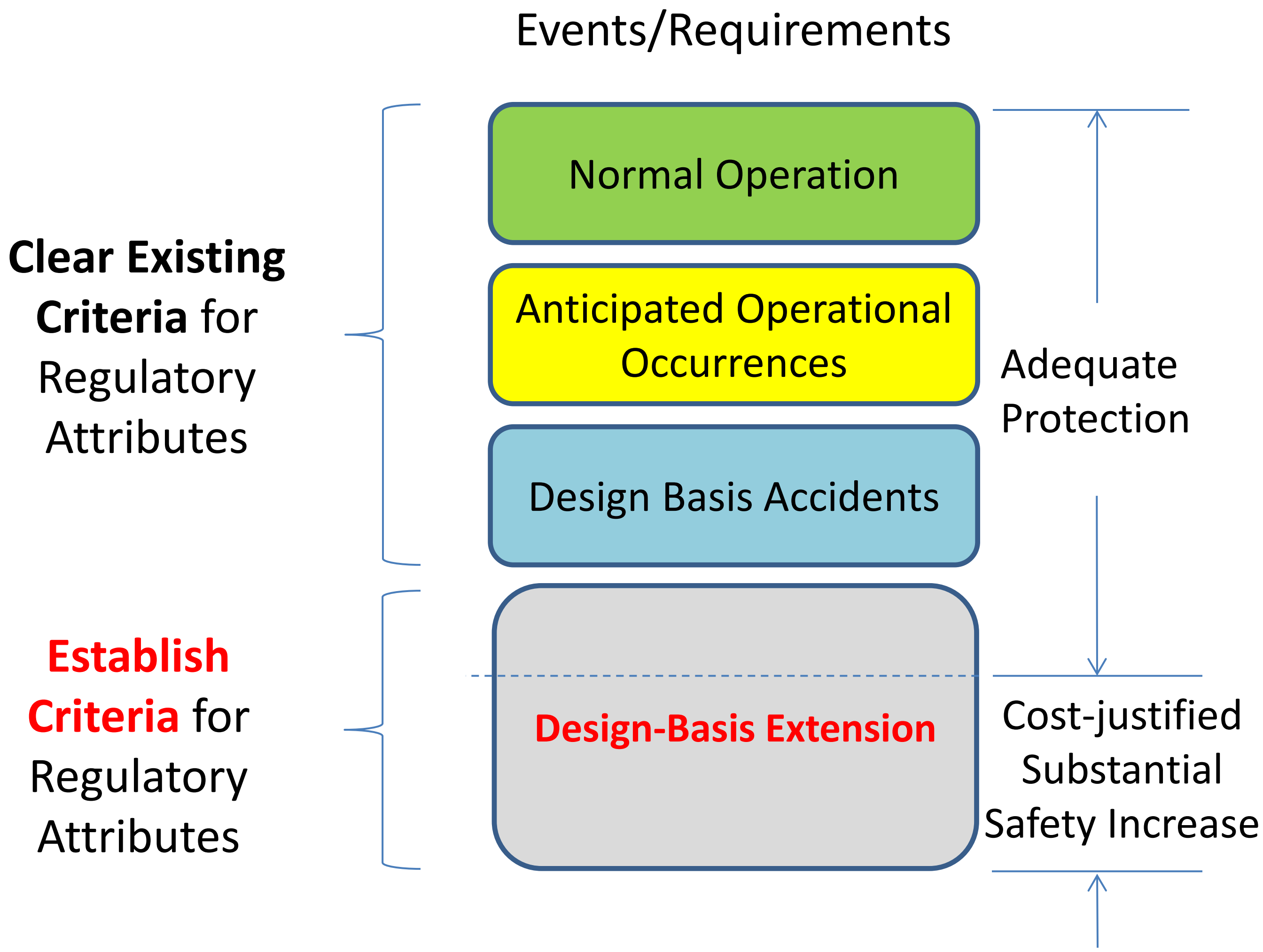


Figure ES-1 A Proposed Risk Management Regulatory Framework

Improvement Activity 1- Establish Design-Basis Extension Category



BWROG IRIR

Future of PRA and Risk Management Regulatory Framework

November 4th, 2015
BWROG IRIR Chair
Robert Rishel (Duke Energy)-
Director, Nuclear Engineering PRA

BWR Expertise – Proven Solutions

Topics – BWROG Integrated Risk Informed Regulation (IRIR)

- BWROG near term vision of PRA
- BWROG Planned submittals 2016-2017
- BWROG IRIR Future PRA Applications
- BWROG PRA Technical Adequacy Peer Reviews
- PRA Technical Adequacy Question
- BWROG Concerns With Option 2 or 3
- Conclusions

BWROG Near Term Vision of PRA

- PRA development is a continuing evolution
  - Incremental approach
  - Licensees continue develop new PRA hazard models
  - Dependent upon business need
- PRA model maintenance is a continuous process
  - Model upgrades as needed
  - Update PRA model consistent with plant design and operational changes
- PRA model development and maintenance costs have significantly increased

BWROG Near Term Vision of PRA

- Concerns with over conservatism
  - Fire PRA
  - Concern with similar impact of Seismic PRA results
  - Impact ability to use risk informed applications
- Development and acceptance of new methods is slow and hinders PRA hazard model development

Current plans are to continue with current approach (Option 1)

BWROG IRIR Planned Submittals 2016-2017

- Continue with Licensee Controlled Tech Spec Surveillance Frequency (Risk Informed Initiative 5b)
  - Approximately 6 BWR Licensees expect to submit 2015-2017
- Submit for Risk Informed Technical Specification Completion Time (Risk Informed Initiative 4b)
  - Approximately 8 BWR Licensees expect to submit 2015-2018
- Containment Extended ILRTs Appendix J
  - Expect most will apply as need dates approach

BWROG IRIR Potential Future PRA Applications

- Extended Tech Spec Completion time for containment isolation valves
- Risk Informed SSC categorization
  - 10 CFR 50.69
- Use of Licensee PRA as a SPAR replacement

BWROG PRA Technical Adequacy Peer Reviews

Improvements made

- Incorporated NRC feedback on Peer Review process
- Greater emphasis on Peer Review Team Leader being a leader
- Training of peer review team leaders is occurring
- Improved licensee ownership of "being ready"
- Continue to ensure peer reviewers are technically knowledge
- Use of "working observers" as part of the training process.

BWROG PRA Technical Adequacy Peer Reviews

Improvements made

- Peer Review team expectations
  - Review 40% of the Supporting Requirements before site visit
- Use of licensee follow-up Peer Reviews has increased
  - Determine if F&Os resolved in some specific areas of weaknesses
- Industry Peer Review Task Force has provided some guidance on “what is technically acceptable” for limited number of Supporting Requirements

PRA Technical Adequacy Question

Understanding the “Gap” between current PRA Peer Review and what would be needed for Option 2 or 3

- Limited resource issue
  - Same small group of individuals
- Use of objective criteria has same consistency issue
  - Individuals make determination of acceptability
- Concern with NRC staff members making individual judgments beyond ANS/ASME PRA Standard - R.G. 1.200 requirement
- Current process relies heavily upon “consensus” of Peer Review results

BWROG Concerns With Option 2 or 3

- Projected benefits are not realized or achievement timeline stretches out
- Concerns with costs to achieve a PRA model that NRC staff determines is adequate
- NRC and Licensee interactions on specific technical elements PRA elements

Conclusions

- Current Licensee staffing support the continued incremental increase in PRA
- Fire PRA has become a large consumer of resources limiting other work
- Continued concerns with conservatism in Fire PRA and the efforts required to remove the conservatism
- Licensee are continuously improving the technical adequacy of their PRAs models
- BWROG will continue to work with the industry (NEI/PWROG/EPRI/ANS-ASME) and NRC to make improvements in the PRA Peer Review process
- BWROG agree with NRC Staff on use of Option 1

QUESTIONS

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Advisory Committee on Reactor Safeguards Full Committee

Davis-Besse Nuclear Power Station

Final & Supplemental Safety Evaluation Report

November 4, 2015

Rick Plasse, Project Manager
Office of Nuclear Reactor Regulation

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Overview

- LRA Submitted by letter dated August 27, 2010
- Pressurized Water Reactor (PWR), Babcock & Wilcox nuclear steam supply system
- Operating license for NPF-3 expires April 22, 2017
- Located approximately 20 miles east of Toledo, OH

Safety Review Results

- Safety Evaluation Report (SER) with Open Items was issued July 2012
- ACRS License Renewal Subcommittee Meeting held September 19, 2012
- Final SER was issued September 2013
- Supplement to SER was issued August 2015
- ACRS 2nd License Renewal Subcommittee Meeting held September 23, 2015

Open Item B.1.4-1: Closed

OI B.1.4-1 Operating Experience

- **<u>Issue</u>:** During review, LR-ISG-2011-05, “Ongoing Review of Operating Experience,” was issued

- **<u>Basis for closure</u>**: Applicant provided additional information that addressed the guidance in LR-ISG-2011-05

Applicant will enhance AMPs or develop new AMPs when necessary to ensure effects of aging are adequately managed

Open Item 4.2-1: Closed

OI 4.2-1 Reactor Vessel Neutron Embrittlement (SER Section 4.2.2):

- **Issue**: Reactor vessel welds with unknown initial upper shelf energies (USE) require an equivalent margins analysis (EMA), per §Part 50, App G, requirements

- **Basis for closure**: EMA submitted and approved to demonstrate that the welds will have adequate margins of safety on USE, as required by §Part 50, App. G

- EMA provides an acceptable basis to accept the USE TLAA under §54.21(c)(1)(ii).

Open Item 4.2.4-1: Closed

OI 4.2.4-1 Pressure-Temperature (P-T) Limits:

- **Issue:** Methodology (Report BAW-10046-A, Rev. 2) invoked by Tech. Spec. 5.6.4 for calculating P-T limits may not assess potentially limiting reactor vessel non-beltline locations

- **Basis for closure**: Applicant demonstrated Report BAW-10046, Rev. 2, appropriately accounts for potentially limiting reactor vessel non-beltline locations near geometric discontinuities.

- TS basis remains valid to accept under §54.21(c)(1)(iii).

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Safety Review Results

- Final SER issued September 2013 (all open items were closed): 44 AMPs total

Staff Disposition of Program	Existing AMPs	New AMPs
Consistent with the GALL Report	9	5
Consistent with enhancements	11	2
Consistent with exceptions	2	-
Consistent with both enhancements and exceptions	5	-
Plant specific	4	6
Subtotals:	31	13

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SER Supplement 1

- Supplement 1 to SER issued August 10, 2015
  - Reactor Vessel Internals Inspection Plan and Program
  - Annual Updates in 2013, 2014, and 2015
  - Updated information and commitments in response to recent industry operating experience
  - New plant specific program Service Level III Coating and Linings Monitoring Program
  - Steam Generator Replacement (Spring 2014)
  - Shield Building Laminar Cracking Propagation
- Conclusion is unchanged
- List of Commitments in Appendix A
  - Several commitments completed and reviewed by NRC staff

Shield Building Monitoring Program (OI 3.0.3.2.15-1)

- **Shield Building Monitoring Program to manage aging effects on laminar cracks; preventive protective coating applied. Plant-specific prevention & condition monitoring AMP, supplements Structures Monitoring Program**

- **Scope includes SB Wall Concrete & Reinforcing Steel; SB exterior concrete coatings**

- **Periodic visual inspections of representative sample of core holes; Visual inspections will be supplemented with NDE (i.e., Impulse Response (IR) Mapping)**

- **Opportunistic visual inspections of rebar near laminar cracking**

- **Periodic visual inspections of exterior coating every 5 years & coating reapplied every 15 years**

- **Personnel qualifications per ACI Report 349.3R Ch. 7**

Shield Building Monitoring Program (contd…)

Operating experience of crack propagation:

- AMP considers and incorporates future operating experience, as necessary
- Accordingly, the applicant revised AMP to incorporate plant-specific OpE of laminar crack propagation discovered in 2013 & 2015, attributed to “ice-wedging” phenomenon
- Revised AMP increased inspection sample size of core holes, increased inspection frequency, and conducts IR to confirm extent of crack propagation

Shield Building Monitoring Program (contd…)

Adequacy of sample size and distribution:

- Representative sample for inspection consists of a minimum of *28* core hole locations, with provisions for consideration of past evidence of propagation and expanding inspection sample.
- *14* are cracked covering the spectrum of locations with highest prevalence of cracking and a range of observed crack widths; includes the 3 maximum observed crack widths, to monitor crack width & planar limit of propagation.
- *14* are uncracked but generally located near areas of known cracking providing ability to monitor propagation including 5 leading edge bores to monitor limits of recent planar propagation.

Shield Building Monitoring Program (contd…)

Acceptance Criteria for Core Bore Inspection Findings:

- **Need for corrective action evaluated in Corrective Action Program using evaluation hierarchy in Figure 5.1 of ACI 349.3R, if any of below criteria not met.**

Qualitative: *Cracking remains* ***passive***

- No discernible change in existing cracks (width, planar size)
- No Indication of new cracking in bores or from IR mapping

Quantitative: *Bounded by qualitative criteria; and bounded by SB calculations-of-record*

- Crack width does not exceed 0.013 inch
- Extent of circumferential planar crack limit does not exceed that in SER Table 3.0.3.3.9-2.

ACI 349.3R Evaluation Heirarchy

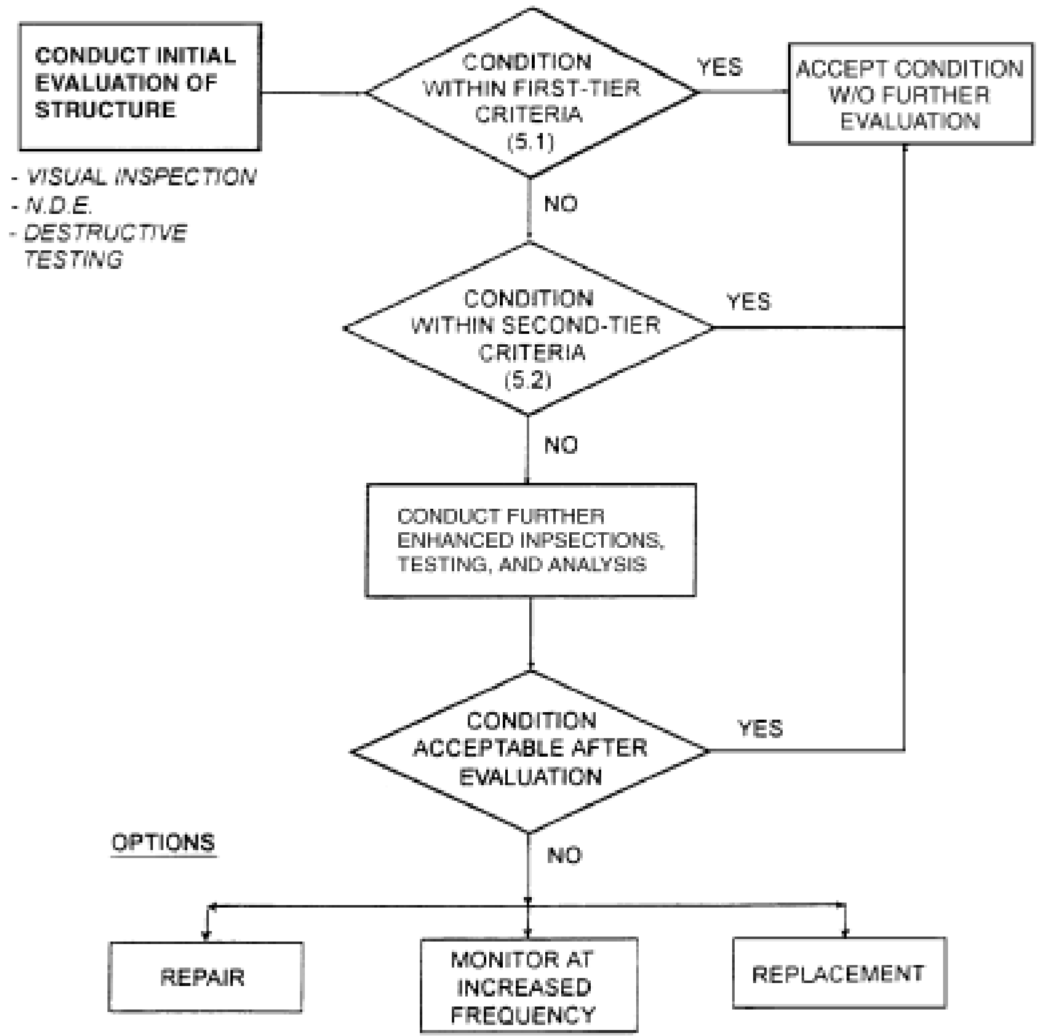


Fig. 5.1—Evaluation criteria hierarchy.

Shield Building Monitoring Program – Conclusion

- **In summary, the staff finds the SBMP AMP acceptable because:**

- Laminar cracks are inspected at a 1 year interval and this interval will not be progressively incremented to 2/4 years unless cracks become passive
- A representative sample of no less than 28 core bores will be inspected at every inspection to effectively monitor crack width and planar limit
- The use of visual inspections and Impulse response testing can effectively detect changes in laminar cracking
- Inspection findings will be evaluated by qualified personnel using the evaluation procedure in ACI Report 349.3R
- The acceptance criteria of crack being “not passive” would trigger further evaluation under the corrective action program if inspection findings indicate discernable change in the cracks

Shield Building Monitoring Program – Conclusion (contd..)

- Based on the AMP attributes discussed in the previous slides, staff concludes that through implementation of the AMP, the applicant will be able to adequately monitor the cracks, perform structural evaluations, and take timely corrective actions, if necessary, prior to loss of function

- Staff thus concludes that there is reasonable assurance that aging effects on the shield building laminar cracking will be adequately managed by the Shield Building Monitoring Program, such that intended functions will be maintained during the period of extended operation.

- OI 3.0.3.2.15-1 is closed and staff evaluation is documented in SER/SSER Section 3.0.3.3.9.

Conclusion

On the basis of its review, the staff determines that the requirements of 10 CFR 54.29(a) have been met for the license renewal of Davis-Besse Nuclear Power Station

Davis-Besse Nuclear Power Station License Renewal Application

Advisory Committee on Reactor Safeguards
Full Committee Meeting
November 4, 2015

AGENDA

- **Introductions & Opening Remarks**
- **Background**
- **License Renewal Application Description**
- **Closure of Open Items**
- **Containment Vessel Inspections**
- **Summary & Closing Remarks**

Introductions

- **Brian Boles – Site Vice President**
- **Ken Byrd – Director, Site Engineering**
- **Cliff Custer – Fleet Project Manager**
- **Steve Dort – Site Project Coordinator**
- **License Renewal Core Team Members**
- **Aging Management Program Owners and Subject Matter Experts**

Background – Site

Davis-Besse Site

- Southwestern shore of Lake Erie in Ottawa County, Ohio
- ~20 miles East of Toledo, Ohio
- 954 Acre Site
  - 733 acres leased to US Government as wildlife refuge
  - 221 acres for Plant structures & equipment

Background – Plant

- **Design**
  - Pressurized Water Reactor
  - Babcock & Wilcox nuclear steam supply system with raised-loop design
    - 2817 Megawatts thermal / 908 Megawatts electrical rating
  - Bechtel Engineering construction management
  - Facility Operating License expires April 22, 2017

Background – Upgrades

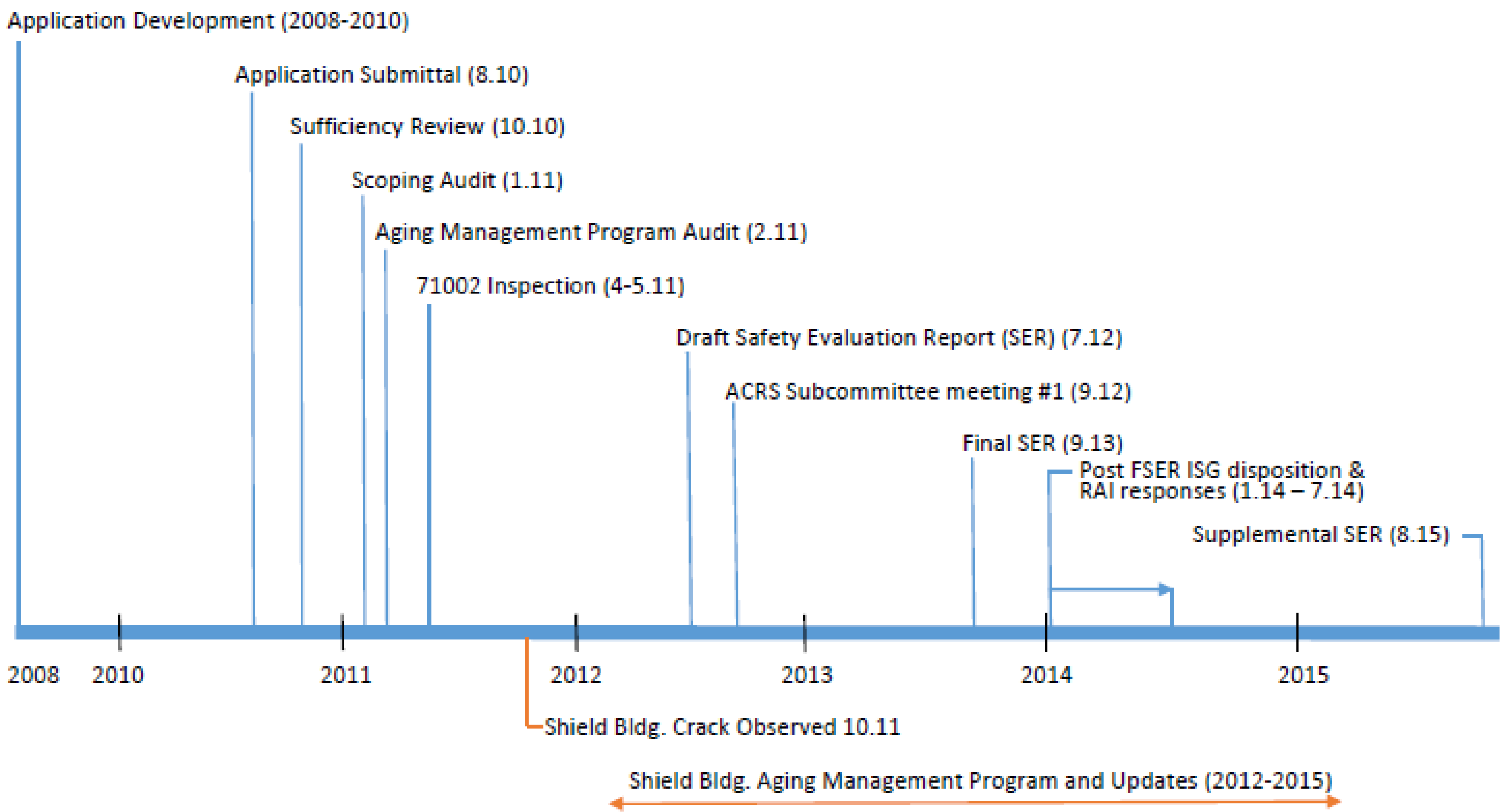
- **Equipment Improvements**
  – Replaced Steam Generators, related Feedwater piping & Reactor Coolant System hot legs
  – Replaced Reactor Head
  – Installing Emergency Feedwater System



License Renewal Application (LRA) – Details

- **Developed to NUREG-1801 Rev 1, reviewed to Rev 2**
  - AREVA; FENOC core team
  - Site review and concurrence
  - Industry peer review prior to submittal
- **44 Aging Management Programs (AMPs)**
  - 13 New
  - 31 Existing
- **55 License Renewal commitments**

LRA – Review Timeline



LRA – Closure of Open Items

- **4 Open Items were addressed and closed in the Safety Evaluation Report (Sept 2013) [Section 1.5]**
  - Operating Experience
    - Developed a process to align with LR-ISG-2011-05, “Ongoing Review of Operating Experience”
  - Reactor Vessel Neutron Embrittlement
    - Provided Equivalent Margins Analyses for the RV shell region weld materials
  - Pressure-Temperature (P-T) Limits
    - P-T limit curves are and will be developed for all ferritic materials of the reactor coolant pressure boundary
  - Shield Building
    - Developed a plant-specific Shield Building Monitoring Program

OI B.1.4-1: Operating Experience (OE)

- **Systematic review of plant-specific and industry OE concerning age-related degradation and aging management**
  - Aging Management Evaluation (AME) checkbox added to Corrective Action Program and OE Program to flag age-related degradation
  - Evaluate material-environment combinations and AMPs
  - Will enhance AMPs or develop new AMPs based on AME results
- **Process will ensure the continued effectiveness of the license renewal aging management programs**

OI 4.2-1: RV Neutron Embrittlement

- **RV Beltline Upper-shelf Energy (USE) Evaluation**
  - Analysis using generic mean value of 70 ft-lb to project 52 EFPY USEs considered not statistically conservative
  - Selection of lowest value resulted in 52 EFPY USE of < 50 ft-lb
  - 10 CFR 50 Appendix G requires end-of license USE to be no less than 50 ft-lb, or demonstrate that lower values of USE will provide margins of safety against fracture, as determined by equivalent margins analysis (EMA)
- **FENOC Response**
  - In accordance with 10 CFR 50 Appendix G, FENOC elected to qualify welds by EMA
  - EMA demonstrated adequate margin of safety against fracture for all beltline welds

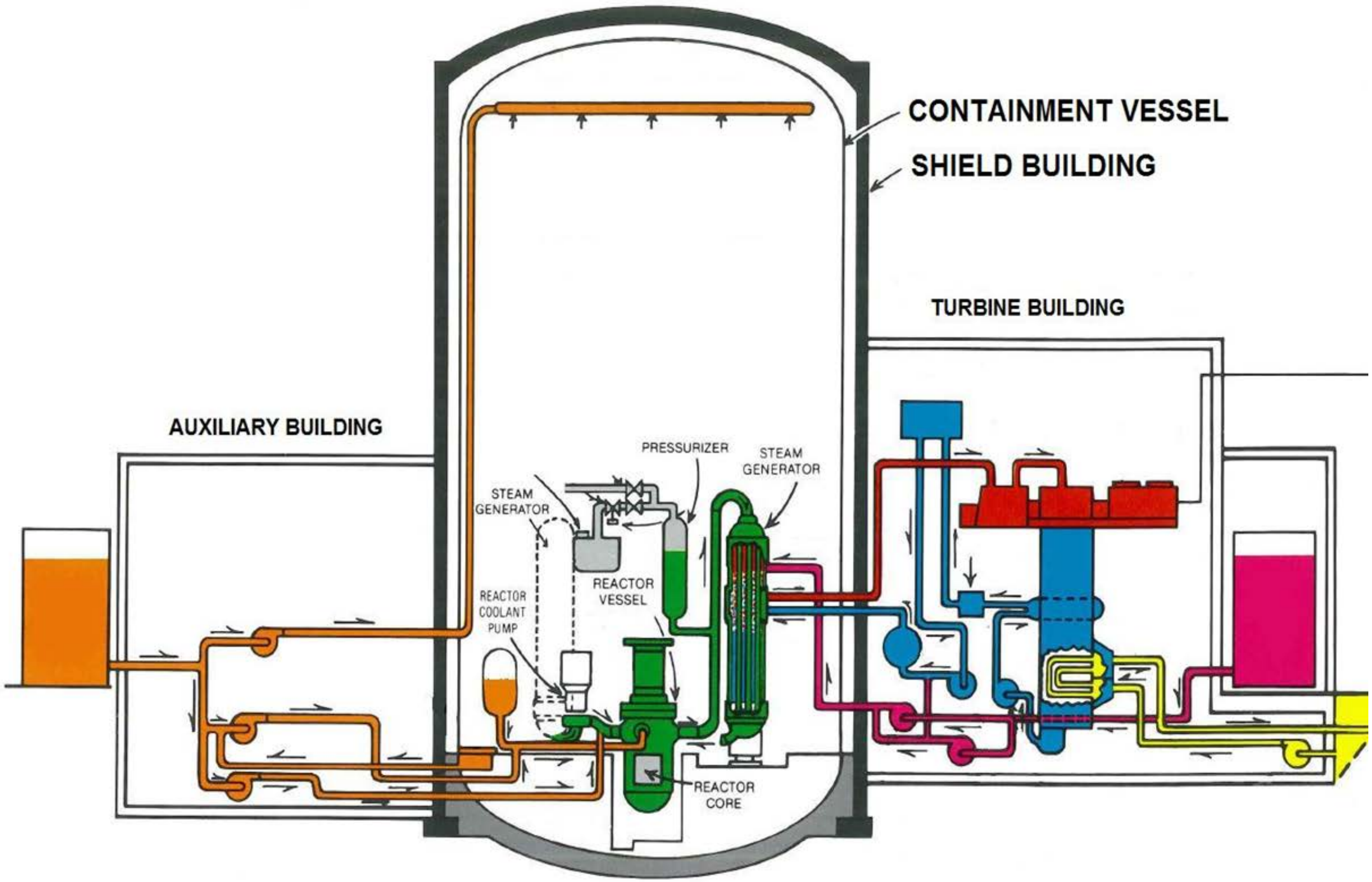
OI 4.2.4-1: P-T Limits

- **RAI 4.2.4-1 Request**
  - Describe how P-T limit curves to be developed for use in the period of extended operation, and methodology used to develop these curves, considered all Reactor Vessel materials (beltline and non-beltline) and lowest service temperature of all ferritic reactor coolant pressure boundary materials
- **RAI 4.2.4-1 Response**
  - Davis-Besse P-T Limits generated in accordance with 10 CFR 50 Appendix G and R.G. 1.99 Rev. 2 using methods described in approved topical report BAW-10046A
  - BAW-10046A considered all ferritic materials (beltline & non-beltline material)

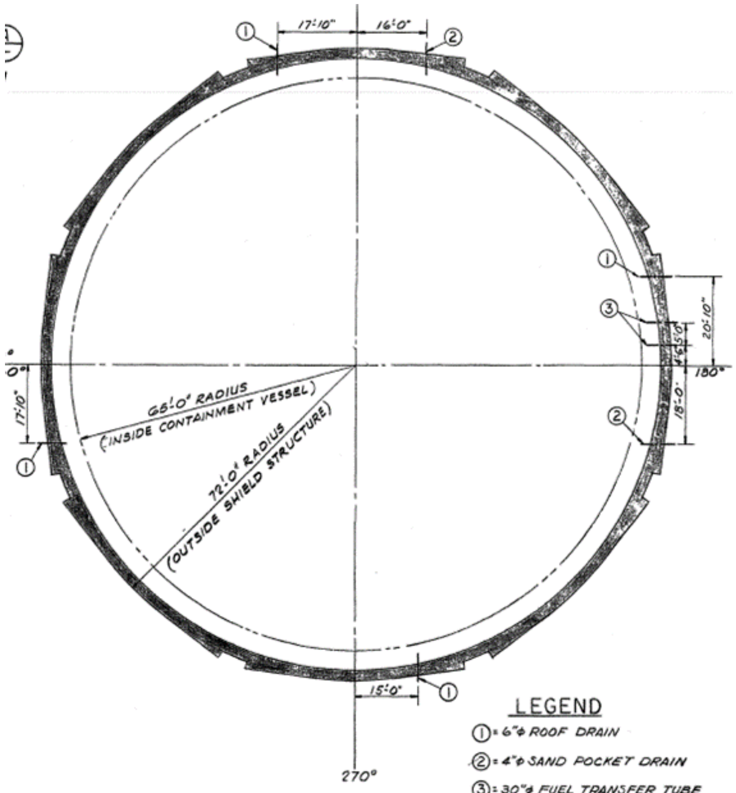
OI 3.0.3.2.15-1: Shield Building

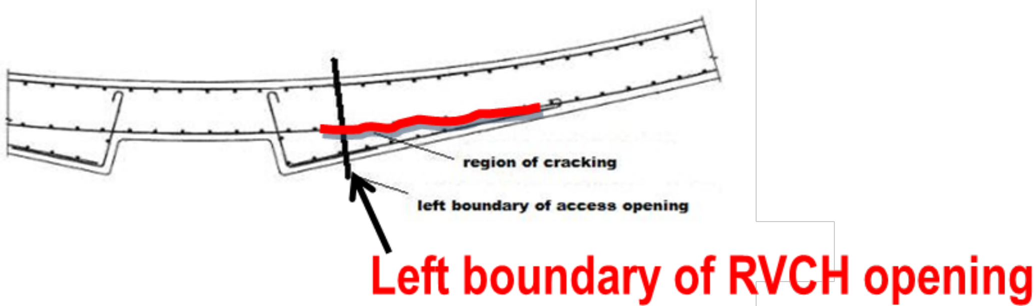
- **Request**
  - Develop an AMP to monitor crack changes so that the safety function of the Shield Building is not affected during the period of extended operation
- **Discussion**
  - Describe the Shield Building Initial Condition
  - Provide a timeline of Shield Building activities
  - Provide description of monitoring program
  - Provide basis for conclusion that Shield Building condition is acceptable with continued monitoring

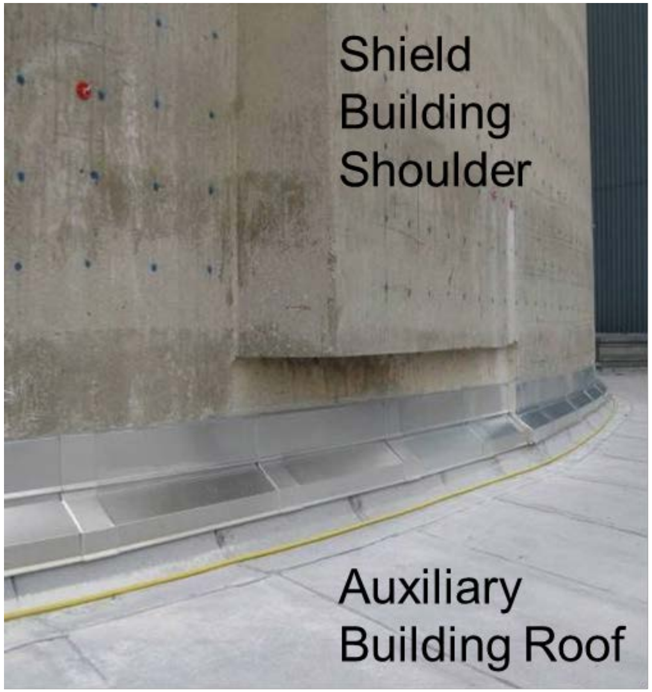
Shield Building



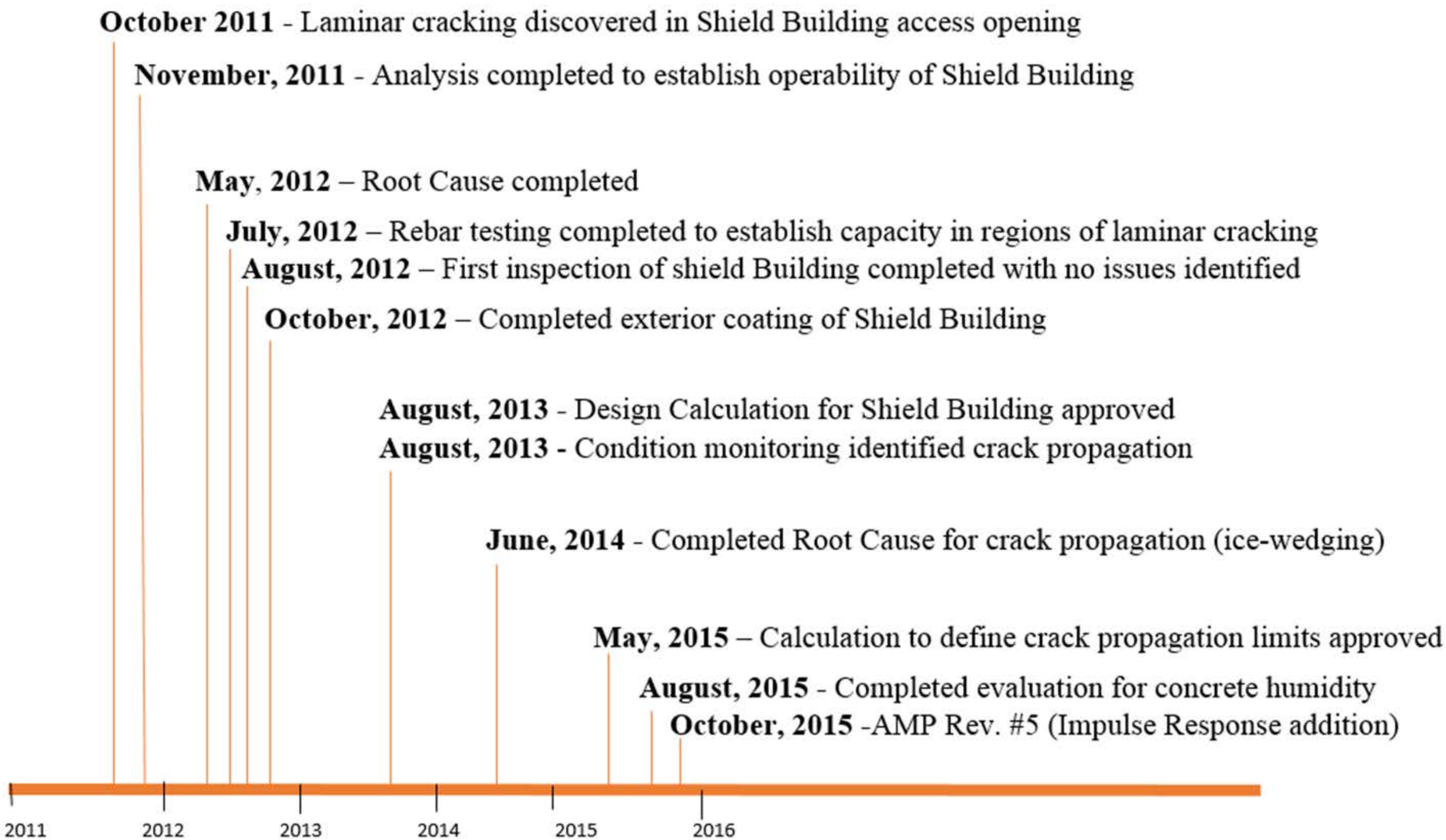
Shield Building







Shield Building Timeline



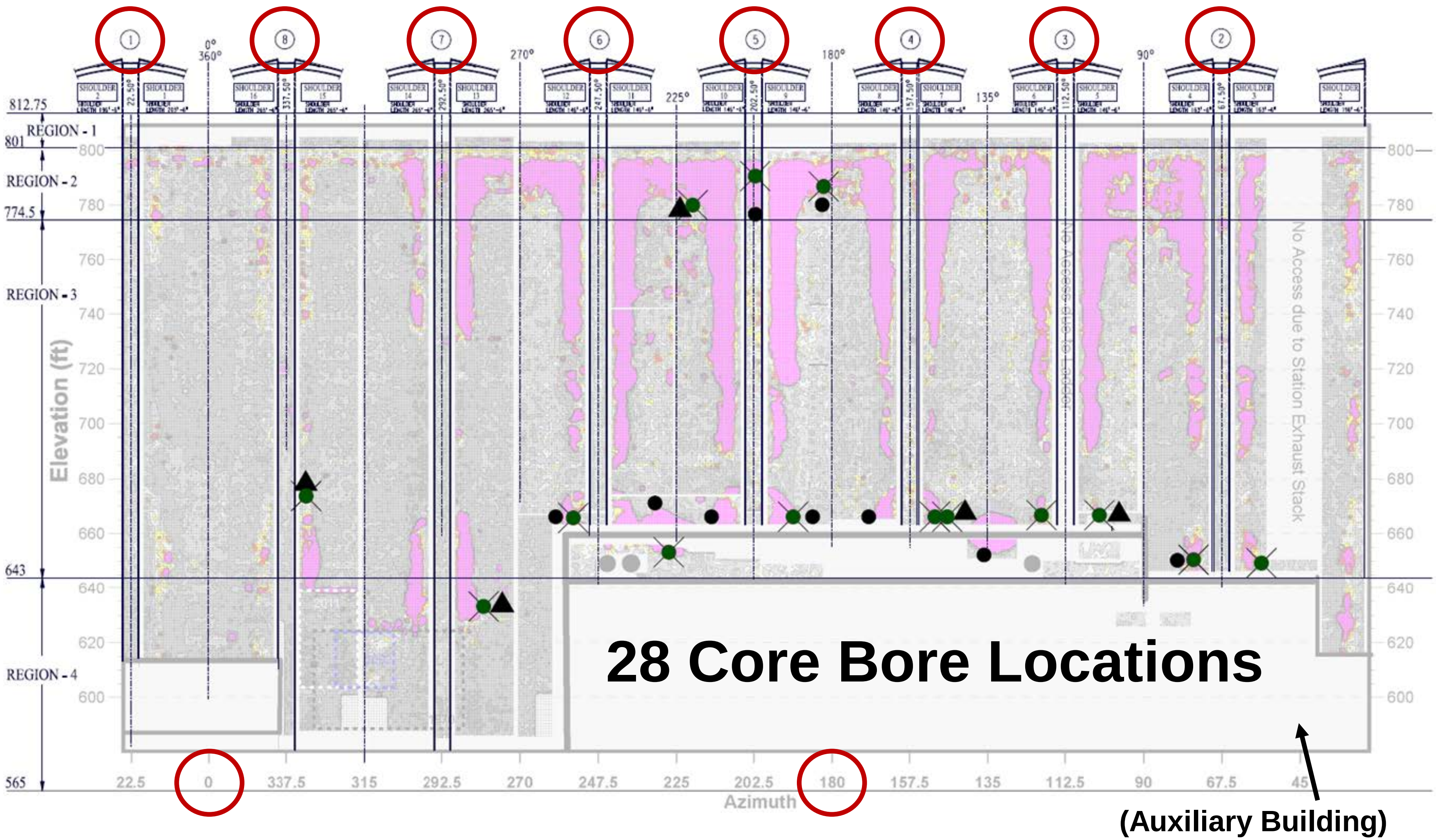
Shield Building Monitoring Program

- **28 Core bores will monitor both cracked and uncracked areas**
- **Fourteen areas of potential crack propagation**
  - Six core bores located in areas adjacent to known cracks to monitor crack propagation (Shoulders 4, 8, 9, 10, 11, and 12)
  - Four core bores monitoring leading edge where crack propagation has been identified (Shoulders 5, 7, 13, and 15)
  - Three core bores in areas greater than 780 feet
    - One core bore monitoring leading edge
  - One core bore in Main Steam Line penetration areas

Shield Building Monitoring Program

- **Fourteen core bores in various areas of laminar cracking to monitor changes in crack characteristics**
- **Frequency of Inspection**
  - Yearly inspections if changes are noted
  - If yearly inspections result in no changes, then inspection intervals increase to every other year
- **Extent of cracking is well understood and matches the Monitoring Program**

Shield Building Monitoring Program



Impulse Response (IR) Mapping

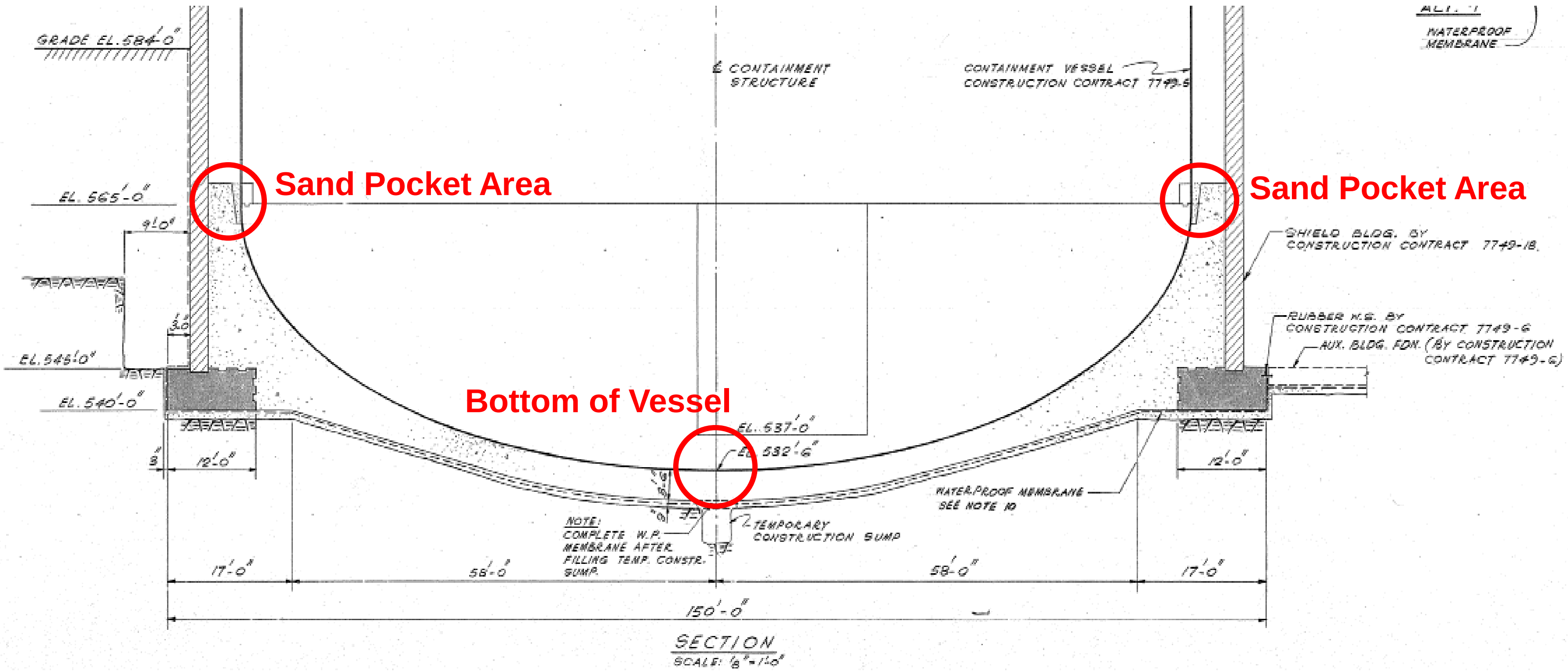
- **Shield Building Monitoring Program modified to require IR mapping**
  - Where crack propagation is identified, IR mapping (minimum 100 sq ft) will be used to help characterize extent of crack propagation
- **Additional IR mapping as follows:**
  - Two IR locations (10 ft x 10 ft) in known crack areas and away from existing core bores to monitor any changes in leading edges
  - Two IR locations (10 ft x 10 ft) not currently known to contain laminar cracking and away from existing core bores to establish cracking has not expanded into these areas
  - To be performed in 2016 and 2018

Shield Building Monitoring Conclusions

- **Test results & evaluations suggest crack propagation from ice wedging will decrease as the Shield Building dries out**
- **Margin in the structural calculation is sufficient to allow continued monitoring during the time building is drying**
- **Margin in the structural calculation provides sufficient time to develop additional actions if required**
- **Monitoring scope and frequency is appropriate for the identified condition**

Containment Vessel Inspections

Shield Building / Containment Vessel Foundation



Containment Vessel Inspections

- **Ground Water Intrusion in Sand Pocket**
  - Containment Vessel 1.5” carbon steel plate
  - 5 representative locations were investigated
  - 45 total ultrasonic test (UT) readings
  - All UT readings at or below the grout interface were above required mill tolerance thickness
- **Therefore, sand pocket seepage has negligible affect on the Containment Vessel**

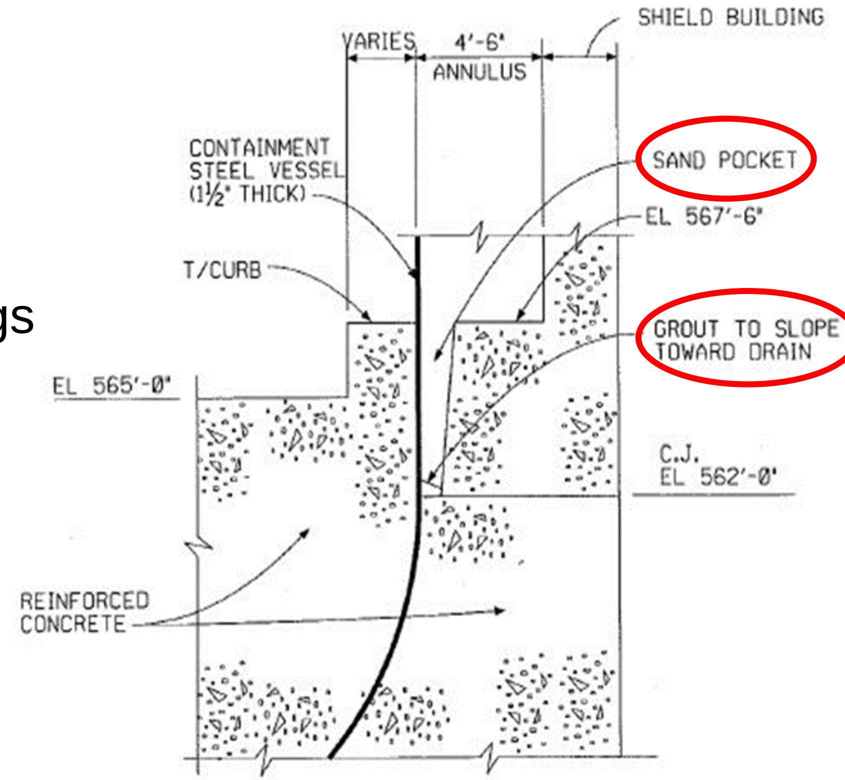
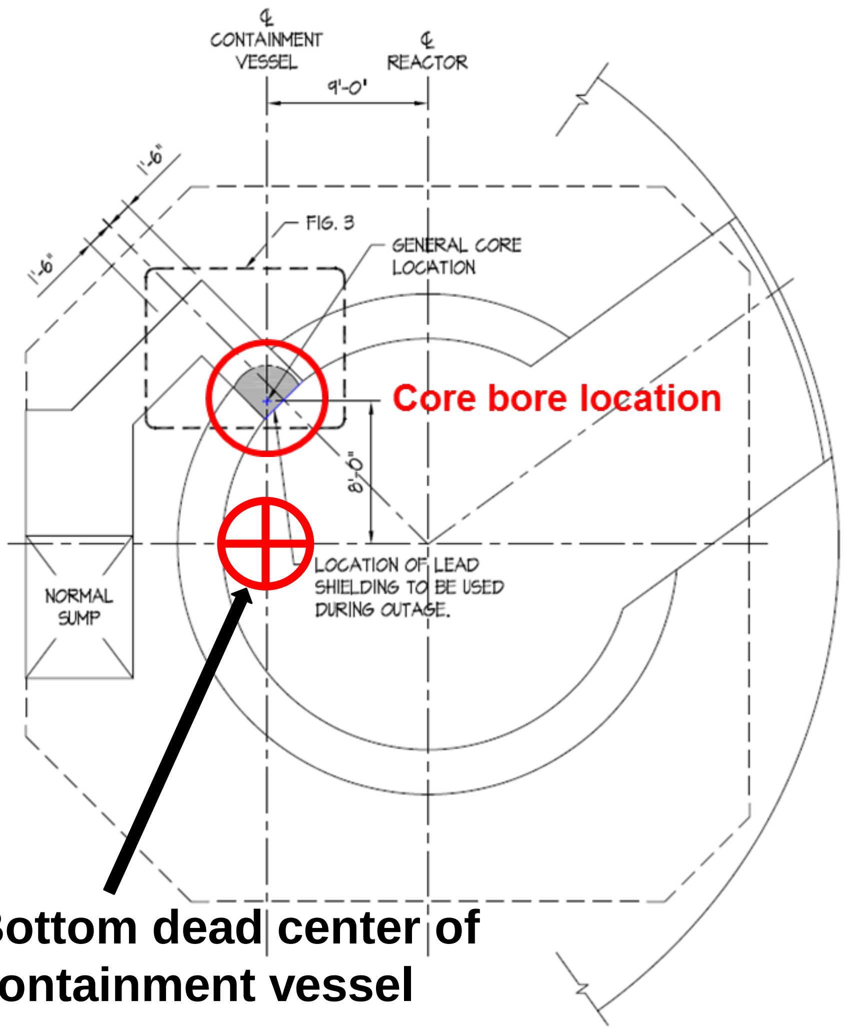


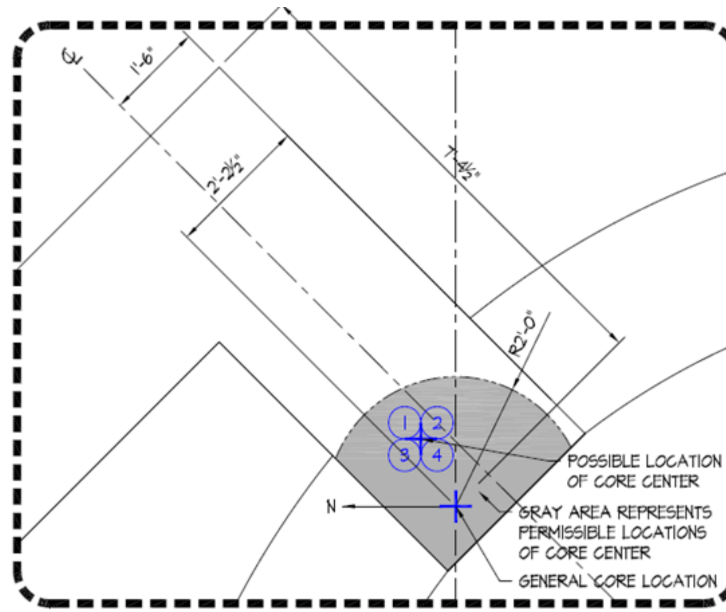
Figure 1. Sand Pocket Area

Containment Vessel Inspections

Refueling Canal Leakage – Effects on Containment Vessel



Bottom dead center of containment vessel



Conclusions

- ✓ No signs of water
- ✓ UT reading > 1.5”

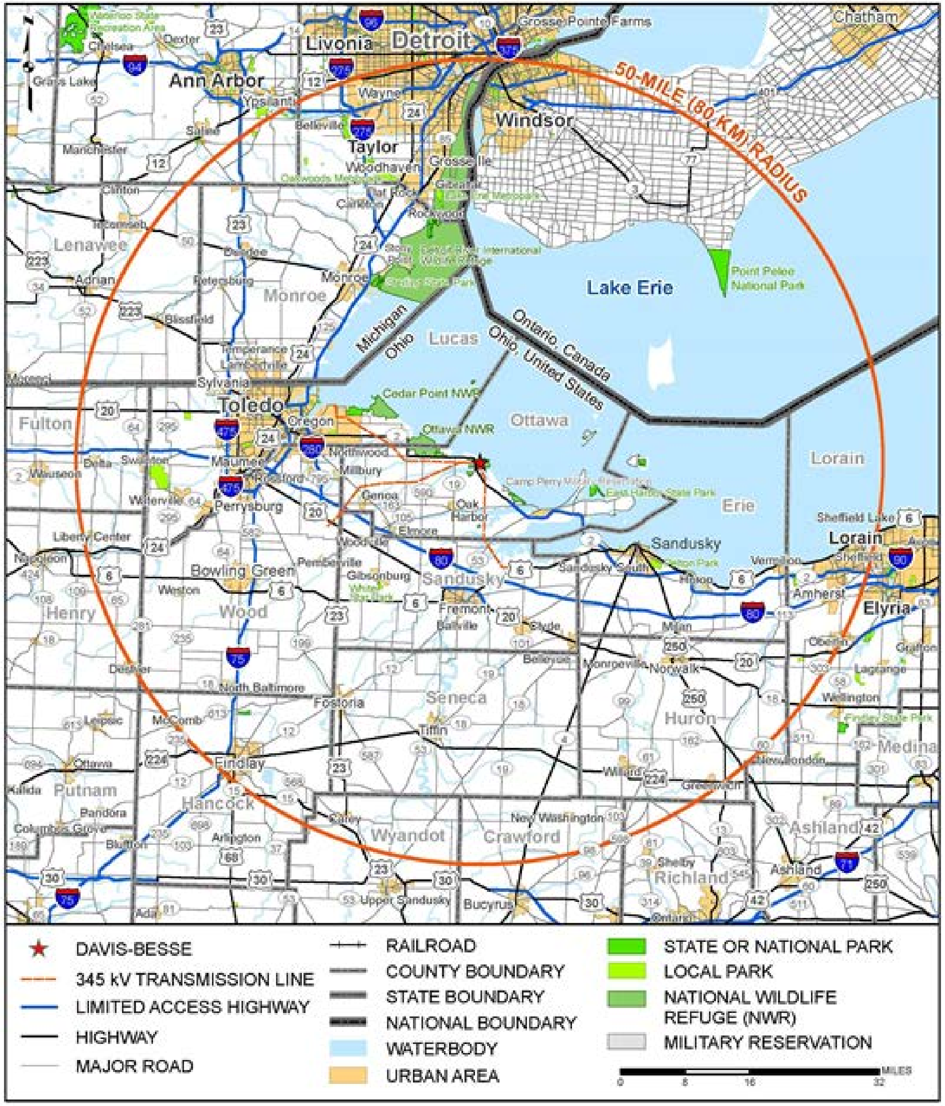
Closing Remarks

- **Application has received a thorough staff review**
- **Current with Interim Staff Guidance expectations**
- **Implementation efforts are in progress**

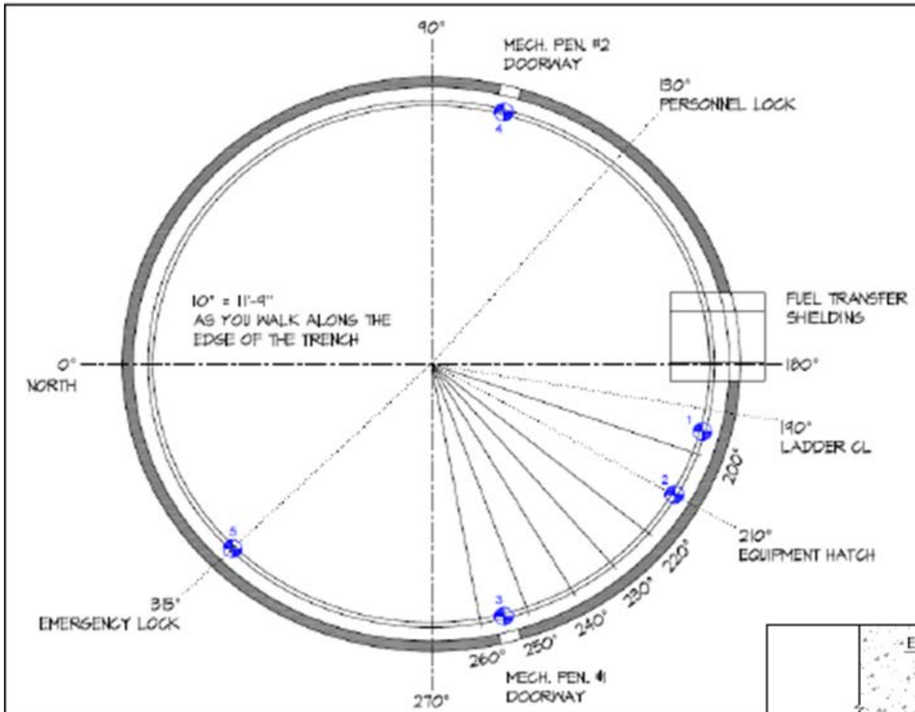
Questions?

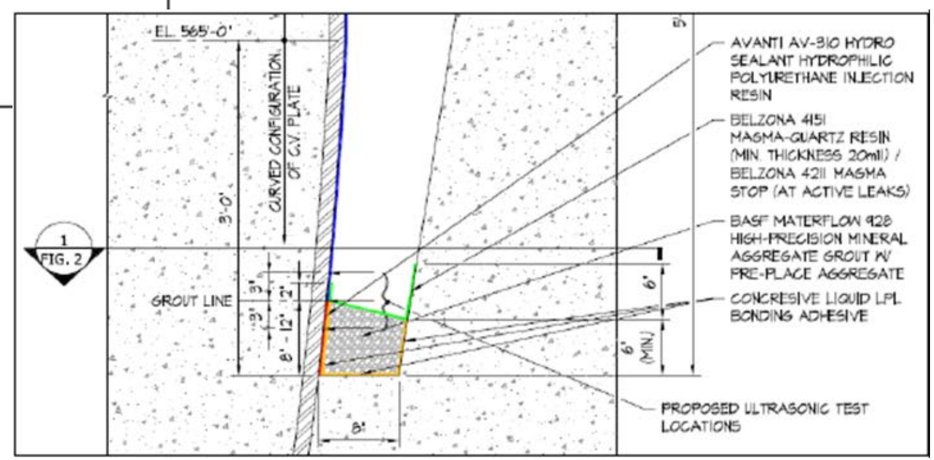
Backup Information

Davis-Besse Site 50-mile Radius



Containment Vessel Examination (exterior)





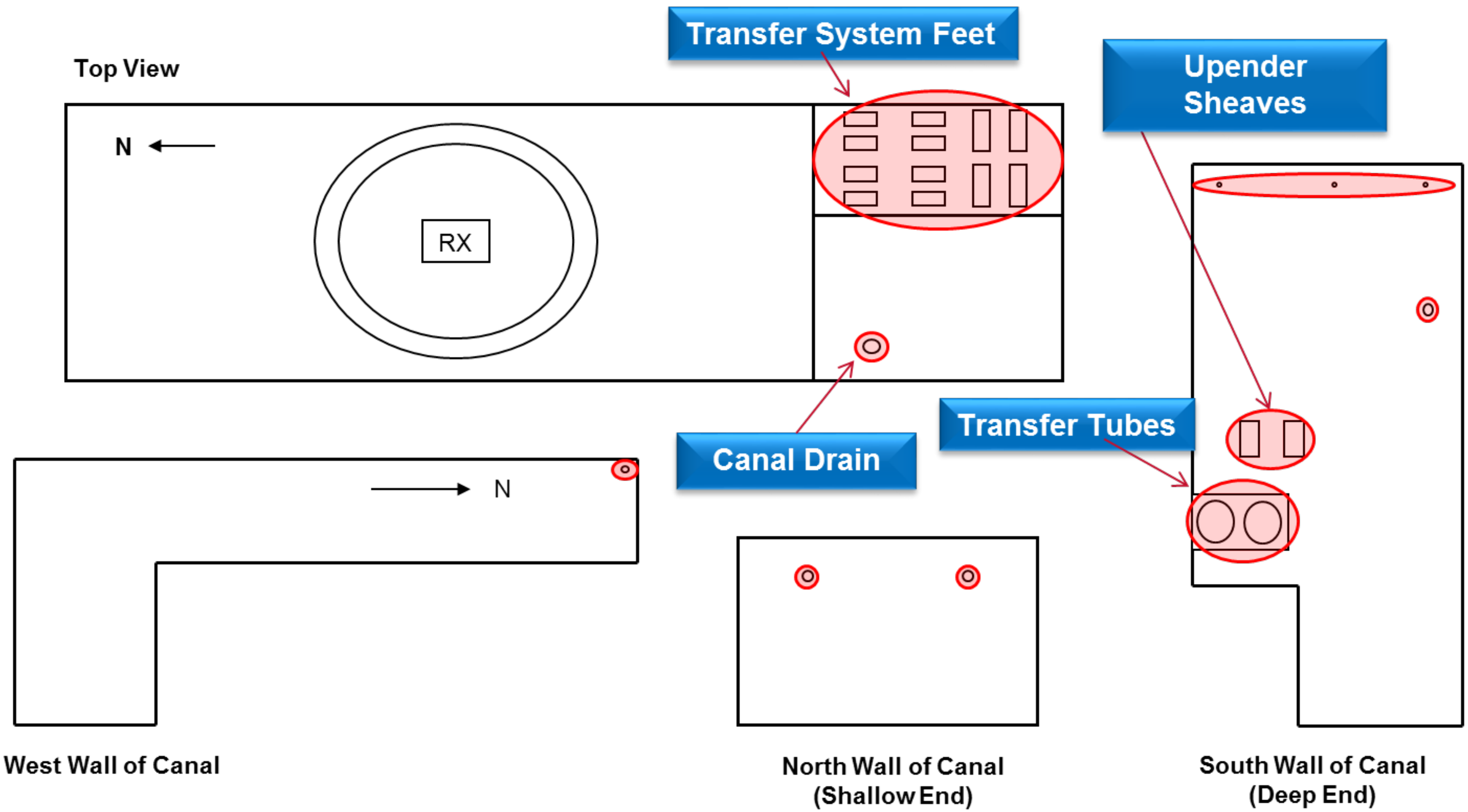
Containment Vessel Examination (exterior)

Containment Vessel Examination (interior)

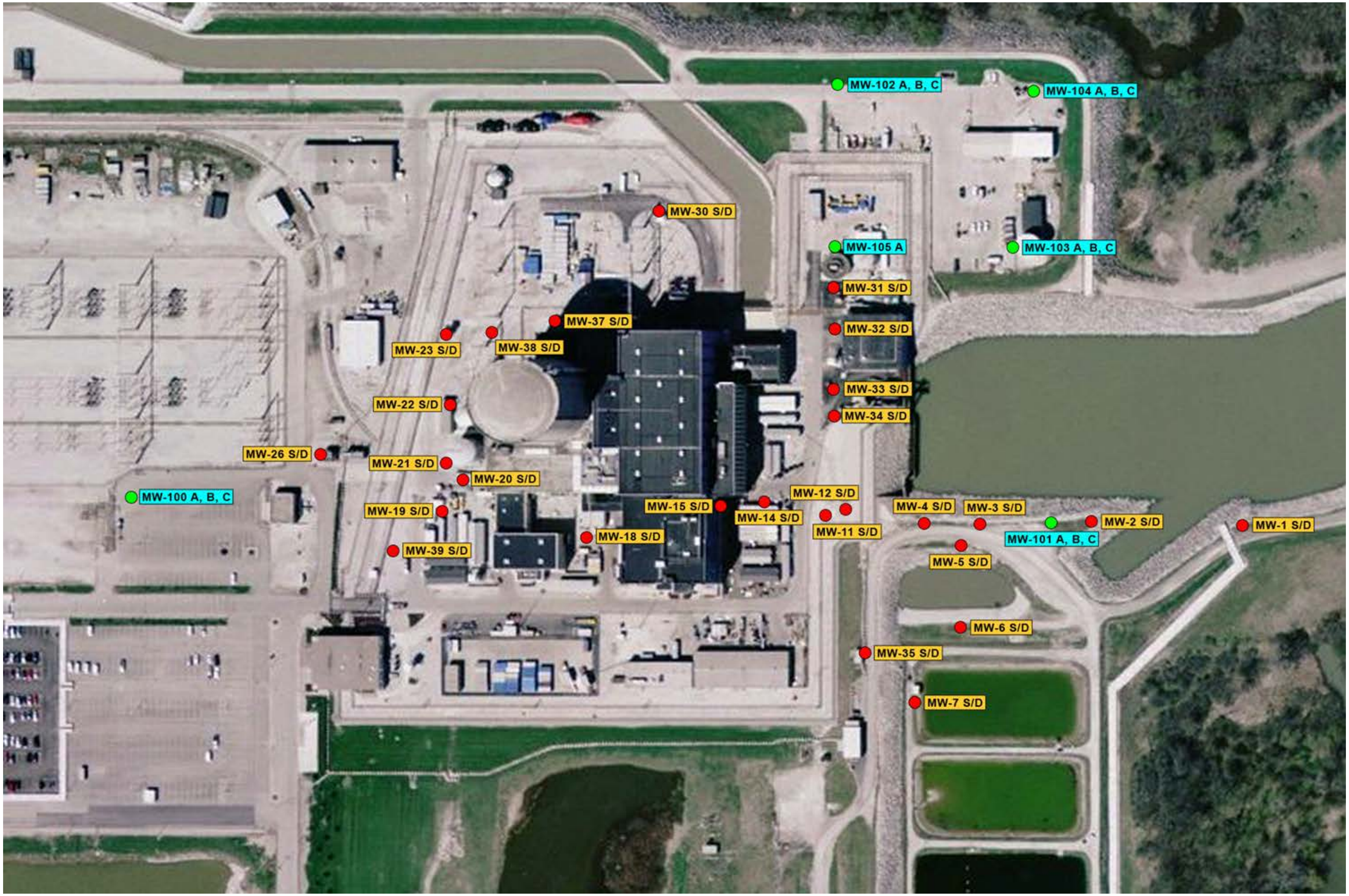
Refuel Canal Leakage Mitigation

Refuel Canal Leakage Mitigation

Repair Options

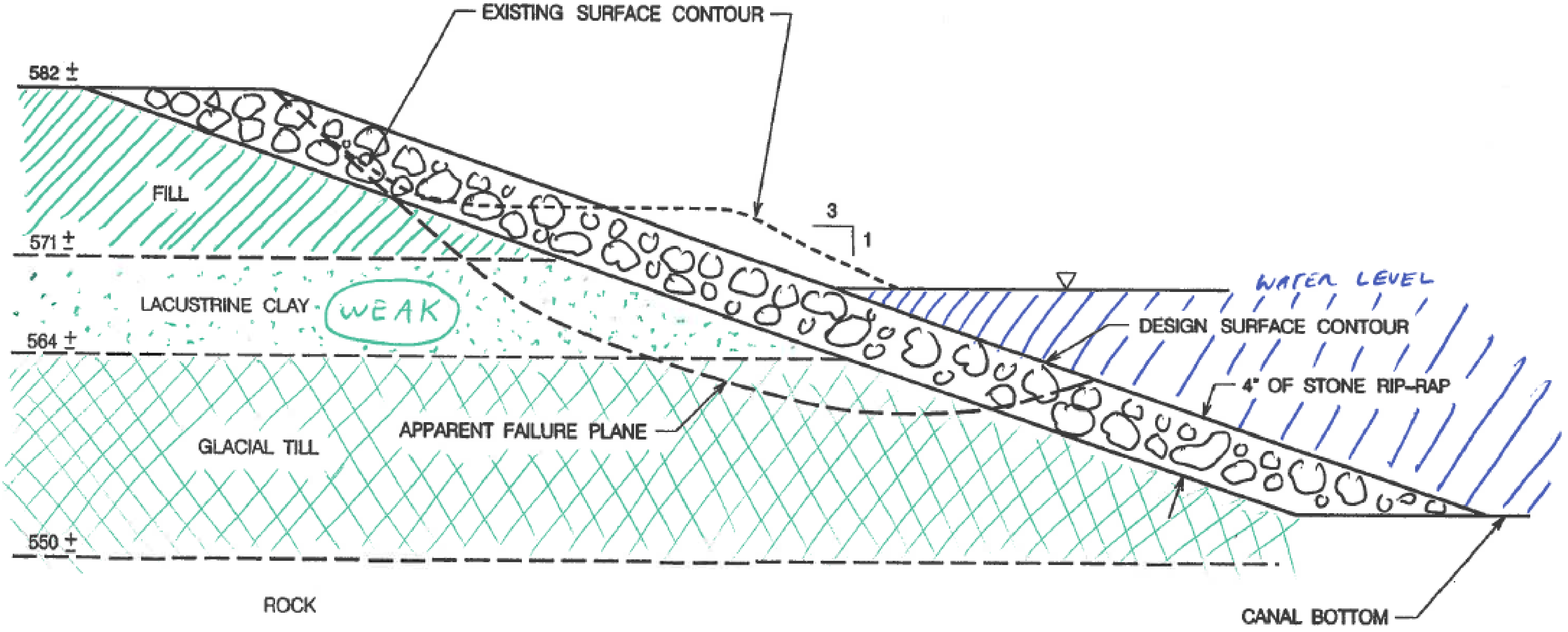


Davis-Besse Groundwater Monitoring Wells



Intake Canal Slope Repair

- **License Renewal Commitment #48**
  - Existing slope protection rock removed
  - Soil re-graded to 2:1 slope
  - Slope protection rock added at 4:1 slope



Service Water System Supports

Service Water System Supports

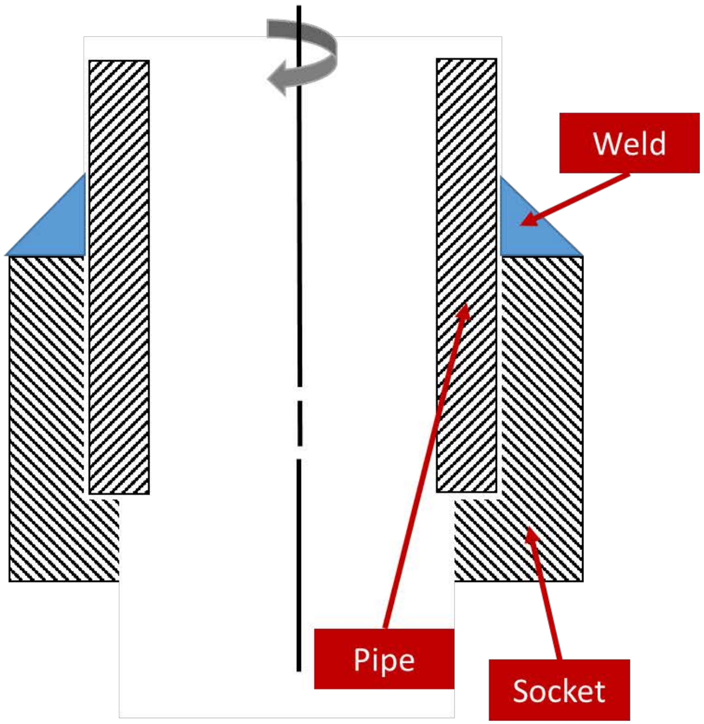
Service Water System Supports

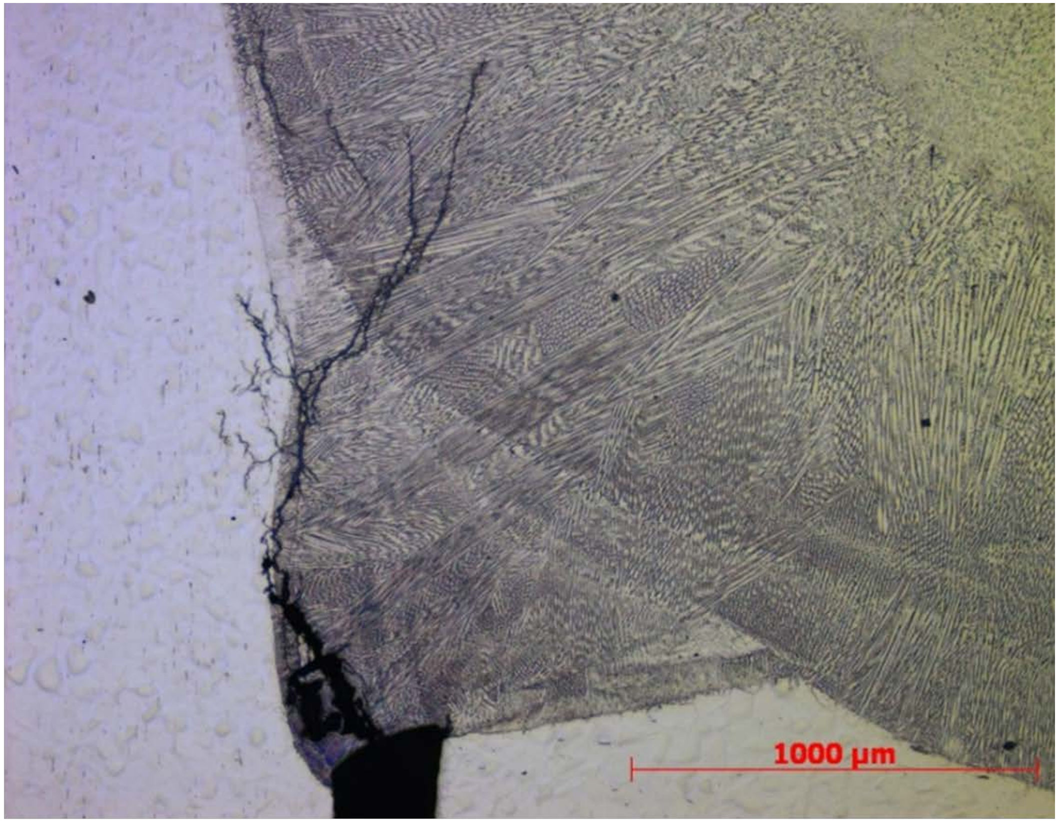
- **Surface rust / discoloration was noted**
  - Condition was evaluated in a Condition Report
    - Condensation from Service Water pipes dripped on support, creating surface rust
    - Structural integrity of support not challenged
    - Support deemed acceptable for continued service
  - Evaluated per ASME Section XI, IWF-3410(b)(5)
    - "Roughness or general corrosion which does not reduce the load bearing capacity of the support…" [non-relevant condition]
  - InService Inspection (ISI) program
    - 10-year Interval
    - Next examination of this component scheduled in 19RFO

Small Bore Piping Inspection Results

Weld	Orientation	Defect Location (Circumferential)	Percent Through Wall	Defect Notes
SG-2-CHD-29 *	Vertical	180 *	1-5 % *	In weld. Near socket interface. *
SG-1-HLV-3C	Horizontal	180	1-5 %	In weld near triple point.
SG-2-CHD-23	Horizontal	0	40-50 %	In weld and socket base material near triple point.
SG-1-CHD-8	Vertical	270	40-50 %	In weld and socket base material near triple point.
		270	55-65 %	In weld and pipe base material near triple point.
SG-2-CHD-24	Horizontal	180	40-50 %	In weld and pipe base material near triple point.
		270	55-65 %	In weld near triple point.
*** NOTE * - Examination of this weld noted OD indications. This was evaluated to be a fabrication flaw.**				

Small Bore Piping Inspection Results

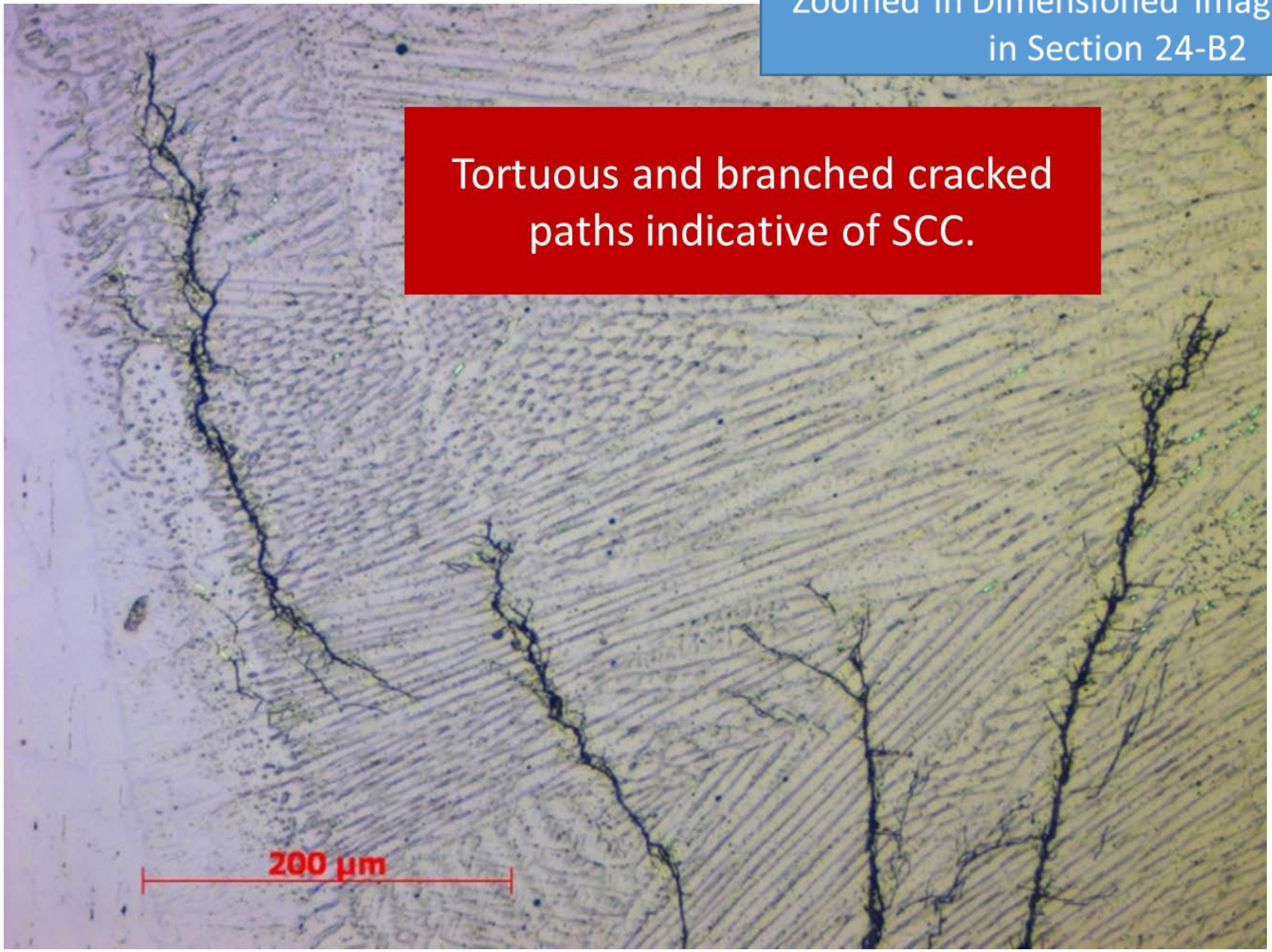




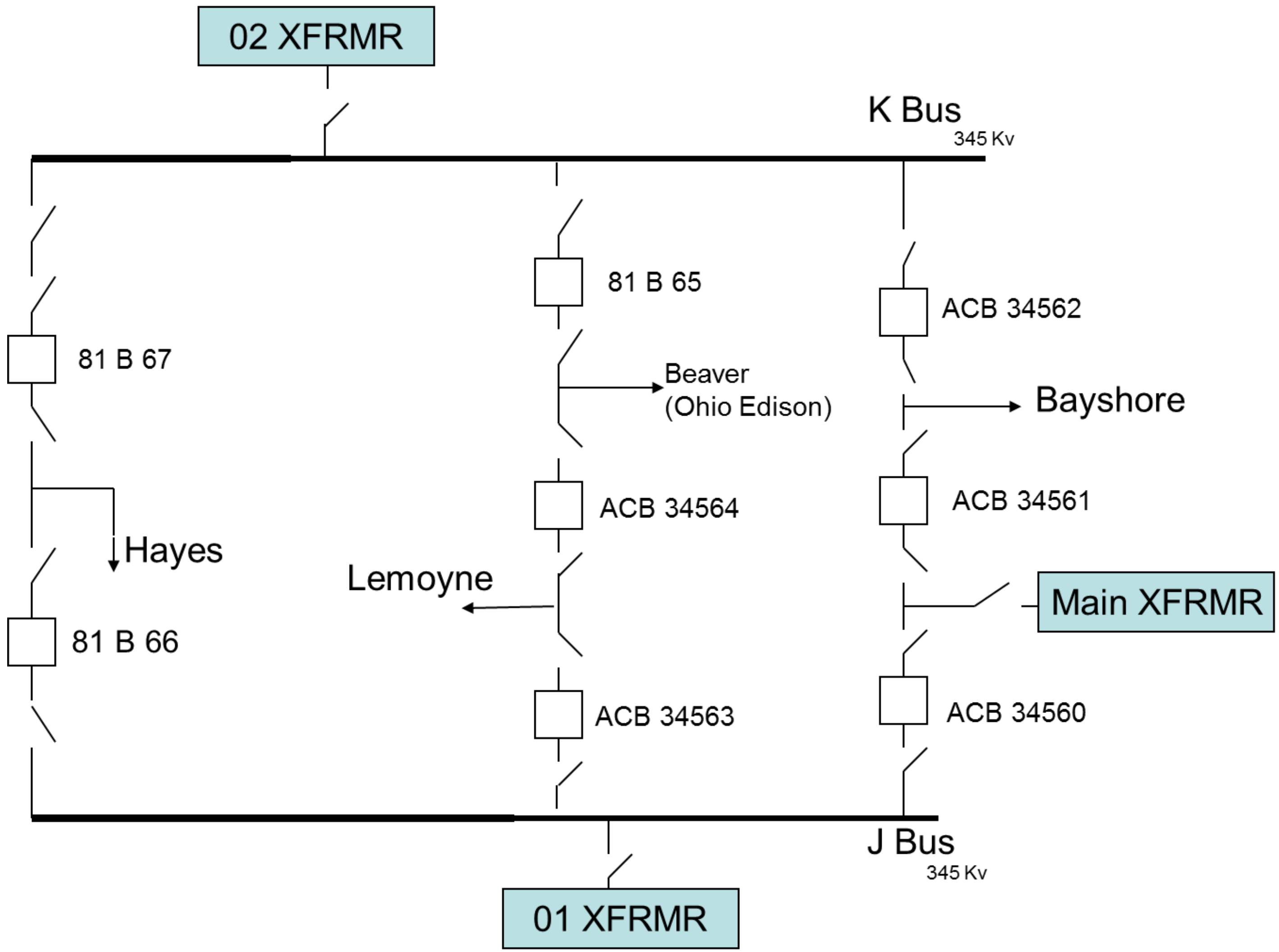
Dimensioned Image of Defect in Section 24-B2

Small Bore Piping Inspection Results

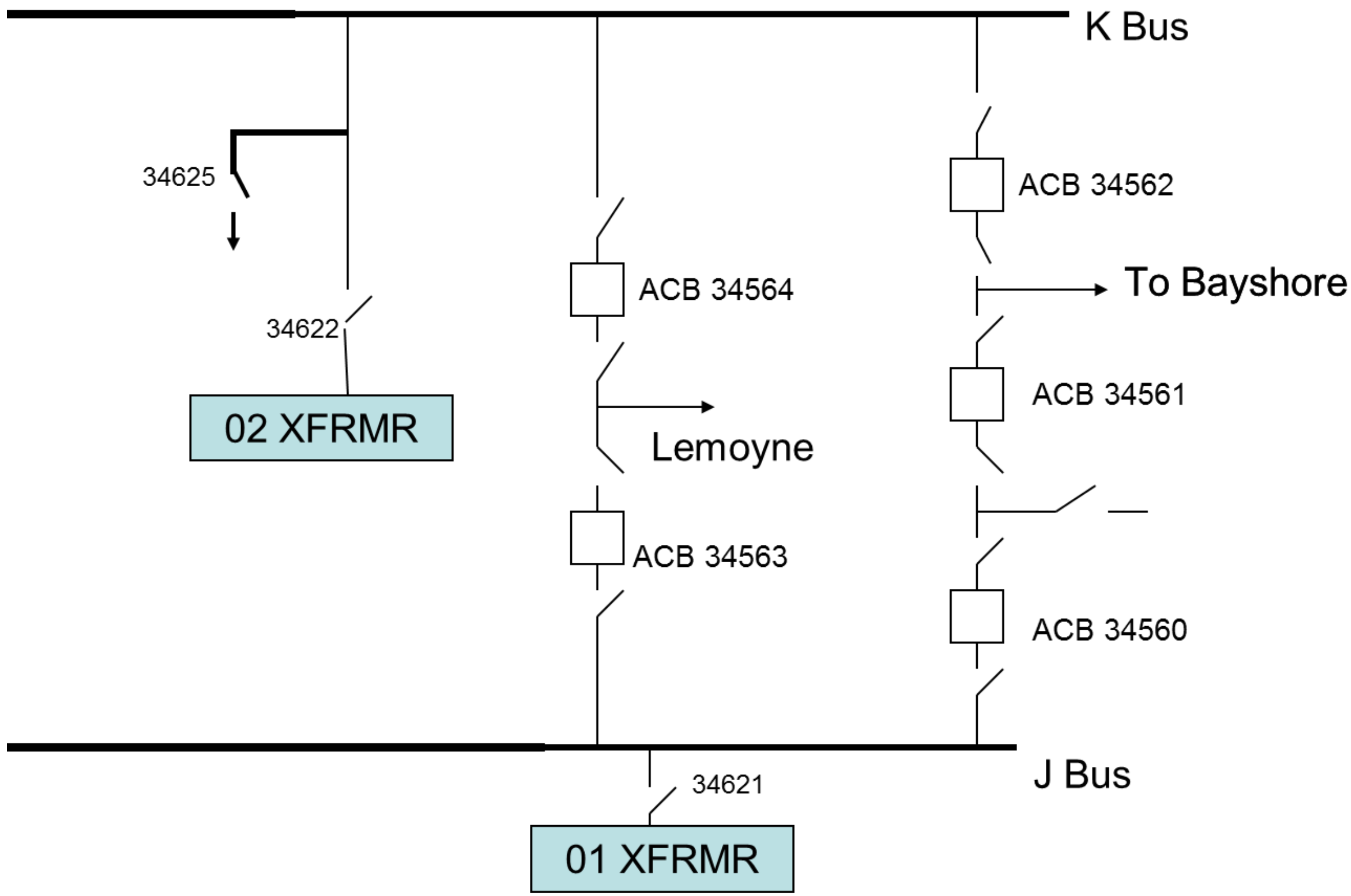
Zoomed in Dimensioned Image of Defect in Section 24-B2



Switchyard Breaker Arrangement (current)

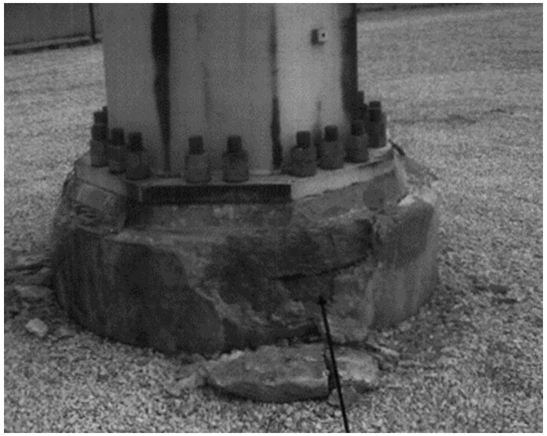


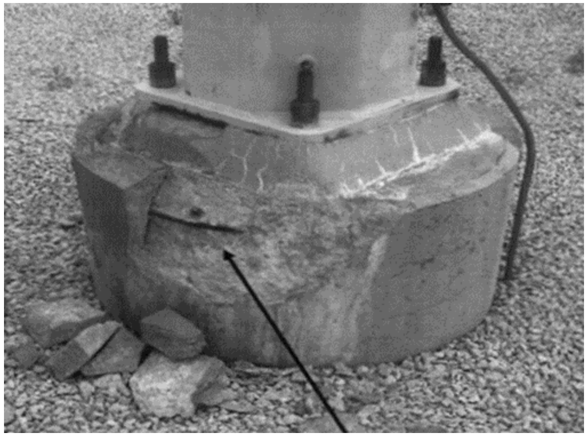
Switchyard Breaker Arrangement (original)



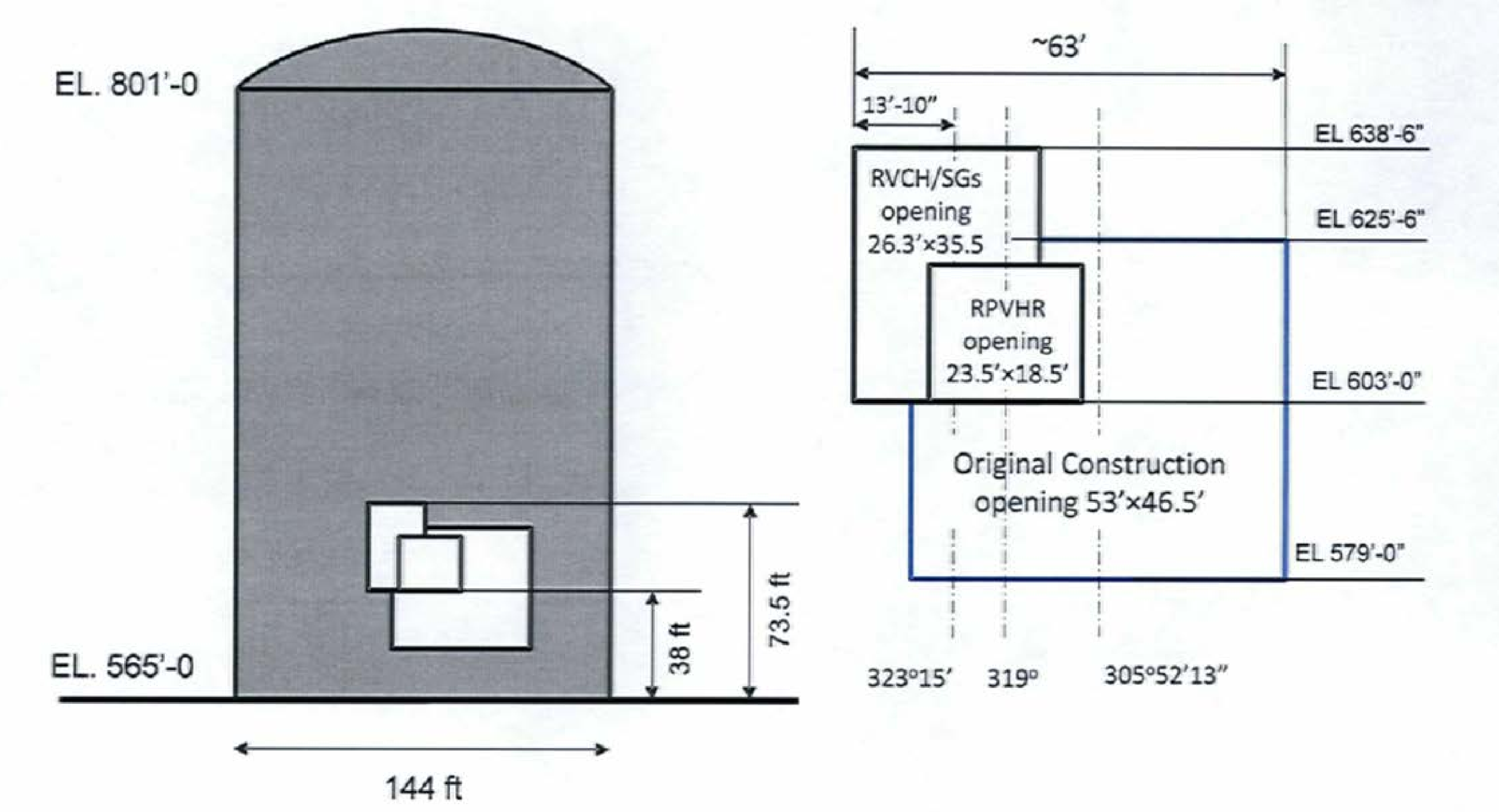
Switchyard Foundations

- **Degradation noted in the form of concrete cracking and spalling**
- **FENOC Order 200652044 written for rework of foundations**
- **FENOC walkdown completed 9/1/15**
- **Order start date 9/14/15**





Access Openings in the Shield Building

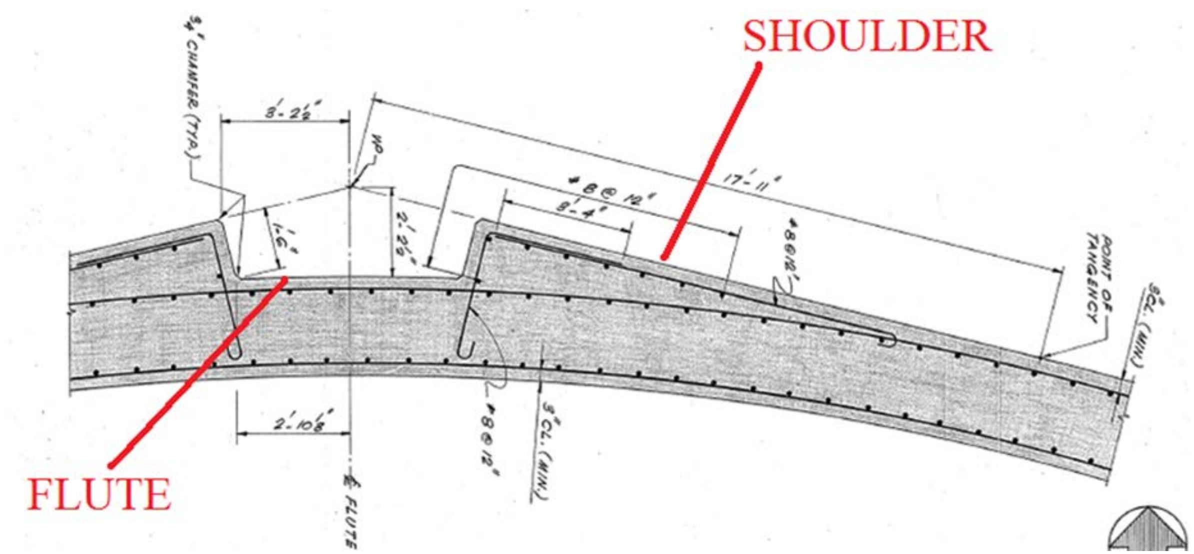


Shield Building Analysis and Margin

- **Evaluation of Shield Building with Observed Cracking**
  - Provided reasonable assurance the Shield Building will perform design functions
  - Considered reinforcement ineffective in regions of laminar cracking
  - Calculations were reviewed by the NRC prior to restart

Shield Building Analysis and Margin

- **Seismic II/I Evaluation of Flute Shoulder**
  - Demonstrates that with crack in shoulder area, rebar capacity will prevent concrete from falling
  - Factor of Safety of 4.4



Spalling outside the Shoulder Areas

- **Spalling of large sections**
  - 11 of 13 core bore indicate the crack is within or behind the horizontal or vertical rebar
  - Concrete is firmly attached to the reinforcing steel
  - Reinforcing steel mat capacity is sufficient to restrain large sections of concrete from falling
- **Localized spalling**
  - Safety related structures are design for a tornado missile impact
  - Equivalent impact energy would equal a 6 ft. X 6 ft. X 3 inch section of concrete
  - Tornado missile would bound any localized spalled area

Root Cause Overview

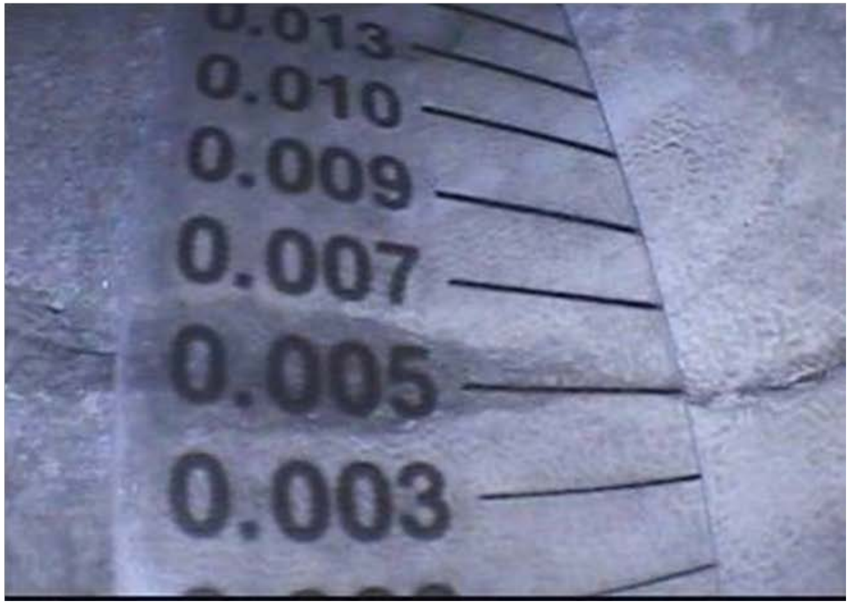
- **Performance Improvement (PII)**
  - Established independent team of experts
  - Established a comprehensive Failure Modes Analysis
  - Investigated the design, materials, construction methods, and present day operational conditions
  - Performed concrete tests
  - Performed analyses
  - Identified root cause

Investigation

- **Impulse Response (IR) testing methodology used to investigate extent of crack**

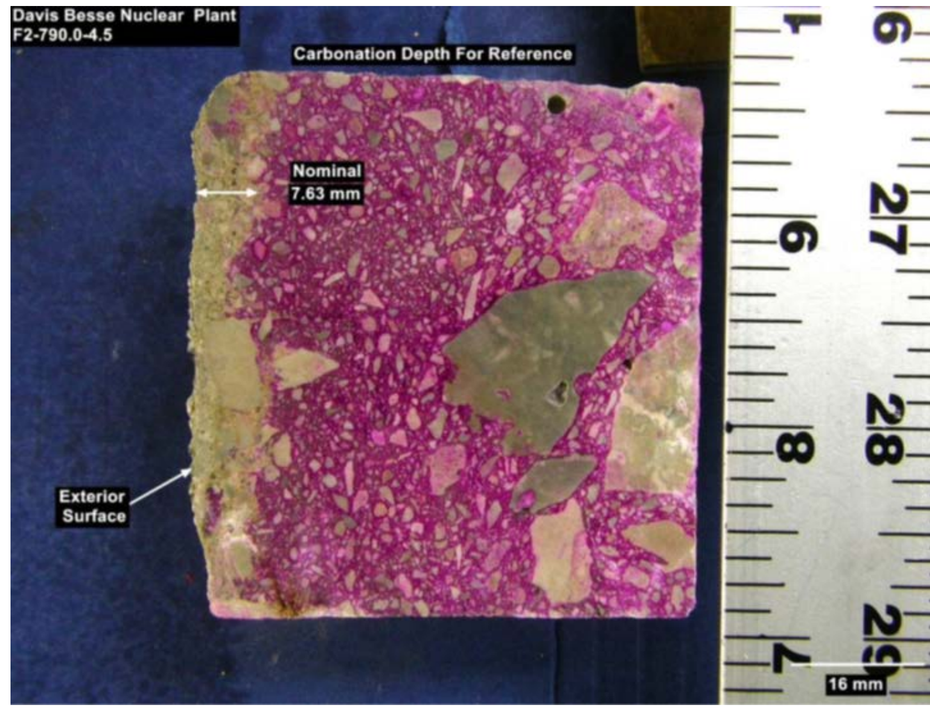
Investigation (cont.)

- **Core bores validated IR testing results to determine crack depth and to determine crack width**
- **Cracks are very tight**



Shield Building Concrete Tests

- **16 samples were tested for carbonation**
  - Average depth of carbonation is 8.57 mm (0.337 inches)
  - Maximum average 11.7 mm (0.46 inches)
  - Typical for concrete 40 years old



Shield Building Root Cause

- **Performance Improvement International (PII)**
  - 36 concrete cores tested - Concrete is sound
  - Normal building stress are very low
  - Correlation between crack location and the physical layout of the reinforcing steel
  - Ontario Ministry of the environment Study address similar condition on their above ground water tanks in Ontario
  - Extreme environment event has the condition to create stresses beyond normal design
  - Validated by complete computer modeling

Moisture Intrusion and Low Temperatures

- **January 25-27, 1978, was the worst in terms of:**
  - Moisture
  - Winds
  - Temperature
  - Duration
  - Pressure

Shield Building Root Cause

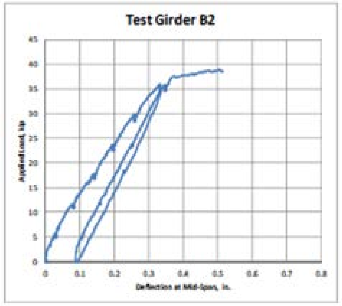
- **Blizzard of 1978 had the conditions to create cracking**
  - High winds and driving rain for three days
  - Sudden drop in temperatures to near zero degrees
- **Root Cause:**
  - Lack of water sealant on the concrete exterior
- **Contributing Causes:**
  - Shoulder reinforcing details (discontinuity and no radial rebar)
  - High density of rebar spacing
  - High moisture, severe wind, and low temperature conditions

Rebar Splice Capacity Tests

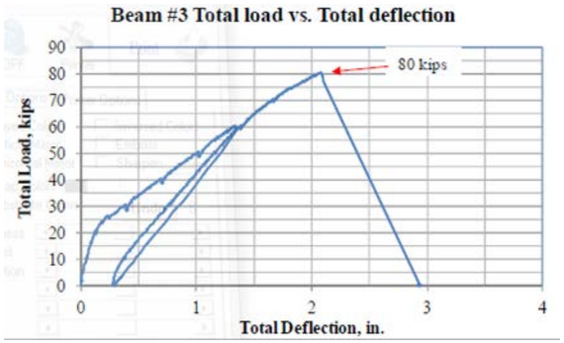
- **Tests were developed and conducted at two nationally recognized universities**
- **Professors are industry experts and are American Concrete Institute (ACI) Committee members**

Rebar Splice Capacity Tests

- **Conservative Test set Up**
  - Two different test methods
  - Lap splices side by side, spaced 6 inches apart
- **Purdue Tests Results**
  - All bars achieved yield



- **Kansas Tests Results**
  - Achieved near design capacity



Rebar Splice Capacity Tests

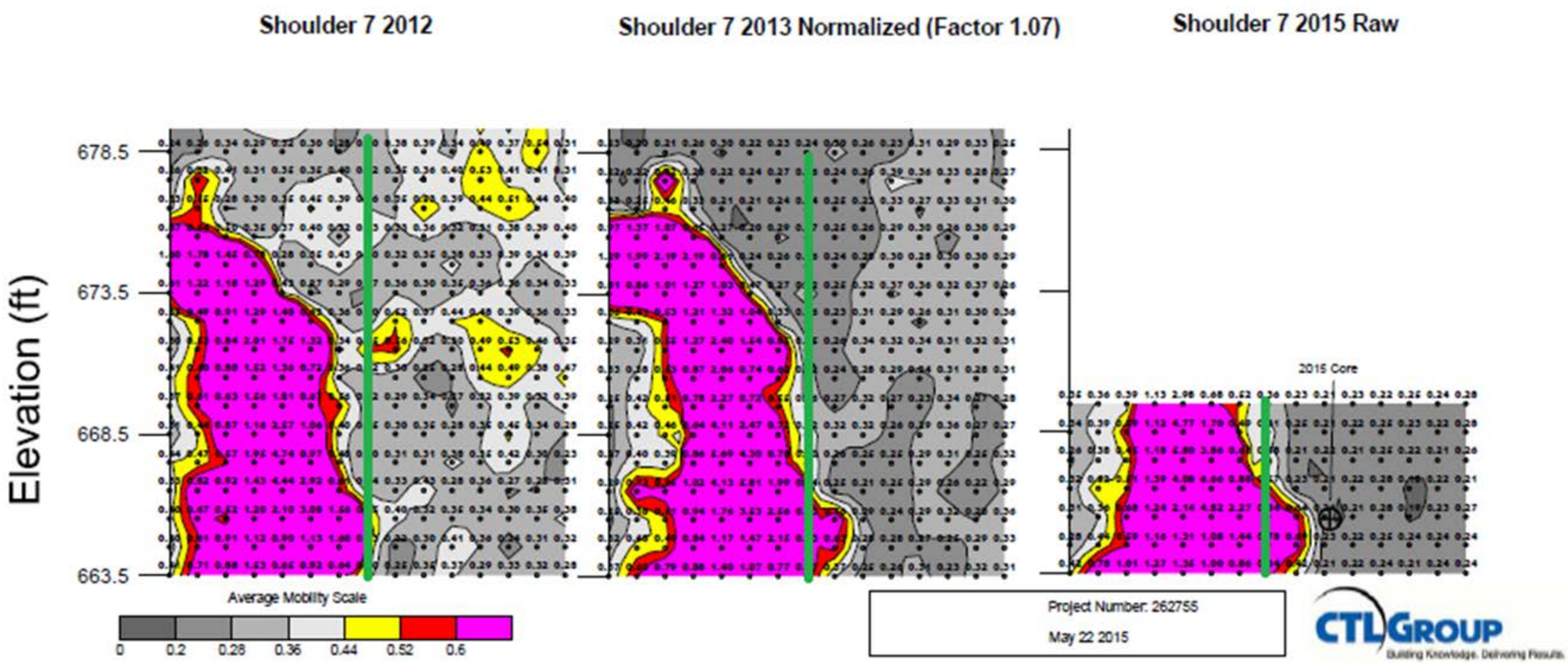
- **Based on the Test Results and conservative nature of the test**
- **Design capacity can be used for the Shield Building analysis**
- **Prudent to reduce reinforcing steel capacity by 8%**
- **Applied this reduction factor to the structural calculation**

Shield Building Calculations

- **Shield Building Design Calculation**
  - Design Calculation for Shield Building for existing condition
  - Analysis performed with a three dimensional finite element analysis using ANSYS
  - Capacity of Lap Splices based on test results included
  - Seismic loads from original design used based on evaluation of no adverse effects of laminar cracks on seismic analysis results
  - Results showed Interaction of 0.76 for rebar and 0.81 for concrete

Long Term Monitoring

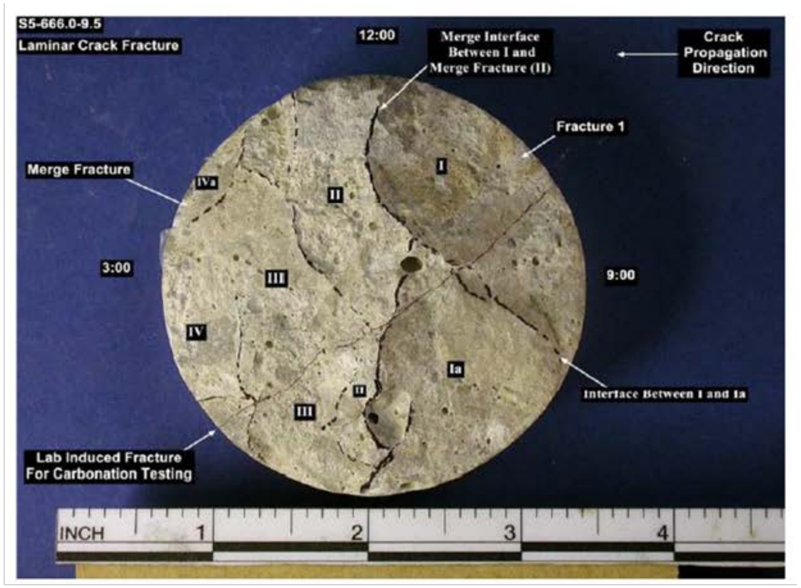
- **Monitoring in 2013 identified changes in eight of eighty core bores inspected**
- **IR also confirmed changes in condition**



Crack Propagation Cause Investigation

- **Core bore extracted from an area of crack propagation**
- **Cracked surface is different from all the previous samples.**
  - Noticeable ridges – stepped fracture planes

Original crack surface (2011)



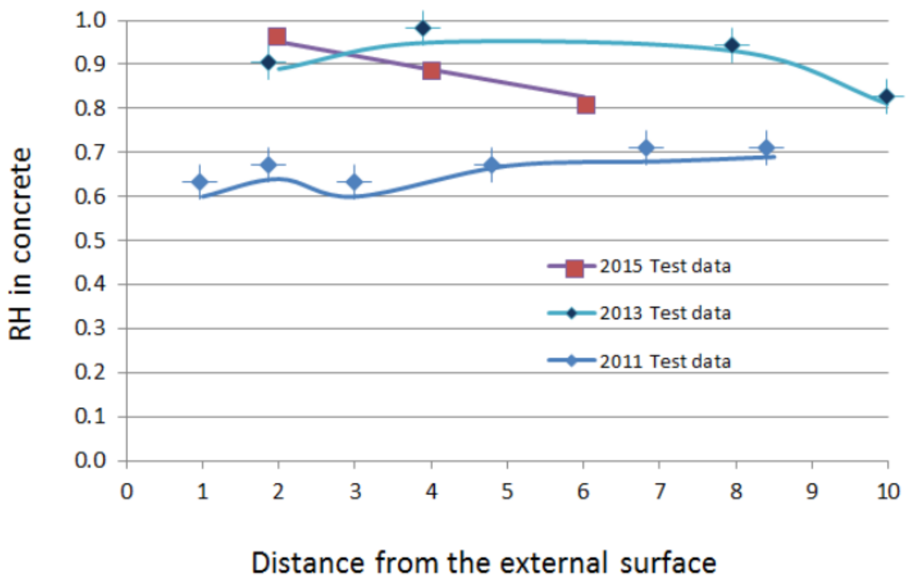
Crack propagation surface 2013

Crack Propagation Cause Investigation

- **Cause determined to be Ice-Wedging**
- **Ice-Wedging requires three conditions**
  1. Pre-existing crack
     – 2011 identified condition
  2. Freezing Temperatures
     – In-situ bore measurements determine that freezing temperatures have occurred.
     – Freeze damage evident in extracted samples
  3. Water accumulation at the crack location
     – Increase in relative humidity of the conc

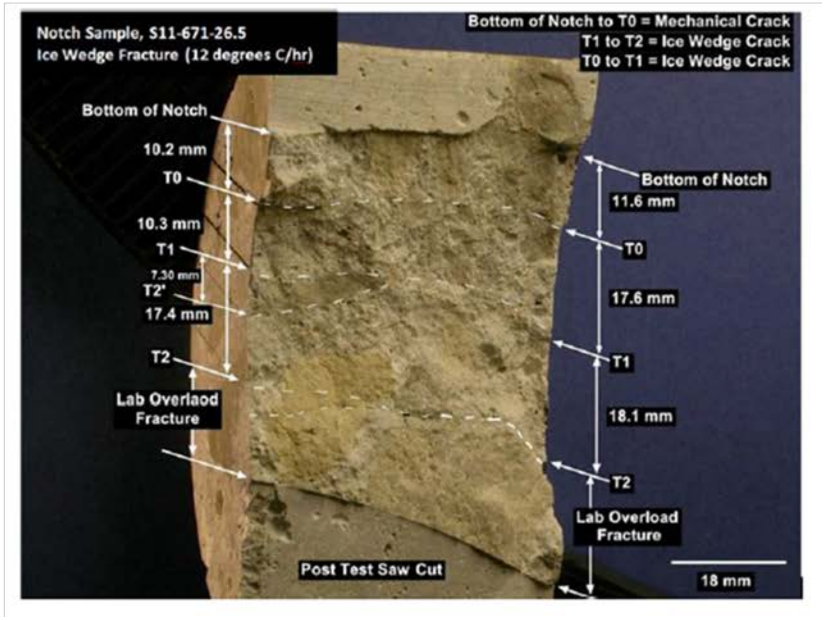
Crack Propagation Cause Investigation

- **Relative Humidity accumulation increase in the near surface and crack locations between samples collected in 2011, and 2015**
- **Building was coated in summer of 2012**



Crack Propagation Cause Investigation

- **Ice-Wedging – Laboratory Simulation**
  - Used existing core from the Shield Building
  - Replicates failure surface & crack growth
  - Identifies crack growth at approximately ½ inch / freeze cycle

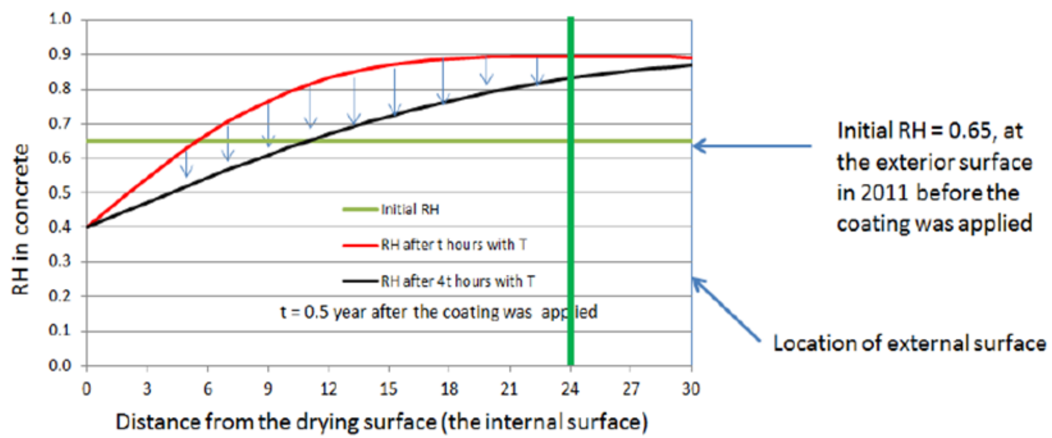


Relative Humidity of the Shield Building

- **Core bore samples tested for relative humidity in 2011, 2013 and 2015**
- **Relative Humidity (RH) near external surface is high**
- **RH gradient drives moisture toward the inner surface**
  - If internal surface of a test sample is exposed to dry environment the drying out process can take place quickly
- **Higher inner surface (annulus) temperature drives moisture toward coating of the building**
  - Moisture can not freely evaporate at external surface
  - Moisture accumulates under the coating

Shield Building Moisture Evaluation

- **Method**
  - Determined moisture diffusivity of concrete using samples from Shield Building
  - Determined temperature distribution in the wall using plant and meteorological data
  - Evaluated concrete RH considering temperature and moisture diffusivity
- **Results**



Driving Forces for Moisture Transfer in Concrete

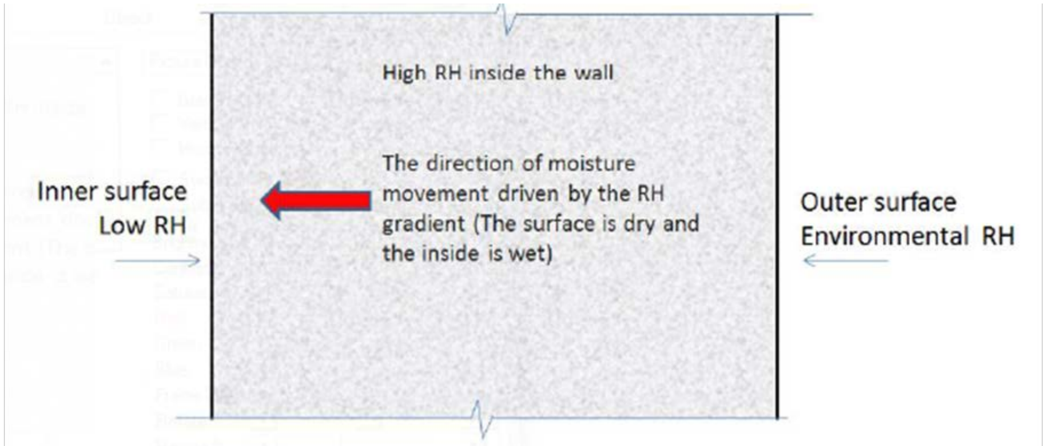


Figure 1- Moisture movement considering RH gradient as the driving force for moisture transfer in the concrete wall. T = Constant

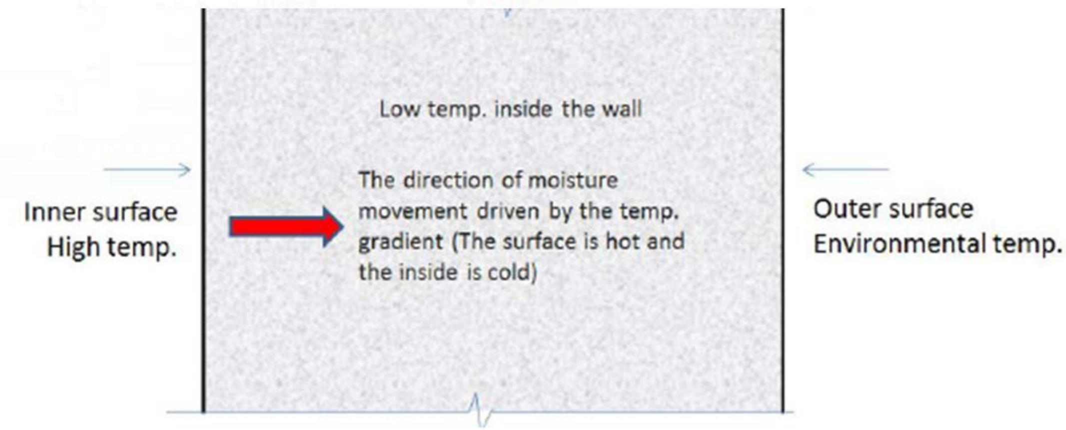
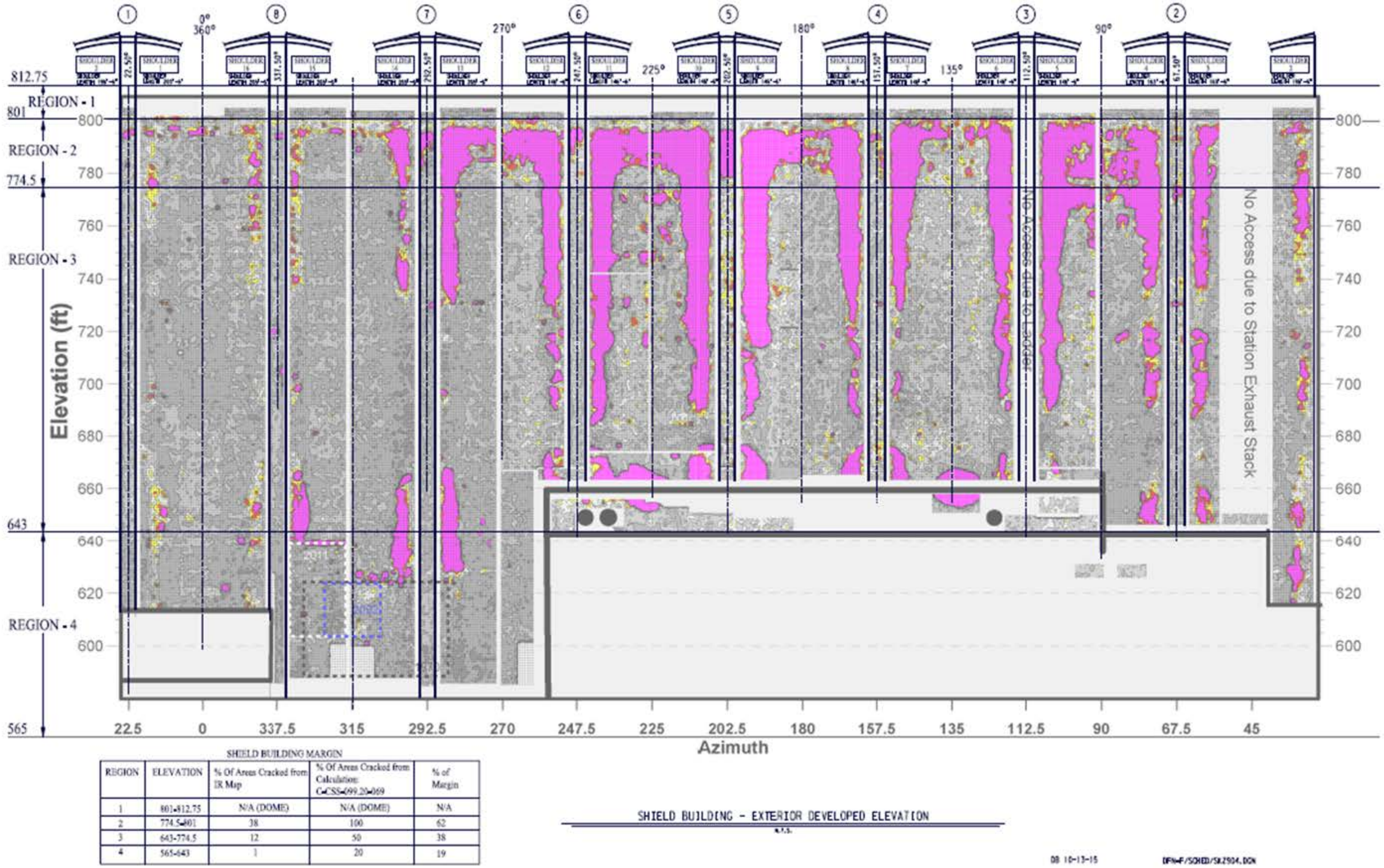


Figure 2- Moisture movement considering the temperature gradient as the driving force in the wall. T ≠ Constant

Shield Building Calculations

- **Shield Building Crack Propagation Calculation**
  - Determined an approximate extent of cracking for which the seismic loads from the original design remain valid
  - Additional margin is available, but not quantified at this time

Shield Building Margin

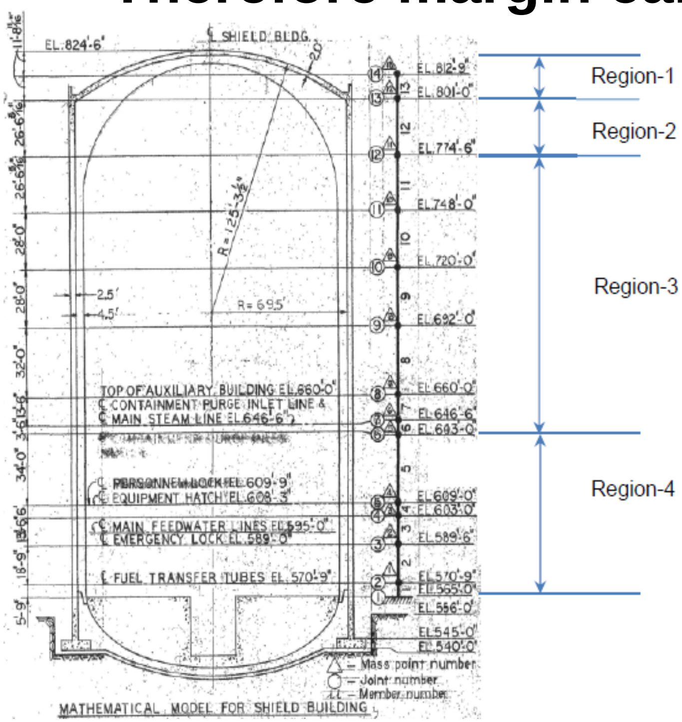


SHIELD BUILDING MARGIN

REGION	ELEVATION	% Of Areas Cracked from IR Map	% Of Areas Cracked from Calculation: C-CSS-099.20-069	% of Margin
1	801-812.75	N/A (DOME)	N/A (DOME)	N/A
2	774.5-801	38	100	62
3	643-774.5	12	50	38
4	565-643	1	20	19

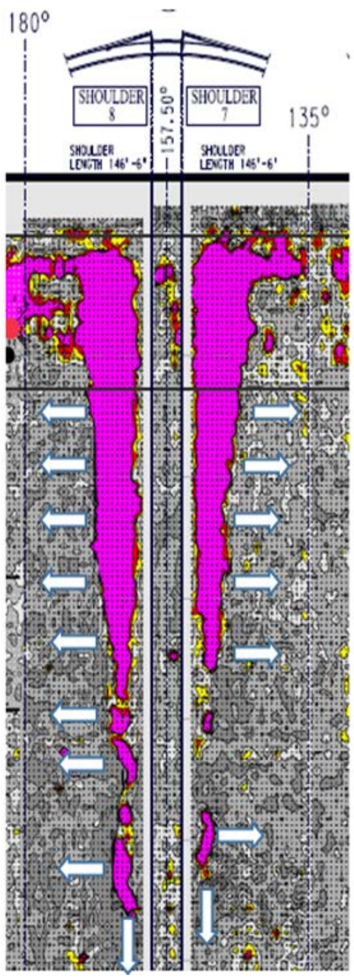
Shield Building Margin

- **Region 2 analyzed for 100% of the area as cracked**
- **Region 3 analyzed for 50% of the area cracked (actual cracked area from IR map approximately 12%)**
- **Therefore margin can be established as 50% - 12% = 38%**



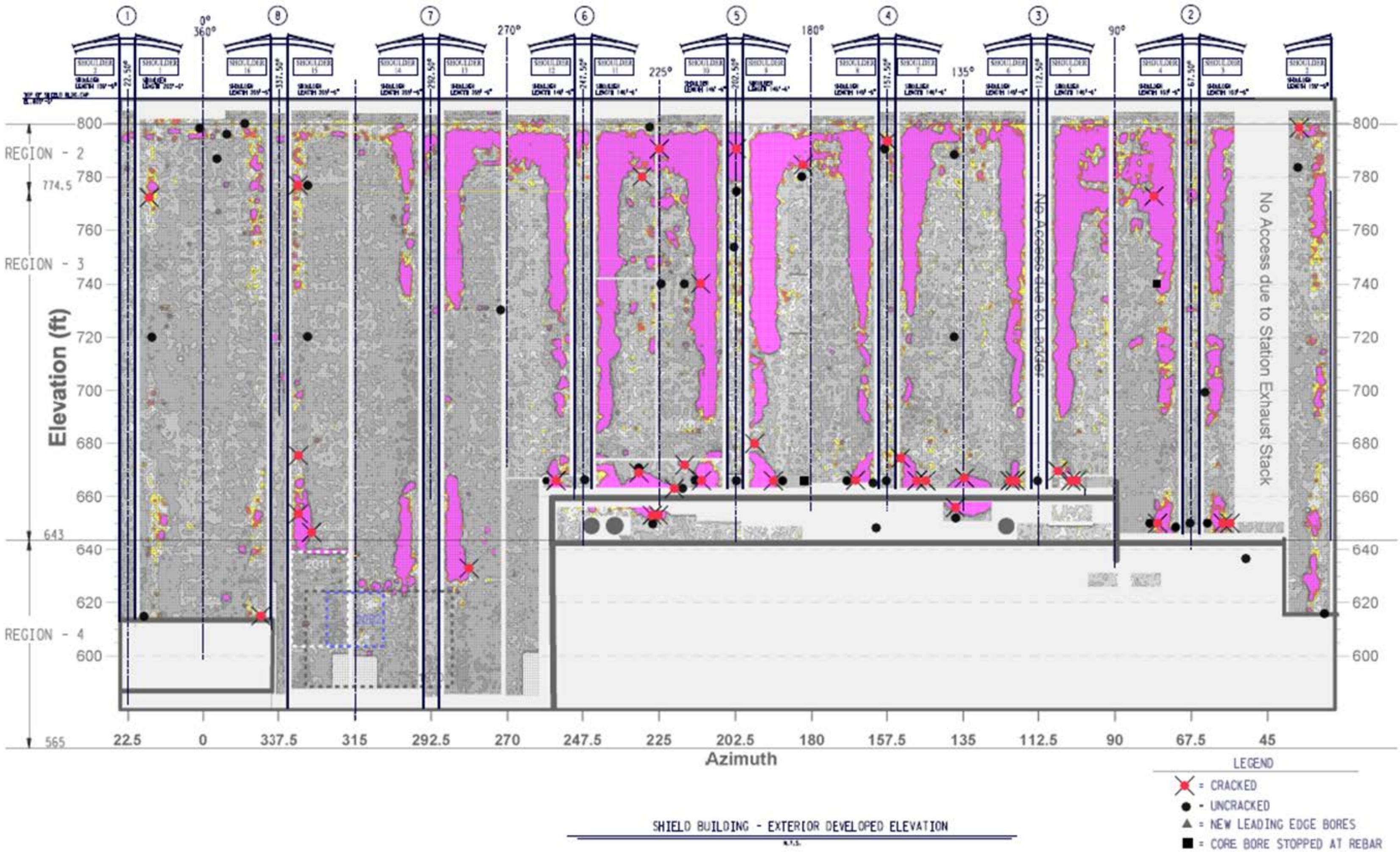
Region	Elevation	% of areas cracked from IR Map	% of areas cracked from calculation C-CSS-099.20-069	% of Margin
1	801-812.75	N/A (Dome)	N/A (Dome)	N/A
2	774.5-801	38	100	62
3	643-774.5	12	50	38
4	565 - 643	1	20	19

Shield Building Margin

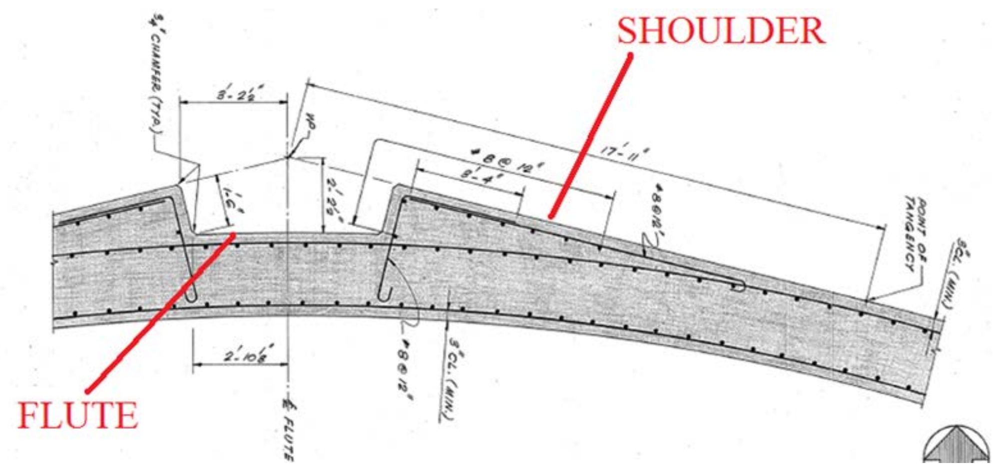


- **Margin can be established as follows:**
  - Region 3 = Consist of 59,438 ft^2
  - 38% margin equates to 22,586 ft^2
  - Region 3 has approximately 1300 linear ft. where cracks can propagate
  - Crack propagation rate is approximately 0.75 ft. per year
  - One year crack growth equals to:
1300 linear ft. x 0.75 ft. = 975 ft^2 per year
  - Margin = 22,586 ft^2 / 975 ft^2 per year
  - Margin = approximately 23 years
- **Conservative number because:**
  - Not all areas are cracking
  - Concrete is expected to dry out in 2-8 years

80 Core Bores Locations



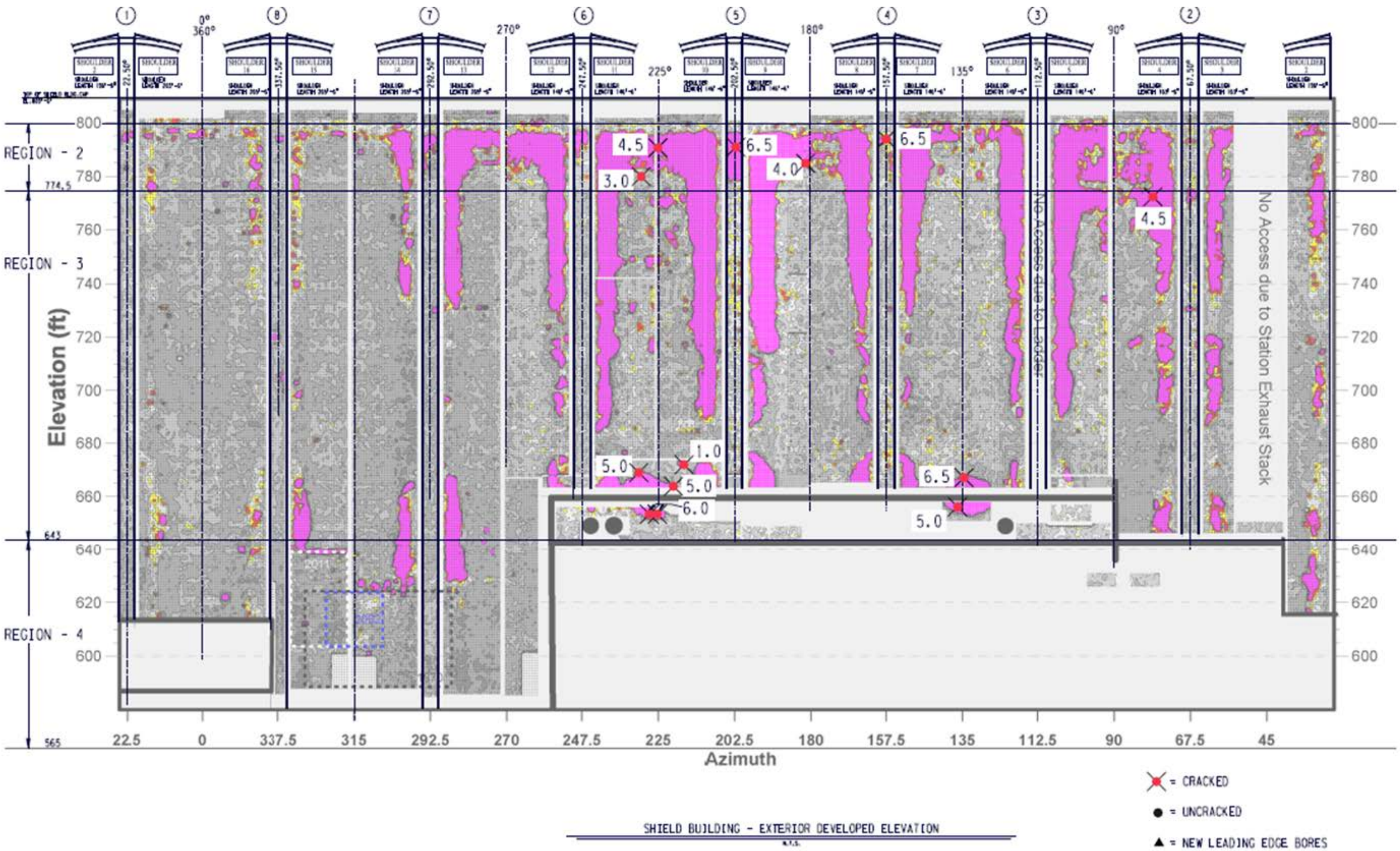
Shoulder Area Reinforcing Details



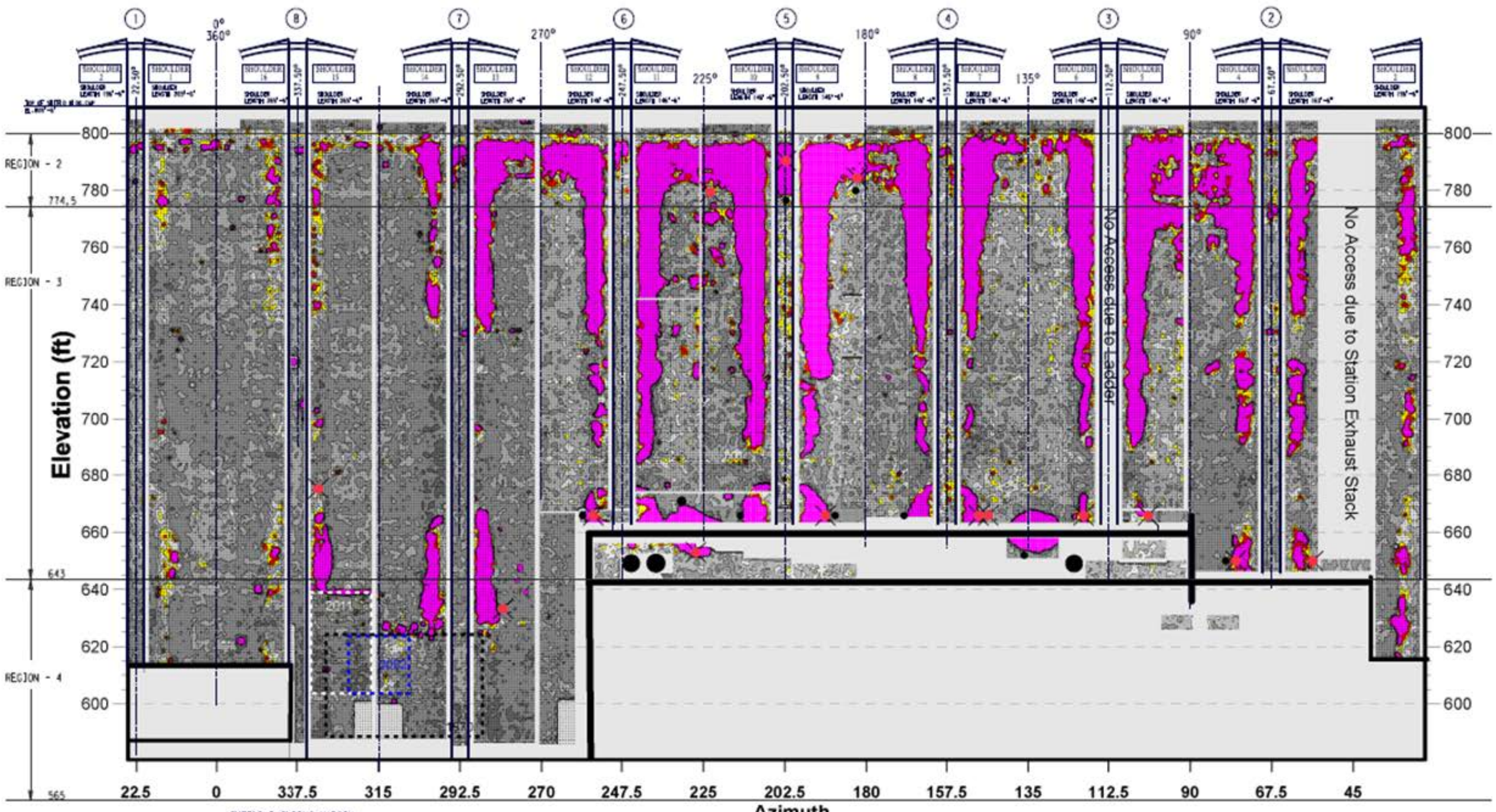
- Shoulder areas were evaluated for design loads
- Shoulders consist of #8 rebar (area = 0.79 in^2) spaced 12” vertically
- Required area of reinforcing steel = 0.089 in^2 << 0.79 in^2 (Area provided)

- Margin of Safety is 4.5

Crack Depth in the Shield Building Barrel



Shield Building by Regions

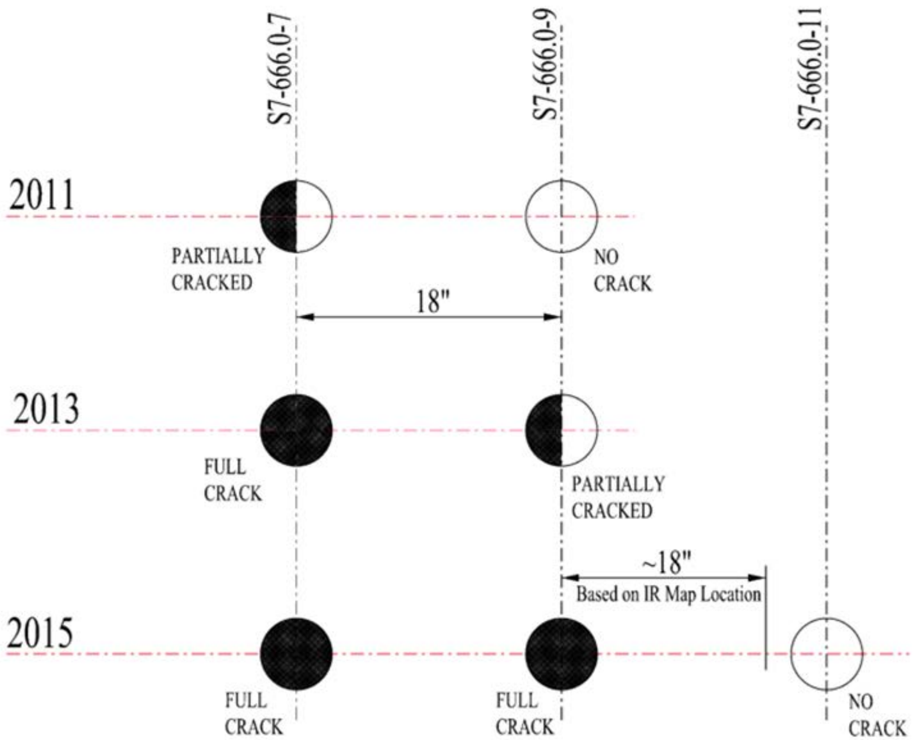


SHIELD BUILDING MARGIN

REGION	EXISTING PLANER LIMIT % CRACKED	PLANER LIMIT % ANALYZED	EXISTING CRACK LENGTH	ANALYZED CRACK LENGTH	CRACK GROWTH MARGIN
1	0	0	0 FT.	0 FT.	0 FT.
2	70	100	316 FT.	452 FT.	136 FT.
3	20	50	90 FT.	226 FT.	136 FT.
4	0	20	0 FT.	90 FT.	90 FT.

SHIELD BUILDING - EXTERIOR DEVELOPED ELEVATION
WITH TABLE 1 - REQUIRED BORE INSPECTION LOCATIONS PAGE 35 EN-DP-01511

Crack Growth Rate



- **2011-2013 Crack Growth**

  1.5 ft/ 2 years = 0.75 ft./yr.

- **2013-2015 Crack Growth**

  1.5 ft/ 2 years = 0.75 ft./yr.

Structural Margin

- **The controlling load combinations using the Allowable Working Stress are:**
  - Circumferential reinforcement – outside face: 0.76
  - Meridional reinforcement – outside face: 0.75
  - Circumferential reinforcement – inside face: 0.83
  - Meridian reinforcement – inside face: 0.88
  - Concrete: 0.81 of design allowable

License Amendment Request

- **ACI Code provides no guidance on laminar cracking**
- **ACI Code does provide guidance on evaluating conditions not addressed in the Code**
  - Rigorous analysis, sound engineering principles, and specific testing as examples
- **Design Calculation documents Shield Building will perform its design function**
- **NRC Inspection 2014-008-01 resulted in 10CFR50 violation**
  - Change in methodology using ANSYS software
- **To Resolve the NRC violation**
  - Licensee is revising 50.59 Evaluation and will submit LAR after its spring outage (mid 2016)

Root Cause – Exhibit 61 – Page 12

Exhibit 61

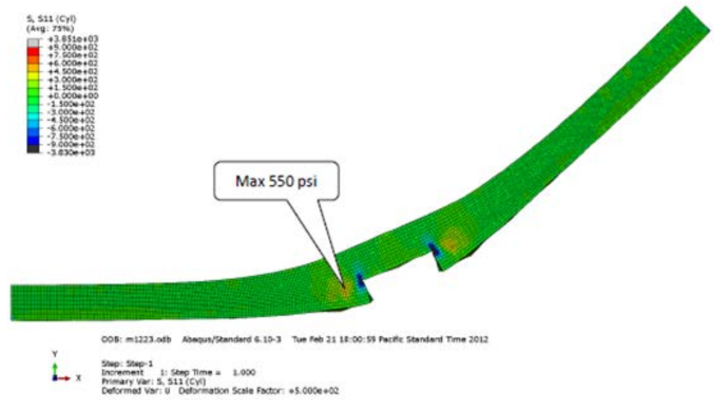


Figure 9 – Radial Stress (psi) during the Blizzard of 1978; Deformation Scale Factor 500X

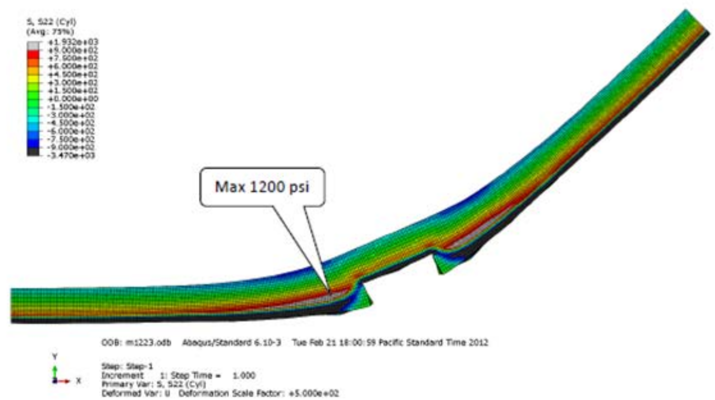


Figure 10 – Hoop Stress (psi) during the Blizzard of 1978; Deformation Scale Factor 500X

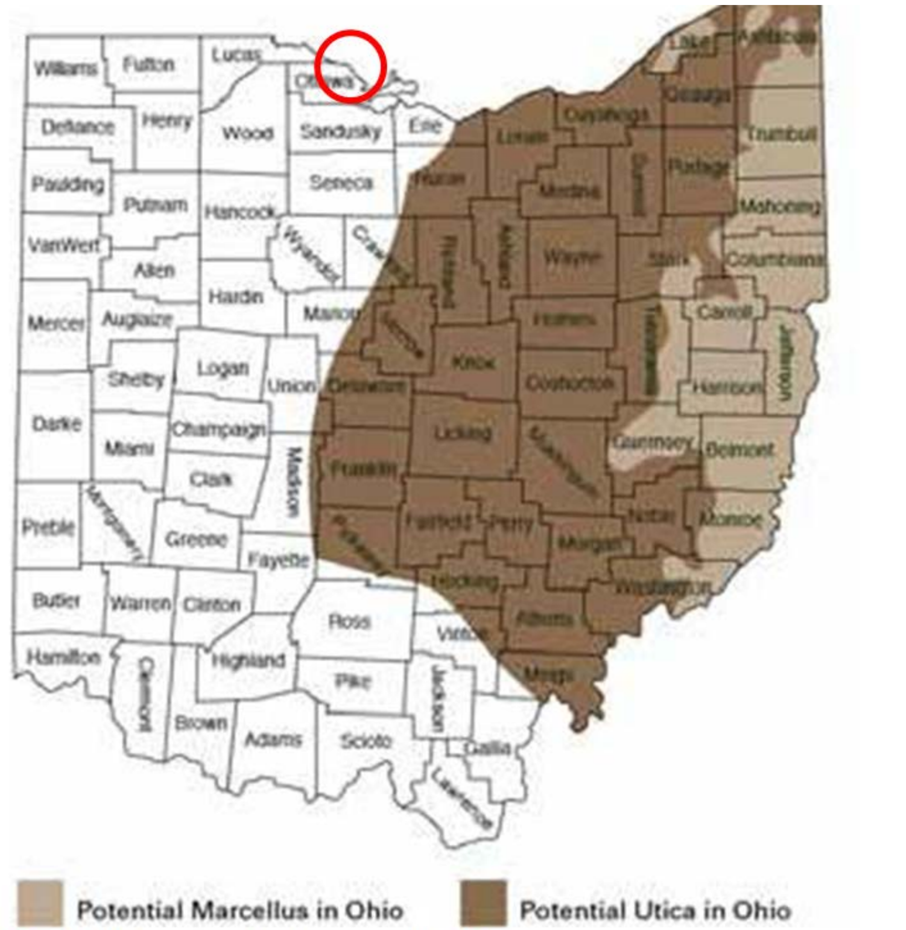
- **550 psi is the maximum radial stress**
  - **No radial rebar to resist the load**
  - **ACI Modulus of Rapture is 7.5√ fc' or 7.5√ 5000 psi = 535 psi**
- **1200 psi is the maximum hoop stress**
  - **Hoop reinforcing bars**
    #11 bars (1.4 sq in) every 12 inches

Shield Building Monitoring Program

- Exterior Coating
  - Shield Building Wall, Dome, and Emergency Air Lock Enclosure walls inspected visually
  - Acceptance criteria is ability of coating to continue to be effective
  - Five year inspection interval
  - Recoat the exterior surfaces in 15 years
- Rebar
  - Visually inspect when exposed
  - Acceptance criteria is no loose flaky rust or reinforcement section loss

Fracking-induced Earthquakes in Ohio

- **Most horizontal fracking is near the Pennsylvania and West Virginia state lines in the Marcellus shale region**
- **Davis-Besse is over 125 miles from the Marcellus shale region**
- **Northwest Ohio does not have a shale formation conducive to horizontal fracking**
- **Fracking-induced earthquakes are not a concern at Davis-Besse**



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OhioShaleMap.jpg (305 × 337 pixels, file size: 21 KB,

Annulus Water Analysis

- **Water samples from annulus in sand pocket area**
- **2005-2014 Groundwater Chemical Analysis Average**
  - pH 10.32
  - Sulfate 1881.7 (mg/L) > 1700 max
  - Chloride 1665.3 (mg/L) < 2870 max