Official Transcript of Proceedings

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee

Docket Number: (n/a)

Location: Rockville, Maryland

Date: Wednesday, February 17, 2016

Work Order No.: NRC-2182 Pages 1-364

NEAL R. GROSS AND CO., INC.
Court Reporters and Transcribers
1323 Rhode Island Avenue, N.W.
Washington, D.C. 20005
(202) 234-4433

DISCLAIMER

UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, as reported herein, is a record of the discussions recorded at the meeting.

This transcript has not been reviewed, corrected, and edited, and it may contain inaccuracies.

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

+ + + + +

PLANT LICENSE RENEWAL SUBCOMMITTEE

+ + + + +

WEDNESDAY

FEBRUARY 17, 2016

+ + + + +

ROCKVILLE, MARYLAND

+ + + + +

The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B1, 11545 Rockville Pike, at 8:30 a.m., Gordon Skillman, Chairman, presiding.

COMMITTEE MEMBERS:

GORDON R. SKILLMAN, Chairman

DENNIS C. BLEY, Member

RONALD G. BALLINGER, Member

CHARLES H. BROWN, JR., Member

HAROLD B. RAY, Member

PETER RICCARDELLA, Member

JOHN W. STETKAR, Member

ACRS CONSULTANT:

WILLIAM SHACK

DESIGNATED FEDERAL OFFICIAL:

KENT HOWARD

ALSO PRESENT:

ARACELI BILLOCH-COLON, NRR

STEVEN BLOOM, NRR

BENNETT BRADY, NRR

BUTCH BURTON, NRR

CLIFF DOUTT, NRR

CAROLYN FAIRBANKS, NRR

MIKE GALLAGHER, Exelon

JAMES GAVULA, NRR (via telephone)

JERUD HANSEN, NEI

MATT HARDGROVE, NRR

BILL HOLSTON, NRR (via telephone)

HEATHER JONES, NRR

ROGER KALIKIAN, NRR

JANE MARSHALL, NRR

JAMES MEDOFF, NRR

SEUNG MIN, NRR

JOSE PIRES, RES

PAT PURTSCHER, NRR

MOHAMMAD SADOLLAH, NRR

TABLE OF CONTENTS

P R O C E E D I N G S

8:30 a.m.

CHAIR SKILLMAN: Good morning. This meeting will now come to order. Welcome to all of you. Mics are on? Both mics are on. Better? Okay.

Welcome to all of you. We've been looking forward to this meeting for a good long time.

This is a meeting of the Plant License Renewal Subcommittee. I'm Gordon Skillman and I'm chairman of this subcommittee.

ACRS members in attendance are: Dr. Dennis Bley, the current ACRS chairman; Mr. Harold Ray, a prior ACRS chairman; Peter Riccardella, a current member-at-large; John Stetkar, prior ACRS chairman; Dr. Ron Ballinger; and our consultant, prior ACRS chairman, Dr. William Shack. Welcome to each of you.

Mr. Kent Howard of the ACRS staff is the Designated Federal Official for this meeting.

Today, we will hear presentations from the NRC staff on the draft guidance documents for Subsequent License Renewal, that is, life beyond 60. We have not received prior written comments or requests for time to make oral statements from members of the public regarding today's meeting.

The entire meeting will be open to public attendance.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full committee.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the Federal Register. A transcript of this meeting is being kept and will be made available as stated in the Federal Register notice. Therefore, I request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee.

The participants are requested to please identify themselves and speak with sufficient volume and clarity so that they can be readily heard. I ask that you please silence your personal electronic devices.

As we begin, I would like to offer several thoughts to ensure that they are part of the record and that they are not missed as we go through this very busy agenda.

My colleagues and I have reviewed nearly 2,000 pages of background material for today's meeting. It appears that the SRM of August 29, 2014 in the Commissioners' direction identified four main technical issues. These issues are reactor pressure vessel neutron embrittlement; irradiation-assisted stress corrosion cracking on the internals and primary components; concrete; and containment degradation and electrical cable and condition assessment. And these items are very clearly identified throughout the SLR documentation.

Further, the AMPs and the TLAAs for which there is SLR demand, are thoroughly enumerated and we will hear about these in the coming presentations.

In this meeting, we would like to hear about several other items that the entire ACRS identified in our May 22, 2014 letter. These are design basis validation where treated in the SLR documents or if not treated in the SLR documents, where those are enumerated, and finally, treatment of risk. Where is treatment of risk identified throughout the SLR documentation?

There are two additional areas we would like to hear about. Why is there a separate set of documents for SLR? This is an administrative item. And related to that, how will the SLR documents neither conflict with nor detract from the non-SLR documents that are currently in use? In other words, there are two sets of documents. How do we make sure that they don't contradict or conflict with each other?

I would ask my colleagues if they have any items such as these that they wish to provide for the record to do so now, or as we proceed into the early part of the meeting, to please identify those.

With that, I would like to call upon Jane Marshall to begin the presentation. Thank you.

MS. MARSHALL: Thank you, Chairman Skillman. Good morning. I'm Jane Marshall and I'm the Deputy Director for the Division of License Renewal in the Office of Nuclear Reactor Regulation. My staff and I appreciate the opportunity to come before you today and discuss the Generic Aging Lessons Learned, or GALL, report and Standard Review Plan, or SRP.

The version of these documents that we'll be discussing today are designed to support the preparation and review of applications requesting renewal of nuclear plant operating licenses for operation beyond 60 years. This time frame is generally referred to as subsequent license renewal or SLR.

As an abbreviated background, early in 2014, the staff submitted to the Commission SECY paper 14-0016 entitled Ongoing Staff Activities to Assess Regulatory Considerations for Power Reactors' Subsequent License Renewal which discussed several suggested staff revisions to 10 CFR Part 54, the license renewal rule.

Members of the Department of Energy, or DOE; the Electric Power Research Institute, EPRI; and the Nuclear Energy Institute, NEI; and the NRC staff, met with this subcommittee on April 8, 2014 and with the ACRS full committee on May 8, 2014, to discuss the SECY paper and to share information on current research in certain technical areas. Following these meetings, the ACRS issued a letter to the Commission on May 22, 2014, affirming that the license renewal rule, as currently structured, is the appropriate option for subsequent license renewal, that it maintains a well-understood process for life extension, and that it preserves the regulatory lessons learned.

The ACRS letter also stated that the GALL report, NUREG-1801, once updated to reflect the latest operating experience and lessons learned, as well as evolving research, is the appropriate supporting guidance for SLR.

On August 29, 2014, the Commission issued its SRM regarding SECY 14-0016. Among other things, the SRM directed the staff to keep the Commission informed on the progress in resolving several issues related to SLR: the reactor pressure vessel neutron embrittlement at high fluence, irradiation assisted stress corrosion cracking of reactor internals, concrete and containment degradation, and electrical cable qualification and condition assessment.

In August of last year, the staff sent a Commissioner's Assistant Note to update the Commission on staff activities associated with these technical issues. On November 17 of last year, the NRC staff from the Offices of Nuclear Reactor Regulation and Nuclear Regulatory Research, as well as representatives from DOE, EPRI, and NEI, met with this subcommittee to discuss current and future research activities in the technical areas I just described, as well as in the area of neutron fluence. During that meeting, we stated that we would return in February to discuss the most significant changes to the GALL and SRP to support SLR.

Well, here we are, as promised, and luckily this is scheduled between the snow storms.

Today, we'll share with you the more significant changes to the GALL and the SRP that the staff is making to support the preparation and review of the SLR applications. During our presentations, we'll provide specific information on how the staff will address issues through subsequent license renewal, including those technical issues for which research findings might not yet be available when SLR applications are under review. This would include submittal of plant-specific evaluations and programs or further evaluations to address the issues to ensure adequate aging management of structures and components within the scope of the license renewal rule.

Our hope is that at the conclusion of this meeting, the subcommittee will have an understanding of why the staff developed the GALL and SRP to support SLR, the proposed differences to the GALL and the SRP to support SLR from Revision 2, the basis for the proposed differences, and the plan and the time table for the next actions related to this project.

Unless you have questions for me at this point, I'd like to turn it over to Jerud Hansen with NEI to make his opening remarks.

CHAIR SKILLMAN: Thank you, Jane. Jerry?

MR. HANSEN: Thank you, Jane. Again, this is Jerud Hansen with NEI. On behalf of NEI, the industry, we appreciate the efforts of the NRC staff in maintaining an open dialogue regarding changes to the GALL SLR. The continued scheduling of public meetings remains critical in maintaining this open communication which will ultimately lead to an even higher quality final document.

The industry review team has been working diligently to provide quality feedback to the staff by the comment due date of February 29th, as well as during these scheduled public meetings.

During the review, the team has identified a number of comments that will be provided to the staff for consideration.

Also, we've engaged with the staff during the public meetings over the past two months and have provided our more significant concerns. We believe the additional dialogue interaction during these meetings was necessary to communicate the industry perspectives due to their significance and potential implications for future applicants. We will continue to work with the staff on addressing these various items.

There are several areas within the GALL where we feel the increased scope of inspection or the frequency of inspection was changed, without supporting OE or technical information. This is a particular concern to the industry with our focus on delivering the nuclear promise. We should be doing what makes sense based on OE or research and reduce activities that are not supported by technical data or OE in an overall effort to sustain nuclear energy as a viable option for the country's future energy needs.

Again, the industry is appreciative of the attention and the priority that GALL SLR is receiving and the efforts of the staff to develop a process that will be helpful, but more importantly, assure the continued safe operation of the plants for 20 additional years. Thank you.

CHAIR SKILLMAN: Jerry, before you escape here, how has NEI communicated those areas where you have concern?

MR. HANSEN: So far, we've communicated them in the public meetings. We have an additional public meeting scheduled for this Friday, the 19th where we're going to use that opportunity to communicate these concerns. We'll also be scheduling a follow-up meeting in the April time frame to have a follow-up discussion on any of these issues we've identified. And we're also for certain issues, we are going to request that we continue discussions in public meetings based on those issues specifically.

CHAIR SKILLMAN: Thank you, Jerry.

MEMBER BLEY: I've got another question, Jerry. I don't see that you folks are on the agenda to talk again today, so let me ask you now.

I haven't seen the particular issues you're raising. Can you tell us a little bit about why, as we go from the period of time of which we have operating experience into an extended period of time without experience at those years, you're leaning so heavily on operating experience as the basis for setting test and inspection intervals? I may have read more into your statement than you intended.

MR. HANSEN: That's a good question and to add to the first question, I would also like to add that aside from the meetings, we're also going to provide our concerns in written comment.

MEMBER BLEY: Good.

MR. HANSEN: For the questions of OE specifically, I would like to call on members of our industry to assist in answering that question. So Mike Gallagher, please, with Exelon.

MR. GALLAGHER: This is Mike Gallagher with Exelon. Yes, I can answer that question. In regards to issues that are related to say an extended operation such as that are impacted by fluence and radiation, we would agree with you that there should be differences and there are differences and they're accounted for in things like the TLAAs and say the vessel surveillance programs and things like that.

There's many programs where even in the first round of license renewals, existing programs were sufficient and will continue to be sufficient. They're normal, say, degradation mechanisms, corrosion, that type of thing. Just one example of what we're talking about, say for one of the things that was added in the inspections would be performing UTs of containment shell liner when liner surface is inaccessible from one side on a random and focused basis every ten years. So we have the IWE program which does inspections every ten years of the containment liners. This is asking for additional inspection where you would do random sampling of the containment liner.

And in our opinion, it's really not necessary or driven by the operating experience. And there's no degradation mechanism that would be driving that extensive effort.

We want to put the resources on the right things so we can maximize the safety and reliability of the plants. That's an example.

MEMBER BLEY: And we'll look forward to hearing details of comments later.

MR. GALLAGHER: And our comments will be in writing. Thanks.

CHAIR SKILLMAN: Jerry, thank you. Mike, thanks. Jane, back to you and your team.

MS. MARSHALL: Thanks. At this point, I'd like to turn it over to Steve Bloom for his remarks.

MR. BLOOM: Good morning. My name is Steve Bloom. I'm the branch chief in charge of the Subsequent Renewal Guidance and Operation Branch in the Division of License Renewal in the Office of Nuclear Reactor Regulation.

Today, we will begin with an overview of the license renewal process. Bennett Brady, who is sitting to my left, will then discuss the subsequent license renewal activities that we've had. And finally, for the rest of the day, the staff will discuss the significant changes to the SLR documents related to structural, electrical, reactor vessel, and mechanical Aging Management Programs, better known as AMPs, for reactor operation beyond 60 years.

Next slide, please.

I would like to provide a high-level status of the license renewal activities. The first license renewal was for Calvert Cliffs and was approved in the year 2000. Since then, 83 units have received renewed licenses. We have 11 additional units currently under review. The industry has indicated that six units will come in for license renewal between 2016 and 2022. At the current rate, by the end of 2016, 45 units will have more than 40 years of operation.

Oyster Creek, which was the first licensee to enter the first period of extended operation, did so in 2009. Older plants such as Oyster Creek, Nine Mile, and Ginna, will reach the end of their first period of extended operation in 2029.

Next slide, please.

In 1991, the license renewal rule was established and in 1995, the Commission reaffirmed that rule. The licensing beyond 60, the staff believes the license renewal rule has provided an effective basis for ensuring safe operation during the license renewal period and will continue to be an effective basis for the subsequent license renewal period.

Consistent with the license renewal rule, the focus of subsequent license renewal is on whether there is need for additional aging management activities during the second period of extended operation. The staff is also working on optimization process to streamline the review of such subsequent license renewal application and to update any inspection procedures.

The staff technical review ensures effective aging management of the AMPs in conjunction with the NRC's licensing and oversight programs.

Next slide, please.

The purpose of the GALL SLR report, better known as NUREG-2191, is to provide a generic evaluation of existing Aging Management Programs. This report is an acceptable method to manage aging effects and plant-specific alternatives may be proposed. The purpose of the SRP SLR or NUREG-2192 is to provide guidance to the NRC staff in reviewing these subsequent license renewal applications.

Next slide please.

So now I think I'm going to answer one of the questions that you raised. Why GALL and not -- why do we call it GALL and not SRP Rev. 2? Revision 2 of the GALL and SRP will continue to serve as the guidance documents for licensing applications for operations between 40 to 60 years of operation or the initial license renewal period. These documents function as the starting point for the development of the SLR documents.

The GALL report and SRP for SLR will provide the guidance for 60 to 80 years of operation and as directed by the SRM in SECY 14-0016, the Commission directed the staff to update the current licensing guidance documents through operation beyond 60. The new documents provide several Aging Management Programs where the NRC expects further evaluations and a plant-specific analysis due to the lack of knowledge related to the technical issues or lack of operating experience for the period of 60 to 80 years of operation.

If we develop Revision 2 to the GALL and the SRP instead of a new document, the staff would possibly be making initial license renewal applicants develop unnecessary plant-specific Aging Management Programs instead of following what's already been generically approved in the past as discussed in Revision 2 of the GALL and SRP.

Licensees may adopt a program from the GALL SLR in their initial application. However, no licensee will be required to do so. I'm hoping that answers your question, but I'll answer any more that you have relative to that if you have any right now.

CHAIR SKILLMAN: Well, let's just pause because this is an area that several of the members were -- concerned is too strong a word -- alerted to, based on the concern of administrative turbulence. We didn't want to see a situation where we had a licensee saying well, I'm just going to pick from one and not the other. Or why do I have to stick with Rev. 2 when I can jump into the SLR NUREG?

So I'll ask the members if they wish to opine or raise any questions here.

MEMBER BLEY: I think we'll come back to this later, after we see some more details.

MEMBER STETKAR: Rather than do it on a generic sense, I'm going to raise several questions about differences in scope and requirements. And why suddenly, when we cross a fine threshold that's defined by time of one second on a calendar, suddenly things become different? It just doesn't make any sense to me. But as Dennis said, I think it's better to address it on specifics and find out why the staff decides to change their mind about things.

MR. BLOOM: Okay, but to kind of answer one of the questions you had, Mr. Bley, licensees can take, if there's some program that they want that's in the GALL SLR, that for some reason they think it's better for them, they can say that they're going to adopt that program.

MEMBER STETKAR: In general, by the way, for the record, the programs in the SLR are more restrictive, so I doubt that any licensee will do that. So we'll just put that as a given.

MR. BLOOM: But they can if they want. If for some reason they wanted to --

MEMBER STETKAR: I'll drive 30 miles an hour on the freeway -- well, I can't on the freeway --but I'll drive 50 on the freeway because I'm conservative.

MR. BLOOM: Well, I was trying to address the question. They can pick, if they want something they want out of the SLR document, but that's up to them. But we're not going to make them do that.

MEMBER BLEY: Just a little question about the layout of things. I haven't had time to really study this in great detail. When I went through the tables, things are either new, modified, or deleted.

MR. BLOOM: Correct.

MEMBER BLEY: If they've been deleted, I think generally, they're replaced with something else. I mean you could come here and say I want to do the one here and oh, it's deleted.

MR. BLOOM: Well, sometimes it's deleted and we'd have to get to the technical basis document to explain each one and without going over -- sometimes they were deleted because we realize that the line wasn't really correct. We found errors when we did our review of stuff that needed to be deleted because combinations --

MEMBER BLEY: Well, have you gone back to Rev. 2? Are you going to update it in a similar fashion if you found they were wrong? That's part of what we were talking about when we're concerned about having two different documents that have a lot that's the same, but maybe not quite the same. And if you actually went through carefully and you found things that weren't right, we're kind of locking on to continuing them.

MS. BRADY: This is Bennett Brady. Actually, we deleted a lot of items. One program we took out was M16A, the vessel internals. I'm sure we'll be hearing -- talking a lot more about that today. When that program was taken out about GALL for subsequent license renewal, the related items were also taken out.

Other things that were combined, so they were not really deleted, but the line items were modified. And during this, I was going to talk about later, we did do an extensive review of the table line items. We cross checked each of them by the GALL and SRP to make sure they are consistent. And yes, we did find a lot of errors and we have corrected them. And we would hope that people --

MEMBER BLEY: You've corrected them in the subsequent, but did you correct them or do you have notes on correcting them later on the next revision to the --

MS. BRADY: Well, we don't think there will be a next revision.

MEMBER BLEY: Because they're already done.

MS. BRADY: We do have --

MEMBER BLEY: But sometime in the far future there might be.

MS. BRADY: We do have a very responsive ISG, Interim Staff Guidance, process that addresses new issues as they come to our attention. And we already, since we began the development of these documents, we've had new operating experience with ductile iron being susceptible to selective leaching and we are getting out a new ISG on that shortly. And actually, it will be in a supplement to our current guidance.

MEMBER BLEY: Okay, so ISG could cover --

MS. BRADY: And Bill Holston will be talking to you about that later today.

MEMBER BLEY: Two more questions for me. Everything gets a new, modified, or deleted. Things that weren't changed, do they get hooked with an M?

MS. BRADY: Modified if they --

MEMBER BLEY: What if you didn't change them? Everything I can find is --

MS. BRADY: Blank, yes.

MR. BLOOM: It would be blank. It would be blank. There would be no modifier.

MEMBER BLEY: I haven't found any blank

ones.

MR. BLOOM: There are a few.

MEMBER BLEY: I haven't found them yet. That's why I was asking. So anything that says M really was changed?

MR. BLOOM: Yes. And it could have been a minor change, but there's a difference between modified and editorial, too.

MS. BRADY: We are going to be adding to that column and we're going to add an E for editorial. And some of the modified items will just go E.

MEMBER BLEY: To become editorial.

MR. BLOOM: Right.

MEMBER BLEY: That will make more sense for me. And the last thing is you mentioned the basis document. I'm not sure we got that, did we?

MR. BLOOM: No, you didn't get that. It hasn't been finished yet. Because once we're done with hearing all the comments that come from our stakeholders, then when we revise the final document, then we'll have to finalize that document and issue it at the same time or close thereafter.

MEMBER BLEY: During today's talks, we'll hear things that come from the basis document.

MR. BLOOM: Right, you'll hear the basis of why people are thinking, but that document has not been finalized, so it hasn't been issued yet.

MEMBER BLEY: Sorry for the run-around.

MR. BLOOM: No, that's fine. I asked these questions. I wanted to hear -- I wanted to address one of the initial concerns of the staff.

MEMBER BROWN: Pardon my delinquency. I was a few minutes late for the lead in here, but what explicitly -- I just heard the comments a minute ago about who would ever go ahead and use the subsequent -- maybe I heard it wrong, one set of information or documents, whatever it is, as opposed to another set. And that doesn't mean, if you want to go 60 to 80, you have to use the SLR.

MR. BLOOM: No, you have to realize, these guidance documents, whether it's Rev. 2 which is 40 to 60 or the GALL SLR for 60 to 80 are what we find as acceptable programs. A plant could come in with plant-specific on every single program out there if they think they have a better way. The review might take longer because we haven't initially gone in with our position, but they could take anything they want.

MEMBER BROWN: So one more clarification. Since I've only been on the committee for eight years and have been through several of these, the subsequent ones, no, no, 40 to 60s. They're required to follow 40 to 60 GALL --

MR. BLOOM: No, they're not required to follow --

MEMBER BROWN: Oh, they're not.

MR. BLOOM: They're not required.

MEMBER BROWN: But they generally --

MR. BLOOM: They generally do. Yes.

MEMBER BROWN: And the flavor I get is in this circumstance, and I'm just trying to take more of my cohort's comments here, why would they do the SLR one if they could go ahead and do this other stuff because it's more restrictive or what have you or more difficult?

MR. BLOOM: Again, they could try --

MEMBER BROWN: Is my understanding correct?

MR. BLOOM: No, you are. They could try to come in and say we want to still follow Rev. 2. The problem is the staff's ingoing position is we think what's in GALL SLR is what we need.

MEMBER BROWN: Okay, you've clarified. I understand that there's a lot of choices then that the licensees can make in terms of how they want to proceed to the 60 to 80 which make it, in your mind, more intensive for your review as opposed to if they don't follow it, you've got to look -- okay, I got it.

MEMBER BLEY: But there is only like half a dozen plants after this spring that will be left.

MR. BLOOM: For the initial --

MEMBER BLEY: For the initial ones, right?

MEMBER BROWN: That part I understand.

MR. BLOOM: That's right, the initial reviews there were only -- as I said, there was 11 in-house -- or 11 that they've told us. There's only two more that yet haven't told us that they're even planning to come in and those happen to be Watts Bar 1 and 2. But beyond that, no one is going to come in for initial review.

MEMBER BALLINGER: So the licensees have been volun-told.

MR. BLOOM: They have what? I'm sorry?

MEMBER BALLINGER: They have been volun-told about using GALL SLR. In other words, they don't have to.

MR. BLOOM: No, they don't.

MEMBER BALLINGER: But the hammer is in your hands. I understand what you're saying. I don't want to say it that way, but yes.

MEMBER BALLINGER: In the military, they call it being volun-told.

MEMBER BROWN: Let me ask relative to the 60 to 80 one, I would have imagined that -- this is my own perception, not necessarily reality, that going 60 to 80 would in your own mind, would say look, we have to look more carefully and more stringently at certain things than we did earlier, just because of the time lapse, but yet, I thought I heard people talk well, you've got time limited aging analysis. You've got all these things we've used before. We could just choose to do them the same way and I'm a little bit struggling with why -- this is a pretty long time period to be dealing with it. I'm not against it, it's just that --

MR. BLOOM: I would not say it the way you did. I would say as we characterized earlier, in our mind, it's in areas that we don't have enough research to show what the effects could be during that period of 60 to 80. Definitely, we don't have enough operating experience because no plant has ever gone that far. As it turns out, we're probably the furthest in the world of plants going out that far. But it's more in areas where we don't think there's enough technical basis to substantiate just continuing on. We think that more needs to be looked at.

MEMBER BROWN: Okay. Thank you.

MS. BRADY: This is Bennett Brady. To give you an example, you asked the question of how do we make sure the two documents aren't conflicting each other. We think that there's been good operating experience in the varied piping programs. And so we have -- I think you would say we have made the varied piping programs for subsequent license renewal less stringent, as you would call it, and so therefore, the 40 to 60 program was more stringent. We are now writing out an ISG, we'll be getting it out shortly that makes the 40 to 60 program the same as the program from 60 to 80.

MEMBER STETKAR: Bennett, just out of curiosity, another -- it's an update to license renewal ISG 2011-03? That's the varied piping in tanks, ISG?

MS. BRADY: Yes.

MEMBER STETKAR: You're going to update that one to make --

MS. BRADY: I'm not sure what the new number is, yes.

MEMBER STETKAR: Consistent with the subsequent license renewal?

MS. BRADY: That is correct.

MEMBER STETKAR: That is in some cases less stringent than the current ISG, correct?

MS. BRADY: Correct.

MEMBER STETKAR: Okay. Thank you. Just wanted to correct the fact that in the subsequent license renewal requirements for some inspections are less stringent. You said there are more stringent.

MS. BRADY: Yes. And Mr. Holston will be talking about that later today.

CHAIR SKILLMAN: Okay, Steve, you've got about five or six more slides and you can bring us back --

MR. BLOOM: I'm not going to finish up, actually.

MEMBER RAY: Did you ask that design basis validation be addressed? Do you expect that to occur later today?

CHAIR SKILLMAN: Yes, sir. I do. Steve said he'd get to it at some point in time. Maybe this is a good time. Maybe you want to --

MEMBER RAY: I don't mean to --

MR. BLOOM: I guess your terminology --

CHAIR SKILLMAN: I'm aligned with Harold. We'd like to be comfortable -- I understand what was in our letter, our recommendation 5 was design basis validation we picked up in the Fukushima activities. Our text is on page in our letter, the context of that. And this is an anxious issue for us.

We see issues of natural phenomena all around us. So here we are at a very old plant wishing to have 20 more years. How do we know when it goes into that next, if you will, PEO, period of extended operation? By golly, it is good for the next 20 years knowing aggregate change has been incorporated insofar as natural events. It's just that simple.

MR. BLOOM: The quick answer before I turn it over to someone else is that the current licensing basis has to be maintained whether it's 0 to 40, 40 to 60 or 60 to 80. As you said, during the initial -- the last meeting we had and your letter to us, you asked us to watch over what was going on with Fukushima. We are always in contact with the Fukushima staff. And so we actually asked them when we heard that you wanted to understand this today, we asked the Fukushima staff what's the status of what's going on.

I'm going to turn it over to Butch Burton who actually has that response.

MR. BURTON: Good morning, everybody.

CHAIR SKILLMAN: Good morning, Butch.

MR. BURTON: I'm Butch Burton. I'm one of the project managers on the SLR project. And yes, just going back a little ways, when we were preparing the SECY-14-0016 which all of you are familiar with and you actually commented on.

One of the things that we were looking at when we were trying to determine are there any changes that need to be made to the license renewal rule Part 54 and we sent up that SECY paper with some proposals. And as you know, subsequently, the Commission, with your input decided that the current regulatory framework was sufficient to support subsequent license renewal. But one of the items that we had in the paper, again, which Dr. Skillman just mentioned, was we wanted to take a look at -- is there anything we need to do to take another -- take an assessment of site characteristics and natural hazards as we move into these extended periods of operation.

And as Steve said, the decision was made that there was a lot of work going on with the JLD, the Japan Lessons Learned Division, and that they were looking at a lot of these. And as you know, their main focus was on seismic and flooding. And you've seen some of the outputs from there. But they also said that they were going to look at some of the other external hazards a little bit later on. So as Steve said, we committed at that time to kind of stay aware of what the JLD was doing. And we did recently talk to them to see what the status was, because as you know, with some of the Project AIM and re-baselining, there's an awareness that that may impact some of the things that the JLD is doing. So we wanted to find out what their latest thoughts were on that.

And what they said to us was that apparently, at the end of last year, they did submit a Commission paper that discussed how they were going to deal with some of the remaining Fukushima recommendations. And for some of the things beyond seismic and flooding, they were going to take another look and try and disposition them based on low consequence, low risk, that kind of thing.

There may be some issues they recognized that they couldn't disposition on that basis and that they were going to take another look at that. What they have committed to the Commission is that by the end of this year, they are going to provide a paper basically giving the next actions, the plans, and timetables for some of those issues. And in the meantime, they've also committed to providing an interim response in the May time frame this year.

So we're looking at the work that they are doing and how these things are going to fall out. And if they fall out in terms of yes, there are some of the external hazards and site characteristics that perhaps it might be a good idea to look at, then they would probably pursue that through their own rulemaking. If it doesn't look like it's going to go that way then, one of the options is for us to look at that. They may not commit to that as part of what I call a "right now" issue, a Part 50 issue. But then we would have to go back and look at that and say well, is that something that perhaps needs to be looked at as a license renewal issue?

But before we make that commitment, we really want to let their process play out to see where they're headed because obviously if they're going to take care of it on their end, then we wouldn't necessarily need to look at it on our end. But they're still working through that.

So that's the latest and greatest from the JLD and we'll continue to stay in touch with them to see how that plays out. That's kind of the latest that we have.

MEMBER STETKAR: I just want to get one thing on the record. The staff is very, very effective at pigeon-holing things and disposing of them in isolation. ACRS not so much. One of the things that I've observed is that as part of that JLD exercise, the JLD has unilaterally concluded that man-made hazards are off the table. Changes to man-made hazards are off the table because I guess Fukushima happened because of not a man-made hazard.

So if I have a plant that's been operating for several years and somebody has built the largest munitions factory in the world at its fencepost, what regulatory inspections, oversight, reviews are performed for that plant to look at the fact that their licensing basis may have changed because when they submitted their initial FSAR, that plant wasn't there. It was a cornfield. And they're not required in their FSAR to my understanding to update that information. They are not required to examine it under the current license renewal guidance and they are certainly not required, so far, to examine it under subsequent license renewal.

So I'll get away from the little focus on seismic events and flooding events because that's Fukushima. Let me ask about that. Because the JLD has already spoken on that issue. It's off the table.

MR. BURTON: Yes. I get your point. There's both natural and man-made hazards that you need to look at. I have a different example. I usually think about okay, in the last 20 years if someone has built a huge chlorine plant nearby and what's the effect of that on control of habitability, things like that. Those are the kind of issues. So yes, it's more than just natural hazards. It's also man-made things.

MEMBER STETKAR: Or a large airport.

MR. BURTON: Or an airport. Sure. Absolutely.

MEMBER STETKAR: Or a military installation, maybe not military because they're cutting back also.

MR. BURTON: And even beyond that. Even changes in population. Right now we capture some of that through some of the emergency planning and things like that, but it is a large, global kind of look that you need to make and the question is do you need to make those kinds of assessments periodically and if periodically, how often? That's another question.

But again, you know, in an effort not to step on JLD's toes or work at even possibly cross purposes, we want -- since they were out in the lead with regard to some of these things, we wanted them to finish their work, see where they're coming out and then we'll be in a better position to go back and take another look to consider perhaps some of the things they didn't consider, understand why they didn't consider those and then we can go on and kind of make our own assessment.

Beyond that, it's hard to comment much on the decisions that they are making and that they've made, but I definitely get your point in terms of if there are things that they've taken off the table. We may need to take another look at that and say well, why did they do that, under what time frame and circumstances did they make that assessment? Because I don't know necessarily their thinking specifically about license renewal and extended periods of operation. They may be thinking specifically right now, Part 50 kind of space, that kind of thing. But we are aware of it. We are definitely aware of it.

MEMBER RAY: So if we commented that this is a pending or an open item much as you have just done, that wouldn't be inconsistent with where you are? We simply observed that what you said is the case.

MR. BLOOM: Yes. I don't think -- I think we kind of made that point in the original SECY paper and obviously you've commented on that. And I think that's pretty much still where we are.

And I think --

MEMBER RAY: It's not clear that's still where we are, but you've made it more clear.

MR. BLOOM: Okay, yes, and we're waiting for them to finish their work and we'll see where they stand and we'll come back and take another look at the need to do that.

MEMBER RICCARDELLA: Is there a placeholder in the GALL SLR for those considerations?

MR. BURTON: Actually, in thinking about what we've been standing here talking about, the GALL is for the safety side of the review. There is another side which is the environmental. And I'm wondering and I don't know this for a fact because I don't think the right person is in the room that as part of the review for the Environmental Impact Statement, when that's revised for a license renewal or subsequent, that looking at manmade hazards such as the plant that's next door or things like that would not be incorporated as part of that review.

MEMBER RAY: We've been down that road a bit and I think we don't want to district the whole thing. There may be elements of what you say that's applicable to environmental, but we are talking about safety.

MR. BLOOM: I understand that, but I don't know -- right. I think those things are considered there, but again, I don't have the right person in the room to answer that directly.

MEMBER RAY: In any event, the only thing I'm trying to do now is say -- is to put forward the idea that it's worth tracking this explicitly.

MR. BLOOM: Okay, I understand.

CHAIR SKILLMAN: I want to reinforce Harold's comment and John's comment and I want to bring to your attention, this is Enclosure 2 of the SECY that you referenced. And on page 6 of that SECY, middle of the page, the sentence is "in addition to these on-going evaluations," that is referring to the prior paragraph, "as a result of the Fukushima Daiichi Power Plant accident, efforts are under way by the staff to reevaluate the design basis" that's an important term, "design basis of nuclear power plants against seismic and flooding hazards against present day requirements and guidance." We clearly understand.

The next paragraph is "in addition to

those ongoing evaluations, the Commission approved the staff's development of a rulemaking plan to evaluate an additional requirement to periodically reassess external hazards in the future." We understand that that rulemaking did not occur. But the spirit of that rulemaking is what we're talking about here, and we want to make sure that that does not get lost in the forest of technical detail for SLR. That's the point. And I think Harold has made the point. John has made the point. And as long as we're aligned on that, we're good to go.

Colleagues? Harold, you're good? Pete, you're good? John?

MEMBER RAY: I'm fine with just making the note explicit.

CHAIR SKILLMAN: Charlie and Dr. Shack? Dr. Bley?

MEMBER BLEY: For now.

CHAIR SKILLMAN: For now. Back to you, Steve.

MR. BLOOM: Actually, I'm going to turn it over to Bennett.

CHAIR SKILLMAN: Thank you. Thank you, Butch.

MR. BLOOM: I'm going to turn it over

to Bennett who will finish the slides, as you say, to deal with the overview of the subsequent license view including the process, major activities and the schedule.

Next slide.

MS. BRADY: As Steve mentioned, I'm Bennett Brady. I'm a senior project manager in Steve's branch.

Before we get into the specifics of the change to the GALL and SLR, I would like to tell you first a little bit about why we made changes, what was the basis for the changes. Then I would like to give you sort of an overview of the major and generic changes in the two documents and finally, our schedule for producing the final GALL and SRP.

We've already talked some about why do we make changes. Before we begin developing the two documents, we set up our rules of operation, what would be a basis for making a change, if it didn't fit into one of these categories, let's not make that change. First of all, was expected aging differences, operations beyond 60 years. We've talked about that some today and we talked about that the major expected aging differences when we met with you in November.

Second, what were the lessons we learned from reviewing applications for GALL 2 and SRP 2, and also we conducted three, what we call, AMP effectiveness audits at three units in the PEO to see how are these Aging Management Programs performed, what were their lessons learned from conducting the inspections with these Aging Management Programs.

Number three was to improve efficiency and effectiveness in applications and NRC review. We went back and looked at four or five recent applications to look for component and aging mechanism combinations that were not in the GALL 2 to add them to this, so this would reduce the licensees having to make explanations of why they added in the RAIs, potential RAIs from that.

And four, of course, we review new operating experience. When you hear about the reviews of the various AMPs today, you'll be hearing a lot of data on operating experience.

And then fifth, gaps and errors in GAL and SRP. And in fact, a new error came to us from the ACRS just a couple of weeks ago in the water control structures AMP. We will be correcting that.

Next slide, please.

This is our overview of the changes. As you know, all the Aging Management Programs have ten elements. And three of these elements, corrective actions, confirmation process, the administrative controls, refer to the applicant's quality assurance program under Appendix B of Part 50.

We have standardized the wording so that from these three I would say the same through all the Aging Management Programs.

We've added more detail, final safety analysis reports, supplement summary descriptions, and these are in both the GALL and SRP. We wanted the summary descriptions to capture what we consider the critical elements of each area.

We have a few new AMPs, not many, really, XM2 neutron, fluence monitoring. We discussed that with you in November. XIM42, internal coatings and linings. That was actually a new ISG recently. We have a new electrical AMP, high-voltage insulators. We've also added a new chapter to the SRP, technical-specification changes. 5422 of the rule requires the applicants to report on tech-spec changes that they will need to make in implementing their AMPs. And this chapter provides guidance to the reviewers on where to look for potential tech-spec changes and how to review them.

Next slide, please.

We've also renamed the GALL chapters 9 and 10 to more correctly reflect exactly what they are. We had one electrical AMP, E3, that we've now divided into three AMPs to address specific aspects related to potential submerged cables, low-voltage cables, medium-voltage cables, and I&C cables. And we've deleted two AMPs, XI.M6 and XI.M16A and replaced them new further evaluation items. We'll be talking about those two later today.

We have had a lot of new further evaluation/plant-specific sections to review new component aging mechanisms that we thought should be included.

I've already mentioned about the tables that we did an extensive review of that in what we call a cleanup which might be considered more editorial changes. And as Dr. Bley mentioned, we have a new column to indicate whether they are new, modified, or deleted items.

This is our schedule for getting out the final GALL. We'll be having another public meeting this Friday, February 19. We had a public meeting on January 21 on the mechanical Aging Management Programs and reactor pressure vessel Aging Management Programs. We scheduled a meeting for January 22 to talk about the structural engineering program. Got snowed out. And so this meeting this Friday is out make up public meeting.

On February 29, our public comment period ends. During the RIC, we'll be giving two sessions on subsequent license renewal, one by NRR and one by Research on March 9.

In April, we will go out with a supplement to our GALL SLR. I mentioned that before. There's quite a number of items in that. That will go out for public comment for a month. May that public comment period will close. Then back in March 2017, we will come back to the ACRS full committee with our draft GALL, final GALL, final SRP.

And then in mid-2017, we will publish the three NUREGs, the GALL, final GALL SLR, the final SRP SLR, and the final Technical Basis NUREG that we'll give our reasoning and our response to the comments. And then in 2019, the first SLR application is scheduled to come in.

MEMBER BLEY: These are all of the things that are coming. And I know you've told us about this earlier -- maybe with the SECY or something. You had a whole series of public meetings before you developed the draft.

MS. BRADY: Correct.

MEMBER BLEY: So you heard from industry all the way along?

MS. BRADY: Oh, yes. And then they provided the extensive comments before we even began our process. And we would do those and disposition. Then we've had meetings to tell them where we were going with these draft documents. And we will be having lots more meetings, I'm sure.

CHAIR SKILLMAN: Thank you, Bennett.

MS. BRADY: Thank you.

CHAIR SKILLMAN: Thank you.

MS. BRADY: Now we will get into the specific changes. We were going to talk about the structural changes. I understand our first speaker, John Burke, had an accident. I don't know whether it's snow related or not. Dr. Andrew Prinaris will be speaking for John Burke.

CHAIR SKILLMAN: We are running behind schedule, so I'm going to ask the next several speakers to please proceed forthwith. Unless there are questions from the committee, please feel free to move along quickly. I'm going to try to keep us on schedule. Thank you.

MR. PRINARIS: Good morning. I'm Andrew Prinaris structural engineer with the Office of Nuclear Reactor Regulation. Along with me, my colleague, Bryce Lehman, we'll be covering the AMPs that have been updated.

First, we're going to address the AMPs that are ASME Section XI, Subsection IWI, IWL, and IWF code-related. And thereafter, we're going to follow with those that are related for structural -- with structural design and codes or Reg Guides and that would be like the masonry structures, monitoring inspection of water structures, etcetera. And then we'll get into the ones that they are addressing regulations which would be the Appendix J and time limited aging analysis. That's the main frame.

We also made those changes -- what we are not going to discuss is AMP S8 which deals with protective coating and monitoring and maintenance.

That has hardly changed from Rev 2 of NUREG-801. It practically remains the same so there is no need to discuss it further.

We also are going to discuss two further evaluations. One relates to ASR and the other one to irradiation of concrete and those are going to be in NUREG-2192.

I'd like to make some points and I've heard a lot of discussion going. All the changes and clarifications were implemented following rigorous vetting that included review of the RAI database, especially those that were asked repetitively and identified issues found on past applications. Our focus was to streamline the current review process while maintaining and implementing the principles of good regulation.

Reviews are to be objective, unbiased, and constant while taking into consideration technological uncertainties, resolution of prior issues and diversity of licensees while maintaining risk at an acceptable low level.

The GALL SLR provides a method to satisfy 10 CFR 54. Its intent is not to lock the plant into inappropriate, impractical and unnecessary actions.

In the review of the programs, I'll identify the new aging management activities as additions versus those that are listed as clarifications. And we're going to jump right into the first ASME AMP related. That's the one coded XI.S1. It's regarding subsection IWE.

In all these AMPs including these of the ASME, we tried to maintain a common verbiage on structural bolting. So we approached and listed similar to this AMP and the IWE and the structure's monitoring specific verbiage that will be common. This is one top level comment.

The other comment I would like to make and I'm sure may have been discussed already is related to bulges. In a number of the audits, we have seen bulges in the liners. And our concern is not what has happened during construction and has been resolved. Our concern has been during -- if you do have a bulge, there is a separation from the concrete and elimination of passivation. So if there has been a study in the past, what we would like to see, and we have addressed this in the AMP, does that study still hold or does it need to be revisited and reevaluated.

We also clarified some issues regarding

supplemental examinations, specifically those of the two-ply bellows and -- next slide, please -- those specifically of two-ply bellows and those of dissimilar welds. t

In the case of two-ply bellows, there has been an IN 9220 that addressed the issue. Some of the licensees have changed the bellows so they can do an IRLT. But still if there are issues, what we are saying is we recommend additional appropriate techniques, whatever those techniques may be, to be implemented so they can detect cracking for two-ply bellows.

We also looked at the inaccessible areas and there may have been a comment, some of the inaccessible areas, they may have issues. We tried to address how we are going to approach those issues and in specific areas that they may draw our attention and also what has been identified as random.

We also revisited this regarding the operating experience. We added a number of INs that address corrosion. They address leak chase channel systems, concrete containment susceptible to liner plate corrosion, etcetera.

We addressed the tables of NUREG-1611 regarding transgranular stress corrosion cracking and stress corrosion cracking.

I'm going to be abbreviating and moving fast because I know we are behind schedule.

The next item of discussion, the next AMP is the IWL. This AMP has hardly changed except we have added that photography made the good instrument where quantitative data cannot be collected. Photography can be a very valuable technique, especially if you can scale the photographs. And this particular technique is referenced in two ACI publications. They are part of the ASME. In fact, in IWL-2310, visual examination and personal qualification, the two documents ACI 201 and ACI 349.3 discuss the value that photographs bring into the evaluation of possibly cracking or what cannot be measured at that point. We added some additional acceptance criteria consistent, as I said, with the ACI 349.3.

The next part of this AMP that has been visited has been the operating experience. In the operating experience we added an IN regarding the licensee pursuing inspections, that they really were not up to snuff with ACI 201.1 and ACI 349.3

that they are part of the ASME code.

In addition to the operating experience, we brought forward the inspection report related to delamination issue and we said well, if you are going to be doing, for example, steam generator replacement, this is a point of interest and should be paid attention. This is not age related, but it draws attention to the licensee, something that they need to observe.

CONSULTANT SHACK: Looking at that, there was sort of one change in the wording. In the current one, it says the code specifies augmented examination requirements. In the previous version, following post-tensioning system replacement repair. And the other one, the previous version it was a more encompassing thing. Post-tension system repair and replacement activities are to be in accordance with the code, rather than just examination afterwards.

Is there a difference or is one just a more accurate statement of what the code actually requires?

MR. PRINARIS: The code requires examination and we also have INs that tell us how to -- or they tell the licensee how to do the actual lift of force measurements. And those are going to be revisited further down in 10, limited aging analysis.

CONSULTANT SHACK: Okay, so there was no change in coverage really in going from activities to examination. The code really only focused on examination?

MR. PRINARIS: The code focused on examinations. We reinforced some additional things. And you're going to hear about them and I'm sure you may be hearing farther down on Friday.

CONSULTANT SHACK: Okay.

MR. PRINARIS: If anything, we want to make sure that safety is maintained.

CONSULTANT SHACK: Well, these additional things, where are they mentioned? They don't seem to be in this document.

MR. PRINARIS: You'll be hearing them, I mean, farther down of the discussions today.

CONSULTANT SHACK: Okay.

MR. PRINARIS: I'm going to move to the last of the group, the ASME related program of IWF. We added evaluation of inaccessible support areas when accessible areas indicate degradation may exist in inaccessible areas. Again, we reworded some issues that had to do with bolting and when we put in the AMP all bolting, that all bolting perhaps needs further clarification, meant all bolting in the sample, not all bolting across the plant regarding these support areas.

CHAIR SKILLMAN: Andy, let me ask about that first bullet. That suggests that you would only look at inaccessible areas only when accessible areas are indicating degradation?

MR. PRINARIS: That's correct.

CHAIR SKILLMAN: Is that an appropriate --

MR. PRINARIS: We have maintained this across the board for most AMPs and most audits we would address what is happening in the accessible areas as an indicator. If there are issues arising from this observation, then where they're going to look for opportunistic exam times or we are going to suggest some other way, but practically what is taking place in the accessible areas is an indication of the inaccessible areas.

CHAIR SKILLMAN: Except that when you find something that is occurring that may be applicable to an inaccessible area, you probably ought to take a look, but I don't accept an argument in the other direction that is that you don't have to look in the inaccessible areas if there's no obvious degradation in the accessible -- this is kind of the reason that there are rounds on a ship or on a power plant, where no matter what's going on, you're out and about on a regular basis looking and poking.

MR. PRINARIS: I'll give you an example. You know, some of the tendons, for example, maybe flows to a radiation area. Then you cannot physically, you cannot --

CHAIR SKILLMAN: Get there.

MR. PRINARIS: Right.

CHAIR SKILLMAN: I understand.

MR. PRINARIS: So you look on either side and see is there something that could be affecting this and then there are other mechanisms and I'll discuss some of these specifically on the tendons. Is there something that trending is not cutting it? We dissect the information that the applicants provide us to make sure that safety is maintained.

CHAIR SKILLMAN: This is the perfect example of you don't know what you don't know. And the only way to find out is to go take a look and so I would suggest that there needs to be an awareness that in some cases, even though there might not be trend data, you probably ought to at least poke at least once, particularly when you're talking about adding 20 years.

MEMBER BALLINGER: I'd like to kind of reinforce that because just because you don't see something in an accessible area does not mean it's not present in an inaccessible. In fact, we've been surprised many times, where we thought everything was fine and in an inaccessible area, lo and behold, it wasn't so fine. So I don't know if that's the right criteria.

MR. PRINARIS: Let me get, for example, farther down and maybe this question will be answered. And if not, I'll entertain it at the very end.

MEMBER BALLINGER: Okay. In particular with respect to corrosion and things like that, it's usually the inaccessible areas that bad things occur.

MR. PRINARIS: Well, this is one of the reasons that bulges are of concern. And you look at the bulge, some of these bulges are way up there. And yet, we address the issue. Whatever the applicant takes a step, however, he is going to tell us if there is a thinning because of the release of the liner from the concrete and now some active degradation is taking place, especially where the strains are excessive in a bulged area because of plastic collapse, you're going to know a little bit more. So I mean we have addressed this, by the way in certain plants.

CHAIR SKILLMAN: This is a poor example, but it illustrates exactly the reason for my concern. After the TMI2 accident we did not go into several of the facilities for six years. And when we did, the first thing we had to do was put in lights because the light bulbs had broken, had died. And what we learned is that the spiders needed name tags they were so big. I'm telling you the water spiders were three inches in diameter.

And the state of rust was remarkable. That's a bad example, but it illustrates you don't know what you don't know. You need to keep looking. So I'm going to stick with Dr. Ballinger --

MEMBER BALLINGER: This is a generic problem, not just with liners and stuff. You've got to be careful that you don't deceive yourself into thinking something is fine because you can't get to it.

CHAIR SKILLMAN: I think we've made our point. We'll be glad to hear what you have to say. Thank you, Andy.

MEMBER RICCARDELLA: Just for clarification, we're talking IWS which is component supports, right?

MR. LEHMAN: Yes, so I think some of the stuff you're talking about, we have in IWE and IWL where we've sort of taken a more closer look at the inaccessible areas, but for this IWS specific, it component supports.

MEMBER RICCARDELLA: You're talking thousands and thousands of component supports. I think the sampling where you're covering just the accessible ones I think is probably pretty good sampling.

MR. LEHMAN: Yes, it's a sampling program as well.

MR. PIRES: This is Jose Pires. I would just like to make a comment. I think that only applies, my understanding, to those parts in which these extrapolations has some validity. When you have a particular construction detail, for instance, you think there may be some corrosion there and that corrosion will not be evidenced by something like that, by an accessible area. You have programs for the inspection of those details. So there's a limit to the feasibility of that, in that regard.

So I think for containments there may be some part of the liner where maybe some water might accumulate or is suspected, and that is completely different from what happens in the rest of the liner. That is a separate consideration.

CHAIR SKILLMAN: Okay. Thank you. Let's march. Let's keep on going.

MR. PRINARIS: It has not been unusual where we went back to the licensee in the past and they have provided us with plant-specific on issues that we have raised. So I assure you our audits are comprehensive, at least from the license renewal perspective.

The next point on IWF, next slide, please, As I mentioned we clarified the bolting across the AMPs and specifically we addressed those that could be susceptible to stress corrosion cracking. And then we looked at the sample size that we have been looking all along and the licensees actually have been looking all along, consistent with ASME code. And what we suggested in this particular new GALL SLR is an increase of five percent for the supports outside of the existing sample. And the 5 percent is, for example, if you have 10 percent, it will be 10.5 percent. The percent increase is a roaming increase in the sample size to provide this additional confidence of adequacy for reducing any existing uncertainties in our review. So we've taken this additional step and say okay, we would like this additional increased augmentation of the sampling aside what the code has provided.

And at the end, we added one more recommendation where we have some supports that they have been reconditioned, although they do meet the acceptance criteria. Then we suggest the addition of a similar support as that has been reconditioned.

This concludes the ASME related AMPs. And now I'm going to move to those that are related to codes, structural codes or Reg Guides.

They all have a common theme and oftentimes, applicants have combined some of these, for example, they have combined the masonry, as well as the water-related structures and structures monitoring all into one. Although they did separate their operating experiences, you could distinctly look at them and see what each of these AMPs has addressed as an operating experience. But there are some common factors and I'm going to address those in this particular slide.

We clarified that coatings are monitored for indications what is happening in the substrate just below the code. And reworded again parts for the bolting. We addressed that some bolts even though they may not be as susceptible to stress corrosion cracking still we need to be looking at these.

We also took -- some of these has come -- what I'm going to mentioned next from experience, inspections related to --

CONSULTANT SHACK: Go back to that first bullet. It seemed to me that you took language out to cover the protective coatings. In the old GALL, there was a statement if protective coatings are relied upon to manage the effects of aging for any structures, the structure is monitored -- is to address protective coating and maintenance. And that's gone.

MR. PRINARIS: I believe we said we are looking what could happen below the substrate.

CONSULTANT SHACK: You may have added it somewhere back in.

MR. PRINARIS: Some of this has been moved around. That's for sure.

CONSULTANT SHACK: Okay.

MR. PRINARIS: I'm going to take your note and try to address it.

CONSULTANT SHACK: That just surprised me a little bit.

MR. LEHMAN: Yes, the deletion I think you're talking about is in the program description.

CONSULTANT SHACK: Yes.

MR. LEHMAN: We expanded on protective coatings at the end of element 3, parameters monitored or inspected. It's a little slightly different wording, but I think the focus was on generally the coatings are not what's being age managed. It's the underlying materials.

CONSULTANT SHACK: Right, it's really the structure.

MR. LEHMAN: Exactly. So make it clear that coatings still need to be inspected, but not for themselves to make sure that the underlying structure is acceptable.

MR. PRINARIS: Dr. Shack, I would like to say the following. When we do the audits, we address the elements of the AMP not per se that much is in the description of the program. So you have seen a movement into the elements. It is the applicant that has to address do I satisfy this element? Do I satisfy -- and that brings it more strength in the --

CONSULTANT SHACK: Fair enough.

MR. PRINARIS: Going forward, again, we are talking here about inaccessible areas and aggressive groundwater. The focus of all of these AMPs is to detect aging degradation and quantify the effects of aging before there is a loss of intended functions. So some of these AMPs they have the wording we would like to know the volume, as well as the chemistry of the water collected, if it is possible to collect that water, and there is a reason for it because we can tell what is happening. The chemistry of the water, if there is leaching, if the porosity of the concrete is increasing by calcium release, etcetera. And the same thing if you do see iron within the water sample, that we do know that the rebar is getting degraded then.

So this is the reason why I have taken -- it is not a descriptive environment, but it is something to draw the focus of the applicant to if there is water that substantiates, to further look, please tell us what is happening. And all of this, the reason they're putting the elements of the AMPs is instead of us getting asked the RAI, we go out and we see something, we keep asking RAIs because the sample is cycled sometimes. We bring it up front and say okay, we really want to make sure we can complete this review in a timely fashion.

And as far as the baseline inspections, if applicants have not used quantitative acceptance criteria in the past, a baseline inspection we feel it should be completed prior to the subsequent license renewal, so it gives us an indication where a particular structure may be or a condition of the particular structure.

The major -- now we're going to go specifically on every AMP. And the next one in line is the masonry walls. And the major difference here has been the unreinforced and unbraced walls. We are providing the guidance. Those have to be inspected every three years instead of every five years.

And we based our thoughts on two issues. One was these are unreinforced and unbraced, so it could be a condition of A2 over A1 and we maintain that safety. And the second one we looked at the National Concrete Masonry Association documentation regarding concrete masonry walls, and in fact, their specifications call for unreinforced and unbraced walls to be inspected annually. So we've been five years on annually. And something that the applicants do rigorously, we believe three years is the adequate time for this inspection.

MEMBER STETKAR: Okay, you're going to hear this from me. I'm not a structures guy, but it's time to start raising it. Why when the clock ticks over to suddenly 1 second after midnight on the 61st year does it suddenly become a 3-year concern when for the first 60 years it was a 5-year concern?

MR. PRINARIS: I think the answer on this in my mind and in the mind of my colleagues when we set on these tables and we vetted these things, when we go 62 years the uncertainty has increased on many occasions. We have looked at this point in time, whatever we had in our hands and NUREG-1801 and -1800, and we evaluated according to the AMPs. And wherever there were issues, we asked the RAIs to supplement.

But the bigger question became all right, we're going 60 to 80, there is a lot of uncertainty, a lot of things we don't know. By and large, the --

MEMBER STETKAR: But we're a lot more certain at year 59. But that's what the guidance says.

CONSULTANT SHACK: But I have the same problem, John, from 39 to 40.

MEMBER STETKAR: Yes. And maybe at some plants from 7 to 10.

CONSULTANT SHACK: I mean there is a certain arbitrariness in picking any of these numbers, but --

MEMBER STETKAR: The question is why be arbitrary. If 5 is good for 60 years, why isn't it good for the last 20 years? Just because it's the last 20 years and somebody wants to make it -- sounds like we're more rigorous. So I'm asking for the technical basis. I'm not asking for opinions. I'm not asking for --

MR. PRINARIS: There are other things, too. There is a Maintenance Rule Reg Guide that the applicants follow. There is a Maintenance Rule inspection.

MEMBER STETKAR: They're following it now though.

MR. PRINARIS: Yes, they are.

MEMBER STETKAR: And they'll follow it through year 60, 59.99999.

MR. PRINARIS: We emphasize that these things are important in the application. The other thing is there --

MEMBER STETKAR: I'm asking for the technical basis though, sir. I'm asking for the technical basis for increasing the frequency of those inspections, not a feel-good opinion. I'm asking for a technical basis. If you don't have one, just take it away. It's on the record. Staff can come back and answer our technical questions after greater consideration later. It's a question.

MEMBER BALLINGER: It's obviously true, I suppose, that with time the uncertainty increases. But does it make a difference in this case? In other words, regarding the technical basis.

MEMBER STETKAR: If you've been

inspecting it every five years --

MEMBER BALLINGER: That's right. On what basis do you say all of a sudden uncertainty has increased when you've been inspecting the thing every five years for the last 40 or some number?

MEMBER STETKAR: Forty to 60 anyway.

MEMBER STETKAR: Forty to 60 anyway.

MR. PRINARIS: Bear in mind that there are a lot of these organizations like ACI or the Masonry Concrete Association. They do go through their reviews and they find out some things need to be augmented or changed or -- for example, I'll give you, for those of you that may have an idea of the concrete code, when I went to school it was a few pages. Now it's 500 pages, the concrete design code.

So there are increases, technological advances that need to be taken into consideration. As I said before, we looked at these things and we brought them forward. Now between the 39 to 40, it's the applicant's decision and as for us to evaluate what they bring to the table when we do the basis document review.

MEMBER RICCARDELLA: You know, I don't think it's unreasonable, John, as a general concept that as things get older, you check them more often. Think of your own medical checkups that you do, you know? I won't mention the specifics, but there are certain things you start doing more frequently as you get older.

MEMBER STETKAR: On the other hand, I have an annual physical and I've had that annual physical for years and I look at the trends in my annual physical. And if I see a change in the trend, I go have that specific issue checked maybe once every six months.

And in this case, we have evidence of from 5-year inspections of these things, 4 years, anyway, 40 to 60. And yes, if I have -- I'm not arguing at a specific plant if I have evidence of problems with some walls at that plant and I'm just making a case on the walls because it's the first one, so I don't have to say this on every other thing that I've discovered.

If you don't have evidence of a trend, why just go look -- why should I go to the doctor every six months simply because I turned 60 when I have 30 years of annual physicals that don't show a trend, just because I turned 60? Or just because I go to Medicare and maybe Medicare -- well, Medicare won't pay for it, but -- see, my whole point is if there's an actual technical basis, then I'm happy. If it's just a feel-good thing, why --

MR. PRINARIS: The technical basis here is when we look at these new codes that are coming online and I may be facing you a few weeks, months from now on some of the Reg Guides that are involved. A lot of new things -- testing continues, things come up, and things are improved from the perspective now we need to be paying more attention to this and codes are rewritten. And we have looked at these things. Now between how one year changes to the next, that I cannot tell you.

MEMBER STETKAR: Go on, Dick has to keep us on schedule. I made my point.

CHAIR SKILLMAN: Well, I would like to kind of get where Pete, or Dr. Riccardella is. I think the data for people aging shows that there is value in more frequent inspections the older we get. I think that there's a balance between do you really have to change the inspection frequency on the first day of the 61st year against -- is there really a risk that's associated with not having a more frequent inspection? But I think that there's a defendable argument on both sides of that equation and I think we should be mindful of that.

As the plants age, specifically where there is not a lot of data that confirms that continuing to age in the same cadence and pace that the plant has been accustomed to, that there may be a phenomenon that hasn't been discovered, but there needs to be some science when we say you've got to increase inspections because that is a burden for industry. And the burden is expensive. So there needs to be a good, solid basis for saying let's increase the pace.

And I would think that there's plenty of data out in the world of structures that would show that big strong concrete structures that have been in use for decades probably don't go through some rapid change obligating more frequent inspection, but I think we need to have signs to back up any change.

MR. PRINARIS: I agree and some of these structures are indeed massive. We are talking some -- unbraced walls and the specific bullet is for those type of walls that we dropped and we based primarily on the standard.

MR. BURTON: Yes, this is Butch Burton again. Let me -- I want to, I guess, try and make more a general point. Sometimes you make changes based on things that you've seen and you know. Sometimes you make changes based on things you haven't seen and you don't know. But -- and certainly in the prior case, you can prepare sound, technical basis to support that. In the latter case, it may be a little bit more difficult and some of the basis may have to be something in terms of I don't know whether this necessarily -- I haven't seen it happen, it may happen in the future, it may not. If it does happen, it would lead to really bad things and in some cases that may be the kind of argument that you have to make to support something like that.

Like for instance, I've heard a lot about shingles. And they say get your shingles shot when you turn 60. I've never had shingles. But the consequences of getting shingles look pretty bad, so I'm going to get my shot. So I definitely appreciate the need to have a sound technical basis and I agree with that. And I think we're committed to that. The challenge of preparing a technical basis for something that you haven't seen and may be a little more challenging and I think the basis has to involve the consequence if you miss it, if you follow what I'm saying. So sometimes that may have to be the basis. But it's not as solid as something that you have seen or experienced. But I think as we move forward, we prepared out technical basis document, we're going to have to make those kind of arguments in those kinds of situations. So I do take your point.

MEMBER BALLINGER: But I think we really need to be careful that we don't have mission creep here, all right? Shingles, for example, I've had them. They're very unpleasant. It's a known surprise. All right? I'm surprised when I got them. I didn't expect to, but I knew about them. There's no basis -- if you have a wealth of inspection data every five years and you don't see any trend, and there's no thermodynamic or other kind of reason where you would expect a surprise, then there's no reason, I don't think to change things.

If you somehow expect a surprise, then you have to go back and say well, on what basis might I expect a surprise? Stress corrosion cracking happened to be one of them where you can get surprise and you would expect that over time that's not going to be much of a surprise. It's just a matter of time. So we have to be careful that we don't end up with just arbitrarily assuming that we're going to be surprised on everything and therefore increase -- decrease the inspection interval, if you will --

MR. BURTON: Right.

MEMBER BALLINGER: Or add inspection just because well, it's the future. We're going to be surprised.

MR. BURTON: And I agree with that. And it's not just whether you think you may get a surprise, but what are the consequences of that surprise. If the surprise is something really bad --

MEMBER BALLINGER: That factors into it, too, but I don't see some of that here.

CONSULTANT SHACK: Just another thing, some inspections tell you a lot. If the wall hasn't fallen down or shown visible cracks, that doesn't tell me a whole lot about the damage that might be accumulated.

In a pressure vessel, I can make the argument that I know the fluence and I know it's going to creep up. I have ways of measuring that.

In cases where you can't track the kind of damage that might be occurring, it seems to me that it's reasonable to perhaps increase the inspection. So you have to consider what your inspections have really inspected over the past 40 years versus the future. And in this particular case, I mean the fact that the consensus document says inspect every annual year seems to me a good, strong, sound, technical basis for decreasing it from five to three.

MR. PRINARIS: Again, these are unenforced and unbraced walls.

MEMBER RICCARDELLA: Are there a lot of those types of walls in a nuclear plant? I'd be surprised.

MEMBER BLEY: A lot fewer than there used to be.

MEMBER BALLINGER: But we need to be careful that we don't translate may or might into well, sure.

CONSULTANT SHACK: That's why you have a one-time inspection program for places where you think there really is -- we know there are mechanisms for unreinforced, unbraced concrete walls. And I think there is -- if you can't quantify the distinction in all cases, there is this notion that you are accumulating damage. If you haven't got good ways to inspect or quantify it, increasing the inspection frequency is a reasonable thing to do. Again, there's a certain arbitrariness in doing it at 60 years.

MEMBER BLEY: And that links to the piece of risk. We just heard it. If the consequences are high, maybe we want to look, but also if the likelihood is increasing, the kind of thing Bill cites is a place where you have reason to suspect the likelihood to be increasing if it's something you can't observe, but you know there are mechanisms getting us there. So I think --

MEMBER STETKAR: How do the visual inspections give you confidence that you're inspecting that mechanism any better every three years any better than any five years?

CONSULTANT SHACK: They don't.

MEMBER STETKAR: Okay, thank you.

CONSULTANT SHACK: When any damage occurs to the point where it is visible -- I've got a head start.

MEMBER STETKAR: They're only visual inspections. Go look at the wall. It's either cracking or it's not.

CHAIR SKILLMAN: Let's proceed. Andy?

MR. PRINARIS: I believe we are S6 now which is the structures monitoring program. Something that the mechanical people have been doing, we added and noted that the elastomeric materials are subject to tactile inspection. Again, the same thing that I discussed with you a few slides before regarding in leakage to look at the volume and the chemistry. And something that we clarified was regarding the groundwater chemistry and to look at the seasonal variations. The seasonal variations are important because it could be high water table that can drive additional fluid by pressure through the wall and also can tell us whether there are elements on the surface that are filtrated right through the water into the wall.

The next AMP that I'd like to visit is inspection of water control structures. On this particular AMP, we separated the wording regarding the Regulatory Guide 1.127 from the title. I would like to reemphasize that whether the plant follows Reg Guide 1.127 or not still the plant has to address water-control structures and the elements of this program should be covered.

The point in this particular program of interest is submerged concrete structure should be inspected during periods of low tide. They are no longer inaccessible, but you should have that opportunistic approach to inspect when they are accessible and to be at five years. And if you cannot do it, then provide a technical justification. The same thing if there are silt accumulation or vegetation or marine growth, those are not considered inaccessible areas, but they can be cleaned and inspection of the concrete or other structures can take place.

That brings us to two further evaluations. One is ASR, an active research, on-going research in this particular aging effect. The further evaluation starts by looking visually at trying to address whether there is a map or patterned cracking, then followed by petrographic examinations and reactivity tests whether ASR is taking place.

There are certain tables in the SRP that have been updated and those you can look at the numbers of the slides.

The additional and new further

evaluation is regarding radiation. Some numbers are given there. Those are of the current level of research where we are and our research, Office of Research, along with NRR, is addressing this particular point to find out where exactly the threshold will be that will be affecting concrete structures.

Again, there are entries on the SRP. And that brings us to the next level, the AMPs and Time-Limited Aging Analysis that they are --

CHAIR SKILLMAN: Andy, before you proceed into 4 and 5 --

MR. PRINARIS: Yes, sir --

CHAIR SKILLMAN: -- is , is this a good time to take a bio break?

MR. PRINARIS: It's up to you guys. I think it's a good idea.

CHAIR SKILLMAN: For some.

MR. PRINARIS: I'll probably address some of the thoughts that you had, the importance of trending, etcetera.

CHAIR SKILLMAN: My preference is to keep on going, but my common sense says take a break. Let's recess for 15 minutes. Let's come back at 25 after on that clock.

MR. PRINARIS: All right. Thank you.

(Whereupon, the above-entitled matter went off the record at 10:09 a.m. and resumed at 10:24 a.m.)

CHAIRMAN SKILLMAN: Ladies and gentleman. we're back in session. Late breaking news, I'm going to claim a hard stop at 11:45. A number of the members have other activities that they must attend to, so let's march hard.

MR. PRINARIS: Sure.

CHAIRMAN SKILLMAN: And, Andy, take it away.

MR. PRINARIS: All right. We're now getting into the ones that they are related to regulatory aspects, and I'm going to reshuffle a little bit here and we're going to start with 54.21(c), Revisions (i), (ii) and (iii) regarding the tendons. And regarding the tendons this -- what has changed from 1800 to this new GALL SLR is we introduced the wording and the title of un-bonded tendons to make it specific that we are discussing unbounded tendons with this particular time-limited aging analysis.

The next thing I want to say is the Standard Review Plan is for the benefit of the staff and the applicants do follow because we do evaluate with certain leeway what the applicant send us regarding the regulations.

Again, to refresh some of these things, the (i), (ii) and (iii) relate to analysis. The (i) is analysis that was performed at the beginning of time, meaning when the plant was commissioned, and it could have been done for any number of years. It could have been for infinite number of years, in which case the analysis is valid. The (ii) is when the analysis has been projected to a particular year, and most often that had been 40 years. And the (iii) is if (i) and (ii) cannot be satisfied, then you do have a managed approach to the tendons. We added to the areas of review that predicted lower limit, and I'll discuss a little bit more on predicted lower limit. We moved it to plant-specific time-limited aging analysis because predicted lower limits are different for every plant and they are plant-specific. We also looked at additional and supplementary aging effects, like breakage of tendon wires, effects of stress corrosion cracking, improper anchorages and so on and so forth.

Losses in tendons are those that happen

in the beginning of time. And then they are losses that have -- they are time-dependent and there are losses also that they are based on environment or environmental losses. And those at the beginning of time is, for example, those involving friction and so-called frictional losses, losses due to initial setting, losses due to elastic shortening.

And for those that are not familiar with elastic shortening, just imagine you have a rim in a car and you had a flat you are replacing. You are not going to tie all the bolts clockwise or counterclockwise, but you're going to do it on opposite sides because you're pulling on one tendon one side. Something else is happening elsewhere.

So there is quite a bit of writing in Reg Guide 1.351 regarding the elastic shortening. And it is actually a very sophisticated analysis how you are going to be tensioning these tendons in the beginning of time.

The ones related to time are creep, shrinkage, relaxation of tendons. Creep and shrinkage involve definitely aggregates, and depending what aggregate they use in the concrete, you can have different aspects of creep and shrinkage. And those are important. And the reason I'm saying important also is if you begin de-tensioning for steam generator replacement, you got to be aware of these things.

And relaxation of tendons is you stretch a metal and the grain structure changes. And then if there are issues replacing tendons, etcetera, there are some relaxation things taking place in the existing tendons. What I'm trying to drive is a complex situation that the reviewer as well as the applicant needs to be aware of.

The additional thing that we took away from 4.5 regarding the (ii) -- and I'm going to go back to slide 8, to a previous slide. On (ii), in the past in NUREG-1800, Rev. 2 and Rev. 1, we had wording; and in fact you can see it, that said if you cannot make the computations, they you got to have some sort of a program that will address the review procedure. That is not based on any regulatory aspects and we just deleted it. We believe this was an error and is no longer in SRP SLR. The SRP SLR addresses analysis in (i) and (ii) and management in (iii).

Yes, sir?

MEMBER RICCARDELLA: You say in the last bullet there's an acceptable substitute. And acceptable substitute for what? For the --

MR. PRINARIS: For the analysis.

MEMBER RICCARDELLA: For the analysis? Okay.

MR. PRINARIS: Yes, the way it was written, like -- and could have been the IWL, could have been some other, but it was a program related -- it should have been in (iii) where you manage the tendons through a program. And this leads us from TLAA 4.5, which is the tendons, into what would be the program managing the tendons in the (iii).

The program name is X.S1. This is a group of Aging Management Programs specifically related to time-limited aging analysis. What we have introduced here in addition to what we had in the TLAA 4.5 is we introduced the word again "unbonded" to ensure that this addresses unbonded tendons. We look at the tendons, hoop tendons, vertical tendons, and dome tendons, and variations of those. And then how we're going to evaluate, analyze, measure, etcetera, we put it in Element 4. We also mention this is a Condition Monitoring Program, and although corrective actions are not specifically detailed, they are to be taken before the intended function of the tendons is reduced.

There are three lines here of discussion. The lines are the minimum required value, which is a constant value from day one, and it is the design value that the containment is designed for. It's a constant and therefore is not subject to time-limited aging analysis and it drops off. So there are two other lines of discussion. One is the predicted lower limit and the other one is the trending.

Most plants have had the predicted lower limit lines computed to 40 years of operation. And you can see that falls under (i). During (i) the time-limited aging analysis was done for 40 years, so if you look at the (ii), you either have to recompute those numbers or you are going to manage. In the management perspective the predicted lower limit is a line, which also the Reg Guide 1.351 delineates how to actually do the line is very important.

Any measured pre-stressing force should never fall first of all below the MRV, which is the minimum required value. It should always be above it and exceed it.

CHAIRMAN SKILLMAN: Andy, you're

spending so much time on this. Is operating experience indicating that there is a relaxation or a change in the tendon tension? I dealt with these for years, and from inspection to inspection there was virtually no change. So I don't understand why so much emphasis is being placed here.

MR. PRINARIS: The predicted lower limit line is a compass, and the compass is versus where you are in point versus where you're going in point in time. The predicted lower limit will tell you where I should have been. If my trend line is way above the predicted lower limit, there is something that has unusually taken place. Perhaps a number of tendons have been replaced that may affect re-tensioning the structure and possibly some cracking taking place re-compressing the actual structure.

CHAIRMAN SKILLMAN: I understand the theory, but I'm asking what experience is driving this emphasis.

MR. PRINARIS: The emphasis -- these are important. The trend lines are important. We try to do to understand the level of the pre-stressing and the level of the containment where it is before it crosses the MRV line, the trend line.

Bear in mind, all of the tendons are -- the selected tendons for measurement are random. And the MRV line is an average line representing the entire force on the containment.

CHAIRMAN SKILLMAN: Yes.

MR. PRINARIS: So between randomness of the tendons and a constant number that is for the entire containment, the trend line, if it is crossed before some time, before the period of the extended operation or into the extended operation, that is a cause for alarm.

CHAIRMAN SKILLMAN: Yes, I understand that. What data is saying that this is occurring?

MR. PRINARIS: It is not the data that is occurring. The ASME Code represented only as a point. We -- in the Reg Guide; most of the plants, if not all of the plants, 1.351, we represent as a line, the predicted lower limit line, and we draw the importance of this line.

CHAIRMAN SKILLMAN: Okay. But I hear you saying there isn't any data that shows that there's degradation, which I would expect.

MR. PRINARIS: Well, there is constant trending downwards.

DR. SHACK: Yes, I mean, you have a

statement in the area of review: operating experience with a trend of pre-stressing forces indicate the pre-stressing tendons lose their pre-stressing forces at a rate higher than predicted. Again, that seems to --

CHAIRMAN SKILLMAN: Okay.

DR. SHACK: -- contradict your experience, but --

CHAIRMAN SKILLMAN: Okay.

DR. SHACK: -- that statement is made at any rate.

CHAIRMAN SKILLMAN: So now I understand the emphasis that you're placing here. Let's move on.

MR. PRINARIS: Are you referring to bullet No. 3?

CHAIRMAN SKILLMAN: I was really thinking of 2 and 3 as a pair, and I was reflecting on my own experience where there was very little change. And I was not ascribing to that any significant degradation in the capability of containment. You are pointing to, I think, a concern that over the course of time the containment can be degraded. So I understand that.

MR. PRINARIS: There are a number of

tendons that they break or the wires break, and so some relaxation takes place. And a number of plants have happened. For example, I've been looking at the FSAR of Calvert Cliffs, and in fact they do have a specific approach how to deal with the breakage of -- of these wires. And our concern is if indeed something is taking place, let's be aware of it.

CHAIRMAN SKILLMAN: Yes, I agree.

MR. PRINARIS: And we're not asking to do all the predicted lower limit. The ones that they are sampled do the predicted lower limit and then figure out how you're going to do your predicted or lower line and see your trending if it crosses that line. We never want to approach the MRV for the benefit of safety.

CHAIRMAN SKILLMAN: I understand.

MR. PRINARIS: And those are what the three bullets practically try to address.

CHAIRMAN SKILLMAN: Okay.

MR. PRINARIS: The next AMP is again regulatory-based. And Bryce, as a colleague, I remember we addressed this back and forth in this particular AMP and we said do we really need this AMP? I mean, already the regulations require it.

So what makes it to be -- as I mentioned at the beginning, we tried to abide by the principles of good regulation. And when we looked in the past versions of the NUREGs, we saw something that we repeatedly ask also as RAIs.

There are portions of components of the containment. They have not been subjected to local leakage rate testing or they cannot be because they may be submerged, or whatever the condition may be. And those have been excluded from testing. Then we have the ILRT that takes place every 10 years, and upon a review and approval maybe 15 years.

So we introduced in scope of the program if you're going to exclude certain components, tell us what other AMPs are you going to use to age manage these components? And that is the major point of this AMP that has changed from the past. It is based on repetitive RAIs. And the plants addressed this effectively on a basis -- on a document that was attached to their basis describing what exactly are doing for these particular excluded components. Again, it's for the safety purpose and is addressed effectively.

The last TLAA that we have worked on is metal containment, liner plate penetrations and fatigue. This particular one we have taken a step to address what most licensees have been addressing in their license renewal applications regarding liners or metal containment. If addition to fatigue analysis, if they are fatigue waivers and how they are dealing with fatigue waivers. So we formally introduce the fatigue waivers in TLAA 4.6 as part of the review process. And we also addressed the penetrations that they're either the mechanical/electrical, namely personnel airlock equipment hatch, control rod drives, etcetera.

Something that has been missing from this particular TLAA was if there were cyclic loads we often had difficulties identifying the cycles, and we had to ask RAIs. To eliminate that process we requested in the guidance because these are guidance documents that the applicant may or may not follow, but we are asking if you do have these cyclic loads related to a specific penetration or component related to this TLAA, list us the cyclic loads and the type and number of occurrences.

We also introduced a reference, which is quite voluminous, and it is a good reference especially for the staff since the SRP is for the benefit of the staff. It discusses the electrical and the mechanical penetrations.

DR. SHACK: Yes, I was just thinking, the thing that struck me as curious is you give these instructions to the staff, but really it's an instruction to the applicant, also. I mean, if the staff is going to ask this and -- doesn't it belong then in the GALL guidance?

MR. PRINARIS: We have a lot of SRPs. And when I see you again, I'm sure in some of these Reg Guides -- oftentimes we look at these SRPs and we try to put them into the Reg Guides as a guidance to the licensees or new applicants. And then we try to also provide a basis document to the Reg Guide and say, okay, this is the reason why we are doing these things. And then it becomes both for the benefit of the staff and the applicant.

We introduce the fatigue waiver evaluations into the time-limited aging analysis for (i) and (ii). Some of these have never had originally time-limited aging analysis and therefore they are not under the purview. And some of them, if things have changed in the plant -- and of course they revisit the analysis and extend the analysis that will satisfy the (ii).

The (iii), we took a very broad

approach when addressing what programs are we going to use to evaluate whether or not the penetrations or openings of the liners or metal plates can satisfy the managing of these? We looked into the mechanical portion of the GALL SLR, the program identified X.M1. Very similar to X.S1 that I just discussed. And the X.M1 is cyclic loading, and I'm sure later this afternoon my colleague Jim Medoff may be discussing.

In addition to this we said, look, the applicant can choose any number of other programs. He is not really locked in. Just like I said at the beginning, you are not locked into this. We want to make this as broad as possible. There may be other programs or plant-specific activities, or a combination of these things that can manage the cyclic loading of these components. And if there are, then they have to satisfy the Branch Technical Position at the back side of the SRP SLR in Appendix A. And then when we did all these changes and identified the components, we went back into the line items, table 3.51 specifically, and we updated to reflect that the areas of review are going to include metal plates, personnel airlock equipment hatch. We made it more specific rather than originally was said.

And that brings me to the end of the discussion.

CHAIRMAN SKILLMAN: Andy, thank you.

Colleagues, do you have any further questions for Andrew or Bryce?

If none, thank you, and let's begin the electrical portion. Thank you.

Bennett, are you going to remain or are you going to back away, too?

MS. BRADY: I'll stay.

CHAIRMAN SKILLMAN: You'll stay? Okay. Thank you.

Gentlemen, please proceed.

MR. DOUTT: My name is Cliff Doutt. I'm a member of DLR. To my right is Mohammad Sadollah and he'll assist me and keep me honest I think through the presentation.

CHAIRMAN SKILLMAN: Cliff, it will help if you will bring the microphone closer to your person. Thank you.

MR. DOUTT: Is that better?

CHAIRMAN SKILLMAN: Yes, sir. That's better.

MR. DOUTT: Okay. Good. What we're

going to talk about today electrical changes to the Standard Review Plan and the GALL Report with respect to SLR.

Second slide. The first thing we'll talk about is X.E1, which is environmental qualification. We'll also include Chapter 4.4 in here, which is associated with E1. Essentially the discussions are similar.

What we did here is we added discussion in the SLR extension of the components of environmental qualification or qualified life, or designated life from the standpoint of going from to 60 to 80. Part of that was environmental monitoring clarification. What's currently one of the assumptions in EQ of course is there is design-basis temperature environment radiation. What happened in 40 to 60 years is in some cases those numbers may be conservative and they were used to extend the quantified life. And from 40 to 60 in Rev. 2. That may continue. We provide some additional clarification as to how that may be done and some expectations. It was there previously. It's basically some additional guidance.

We also added an adverse localized environment inspection walkdown based on plant-specific operating experience, corrective actions procedures or visual inspection. We added this. It's similar to XI.E1, which is the insulated conductors and connections. In effect, what this is doing, we want to do a visual walkdown of EQ cables as we did with the non-EQ in Rev. 2. So it's similar. We'll talk a little more about it when we get to the next one.

We also added 50.49 discussion on the application of maintenance of margin. This is just to emphasize that the -- going from 60 to 80 and maintaining the qualification that the original margins uncertainties that need to be maintained based on the licensing basis. And it's basically a clarification and reemphasis.

The other thing we talked about is ongoing EQ, condition-based qualification, ongoing qualification, or just condition monitoring. This was in Rev. 2, as I mentioned, however, from 60 to 80 this provides an alternative if the analysis would not be successful and this involves condition monitoring cable. It can be what we did here, basically talk about it, we added some conceptual implementation how this would be done. It's allowed by 50.49. It mentions it. The standards mention it. So it's not new. We're just providing that option in the GALL and emphasizing that as another option.

Let's see. And I think that's it. I think next slide.

XI.E1, electrical insulation, insulation for electrical cables and connections. Again, we added additional guidance in adverse localized environments. This is again the same thing. Based on procedures, walkdowns and operating experience. One of the changes, if you look, when we did Rev. 2, it was identifying cables that were in an adverse localized environment. We changed that flavor a little bit. It's to look for adverse localized environments currently. It is also to look and see if in fact from operating experience cables were exposed to an adverse localized environment and dispositioned from a standpoint of either life -- 40 years or whatever. So that can be accounted for. So there's a little bit of difference.

We also added in different methodologies for identifying the areas to be looked at. A couple things were in scoping. We had mentioned it. It's in the GALL Report under scoping and screening, and it's a method that's also consistent with EPRI guidance. And we just clarified that that is also an option.

We also took fuse holders, insulation of the fuse holder, insulated part. We moved that to the fuse holder AMP just to be consistent and put it all in one place to be a little more efficient. And it didn't fit here. We just felt it fit there better. And we added sampling -- on a sampling basis for the accessible cables that you're looking at if you should find something and follow up with testing on a cable that you found in an adverse environment.

Other than that, I think that's the major changes on XI.E1.

MEMBER STETKAR: Cliff, the last bullet there, the sampling basis, the detection of aging effects just says utilizes population and includes a representative sample of in-scope stuff.

MR. DOUTT: Yes, we --

MEMBER STETKAR: We've, at least in the eight-and-a-half years I've been going through these things, we've had several discussions about exactly how does one determine what a representative sample is.

MR. DOUTT: Right.

MEMBER STETKAR: Things like buried piping come to mind. Small bore welds and things like that. And this is one of the few sections in this NUREG where there's no guidance of what that representative sample might be.

MR. DOUTT: Well --

MEMBER STETKAR: So --

MR. DOUTT: -- it's similar to -- E6 also has the same -- it has the 25 percent. So in this case though the samples is the accessible. Okay? So it's a little misleading.

Now, when we say representative of that, probably what we're really saying is that if -- within that accessible visual inspection if you should find something that needs to be tested, then that would be your -- that's where it would be tested. So --

MEMBER STETKAR: I'm sorry. Explain that again? What is a representative -- I understand this is only accessible, so --

MR. DOUTT: Yes, this is --

MEMBER STETKAR: -- what is a representative sample of that?

MR. DOUTT: Backing up, originally in

Rev. 2 it said "sampling program." And sampling there really just meant whatever the accessible cables were.

MEMBER BLEY: I mean, 100 percent of what --

(Simultaneous speaking.)

MR. DOUTT: A hundred percent accessible is a sample. That's what it meant.

MEMBER BLEY: Did it say that? I don't remember.

MEMBER STETKAR: No, it didn't.

MEMBER BLEY: I don't think it did.

MEMBER STETKAR: It was not -- I didn't and it wasn't explicit.

MR. DOUTT: If you go back, it says it's a sampling program, however, what -- really you're looking at 100 percent of whatever the accessible walkdown was. And in this particular case you would do that -- the intent here was if you had an adverse -- and the cable was shown to be that, then that test would be done. So of the accessible sample, if you found particular cables to be tested, that was the intent of this. It shows a representative sample, but that's -- if we wanted to do it that way, we'd do it like we did E6 and --

(Simultaneous speaking.)

MEMBER BLEY: I'm just curious how either a licensee or a reviewer would divine that.

MR. DOUTT: I agree representative is i this particular case --

(Simultaneous speaking.)

MEMBER STETKAR: Well, in all other cases --

MR. DOUTT: Yes, we do --

MEMBER STETKAR: -- the guidance is pretty doggone clear --

MR. DOUTT: Right.

MEMBER STETKAR: -- about what the expectation is for sampling. In some cases it says inspect all, which is not a sample. It's all. In other cases it specifies 20 percent, maximum of 25. There are some other numbers that float around. But in this case it's left to --

MR. DOUTT: Yes, they --

MEMBER STETKAR: And why do that if it's a known issue? It's come --

MR. DOUTT: It's actually --

MEMBER STETKAR: My point is the selection of the sample has been a known issue in terms of numerous RAIs and negotiation between the staff and the industry and individual applicants on several items. So why raise that here?

MR. DOUTT: I tend to agree. We've had that comment. E6 does what you're saying. It essentially does it at 25 or whatever. One of the things we found in the effectiveness audits, when you did connections and said representative samples and said 20 percent of, it was more important to identify the type of connection and make sure you had a --

MEMBER STETKAR: In other places it says you parse up --

MR. DOUTT: Yes.

MEMBER STETKAR: -- everything into -- I'll call them defined populations.

MR. DOUTT: Yes.

MEMBER STETKAR: And it says take a 20 percent sample of each defined population. So that's pretty clear.

MR. DOUTT: And that's what we found in -- in the effectiveness audit what was happening was that the first part wasn't necessarily being done. We had this comment. And I would agree we can --

MEMBER STETKAR: Okay.

MR. DOUTT: -- certainly fix this.

MEMBER STETKAR: Thank you.

MR. DOUTT: The intent was as you said.

MEMBER STETKAR: Thank you.

MR. DOUTT: Next one, E2. E2 is electrical insulation, cables and connections, requirements for instrumentation circuits. This is neutron monitoring and such. The only change here, and it's not really significant, we just clarified the guidance on the adverse localized environment. Made it similar to read to the other AMPs. And there's another major change.

In E3, or XI.E3, originally XI.E3 was power cable. Based on going forward, we split this into three parts. The first, A, is medium-voltage. We did instrumentation controls and lower voltage power. A couple reasons to do this: One is that the testing and type of cables in that are different. Splitting these us is more consistent with what industry guidance is doing. It's more consistent with our Reg Guide and our NUREG.

MEMBER STETKAR: Does the scope -- if I step --

MR. DOUTT: The next thing is scope

changes.

MEMBER STETKAR: Well, no, let me step way back from this. I read all three of these things. Substantively and functionally I don't see any difference among -- the words are a little bit different.

MR. DOUTT: Right. Right.

MEMBER STETKAR: And I agree the testing method might be different given the type of cable, but it doesn't specify the testing method. It just says --

MR. DOUTT: Right.

MEMBER STETKAR: -- a proven testing method.

MR. DOUTT: That's correct.

MEMBER STETKAR: And it's left up to figure -- everybody to figure out what that is. So is the intent now for people to apply an Aging Management Program to every single underground or buried cable regardless of its voltage, less than 35 kV, or its function? Instrumentation power, control, whatever. Everything.

MR. DOUTT: Scope's been expanded to include all.

MEMBER STETKAR: All? Okay. Why then

do we need three separate programs for people to keep track of if the functional requirements and the words are all the same and the scope is just basically including all of the cables?

MR. DOUTT: Based on tests, research, OpE, how the cables are constructed and the tests that are applicable, we thought we would just clarify where we were talking. Before when we did it all in one, we listed testing. And it would be applicable to some of the cables, some of the others. So it was really clarification and is consistent --

MEMBER STETKAR: But it only just says -- each one just says one or more proven conditional -- I'm sorry. I'm reading from the wrong one, but a -- if I can find the right words.

MR. DOUTT: Applicable test method?

MEMBER STETKAR: It's something like a proven test method.

MR. DOUTT: Yes, that would be --

MEMBER STETKAR: Or a proven technique. And that's all it says. It doesn't specific what types of tests they're doing.

MR. DOUTT: One of the reasons --

MEMBER STETKAR: And it says that for

each type of cable.

MR. DOUTT: Yes, we took -- that's a change from Rev. 2.

MEMBER STETKAR: No, no. But my whole point is you're making the argument that they're separate because the actual tests that people may apply to each type of cable may be different. And I get that.

MR. DOUTT: And the other thing, reason we broadened this out like that is that the current research and things that are going on from a condition monitoring point of view, we originally specified test, but over time that may in fact change. And so we left that open on purpose. And that would be determination -- if our confirmatory research or industry's research or EPRI or whatever -- if those are -- whatever should come up in the next -- that becomes the industry standard or it's a proven -- and they present that, we can adjust this as we go, or not, but we can accept that at times. If we put defined test here, what we have right now -- initial applications, in some cases, you know, if you look into condition monitoring or some other types of work, we just left that open as an option. We didn't want --

MR. SADOLLAH: If I may add to that --

MR. DOUTT: Sure.

MS. SADOLLAH: -- if this were to be one AMP, and you went out there and looked at the AMP, and audit had looked it or as the applicants are developing the AMP, it would be basically a three-part AMP. It would say for these low-voltage cables, these are the applicable test methods for a medium-voltage. And by splitting it up it may make it more efficient. It may make it easier to develop and to audit the AMPs.

MEMBER STETKAR: I guess I could get it if indeed you actually specified test methods, but you don't.

MS. SADOLLAH: Right. At this point as we speak --

MEMBER STETKAR: This point? Okay.

MS. SADOLLAH: -- there's so much --

MEMBER STETKAR: Okay. So --

MS. SADOLLAH: -- new information being gathered. We don't have that information.

MEMBER STETKAR: So this is just -- what I'm hearing is --

MS. SADOLLAH: But the research is going to inform --

MEMBER STETKAR: -- this is anticipatory of things coming down for --

MS. SADOLLAH: Right. Right.

MEMBER STETKAR: -- the next revision of this GALL.

MR. DOUTT: Not necessarily the next revision, but it could be as things would happen. An ISG to this AMP would be -- modify the AMP and would include this particular test if that turns out to be the case.

MS. SADOLLAH: As you recall, there's a whole host of research and information being gathered as we speak, the next couple of years, will be completed for the cables. So all that is going to inform into what's going to happen with these cables? What are the good appropriate test methods, good qualifications and techniques?

MR. DOUTT: And that information would show up in the form of NUREG, Reg Guide or the standard as well.

MEMBER STETKAR: I'm going to try to keep this moving here.

MEMBER BROWN: But before you move on, on the testing, I mean, five years ago we had this same discussion when you were talking about just the license renewal process in itself about the acceptable methods. And I mean, there was a potpourri, a list of --

MR. DOUTT: Right.

MEMBER BROWN: -- methods which nobody could really say any one was the definitive test. So that was five years ago, I mean, roughly.

MR. DOUTT: Yes.

MEMBER BROWN: I mean, you can -- what, four, six, whatever it was when we had these previous discussions. So you're saying in the last four or five years we still haven't identified anything else. So I'm a little bit reluctant to put too much faith in this if there's more research being done to define all this over the next few years and then therefore we can leave this thing open to somebody telling me that they've got a proven method. But yet how do you know it's a proven method? So that just seems to be a little bit -- not very substantial.

MR. DOUTT: And from the five years there have been some additional tests that are being used. And we could certainly reference those. And again, they have -- essentially in the medium- voltage realm, mostly in the shielded medium-voltage realm. Other things are pretty much constant. We did this -- the reason we did this was just leave it open.

So as things come down the pike, we're looking at -- on the November 17th presentation research that was presented, all that's due around the 2018 time frame. And we felt that that -- specifying some particular, we could do two or three, but that's not all-inclusive. It's just a suggestion again. When we suggest a proven test here, there's either a standard or there's a Reg Guide or NUREG or something that's also discussing it. And those are referenced. So you could easily -- that's where you would go if new information was out, if there's a NUREG, Revision to the Reg Guide, or we need an ISG industry standard. We can do an ISG to this if we feel that we need have this particular test. But that was the idea.

MEMBER STETKAR: Let me -- Dennis?

MEMBER BLEY: Go ahead.

MEMBER STETKAR: Suppose I have a 125-volt DC power cable that goes to a little motor, or a small motor, something like that. Is that a medium-voltage power cable or is that an instrument and control cable?

MR. DOUTT: I think we call it a low-voltage power.

MEMBER STETKAR: Okay. That's my interpretation of this.

MR. DOUTT: Okay.

MEMBER STETKAR: What's the difference between that and a 125-volt instrument and control cable that goes to an instrument -- power to an instrument?

MR. DOUTT: Now we're just being particular as to where the application was in general.

MEMBER STETKAR: But you're saying the different testing methods might apply to each of those cables --

MR. DOUTT: They may or not.

MEMBER STETKAR: -- and you know they kind of look like they're identical?

MEMBER BROWN: To me 125 volts is 125 volts. Whether it's running off to a cabinet somewhere or whether it's going to a motor it should be --

MR. DOUTT: Yes, one of -- like --

MEMBER STETKAR: My whole point is that we're looking at cables. We're not --

MR. DOUTT: Yes.

MEMBER STETKAR: And we're differentiating different programs now saying that somehow that 125-volt thing that I put in the instrument box might be somehow different from the 125-volt thing that I put in the power box, despite the fact that the cable sort of looks the same and its voltage is the same and it's duty is the same.

MEMBER BROWN: But the amperage could be the same and the heating -- the component could be different and --

(Simultaneous speaking.)

MS. SADOLLAH: Yes, and usually another characteristic difference would be instrument cables would be twisted pair shielded cables. So especially for shielded cables there's a whole set of testing that is good and applicable and usually repeatable that is not with unshielded cables. So 125-volt DC cables probably more than likely are unshielded. And there are different sets of testing, different -- the different aging mechanism can appear there that you won't see it in the twisted pair shielded cable. And a motor load and a control load are different and amperage is --

(Simultaneous speaking.)

MEMBER BROWN: I would comment that if there were circumstances where I had 125-volt power cables going into an instrument cabinet and they were shielded -- because if I didn't I would get interference going in and all my source range nuclear instruments were going bananas. So saying that they're most likely twisted pairs, that these have real power because there was --

MR. DOUTT: And loading could be -- and the motor load may be more -- in control of --

MEMBER BROWN: That's somewhat less susceptible in many circumstances. So anyway, I --

MEMBER STETKAR: Bigger picture again, what -- now I get it. You know, we've been following this for a long time, and we followed it -- the last snapshot that I took is we followed it down that certainly power cables of 400 -- oh, excuse me. Can you guys stop talking, please?

PARTICIPANT: I'm sorry.

MEMBER STETKAR: Thanks. Power cables down to 400 volts and above are currently included in the scope of AMP XI.E3. So now what operating experience or revelations have we had that we suddenly have to include -- I'll call them low-voltage small cables to avoid the connotation of 125-volt DC power versus instrument and control cables, in the scope of this at 60 years plus one second?

MR. DOUTT: Well --

MEMBER STETKAR: What operating experience do we have or what research that says that now those cables are subject to aging in an environment where they're buried or underground, inaccessible?

MR. DOUTT: I was actually thinking this was going to come up on the EQ side of the fence, but --

MEMBER STETKAR: No, this is --

MR. DOUTT: I know where we're at.

MEMBER STETKAR: -- explicitly not-EQ, so -- I was going to raise it on the EQ, but I'm drawing my battle lines in terms of time.

MR. DOUTT: One is there is -- I guess what we don't know we don't know, but --

MEMBER STETKAR: But we know it up to 59.9 years.

MR. DOUTT: -- there have been instances of a lower voltage cable under 400 failures. The reason we picked 400 was based on the original Generic Letter and based on what was there. Actually, the Generic Letter asks from zero up. There was some clarifications at that time, whatever, where in some cases 480 reporting was okay, 400 was all right. So some data was there; some wasn't. But anyway, since that time there have been some low-voltage and instrumentation -- it could be just jacket material, it could be submerged, whatever the case may be. But there's not a lot of knowledge there over the extended period of time. So that's one aspect of it.

And there's a lot of -- actually research is being done concerning low-voltage, medium-voltage as to what the aging mechanism might be. They are different. The medium we don't have --

MEMBER STETKAR: The stuff that I've seen; and maybe I -- I certainly haven't seen it all, but is focused on those medium-voltage power cables typically in the couple hundred volts, few hundred volts range, not 125 volts --

MR. DOUTT: Right.

MEMBER STETKAR: -- or for instrumentation circuits.

MR. DOUTT: But the concern here is is

there --

MEMBER STETKAR: Differences in terms of can they develop water trees?

MR. DOUTT: Right.

MEMBER STETKAR: What other sorts of aging mechanisms are there?

MR. DOUTT: Right. Right. And the water tree meaning voltage up.

MEMBER STETKAR: Right.

MR. DOUTT: Now that failure mechanism isn't there. We've seen like we did in Rev. 2, there's water intrusion issues. We've seen failure. It may be attributed to water intrusion, but what the failure mechanism effect is is not particularly clear. So since we have an unknown there, we know they're doing research in this area. And so we've added in -- we've expanded the cables. We know they're submerged. Based on audits and all that right now, cables that were protected are the 400 and above. Instrumentation cables below that may be continually submerged. We don't have a lot of information on that. One of the angles why we would do this is again, we don't have OpE 60 to 80, so we're not sure.

The other side of this, too, not --

depending on what cables we're talking about, we either have qualified cables in an environment, which is not this case, but we would have design -- it would be design life, which is 40 years as well, or 60 years depending on where we're at. So when you say from 60 to 61 minute, from our point of view, from a design life or service life we've exceeded that. So at that point we would -- we're lacking some data. So let's take a look and see where we're at.

Same with EQ. EQ is to 60 years currently. Sixty years and one minute, you can maintain that qualification over the life of SLR. So the same thing with design life. So that's one of the intents for including all the cables.

We also don't know failure modes and effects. There could be -- at some point we have a need that we don't know about based on a particular type of cable. One of the -- in original inspection -- if you did the original inspections, basically it may have been by analysis, may have been just from experience, and we would modify that based on operating experience, if we'd done tech spec surveillance intervals. We could do the same thing here. If research shows what's going on, we can do an ISG. But right now our knowledge base is limited.

And we have a potential for new aging mechanisms and effects. Based on current history, not likely, but it may -- the potential is there.

MEMBER STETKAR: Do you have any notion -- expanding the scope of this to instrument control cables, I've looked at the General Letter responses and kind of looked at the applications under the current license renewal process, and typically if I look at medium-voltage cables, in-scope medium-voltage cables, 400 volts and above, most plants have kind of a handful of that.

MR. DOUTT: Right.

MEMBER STETKAR: There aren't really all that many. If I expand those to instrument control cables and low-voltage power cables, in-scope, meaning anything that's important to safety, not necessarily just safety-related, do you have any idea how much that might expand the scope of licensees' or applicants' inspections?

MR. DOUTT: The data is --

(Simultaneous speaking.)

MEMBER STETKAR: And tests.

MR. DOUTT: -- because on the

reporting, if you look at those applications in the report, they were reporting 400 up.

MEMBER STETKAR: Yes, that's right.

MR. DOUTT: The Generic Letter does ask for all --

MEMBER STETKAR: But they didn't --

MR. DOUTT: -- but they didn't report.

MEMBER STETKAR: But they negotiated --

MR. DOUTT: So --

MEMBER STETKAR: -- right, what they negotiated.

MR. DOUTT: -- lack of information. One of the things that E3 and E2 have done from a plant point of view currently is that there is a Condition Monitoring Program Plan. And that's really what we're doing. We're adding condition monitoring for submerged cable, all of them, as you would elsewhere. E1 is all cable, except for submerged, essentially. So you're really just saying we need -- this is a Condition Monitoring Program and keeping them dry and -- or as best you can basically in this particular case. We have seen some situations where jacket materials weren't affected by the water, either by what was in -- you know, water contaminants or whatever, like that. The numbers I don't think would be significantly higher. I wouldn't expect that from the standpoint of when you're looking at the medium-voltage. We also just said power cable, 400 volts. But that's the intent.

MS. SADOLLAH: I guess when it comes to cables, in general you can say what changes past 60 years? we've never seen any cable that was sold -- even to this day if you buy a brand new cable, you will almost never see a cable that has a design life of more than 60. Forty to sixty is about all you can get. So when it comes to going past 60 and cables, 60 almost becomes a little bit of a magical number as far as what the manufacturers claim the design life is for a certain cable.

MR. DOUTT: Yes, either design life for non-EQ or qualified life.

CHAIRMAN SKILLMAN: Please proceed.

MR. DOUTT: All right. I think we have another slide on this one, actually.

MEMBER BLEY: I'm just a little curious on that one. I want to know how far you delved into it. And I don't know the answer to this, but perhaps the manufacturers have only had 40 or 60 because they never had a request for anything longer. Is there any basis the design life, or was it just a going-in assumption that -- if you've chased it at all. I just don't know.

MS. SADOLLAH: Yes, that may very well have been a number picked from the air. It also has a lot to do with the testing that's been done. A lot of the testing that has been done, accelerated aging testing --

MEMBER BLEY: Yes.

MS. SADOLLAH: -- they stop at year 60.

MEMBER BLEY: They stop it, the equivalent of 60?

MS. SADOLLAH: Right. Nobody saw big reasons to go past 60 to 80. Now, in the confirmatory research NRC's going to be doing we will hopefully go beyond 60 to 80.

MEMBER BLEY: Okay.

MR. DOUTT: Yes, this is strictly based on what testing is currently done, qualifications --

DR. SHACK: But that's because they only had a design life of 60 years.

MR. DOUTT: That's right. That's all they needed to do.

MS. SADOLLAH: And they like to sell you more cables faster.

MR. DOUTT: Anyway, on the next like, which I -- we think we've talked about the first one, limited test statement. We did that. As we discussed, that was our thoughts.

MEMBER BROWN: Before you leave that, do you have any actual data that shows -- I mean, I have a real experience. I mean, my telephone cables have been installed for 56 years, and I'm now on my third twisted pair from the main telephone terminal that ran through the streets and underground all the way to my house and on the second pair from the little post in my back yard to my house. And that's low-voltage. That's very low-voltage cable all the way through. I call that kind of an instrumentation and control cable, although it's voice-type stuff. So it fails. I mean, it's very definitely failed and moisture got in somewhere and the line became so noisy you couldn't use it. So they're running out of pairs.

(Laughter.)

MEMBER BROWN: I don't like to hear that because I don't know what I'm going to do when that last pair --

MR. DOUTT: Same situation --

MEMBER BROWN: -- goes belly up. They're going to -- because I don't know how they're going to run it, because there's no place to run it. It's all underground for about 300 yards.

MEMBER BLEY: In my neighborhood when people aerate their yards is kind of the source of a lot of --

(Laughter.)

MEMBER BROWN: Well, that's because they didn't bury the thing the way they were supposed to. That's a different issue.

But anyway, I'm saying, I mean, do you have any data that shows -- from these plants that's -- where this type of cable has failed, or is it just --

MR. DOUTT: Not by particular type. There is the responses, there is some OpE, like I said, some jacket degradation, cable failure attributed to water intrusion, but not what -- the failure mechanism was not clear.

MEMBER BROWN: Okay. All right. I just was curious whether this was all hypothetical and nobody's ever told you.

MR. DOUTT: Oh, no.

MEMBER BROWN: But they have had some failures and you are aware of them?

MR. DOUTT: And the same situation. If you have your power cable in your neighborhood, underground service, that --

MEMBER BROWN: It's all underground also.

MR. DOUTT: It's also underground and there's --

MEMBER BROWN: I was waiting for that.

MR. DOUTT: And then if you look outside the nuclear industry in different time frames on those cables, they're failures and expected failures is not, you know --

MEMBER BROWN: Okay. Well, the power cable, the transformer blew up before the cable failed, so that was a nice one.

MR. DOUTT: But if you look at the redundancy and they do that --

MEMBER BROWN: But it worked. We still got power back, but the transformer blew up.

MR. DOUTT: Right.

MEMBER BROWN: It literally blew up.

MR. DOUTT: Anyway --

MEMBER BROWN: All right. Okay.

CHAIRMAN SKILLMAN: We get to transformers further on down the light here, Charlie.

MEMBER BROWN: Yes, let's go on. I just wondered if you had any actual related that you could make --

MS. SADOLLAH: Well, EPRI and DOE are looking more and more into even low-voltage cables. There is a fair amount of, as we said, research being done as we speak and data collection.

MEMBER BROWN: Okay. Thank you.

MR. DOUTT: Hopefully the second bullet -- what we've done -- event driven. We just clarified it. We split it out from the periodic to make it clear that that was a separate inspection. And we also included submarine cable or cable that was designed for submergence in a one-time test, which we didn't do before. We thought that that would be -- to see how we were doing in that regard as we go up from 60 to 80. That's the only other major change from E3.

Next slide. On E4, actually there wasn't a major change on E4, but we did mention scope expansion to include cable bus. We describe

-- it was talking about it there, but actually we added cable bus as a further evaluation line item. And that's not --

MEMBER STETKAR: For clarity, it's cable buses need a plant-specific AMP, is that correct?

MR. DOUTT: Yes, further evaluation would require -- yes.

And we just mentioned it here because this AMP is a good pointer to -- in discussion to why that wasn't here and why it would be further evaluation on a plant-specific basis.

We removed sampling from the -- generally just because you're going to do the maintenance, you're going to look at all the bolted connections. There are some stamps and when you skip some connections you get bit later. So basically this is a -- we just got rid of sampling in the end.

MEMBER STETKAR: I'm sorry. What was the justification for removing sampling?

MR. DOUTT: From the sampling point -- we removed sampling simply because when you -- if you do a section, you're going to look at all of them. So, and we've also had some cases where --

either a procedural mistake or whatever, but skips -- when things were skipped, and that became an issue later. You know, bus failure based on some of that. So it wasn't a particular issue of sampling in this case when you look at it. Plus visual and whatever other techniques are available. So we removed sampling from that. It wasn't really -- based on a time frame all those sections will be looked at over time generally in the plant anyway.

And the other thing we did here was to get rid of plants and description accessible, inaccessible buses, which we hadn't had before. We ran into this on a couple audits where we added some additional clarifications, what to do if you have an inaccessible bus and how to treat that. So that was added in. And that's just based on our audit experience.

Next slide.

MEMBER STETKAR: Oh, one thing. I'll just make this point once so I don't have to repeat myself. Take a look at -- and this is throughout the electrical area. You've cut and pasted things for corrective actions that are irrelevant. For example, in this bus area, E4, it says engineering evaluation considers the significance of the calibration.

MR. DOUTT: Oh, that's --

MEMBER STETKAR: Calibration of what?

MR. DOUTT: That's an error.

MEMBER STETKAR: Yes, it is. And those same terms about examining calibrations, re-calibrations, circuit troubleshooting are pervasive here. Somebody just cut and pasted a bunch of stuff.

MR. DOUTT: Yes, there's not -- there was a generic thing that got ---

(Simultaneous speaking.)

MEMBER STETKAR: Yes. Sure. Yes. First time I read it, it made sense. After that it doesn't make sense.

MR. DOUTT: Yes, it was a generic wording that got added in.

MEMBER STETKAR: But the point is who's reviewing this stuff internally? I mean, this is going out for public comments, for crying out loud. You shouldn't rely on ACRS members to bring this stuff up. It ought not to get this far.

MR. DOUTT: I agree.

MEMBER STETKAR: So good question. In management who's actually reading this thing end to end? I'll bring up the editorial stuff. There's a bunch of stuff editorially that doesn't make sense. There's incomplete sentences. There is stuff that was in NUREG-1801 that describes something very, very well that's now incoherent, from an English language point of view. It's really clear that nobody read through this document end to end. So I'll just -- that's for management.

MS. BRADY: We hear you. Thank you.

MEMBER STETKAR: It ought not to go out for public comments within incomplete sentences and stuff like that. I'll bring up some others where the editorial stuff -- I couldn't figure out something technically because the editorial stuff -- this isn't a case --

MR. DOUTT: We're aware of some of it.

MEMBER STETKAR: Well, if you're aware of it, why didn't it get changed?

MR. DOUTT: Because I just -- anyway.

MEMBER STETKAR: Oh, okay.

MR. DOUTT: On E5 there's no change, and E5 actually was just to bring in the insulated fuse insulators, mostly the fuse portion of this AMP. There was no other major changes.

On E6 originally we replaced the one-time inspection with a periodic inspection every 10 years and/or every 5, depending on how the -- what the inspection is, visual or whatever. We basically did this simply because we're going from 60 to 80. This provides some OpE feedback and trending which wouldn't be available otherwise, and there's a significant number of connections.

Basically what this AMP originally did is confirm that the applicant's existing program was doing its job. There was no adverse trends and failures were low. However, going forward, not doing another one-time, we're not sure if we're going from 60 to 80, whether we can -- we don't have the OpE. The OpE may not be folded back in. This ensures it. What happened with the plant -- the license -- original application we confirm an applicant's program, but it's not an AMP. So it doesn't have the elements. So we prefer to have an AMP, have the elements. And that way we can get the operation feedback and we can keep trying to get a better feel of what's going on. So we just added it in the second inspection.

MEMBER STETKAR: In this, Cliff, I want to understand whether or not the scope changed.

MR. DOUTT: I don't believe so.

MEMBER STETKAR: Okay. Let me -- in the parameters monitored and detection -- parameters monitored says representative samples of each type of electrical cable connection are tested. I get that. Detection of aging effects. Now it gets more specific. Twenty percent of a connector type population with a maximum sample of 25. In the current GALL Rev. 2 it just says a representative sample of electrical cable connections is tested and 20 percent of the population with a maximum sample of 25.

MR. DOUTT: Right.

MEMBER STETKAR: Now, suppose I have a plant that has 10 different types of in-scope connections and there's a population of 100 connections in each type. According to the NUREG-2191 version of this AMP I would need to test 200 connections, 20 of each of those 10, because 20 is 20 percent. It's less --

(Simultaneous speaking.)

MR. DOUTT: In Rev. 2?

MEMBER STETKAR: Huh?

MR. DOUTT: In Rev. 2?

MEMBER STETKAR: No, that's in 2191, what we're talking about today.

MR. DOUTT: That's correct.

MEMBER STETKAR: So I'd need to test 200. If I read the words literally, under Rev. 2 of Gall I would only need to test a total of 25.

MR. DOUTT: That's correct.

MEMBER STETKAR: So I have increased the scope of the testing requirement substantially here.

MR. DOUTT: Yes. One of the things that --

MEMBER STETKAR: You haven't noted that here as a bullet of a significant change.

MR. DOUTT: It was -- well, with the -- as you read it, that's true. What was the -- when we went to effectiveness audits and looked at what was done, the expectation was that the type of connections would be identified of those connections would be done. What turns out is in some cases there are a very limited number -- as you point out, a very limited number of connections were tested. So based on the AMP audits we wanted to clarify this is what we meant. We didn't feel it was a substantial change. We just felt that it was not necessarily what was happening consistently when we looked at the audit.

MS. SADOLLAH: The intent of Rev. 2 also was to do sampling of each type of connection, not just 20 percent of all the connections regardless of type voltage, size, method of installation. So we kind of clarified expanded on what Rev. 2 really meant to say, because in our audits we ran into this. We would ask, okay, so how many -- which ones are going to be included in this population? If the answer was all of them, we would say, well, really they're different. There's crimp connections, there's bolted connections. So you really need --

(Simultaneous speaking.)

MEMBER STETKAR: So what's happening now? This is something I haven't stumbled over in our license renewal reviews. Are people actually committing to samples on a connector type basis now for current license renewal?

MS. SADOLLAH: Even like Fermi, for instance, and I think LaSalle, yes, they said that, yes, well, we got crimps of certain size. We're going to do --

MR. DOUTT: These types. These types. Yes.

MS. SADOLLAH: -- 20 percent of those.

We got --

MEMBER STETKAR: Okay.

MS. SADOLLAH: -- bolted connections. We're going to do 20 percent of those and so on.

MEMBER STETKAR: Okay. So people are actually applying --

MR. DOUTT: So it was something that almost always ended up in an RAI.

MEMBER STETKAR: Okay.

MR. DOUTT: Hopefully this would eliminate the RAI.

MEMBER STETKAR: No, it certainly clarifies it. I just wanted to make sure that it -- in practice again that we don't suddenly at 60 -- you know, 59 years or 60 years and one second tremendously increase the amount of --

MR. DOUTT: Scope.

MEMBER STETKAR: -- scope.

MR. DOUTT: What we found in audits was that you could take motor type. Those would be the ones, you know, in --

(Simultaneous speaking.)

MEMBER STETKAR: It doesn't make any difference how I defined the population. It's I just want to get the concept of what's going on and how that --

MR. DOUTT: That's right.

MEMBER STETKAR: -- how it's being applied currently. Okay. Thanks.

MR. DOUTT: Let's see. And we added a new AMP E7. This was a further evaluation of the plant-specific AMP. We generally got plant-specific AMPs more -- and in operating experience. We just changed this to a -- kind of reverse it. Now you have an AMP and you take an exception, fine. But we added this in. Just in general it seemed to be the thing to do based on what we saw with OpE and in our audits. And essentially it's the same as the further evaluation.

Next slide. And this is for Chapter 6 and SLR Chapter -- or in SRP 3.6. Generally the changes here are just reflective of what we did in the AMPs in previous slides. We added a localized environment and additional guidance. We expanded the condition monitoring and we added line items to address cable bus high-voltage insulators. And line items were revised to be consistent with the changes in the AMPs. And added the cable bus as a new line item. A couple line items were -- it looks like they were deleted and reversed, but basically we pulled out -- you'll see some cases where the aging management -- aging effects and mechanisms are combined. We split the AMP. We split the line item to more clearly define what the aging mechanism effect was. But that's I think one change. I think it's fuse holders. But it's -- no, that's it. No, just the added -- the line items for cable bus, and that's the major change there.

Any other questions?

CHAIRMAN SKILLMAN: Go.

MR. DOUTT: That's it.

CHAIRMAN SKILLMAN: Thank you. We're ready for our next team.

MR. MEDOFF: Good afternoon, everybody. I'm Jim Medoff from the staff.

CHAIRMAN SKILLMAN: Jim, welcome.

MR. MEDOFF: I was assigned to brief you on the new chapter. It's Standard Review Plan Chapter 5.

As Bennett Brady had said earlier, we have a requirement in the regulations, 10 CFR 54.22. This is a regulation that requires -- when you submit your application requires the applicant to identify any existing tech specs that you'd need to change or any new tech specs that you might need for aging management. It doesn't automatically force them into changes, but it's basically telling them to go back, review their CLB to see if you got -- if you do need tech specs for aging management.

In the prior versions of the GALL and the SRP we didn't have any guidance on this. Since we had the existing requirement we felt it proper to write the new chapter on it, because it was lacking in the previous versions. And that's what we did.

One of the things we did to help them out is we provided a couple examples of existing tech specs that may relate to time-limited aging analyses or Aging Management Programs. Examples of these are if you look at the admin controls tech specs sections of the tech specs, plants may have tech spec requirements for their Fuel Oil Testing Program. And some of those may refer to specific ASTM standards.

Now those ASTM standards may be sufficient for either the current crop of applications or even a subsequent renewal application, but for instance let's say ASTM updated a standard. An applicant would then go back and find that standard is adequate for aging management, but that standard is not referenced in the current tech spec. They could come in with their LRA and propose a tech spec change to try to get us to accept the newer standard into the tech spec requirement. So it's not forcing them into anything. It's really requiring we go back to their tech specs, or even any license conditions they have in their license to see if they need to be amended for aging management.

CHAIRMAN SKILLMAN: Jim, in a way this sounds like the old 50.54(f) campaign of many years ago where licensees had to go back, cull through the license and make sure that they were current.

MR. MEDOFF: Right.

CHAIRMAN SKILLMAN: Is that the same type of activity that you envision here where an applicant for SLR would go back and really touch all of the pieces of their tech specs to identify where changes must be identified? Is that what you're really communicating here?

MR. MEDOFF: I think since we have the existing requirement in the rule I would assume that they would need to do that based on their scoping assessment and their integrated plan assessment to see what's needed for aging management. The other example that we provided in the new section is a lot of these plants, even the boiling water reactors and definitely the PWRs, will have administrative control sections for updating their P-T limits, which are definitely TLAAs for their applications. Usually those tech specs reference the approved methodology for updating the tech specs so that when they send them in it doesn't have to be for review and approval. They just send in the new pressure-temperature limits reports with the tech specs to the staff for information because we've already approved the methodology for updating it.

That doesn't mean that their approved methodology in the existing tech spec is inadequate, but I think we've had some cases in the P-T limit reviews where we had to issue some RAIs because in capsule reports it would say one thing and then they would -- their vendor would write a TLAA report including the neutron fluence methodology, which is part of the P-T methodology. And they would differ and we would end up asking questions on why they were different. So it would make us wonder whether the methodology in the tech spec was out of date or inadequate and they would get existing RAIs.

So basically the new section is a reminder to go back to your CLB, make sure that either we don't need new tech specs or tech spec changes to manage aging, or if they do find that out, to send them in with their application.

CHAIRMAN SKILLMAN: Jim, this is a yes or no question.

(Laughter.)

CHAIRMAN SKILLMAN: For an applicant for subsequent life renewal, if one were to review this Chapter 5 for their application, would one have in substance the crucial changes for tech specs accounted for?

MR. MEDOFF: Say that one more time?

CHAIRMAN SKILLMAN: If one were to review the new Section 5 for a subsequent life renewal applicant, would one have in that Section 5 a thorough accounting for the changes to those tech specs for that application?

MR. MEDOFF: In terms of really concrete guidance of everything they would have every --

CHAIRMAN SKILLMAN: Not what they have

to. What they are committing to do. This is a change in tech specs. What I'm asking for is whether or not this is kind of an oozing requirement or whether the consequence of this new Chapter 5 provides in one place a complete compendium of the changes that will be in that applicant's tech specs to go from 60 to 80 years.

MR. MEDOFF: Well, it wasn't written for the intent of telling them they have to include a tech spec change or identify a new tech spec for aging management. The rule is very high-level. It only requires them to include in their applications any new tech specs or tech spec changes they do find they would need for aging management.

CHAIRMAN SKILLMAN: It's a compendium --

MR. MEDOFF: Yes.

CHAIRMAN SKILLMAN: -- of what they have found they need to change to go from 60 to 80?

MR. MEDOFF: Yes, based on their review.

CHAIRMAN SKILLMAN: Understand. Yes, thank you. That's what I was asking.

MR. BURTON: Let me just -- part of that. This is Butch Burton again. One of the things to understand is that one of the future actions we have is to talk with industry to see what will this new license renewal application look like? And we still have to -- we're in the very beginning stages of that, to start to talk about that.

But, yes, in our minds, staff, what we would expect to see in that Chapter 5 is a laundry list that as a result of changes that we're making in the license renewal application as it relates to tech specs, here's what it is. Here's why we're changing it. And just have a laundry list of that. That's our expectation now. But we still have to talk with industry to see if they will be of the same mind set. And there may be some compromises. But that's our going-in position for this.

CHAIRMAN SKILLMAN: Well, that was my take-away when Bennett introduced this topic a couple of hour ago, and to me it is a crucial piece of the thoroughness of the application for SLR and it ties to the discussion that we had about licensing basis and the other issues pertaining to the facility. So I mean, this is a good thing, but I was just trying to get clear in my mind exactly what the product is intended to be. And I hear you say it's really -- Butch said it's a compendium of the tech spec changes because therein lie at least a large part of the defense of the plant from an operating perspective.

MR. MEDOFF: Right.

CHAIRMAN SKILLMAN: So I got it. Thank you.

MR. MEDOFF: Just if I may, one thing, just mention that the pressure-temperature limit tech specs and the admin control section of the tech specs, some of the plants don't have them. Some have their P-T limits and limiting condition of operations. Every time they update them they have to send in a 50.90 license amendment. Now they could -- like for instance, LaSalle I think the P-T limits are in the LCOs, but they could wait until they reapplied for subsequent renewal or if they want to adopt a PTFR approach they could come in with the tech spec change under 54.22 and propose it as part of their application. That's an option.

So it's not forcing them to, but they need to go through their CLB and see what they do need to manage aging.

CHAIRMAN SKILLMAN: Okay. Thank you,

Jim.

With that, I see we have concluded what were intended to be the morning's discussions.

Jane, is that where you see we are, too?

MS. MARSHALL: Yes.

CHAIRMAN SKILLMAN: That being the case, we are going to recess until 12:25. So let us resume at 12:25 on that clock.

MEMBER BROWN: 12:25 or 45?

CHAIRMAN SKILLMAN: 12:25.

MEMBER BLEY: That's fine.

CHAIRMAN SKILLMAN: I'm sorry. I'll tell you what let's do. Let's convene at 12:30. We're behind schedule. So 12:30 on that clock. Forty-six minutes. We are recessed.

(Whereupon, the above-entitled matter went off the record at 11:42 a.m. and resumed at 12:31 p.m.)

CHAIRMAN SKILLMAN: Let us begin. To all in the room, please see that we've moved Mr. Purtscher to the first of the agenda items after lunch time, and we will do that now. We will commence.

Pat, please begin.

MR. PURTSCHER: Thank you. So I'm talking about the GALL Chapter XI.M12, the thermal embrittlement of cast austenitic steels. There are two main points that came out our panel review. The first, as you see in the slide, regards pump casings. These are no longer exempt from the AMP requirements. Specifically, the code case requirements were not incorporated in the code, our VT1 visual exam of the external surfaces of the weld of one pump casing out of the population plus an evaluation to demonstrate the safety and serviceability of the pump casing, essentially a flaw evaluation. So basically that's what's changed with regard to the pump casings themselves.

The AMR line items were adjusted to account for this in the revised GALL.

MEMBER STETKAR: I'm sorry, Pat. I was shuffling through papers here. The reason the pump casings are included for subsequent license renewal is what?

MR. PURTSCHER: The code case was partially taken up in -- was accepted by the code so that it was not necessary, but not all of the parts of the code case were incorporated into the code. So that's where there's just these separate

AMR line items.

MEMBER STETKAR: I'm still -- I'm not a code guy, so you're going to have to explain it to me.

CHAIRMAN SKILLMAN: Is that pointing to a reduction in defense-in-depth or a reduction in commitment?

MEMBER STETKAR: Pump casings were formerly not included.

CHAIRMAN SKILLMAN: They were passive components, I know that. So not including or having part of the code case withdrawn represents if you will a reduction in commitment? Is that what's really happening here?

MR. PURTSCHER: I'm not really a code person either, but --

MEMBER STETKAR: Well, but I want to get back to -- it doesn't make any difference --

MR. PURTSCHER: Right.

MEMBER STETKAR: -- because this is NRC guidance to applicants. Under GALL Rev. 2 it specifically says valve bodies are included in the scope.

MR. PURTSCHER: Right.

MEMBER STETKAR: It specifically says

valve bodies. It now also requires pump casings and valve bodies.

MR. PURTSCHER: Right.

MEMBER STETKAR: And I want to know why in year 60 plus one second pump casings become a concern.

MR. PURTSCHER: Pump casings were covered by the code case previously.

MEMBER STETKAR: Okay. Thank you. That's -- thank you. Thank you.

MEMBER BROWN: And the code case was --

MR. PURTSCHER: Withdrawn.

MEMBER BROWN: I'm reading the words.

MEMBER STETKAR: Thank you. Now I get it. I guess, two or three times, after a while it sinks in.

MEMBER BROWN: And I'm trying to get the next thing you said. Were then the requirements from the code case transferred to the GALL as guidance or --

MR. PURTSCHER: Right, the parts --

MEMBER BROWN: -- in total or --

MR. PURTSCHER: -- that weren't incorporated into the code were transferred. So it still covered all --

MEMBER BROWN: I've lost it then. So not all of the code case was thrown out, just part of it, or deleted?

MR. PURTSCHER: Right.

MEMBER BROWN: And the parts that were deleted are put into the GALL, or --

MR. PURTSCHER: The code case was deleted. Part of it was incorporated into the code --

MEMBER BROWN: Okay.

MR. PURTSCHER: -- as a revision to the code. And the parts that weren't were these other --

MEMBER BROWN: Okay. All right. I understand what you're saying then. All right. Thank you.

MR. PURTSCHER: And then so the second -- the next slide regarding Code Case N-824, that's regarding the ultrasonic inspection of CASS piping. And the 10 CFR 50.55(a) proposed rule was published in the Federal Register for public comment on September 18th of 2015. We received public comments. Those were closed on December 2nd of 2015, and the staff is currently addressing those comments.

The conditions on the use of the code case in the proposed rulemaking as slightly different from that anticipated at the time when the AMP was drawn up for the SLR GALL. The conditions do not prohibit use of piping with thickness greater than 1.6 inches. Therefore, the wording in the final AMP will change to reflect the conditions in the rule when it's published. So we want to make sure that they're consistent throughout. And probably this will just say that the UT will be performed in accordance with the methodology of the code case in 824 as conditioned in 10 CFR 50.55(a).

MEMBER STETKAR: Pat, so I read through this. The term in the new version of the AMP uses the term "potential significance" or "potentially significant." GALL Rev. 2 uses the concept of susceptibility. To me those are different concepts. Susceptibility means I'm susceptible to some sort of aging mechanism. Significance means some sort of quality judgment based on is it important? Is it important enough? So I'm curious why the term "potentially significant" has -- the term "susceptibility" has been replaced with this notion of potentially significant or significance.

MR. PURTSCHER: I think because --

MEMBER STETKAR: It's subtle, but --

MR. PURTSCHER: It is.

MEMBER STETKAR: -- if I'm trying to split hairs about what I need to look at and start to make arguments about, well, this isn't significant even though it's susceptible.

MR. PURTSCHER: Well, I'm not sure if part of that came out of the probabilistic fracture mechanics assessments that have been done on CASS piping, but I'm --

MEMBER STETKAR: I would just -- you may want to think about it from the -- I'm just raising it because I stumbled over it once and I thought, well, maybe this is just one word, but it's indeed systematically changed throughout this AMP.

MR. PURTSCHER: Right, and it's intentional.

MEMBER STETKAR: It is definitely an intentional change.

MR. PURTSCHER: Yes. I mean, we've talked about this quite a bit, really. And the evidence from the testing that's been done I think is just not that conclusive to say that it's susceptible given the information that we had. It's potentially significant.

MEMBER STETKAR: Well, but I mean, the old wording said -- used terms like "determination of the susceptibility and for potentially susceptible components." So it's also rather vague.

MR. PURTSCHER: Right.

MEMBER BLEY: Is there anybody here who can tell us why the language was changed? It sound --

MR. PURTSCHER: I don't know, Jim, do you -- I don't think we can define that very well.

CHAIRMAN SKILLMAN: I think we ought to get an answer to this.

MR. BLOOM: This is Steve Bloom. Unfortunately the gentleman who really would have the answer is away at the code meeting this week. And so we are unable to get a definitive answer, but in the future we will find the answer.

MEMBER STETKAR: Yes, take it back, because if that change -- it's obvious that it was intentional. And if it was based on some type of risk-informed argument, I think we'd like to hear that.

MR. BLOOM: Yes, sir. We will get the right person to get you an answer.

MEMBER STETKAR: Okay. Good.

DR. SHACK: I was just going to quibble about your table where you have the low and high and the "or." And the only thing it means is that the percentages define what you mean by low and high.

MR. PURTSCHER: I'm not sure which table.

DR. SHACK: It's X.M12-1. There's a table, at least in the --

MR. PURTSCHER: Oh, it -- yes. I don't have that in front of me, but yes.

DR. SHACK: Yes, just take a look at it. You've got low and high and there's not an "or." They're both -- they mean the same thing. There should be a parenthesis around the 0.5 percent. That's what you mean by low.

MR. PURTSCHER: Right. Oh, right.

DR. SHACK: And two to three percent is what you mean by high. There's no "or" about it.

MR. PURTSCHER: Right.

DR. SHACK: That's an editorial comment.

MR. PURTSCHER: Yes. Okay.

MEMBER STETKAR: Pat, what else you got?

DR. SHACK: John, just to get a -- the susceptible is a material condition, right?

MEMBER STETKAR: Yes.

DR. SHACK: And so you --

MEMBER STETKAR: Yes, but I mean, this whole thing is organized around --

DR. SHACK: Well, the table is organized around susceptible, which really is --

(Simultaneous speaking.)

MEMBER STETKAR: -- they retain the term "susceptible" in the table.

DR. SHACK: Because again significant then becomes -- that's a susceptibility plus a consequence.

MEMBER STETKAR: Right, that's my whole point.

DR. SHACK: Yes.

MEMBER STETKAR: But because somebody consciously changed that thing from -- and "susceptible" is still used in the table, right?

DR. SHACK: Right, which seemed to me the actionable part of this thing.

MEMBER STETKAR: Okay.

DR. SHACK: Yes.

MEMBER BLEY: But the words modify it.

(Laughter.)

MEMBER BLEY: Or one could argue that they modify it.

MEMBER STETKAR: If it's going to cause somebody 37 cents, people are going to argue about it.

CHAIRMAN SKILLMAN: Colleagues, anything else for Pat? Pat, anything else for us?

MR. PURTSCHER: No, like I say, I really don't understand why we didn't change it in the table headings, because I --

CHAIRMAN SKILLMAN: Now, there we go. That's a concern.

(Laughter.)

MR. PURTSCHER: Yes, I know, because -- well, but I think that does seem inconsistent with --

(Simultaneous speaking.)

MEMBER STETKAR: So there you go, Dr. Shack.

CHAIRMAN SKILLMAN: Let's leave this as a bring-back, please. Okay. Enough. Let's go back.

Pat, thank you.

MR. PURTSCHER: Okay.

CHAIRMAN SKILLMAN: And this will bring us back to our slide 48, and neutron fluence.

And so, Matt, are you the --

MR. HARDGROVE: Yes.

CHAIRMAN SKILLMAN: -- lead here?

MR. HARDGROVE: Yes.

CHAIRMAN SKILLMAN: So please proceed.

MR. HARDGROVE: Okay. Good afternoon. I'm Matthew Hardgrove from the Reactor Systems Branch in the Division of Safety Systems. Myself, with Jim Medoff to my left from the Division of License Renewal, want to briefly discuss with you today the new neutron fluence monitoring AMP for subsequent license renewal.

Next slide, please. To recall the November meeting discussing subsequent license renewal, licensees are considering operation from 60 to 80 years. Programs with the GALL will look to manage the aging effects for this time period, like neutron embrittlement. The staff has been seeing license renewal applications containing neutron fluence evaluations for reactor vessel internals in areas outside of the traditional beltline area.

Next slide, please. The neutron fluence AMP was created by the staff based on license renewal applications containing neutron fluence evaluations in non-traditional places inside the reactor vessel.

Within these license renewal applications the staff was asked to review neutron fluence evaluations outside the beltline and make determinations. These evaluations have challenges applying regulatory guide 1.190 adherent methods to these methods that are outside the beltline. The AMP acknowledges for subsequent license renewal that neutron fluence evaluations may be applied in ways that are outside the scope of Reg Guide 1.190. The staff is working with the Office of Regulatory Research on new guidance for outside the scope of Reg Guide 1.190 methods for reactor vessel internals and outside the traditional beltline area.

Next slide, please. The new neutron fluence AMP contains multiple parts. The AMP provides a method for accepting reactor pressure vessel neutron embrittlement TLAAs in accordance with 54.21(c)(1)(iii). The AMP is to be used in conjunction with another AMP, XI.M31. The acceptance criteria of the AMP is that the regulatory requirements for updating the analyses and submitting the analyses to the NRC as defined in the applicable regulations or tech spec requirements.

Next slide, please. The detection of aging effects and monitoring will focus on the components in the reactor pressure vessel beltline being consistent with Reg Guide 1.190. Methodologies being applied for reactor vessel internal components or reactor pressure vessel components outside the beltline may need additional justification on a plant-specific basis.

CHAIRMAN SKILLMAN: Matt, how will you know that additional justification is needed? What will be the trigger for that?

MR. HARDGROVE: Typically the trigger for that will be -- and I've personally reviewed this through an example in the past for another plant going for license renewal of what areas are kind of getting past the threshold and having to be analyzed for license renewal applications moving forward.

So to elaborate on that more would be typically we'd look at the traditional beltline region. There is a screening and criteria for 1 times 10 to the 17th. And anything that exceeds over that, that would be outside of that traditional region. Something -- you know, something higher in the core or anything like that, that would be something that would get to the all the staff as something that would be needing additional justification because it's outside of what we traditionally be seeing.

CHAIRMAN SKILLMAN: Okay. Thank you.

MR. HARDGROVE: Next slide, please. The staff has held multiple discussions with members of the industry with the creation of this --

DR. SHACK: Is this --

MR. HARDGROVE: Sorry.

DR. SHACK: Is it clear with 1.190 that it only applies to the beltline region?

MR. HARDGROVE: I would typically say yes.

(Laughter.)

CHAIRMAN SKILLMAN: Typically? Non-typically what would you say?

DR. SHACK: That sound clear as a bell, yes.

MR. HARDGROVE: The Reg Guide was designed with focusing on the traditional beltline. As plants have been operating longer and seeing how different things have changed for how plants operate, we started seeing new things that come into play.

DR. SHACK: No, but I mean is there a consistency check within 1.190 that lets you know when you can apply it and when you can't? It sounds as though you may need to revise it to say it's valid when and it's not valid --

MR. HARDGROVE: Right, and that is one of the things we are working with with the Office of Research for finding ways to update the Reg Guide.

So the staff has held multiple discussions with members of industry regarding the creation of this AMP. The draft AMP has gone out for public comment and a public meeting was held back in January to hear the initial feedback from the industry.

And that concludes my presentation.

MEMBER STETKAR: Butch asked me to

alert him when I found the thing that I was searching for before lunch. I found it. It's in this AMP. Under the detection of aging effects; and I think I know, but I want to make sure, it says, "If all surveillance capsules have been removed and tested, a plant may seek membership in an ISP." And it says, "In addition, the plant institutes a Supplemental Neutron Monitoring Program," yadda, yadda, yadda. There's two Ds in yadda. "Alternatively this program can propose implementation of in-vessel irradiation of capsules with reconstituted specimens from previously tested capsules and appropriate and neutron monitoring." And appropriate something else, or just and appropriate neutron monitoring?

MR. HARDGROVE: I would just say the "and appropriate neutron monitoring."

MEMBER STETKAR: Okay. I wasn't quite sure whether something got inadvertently omitted or whether the "and" was superfluous.

MS. FAIRBANKS: You found another editorial comment.

MEMBER STETKAR: But this is one where if there was something else --

MS. FAIRBANKS: Absolutely.

MEMBER STETKAR: -- and appropriate inspection, and appropriate trending, and appropriate something or other, you know, could have had an implication about what people need to do.

MS. FAIRBANKS: You're right.

MEMBER BALLINGER: Reg Guide 1.190 is specifically for the beltline. This guide describes the application and qualification of a methodology acceptable to the NRC staff to determine a best estimate neutron fluence experience by materials in the beltline region of light water reactor pressure vessels.

DR. SHACK: Yes, but the question is there a rigorous definition of beltline --

MEMBER BALLINGER: Well, give me a chance.

CHAIRMAN SKILLMAN: So, Ron, do you want time here or should we keep on going?

MEMBER BALLINGER: No, no. No, no, no.

CHAIRMAN SKILLMAN: Okay. Thank you.

So, Matt, you are complete?

MR. HARDGROVE: Yes, I'm done. Thank you.

CHAIRMAN SKILLMAN: So that would then

bring us to Carolyn.

MS. FAIRBANKS: Okay. I'd like to discuss Chapter XI.M31, Reactor Vessel Material Surveillance.

This program involves the requirements of Appendix H to 10 CFR Part 50. That's the reactor Vessel Material Surveillance Program requirements. The purpose of that appendix is to monitor changes in fracture toughness for the ferritic prop materials in the beltline in that those changes result from exposure to neutron irradiation and the thermal environment.

I think pretty clearly this is a program that starts with the startup of the plant. They construct the capsules. And there is a progression here where the original license in the withdrawal schedule can clearly be seen in Appendix H in the reference to table 1 in ASTM E185-82. There was recommendations for adjusting that program in the GALL Reports to cover 60 years, so now we are updating the recommendations for adjusting the program so that there's adequate coverage through 80 years of operation.

A number of the items on the next couple pages are just clarifications for licensees to assist them in developing a submittal. So in the program description we've provided some updated differentiation between plant-specific programs and integrated surveillance programs, referred to as ISPs.

Next slide, please. Also in the Scope of Program, Detection of Aging Effects, and Monitoring and Trending there are improved criteria descriptions for implementation again of plant-specific programs and integrated surveillance programs. Under Parameters Monitored there are updates to the capsule removal schedule and reference to Reg Guide 1.190 does not describe conformance criteria.

Next slide, please. Detection of Aging Effects and Monitoring and Trending Elements. Here we have recommended withdrawal and testing of an additional capsule during subsequent period of operation that achieves capsule fluence between 1 and 13 times the maximum ID fluence.

There are a couple of things that are a little different here. One is that this is an additional capsule that we're requesting be tested. The recommendation was that this be done during the period of extended operation because there was a recommendation in the GALL that once capsules were getting to fluence levels that were greater than 60 years, or between 1 to 2.6 year equivalents -- it was recommended that they be put into storage before they accumulated so much fluence that their results would have as much meaning when they were compared to operating conditions.

The capsule contents include specimens that are tested. Because those capsules are closer to the core they have a higher lead factor. Those results are compared to Reg Guide 119 for the level of embrittlement, and we're looking for consistency so that we have insight that the vessel is aging consistent with what we're projecting in our models. The target fluence -- so we had anticipated that most licensees would probably put standby capsules into storage and might need to reinsert those to get a fluence that's between 1 and 13 times the 80-year equivalent of the ID fluence.

Typically, before, if you looked at the Appendix H recommendation for the original withdrawal schedule or for the 60-year capsule for license renewal, we had recommended one to two times the EOL value, or PEO value. To calculate that out to 80 seems like we're pushing it out to fluence values that may not be so applicable when we're going to 80 to 160, so the recommendation was 1 to 13 times the maximum ID fluence.

And then we have included alternative management activities as well in case a licensee is -- tested all of their original capsules. They have options that are described in greater detail in the SLR document for joining an ISP potentially or reconstituting specimens that have been tested from previous capsules.

That's my last slide.

CHAIRMAN SKILLMAN: Carolyn, are there any licensees that have had difficulty in ensuring that they have specimens that will give them a leading indicator? I would think that if they are all compliant with the current regulations, the answer would be no, but I'm curious if there are outliers.

MS. FAIRBANKS: We have not encountered anything so far. Most of the boilers are members of an Integrated Surveillance Program. I think it was probably good planning originally that most licensees had a good number of standby capsules. We've seen them trying to adjust a little bit. The original plan when capsules were first tested was to pull the highest lead factor capsules first. That way they were getting better insight into embrittlement trend curve that didn't have so much data on which it was based. Our trend curve now has probably better data. That left some licensees with lower lead factor capsules, and some of those are actually moving them to higher lead factor locations to get more relevant data. So we have not run into anybody yet having difficulty with that.

CHAIRMAN SKILLMAN: Thank you.

MS. FAIRBANKS: And there's also that potential of taking tested specimens and reconstituting them --

CHAIRMAN SKILLMAN: Yes.

MS. FAIRBANKS: -- and inserting them.

MEMBER RICCARDELLA: By standby capsules you mean capsules that were removed but they didn't test the specimens?

MS. FAIRBANKS: Standby capsules really is another for excess capsules. Licensees, depending on their projected amount of embrittlement, wouldn't have been required to have pulled three, four or five capsules. If they had eight capsules in the vessel, those five would just be standby because they were not scheduled to be withdrawn to --

(Simultaneous speaking.)

MEMBER RICCARDELLA: I see. So they were continued --

MS. FAIRBANKS: So they may be in the vessel or -- the recommendation where they accumulated too much fluence to have data of value is that they be moved to storage, usually spent fuel.

MEMBER RICCARDELLA: But now they could put them back in?

MS. FAIRBANKS: Now they could be transitioned from being a standby capsule to being a capsule to meet the 80-year testing recommendation as well.

MEMBER RICCARDELLA: Thank you.

CHAIRMAN SKILLMAN: Colleagues, any questions for Carolyn?

Hearing none, Jim, we're to you on Chapter 4.2, please.

MR. MEDOFF: Yes, James Medoff with the DLR staff again.

I'm going to talk about the changes to

our chapter in the Standard Review Plan for neutron embrittlement TLAAs. These are typically generic TLAAs for the industry. Many of them that we have in Chapter 4.2 are mandated by regulations such as 10 CFR Part 50, Appendix G for upper shelf energy or P-T limit TLAAs, or in 10 CFR 50.61 for pressurized thermal shock assessments for PWRs.

Most of the edits to Chapter 4.2 were editorial. We did do a few things earlier on. In the past applications some of the applicants did identify their neutron fluence methodologies, which are inputs to these STLAA's themselves, so we added a subsection with some acceptance criteria, and reviewed procedures for these types of TLAAs was based on past applications. As always, an applicant would go through its analyses, compare them for the TLAA identification criterion in 54.3 to see if they are TLAAs, but since some past applicants had added them as TLAAs in their applications, we decided to add this section.

One of the things that has happened since the approval of some past LRAs is that they did not meet this -- for PWRs we're talking about. They did not meet the PTS screening criterion 50.61 in their original applications and they may have had a commitment to apply the corrective actions in the 50.61 rule three years ahead of time of coming into -- of exceeding the limits in the rule or to send in a 50.61(a) alternative PTS assessment as a license amendment.

So we had to update the criteria for the PTS assessments to identify that based on your CLB your PTS assessment may be based on the 50-61(a) requirements or the original 50.61 requirements depending on the CLB. That's just to keep it up to date with current licensing basis. I think we've had a few plants that have submitted 50.61(a) submittals down to the Division of Engineering.

MS. FAIRBANKS: We've got one, right? Yes, that rule came into effect in 2010.

MEMBER BALLINGER: Is this Palisades?

MR. MEDOFF: Correct. So we just wanted to be consistent with that.

Matt talked about the new AMP X.M2, the neutron fluence monitoring AMP. Some of the criteria we had in XI.M31 reactor vessel surveillance had some neutron fluence monitoring stuff. We moved some of that out of XI.M31 into X.M2, but they're supposed to be used in conjunction with one for monitoring your fluence levels in your vessel, which is the X.M2. One is you follow the XI.M31 when you're pulling and testing capsules. So they're all providing inputs into these TLAAs. so if you were going to accept one of these TLAAs under 10 CFR 54.21(c)(1)(iii) using the old XI.M31, now it's using the XI.M31 and the X.M2 in conjunction with each other --

MEMBER BALLINGER: Okay.

MR. MEDOFF: -- as there are some inter-relationships.

And one of the things is for the boiling water reactors many of the plants in their current licensing basis for the fourth interval may have these relief requests to eliminate ISI examinations in their circ welds. Those are based on a time-limited neutron fluence methodology in Topical Report BWRVIP 05. The assumptions for fluence on that were based on 80 years, but only on an 80 percent capacity factor at operations. And so, if these are going to come in as TLAAs in their applications, as they may, we're going to review them on a case-by-case basis because a lot of the plants are operating at higher capacity factors than 80 percent at this point. A lot of them we've confirmed that they're not exceeding the fluence levels assumed in the 05 methodology.

MEMBER BALLINGER: Okay.

MR. MEDOFF: And that's about it for 4.2.

CHAIRMAN SKILLMAN: Thank you very much. We are now into Chapter XI.M6. And, Jim, you're still up.

MR. MEDOFF: Yes.

CHAIRMAN SKILLMAN: Let's go.

MR. MEDOFF: GALL AMP XI.M6 is the current methodology for inspecting control rod drive return line nozzles in boiling water reactors. There's a little bit of a history. I'll go quickly through that. It's basically an old Generic Safety Issue, some NUREG reports and some GE-recommended augmented in-service inspection practices. They basically took the code volumetric requirements for the nozzles and augmented them for additional coverage on the inner one radiuses of the nozzles.

Some of the things: The issue at hand for these components was the nozzles were cracking due to cyclical loading or fatigue. There was a lot of thermal cycling in the nozzles. So that's what the recommendations were written to try to relieve or try to inspect for. One of the things they were allowed to do under the GSI initiatives and the NUREG methodology was you could also modify your plant design to cut the nozzle and reroute the line to another portion of the system; this was mainly the recirc loop or the feedwater lines, reactor water cleanup system, and have the fluid reenter the reactor vessel that way. If you rerouted the lines during an initial design modification, what happened is the fatigue issue for the nozzle should have gone away.

So we decided that because most of the plants have either modified their designs, or for the BWR-2s we only have one BWR-2 that's going to come in for license renewal and it has updated procedures due to the inspections of the nozzles, we decided that that AMP wasn't really needed anymore for the nozzle-to-vessel welds and we decided to take it out. For the plants with the rerouted lines, or even if you capped your nozzles, we have some further evaluation criteria that were written to help them out with their Aging Management Programs that they would use for those configurations.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: And that's pretty much it. And that's taken up about two slides there, but that's basically what we did for that AMP.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: We did tell the industry to look over those for their evaluations and maybe help us out with maybe the modifications throughout the industry to give us comments on that.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: Okay. Are there any further questions on that X.M6?

MEMBER RICCARDELLA: There was a similar fatigue problem with feedwater nozzles. Is that covered in an AMP?

MR. MEDOFF: We did retain that AMP. It's not a formal comment yet, but we did have a meeting with the industry on the 21st of January this year. They did want to talk about that because I think the industry preliminary comments, not formal yet, was that we could take that one out as well.

As you said, that feedwater nozzle AMP, XI.M5, is also based on that Generic Safety Issue. And so, I think the industry has stated at that prior meeting that the ISI initiatives plus whatever PDI requirements in 50.55(a), the performance demonstration initiative requirements, should be good enough. If that comments comes in formally, we will look at it and see -- take appropriate action.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: The next two AMPs I'm going to talk about talk about reactor vessel internals. One is for the boilers. The current AMP in GALL Revision 2 is XI.M9. For the PWRs, which I'll talk about a little bit later, it is XI.M16. They're based on industry reports. From EPRI it's the BWRVIP inspection evaluation guidelines for the boiling water reactors, later on when I talk, XI.M16(a). It's MRP-227, which is a sampling-based program.

One of the things, as I go into my discussions on these AMPs I'll get into a little bit why the way we did recommendations in the draft GALL documents and the Standard Review Plan documents -- why it was treated a little bit differently for the PWRs, for the BWRs, because there's a reason for that.

So let's start with XI.M9. It's the

one for the boilers. It's based on a bunch of VIP I&E guidelines. We decided to retain this AMP because unlike the program for the PWRs, we have a series of inspection evaluation guidelines. It's a much more comprehensive program. It look at a larger percentage of internal components when you compare it to that for the PWRs. So we decided to retain these inspection and evaluation guidelines. We may have modified the scope. As you see on this slide we added loss of preload because we had some -- that is an aging effects from some internals that wasn't in the AMP. So we added it. We added cracking due to cyclical loading and flow-induced vibrations because that wasn't an aging mechanism for the steam dryers. So you can see we modified the AMP, but it's really for the most part pretty much as we had before.

Instead of modifying the AMP for supplemental inspections, what we did is we took the linked AMR line items. And if it was on an aging effect for like an irradiation-induced effect such as irradiation stress corrosion cracking or loss of fracture toughness due to neutron irradiation embrittlement, loss of preload due to irradiation- assisted creep, then we didn't tell them to automatically augment the guidance in the applicable inspection evaluation guideline. What we did is we created further evaluation to tell them to go back, re-review them to see if they needed to be modified. So we're not forcing them into anything. We would expect that if you had an irradiation effect for a component in one of those I&E guidelines, that we'd go back, re-review them to either justify that they remain acceptable as currently written or to augment them if they found out maybe the inspection frequency should be a little more often or they need to increase sample size, things like that. But we're not forcing them into anything. We're just for irradiation-type effects to go back and look at the existing guidelines to see if they need to be tweaked a little bit.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: And that's pretty much how we handled the boilers.

Let me go into --

DR. SHACK: Just a question I had. There's a discussion in here about susceptibility of CASS austenitic stainless to neutron and thermal embrittlement. And apparently there's a staff-approved screening method that covers both neutron and thermal embrittlement for BWRs, which is -- it's an issue for PWRs. But where is that referenced? That doesn't seem to be a VIP document that covers that.

MR. MEDOFF: No, well, maybe the industry can help me out a little bit. Let me take my stab at this. The current guidelines that we use for BWR vessel internals and for even CASS reactor, you know, Class 1 piping or vessel components, is in a license renewal position that was put out in the year 2000. We call it the Chris Grimes Letter.

DR. SHACK: But that's thermal embrittlement.

MR. MEDOFF: Right. But I think that document gets into some -- it's gets into thermal embrittlement, but I think it has something in it --

DR. SHACK: Oh, okay.

MR. MEDOFF: -- about neutron embrittlement.

DR. SHACK: There's something there in the neutron?

MR. MEDOFF: And we were aware that

that is way out of date for internals, so I think there's a preliminary effort to get that updated because I think if you look at the MRP report for PWRs -- and I think that the BWRs also have a -- when we get into neutron --

DR. SHACK: This sounds like a blank check here in the guidance, that there's a staff-approved method that covers it.

MR. MEDOFF: In terms of VIP documents?

DR. SHACK: Well, I don't know where it comes from. That was my question.

MR. MEDOFF: Yes.

DR. SHACK: Where did it come from? I couldn't find a VIP document that would seem to cover it, but I --

MR. MEDOFF: I'd have to check back with one of my counterparts in the Division of Engineering, Ginesh. If you give me that as an item, I will check on that.

DR. SHACK: And that first bullet about they evaluate the need for supplemental inspections, I could find that in the Staff Review Plan, the SRP. I didn't find it in the GALL.

MR. MEDOFF: I think when this -- and Seung Min is in the audience. He can help out because he was the tech lead for this AMP. But I think when we put it in as a line item in the slides, it was really talking about what we did in the further evaluation section in the SRP.

MR. MIN: Yes, this is Seung Min, and with respect to the first question from Dr. Bill Shack about neutron embrittlement threshold level in terms of fluence, actually XI.M9 includes the criteria that is 10 to the 17th neutron per centimeter squared with energy level greater than 1 MeV. And that is exactly same position described in the May 2000 Grimes Letter position, as Jim Medoff said. So that is pretty much conservative --

DR. SHACK: Okay. Take a look at that paragraph that's lines 27 to 38 under the parameters monitored and inspected. It certainly sounds like there's something out there that handles neutron embrittlement of CASS stainless.

MR. MIN: Yes, but at the same time, if I would a little bit, currently DE staff is reviewing BWRVIP 234 to -- is what's current licensing basis position for the thermal and neutron embrittlement criteria, screening criteria. So the NR staff is coordinating with DE staff to potentially incorporate those positions, but it hasn't been finalized officially yet. But we are anticipating the report to be issued pretty soon.

MR. MEDOFF: You said lines 27 through 38, monitoring and trending?

DR. SHACK: Yes, parameters monitored or inspected.

MR. MEDOFF: Okay. We'll go back and look at those.

DR. SHACK: And again, I'm must curious about why these things are in the Staff Review Plan, but not in the guidance to the applicant. And it may be that they just consider them all one in the same, but it just --

MR. MEDOFF: Because usually when there's something that we need to request of the applicant, further evaluation, it's put in as a specific chapter in whatever system you're talking about. Since the internals are part of the RCS chapter, we put it in as a new section for Chapter 3.1. You may have some reference into it in like the program elements, but the real further evaluation would be in the SRP.

CHAIRMAN SKILLMAN: Thank you, Jim. Let's proceed.

MR. MEDOFF: Okay. Now here's the corresponding case. The next AMP we're ready to talk about is XI.M16A. This is the current version in GALL Revision 2. It's PWR vessel internals. It's based on an EPRI MRP Report, which is specifically EPRI MRP Report (MRP)-227-A. It was approved by the staff.

This methodology that got referenced in the AMP is a sampling-based methodology. It's not as comprehensive as the program for the boilers. It used a number of functionality and failure modes evaluation criticality analysis to rank the PWR vessel internals, and basically it binned them into one of four categories. If it's a really safety-significant program that would have consequences and you could have aging, that would be of a concern as assessed through a 60-year level, because it was a 60-year report. Then they'd bin those as a primary component for an augmented examination and they would tell you whether they would inspect by visual or ultrasonic.

If you found degradation in one of those primaries, they had -- some of those had other additional components where they would expand the scope of the inspections to other component locations. Those were the expansion components. Other components were already had existing program requirements like they were part of the core support structures, so they had ASME inspections. They were applying visual inspections to the components, those they may have had in the inspection categories.

And then final category was binned in these other components called no-measures that they would not inspect under the methodology either because there were no consequences. No matter what you did with the component, how bad the aging effect would ever get, it could fail through-wall and you would have no safety consequences, no impact on the safety-related component and its vicinity. Or maybe it did have a potential safety consequence, but the 60-year assessment didn't assess aging enough to bin it as a concern for the initial license renewal application. That's basically how the program worked.

The issue that we had for 80 is going out to an 80-year assessment, especially if you're talking about a time-dependent parameter or like anything that was influenced by fluence or cyclical loads. The question is, if you went out to the 80-

year assessment component and it was wanted in either no-measures or expansion category, would the inspection ranking change because now you're going out to 80?

Now, it wouldn't change if there were no consequences of failure. Those would always stay the same. It wouldn't change for the lead primary components because they would always stay the same. But it's the ones that were expansion components or maybe in no-measures components because the 60-year aging wasn't significant enough to be a safety concern for the initial inspection set. Those were the ones we would wonder if you're going out to 80 would the inspection ranking change.

So we don't know how going out to an 80-year assessment would impact the inspection rankings, so we couldn't really rely on the current approved report because it was 60 years. So what we did at the time is we made the decision to delete the AMP and to put a further evaluation recommendation in the SRP requesting submittal of a plant-specific program from the PWR industry members if they were applying for subsequent renewal. That's not to say that they couldn't use the MRP Report as their initial starting basis with maybe some additional tweaks, but that's how we put it out in the draft document. That's what our initial decision was on that.

Since that time we've had some industry feedback that this is a little bit impractical for them. We've been directed by our management to go back and look at our approach to see if there's something more amenable, another option we could adopt that's more in line with the industry's perspective. So we're going back to that and we'll take a look at it. We expect to see formal comments on this when we get them in from the industry at the end of the month.

CHAIRMAN SKILLMAN: Isn't there something in this, Jim, that is very, very plant-specific and hence the idea of having -- plant-specific analysis makes the most sense? The reason I say that is because you have reactor vessels that have come from different manufacturers. Within the manufacturers you have different processes, different materials. You've got different power levels, different power schemes. Some are base-loaded, some are cycling.

So at the end of the day this really

boils down to a plant-unique set of analysis based on the plant history, based on the construction history of the major components, and that type of thing. So it seems like a unique analysis for a specific plant actually makes the most sense.

MR. MEDOFF: That is true, but this will clear it up for you. When they developed the initial MRP methodology, they had members of the industry as part of the EPRI MRP team to develop the methodology. They also had the vendors. So Westinghouse covered the designs for the CE units and the Westinghouse design units. They had AREVA in on the methodologies as coming up with the generic design assumptions for the BMW units. So they already took into account the differences in the manufacturers of the NSSS system when they did that.

I talk about the MRP-227 Report, but there were a lot of background methodologies that were factored into it. One of the background reports would have the functionality analysis. It would tell you what the component was intended to do and what would happen if it failed. They did a failure modes and effects analysis in another report. And they actually had some other background reports with some of the inspection methods. And a member from EPRI is shaking her head in the affirmative.

So the initial expectation was that it was a generic sampling program with initial design assumptions. When we wrote our SE on that, we did acknowledge that the design assumptions could differ when you compared the plant design to actually the assumption in the report. We have an action item that they have to go back, identify those differences and reconcile them against the MRP methodologies.

So that we already have accounted for in the action items on use of this 60-year report for the initial group of applicants. It's just going out to 80 there's a little bit uncertainty on how the inspection categories would change, if at all, because we just don't know. And the industry has told us we're not going to get an 80-year version of the report until several years down the road. I think they've mentioned 2020 for -- I think a best educated guess of getting into it at the earliest.

CHAIRMAN SKILLMAN: Thank you, Jim.

MR. MEDOFF: Are there any other

questions on these two programs?

(No response.)

MR. MEDOFF: I guess I'm still up.

CHAIRMAN SKILLMAN: You are.

MR. MEDOFF: Gall Chapter IV. We did a review to review the AMR line items for the reactor coolant system. I'm just going to go through the major changes.

Understand that Bennett Brady discussed earlier that there's going to be new a column with the M for modify, D for delete. We're going to add E for editorial. A lot of the changes to the AMR line items were editorial, so I'm not going into all those, so just understand that. So I'm just going to go through a few of the changes that we made to the AMR line items.

As a benefit for the industry we had some line items for the reactor vessel beltline components, two of them, two or three, one for nozzles, one for shell components might tie to the TLAAs. We might have two or three that tie to the Surveillance Program because the TLAAs in the Surveillance Program were interrelated. There was no reason to have two or three of these when you could have all the components in one, so we decided to consolidate them down just to one line item for each, one tying to the TLAA and one tying to the Surveillance Program leading to the vessel tables. We have a vessel table for the boilers. We have a vessel table for the PWRs.

That should make it a little bit more efficient for the industry. They'll just see one line item, apply it to their applications when they're coming in. It should simplify matters for them. So we think that's the change where we get into efficiency for the industry.

We took the AMR line items for fatigue. Nothing has really changed technically. These are tied to the fatigue TLAAs, but we had a wide variation of wording in these even though the tech -- if you looked at the columns, they pretty much told you to do the same thing, go to the chapter, Chapter IV that had the applicable TLAAs. And nothing's changed there. But we wanted to make sure the way we had them worded was consistent throughout, so we did that administratively.

The big changes came to the ones for the PWRs under the current approach. Since we were deleting the AMP we felt we only needed a few line items for these components, one for cracking, one for non-cracking effects and we linked it up to the new further evaluation column. As always, we had the comment from the industry. We'll decide whether to keep that approach or whether we add a modified approach where maybe we can retain the AMR line items for PWR internals in our ISG. That's ISG -- LR-ISG-2011-04.

As I said earlier before we took the AMR line items related to radiation effects for the BWR internals, we were changing those further evaluations from no to yes in those AMRs just to be consistent with the new FE section that we wrote. A lot of other AMRs carried over from the prior version of the GALL or NEI ISGs. We may have modified the limited editorial matter. So that should cover IV.

We're going to -- the next section is 3.1, so we're on the next page.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: We did the same thing for the AMRs in 3.1 that link up with the AMRs in Chapter IV. Those were done in sync with each other because one feeds off of the other.

So now the major changes in 3.1 deal with the changes to the FEs. I'm only going to talk about or reference the ones that we had major changes to.

The section in 3.1.2.2.1 is the one on fatigue. We updated that to be consistent with changes to Section 4.3, which I'll talk about a little bit later. What we did is we expanded the list of cyclical loading analyses. We were getting a lot of RAIs and exceptions in prior applications because they may have been applying beyond what the scope of the AMP actually said. So we tried to expand the list so that we could reduce RAIs in the future. That should be an efficiency for the application.

For 3.1.2.2.3 we updated the sections especially for the -- to add in the new X.M2 to be used in XI.M31. That's consistent with the changes I discussed before.

3.1.2.2.9, that is the new FE section for the PWR internals acknowledging the industry preliminary comments. We'll go back and look at that wording to see how that further evaluation needs to be tweaked down the road. But I think the FE section will stand since we do have a little bit of an 80-year gap on the MRP methodology.

3.1.2.2.10, it's a new FE section on

loss of material due to wear and CRD nozzles and nozzle thermal sleeves. We had some past applications with this as an additional aging effect, so the new FE section is based on the past LRA experience.

We had a new section 3.1.2.2.12 and 3.1.2.2.13. This is the new FE sections for the BWR internals. One's on cracking effects; one's on the non-cracking effects. Those are the ones that are induced by radiation.

We have a new section 3.1.2.2.14. This is based on loss of preload in BWRs with core plate rim hold-down bolts. We did some TLAAs in past applications on that, so we wrote the appropriate FE section.

3.1.2.2.15, that's loss of material due to boric acid corrosion in some steel generator channel head that may be clad with stainless steel or nickel-alloy. This is based on an information notice, so the staff felt it appropriate to just create an FE to see if the information notice information would impact their Steam Generator Programs.

We have some FEs in 3.1.2.2.16 and 17. Those are the new FEs associated with the CRD return line changes.

And then we have a couple of new FEs for -- one for stainless steel piping in concrete. If you look at the AMRs in table IV.E, that's a none-none, but we realized that based on past experience with assessment of steel in concrete, especially on the structural side, you could have some moisture intrusion where maybe you could need a postulated loss of material due to corrosion effect for the steel components imbedded in the concrete. Therefore, we wanted to make sure that if there was some chance of moisture intrusion to the imbedded steel or stainless steel components you would go back and assess to see whether none-none was really applicable for those components.

And then 3.1.2.2.19 dealt with loss of material due to pitting and crevice corrosion and microbiologically influenced corrosion. We created some further evaluation criteria on whether you would use a one-time to confirm absence of aging on that or whether if you've had aging you would proposed a periodic. And then we had specific threshold levels for doing that.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: And that's it for Chapters

IV and 3.1. Are there any further questions? Those are the --

CHAIRMAN SKILLMAN: Main ones.

MR. MEDOFF: -- predominant changes.

Next AMP I'm ready to talk about is XI.M1. We updated this AMP for efficiencies for the industry. The bus rate is -- to state this is an AMP that is used in one of accepting fatigue for cyclical load analyses in accordance with 54.21(c)(1)(iii), which is the effects of aging in the TLAA using an Aging Management Program or aging management activities. For these cyclical loading analyses fatigue monitoring is one way to do the (iii) acceptance. The problem was when we had the scope of the AMP written in the last version of the GALL, it was limited only to cumulative usage factor-type of fatigue assessments or environmental-assisted fatigue assessment, which we've had many discussions with you in the past.

A lot of plants would use the AMP as an extension for like cyclical flaw evaluations or fatigue flaw growth evaluations even though the AMP didn't say specifically you could apply it to those type of cyclical loading analysis. We got sick of writing RAIs on why are you doing this, where is my exception to GALL, so we decided to increase the scope of the AMP so we don't have to keep writing RAIs for the industry. And I hope Mike Gallagher's smiling at this because I think the industry knows about all the RAIs we went through in the past applications. So this really should create some efficiencies for the industry.

CHAIRMAN SKILLMAN: So did it make it better?

MR. MEDOFF: It will make the reviews go easier.

CHAIRMAN SKILLMAN: Okay.

MR. MEDOFF: There's no reason not to let -- the AMP is based on cycle counting. There's really no reason not to let the industry use this for all types of cycle-based assessments. You're doing cycle counting. You're going to count against the assumptions in the assessments. As you can see in the bullet elements one of the things we did clarify is in the acceptance criteria. We reminded the industry that when you're doing your cycle counting, you're summarily loading counting of the transients that may be occurring, but you may have common transients and various type of cyclical loading analyses, but the assumed number of cycles could differ.

So I could have one assessment with 100 startups. I could have another with 200 startups assumed. Well, I don't want to take corrective action of 98 for the assessment that's used in 200. And that's a little bit too soon, right? So we wanted to make sure that -- like in the acceptance criteria we stated that when you're doing cycle monitoring make sure you're doing it relative to your assumption in each type of assessment, because they should be taking corrective actions at the appropriate point. And that should be an efficiency for them.

CHAIRMAN SKILLMAN: What is your assumption? What I should ask is what is the Agency's assumption regarding the accuracy of the licensee's cycle counting? I'm waiting for you to say we know it's bulletproof and, boy, it's right on the money, but I'm not sure that's what you're going to say.

MR. MEDOFF: Well, I would say since a lot of -- especially -- let me bin this a little bit. If I'm talking about cycle counting for Class 1 components, especially if you have a tech spec in the admin controls that says you're going to count against transients in this section of the SAR, which -- in Section 5 of the SAR, which may apply to your -- like the CUF analyses for the Class 1 components, I have a tech spec requirement that is telling me I'm going to count against my assumption, by design-basis in the FSAR. Especially like on the transient tables they'll tell you what the limits are on each one of those transients that go into the assessments.

Since we have a tech spec requirement I would expect the plants to have well-defined plant procedures on doing this. And as in past LRAs we confirm that they do have the procedures in place. We don't review the adequacy of those procedures. That's really something that's defined for the regions to review. So we assume that the procedures are adequate if there are issues with the procedures for doing that and it's part of the reactor oversight process.

CHAIRMAN SKILLMAN: I'm just remembering several of the LRAs that we reviewed, the introduction was we had to go back and recalculate because we found that we had not been as disciplined as we needed to be in cycle counting. And so the question that's kind of emerging in my mind is we're going to have an applicant that has a moldy-oldy reactor vessel with lots of copper that's been justified several times that found its way from the B&W shop, the Rotterdam and back to some site somewhere and it's coming right on up to its first day of 61st year and they say, you know, we really didn't get that cycle count exactly as it should have been. We fixed it. And so I'm thinking how do we make sure, how do we trust and verify?

MR. MEDOFF: Well then, as I said, the normal way is through the reactor oversight process, because under our license renewal procedures that's -- adequacy of procedures is really a current operating space issue. If there are any issues with those procedures, again the regional inspector should be looking at it.

That being said, when we get a TLAA related to this -- the AMPs and the TLAAs relate here, so if we have a TLAA in Section 4.3, which I'm prepared to talk to in a couple of minutes, they go into some -- their cycle counts, especially if they're accepting the TLAAs under the (i) or the (ii) criteria, (i) being previous assessments bounding for 60 years or even 80 years if you're doing SLR. (ii) means I projected my cycles out and my -- I'm still within the acceptance level for like my CUF analyses.

So we do go into some cycle counting review as part of the TLAA's review. I have had issues in the past where the applicants would say we don't have to count this cycle because any increase in one additional cycle of this transient is really not going to change my fatigue value very much. And then I would go back to the tech specs and the FSAR cycle counts and the tech specs would tell them to count. So I didn't care whether there was only a small change. The tech spec tells them to count. So now we call them out on the review.

So there is a certain amount of the review of the counting projections when we do the TLAA reviews. It's not normally part of the AMP. So there is some --

CHAIRMAN SKILLMAN: That's good. Thank you.

MEMBER STETKAR: That's a long answer. I was hoping to hear we sorted all of that stuff out for the current license renewal --

CHAIRMAN SKILLMAN: And we --

CHAIRMAN SKILLMAN: -- but I didn't

hear that.

CHAIRMAN SKILLMAN: And we know it's accurate.

MEMBER STETKAR: Well, no, that we've all agreed on the accepted number.

MR. MEDOFF: Yes.

MEMBER STETKAR: Don't bother me with the facts. As long as everybody agrees on the accepted story, we're okay.

No, in seriousness, shouldn't this notion of cycle counting as a basis for fatigue monitoring be sorted out in the context of the current license renewal such that by the time we get to subsequent license renewal people know how to count things in the period from --

MR. MEDOFF: I would hope so.

MEMBER STETKAR: -- like 40 to 60 years so that you don't have to revisit it at 60 years?

MR. MEDOFF: Actually I --

MEMBER STETKAR: But I'm not gaining this confidence.

MEMBER RICCARDELLA: I think most plants have automated the process now --

MR. MEDOFF: Yes, and I think --

MEMBER RICCARDELLA: -- pretty well.

MR. MEDOFF: -- we've approved that in the past applications. Most of the efficiencies to be gained here on the changes to X.M1; and we also retitled it because we expanded the scope, was to avoid these -- what I call these administrative RAIs. I mean, I just got sick of saying why are you applying this to a fatigue flaw growth? And the only reason I had to ask the question is because the scope of the AMP was too limited. So, yes, I would expect them to have their cycle counting stuff all worked out for the future applications. That would be my hope. But that doesn't mean we're not going to review them when they come in.

CHAIRMAN SKILLMAN: Fair enough. Thank you.

MR. MEDOFF: The next thing I'm prepared to talk to is the related TLAAs. That's Section 4.3, Metal Fatigue.

Things pretty stayed the same. We did make some clarifications. We expanded the scope of the assessments to all the assessments we added into the AMP. So you have fatigue flaw growth, fatigue waivers, CUFs, environmental fatigue analyses, cycle-based fraction, mechanics analyses.

You may have some methodologies that assume flaw size that are growing out of fatigue that may be TLAAs. So the point is we want them to -- all those should fall into this chapter.

We updated the scope of the analyses in the chapters. Then we binned them into two categories. One is the environmental fatigue calculations, because we have some NUREG reports out doing the FE and adjustments of the CUF values. We've had numerous discussions on the environmental fatigue assessment criteria. I think we updated those criteria.

And then the second bin would be all other types of cyclical analysis including the design-basis CUFs, the expansion stress analyses for B-31 components, etcetera, etcetera.

One of the things we did is we updated the (iii) criteria. Again, we continued to cite the X.M1 AMP that I just discussed earlier. It's now the cycle load monitoring AMP. That's one way to accept under (iii). If you're using some other AMP under (iii), maybe an inspection type of program to accept an analysis that has cracking by fatigue or cumulative fatigue damage, those will be reviewed on a case-by-case basis.

And one of the things we did remind them that is if you're using an inspection-based AMP or a condition monitoring for (iii) acceptance of your TLAA, that you would actually want to do -- the AMPs should be an inspection of that component. So if it's a sampling-based AMP you're citing for (iii) and that's not really going -- that component's not in the sample to inspect, that's not a good AMP to give to us because you're not looking at the component for the fatigue crack.

And that's about it.

CHAIRMAN SKILLMAN: Jim, thank you. And, Carolyn and Matt, Heather, thank you.

Colleagues, any questions for this part of the team?

Hearing none, we're going to move onto XI.M7, which is boiling water reactor stress corrosion cracking. That will be your slide 75.

MR. KALIKIAN: Good afternoon.

CHAIRMAN SKILLMAN: Roger, welcome. Please proceed. Thank you.

MR. KALIKIAN: My name is Roger Kalikian, DLR staff.

XI.M7 was just minor modification. With the elimination of the XI.M6 Jim talked about, the CRDM return line nozzle cap and the associated welds were added to the scope of this program. So that was really the only real change to this program.

MEMBER STETKAR: Roger?

MR. KALIKIAN: Yes?

MEMBER STETKAR: Not so much, the scope of the program now says that it applies to all BWR piping and piping welds made of austenitic stainless steel and nickel-alloy that are four inches in diameter, or four inches or larger in nominal diameter, containing reactor coolant at a temperature above 60 degrees C, 140 degrees F. It used to say 93 degrees C, 200 degrees F. Why did we drop the temperature threshold by 60 days Fahrenheit?

MR. KALIKIAN: So that change was an editorial change that happened late in the process. It wasn't meant to change. A panel didn't discuss that change, so it was just --

MEMBER STETKAR: Well, wait a minute. It's not an editorial change. It's a technical change. My question is why was that change made and what additional piping and welds are now in scope for this AMP after 60 years that were not in scope before 60 years?

MR. KALIKIAN: So what I'm trying to say that change was not an intentional change. We took that question from the industry as well. We're going to change back to --

MEMBER STETKAR: You're going to change it? Okay.

MR. KALIKIAN: Yes, it was just --

MEMBER STETKAR: Okay.

MR. KALIKIAN: -- an unintentional change.

DR. SHACK: It was a mistake.

MR. KALIKIAN: It was a mistake.

MEMBER STETKAR: It was a mistake.

MR. KALIKIAN: It happened very late --

MEMBER STETKAR: Not caught in the technical review --

MR. KALIKIAN: Well it actually --

MEMBER STETKAR: -- of the document.

MR. KALIKIAN: -- happened way late in the process.

MEMBER STETKAR: Yes. Okay. Thanks. So another example of things that you stumble across and say, my God, this --

DR. SHACK: what happened to the final

reader?

MEMBER STETKAR: -- what happened -- thank you.

MR. KALIKIAN: Thank you. The next program is the XI.M11, cracking of nickel-alloy components. This program was changed. The scope was revised to include the branch connections and their welds, branch connection welds. It was also revised to add the bottom-mounted susceptible nickel-alloy instrument nozzles. It would be just baseline inspection prior to the subsequent license renewal.

MEMBER RICCARDELLA: Is that a sampling inspection or 100 percent?

MR. KALIKIAN: The baseline inspection usually would be 100 percent. So the bottom-mounted nozzles, normally there are about 58 of them.

MEMBER STETKAR: And again, that's not required under GALL Rev. 2, so why do we need that going into 60 years?

MR. KALIKIAN: So, we have some operating experience that we've had some leaks and we know the bottom-mounted RCS looks like a lower temperature, so they're less susceptibility. But the panel felt that you would -- going out to 60 to 80 it would make sense to do at least a one-time inspection. There's also a provision that they could do mitigation, the applicants. And the industry has been working on that. And if they did that, then they wouldn't need to do the volumetric examination.

MEMBER BALLINGER: This is an ongoing thing. The plants have all inspected their bottom instrumentation as a result of South Texas and other things. And the mitigation is in place, right?

MR. KALIKIAN: South Texas did inspect theirs, but not everybody --

(Simultaneous speaking.)

MEMBER STETKAR: Not everybody has done this.

MEMBER BALLINGER: Wasn't there a Generic Letter that went out or anything?

PARTICIPANT: No.

MEMBER BALLINGER: No? Okay.

CHAIRMAN SKILLMAN: That's a tough inspection.

MR. KALIKIAN: The industry has been proactive. I mean, they have --

CHAIRMAN SKILLMAN: That's tough.

MR. KALIKIAN: -- been working on finding methods for doing this. And some licensees want to use it as -- versus getting out of doing visual inspections. We took comments from the industry, so we'll be addressing those.

CHAIRMAN SKILLMAN: Say again, please?

MR. KALIKIAN: When we presented this to the industry, they had some comments on the new scope and they're going to provide those comments to us.

CHAIRMAN SKILLMAN: I'll bet, yes.

MEMBER STETKAR: Oh, yes, this is not easy to do.

CHAIRMAN SKILLMAN: I think even though this is an expansion, I suspect this is one -- or I don't suspect. My belief is this is one that's valuable. That is an area of the plant that very few people ever go and look at. And to look at that area, you've got to strip the insulation off the bottom of the reactor vessel. And if you want to really get into the end of the nozzles, you either have to go down from the seal table or you have to remove the fuel and the internals and go down into the vessel. So this is not an easy place to get to. And these tubes are normally one-inch schedule 160. They're tough as can be, but they actually vibrate. So there's a little bit of movement down there. So there is good reason to go and take a look heading into the 60 to 80-year time frame. I get it. Thank you.

MR. KALIKIAN: The next program is the XI.M35, ASME Code Class 1 Small-Bore Piping. The program here was just slightly modified. The previous program was a one-time inspection for plants that had no experience of cracking or age-related failures of small-bore piping, or plants that had some and they had mitigated it and had solved the problem. So it was a one-time inspection. And that plants that had issues, they were to provide a plant-specific program for the small-bore piping. The revised program gives guidance for a plant-specific program for the --

MEMBER RICCARDELLA: Is this the vibration fatigue concern?

MR. KALIKIAN: No, this is just small-bore piping. There would be stress corrosion cracking. There could be fatigue as well, yes.

CHAIRMAN SKILLMAN: Please proceed.

MR. KALIKIAN: So a table was added

just to clarify the different categories in the sampling guidance that the staff had with the generic guidance. So that was it.

CHAIRMAN SKILLMAN: Okay. And with that, sir, you're done?

MR. KALIKIAN: Yes, unless you have questions.

CHAIRMAN SKILLMAN: Okay. Colleagues, any questions for Roger?

MEMBER STETKAR: No, just, Pete, I don't know how many of these License Renewal Subcommittee -- we've been following that small-bore piping stuff ad nauseam for years, and it seems to have finally stabilized. And it's consistently stable at least in the subsequent license renewal guidance.

MEMBER RICCARDELLA: Yes, the reason I suggested if it's vibration fatigue, vibration fatigue isn't really a time-dependent factor. It's a threshold-type effect where you're either above it or you're below it.

MR. KALIKIAN: Well, this wouldn't be meant for like high-cycle fatigue. It would be low-cycle fatigue.

MEMBER RICCARDELLA: But I think most

of the experience with small-bore piping has been -- where we've had failures has been vibration fatigue.

MR. KALIKIAN: Right, you could have high-cycle or low-cycle. If it was high-cycle, it wouldn't really work because it would fail before you did the inspection.

CHAIRMAN SKILLMAN: Colleagues, any further questions for Roger?

If not, we're miraculously back on schedule. And what we're going to do is to take a 15-minute recess. We're going to call a halt here at five minutes to 2:00 and we're going to reconvene at 10 minutes after 2:00 on that clock. We are in recess.

(Whereupon, the above-entitled matter went off the record at 1:53 p.m. and resumed at 2:09 p.m.)

CHAIRMAN SKILLMAN: Ladies and gentlemen, let us continue. We are beginning with Item XI.M7, BWR Stress Corrosion Cracking. And for this portion of our meeting -- excuse me.

DR. SHACK: We're on M17.

CHAIRMAN SKILLMAN: We are --

DR. SHACK: FAC.

CHAIRMAN SKILLMAN: I am sorry. We are at M17, FAC, with James Gavula by telephone.

Jim, are you there?

MR. GAVULA: Yes, I am. Good afternoon.

CHAIRMAN SKILLMAN: Good afternoon, Jim. I apologize. I've got three or four different schedules in front of me and it's my fault. You're up, and please proceed.

MR. GAVULA: Very good. Thank you. Since I can't see the slides, we're just going to --

(Laughter.)

MR. GAVULA: -- do this by the Braille method, okay?

CHAIRMAN SKILLMAN: We are on slide 78, Jim, if you have --

MR. GAVULA: Very good. And that's what I'm looking at. Hopefully we're looking at the same thing.

Just to briefly go through just a quick point for the Flow-Accelerated Corrosion Program, in somewhat of a departure from the industry guidance contained in NSAC-202L the AMP now includes guidance to reassess any piping system that has previously been excluded from the FAC Program due to limited operation as currently allowed by NSAC-202L.

This change is to ensure that adequate bases exist to justify this exclusion after 60 years of operation. The intent is to use actual wall thickness information in this reassessment, however, a representative sampling approach will be allowed. Any questions?

MEMBER STETKAR: Yes, a couple of them, Jim. First of all, in the scope of program GALL Rev. 2 says that it applies to carbon steel lines containing high-energy fluids. That high-energy fluid qualifier has been removed from subsequent license renewal. Why was that done, and was it intentional?

MR. GAVULA: Yes, it was.

MEMBER STETKAR: Okay.

MR. GAVULA: If you read the guidance, the high-energy portion of the system doesn't affect the rate of flow-accelerated corrosion. It only affects the consequence of a failure. You can get the exact same wall thinning for moderate-energy systems as you can for high-energy systems. So the intent is not to necessarily focus --

MEMBER STETKAR: Okay.

MR. GAVULA: -- on high-energy.

MEMBER STETKAR: This is something I know nothing about, but I'm going to rely on you and the good Dr. Shack to keep me honest. Have current license renewal applicants relied on that qualifier to only look at lines that contain high-energy fluids? In other words, will the scope of this program expand substantially for subsequent license renewal?

MR. GAVULA: Basically no. The original wording came out of Generic Letter 88-09, I believe. My numbers are kind of fuzzy at this point. That's where the initial -- it was a failure at Surry that prompted the initiation of the program. And that was a high-energy line, and the initial focus was for people to look at high-energy systems. Since then everybody basically goes through and looks at every system in their plant to identify those that are susceptible to FAC and go through appropriate monitoring based on that. So I don't see any change in that regard.

MEMBER STETKAR: Okay. Good. That's reassuring.

One other one that I had was the

discussion for subsequent license renewal emphasizes the fact that you're also concerned -- not only about flow-accelerated corrosion, but erosion. Is that aging mechanism in practice being covered under current license renewal programs, or is that something new that has been added only for subsequent license renewal?

MR. GAVULA: There was an ISG issued, 2012-01, which addresses erosion mechanisms, wall thinning due to erosion mechanisms, which in the course of doing many of the AMP audits it became apparent that a number of applicants were monitoring erosion in their systems through the Flow-Accelerated Corrosion Program.

MEMBER STETKAR: Okay.

MR. GAVULA: That meant that they weren't really following the strict guidance, but the applicability would certainly be there as far as doing the monitoring, predicting wear, etcetera. So even though it may appear that this is a change for subsequent license renewal, it's currently in place with respect to the -- or using the ISG 2012-01.

MEMBER STETKAR: Okay. Thank you.

CHAIRMAN SKILLMAN: Colleagues, any

questions on that AMP?

Hearing none, Jim, we are on slide 79.

MR. GAVULA: Very good. That's M.20, Open-Cycle Cooling Systems. Just wanted to highlight one of the changes that's being made to the program. Because heavy tuberculation has been found in some service water systems, the SLR Program includes consideration of portions of the system where flow monitoring is not performed. The intent is to develop more realistic friction or roughness factors for those portions of the system where flow monitoring is performed in order to confirm that the design flow rates will be achieved with the overall fouling within the systems.

Any questions?

CHAIRMAN SKILLMAN: Colleagues, any questions?

Hearing none, Jim, thank you very much.

MR. GAVULA: Thank you.

CHAIRMAN SKILLMAN: Okay. Bill Holston, are you there, please?

MR. HOLSTON: Yes, I am.

CHAIRMAN SKILLMAN: Bill, we are on slide 80, and you now have the floor. Go ahead.

MR. HOLSTON: Okay. Thank you. I'm

going to first talk about Interim Staff Guidance related to mechanical AMPs. And why I'm doing that is just prior to starting the analysis of what changes would be necessary for subsequent license renewal, we had come to the conclusion that based on plant-specific operating experiences several Aging Management Programs should be changed to address that operating experience.

And as we evolved through writing those ISGs, we started doing the subsequent license renewal technical reviews and of course recognized that the changes for the Interim Staff Guidances were equally applicable to the subsequent period of extended operation. And those six AMPs are listed on slide No. 80. And if you go slide 81, you can see the three Interim Staff Guidance documents that addressed changes to those six programs.

And what I'm going to do in the next few slides is just cover some of the highlights of those ISG changes that were most significant to subsequent license renewal.

So if you can go to slide No. 82, Interim Staff Guidance 2012-02 implemented a significant number of changes to internal surfaces on various components: piping, heat exchangers, tanks, etcetera.

The first thing we addressed was recurring internal corrosion. So what do I mean by that? Well, we built the AMPs for what was presumed to be a somewhat normal level of loss of material, and yet we are finding some plants that routinely had continuing problems, same aging mechanism. Maybe extensive MIC in their system, maybe extensive loss of material. And so, we said, okay, if you have that level of degradation, they you need to do something more than is just published in the existing AMPs, those recommendations.

So we made a measure of do you have more than one occurrence of that mechanism per refueling outage that occurred over say 3 or more sequential cycles for a 10-year period or 2 or more sequential cycles for a 5-year period? So we quantified the number of degradation events. We also quantified the level of degradation. Obviously if you were to go into a schedule 80 piping system and find a five-mile-deep pit, we're not interested in that. That's loss of material. However, it's not of the significance that we think you would need to augment your programs. So we said if you have 50 percent or greater through-wall, that's what we're addressing.

And so, we've implemented this with several existing plants. And what happens is if they've identified recurring internal corrosion, then they augment inspections, maybe additional UT examinations. Some plants have been doing above-ground guided wave to narrow down to where there are specific issues and then doing follow-up UTs of those areas. And so basically they commit to doing more inspections than would be in the Aging Management Programs. So that's recurring internal corrosion.

We found that probably in at least --

CHAIRMAN SKILLMAN: Bill?

MR. HOLSTON: Yes, sir?

CHAIRMAN SKILLMAN: Before you go on, let's just talk about that one issue for a second. As a practical consideration is there any commonality in the water supplies of those plants for which the accelerated degradation mechanisms have been found, and contrary-wise in the water supplies, raw water supplies for those plants that are not experiencing that accelerated degradation?

MR. HOLSTON: Yes, sir. I can't recall

of an instance where we have found it outside of raw water systems. So your treated water systems are reasonably -- have not seen recurring internal corrosion that I can recall off the top of my head. And so it's fire water systems that come from a lake or a stream. It's service water systems are typical systems that fall under recurring internal corrosion.

CHAIRMAN SKILLMAN: What I was really asking is whether or not there are some plants that for instance are on the Great Lakes that have very soft water that do not have this characteristic, whereas plants, perhaps some of the riverine plants have extremely hard water and therefore do have this problem.

MR. HOLSTON: I can't recall having done a license renewal application on a plant that takes its water source from the Great Lakes. I'm trying to think. No, I can't recall one. And I have not done any differentiations. And Jim Gavula actually has done several of these for the service water systems where soft water versus hard water is evident.

CHAIRMAN SKILLMAN: Okay. That was just a curiosity question to broaden our knowledge here. Thank you. Please continue.

MR. HOLSTON: Okay. The next area is AMP XI.M27, which is Fire Water Systems. Fire water system AMP was based upon the fact that the systems are pressurized so you could detect leakage doing ultrasonic examinations, but it was not very heavily engaged towards flow blockage. And we had an information notice that was issued where plants that had normally dry fire water sprinkler systems where they were periodically wetted and portions of the system didn't drain very well that significant flow blockage had occurred. And we used that as a springboard to really examine how are we managing aging effects associated with fire water systems?

We used NFPA 25, which is a water systems testing inspection document that the National Fire Protection Association put out and adopted five key inspections and six key tests from NFPA 25 that after our review we recognized that would provide valuable input to detect either loss of material or potential flow blockage.

So examples are sprinkler inspections, suction screen inspections, fire water storage tank instructions. The obstruction inspections that are done every five years, flow tests, hydrant tests, main drain tests and deluge tests or deluge valve testing are all examples of those. All of them would tell and owner an early warning whether flow blockage was going to become an issue.

In addition, we directly addressed the issue of normally dry sprinkler piping because it wasn't only one plant that had that operating experience. There were two or three plants that had the operating experience and one plant had it in multiple systems within their plant. And so, if a plant has normally dry systems, which a lot of plants have pre-action fire sprinkler systems, and if it gets wetted, then they review the piping arrangements.

Now what we found in the industry is it not only just maybe inadvertent sagging between two pipe supports that cause a problem. We've also found some design configuration issues. For example, one plant had a drain valve at the 9:00 position on the pipe. And that was one of the examples in the information notice. And if you looked at the bottom 180 degrees of the pipe; this was zinc-lined pipe, all the zinc coating was gone, corroded, and it had caused a flow blockage issue. So that's an overview of what we did with AMP 27.

AMP 29, which is the Tanks Program, we had operating experience on three tanks, one tank that had pretty severe pitting through-wall and another two tanks that had cracking. And we found that two of the tanks were outside the scope of AMP 29 because AMP 29 had historically been an above-ground tank outside of the enclosed spaces. And so we recognized that, well, wait a second, cracking occurred and what was the common factor?

Well, they were the same as outdoor tanks. People had refueling water storage tanks that were outside. Some people had refueling water storage tanks that were inside. They're large volume atmospheric tanks. And so we expanded the scope of AMP 29 to address additionally the indoor tanks to catch those plants that weren't necessarily doing the -- would not be necessarily implementing AMP 29 for those tanks because they were indoors.

And that's the principle change to AMP 29.

Well, we also added visual and surface exams of tank internals. Prior to that it was pretty much an external inspection program.

And AMP 38, which is the Internal Surfaces Program -- AMP 38 is a periodic or was a -

- periodically if you opened a system in the process of doing preventive maintenance or surveillances, you took advantage of that opportunity and had your craft or technicians do an inspection on the insides of the pipe. And that way the applicants would record, well, gee, we looked at some carbon steel piping exposed to treated water, we saw some degradation or no degradation. However, we found that plants were citing AMP 38 and it was okay to cite AMP 38, but there was no backstop to ensure that for each material, environment and aging effect combination there would be some minimum number of inspections.

And so we changed to a minimum sampling frequency in each 10-year period of either 20 percent of each material, environment an aging effect combination or a maximum of 25 components to be inspected. So that's the big change to AMP 38.

MEMBER STETKAR: Bill, when I read through AMP M38, and there's -- the same comment applies to AMP X1.M21A, which we're not discussing today, but I read it, in the NUREG it does specify, as you mentioned, the 20 percent of the population, maximum of 25 components. But then it goes on to talk about sampling for multi-unit sites. And it says, "For multi-unit sites where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections at the site as follows: For two-unit sites 19 components are inspected per unit, and for a three-unit site 17 components are inspected per unit."

How did the staff come up with those numbers? They seem --

MR. HOLSTON: They were higher-level mathematical equations that -- no, I'm just kidding. When we issued AMP 41 -- so I'm going to step back to a different AMP, and that was the buried pipe AMP.

MEMBER STETKAR: By the --

MR. HOLSTON: And in GALL Revision 2, and then in the Interim Staff Guidance issued afterwards we created a table that said this is how many inspections of buried pipe you have to do based upon whether you have functioned FAC protection or cathodic protection that's installed but not meeting acceptance standards all the time. And we developed those tables based upon a single-unit site.

MEMBER STETKAR: Yes.

MR. HOLSTON: And we said if you're a two-unit site, then you have to increase the total number of inspections by 50 percent in that table, and if you're a three-unit site you have to double the number of inspections sites in that table.

So if you do the math, it's the exact same thing we're doing with AMP 38. And what it basically involves is if you do a sampling basis and you want to come to a 90-percent, a 90/90 certainty -- now the Commission said when an engineer establishes reasonable assurance, it's not a quantitative value. It's based upon the experience of the engineer and of course the other reviewers. So that's where we adopted the 20 percent and the 25 percent maximum. The 25 maximum is actually a calculated number you can work out.

MEMBER STETKAR: Yes.

MR. HOLSTON: The 20 percent is kind of based on experience level.

MEMBER STETKAR: Right.

MR. HOLSTON: And so that's exactly those numbers. If you take a two-unit site and multiply the 25 by 1.5 and then divide it by 2, you have 19 per unit.

MEMBER STETKAR: Okay. I now know how

you came up with it. Thank you.

MR. HOLSTON: Okay, sir.

So then shifting over to the last two AMPs, AMP 29 and AMP 36. Twenty-nine is Aboveground Metallic Tanks, which I just referred to before, and AMP 36, which is the External Surfaces Program. Again, based on some operating experience we had the chance during some audits to look at some pipe that had the insulation removed and we found accelerated loss of material underneath that insulation compared to the same material, steel, where it was just exposed to the indoor air environment. The phenomenon is called corrosion under insulation, and corrosion under insulation, there's actually an entire standard out there on it.

So we adopted corrosion under insulation. We recommend for those two AMPs that in the first 10-year period you go out and you remove a set amount of insulation. It's sampling-based and you inspect the piping or the tank. And if you see no loss of material, no indications that they've got cracking. Of course the loss of material is beyond what you might expect, just surface rust when you have normal piping. The subsequent to that if the piping insulation is jacketed and you've got controls in place to control the jacketing, then you inspect the jacketing. And so we don't recommend in the latter 10-year period to pull off more insulation if you're just seeing no results. However, we do want you out there looking at the jacketing, because the jacketing is what's protecting and preventing the moisture to get in and cause corrosion under insulation.

So those were the six AMPs that we addressed in 2012-02. Are there any comments or questions on that ISG before I shift to the next one?

CHAIRMAN SKILLMAN: No questions. Please go ahead.

MR. HOLSTON: Okay. We'll go to slide 83. The next ISG is 2013-01, and this generated a new Aging Management Program. Again, based upon experience going out on audits, looking at plant-specific operating experience, we found that there were cases of degraded internal coatings. Now you all know that we addressed containment internal coatings in AMP S8, but we hadn't addressed anywhere -- tangentially we had, I should say, in a couple AMPs brief mentions, but we hadn't really taken on internal coatings on piping, heat exchangers and tanks in what I would call maybe an aggressive manner or driving to the point.

Well, what we saw was two consequences of the loss of coating integrity. One was accelerated corrosion on the base material and the other one was downstream flow blockage issues. And we went and looked beyond just the operating experience we had in the AMPs we had done and saw it in other places in just general areas where we were able to look at operating experience, both in some previous information notices and even an international case.

So we developed AMP X1.M42 to address those internal coatings. It requires periodic inspections and then depending upon what you see, you either do the inspections again in six years or you do them in four years. In regard to tanks and heat exchangers you look at all accessible surfaces. And in piping you either look at 50 percent or you look at -- of the piping that's internally coated you look at 73 one-foot axial inspections.

So where did I get the 73 number?

Well, the 73 number came -- it's the same number if you run the equations for 95/95 certainty that you do for 90/90. 90/90 you get 25. 95/95 you get 73. Not that we were fixated on a deterministic number, but we recognized when it came to coatings there were not really good controls on early coating issues. For the plants that were built in the '60s and '70s folks didn't necessarily recognize the potential impact for those coating failures, and so maybe humidity levels, drying -- curing times weren't controlled as well. And in fact we provide a provision in the AMP that says, hey, if all the coatings you installed met standards that were national consensus standards like those that are cited in Reg Guide 1.54, then you can do 25 one-foot inspections instead of 73.

We also establish recommendations for qualifications for inspectors and coating specialists. Those are cited in Reg Guide 1.54. A coating specialist is different from an inspector. And inspector goes out and looks at results and the coating specialist analyzes results. And then we established acceptance criteria. Peeling and delamination we don't allow and other indications are evaluated.

So any questions on ISG 2013 and the concept of internal coatings?

CHAIRMAN SKILLMAN: Please proceed.

MR. HOLSTON: Okay. Slide 84, the last of the ISGs, ISG 2015-01. Now I elected to discuss 2015-01. 2011-03 -- both of those address buried piping. Shortly after we issued AMP 41 in Gall Rev. 2 we issued ISG 2011-03 to fix some tweaks that needed to be adjusted. And they're principally addressing, well, what if you have a plant that doesn't have cathodic protection or has cathodic protection but it's not functioning to meet acceptance criteria consistently? And so I'm not going to discuss 2011-03 because it was overtaken by 2015-01.

Now, 2015-01, interesting enough, is a case for operating experiences proven to be pretty good. Back in 2009 when we developed GALL Rev. 2 in AMP 41 and when we developed 2011-03 there was a lot of uncertainty in regard to buried piping. The industry was just initially implementing its NEI 09-14 document, which was a program to go out and make sure you knew where all your buried pipe was, set up an inspection schedule, conduct those inspections and develop basically an Aging

Management Program for your buried pipe, whether you're in license renewal or not. In essence that's what 09-14 did.

And so based upon that there's been a lot of inspections done. And in fact, in our going out and doing AMP audits we've reviewed a significant number, probably close to 90 to 100 buried pipe inspection results. We also carefully looked at the operating experience. And so what we did was, if you look at AMP 41 and you look at the older ISG, we had a rather significant number of buried pipe inspections that would be conducted depending upon your preventive measures. How good were your coatings? How good was your cathodic protection?

We stepped back on that and adopted the NEI 09-14 approach with one exception. If you read 09-14, NEI 09-14, basically had you go out and do one to three inspections depending upon if you've gone out and done an inspection with guided wave and you've looked at a certain amount of the piping. Then you might look at one direct examination. And if you haven't used guided wave or some other inspection technique you would do three. So we have not yet recognized guided wave as a method to limit the number of inspections or credit guided wave for inspections. We've worked both the Division of Engineering folks and myself in the Division of License Renewal with EPRI. We don't think the state of the art is there yet.

So we adopted three. We didn't adopt the one to three. We adopted the three. So if you have a cathodic protection system that's working well, meeting your acceptance criteria, its availability is very good, you do one inspection. If you don't have it on line as much as you should, maybe it takes six months to repair it when one of the cathode-anode beds is out, or if it's not protecting adequately, the plants do an annual survey and say 500 feet of it isn't being -- doesn't have negative 850 millivolt, basically one of the measures for cathodic protection acceptance, then you would do three inspections.

And if your cathodic protection system is not operating to availability and effectiveness and you have adverse OE, then you're going to do six inspections in each 10-year period. So that's what we established as -- what I'm talking about there is the modified number of inspections. You're either doing 1, 2, 3, or 6 per 10-year period.

We expanded the cathodic protection acceptance criteria. Initially we had -- the only acceptance criteria we had was negative 850 millivolts off, instant off versus instant on. We had stated that you could do 100-millivolt polarization if you demonstrated that the metal was protected. If you recall right, when you look at a buried pipe system at a power plant, all the systems are grounded, you have a huge amount of copper in the ground, so that copper material, grounding material affects the readings you can get. And so although the NACE standards had 100-millivolt polarization as an effective measure, it's not as effective in a mixed metal environment.

And so we eventually got one plant -- well, there were several plants that wanted to use that criteria, but after a couple RAIs they backed out. And so we had one plant, an Exelon plant that came through. And so we adopted one -- another way to demonstrate that your cathodic protection system is working well enough is to use buried coupons that could actually measure your corrosion rates. And so, the other cathodic protection acceptance criteria we adopted was if you find very high resistivity soils, you can either have negative 750 millivolt or you can have negative 650 millivolt. So we adopted that also.

The second to last bullet, coatings on underground components. Now underground components aren't buried in the soil. They're not imbedded in concrete, but surrounded by soil. They're in an underground vault. So they're exposed to air. And based on our operating experience there's a lot of plants that have portions of their piping underground and most of them have some issue with in-leakage of water or high humidity. And based upon that review we revised the recommendations to say that those underground piping systems had to be coated if you wanted to do the number of inspections that's cited in the AMP.

And so if a plant comes in, we're not going to force anybody to coat their underground piping, but we'll follow up and say, well, how many additional inspections you going to do or how -- you're going to do them more frequently based upon those conditions. And of course we'll look at their operating experience. If they have vaults that are dry as the desert, then we're not going to worry about that. But if they have in-leakage to the vaults or the humidity levels are high, we know that the steel piping corrodes.

And the last change was that we have a sample size increase based on potential challenges to the pressure boundary. Prior to that we just basically said, hey, if you see an indication, you got to increase your number of samples. How we've specified it to be based on consequences.

Any questions on 2015-01?

MEMBER STETKAR: Bill, I didn't have 2015-01, so unfortunately I have to apologize because I went back to 2011-03. Are the sampling requirements in NUREG-2191 consistent now with ISG 2015-01?

MR. HOLSTON: Yes, sir, they will be. What we --

MEMBER STETKAR: They --

MR. HOLSTON: I'm sorry. I might have cut you off there.

MEMBER STETKAR: You said they will be or they are in what we saw?

MR. HOLSTON: They will be. What's in the NUREG that you read was 2015-01 prior to public comments. So the public comments came in this summer. We addressed those public comments. We issued 2015-01 final last month. What we told the industry was that 2015-01, those changes, we would take what's in the NUREG you have in front of you. We would take AMP 41 out of there and replace it with the 2015-01 AMP. And so but the only difference you see between what you see there is a few changes based on public comments.

I'll give you one example. We had two means to qualify a coatings inspector for looking at buried pope coatings. One was an EPRI course, one was a NACE course. And the industry requested that, you know, can we use any of the standards that are cited in Reg Guide 1.54 for qualifying coating specialists? And we said makes sense to us. They're coatings. The qualifications are the same. So that's an example.

MEMBER STETKAR: Yes, most of what I stumbled over -- the biggest difference when I was looking at number of required inspections for buried pipe, in 2011-03 there was a progressive number of inspections. Years 30 to 40, for example, you'd inspect five -- depending on the category of your protection, but you'd inspect five percent. Years 40 to 50 you'd inspect six percent. Years 50 to 60 you'd inspect seven-and-a-half percent, for example. That's for category E. In the version of 2191 that we reviewed that notion of progressive numbers of inspections has been replaced with just a single inspection requirement, depending on the category. In particular for category E it's five percent.

So because I don't have 2015-01, that's a concept that has changed in terms of as you get further out in life. 2011-03 was requiring a larger number of inspections, whereas the version of 2191 that we have just has a fixed percentage.

MR. HOLSTON: Yes, sir.

MEMBER STETKAR: Okay. And that fixed percentage is in ISG 2015-01 post-public comments?

MR. HOLSTON: Yes, sir.

MEMBER STETKAR: Okay.

MR. HOLSTON: There were no changes to that table of inspection quantities. And we changed to not be increasing the number because the wide -- I mean, we looked at operating experience from plants that were just about to enter their period of extended operation. Well, for example, Indian Point, I looked at 25 inspections there. And so that was pretty aged piping. And we determined that we didn't really have to increase the number of inspections every 10-year period. The number of inspections would tell the plant whether there was something going on. And that's the purpose for the expanded sample size if you find something.

MEMBER STETKAR: Yes. Okay. Well, is it? It doesn't make any difference because as I said I was comparing what we have for NUREG 2191 with what is written in ISG 2011-03, which you've told me is now out of date. So I was comparing apples and, I don't know, some other fruit or vegetable.

MR. HOLSTON: Okay. Yes, sir.

MEMBER STETKAR: Thank you.

MR. HOLSTON: Okay. Any other questions on 2015-01 and buried piping?

(No response.)

MR. HOLSTON: Okay. Slide 85. Now there were two AMPs that we had not made any changes to as a result of industry operating experience per se, or at least we hadn't changed them Interim Staff Guidances that we did adopt for changes for subsequent license renewal, so I'm going to cover those next.

So the first one was AMP XI.M32. AMP

XI.M32 is a one-time inspection program, and that was for aging effects that you didn't expect to occur, but you know if you're in a lab they might occur, or an aging effect that could occur but it's going to progress so very slowly that it's anticipated that there would be no impact or loss of intended function of an in-scope item.

So a set of one-time inspections were done with the plants as they enter the first period of extended operation and we determined that, based on the fact that plants have an additional 20 years of operation, it was worthy to do another one-time inspection. So I guess we maybe should have changed to title of the AMP to the second-time inspection, but we kept it as one-time inspection.

The inspection quantity is unit-based. We had some operating experience from regional staff going out on 71-003 inspections that plants were saying, well, I'm licensed for a two-unit site or I'm licensed for a three-unit site, so I'm going to go out and do a one-time inspection quantities based upon the whole site. And we said, well, no, you license unit one and you license unit two. We want you to do -- let's say if you're not a percentage-base but you're a quantity-base, we want you to do 25 on Unit 1, we want you to do 25 on Unit 2, and for each material environment aging effect combination.

Now you might question why did you not use that 19 number for the one-time inspection program like we cited for the AMP X1.M38, and the reason is is a one-time is a one-time inspection. That's it. You get one shot. You look at it one time in the 50th to 60th year of operation and if you don't see any degradation, it doesn't happen again. We allowed a reduced total number on a site-wide basis for periodic programs for every 10 years you were going to go in and look at those programs. We say if a program is not used for aging effects that didn't need acceptance criteria in your previous one-time inspection, for those you would have a periodic program, not a one-time, or based upon review of plant-specific or industry operating experience, some experience, something new has happened and we have more information on that aging effect combination in that environment.

We added one new one-time inspection and that's that we added a long-term loss of material. So going back to, for instance, my design days and designing piping systems or modifying piping systems, you always looked at a corrosion allowance. And of course those corrosion allowances back in the '80s and the '70s were based on 40 years of plant life. We didn't sit there and project, well, are we going to have 60 years? Are the plants going to be around 80 years or 100 years?

So given now that plants are going to go into the 60th to 80th year of operation. we looked at what we could expect in a lot of various water systems, for what would be typical loss of material rates and concluded that for raw water systems, waste water systems, even treated water systems where there were no chemical additives that would mitigate loss of material, that those systems could breach by the latter part of the 60-80-year piping term, if it's steel piping, to enough of a loss of wall thickness that just general corrosion would be an issue.

So we also knew there were a lot of plants out doing more than what was in the AMPs, more than what was in their licensing basis. They were out there doing random ultrasonic examinations, looking at the wall thickness. So basically what we said, if you've done an inspection and done ultrasonic examinations so you know your loss of material rate's okay in the 50th to 60th year, then you can just credit what you're doing already on a voluntary basis.

However, if you haven't, then you need to do the typical sample size, which is 25 components or 20 percent of the piping, go out there do wall thickness, demonstrate that your loss of material rates aren't exceeding what would cause you a problem in the 60th to 80th year of operation.

And then we revised to include an expanded scope of inspections when acceptance criteria is not met. So that's what we did with AMP 32.

Are there any questions on that?

MEMBER STETKAR: Yes, I just want to make sure I understand the rationale, because the scope of the -- and how many units are going to be affected by this. The scope now says that I don't need to apply this if two conditions are met: One, the environment for the steel components includes corrosion inhibitors as a preventive action and periodic wall thickness measurements on a representative sample of each environment have been deducted every five years up to at least the 50 years of operation. I need to satisfy both of those. If I don't satisfy either one of those, I now have to do my one-time inspection.

That to me says that even though if I've been doing wall thickness measurements every five years, but if I don't have corrosion inhibitors you're still going to force me to do this one-time inspection. Why?

MR. HOLSTON: Well, we actually -- we revised that. I wasn't at the beginning of the call; I'm out here at the ASME Code meetings, but I think Bennett talked to you about a supplement that's going to be issued here shortly in March. Did she talk about that?

CHAIRMAN SKILLMAN: Yes, she did.

MR. HOLSTON: Yes, so in that supplement we've revised that. So --

MEMBER STETKAR: Okay.

MR. HOLSTON: -- what I've stated is actually what is in the supplement --

CHAIRMAN SKILLMAN: Okay.

MR. HOLSTON: -- and we are putting that out for public comment. And I should have mentioned that that was --

MEMBER STETKAR: Okay.

MR. HOLSTON: -- affected by the supplement. So in the 50th to 60th year if the applicant has done a representative sample of wall thickness measurements, or if they're using corrosion inhibitors, they will not have to do this one-time inspection.

MEMBER STETKAR: Okay. Thank you. That's what I thought I heard you say, but I just wanted -- it wasn't what I read. So thanks.

MR. HOLSTON: Right, yes.

MEMBER STETKAR: That clarifies it.

MR. HOLSTON: Yes, I should have mentioned that that was revised in the supplement. I admire your attention to detail, sir.

MEMBER STETKAR: It's a plague, believe me. People hate me for this. I hate myself for this. That's on the record. I have deep psychological problems with this.

(Laughter.)

MR. HOLSTON: Okay. Are there any other questions on AMP 32?

(No response.)

MR. HOLSTON: Okay. If we can go to slide 86. The other AMP that we modified was AMP

33 which addresses selective leaching. So AMP 32 in GALL Rev. 2 was really written kind of based on the assumption that not a lot of plants are having selective leaching occurring, and if it's occurring, it's really slow, so we're going to do a one-time inspection and you're going to demonstrate you don't have it. And if you don't have selective leaching going on, then your one-time inspection's good. If you have it going on, then you write a periodic program. What we found as we looked at operating experience at the plants and reviewing license renewal applications that probably at least 50 percent of the plants have selective leaching going on right now. So we revised it to be a periodic program.

Now this AMP was an interesting one because we had talked to the industry during the development of this AMP and they actually came with a proposal that they said, look, we agree it should be periodic, but what we would like to do is maybe fewer visual or mechanical scraping inspections and we'll do some -- actually cut out the components and section them to look and see if selective leaching is occurring. And so that's basically what we've done. So in the AMP 33 you would have looked at 25 locations. Now you're going to be looking at 10, but you're going to do 2 destructive examinations in each of the material and environment combinations.

In addition what we did was we said, look, for closed-cycle or treated water if your plant-specific operating experience is good, we're going to allow you to do a one-time inspection. We aren't seeing selective leaching in those two environments. Where we're seeing them are in raw water, waste water, groundwater and soil. And so you have kind of a two-part program. You have a one-time inspection going on for the closed cycle and treated water. You have periodic, which periodic is every 10 years going on for those more aggressive environments.

The third thing we did was we added ductile iron. So a couple of us were at a very tight integrity meeting, an EPRI meeting a year ago. And at it one of the plants presented a case that they found selective leaching in ductile iron. So one of our engineers did some research on this and actually found through digging through a lot of information that ductile iron is susceptible to selective leaching. It's just a bit less susceptible. And it has to do with the phase and the concentration of those phases, whether they're broadly distributed. And if they're broadly distributed, then you get more aggressive selective leaching versus nodule, where you get less.

So we added ductile iron. We have that SLR supplement related. I put their flag there. Should have put up that flag on the other one on long-term loss of material because you won't have read that ductile iron was included in the scope in the documents that were issued in December.

MEMBER STETKAR: Yes.

MR. HOLSTON: The supplement adds ductile iron.

So are there any questions on AMP 33?

MEMBER STETKAR: And just to make sure I understand, you said that the tradeoff between a reduced number of periodic samples versus a destructive examination was proposed by the industry?

MR. HOLSTON: It was proposed by the industry. And actually, it was advocated for by one of our regional inspectors who has since retired that went out to plants and found one plant where they did the visuals and didn't find anything. And they were proactive in this area. They went and pulled a couple samples. I think what they had was they had a PIV in their fire water system that needed replacement. So they said we pulled it, might as well section it.

MEMBER STETKAR: Yes.

MR. HOLSTON: They found the selective leaching going on. Very low consequence. It was like less than 10 percent loss of material. So it wasn't a threat. But we recognized with that -- and there's another plant that we're working on with aluminum bronze selective leaching where we recognized the value of actually taking out samples, sectioning them and looking for selective leaching. I mean, you go in visually, you can see with copper it gets -- it's reddish. Gray, cast iron, if you scrape it. If you hit where it's occurring, I mean, you actually scrape the metal out of the wall. But since you're not scraping 100 percent of all the surface, you may miss it.

And so that's why we said we recognize that destructive examinations are more expensive. You got to cut something out, you got to do lab testing. So if you're willing to do some destructive -- well, change from "you're willing to" to "you will do" destructive examinations -- but to balance that we said we'll just do 10 visual/mechanical inspections.

So it really was a meeting of the minds, not a -- industry came in and we said, well, okay, we'll let that happen. It was actually where we were heading ourselves internally based upon some folks that saw stuff in the field.

MEMBER STETKAR: Thank you.

MR. HOLSTON: Okay. Any other questions on AMP XI.M33?

(No response.)

MR. HOLSTON: Okay. Slide 87. So I'm going to shift out of the AMPs. Between Jim Gavula and I we've kind of addressed most of the plant AMPs that were affected, and I'm going into now Standard Review Plan Sections 3.2, 3.3, 3.4, corresponding GALL Chapters V, VII and VIII about engineered safety features, auxiliary systems and steam and power conversion systems.

So there's a lot of aging management review items in that total. We actually either created new, modified or deleted 1,200 line items. Of that 1,200 about 300 of them are editorial changes. So if you were looking at the production tool you might see something where it says it's modified, but the only thing it did was take out the term "piping element," which is really glass. That's what piping elements are. They're glass elements like level gauges and that kind of thing when the material was steel. It doesn't make sense to say piping, piping components and piping elements.

We also took some line items where we took further evaluation details out of the AMR tables after confirming that they were in the further evaluation section and pulled that out of the tables. So the tables are a lot cleaner. They're marked as modified right now when they're really editorial. So there's 1,200 changes. About 300 of them were editorial.

One of the other things we did that affected probably about 80 line items was we eliminated galvanic corrosion as a cited mechanism in the tables. Now, does that mean plants won't -- you know, they go out, oh, look, this is galvanic corrosion versus just general corrosion, so the NRC doesn't care about galvanic. We're not going to have to address that. No, that's not what we did. But galvanic corrosion is really controlled by design and it's controlled by good maintenance practices. If you don't have them, there's a very low likelihood that you're going to detect galvanic corrosion before it gets you.

And so what do I mean by that? Well, if you design a piping system, you do a modification and you got carbon steel piping and you have an AL6N line tapping of it, you're probably going to have a leak. And we had one plant that had a leak in less than a year because of the galvanic corrosion that occurred. So what do you do? Well, you got to coat that piping, the carbon steel piping to protect it. You all are probably familiar with branch lines, copper branch lines off of carbon steel lines. And you go to a pipe support and it's got a rubber grommet to isolate it. So maintenance takes it apart, forgets to put that rubber grommet back in, doesn't understand what that rubber grommet back in puts up, grounds the system, connects it electrically and before you know it the carbon steel at that penetration and the piping's gone and you got a leak. So those are really what controls galvanic corrosion.

We did not eliminate from Chapter 9. We

said, hey, galvanic corrosion is a mechanism, but we explained that that's controlled by design and by good maintenance practices versus really any Condition Monitoring Program we could come up with.

So that's the big picture. Any general questions? I'm going to go over the next couple of slides on some specific changes we addressed within these changing aging management items. So are there any questions on slide 87?

(No response.)

MR. HOLSTON: If we could go to slide No. 88. So here are some new further evaluations we did. We had address loss of material for stainless steel in environments where you expected to have halogens present. We also addressed cracking. But we had not in GALL Rev. 2 as aggressively addressed aluminum alloys as we did stainless steel. And you can see this SLR supplement related flag right there.

So we stepped back and we looked at loss of material and cracking for those two mechanisms, or for those two materials. And in the GALL Rev. 2 we had, hey, you could have an issue with cracking or loss of material with stainless steel if you were near an ocean, if you were near a highway with high salt content, if you were near a factory that put out -- maybe a fertilizer factory. Those are very qualitative subjective measures to base an aging management review item on.

So we came to -- we set aside aluminum cracking; I'll address that next, but for loss of material for stainless steel, loss of material for aluminum and for cracking for stainless steel we said, look, this could occur in any air environment. It's not just a matter of outdoor, which all the previous times were focused on, because it was thought that there was more possible halogens in outdoor air. What if you have a stainless steel or aluminum pipe running through the turbine building and above it is a bolted flange surrounded by insulation and that insulation is composed 99 percent of halogens? Just, you know, exaggerating. But you can have leakage. Operational leakage is a normal thing that we manage aging effects for through that insulation dripping onto the stainless steel or aluminum and causing loss of material cracking.

So we changed to any air environment, not just outdoor, and we said you need to look at operating experience. If you do a 10-year operating experience search, you do a one-time inspection and you don't see it, then that one-time inspection is adequate to address the stainless steel and the aluminum. We allow them to credit the Coatings Program as an alternative because if you coat that piping or that tank or heat exchanger or external surfaces, then you don't have the environmental impact. But then of course you have to manage the coatings.

We provided a potential exclusion for internal surfaces, because if you're operating experience and your results of your external inspections don't reveal any loss of material or cracking, then we wouldn't expect them to be on the internal surfaces. And we added into Section 3.1 stainless steel. That had not been in there before. Cracking of aluminum alloys is a different story. There are certain grades of aluminum that are susceptible to cracking, and there are those that are not. We have a highly experienced engineer that joined us from the Navy Air Program that is very familiar with aluminum alloys and all who developed a list that said if you have these grades or these types of aluminum, then there is no issue of cracking. If you don't have those then you're going to have to address it. And so the cracking of aluminum alloys is material composition and environmentally focused.

Any questions on those changes for aluminum and stainless steel?

(No response.)

MR. HOLSTON: Okay. Next slide, and I may note my last slide.

So we had a conflict within GALL Rev. 2. GALL Rev. 2 said if you have stainless steel or you have carbon steel piping imbedded in concrete there are no aging effects. Well, that works fine if it's imbedded in concrete where the concrete is dry. However, when AMP 41 was developed in GALL Rev. 2 it said, hey, if you have concrete or steel or carbon steel imbedded in concrete that is surrounded by soil, you need to manage the aging effects associated with that because the concrete could get cracks in it, and with the cracks you could get moisture to the surface. And of course that could carry adverse deleterious compound to the surface, cause cracking or loss of material. And so there was an internal conflict.

We addressed that via requests for additional information. We would typically get a utility saying, well, it's no aging effect, and we'd say, well, where's the concrete? Is it outside or it inside? And so we fixed that by addressing that in a further evaluation section so that there's a differentiation between say concrete -- say a drain line that's encased in concrete in the turbine building. And that, one, has no aging effect on the concrete side, whereas out in the tank farm it would have aging effects.

We also addressed -- the next bullet is a further evaluation for loss of material and components exposed to treated water, treated borated water or sodium pentaborate solutions. And that ends up being either you manage it with the Water Chemistry Program M2 and periodic or one-time base inspections based on temperature, oxygen levels and pH that we establish within a further evaluation. If you're within the good side of the temperature, pH and oxygen levels, then it's a one-time inspection. If not, you're going to do periodic visual inspections.

And we revised existing a further evaluation section that talked about loss of material for spray nozzles in drywells and suppression chambers, but it didn't address flow blockage. And like the lesson we learned with fire protection piping, if it's dry most of the time, periodically gets wetted, doesn't drain well, or in this case because you might have stainless steel but you have upstream carbon steel for 500 feet, you could get flow blockage. So we adjusted that further evaluation to also address flow blockage.

And that is the end of my presentation on those specific chapters of the GALL and the Aging Management Program.

CHAIRMAN SKILLMAN: Bill, thank you very much.

Colleagues?

Bill, standby we've got a question here.

MEMBER STETKAR: Yes, I got confused. I started reading the GALL Report, Chapter V, Engineered Safety Features. And this will be just note taking for you, because it's way too complicated to try to do in real time.

But if I look at GALL Chapter V, table A, item No. VAE-428, it says that I need a plant-specific Aging Management Program. I stumbled across this because I saw a lot of new plant-specific Aging Management Programs and our experience from current license renewal is there typically aren't all that many of them. So I decided to see what's prompting this.

That particular item refers me to in the Standard Review Plan, table 3.2-1, item No. 85. So I go to that table. I look up item No. 85. And it refers me to Standard Review Plan Section 3.2.2.2.12. So I go. I read that section. And that section seems to tell me that I'm covered well by Generic Aging Management Programs. It doesn't say anything about plant-specific programs being required. So I'm not sure what's the basis now for my need for a plant-specific Aging Management Program.

I came across another reference. I came across another similar one in Chapter VIII, table B-1, item VIII.B1.SP-87, which goes to the Standard Review Plan, table 3.4-1, item 85, which goes to Standard Review Plan, Section 3.4.2.2.9, which similarly doesn't seem to point me toward any plant-specific programs. And there are other ones that I didn't list. I don't want to just go on.

My question is am I missing something or -- because I did follow through on a couple of others that eventually got to parts of the Standard

Review Plan that says, oh, this is a concern and it has to be managed on a plant-specific basis.

So I was wondering if people have done those crosswalks.

MR. HOLSTON: Yes, sir. Yes, I had to explain that one. So E4-28 -- not that I have this memorized. I just happened to be sitting my hotel room with my computer. But nickel-alloy, treated water, treated borated water, loss of material. And when you go -- so that says you have to go to a further evaluation, and the further evaluation is similar to the one I was talking about before. You look at oxygen levels, you look at pH, you look at temperatures. And you're either going to have an AMP XI.M2, which is water chemistry --

MEMBER STETKAR: Right.

MR. HOLSTON: -- or you're going to have water chemistry in a one-time program or water chemistry in a periodic program. Because of the further evaluation; and we didn't have a specific singular program, we would put plant-specific AMP in the table.

MEMBER STETKAR: Okay.

MR. HOLSTON: And then the applicant would go to the further evaluation and say, well, look, I've got the best water in the world, so I'm just really going to manage it with water chemistry. And that's what they'd say.

Now you're saying flood. The industry came to us; we had a public meeting about three weeks ago, and said can you develop further GALL table items that would be specific to the AMP that you're looking for? And so -- and then rather than having these plant-specific designations you would have a line item for where you have to do water chemistry. Well, recommended water chemistry. You have a line item for you do water chemistry in one time and you have a line item for where you do water chemistry in AMP 38, which is internal inspections. Right?

And so we looked at that. We got together as a team. We have a cross-cutting expert panel. And we said we think we can do that for a whole lot of those further evaluations. Well, there's what probably about -- I don't know, maybe about 50 further evaluations, maybe 60.

MEMBER STETKAR: Yes.

MR. HOLSTON: So we're going to be doing that. And so in the final version you'll see less of those plant-specific AMPs, but you'll see more --

MEMBER STETKAR: Okay. Because the reason -- because, you know, an example -- and again, dwelling on details sometimes is pointless, but there are examples in those crosswalk tables that do refer to multiple AMPs. You can use X or Y. You can use X and Y, things like that.

MR. HOLSTON: Right.

MEMBER STETKAR: And I started focusing on those entries that are either new or modified and said plant-specific. And as I said, in some places I found Standard Review Plan guidance that led me to have confidence that, yes, this does need to be managed by plant -- what I would consider a plant-specific program. But in many other cases I ran into what we've just discussed, where there seemed to be generic options available cited in the Standard Review Plan. An applicant could pick A or B, or A and B, but if they selected A or B, or A and B from the generic, they wouldn't need a plant-specific program. So I'm glad to hear that you're going to take a re-look at that.

MR. HOLSTON: Yes, sir. Yes, it was never our intent that they -- we'd see a massive number of unique individualistic plant-specific

Aging Management Programs. It's just a designation to get you the further eval. And then you've hit the nail on the head. That's exactly what -- we're going to go back, look at it and get more specific. More line items, but less plant-specific AMP designations.

MEMBER STETKAR: Okay. Thank you.

CHAIRMAN SKILLMAN: Bill, thank you.

Colleagues, do you have any questions for Bill before we end this portion of our meeting today?

Hearing none, Bill, thank you very much. You're relieved. Thank you.

MR. HOLSTON: Okay. Thank you, sir.

CHAIRMAN SKILLMAN: Yes, sir.

With that, we are going to open the phone line. It's open.

Ladies and gentlemen on the bridge line, if anyone is there, may I ask you to please just speak so that we know that you are there.

MR. HOLSTON: Well, Bill Holston's still here.

MEMBER STETKAR: Yes, hi, Bill.

(Laughter.)

CHAIRMAN SKILLMAN: Thank you, Bill.

Anybody else, please?

MS. RUDOLPH: Angela Rudolph.

CHAIRMAN SKILLMAN: Hello, Angela.

Is there anybody else?

(No response.)

MEMBER STETKAR: That's okay. As long as it's open.

CHAIRMAN SKILLMAN: Okay. For those who may be the bridge line and wish to make a comment, may I ask you please to go ahead and make your comment?

Hearing none, thank you. We will close the bridge line. Thank you very much.

To the audience, is there anybody in the audience that would like to make a comment, please?

Thank you. Hearing none. Gentlemen, let's go around the table. If any of you has a comment that you would like to offer, now is that time.

Ron, may we start with you?

MEMBER BALLINGER: Well, I appreciate the presentations. Quite detailed. I'm absolutely amazed that Member Stetkar can remember these numbers. I spent days trying to figure out these numbers.

MEMBER STETKAR: I have a computer and paper.

MEMBER BALLINGER: Yes, but -- never mind. Never mind. But I appreciate the staff's going through this.

CHAIRMAN SKILLMAN: Thank you, Ron.

Dr. Riccardella? Peter?

MEMBER RICCARDELLA: No, no comments other than to say I'm very impressed by the thoroughness of the program and the presentations.

CHAIRMAN SKILLMAN: Thank you, Pete.

Harold?

MEMBER RAY: Well, I would share my colleagues' comments thus far. I guess I'm -- to make a semantic characterization, one could think of extending licenses, renewing licenses, subsequently renewing licenses or relicensing. All of these words have been used at one time or another. We're of course not doing extending licenses. We're not doing relicensing. We're doing license renewal. And we're trying to look at not only license renewal, but subsequent license renewal, which raises the question is there anything about subsequent license renewal other than it's subsequent to an earlier license renewal? And I'm still searching for the answer to that question.

You asked what I would have also asked, which is does it extend beyond the things that we've considered here today in some detail? And I think the answer is, well, it might, but we're not yet sure. And I guess I would focus on that, Dick, as we go forward here so that we aren't automatically bounded in subsequent license renewal by it simply being the same thing but after having done it the first time we're going to do it again.

What is it that makes it different? And there's been questions asked about discontinuities between what's required under license renewal and what may be required under subsequent license renewal, for example. Why would we do it one way a minute before midnight and differently a minute after midnight? And I guess I think, well, that is a reflection of something else that subsequent license renewal may represent as compared with license renewal.

And so I just want us to keep that question in mind. I don't have an answer to it. I'm not here to suggest an answer to it. It may be very simple by saying there's nothing different. It's simply what you did before another time, or it may not. I don't know. I could argue the point one way or another, but I'm not going to do that now.

So I think that the thoroughness and the depth that is being gone into and what is being prepared for the staff to use and the industry to use in pursuing subsequent license renewal is quite thorough, complete and comprehensive as far as I can see, but I'm still wondering what's the basis for subsequent license renewal that's any different than license renewal, which all of us have handled multiple times. And if so, what is it? What is it that's different or in addition to, less than, more than, so forth? And I'm not yet clear on that.

CHAIRMAN SKILLMAN: Thank you, sir. Harold, thank you.

John, any further comments?

MEMBER STETKAR: No, I'd like to thank the staff. You covered a heck of a lot of material. I didn't think we had a prayer of getting through this today and here we are.

The only thing I'd like to do, kind of in closing, is to reiterate that for those programs where the requirements have become more stringent, as Harold said, you know, when the clocks ticks midnight on the 60th year, that the staff be sure that you have good technical bases for changing those requirements, that it's just not something that, well, we -- today we took a snapshot of the people in the room and we thought this sounded like a good idea. Because a step change in requirements ought to be prompted by something that indeed is an actual technical concern, because in some cases there are step changes.

CHAIRMAN SKILLMAN: Thank you, John.

Charlie? Charlie Brown, sir?

MEMBER BROWN: No, I got a lot out of the presentation. I haven't seen a detailed presentation of GALL before in the previous eight years other than the application. Pardon?

MEMBER STETKAR: You weren't here for Rev. 2?

MEMBER BROWN: 2008. Was Rev. 2 before 2008?

MEMBER STETKAR: 2010.

MEMBER BROWN: Well, I must slept through it then.

MEMBER STETKAR: There you go.

(Laughter.)

MEMBER BROWN: But I don't think I did. I wouldn't have done that.

But anyway, this was very enlightening. And I thought they did a good job of presenting the changes, at least the deviations of the changes they were making.

I guess the only thing that's occurred to me in the subsequent license renewal thought process -- and number one, I'm not a materials guy, okay, and I'm not a radiation phenomena guy in terms of long term, but that -- my only concern is there's some irradiated materials phenomena in the stuff that's directly exposed to neutrons and other type stuff in the reactor vessels, etcetera, that we haven't gotten to in terms of an aging effect base. And you listed a beltline and all the other stuff. That's always there, but how do we anticipate that? Is there something we should be doing to maybe think about what we don't know?

And again, not being a reactor vessel materials person and heads and all -- and mechanism shrouds and all blah, blah, blah, etcetera, sometimes things can turn to Swiss cheese when you're not aware of it. And I use that and I probably shouldn't have used that terminology, but you can find a material effect that you weren't anticipating and then all of a sudden you're kind of surprised when the material characteristics change. So that's the only thing that --

DR. SHACK: Just think, it gets stronger all the time.

MEMBER BROWN: I'd like to think that. Okay, that the real world does not typically -- I know my body's not, so I'm not so sure --

DR. SHACK: Right. It's just a little more brittle.

MEMBER BROWN: A little more brittle. Right. So that's really my only other thought is I'd like to have some discussion or presentation of why we think there's not something sitting out there waiting to hit us. I mean, in the eight years I've been here there have been a couple of things that the materials folks have presented that nobody really realized 45 years ago. And that's the only thing that -- and we didn't know it until later when we started noticing certain things. So that's the end of my thoughts.

CHAIRMAN SKILLMAN: Thank you, Charlie.

Dr. Shack, sir?

DR. SHACK: Within the scope of Aging Management Programs this is obviously I think a fairly formidable task and I think they've done a very good job. It's still a work in progress. I think they are addressing the areas where you're still influenced by some research findings that may come up, but again they've gone to the -- I think updating as much as they can and a recognition that there are still some questions where you have unknowns, but the emphasis on surveillance programs and things like that really do address a lot of that. And you just have to keep going. John will keep them busy working out all the appropriate details.

CHAIRMAN SKILLMAN: Thank you. I would like to just make one or two comments here. I want to thank Jane Marshall and Steve Bloom and Bennett Brady and Butch Burton on the record for your effort, for your team, for their thorough presentation for today's meeting. Thank you.

I want to reiterate my concern from the beginning of the meeting, and that is ensuring that the documentation is clear on how changes to natural phenomenon will be accommodated in 60 to 80 years. And I make that comment because I believe that the lens from the public has thickened. I think we are under a thicker magnifying glass than ever before. Other energy is less expensive and hence it makes the nukes extremely vulnerable, not only to financial issues but the political issues.

And when some applicant comes in and says, by golly, I'm ready to go from 60 to 80, I think we as an industry must be prepared to say this is why these machines are good. Here's how we can demonstrate that. And that is including all of the fine detail of the TLAAs, of the AMPs, of the four major issues that we identified at the kickoff, the seven issues that EPRI identified in the subsequent license renewal meeting. In my view we've got to be abundantly prepared for the skeptic, because I think in a way our future generation and our industry life depends on it.

So with that, I want to thank everyone including Charles our recorder. And with that, this meeting is ended.

(Whereupon, the above-entitled matter went off the record at 3:27 p.m.)

Subsequent License Renewal Draft Generic Aging Lessons Learned Report and Standard Review Plan Guidance Documents

Office of Nuclear Reactor Regulation
Division of License Renewal

February 17, 2016

Agenda

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

- License Renewal Background
- Subsequent License Renewal (SLR) Background
- Summary of Significant Changes:
  - Structural
  - Electrical
  - Reactor Pressure Vessel
  - Mechanical

License Renewal Status

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

- **Status of license renewal activities:**
  - 83 units have been relicensed
  - 11 units currently under review
  - 6 upcoming units (between 2016 and 2022)
- **Age of current plants:**
  - By the end of 2016, 45 units will have more than 40 years of operation
  - Older plants will reach the end of 60 years in 2029

Subsequent License Renewal

- The principles of license renewal would continue to be effective to ensure safety for operations beyond 60 years
- Staff assessment of the current regulatory framework is ongoing
- Technical reviews ensure effective aging management

Subsequent License Renewal Guidance

- **Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report (NUREG-2191)**
  - Provides generic evaluation of existing aging management programs
  - Acceptable method to manage aging effects, plant-specific alternatives may be proposed

- **Standard Review Plan for Review of Subsequent License Renewal Applications for Nuclear Power Plants (SRP-SLR) (NUREG-2192)**
  - Provides guidance to NRC staff reviewers to perform safety reviews of SLR applications

Why not GALL & SRP Rev.3?

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

- **License Renewal Guidance (GALL-Report (NUREG-1801) Revision 2 & SRP (NUREG-1800) Revision 2**
  - Provides guidance for 40-60 years of operation
  - Starting point to develop SLR guidance
- **SLR Guidance (GALL-SLR Report (NUREG-2191) & SRP-SLR (NUREG-2192))**
  - Provides guidance for 60-80 years of operation
  - SRM on SECY 14-0016 directed the staff to develop guidance for SLR
  - Changed several AMPs to further evaluations and plant-specific analysis to support technical basis for 60-80 years of operations

Basis for Changes

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Expected aging differences for operations beyond 60 years
- Lessons learned from GALL Report and SRP Revision 2 implementation
- Improve efficiency and effectiveness in applications and NRC review
- New operating experience since GALL Report and SRP Revision 2
- Gaps and errors in GALL Report and SRP Revision 2

Overview of Changes

- Standard language for Corrective Actions, Confirmation Process, and Administrative Controls elements for each AMP
- Added detailed Final Safety Analysis Report Supplement summary descriptions in GALL-SLR Report and SRP-SLR
- New GALL-SLR AMPs:
  - X.M2: Fluence Monitoring
  - XI.M42: Internal Coatings/Linings for in Scope Piping, Piping Components, Heat Exchangers, and Tanks
  - XI.E7: High Voltage Insulators
- New SRP-SLR Chapter 5: Technical Specifications Changes

Overview of Changes

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

- Renamed GALL Chapter IX and X
- Expanded AMP XI.E3 to three new AMPs to address aspects related to potentially submerged cables
- Deleted AMPs XI.M6 and XI.M16A and replaced them with new further evaluation items
- New further evaluation/plant specific sections and aging management review (AMR) items
- Tables in GALL-SLR and SRP-SLR:
  - Added over 500 new items to GALL-SLR tables
  - Cleanup of AMR items
  - Added column for new, modified, and deleted items

Schedule

Timeframe	Description
February 19, 2016	Public meeting on draft SLR GALL Report and SRP
February 29, 2016	Public comment period ends
March 9, 2016	Regulatory Information Conference Sessions
April 2016	Draft GALL Supplement publication
May 2016	Public comment period ends for draft GALL Supplement
March 2017	ACRS Full-Committee Meeting
Mid-2017	Issuance of final SLR GALL Report, SRP and Technical Basis NUREGs
2019	First SLR Application

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

Subsequent License Renewal (SLR) Draft Generic Aging Lessons Learned (GALL) Report and Standard Review Plan (SRP) Structural Changes

Office of Nuclear Reactor Regulation
Division of License Renewal

February 17, 2016

GALL-SLR Chapter XI.S1: American Society of Mechanical Engineers (ASME) Section XI, Subsection IWE

- Reworded portions related to bolting to improve clarity and consistency across structural Aging Management Programs (AMPs) (Element 2).

- Identified bulges in shells and liners as areas of potential distress or corrosion and recommended evaluation for structural impact and corrosion potential. Noted that when possible, quantitative acceptance criteria should be developed for bulges (Elements 3, 4 & 6).
  - A one-time evaluation to demonstrate acceptability and develop acceptance criteria would appropriately address this recommendation. Staff will consider revisions to make this clear.

GALL-SLR Chapter XI.S1: ASME Section XI, Subsection IWE

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Clarified that supplemental surface examinations should be performed for (1) steel bellows subjected to cyclic loads if there are no current licensing basis fatigue analyses, and (2) stainless steel and dissimilar metal welds of penetration sleeves, penetration bellows, and vent line bellows (Element 4).

- Added supplemental volumetric examinations in areas that are inaccessible from one side and susceptible to corrosion. The sample size, locations, and frequency are to be determined on a plant-specific basis each interval (Element 4).

GALL-SLR Chapter XI.S1: ASME Section XI, Subsection IWE

- Added relevant operating experience references, including documents discussing two-ply containment bellows cracking for which leak rate testing was inadequate and instances of through-wall liner plate corrosion (Element 10).

GALL-SLR Chapter XI.S2: ASME Section XI, Subsection IWL

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Emphasized importance of documenting and trending inspection results, including quantitative measurements when appropriate. Noted that photography ***may*** be a useful technique for documenting and trending aging (Element 5).

- Added quantitative acceptance criteria consistent with Chapter 5 of American Concrete Institute 349.3R "Evaluation of Existing Nuclear Safety-Related Concrete Structures" in addition to the acceptance standard in ASME Code, Section XI, Subsection IWL-3000 (Element 6).

GALL-SLR Chapter XI.S2: ASME Section XI, Subsection IWL

- Added relevant references (e.g., Information Notice 2010-14 concerning the containment surface condition examination frequency and acceptance criteria). Also added recent prestressed concrete containment delamination as lessons learned to be considered during any significant containment modifications during the subsequent period of extended operation (Element 10).

GALL-SLR Chapter XI.S3: ASME Section XI, Subsection IWF

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

- Added evaluation of inaccessible support areas when accessible areas indicate degradation may exist in inaccessible areas (Element 1).

- Reworded portions related to bolting to improve clarity and consistency across structural AMPs (Element 2).

- Noted that all bolting within the IWF sample should be monitored for corrosion, loss of bolting integrity (Element 3).

GALL-SLR Chapter XI.S3: ASME Section XI, Subsection IWF

- Clarified that high-strength bolting greater than 1 inch diameter, including ASTM A325 and A490, *should be monitored for stress corrosion cracking (SCC)*. This is IWF specific guidance based on operating experience with these bolts in IWF applications, and is different from the recommendations of the other structural AMPs (Elements 3 & 4).

- Increased the sample size for Class 1, 2, and 3 piping supports, by 5% with supports outside of the existing IWF sample. This provides reasonable assurance that age-related degradation is not occurring outside the existing IWF sample population (Element 4).

GALL-SLR Chapter XI.S3: ASME Section XI, Subsection IWF

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

- Added a recommendation to increase or modify the IWF sample population if a support within the population is repaired to as-new condition without exceeding the IWF-3400 acceptance requirements for increase in scope. This ensures the sample remains representative of the population (Element 5).

Non-ASME Structural AMPs: Common Changes

- Clarified that coatings are monitored for indications of the condition of the underlying material (XI.S6 & XI.S7 - Elements 1 & 3).

- Reworded portions related to bolting to improve clarity and consistency across structural AMPs (XI.S6 & XI.S7 - Elements 1, 2 & 3).
  - Clarified that high-strength bolting greater than 1 inch diameter should be monitored for SCC, *except* for ASTM A325 and A490 bolts in civil structure applications.

Non-ASME Structural AMPs: Common Changes

- Added focused inspections of inaccessible concrete areas exposed to aggressive groundwater/water (XI.S6 & XI.S7 – Element 4).

- Noted that trending is expected and quantitative measurements should be recorded when possible (XI.S5, XI.S6, and XI.S7 – Element 5).
  - Noted that photography ***may*** be a useful technique for documenting and trending aging.

Non-ASME Structural AMPs: Common Changes

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

- Clarified that technically justified quantitative acceptance criteria should be used whenever applicable (XI.S6 and XI.S7 – Elements 5 & 6).

- Noted that baseline inspections should be performed with appropriate quantitative acceptance criteria prior to the SLR period (XI.S6 and XI.S7 – Elements 5 & 6).
  - Technically justified, quantitative acceptance criteria are necessary for effective trending and adequate aging management. If applicants have not used quantitative acceptance criteria, a 'baseline' inspection should be completed prior to the SLR period.

GALL-SLR Chapter XI.S5: Masonry Walls

- Added an inspection frequency of every 3 years for unreinforced and unbraced walls (Element 4).
  - These walls are more susceptible to cracking and crack propagation. As their service life increases more frequent inspections are necessary to ensure cumulative effects of possible degradation are properly addressed.

- Clarified the expectation of a technical justification/engineering evaluation to accept a degraded condition without repair or corrective actions (Element 6).

GALL-SLR Chapter XI.S6: Structures Monitoring

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

- Noted that elastomeric materials are subject to tactile inspection (Element 4).
- Added monitoring of through-concrete leakage for its volume and chemistry and emphasized that through-concrete leakage should be addressed with corrective actions beyond ‘engineering judgement’ (Elements 3 & 4).
- Clarified that the evaluation of groundwater chemistry should occur with a frequency that can identify seasonal variations (Element 4).

GALL-SLR Chapter XI.S7: Inspection of Water-Control Structures

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

- Deleted Regulatory Guide (RG) 1.127 from the title and clarified that the AMP is independent of RG 1.127. The RG is still referenced in the AMP for additional guidance (Title & Program Description).

- Clarified that submerged concrete is not considered inaccessible and should be inspected every 5 years, or a technical justification should be provided for a longer interval (Element 4).

SRP-SLR Chapter 3.5: Containments, Structures and Component Supports – Aggregate Reactivity

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

- Revised the Further Evaluation for Aggregate Reactivity
  - A plant-specific AMP is necessary if reactivity tests or petrographic examinations of concrete samples identify reaction with aggregates, or visual inspections of accessible concrete have identified indications of aggregate reactions, such as “map” or “patterned” cracking or the presence of reaction byproducts (e.g., alkali-silica gel).
  - Deleted references to ASTM and ACI standards.

- Aligned SRP-SLR Table 3.5-1 entries (ID 12, 43, and 50) and GALL-SLR items II.A1.CP-67, III.A1.TP-204, III.A6.TP-220 with the revised language.

SRP-SLR Chapter 3.5: Containments, Structures and Component Supports – Irradiation

- Added a Further Evaluation for irradiation.
- A plant-specific AMP or analysis is necessary if estimated irradiation dose (fluence) received by the concrete from neutron and/or gamma radiation exceeds threshold limits:
  - 10^{19} neutrons/cm^2 neutron radiation (E > 0.1 MeV)
  - 10^8 Gy gamma dose.

- Added SRP-SLR Table 3.5-1 entry (ID 97) and associated GALL-SLR item (III.A4.T-35).
  - Addresses reduction of strength and loss of mechanical properties of Group 4 concrete.

SRP-SLR Chapter 4.5: Concrete Containment Unbonded Tendon Prestress Analysis

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

- Reworded title to include “Unbonded”
- Clarified:
    - “Review Procedures” and “Acceptance Criteria” to 10 CFR 54.21(c)(1)(ii) of time-limited aging analysis (TLAA). Consistent with regulations, reevaluation of unbonded tendon prestressed forces is performed, to ensure prestressed concrete containment design remains valid. Deleted from “Review” and “Acceptance” Sections, tendon management/retensioning program to be an acceptable substitute when tendon prestress force trend lines fall below design values.

SRP-SLR Chapter 4.5: Concrete Containment Unbonded Tendon Prestress Analysis

- **Added:**
  - TLAA reviews for predicted lower limit (PLL) lines and for bonded tendons are performed under SRP Chapter 4.7, “Other Plant-Specific Time Limited Aging Analyses” (Areas of Review).
  - Supplementary “aging effects” (e.g., breakage of tendon wires, effects of SCC, improper anchorages, tendon relaxation when replacing existing inservice tendons with new) to elevated temperatures for loss of tendon prestress (Areas of Review).
  - TLAA Final Safety Analysis Report supplement for 10 CFR 54.21(c)(1)(ii).

GALL-SLR Chapter X.S1: Concrete Containment Unbonded Tendon Prestress

- Reworded title to include *“Unbonded.”*
- Clarified:
  - Focus of program, assess adequacy of measured tendon prestress forces for the sampled group (i.e., hoop, vertical, dome, inverted-U, helical) of unbonded tendons (Program Description).

  - The specifics on how to evaluate loss of tendon prestress (i.e., measure, analyze, trend sampled tendons) (Element 4).

GALL-SLR Chapter X.S1: Concrete Containment Unbonded Tendon Prestress

- Added:
  - This is a condition monitoring program. Corrective actions are taken before tendon forces fall below design values (Element 2).
  - PLL, the minimum required value, and tendon (lift-off) force trend lines for each tendon group are projected to the end of the SLR period (Element 5).
  - Emphasized the importance of PLL line for each trended group of tendons. If the tendon force trend line crosses the PLL line, the cause is determined, documented, evaluated, and corrected (Element 6).

GALL-SLR Chapter XI.S4:
10 CFR Part 50, Appendix J

- **Clarified (Program Description):**
  - Role of the AMP. Emphasized, all containment pressure boundary components are managed for age-related degradation.

- **Added:**
  - Pressure boundary components excluded from 10 CFR Part 50 Appendix J testing need to be identified along with AMPs credited for managing the aging effects (Element 1).

SRP-SLR Chapter 4.6: Metal Containment, Liner Plate, Penetrations Fatigue

- **Clarified:**
  - Fatigue parameters (fatigue analyses, fatigue waivers) for metal containments, metal liners, penetrations (mechanical, electrical) are reviewed. Review also includes personnel airlock, equipment hatch, and control rod drive (CRD) hatch (Areas of Review).
- **Added:**
  - Type and number of occurrences for cyclic loads for fatigue parameter evaluations, are stated (Areas of Review).
  - Electric Power Research Institute reference (TR-1003456) on aging management of mechanical and electrical penetrations (Areas of Review).

SRP-SLR Chapter 4.6: Metal Containment, Liner Plate, Penetrations Fatigue

- **Added:**
  - ASME BPV Code Section III fatigue waiver evaluations for liners, to 10 CFR 54.21(c)(1)(i) or (ii) review.
  - Acceptable programs to 10 CFR 54.21(c)(1)(iii) for monitoring and tracking the number of cycles and occurrences and severity of relevant transients are identified (Acceptance Criteria, Review Procedures).
  - Metal liner/metal plates, personnel airlock, equipment hatch, CRD hatch are included as areas of review to SRP-SLR “3.5.2.2.1.5 Cumulative Fatigue Damage,” Table 3.5-1, item 3.5.1-9 and GALL-SLR items II.A3.C-13, II.B4.C-13.

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

Subsequent License Renewal (SLR) Draft Generic Aging Lessons Learned (GALL) Report and Standard Review Plan (SRP) Electrical Changes

Office of Nuclear Reactor Regulation
Division of License Renewal

February 17, 2016

GALL-SLR Chapter X.E1: Environmental Qualification (EQ) of Electric Components & SRP-SLR Chapter 4.4: EQ of Electric Equipment

- Added discussion on the SLR extension of a component's environmental qualification (qualified life):
  - Environment monitoring clarification
  - Added adverse localized environment inspection/walk down based on plant; specific operating experience, corrective actions, procedures and visual inspections
  - Added 10 CFR 50.49 discussion on the application and maintenance of margin:
    - Clarification added to EQ reanalysis on the maintenance of adequate EQ margins, conservatisms and uncertainties
  - On-going EQ (Condition Monitoring)

GALL-SLR Chapter XI.E1: Electrical Insulation for Electrical Cables and Connections (Non-EQ)

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

- Added guidance on the identification and verification of adverse localized environments based on plant-specific operating experience, procedures, environmental monitoring and previous walkdowns
- Removed fuse holder insulation and transferred to GALL-SLR Report Aging Management Program (AMP) XI.E5
- Added testing on a sampling basis on the accessible cables in addition to visual

GALL-SLR Chapter XI.E2: Electrical Insulation for Electrical Cables and Connections (Non-EQ) Requirements Used in Instrumentation Circuits

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Added guidance on the identification and verification of adverse localized environments that are used as one of the bases of the requirements of the AMP

GALL-SLR Chapter XI.E3 A, B, C – Electrical Insulation for Inaccessible (Medium Voltage, Instrument and Control, and Low Voltage) Power Cables (Non-EQ) Requirements

- XI.E3 was expanded with three new AMPs to address aspects of industry and NRC guidance related to potentially submerged cables:
  - XI.E3A: Medium Voltage Power Cables
  - XI.E3B: Instrument and Control Cables
  - XI.E3C: Low Voltage Power Cables (both alternate and direct current)
- Provides inaccessible cable inspection and test method as applicable to each AMP cable type (adds in-situ or laboratory electrical, physical, or chemical testing)

GALL-SLR Chapter XI.E3 A, B, C – Electrical Insulation for Inaccessible (Medium Voltage, Instrument and Control, and Low Voltage) Power Cables (Non-EQ) Requirements

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

- Limited test criterion statement (testing that is proven and shown to be applicable to the cable type, voltage, insulation and construction)
- Separated event driven from periodic inspections (clarification)
- Included submarine or other cables designed for continuous submerged service (one-time test)

GALL-SLR Chapter XI.E4: Metal-Enclosed Bus

- Scope expanded to mention cable bus in the program description as a plant-specific further evaluation item

- Added guidance on the detection of aging effects (removed sampling)

- Clarified inaccessible metal-enclosed bus features and provides guidance on their treatment and evaluation

GALL-SLR Chapter XI.E5: Fuse Holders

- Electrical insulation portions of the fuse holders were removed from GALL-SLR Report AMP XI.E1 and transferred to this AMP

GALL-SLR Chapter XI.E6: Electrical Cable Connections (Non-EQ) Qualification Requirements

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Replaced the one-time inspection with periodic inspection (once every 10 years or once every 5 years for visual inspection)

GALL-SLR Chapter XI.E7: High Voltage Insulators

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

- New AMP provides reasonable assurance that the intended functions of high voltage insulators in scope and credited for recovery of offsite power are adequately age managed

- Transferred from “further evaluation” based on operating experience:
  - Loss of safety function
  - Corrosion
  - Coating failure

- Designed to periodically (twice a year) visually inspect high voltage insulators susceptible to adverse environments (insulator and conductor connector aging effects including support degradation and surface contamination caused by salt, dust, fog, cooling tower plume, industrial effluent)

GALL-SLR Chapter VI: Electrical Components & SRP-SLR Chapter 3.6 Electrical and Instrumentation Controls

- Same as GALL-SLR AMPs discussed in previous slides:
  - Added additional guidance for the identification and verification of adverse localized environments (Non-EQ)
  - Expanded electrical cable condition monitoring
  - Added aging management review line items:
    - To address cable bus and high voltage insulators
    - For consistency with changes to corresponding AMPs
    - Added cable bus as a new further evaluation plant-specific item

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

Subsequent License Renewal (SLR) Draft Standard Review Plan (SRP) Changes

Office of Nuclear Reactor Regulation
Division of License Renewal

February 17, 2016

SRP-SLR Chapter 5.0: Technical Specification (TS) Changes

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

- 10 CFR 54.22 requires an license renewal applicant/SLR application to identify any new TSs or TSs modifications that are needed to manage the effects of aging
- Previous version of SRP for license renewal did not include any guidance criteria for complying with these requirements
- Staff developed Chapter 5 to define NRC's guidance criteria for complying with 10 CFR 54.22 requirements
- Provides examples of TS requirements that may relate to aging management programs or time-limited aging analyses (TLAAs) (e.g., fuel oil programs, pressure-temperature limit TLAAs)

United States Nuclear Regulatory Commission

Protecting People and the Environment

Subsequent License Renewal (SLR) Draft Generic Aging Lessons Learned (GALL) Report and Standard Review Plan (SRP)

Neutron Fluence, Embrittlement and Reactor Pressure Vessel Changes

Office of Nuclear Reactor Regulation
Division of License Renewal

February 17, 2016

Background

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Licensees transitioning to renewed operating licenses
- Licensees considering 60 to 80 years of operation under SLR
- Programs to manage aging effects for 10 CFR Part 54, (i.e., neutron embrittlement)
- Inspections for monitoring and establishment of neutron fluence thresholds for components
- Applications contain neutron fluence evaluations for reactor vessel internals

New GALL-SLR X.M2: Neutron Fluence Monitoring

- **Why create the Aging Management Program (AMP) now?**
  - The AMP was created based on the NRC staff having to evaluate neutron fluence in non traditional places inside the reactor vessel
  - Challenges have arisen for applying Regulatory Guide (RG) 1.190, adherent methods to outside the beltline
- **New Requirements?**
  - The AMP is optional for licensees as part of the GALL-SLR Report
  - Expectation is that licensees are already taking similar actions in accordance with 10 CFR Part 50 Appendix B
- **Additional Information**
  - The AMP acknowledges that, for SLR, the neutron fluence evaluations may be applied in ways that are outside the scope of RG 1.190
  - NRC staff working on new guidance for outside the scope of RG 1.190

New GALL-SLR X.M2: Neutron Fluence Monitoring

- **Program Description and Scope of Program:**
  - Added to provide a method for accepting reactor pressure vessel neutron embrittlement time-limited aging analyses (TLAAs) in accordance with 10 CFR 54.21(c)(1)(iii)
  - May be used for other non-TLAA assessments
  - AMP to be used in conjunction with GALL-SLR AMP XI.M31
    - Use of X.M2 is analogous to use of AMP X.M1 for fatigue TLAAs
- **Acceptance Criteria and Corrective Action Elements:**
  - When monitoring is applied to NRC approved analyses, regulatory requirements for updating the analyses and for submitting the analyses to the NRC must be adhered to, as defined in the applicable regulations or Technical Specification requirements

New GALL-SLR X.M2: Neutron Fluence Monitoring

- Detection of Aging Effects and Monitoring and Trending Element Clarifications:
  - Monitoring methods for components in the reactor pressure vessel (RPV) beltline to be consistent with RG 1.190
  - Methodology for monitoring reactor vessel internal components or RPV components away from the beltline may need additional justification, on a plant-specific basis
  - Monitoring to be performed in comparison to the neutron fluence methods, assumptions, and results used in the TLAAs or aging management assessments

GALL-SLR Chapter XI.M31: Reactor Vessel Material Surveillance

- **Program Description:**
  - Based on requirements in 10 CFR Part 50 Appendix H
  - Adjusted to provide adequate reactor vessel surveillance program criteria to cover plant operations through a 80-years period of licensed operation
  - Updated to differentiate between plant-specific reactor vessel material surveillance programs and reactor vessel material integrated surveillance programs (ISPs)

GALL-SLR Chapter XI.M31: Reactor Vessel Material Surveillance

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

- **Scope of Program, Detection of Aging Effects, and Monitoring and Trending:**
  - Improved element criteria defined for implementation of both plant-specific reactor vessel material surveillance programs and reactor vessel material ISPs

- **Parameters Monitored:**
  - Updated capsule removal schedule and RG 1.190 conformance criteria

GALL-SLR Chapter XI.M31: Reactor Vessel Material Surveillance

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

- **Detection of Aging Effects and Monitoring and Trending Elements:**
  - Withdrawal and testing of additional capsule during the subsequent period of extended operation that achieves a capsule fluence that is between 1 and 1.25 times the maximum ID fluence that is projected for the reactor vessel through 80 years of licensed operation
  - Program element criteria includes alternative management activities if no surveillance capsules are available for withdrawal and testing during a SLR period

SRP-SLR Chapter 4.2: Neutron Irradiation Embrittlement

- Added “acceptance criteria” and “review procedure” criteria for neutron fluence methodology TLAAs
- Pressurized thermal shock TLAAs for SLR may be based on either 10 CFR 50.61 or 10 CFR 50.61a (depending on current licensing basis)
- AMP X.M2 when used in conjunction with AMP XI.M31, provides one way to accept under 10 CFR 54.21(c)(1)(iii)
- Boiling water reactor vessel girth and axial weld probability of failure analyses for SLR to be reviewed on a case-by-case basis

Subsequent License Renewal (SLR) Draft Generic Aging Lessons Learned (GALL) Report and Standard Review Plan (SRP)

Mechanical Changes

Office of Nuclear Reactor Regulation
Division of License Renewal

February 17, 2016

GALL-SLR Chapter XI.M6: Control Rod Drive Return Line Nozzle

- The aging management program (AMP) in GALL Report Rev. 2 used to manage cracking in boiling water reactor (BWR) control rod drive (CRD) return line nozzles induced by fatigue

- Previously renewed BWRs (e.g., Nine Mile Point, Unit 1 and Oyster Creek) established procedures to perform ultrasonic testing examinations of the CRD return line nozzles

GALL-SLR Chapter XI.M6: Control Rod Drive Return Line Nozzle

- Aging in all other BWRs managed by other AMPs

- AMP XI.M6 is no longer needed to manage cracking in the CRD return line nozzles because cracking can be addressed using other AMPs

- Appropriate aging management review (AMR) line items and SRP-SLR further evaluation sections have been added or modified to account for the revised basis

GALL-SLR Chapter XI.M9: BWR Vessel Internals

- **Scope of Program:**
  - Added: Loss of preload due to thermal or irradiation-enhanced stress relaxation (for core plate rim holddown bolts and jet pump assembly holddown beam bolts)
  - Clarified: Cracking due to cyclic loading includes cracking due to flow-induced vibration (for steam dryers)

GALL-SLR Chapter XI.M9: BWR Vessel Internals

- **Detection of Aging Effects:**
  - Added evaluations to determine need for supplemental inspections
  - BWR Vessel and Internals Project (BWRVIP) report references were updated
  - The SLR term increases neutron fluence levels and operational periods, which can promote (a) loss of fracture toughness due to neutron irradiation or thermal aging embrittlement and (b) cracking due to irradiation assisted stress corrosion cracking in nickel alloy and stainless steel internal components

GALL-SLR Chapter XI.M9: BWR Vessel Internals

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

- **Detection of Aging Effects:**
  - Applicants should evaluate the need for supplemental inspections in addition to the existing BWRVIP examination guidelines
  - Evaluations should consider neutron fluence, cracking susceptibility (i.e., applied stress, operating temperature, and environmental conditions), thermal aging susceptibility, and fracture toughness
  - Supplemental inspections based on evaluations
  - Further evaluation sections added to SRP-SLR

GALL-SLR Chapter XI.M16A: Pressurized Water Reactor (PWR) Vessel Internals

- The AMP was eliminated and a new AMR further evaluation section was developed to request a plant-specific AMP for PWR reactor vessel internals
- Meetings with the industry reaffirmed that Materials Reliability Program (MRP)-227-A (upon which AMP XI.M16A was based) would be revised in 2015 but would not be revised to cover the operational period for 60 to 80 years until 2020
- The staff determined that it would not be acceptable to use a generic AMP without an update of an augmented inspection basis from the industry that would cover the 80 years assessment period

GALL-SLR Chapter IV: Reactor Vessel, Internals, and Reactor Coolant System

- AMR Items related to management of cumulative fatigue damage by time-limited aging analyses (TLAA) administratively edited to be consistent with one another
- AMR items for reactor vessel neutron embrittlement TLAAs reduced down to only one AMR item entry for each of the tables on reactor vessel components (Tables IV.A1 and IV.A2)
- Similarly, AMR items for managing loss of fracture toughness in reactor vessel beltline components using reactor vessel AMPs reduced down to only one AMR item entry for each of the tables on reactor vessel components - the AMR items continue to cite “Yes” for further evaluation but were modified to cite both use of AMP XI.M31 and the new X.M2 AMP (fluence monitoring)

GALL-SLR Chapter IV: Reactor Vessel, Internals, and Reactor Coolant System

- AMR items for PWR reactor internal components in Table IV.B2, IV.B3, and IV.B4 reduced down only to a few generic lines items - Per SRP-SLR 3.1.2.2.9, propose plant-specific AMP for PWR reactor internals

- Further evaluation criteria for AMR items that manage radiation-induced effects in BWR reactor internals changed from “No” to “Yes” (See SRP-SLR 3.1.2.2.12)

- Other AMR items added, carried over, or modified based on previous ISG positions or long term (80 years) aging concerns – e.g., longer term loss of material or aging in insulation

SRP-SLR Chapter 3.1: Reactor Vessel, Internals, Coolant System

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

- Section 3.1 Updated to provide guidance on how AMRs and AMPs/TLAAs relate to one another – similar to the Nuclear Energy Institute (NEI) discussions in NEI 95-10, Revision 6

- Major changes to subsections in Section 3.1.2.2 (further evaluation (FE) acceptance criteria) and Section 3.1.3.2 (FE review procedures):
  - Expanded list of cyclical loading TLAAs in 3.1.2.2.1 and 3.1.3.2.1
  - 3.1.2.2.3.2/3.1.3.2.3.2 expanded to cite use of AMP XI.M31 and AMP X.M2
  - 3.1.2.2.9/3.1.3.2.9 – New FE for managing aging in PWR reactor internals – propose plant-specific AMP for 80 years aging

SRP-SLR Chapter 3.1: Reactor Vessel, Internals, Coolant System

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

- **Changes to 3.1.2.2 and 3.1.3.2:**
  - 3.1.2.2.10/3.1.3.2.10 – New FE for managing of loss of material due to wear in PWR CRD nozzles and nozzle thermal sleeves – based on a past processed license renewal application(LRA) and operating experience for that LRA
  - 3.1.2.2.12/3.1.3.2.12 and 3.1.2.2.13/3.1.3.2.13 - New FEs for managing of radiation-induced effects in BWR internals – evaluate need to modify BWRVIP criteria
  - 3.1.2.2.14/3.1.3.2.14 – New FE for managing loss of preload in BWRs with core plate rim hold-down bolts – justification of AMP or TLAA used to manage loss of preload in the bolt
  - 3.1.2.2.15/3.1.3.2.15 – New FE for managing loss of material/boric acid corrosion in steel steam generator channel heads clad with stainless steel or nickel alloy

SRP-SLR Chapter 3.1: Reactor Vessel, Internals, Coolant System

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

- **Changes to 3.1.2.2 and 3.1.3.2:**
  - 3.1.2.2.16/3.1.3.2.16 (and subsections) and 3.1.2.2.17/3.1.3.2.17 – New FE sections associated with cracking in CRD return line nozzles (including nozzle caps) or return line piping components
  - 3.1.2.2.18/3.1.3.2.18 – New FE proposing need for further evaluation of Section IV.E “none-none” AMR items for steel or stainless steel piping components embedded in concrete
  - 3.1.2.2.19/3.1.3.2.19 – New FEs for managing loss of material due to pitting and crevice corrosion, and microbiologically influenced corrosion

GALL-SLR Chapter X.M1: Cyclic Loading Monitoring

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

- Program Description, Scope of Program, Detection of Aging Effects, and Monitoring and Trending:
  - Elements renamed and amended to clarify that AMP X.M1 is a “condition monitoring” program
- May be used to accept cycle-based TLAAs accordance with 10 CFR 54.21(c)(1)(iii)
- Includes all types of cycle-related TLAAs in SRP-SLR 4.3 and 4.6

GALL-SLR Chapter X.M1: Cyclic Loading Monitoring

- Monitoring to cover number of cycles and severity of design transient occurrences

- States in the program description and detection of aging effects that Technical Specifications requirements may apply

- Acceptance Criteria:
  - Appropriate thresholds to be established for each type of fatigue analysis monitored by the AMP

SRP-SLR Chapter 4.3: Metal Fatigue

- Expanded to include all cycle-based TLAAs in previous LRAs
- Prior environmentally-assisted fatigue analyses will be TLAAs for SLR
- Subsections regrouped by those for: (a) environmentally-assisted fatigue analyses, and (b) other types of cycle-based analyses

SRP-SLR Chapter 4.3: Metal Fatigue

- Additional clarifications for accepting TLAAs per 10 CFR 54.21(c)(1)(iii):
  - – AMP X.M1, Cyclic Load Monitoring, a way to accept under (iii)
  - – Other bases for (iii) to be reviewed on a case-by-case basis
  - – If an inspection-based AMP is used for (iii), AMP must inspect the specific components during the subsequent period of extended operation

GALL-SLR Chapter XI.M12: Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Pump casings are no longer exempt from AMP requirements:
  - Formerly exempted pump casings assuming licensees implemented Code Case N-481 alternative
  - N-481 has been withdrawn, and not all provisions have been incorporated into the American Society of Mechanical Engineers Code, Section XI
  - Therefore, pump casings will now be subject to screening, and augmented inspection or flaw tolerance evaluation if not screened out

GALL-SLR Chapter XI.M12: Thermal Aging Embrittlement of Cast Austenitic Stainless Steel

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

- Code Case N-824 now referenced for detection of aging effects for piping ≤ 1.6 inches in thickness:
  - N-824 provides a method for ultrasonic testing inspection (detection and flaw sizing) for cast austenitic stainless steel (CASS) piping
  - To be incorporated in forthcoming 10 CFR 50.55a rulemaking with conditions
- Program description now clarifies AMP XI.M12 does not cover CASS in reactor vessel internals

GALL Chapter XI.M7: Boiling Water Reactor (BWR) Stress Corrosion Cracking

- An AMR line item (IV.A1.R-412) was added to indicate that this program manages stress corrosion cracking of control rod drive (CRD) return line cap and associated welds.
- Operating experience demonstrates that the program has been effective to manage stress corrosion cracking in BWR piping and welds.

GALL Chapter XI.M11B: Cracking of Nickel-Alloy Components

Program scope revised to include:

- Baseline inspection provision for branch line connections and associated welds that are fabricated with nickel alloys susceptible to pressurized water stress corrosion cracking (PWSCC)

- Baseline inspection of all susceptible nickel alloy bottom-mounted instrumentation nozzles, using a volumetric method prior to the subsequent period of extended operation; alternatively, applicant-proposed and staff-approved mitigation methods may be used to manage PWSCC

GALL Chapter XI.M35: ASME Code Class 1 Small-Bore Piping

- Added a table to summarize sampling guidance
- Added a sampling guidance for periodic inspections of plants where age-related cracking has been identified and periodic inspections are warranted
- No other significant changes were made to this AMP as operating experience (OE) demonstrates that the program is effective in managing aging

GALL-SLR Chapter XI.M17: Flow Accelerated Control

- Added recommendation to reassess piping systems that have been excluded due to limited operation (< 2 % of operating time as allowed by NSAC-202L Rev. 4, “Recommendations for an Effective Flow-Accelerated Corrosion Program”) to ensure adequate bases exist to justify this exclusion after 60 years

GALL-SLR Chapter XI.M20: Open-Cycle Cooling Water System

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

- Included new consideration for determining friction factors based on monitored portions of the system in order to calculate flow rates in unmonitored portions of the system

Interim Staff Guidance (ISG) Related Mechanical AMPs

- XI.M27: Fire Water System
- XI.M29: Outdoor and Large Atmospheric Storage Tanks
- XI.M36: External Surfaces Monitoring of Mechanical Components
- XI.M38: Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- XI.M41: Buried and Underground Piping and Tanks
- XI.M42: Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks (***New – November 2014)***

ISGs

- 2012-02: Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation

- 2013-01: Aging Management of Loss of Coating or Lining Integrity for Internal Coatings/Linings on In-Scope Piping, Piping Components, Heat Exchangers, and Tanks

- 2015-01: Changes to Buried and Underground Piping and Tank Recommendations

ISG 2012-02

- Recurring internal corrosion
- XI.M27: Five key inspections, six key tests – citing National Fire Protection Association 25
- XI.M29: Expanded to certain indoor tanks, expanded inspections
- XI.M38: Periodic minimum sample size
- XI.M29 & XI.M36: Corrosion under insulation

ISG 2013-01

- Internal coatings and linings
- Periodic visual inspections
- Tanks & heat exchangers – all accessible surfaces
- Piping – 50% or 73 1-foot axial inspections
- Qualifications for inspectors and coating specialist
- No peeling or delamination, other indications evaluated

ISG 2015-01

- Changes based on operating experience
- Modified number of inspections
- Expanded cathodic protection acceptance criteria
- Coatings on underground components
- Sample size increase based on potential challenge to pressure boundary

GALL-SLR Chapter XI.M32: One-Time Inspection

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Included a one-time (OTI) for SLR
- Inspection quantity is unit-based
- Stated that program is not used for aging effects:
  - That have not met acceptance criteria based on OTI conducted during the prior operating period or,
  - Based on the review of plant-specific or industry OE
- Added long-term loss of material
- Revised to include expanded scope of inspections when <u>acceptance criteria is not met</u>

GALL-SLR Chapter XI.M33: Selective Leaching

United States Nuclear Regulatory Commission
Protecting People and the Environment

- Recommends OTI for closed-cycle or treated water if past plant-specific OE is acceptable (3%, maximum of 10)
- Recommends opportunistic and periodic inspections for raw water, waste water, ground water, and soil (3%, maximum of 10, with 2 destructive examinations)
- Added ductile iron **[SLR Supplement Related]**

SRP-SLR Sections 3.2, 3.3, 3.4 & GALL-SLR Chapters V, VII, VIII

- Addressed many Material, Environment, Aging Effect and Program combinations that previously cited generic notes F – J, 58 new or modified Table 1 items
- Address items exposed to raw water that do not have a Generic Letter 89-13 function
- Addressed new Further Evaluation (FE) sections or revised existing FEs

SRP-SLR Sections 3.2, 3.3, 3.4

- Loss of material for stainless steel (SS) and aluminum alloys and cracking for SS components [**SLR Supplement Related**]:
  - Any air environments
  - Plant-specific OE search
  - OTI
  - Can credit coatings program as an alternative
  - Potential exclusion for internal surfaces – OE and results of external inspections
  - SRP-SLR Section 3.1 – SS loss of material only
- Cracking of aluminum alloys:
  - Any air environments
  - Material composition and environment focused

SRP-SLR Sections 3.2, 3.3, 3.4

- New FE sections to address loss of material and stress corrosion cracking in concrete environment – concrete attributes, plant-specific OE, and potential for ground water exposure

- New FE section to address loss of material in components exposed to treated water, treated borated water or sodium pentaborate solution:
  - XI.M2 and periodic or OTI based on temperature, oxygen levels and pH
- Revised Section 3.2.2.2.4 (old “5”) to address flow blockage due to fouling in addition to loss of material for spray nozzles in drywell and suppression chamber spray systems