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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE

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WEDNESDAY,

OCTOBER 30, 2002

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Graham M. Leitch, Chairman, presiding.

COMMITTEE MEMBERS:

GRAHAM M. LEITCH	Chairman
JOHN J. BARTON	Consultant
MARIO V. BONACA	Member
STEPHEN L. ROSEN	Member
WILLIAM J. SHACK	Member
JOHN D. SIEBER	Member
GRAHAM B. WALLIS	Member

ACRS STAFF PRESENT:

RAMIN ASSA

TIMOTHY KOBETZ

OTHER NRC STAFF PRESENT:

PT KUO

RAJ ANAND

HANS ASHAR

STEWART BAILEY

WILLIAM (BUTCH) BURTON

JOSE CALVO

BARRY ELLIOT

JOHN FAIR

BART FU

GEORGE GEORGIEV

MARK HARTZMAN

GREG HATCHETT

MEENA KHANNA

SAM LEE

RENEE LI

JIM MEDOFF

MICHAEL MODES

CLIFF MUNSON

DUC NGUYEN

ROBERT PETTIS

OTHER NRC STAFF PRESENT: (CONT.)

JAI RAJAN

DAVID SOLORIO

JIMI YEROKUN

I-N-D-E-X

I-N-D-E-X (Con't)

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

8:36 a.m.

CHAIRMAN LEITCH: On the record. Good morning. This is the meeting of the ACRS Subcommittee on License Renewal. I'm Graham Leitch, Chairman of the Subcommittee. The ACRS members in attendance are Mario Bonaca, William Shack, John Sieber, Graham Wallis and John Barton is with us as a consultant to the ACRS.

The purpose of this meeting is to review the Staff Safety Evaluation Report with open items related to the application for renewal of the operating licenses for Peach Bottom Power Station, Units 1 & 2.

MEMBER ROSEN: Two and three.

CHAIRMAN LEITCH: Two and three it should be. The Subcommittee will gather information, analyze relative issues and facts and formulate the proposed positions and actions as appropriate for deliberation by the full Committee. Ramin Assa is the cognizant ARCS staff engineer for this meeting. The rules for participation in today's meeting have been announced as part of the notice of this meeting previously noticed in The Federal Register on October 22, 2002.

The transcript of the meeting is being

kept and will be made available as stated in The Federal Register notice. It is requested that speakers first identify themselves, use one of the microphones and speak with sufficient clarity and volume so that they can readily heard. I would like to point out that copies of the presentation are in the back of the room and additional copies of Peach Bottom License Renewal Application are also available for reference in the back of the room.

We have received no requests for time to make oral statements or written comments from members of the public regarding today's meeting. We will now proceed with the meeting. I'll call on Mr. P.T. Kuo, Program Director for NRC Division of License Renewal and Environmental Impact for his opening remarks. P.T.

MR. KUO: Thank you, Dr. Leach. Sitting next to me is Dr. Sam Lee who is the second chief for the License Renewal section. Today the Staff is ready to brief the Committee on the safety review of Peach Bottom License Renewal Application. David Solorio is the Senior Project Manager for the Review. He took over the project in August. Prior to that, Raj Anand was the project manager.

Before Dave starts his briefing which will be supported by Staff sitting on the table and also sitting in the audience, I would like to follow up another item that came up from the last ACRS meeting, McGuire/Catawba. At that time, Dr. Bonaca asked whether the Staff has a system to track the commitment so that years later that we can perform inspections. I told the Committee at that time that yes indeed we would have been developing Inspection Procedure 71003. I promised to come back to the Committee today.

I did check and we did have a procedure developed but it is still in the draft stage being reviewed. As soon as it is finalized, I will forward a copy to the Committee. In the meantime, I did check the contents of the procedure. It is certainly very clearly stated that the procedure will have a plant-specific list of all of the commitments that is committed by the licensee and that the Staff will inspect those commitments on a sampling basis. With that, I will turn the briefing over to Dave.

MR. SOLORIO: Thank you, P.T.

MEMBER BARTON: I thought I heard in an earlier license renewal meeting that all these things are going to captured in the FSAR submittal that the licensee would have to make that talked about the aging programs and the commitments. We were told earlier that this was all going to be submitted in the FSAR submittal that covered the extended operating period. So now we hear something else.

MR. KUO: No, that is correct. This is in addition to that that we have inspection procedures to make sure that the Staff after years before the extended operation we will have something to rely on to do our inspections.

MEMBER BARTON: All right, I understand. Thank you.

MR. KUO: You're welcome.

MEMBER BONACA: The concern really, John, was we realize that so of the many of these plants will reach license zero period roughly at the same time and there is going to be a huge amount of commitment on them that is going to have to be implemented and also verified by the Staff. So the challenge is not going to be necessarily for the licensee but for the Staff to deal with all them in a short time.

MEMBER BARTON: Okay, I understand. Thank you, Mario.

MR. SOLORIO: Okay, Thanks, P.T. I'll begin. Can everyone hear me okay? I wasn't sure if the mike was working properly. My name is Dave

Solorio. I work in the License Renewal and Environmental Program Office Impacts Program in the Office of NRR. I'm the License Renewal Project Manager for the Peach Bottom Power Station. I want to acknowledge that Mr. Raj Anand has been doing that prior to me for about a year and he's here with us today in case I need his corporate memory.

I hope you recognize the format of the slides I have today. We will more or less follow what you saw before for the Catawba/McGuire presentation. To my right, I have Mr. Michael Modes and Jimi Yerokun who are up here because later on a few pages you'll see a slide on inspection results. If you have more detailed questions than what I speak on I have them here to address your questions.

The next couple of slides just provide an outline of various staff members along with me who will be making presentations here today. I'm going to ask the Staff members to come up here for transitioning to the presentation to minimize the delay for you.

In a way of background, the Licensing Application for the Peach Bottom units came in on July 2, 2001. Peach Bottom is a two-unit BWR. It's located in York and Lancaster Counties in Southeastern

Pennsylvania. The plant is about 38 miles north-north east of Baltimore and 63 miles west-southwest of Philadelphia. The reactor buildings are separate for each unit. The turbine building, control room, rad waste building, field generator building house equipment used by both units.

Peach Bottom units are BWR/4s, Mark 1 design and supplied by GE. Each unit is authorized to operate at a steady reactor core power not in access of 3,458 megawatts thermal (MWt). The current license for unit two expires August 8, 2013 and unit three expires in July 2, 2014.

CHAIRMAN LEITCH: Dave, Peach Bottom has or has not applied for construction period recapture.

MR. SOLORIO: I don't know that. I could probably get the answer for you before the end of the day.

CHAIRMAN LEITCH: In other words these dates are 40 years from the license.

MR. POLASKI: This is Fred Polaski, production. Yes, this 40 years includes we haven't recapture the construction period so that's 40 years from start-up.

CHAIRMAN LEITCH: Okay, thank you.

MR. SOLORIO: In the way of request for

additional information, we issued 231 by March of this year. In the way of comparison, I looked up how many we issued per Hatch, we issued over 400. It was interesting to note that the RAIs for the aging management review per Hatch were around 170 and for Peach Bottom 40. The scoping RAIs for Hatch were around 200 and around 89 for Peach Bottom.

MEMBER WALLIS: Can I ask how many of these were repeats? I mean did you just send out an RAI and get an answer or did you have to go round and round with some of them?

MR. SOLORIO: There were a few we had to go round and round on them. I don't want to say round and round. I mean we had to iterate on them. There are three or four and actually there is a subject of some open items which the Staff knows about.

MEMBER BARTON: Some of the RAIs end up open items because you couldn't resolve them through the correspondence, right?

MR. SOLORIO: Yes, the schedules are very tight. We don't have a lot of time and with the milestones sometimes RAIs become open items. As far as the number of open items to go, we had 15. That was compared to 18 per Hatch. There were 16 confirmatory items for the Peach Bottom SER which will issued September 13 of this year. The responses to the open items and confirmatory items are due in November of this year.

You are going to hear throughout the presentations today from a number of Staff members that we received draft information from the Applicant which leads us to believe we can close a majority of this. I provided a summary status last Friday. I'm not sure if you have had time to look at it yet but the majority of them are closed and I provided some information on that.

My next two slides are meant to provide a little historical perspective on the license renewal rules which forms the basis of the Staff's review. This slide lists the two license renewal principles which I'm sure all of you perhaps have seen before. The first being the current licensing basis is adequate so with the exception of those instances of the detrimental effects of aging CLB is adequate and provides an acceptable level of safety. Currently licensing basis carries forward so the applicant is expected to meet all the same requirements in the renewal period they will have to meet in the first four years of operation.

In performing the Staff's review, we focus on the following here listed on the slide. We begin with an evaluation of methodology used to identify the structures, systems and components within the scope of an aging management review. As part of the review, we conduct an on-site audit by several headquarters quality assurance staff. At the same time, staff reviews the scope of the structures, systems and components identified in the license renewal application to obtain reasonable assurance that these structures, systems and components have been identified, those within the scope of license renewal.

The next step for the staff's review is to obtain reasonable assurance that the passive, long-lived structures, a subset of the structures within the scope of license renewal, are subject to an aging management review. The staff then reaches a reasonable assurance finding that the identification of the aging effects and management of the aging effects can insure relevant equipment and tenant functions in accordance with the current licensee basis are maintained in the period of extended operation.

The staff also reviews the identification of the time-limited aging analysis to reach reasonable assurance that the applicant's method to determine how these analysis with time-limited instructions will be extended or managed for the period of extended operation. During the review process, the staff also conducts planned inspections on the scoping and screening and aging management activities in accordance with NRC Inspection Manual Chapter 2516, "Policy and Guidance for the License Renewal Inspection Program" and Inspection Procedure 71002, "License Renewal Inspections." The inspection is an integral part of the staff's review that provides additional insurance that the methods, processes and results described in the LRA are sound.

The first inspection conducts was in April of this year. It was lead by Mr. Jimi Yerokun to my far right. It was a two week inspection. The objection was to confirm that the applicant had identified the structures, systems and components required by the rule. The team determined that the scoping and screening was being implemented as described in the LRA. Notable inspection findings were that during the plant walk down, the inspectors identified that non-safety related systems, the container spray and RHR heat filed systems adjacent to the safety related RHR and container spray systems were not within the scope of license renewal and the applicant did not scope fuse clips within the scope of license renewal.

I'll mention that in a later presentation today we'll be talking more about the fuse clips. Feel free to ask questions now if you have them. Also the scoping of the equipment relied upon for the recovery of off-site power is another inspection --

MEMBER BARTON: The fuse clips are not a new issue, is it? The fuse clips have come up on other applications as well, right? It doesn't sound like a new item to me.

MR. SOLORIO: Actually, fuse clips was identified during this inspection and as a result of that, staff had developed a draft in terms of staff guidance to discuss this issue. We are currently in the process of working through that in terms of staff guidance with the industry.

MEMBER SHACK: I think we did fuses before.

MEMBER BARTON: So it was fuses, not fuse clips. We only had half the problem.

CHAIRMAN LEITCH: I seem to recall an issue on fuse clips myself. I don't remember which applicant it was but I do remember a fuse clip issue previously.

MR. YEROKUN: I can try to respond to that. I'm Jimi Yerokun, currently Technical Assistant, Division of Regulatory Improvements in NRR. Before that, I was an Inspector in Region One and I led a team inspection in scoping and screening. At the time we came up on the fuse clips issues I had reviews from records of previous inspectors which revealed that this was a for standard fuse clips.

The question came up. There were previous records of addressing the fuses, passive or active, and that was found but there was no indication that the issue of addressing fuse clips had been discussed and resolved. So subsequent to that, there were staff guidance that was put out to the industry and that issue I believe is being addressed now generically.

DR. LEE: My name is Sam Lee. I'm from the License Renewal section. He's correct that the committee had heard about the fuse clips before. Once we identified this problem, we contacted the Catawba-McGuire, North Anna, Surry, because the applications were going on at the same time so we asked them the same question. Based on that we decided to develop an interim staff guidance. So you hear about it previously.

CHAIRMAN LEITCH: Okay, thanks.

MEMBER BARTON: Now we are going to hear it in the future or do you think this is going to resolve it for future applications?

MR. KUO: We have developed this internal staff guidance and we have sent this paper to the industry and the public interest group for public comments. We haven't been able to finalize that.

MEMBER BARTON: All right. I'm with you. I'm just trying to think about all the issues that you keep hearing over and over again with these applications. You wonder when are you going to resolve some of these. So I'm looking for how do you feel we are with resolving a few slip issues.

MR. KUO: We do have that interim staff guidance process. Then we are following the process to resolve this issue.

MEMBER BARTON: Thank you.

MR. KUO: You're welcome.

CHAIRMAN LEITCH: Is this the appropriate time to ask about the inspection activities?

MR. SOLORIO: Sure.

CHAIRMAN LEITCH: I guess I had a question, Jimi, about your general impression as to the material condition of the plant. I think one of the things that we're interested in is often times the material condition of the plant can convey an impression as to the safety culture that exists at a particular site, the care with which management is treating the plant and so forth. I guess I was wondering if you formed an opinion. Perhaps material condition was not the prime reason for the inspection. But nonetheless as you looked around, did you have some impression as to the material condition of Peach Bottom?

MR. YEROKUN: The scoping and screening inspection that I led, the material condition was I think like you said wasn't a real factor into the scope of the inspection. But nevertheless we did have some plant walkdowns, the systems that we were looking at, and the general impression of the material condition as far as the plant being focused on by management or was it being well kept. We left with the impression that in fact that was the case.

There appeared to some good focus by the applicant's management on keeping the plant up to date material wise. That was one of the inputs provided to the second team that went out for the aging management review as to the impression that we had just from the walkdowns we did. It wasn't a real active inspection but nevertheless I guess we left with the impression that things appeared to be being kept well.

MEMBER BONACA: I have a question of the same nature, general question. Through the SER, there are a number of occasions where the staff identified some drawings or some elements that were not included in scope and the licensee reviewed them and said oh yes they are in scope and we --

MEMBER BARTON: Inadvertently omitted or forgot to put it or something like that.

MEMBER BONACA: -- inadvertently omitted, yes. So the licensee accepted an expansion of scope, minor or major or whatever it was, to include those elements here and there. I understand that there is some complexity there as I was reviewing for example this issue of system boundary realignment where you have interfacing components and you have to detect whether they are in scope or not.

The question I have is when I read what's the confidence that in fact what should be in scope is in scope. I mean clearly the job of the NRC cannot be the one of identifying components, just identifying if the process is adequate. So if you have one finding, two findings it's not a big deal. If you have more, it would be a bigger deal. Just your impression about that. How do you feel about components in scope?

MR. SOLORIO: Well, I think you've been a part of these license renewal reviews since the beginning of these. If you think back for every review there has been instances where the staff had identified some components which the applicant didn't put in. The majority of the time I think it's been a case of they also have processes in place and actually later today you will hear a gentleman speak to the methodology review, the process by which they identified stuff. We look at that. That's part of what the rule requires.

We've always up to Peach Bottom concluded that that was appropriate but unfortunately they're done by humans and things get missed. Also some of it is the applicant's interpretation of a particular requirement which scopes something is different from the staff's and we ferret that through the review process.

MEMBER BONACA: So you feel that this is not usual. I mean what you saw here is pretty much consistent with previous applications more of an issue of almost boundary than anything else.

MR. SOLORIO: Right, and also I guess as we're learning we're identifying a few more things and it's not always that the next applicant in the pipeline had time to incorporate some of those lessons so we're identifying some of the same things again.

MEMBER BARTON: I had the same concern when I reviewed the application that Mario just brought up. It seemed to me that there were more of those "oops I forgot to put that in" in this application than the other ones I reviewed. So I had the same question Mario did. So there's two guys independently looking at this thing thinking that there's more "oops I forgot" this time.

MEMBER BONACA: The reason that I asked the question by the way is because also we have an open item asking the licensee to explain the methodology used to identify components which are in the non-safety category that could in fact be in the safety operation system. That was why I also felt that there was at least two more questions on this page. If you were asking a question and there's an open item of methodology then it opens up the issue of what's there.

MR. SOLORIO: Actually to address that one you just brought up, that was the case if you think back to Hatch, it came up during the Hatch's reviews. So prior to that, the staff had always looked at this issue of course but for some reason there were some special circumstances about Hatch that made it more permitable. In this case, the applicant just didn't have time when they got their application put together to incorporate all the lessons they had to learn because they have been coming to all the meetings for years to try to make sure that they could learn what they could. If I look at the number of RAIs for scoping, there is a significantly less number of RAIs for scoping than Hatch.

MEMBER BARTON: You know you mentioned that but I think that the Subcommittee that looked at Hatch at the time all of us came to the conclusion that that was a lousy application. So it was no surprise to us that there were a heck of a lot of open items and RAIs in the Hatch application as compared to this which was a much better submitted application. Comparing numbers of this to Hatch doesn't really tell me too much.

MR. HATCHETT: This is Greg Hatchett. I'm in the Plant Systems Branch in the Division of Safety Analysis. We looked at this scoping issue for the Peach Bottom plant. One of the things that you should know is that most applicants come in and provide a "early look at their application prior to submittal." One of the things that was discussed during that meeting was they had the application put together primarily three months prior to that and that was during the timeframe that we were going through the issue of non-safety related, safety related within the Hatch application. As a result of that, they didn't have an opportunity to clean that within the application.

Looking forward, the staff had recently had a series of meetings with the industry and several workshops where this issue has also been discussed with the industries looking at addressing this issue up front so the staff doesn't have to ask the same RAIs that you've seen over the last applications that have been submitted and subsequently approved. So this RAI about safety related and non-safety related continues to be asks but the staff is working with the industry to resolve that issue for the fleet of 2003.

Then with respect to Peach Bottom and Hatch and the number of RAIs after the scoping area, we are more focused with the question with regard to the question of scoping to flush out those issues that they did with some of these things that you guys are seeing with respect to systems about the realignment. So the questions were more focused on understanding how the methodology led to the results. Where I think with the Hatch application, the different reviewers were just asking questions with respect to their areas and particularly with regard to scoping so it led to more questions. With regard to Peach Bottom, the overall number of questions that were asked in the scoping arena were more integrated if you will to reduce the number of questions asked to get at how the results were obtained to come to some sort of finding.

MEMBER BONACA: Okay, so the bottomline of your message is that you don't find whatever was there unusual and you still have confidence that scoping has identified components in scope.

MR. SOLORIO: Yes, sir. We either process or unprocess. We're confident that it gets the results with reasonable assurance.

MEMBER BONACA: Thank you.

MR. SOLORIO: The second inspection was for aging management. It was the outside part of the inspection activities which were completed by August 9 of this year. It was also a two week inspection. The objective was to confirm that the existing aging management programs were effective to examine the applicant's plans for enhancing existing programs and establishing new ones. Our findings were that during the plant walkdowns, the inspectors identified cable in vaults were susceptible to cyclic wetting. The applicant actually has replaced a lot of these cables and the staff felt that the aging effect still needed to be managed and that this is a subject and the open item that we'll be talking about later.

MEMBER WALLIS: Where does the water come from?

MR. SOLORIO: Some of these are in vaults and vaults aren't always waterproof. You have manholes over them.

MEMBER WALLIS: It's rain water?

MR. SOLORIO: It's rain water, right. Ground water. Then the last inspection will be a close-out inspection to be conducted in December of this year. The purpose for that inspection is to close follow-up items from the previous inspections and I mentioned some today, address any issues related to the annual update and support to the extent necessary the headquarters' staff as we try to close out confirmatory or open items.

MEMBER ROSEN: Can you tell me more about the annual update? What are you updating?

MR. SOLORIO: There's a requirement and rule that they need to provide an update to the plant configuration for things that are material to a license renewal review that would have occurred from the time of their application. So it's really adaptive. It's doing plant mods. There are other things that they might end up changing as a result of the review. The rule requires an annual update so that the staff can considers any changes before we make our final decision.

MEMBER ROSEN: Good thinking.

MR. SOLORIO: Back to the staff's review, the following guidance is relied upon. You can also think of them as the tools we use to conduct a comprehensive, consistent exam of regulatory review. Unless anyone has questions, I wasn't going to plan on reading them to you.

CHAIRMAN LEITCH: That's fine.

MEMBER BONACA: That's fine.

MR. SOLORIO: Sorry. Couldn't see it all. I didn't realize that. The SER format is as you see on this slide. Today we'll be focusing on Chapters 2, 3 and 4. On this slide I provided a summary of the open and confirmatory items that are discussed in the SER trying to give you an idea of where they lie. In the scoping and screening, there are eight open items. In aging management review, there are six. In TLAA, there's one.

CHAIRMAN LEITCH: Dave, we're going to maybe get in danger of playing the numbers game here but when you talk about open and confirmatory items, these are the items as described in the SER.

MR. SOLORIO: In the SER, yes. I'm not going to --

CHAIRMAN LEITCH: Some of these may have been closed in the intervening time or maybe in the process of being closed but for purposes of today's meeting that's the list that we are talking about, right?

MR. SOLORIO: Yes, sir. And for those that we think we can close, we are going to say that these are an open item that we think we can close. We're not going to call it a confirmatory item to confuse it with the other confirmatory items.

CHAIRMAN LEITCH: Okay, thanks.

MR. SOLORIO: As I said earlier, I previously informed the Sub-committee that 14 of the 15 open items are most likely going to be closed based on the dialogue that we had with the applicant. We received a number of faxes they have given us to respond to our open items. We've had some conference calls to clarify things. We think we're almost done. Now what they need to do is submit this under oath and affirmation in writing to us formally. Of course if anything would change between now and then as far as the details of this I would let Ramin know and he could let you all know.

CHAIRMAN LEITCH: Now a lot of my questions -- Excuse me. Go ahead, Jack.

MEMBER SIEBER: One of the exceptions that you take because it's under review is the use of BWRVIP-76.

MR. SOLORIO: Yes, sir.

MEMBER SIEBER: Will that be resolved by the time that you're ready to resolve the Peach Bottom Licensure Renewal?

MR. SOLORIO: We hope it will. We're told that we're supposed to get some reformation in time to get it done. If you don't what we would probably do is what we are doing for BWRVIP-78 and -86 which is make it a license condition that they need to provide a plant specific approach or commit to implement whatever the results of that BWRVIP are.

Later on today, Barry Elliot will present you the results of -76 so we actually will talk to these reports and tell you where we are with our review of them and such. I actually asked him BWRVIP group and we are on track to get the information as far as I know in time to make a decision before we would renew the license.

MEMBER SIEBER: Maybe I didn't read this right but 76 is a core shroud inspection.

MR. SOLORIO: Yes.

MEMBER SIEBER: So does each one of them have a shroud?

MR. SOLORIO: Yes.

MEMBER BARTON: They better have.

CHAIRMAN LEITCH: I assume, Dave, that we're going to have an opportunity to talk about the specifics of those open items.

MR. SOLORIO: Yes, sir.

CHAIRMAN LEITCH: But you are just summarizing.

MR. SOLORIO: This is just an overview.

CHAIRMAN LEITCH: Because I have a lot of questions regarding open and confirmatory items. There will be time for that later.

MR. SOLORIO: Yes, sir. Each of the presentations that will follow the majority of which will be done by a certain member of the staff who are the leads. They have on their slide and you will see it something on open items and they are prepared to talk about it.

CHAIRMAN LEITCH: Okay.

MEMBER BONACA: I have just a simple question. I think something that relates to the question that Mr. Leitch asked before about physical conditions. That's a judgement you made by looking at components. A couple of things that surprised me when I was reading the application was things that you can't see and yet they speak of physical conditions. One is there is a torus inspection and I'm sure at some point we'll talk about that whereby the licensee says they are committing to one time inspection to determine potential loss of material at the interface between the gas and the liquid. When I was reading that, it was clear that this area has never been inspected and will never be inspected unless you go to license renewal. So I began to wonder about I guess nobody is inspecting it and that surprised me somewhat.

The question I have and this is philosophically because there are other issues similar to this, how can we accept one time inspection which should be purely confirmatory that the loss of material is not occurring when we don't even know if in fact there is loss of material taking place because we have never looked at it. We don't have any experience that tells us anything about it. I'm not saying we should have a failure of power. But the fact is I'm just trying to understand how for example in that case a one time inspection would be appropriate at that time.

MEMBER BARTON: I must have missed that in the application but I know at Oyster Creek we used to inspect the torus every refueling outage. You would go in there and look at the thing because you inspect the coating. You have a coating on there which is really preventing loss of material of the torus.

MEMBER BONACA: That's what I thought but here when I read this, the problem speaks very clearly one time inspection to be perform at a time before they get into license renewal and then if there is some problem then they will resolve the problem or otherwise they won't. I would like to understand more about this. The other issue is the one of depending on the pressure test to determine the adequacy of the barrier.

MEMBER BARTON: That's the internal corrosion of carbon steel issue.

MEMBER BONACA: Yes. Again this is stuff you can't see. Yet they will have to wait until I pressure a system and blow it apart before I can say that there is a bigger issue that's in place internally. So I hope during the meeting we better understand these issues regarding the torus. Maybe licensee can speak about what they have done. If they ever have inspected it.

CHAIRMAN LEITCH: Yes.

MR. POLASKI: This is Mr. Polaski from Exelon. What I'd like to clarify is the one time inspection we're doing is not for the torus proper. There are on-going inspections of the torus shell. The one time inspection is for system piping like the high pressure coolant injection system piping which comes from outside the torus into the torus and comes into the air space and discharges below the water level. So that piping is not now being inspected.

So we imposed a one time inspection to look for degradation of that piping specifically at the air-water interface because that's the area we believe is more susceptible. It is a one time inspection but it will done in accordance to our station procedures and if there are problems found that goes into the corrective action process, generic implications are looked at and very well could if they find something expand to look at other piping or become a routine inspection. It will depend on what we find so right now there are not requirements at all to look at that. We're proposing one time before 40 years. What happens after that depends on what you find.

MEMBER BONACA: So this is just a sample location of piping.

MR. POLASKI: Yes, it will be a sample location for those pipes that we believe will be the ones that would be the bounding locations, the ones that are more susceptible.

MEMBER BONACA: You will have more than one location.

MR. POLASKI: Yes.

MEMBER BONACA: Because it wasn't clear there.

MEMBER ROSEN: Okay, so I think it's a valid concern but I still haven't heard the answer to the question which is what is the condition of the internal of the torus. Is that going to be describe at some point? Not over the piping entering the torus but the torus itself. What has Exelon done at Peach Bottom to look at that torus, its internal condition, what is the extent of the inspection and what was found?

MR. SOLORIO: Well, we have a --

presentation later and that's covered under the presentation. We'll try to make sure that we can focus on that to the extent that we have information on it. I guess you're also suggesting --

MR. KUO: Dr. Bonaca, later on the staff will address your question.

MEMBER ROSEN: What about my question?

MR. KUO: Yes, also your question. Basically you want to know the internal condition of the torus.

MEMBER ROSEN: Yes.

MR. KUO: That will be addressed.

MR. POLASKI: This is Fred Polaski from Exelon. With respect to the question on inspections of the torus, torus inspections for degradation of the internal surfaces are done every refueling outage. It's part of the ISI program. These examination of particular locations where we have some problems in the past with the coating. So it's an on-going routine inspections that's done.

MEMBER ROSEN: That's not the answer to the question. The question is what was found and what was the scope of the investigation. Not whether or not you have done one. You answered the question have you inspected the torus. You said yes it's part of the ISI program. Thank you. Now I want to know what you looked at and what you found.

MR. POLASKI: We have found some degradation of the coatings which has been repaired. We have found degradation of the carbon steel shell and those are the areas that get the inspection again. The inspections have indicated that there are pits. Those are monitored and tracked and the information indicates that there will not be a problem with the life time of those locations based on what we have seen so far. But we will continue to monitor the depth of those pits.

MEMBER ROSEN: Is that the whole answer to the question which is that you found some problems including pits or is there going to be some detail as to where you found the problems, how serious it was, how they were repaired.

MR. POLASKI: We don't have the information with us today on exact locations or depths.

MR. BAILEY: This is Stewart Bailey. I'm with the Mechanical and Civil Engineering branch. This was covered in a series of RAIs about the containment ISI program so the staff did request this information. They did provide details about the extent of the degradation and the locations of that degradation and their inspections.

MEMBER ROSEN: Can somebody pull those RAIs out and read us some of the details? What I'm looking for is some confidence that this particular set of issues has been carefully examined by the staff and the licensee.

MR. SOLORIO: Yes. P.T. said we would get you an answer and we will do that. We'll get the answer and get back to you.

MR. KUO: Dr. Rosen, we will pull the RAIs later on.

MR. SOLORIO: I'll also mention that there are three license conditions that we are more than likely come out with on this review. For those of you who have read Sections 1.6 or 4.3 you will notice that there is another license condition on fatigue management program that we presented in the SER right now. I'll talk to that in a minute. The first license condition is for a requirement to include a summary description of the aging management activities in the LRA and supplemented by the staff's review and the UFSAR in accordance with the 51.71(e) update requirements.

The second will be for a requirement date that the applicant will commit the implementation of all aging management program activities before the beginning of the extended period of operation. I think we talked about a little bit about that earlier in terms of a concern that you all have. For some of the first reviews, we actually had tables in the SER listing a lot of these commitments that you could go to. Now what we evolved to is a UFSAR summary description that we have them put in the UFSAR that you can refer to get an idea of what commitments need still to be done.

The other license condition that currently is in the SER but will not more than likely end up being a license condition is regarding the fatigue aging management program that's discussed in 4.3. Yesterday our Office of General Counsel informed me that because the applicant can control in their UFSAR this program and if they wanted to change the program they would have to do a 50.59 and if they were to use that approach they would be changing the design basis which would require them to submit a license amendment. So this aging management activity which is one of the three approaches they propose to use for the management's aging effect for some rupture vessel closure studs, it might come to reaching or exceeding the CUF of 1. They want to use an aging management program as one of the three options. If they do that we are going to need a license amendment because the staff will need to review this program they were proposed to use to manage the aging prior to its implementation.

CHAIRMAN LEITCH: So I guess one issue is really the legal issue. That is whether this has to be a license condition. I guess what I hear you saying is that it looks like it may not have to be a license condition because any deviation would have to be approved separately anyway. But there is still a technical issue and isn't this the issue that it seems to be held up pending approval of a fluence model?

MR. SOLORIO: I don't know if it's related to that but John Fair is walking up towards the mike.

CHAIRMAN LEITCH: If this is not the appropriate time we can talk about that later in the meeting.

MR. FAIR: I'll be glad to clear it up. I'm John Fair. I'm the reviewer for the fatigue issue. This is technically what licensee have been proposing for when they are managing fatigue if they predict they may exceed the usage factor of one in a period of extended operation they have three options.

They either reanalyze it to show they are good. Repair or replace. Or a number of them have been asking for an option to do some kind of inspection program in lieu of beating the fatigue usage factor criteria.

Our position has been that we haven't reviewed and approved a specific procedure. We're doing that so if a licensee wanted to do that later on in the period of extended operation, we have been requiring them to come in for an explicit review and approval by the staff. So the legal issue was whether that had to be controlled via some more formalize mechanism than the UFSAR supplement. The issue was resolved that as long as it's in the UFSAR supplement they would have to come in for an amendment to make a change to those commitments.

CHAIRMAN LEITCH: Is that the way that issue was resolved with previous applications?

MR. FAIR: Essentially it was. We didn't put the specific wording in about requiring a license amendment but we did require them to put it into the UFSAR supplement so that the mechanism for doing anything different than what's in the UFSAR supplement would be triggered into a license amendment through the 50.59 process.

CHAIRMAN LEITCH: So this issue was not a license conditions previously?

MR. FAIR: No, it was not.

MEMBER WALLIS: What mechanism is used to tighten the studs and loosen them?

MR. SOLORIO: I'm sorry, Graham. I didn't hear you.

MEMBER WALLIS: What kind of mechanism is used to tighten the studs -- This is talking about the right to have the studs, right? The studs that hold the reactor head on. Is that what we are talking about?

MR. SOLORIO: Yes.

MEMBER WALLIS: What mechanism is used when you take the head off to loosen the studs?

MR. SOLORIO: We don't describe that in the SER. I'll have to get back to you with that answer.

MR. POLASKI: This is Fred Polaski from Exelon. The reactor heads studs to loosen them or detach them, they are aluminum studs, there's a machine that actually stretch the studs so that the nut is loosen and the nuts are backed off.

MEMBER WALLIS: I'm just trying to figure out how much some intermittent loading is involved during the process? Is it a steady sort of turning or is it an impact that varies.

MR. POLASKI: No, It's not an impact. It's a steady stretch.

MEMBER WALLIS: It's a stretch and then a steady torque on them.

MR. POLASKI: They are not torqued. The studs are stretched.

MEMBER WALLIS: Can you pull them so you can take them off with your fingers?

MR. POLASKI: Not quite that easy because the nuts are pretty heavy. You stretch them so there is no torque on them and then they can be easily turned loose.

MEMBER WALLIS: So it's a pretty benign process. Thank you.

MR. SOLORIO: And that concludes my remarks for now. The applicant's here to make a presentation.

MEMBER ROSEN: Before Mr. Bohike or his substantives come up, let me bring up one thing more for the staff. This was something, Graham, you brought up some meetings ago and maybe it was already discussed this morning before I got here. That is that many of the time limited aging analyses that are proposed are deferred until the end of the initial operating period. So that all of that analysis that needs to be done and the likely subsequent interactions with the staff are out there in the future. If you read this application, you find that there's quite a few of those. It's not unique to this application. So the point that you were making about a bow wave of work for the staff comes back again. I'm increasingly concerned about that point you raised that the staff needs to be planning a fairly --

Since all of these license renewal applications are coming in the window, all of the work will come in another window 20 years hence or so. It's a major concern to me because none of these analyses and subsequent interactions with the staff that are likely are simple.

CHAIRMAN LEITCH: At the very beginning of the meeting, P.T. did address that issue.

MR. KUO: I can repeat it.

CHAIRMAN LEITCH: Can you quickly summarize for Dr. Rosen?

MR. KUO: Right. We did discuss before you arrived, Dr. Rosen. What I said in the last meeting for Catawba/McGuire and I said earlier this morning, we have developed a draft inspection manual already. This has been reviewed and to be finalized. In this manual we have a detailed list of plant-specific list of what the commitment that each plant has. So prior to the period of extended operation or during that or shortly after that, the staff will start the inspection program such as this to track all the commitments or analysis that you talked about that we reviewed during this review. We will go back to that.

MEMBER ROSEN: Good. I think that's a very healthy step. Now with that in hand you can do the manpower planning that that implies.

MR. KUO: That is correct.

MEMBER ROSEN: My concern is that you will do the manpower planning and there will be a big whoops that there is so much manpower required in such a narrow window that there will be an issue. But that's a staff concern not an applicant concern. But I want to raise it again because I think it's important that the staffing needs to do the planning.

MR. KUO: Actually we've been coordinating with our regional offices and that is the reason why it took us so long to develop this because we wanted to make sure that we have a mechanism to get the necessary resources that we need for this.

MEMBER ROSEN: Thank you.

MR. KUO: You're welcome.

CHAIRMAN LEITCH: Okay. Mr. Polaski.

MR. POLASKI: Thank you, Mr. Leitch. My name is Fred Polaski. Can people hear me? I just want to make sure. I'm Exelon's License General Manager. Bill Bohike who is our Senior Vice President of Nuclear Services wanted to be here and sends his apologies but due to an illness in the family he was called out of town just yesterday and he couldn't be here today.

I guess to start with on some initial introductory remarks. We would like to acknowledge good cooperation from the NRC staff in review of our application. The project managers, Dave Solorio, Raj Anand and also in the environmental area which I know we're not talking about today, Duke Wheeler, the project manager in that area. They were very cooperative I think and helped us expeditious move through a quality review of the application which resulted in a complete, correct and quality SER.

The purpose for today's meeting. We would like to provide an overview of the Peach Bottom license renewal application and report on how the status of the safety evaluation for open items and configuratory items. We believe that the application that Exelon submitted was a good application, provided the information that was required by 454. There were a couple of areas that we recognize after we submitted were not as good as they could have been and presented difficulty for the staff in doing the reviews. One of them was our discussion of our realignment process which I'll go into in some more detail later.

There were also a couple of things that were discovered by the staff and the project team at the same time with the details in the application. It was mentioned earlier about some of the things that were found to be missing in the application. What we discovered was that all of those components had been included in our scoping work. We prepared the aging management reviews and in the translation from the support documents to the application which is an extensive effort dealing with thousands of components. A few of them were missed.

We discovered some of those after we submitted at the same time that the staff had. We were able to work through the process and correct all that. So it was not things that we were trying to hide or didn't want in there. It was just a couple little details. A very small percentage were missed as we went through this.

The other thing we're going to talk about with a little bit more emphasis today in addition to the realignment is the work we did subsequent to submittal of the application where we brought additional equipment in the scope because of the non-safety related/safety-related interaction and I mentioned briefly equipment that needed to be included under the station blackout regulation requirement to do that.

We're also prepared today to discuss time limit aging analyses but we're prepared to provide more support for that later during the NRC discussions. Like Dave mentioned earlier, we have 15 open items, 14 of those we have reached agreement within the staff. It's a matter of closing our paperwork. One we are still working on. I believe we will be able to close that very soon.

A little bit of background on the Peach Bottom application. We began preparation of the application in March 1999. Prior to that PECO which was one of the companies that was merged into Exelon two years ago had done some work back starting in 1996 with the NRC NEI demonstration project. So we've been involved in the work, the industry has been doing since 1996. We started this project in 1999.

Some of the discussion I heard earlier and I know this gets involved is we're the second BWR. Hatch is the first BWR. How does that relate together? Hatch submitted in February 2000 so we were following everything that they did. Then we made some changes in our process and our application format based on lessons learned from Hatch.

We submitted in July 2001. Some of the things that we are changing in the industry like different interpretation if you will of the second scope and criteria for non-safety the way that it occurred after we submitted. So we addressed those areas in RAI space because it wasn't clear what was needed in sufficient time for us to include that in the application.

The other thing was submitted July 2, 2001, the guidance documents for standardization development, NUREG-1800 and -1801. The standard review plan and the GALL were issued in final form in July 2001. They were in development stages so we knew they were there but we didn't prepare the application 100 percent in accordance with that because of the timing issue. We weren't just able to do that.

What I would like to do now is to

introduce the other people we have here from the project team. On my right is Erach Patel, who is the technical lead for preparation of the 454 application. Erach is going to make some remarks later about time limit aging analyses. To my left is Jerry Phillabaum who is a licensing engineer. Also the rest of the team is Ahmed Onnou who is the civil structural engineer on the project. Kevin Muggleston is the mechanical engineer. Paul Thomas, our electrical engineer. Al Fulvio who is mechanical engineer and who was the site liaison with the station and did all the interfaces with the station.

Sitting in the back row Rich Ciemiewicz from Peach Bottom. Rich is in the programs group at Peach Bottom responsible for reactor vessel and internals and he's also the Vice Chairman of the BWRVIP Assessment Committee. There will be a discussion about VIP. The other industry representative we have here today is Robin Dyle from Southern who is also the Chairman of the VIP Assessment Committee. So we have some people here when the questions come up. Just walking back in the room is Dave Honan who is our project manager for the project.

The other person who is not here today

because we're not talking environment but I'd still like to acknowledge is Mr. Bill Maher who worked very closely. He was the lead on that and worked with the staff and I think contributed to a successful environmental report.

The format of the application standard format. I won't read them all to you. You've seen this before from Dave. We're going to discuss Sections 2, 3 and 4, Scoping and Screening Results, Aging Management Review Results, Time Limit Aging Analyses and then Appendix B which is the description of our aging management programs or activities.

On scoping and screening there are three criteria in Part 54.4(a) on identified components that are in scope. The first is those systems, structures and components that are safety related. The second being those that are non-safety related which if they fail could prevent completion of safety functions. I'm going to talk about that some more in detail later because some of the issues are on that. The third criteria is regulated events, fire protection, environmental qualification, pressurized thermal shock which is a PWR issue only so it's not addressed for Peach Bottom, anticipated transients without SCRAM and station blackout. So these were all reviewed and concluded in the scoping process.

CHAIRMAN LEITCH: Fred, a general question about scoping. Peach Bottom No. 1, could you talk about the status of that? Is that decommissioned of all radioactive material gone, no interconnecting systems? Is there any dependence on systems associated with Peach Bottom 1?

MR. POLASKI: No, there is no dependence on Unit 1. Peach Bottom Unit 1 was a high temperature gas-cooled reactor, 40 megawatt electric prototype plant started up in 1967, shut down in 1974. It's been put in safe storage. The fuel has been removed. I believe all the carbon elements in the reactor vessels have been removed.

The vessels have been cut and capped. Steam generators were cut and capped. So inside containment there's still radioactive material, contaminated equipment but it's all sealed up. So of the building has been converted into a training center or simulator as in the building outside containment but there is no connection between Unit 1 and Units 2 and 3. No reliance on any systems from Unit 1.

CHAIRMAN LEITCH: No common systems like compressed air?

MR. POLASKI: No, nothing common at all.

CHAIRMAN LEITCH: Thanks.

MR. POLASKI: Totally separate from each other. A little bit of background on the scoping process. I want to discuss the different data sources we used in the scoping process. We did our initial scoping on a system and structural basis.

So we identified systems that were in scope and structures that were in scope. To do that, a couple main sources of information, the Plant Information Management System. We called it the PIMS system, is a controlled database which controls information on the components in the plant, the systems in the plant.

It's part of a larger system that's our work control process, rad protection and a lot of other functions, but that was a primary source of information. We also used our maintenance rule database.

Maintenance rule scoping, two of the criteria for that are identical or very similar to the first and second criteria, scoping criteria for license renewal. So we used that information also in our scoping process.

And we used the UFSAR extensively in determining which structures were in scope for license renewal. After we had determined what structures were in scope, then we had to identify the boundaries for systems and structures.

In doing that we used several sources of information: piping and instrument drawings, a component record list, which is part of the PIMS system and identifies components specifically with a lot of detailed information on those components.

For structures we used the plan and actual physical drawings of all of the structures. What came out of that part of that process was boundary realignments, and I'm going to discuss that in a little bit more detail.

We've got some slides on that. But that resulted from us defining what were the system boundaries we needed. And I know it was an area that caused some difficulty in the staff's understanding of what we were doing.

And we finally got to the point it was understood, but I'll discuss that a little bit more in detail. And we also generated boundary drawings which show on marked P&IDs, the exact boundaries of all the mechanical systems. And for structures we developed the --

MEMBER ROSEN: Before you get to

structures, hold on a minute. It's been a concern of mine and remains a concern that this process you're describing, which has been used by other licensees as applicants, as well, could have in fact missed some equipment in the electrical and in the instruments -- piping and the instrument -- set of instruments in the plan.

And the reason I think that is because I know that there are extensive electrical single lines, extensive three-line diagrams. There are extensive piping and instrument loop diagrams, so that that support, the drawings, for instance, that you mention here, the P&I.P drawings, if you just look at the P&I drawings and scope what's on those I'm still concerned that you will miss some, perhaps many, subcomponents that are in the electrical and instrument complex that are not specifically culled out on the P&I drawings. Can you address that at all?

MR. POLASKI: I'll address it from two areas. One is that piping and instrument drawings show all of the instrumentation that's pressurized with reactor coolant or other fluid systems, and those instruments are shown on the P&IDs.

All of the detail on the valving for them on the process side aren't shown, but then our use of our component record list identifies all of those detailed valve designs, and so those are all -- we picked them up when we used the information out of the component record list.

On the electrical side, we took an approach -- used the spaces approach for aging management of electrical components. And so we looked at the plan as one entity and didn't get into specifics about boundaries in between electrical systems, but identified all of the types of components that we have in the plan that are electrical kind of components.

So relays, instrumentation were all identified on a generic commodity basis, and we did that by reviewing our component record list, which has in it different component types. So we were allowed to -- like we could go in and identify which kind of instruments we had, reviewed that information against industry information, work that had been done to identify all the different kind of electrical components, and then we performed aging management on those on a commodity basis, not on an individual component basis.

So we believe we've identified and captured everything that's in the plant that would be in scope, and the process actually brings in instrumentation electrical equipment that really doesn't even need to be in scope, because we just assumed it was all in scope. Does that answer your question?

MEMBER ROSEN: I'm not sure. But go on. I'll think about it.

MR. POLASKI: Okay. So we -- those are the drawings we did, which is marked up P&IDs for mechanical systems, and we used the system plot plan to identify all the buildings that were in scope.

The next thing we did was to identify system structure and functions, and from them determine which ones were intended functions. That information was taken out of the UFSAR, and also is a series of documents we have called design baseline documents.

These design baseline documents were created ten to 12 years ago where we pooled together in one location all of the current licensing basis information, design-based information in one source.

And a lot of the information is identical to what's in the FSAR, but it puts it in a format that was easier for us to use because it listed very clearly system functions, which are all in the FSAR, but they're not -- you don't go into our FSAR and find a nice, clean system description, and here are the functions.

There's a long, lengthy description of systems and we had to extract data from that. The DBDs had done a lot of that for us. These are control documents which are being updated as the plan changes. So we relied on those for a lot of that information,

CHAIRMAN LEITCH: Fred, while you're talking about structures, there's an issue in my mind about the Conowingo Dam and how it relates to the operation of Peach Bottom. Could you describe how you dealt with that?

MR. POLASKI: Conowingo Dam --

CHAIRMAN LEITCH: And maybe we need to understand the situation at the four bay at Peach Bottom and how --

MR. POLASKI: Okay.

CHAIRMAN LEITCH: -- and how that all relates to the Conowingo Dam.

MR. POLASKI: All right. The physical layout of the plan, Peach Bottom is on the Susquehanna River upstream of the Conowingo Dam, which is -- the Conowingo Dam I think was built in late 1920's and formed a large pond above it.

Peach Bottom takes its water supplies from that pond, Conowingo Pond, and we call it a pond, but if you look at it, it's a couple miles wide and rather long. It's not what you'd normally think of as a small pond in the woods someplace.

We take our normal water supplies from that. That is not our safety supply of water. We are designed -- the plant design is such that in the event of the loss of Conowingo Dam and the loss of the pond we have on site a self-contained emergency cooling tower, which will provide cooling water through the cooling systems in the plant to take care of any decay heat removal and cooler equipment in a condition where we've lost the pond.

We can't operate without the pond being there. So this would be in shut-down conditions, and we isolate our intake structures from the pond and we got essentially a closed loop internal cooling system. We would then take water from what's left of the pond and use it as make-up water to that emergency cooling tower in the event we would lose the pond.

CHAIRMAN LEITCH: Oh.

MR. POLASKI: So the pond is not in scope from the viewpoint of safety -- however, it is -- well, not the pond -- the Conowingo Dam is in scope from the station blackout viewpoint.

Our station blackout, the way we address that is an alternate AC feed, which is a submarine cable which comes from Conowingo, and we take credit for some of the generating units at Conowingo up through a substation, the submarine cable which comes on site into a switch gear and then feeds power into the normal plant emergency AC systems. So the dam's in scope from that viewpoint, station blackout only.

CHAIRMAN LEITCH: Is -- does the license for the dam extends beyond the proposed life extension of Peach Bottom?

MR. POLASKI: No. The -- I can't remember, I think the current license expires about the same time as the Peach Bottom license does, and it would just have to be renewed, and it's been renewed previously.

CHAIRMAN LEITCH: Yes.

MR. POLASKI: Which is done with FERC and all the other agencies involved with the dam. So we did not address the, you know, renewal of that license in the Peach Bottom license. It's not under Part 54 and we know that if for some reason that dam's license would not be renewed and would be shut down, then we're into a business issue if we would have to be forced to shut down Peach Bottom, so.

CHAIRMAN LEITCH: Right. Okay.

MEMBER ROSEN: Well, that's not the only option, is it? I mean, you would have to find an alternate source to replace the submarine cable.

MR. POLASKI: Well, I'm not even there -- not on -- I'm working -- there has been experience in some dams that were FERC dams that their licenses were not removed and the dams were physically removed.

MEMBER ROSEN: That's right.

CHAIRMAN LEITCH: Right.

MR. POLASKI: Now, this is -- I know of one in Maine and it had a generating unit that was like a three-kilowatt hydro unit. Peach -- or Conowingo was 600, 800 megawatts of generation. So I -- personal opinion, I doubt very much that that license on Conowingo will not be renewed.

In fact, I think -- well, I won't get into it anymore. It just -- you know -- it's a separate process we would have to go through and address, if by chance it wouldn't be renewed. We didn't --

MEMBER ROSEN: Okay. But I was addressing simply the function of the power.

CHAIRMAN LEITCH: Right.

MEMBER ROSEN: And that could be --

MR. POLASKI: Yes.

MEMBER ROSEN: -- replaced, whether or not Conowingo is renewed.

MR. POLASKI: You're right.

MEMBER ROSEN: As long as Conowingo is kept as an impondment vehicle and not as a power station.

MR. POLASKI: Yes. Then we would have to address it some different way, yes. Scoping and screening on the mechanical, and I'm going to talk mechanical, structural and then electrical separately.

We scope our systems on a -- we scoped on a system basis and determined what systems were in scope. For mechanical we then determine what our boundaries are for that system and what's all included within that.

And we used our traditional component numbering scheme at the plant to do that. Each component, each valve, each pump, each heat exchanger, each pressure instrument has a unique identifier that fits in their PIMS component record list.

And included in that is the system number associated with that system and that component. We use that as our initial first cut, what components were in what systems. Now, the numbering scheme, including the system, is based a lot from an operational consideration as to which system those components would be considered part of, because you got a lot of components that are interfaces between systems.

And those numbers are assigned, like I said, from an operational basis, not from the viewpoint of current licensing basis, design basis, and clearly, not from a license renewal perspective when those component numbers were put on prior to plant startup.

After we had identified which components were in which systems we then confirmed interfaces between systems. So we were looking to see -- to make sure we had included all of the components that we needed in those systems.

And we resulted in some boundary realignments being required, and I'll get to that a little bit later, but all of these occurred at interfaces where we needed to get components in the correct systems.

Once we had identified all the components, then the screening process, which is a determination of whether the components are active or passive, was using our component record list, database and guidance from NEI 95-10, the industry guidance on that.

Some components that were a part of the plant are not in the component record list, things like piping segments, some supports, electrical cables. So we did a review on each of these systems to determine what components that we called commodity basis, piping, cables, were on those systems and added to a list that we had generated from a component record list.

So we had a complete list of all the components on each system.

MEMBER BARTON: Before you go electrical, got a question in mechanical.

MR. POLASKI: Sure.

MEMBER BARTON: I noted that rad waste and rad waste ventilation systems are not in scope, and I guess it's kind of puzzling and maybe there's a reason for it. To me it's puzzling in the fact that if you have a failure, a leak in rad waste and rad waste ventilation isn't working, don't you have a potential for radioactive -- radiological release from the site?

And I don't understand why those systems aren't included in license renewal scope.

MR. POLASKI: You could have a potential release. The rad waste system is enclosed in its own building and if you have tanks leaking it would be -- you know -- the leakage would be contained in the building.

But the other thing is that the design is such that you would not exceed 10 CFR 100, and the criteria for in scope --

MEMBER BARTON: So you can have a leak and release as long as you don't exceed 100? That's your definition of not including it in scope?

MR. POLASKI: Yes. And that's the -- Part 54 is what we go by. You may exceed Part 20, but you wouldn't exceed Part 100.

MEMBER BARTON: Okay.

MR. HATCHETT: This is Greg Hatchett of the -- of staff again. With respect to the issue of the rad waste system, the staff had an issue with that, as well, more particularly, the liquid waste portion of the rad waste system.

MR. POLASKI: Right.

MR. HATCHETT: As part of further discussion with regard to open items, because this was one of them, they went back and looked at their design bases in the UFSAR and information about the plant and came to the conclusion that it's not an issue of 10 CFR 100.

MR. POLASKI: Right.

MR. HATCHETT: So much so as it's an issue of 10 CFR 20. And so some of those inconsistencies needed to be addressed, and they're addressed in that through -- at least in the initial response that we got -- through a 50/59 analysis, based on the original license issued to the plant and the design-basis documentation that reflects that it's part of 10 CFR 20 and not 100, and therefore, it's not within the scope of license renewal.

And so the preliminary response that the staff has gotten with respect to that is that they're going to clean that issue up, do the 50/59 analysis, and then from that point it's just an issue of formal documentation with respect to scoping that is not in scope.

MEMBER BARTON: All right. So this issue is still open, but you expect it to end up --

MR. HATCHETT: It will be closed.

MEMBER BARTON: -- end up that they will not be in scope, is the bottom line.

MR. HATCHETT: Yes. Yes.

MEMBER SHACK: I noticed you replaced your pump suction strainers, then, and used larger ones?

MR. POLASKI: Yes, we used these, yes.

MEMBER BARTON: Right.

MEMBER SHACK: Are those components in scope? I can't seem to find them anywhere in the aging management program or, you know, somehow I've just missed them?

MR. POLASKI: They are in scope.

MEMBER SHACK: They're in scope.

MR. POLASKI: Yes. We can show you exactly where they're in scope, with the --

MEMBER SHACK: Okay.

MR. POLASKI: -- we'd pull the application out and show you where they are, but they're there.

MEMBER BONACA: Since we're asking questions about scope, is it a good time to ask some questions here or just --

MR. POLASKI: Sure.

MEMBER BONACA: All right. Well, traveling water screen system, is this part of the service water system? Well, let me go back. The service water system is not in scope.

MR. POLASKI: That's correct.

MEMBER BONACA: Which surprised me, but probably because you have an emergency?

MR. POLASKI: That's correct. The service water system is non-safety-related. Our safety-related service water system, if you will, is what our emergency service water system --

MEMBER BONACA: Is what you call the ESW?

MR. POLASKI: Yes.

MEMBER BONACA: Now, the traveling screens, you have traveling screens associated also with the ESW?

MR. POLASKI: Yes.

MEMBER BONACA: Are they in scope?

MR. POLASKI: No.

MEMBER BONACA: Why?

MR. POLASKI: They are not in scope because there's actually two sets of screens, one at our outer intake structure, which is out right at the Conowingo Pond, and then in stream from there you come probably a 100 yards along intake canals and then there's inner -- set of inner screens in the pump house.

Remember I said earlier, Conowingo Pond is not a safety-related source of cooling water. All right. And so those screens are there to protect debris from coming in during normal operations. But if you would lose the pond we would go closed loop and those -- we would close all gates, isolate from the pond and go on enclosed loop cooling with our emergency cooling tower.

MEMBER BONACA: So if the --

MEMBER SIEBER: You make up to the emergency service water system from the pond.

MR. POLASKI: We would -- if we lost -- if we went closed loop we would have to make up to the emergency cooling toward.

MEMBER SIEBER: You'd have to make it up, right.

MR. POLASKI: Yes.

MEMBER BONACA: So let me understand now --

MEMBER SIEBER: So the screens are still functioning.

MR. POLASKI: No. The makeup -- if we would go closed loop and lose Conowingo Pond would be through portable pumps that we would actually have to take out and through -- you know -- suction piping into what's left of the river, because if you lose the Conowingo Dam there would be no water at the intake structure anyway.

MEMBER SIEBER: Yes, I didn't quite understand that when you said that. Is there some calculation that says if the dam fails that there's still some impounded water there?

MR. POLASKI: Yes.

MEMBER SIEBER: Or are you dependent on the Susquehanna River?

MR. POLASKI: Well, there would still be water in the Susquehanna River that we would use for makeup to our emergency cooling tower, but we would be isolated from the Conowingo Pond.

MEMBER BONACA: Just for logic --

MR. POLASKI: Do we have a --

MEMBER BONACA: -- okay, just to complete that --

MR. POLASKI: Do we have a drawing of the site? Jerry, you got a plot drawing?

MEMBER BONACA: I thought the failure of traveling screens would affect the ESW system, which is a septic grade system, which is in scope.

MR. POLASKI: No. All of the cooling -- all of the screen structures -- the screens are all designated in our design as non-safety-related.

Al, can you add some more to that?

MR. FULVIO: Yes. This is Al Fulvio, from Exelon. Just as additional information on the loss of the Conowingo Dam, the emergency cooling tower is good for seven days without any makeup at all. The other contingency that we would have for makeup to it is to truck water in.

And in seven days, you know, you could easily get truckloads of water that we could just pump into the tower.

MEMBER BONACA: Yes, but I mean, then why do you have the ESW in scope?

MR. POLASKI: The ESW provides cooling water to --

MEMBER SIEBER: Has to be in scope.

MEMBER BONACA: Okay.

MR. POLASKI: -- diesel generators, room coolers and --

MEMBER BONACA: Now, I'm getting confused between the two sources of water there. What you're saying to me, however, is that the failure of the traveling screens will not affect the performance of the ESW system.

MR. POLASKI: That's true. It may affect the performance of the plant.

MEMBER BONACA: Understand. Okay. So that's one.

MEMBER WALLIS: Can I ask about this ESW?

MR. POLASKI: Pardon?

MEMBER WALLIS: Can I ask about this ESW system? You said you have to take portable pumps out into what's left of the river?

MR. POLASKI: If we would get in the scenario where there would be a failure of the Conowingo Dam.

MEMBER WALLIS: Right.

MR. POLASKI: And the pond would --

MEMBER WALLIS: The river's out there a mile away somewhere now?

MR. POLASKI: The river's a mile away.

MEMBER WALLIS: Right.

MR. POLASKI: We've got two ways of making up -- and if that occurs we isolate ourselves on what was the Conowingo Pond. So we have two ways to make up water to the emergency cooling tower. And like Al said, that system is good for seven days without makeup.

One, there would still be some water out in the river and we would have to pump water from there with a portable pump into the plant, or we would truck water in from wherever else we could --

MEMBER WALLIS: So I'm just wondering what the state of the bottom of what used to be the pond is going to be. I mean, are you going to have six feet of silt or something in there? It's going to be --

MR. POLASKI: Yes, it's not going to be

good.

MEMBER WALLIS: -- one interesting job to take something out there and hitch up to the river.

MR. POLASKI: Yes.

MEMBER SIEBER: A pair of boots.

MEMBER WALLIS: There's going to be more than boots.

MEMBER SIEBER: The Conowingo Dam is on the river.

MR. POLASKI: Yes.

MEMBER SIEBER: We're damming up the river.

MR. POLASKI: Yes.

MEMBER SIEBER: The river runs right in front of the plant.

MR. POLASKI: Yes.

MEMBER WALLIS: Right.

MEMBER SIEBER: You have an intake pond between the river and the plant main intake structure.

MR. POLASKI: Yes.

MEMBER SIEBER: And that's where your screens are. To the left of that, which I take it is to the north, is where your emergency service water for the three cooling towers are. They're independent, other than makeup from the river.

MR. POLASKI: Yes. The emergency cooling towers, independent of the river --

MEMBER SIEBER: It's not out. It's real close. You see one from the other, according to these drawings.

MR. POLASKI: Yes. But the emergency cooling tower is right on site, right next to the plant.

MEMBER SIEBER: Right.

MEMBER WALLIS: So the old riverbed comes right by the pond.

MEMBER SIEBER: Yes, it does.

MEMBER WALLIS: It does.

MR. POLASKI: Yes.

MEMBER SIEBER: Sort of.

MR. POLASKI: Sort of.

MEMBER BARTON: Not much you can without the license this way, so you know.

MR. POLASKI: Yes.

MEMBER BARTON: What we are, going to redesign the plant?

MEMBER BONACA: Another question I have is about the RWST --

MEMBER BARTON: Move the river, or what?

MEMBER BONACA: -- the RWST, refueling

water storage, is not in scope.

MR. POLASKI: Okay. Which -- could you say it again?

MEMBER BONACA: Refueling water storage.

MR. POLASKI: Refueling water storage?

MEMBER BONACA: Yes.

MR. POLASKI: That's not in scope. The refueling water storage tank is there as a tank that we keep with water that when you shut down and take the reactor vessel apart for refueling it's used to flood up the cavity.

MEMBER BONACA: Okay. So you don't use that for any emergency --

MR. POLASKI: No.

MEMBER BONACA: -- injections or --

MR. POLASKI: It's non-safety-related.

MEMBER BONACA: Non-safety-related.

MR. POLASKI: It is non-safety-related.

MEMBER SIEBER: You rely on your condensate storage tanks.

MR. POLASKI: The condensate storage tank is relied on -- is non-safety-related.

MEMBER BONACA: Yes, that is out, too.

MR. POLASKI: But it's relied on under some Appendix R fire criteria as a section to the RCIC system.

MEMBER BONACA: And I notice the condensate system and transfer are also out of scope.

MR. POLASKI: Yes. The condensate storage tank and the piping from it to the RCIC system are in scope, but in scope for Appendix R reasons, not safety-related. The condensate transfer system is a system that is small piping --

MEMBER BONACA: Okay.

MR. POLASKI: -- the pump's condensate around the plant to --

MEMBER BONACA: I saw some portions. However, you mentioned some portions are in scope. Is it --

MR. POLASKI: Not specifically the condensate storage system.

MEMBER BONACA: No.

MR. POLASKI: Or the condensate system. But the condensate tank and the piping that's associated with it are in scope. So some very small parts that have condensate in it --

MEMBER BONACA: And I would find it in -- I didn't find it in the application. I would find it through the realignment process?

MR. POLASKI: Condensate storage tank I

think is listed in scope.

MEMBER SIEBER: Yes, it is.

MEMBER BARTON: Yes. The condensate system isn't, but the condensate storage tank is.

MR. POLASKI: Yes, the condensate storage tank is, yes.

MEMBER SIEBER: There's an inspection at the bottom of the tank.

MR. POLASKI: Yes.

MEMBER BARTON: No, they're not inspecting that tank. They're inspection the refueling water storage tank --

MEMBER SIEBER: Storage tank.

MEMBER BARTON: -- and using the results of that --

MEMBER SIEBER: To interpolate.

MEMBER BARTON: -- to -- yes -- to interpolate condensate.

MEMBER SIEBER: To extrapolate.

MEMBER BARTON: Yes, extrapolate condensate to start, and I got a question on that. Maybe I can bring it up now; I can bring it later under structures or whatever. What is it about the condensate storage tank that you cannot inspect the bottom there, so you're going to use the results of refueling water storage tank inspection to bless the condensate storage tank. I don't understand what's going on there.

MR. POLASKI: There's two condensate storage tanks, unit two and unit three.

MEMBER BARTON: Yep.

MR. POLASKI: One refueling water storage tank. To do the inspection you've got to drain and empty the tank. The refueling water storage tanks can be drained and emptied and inspections are done, and those are already scheduled and we do those.

In fact, we did one I think -- Al, the last refueling I think we did one?

MR. FULVIO: Last summer.

MR. POLASKI: Last summer we did one. So you can do those not added. Condensate storage tanks are very difficult to take out of service because they are part of the condensate system when you're running the plant, and when you shut down for refueling you still --

MEMBER BARTON: They're water storage for refueling.

MR. POLASKI: Yes.

MEMBER BARTON: Yes.

MR. POLASKI: You still have water in

those. So --

MEMBER BARTON: But how can you -- these tanks, as I understand your design, are built on -- the base plate of the tank is really on fill.

MR. POLASKI: Yes.

MEMBER BARTON: So it sits on dirt. So how can you say, I don't have any corrosion going on under these two condensate storage tanks, because I don't have any under the refueling water storage tanks, so I guess these other two tanks are okay.

I had a bad experience with condensate storage tanks leaking. So that's why I get kind of, you know, paranoid over this.

MR. POLASKI: Our rationale behind that was that we had three tanks that are designed and built the same, similar environments and conditions. We were going to look at a representative sample, which is the refueling water storage tank.

If we would find anything when we review that, we do that inspection, I'm sure that -- I know that the corrective action process gets you into looking at -- and should they be looking at the other tanks.

And Al, are the results from the summer on the refueling water storage --

MR. FULVIO: They were very good.

MR. POLASKI: Very good. No indication of any degradation.

MEMBER ROSEN: The refueling water storage tank sits on the same fill that the condensate storage tanks sit on?

MR. POLASKI: Yes.

MEMBER SIEBER: No.

MEMBER ROSEN: Yes or no?

MR. POLASKI: Yes.

MEMBER SIEBER: I don't think that can happen.

MR. POLASKI: Well, it could --

MEMBER ROSEN: It does.

MEMBER SIEBER: Well, the fill is the fill and wherever you truck it from, that's what it is.

MEMBER ROSEN: That's right. It's not guaranteed the same fill.

MR. POLASKI: Well, the refueling water storage tank sits right next to the condensate storage tank.

MEMBER SIEBER: And the ground potentials that cause corrosion are different all over the site.

MEMBER BARTON: Right.

MR. POLASKI: Okay.

MEMBER BARTON: So I guess the issue is why don't you do a one-time inspection of the bottom plate of the condensate storage tanks?

MEMBER SIEBER: Well, that's a good question, I think.

MEMBER BARTON: Then why didn't the staff ask for that?

MR. ONNOU: Just some additional information on the sub-face.

MR. POLASKI: You want to state your name, please?

MR. ONNOU: Ahmed Onnou, Exelon, Seoul. The question on the fill under the tanks is essentially the same. It's a design -- it's an engineered fill consisting of sand and gravel.

So whatever we have under the condensate storage tank is represented -- should be the same underneath the other tanks. It's an engineered fill sand brought in, gravel. It's not site ground.

MEMBER BARTON: So the staff is happy with the refueling water storage tank being representative of condensate storage tank bottoms. Is that what I'm hearing?

MS. KHANNA: Yes, we are. Good morning. My name is Meena Khanna. I'm with the Materials and

Chemical Engineering Branch. We did review that. We asked a question in regards to that, and based on what they had said about the refueling -- I'm sorry -- the RWSTs, we were okay with that.

We felt that they could determine if they had corrosion found in the RWSTs, then they would take additional action, and we found that to be acceptable. And they are doing -- and in addition, they are doing an inspection of external surfaces of the CSTs, and they are also inspecting the outdoor condensate piping insulation, as well.

So in combination with all that, we felt that we were okay with that, because our concern was with corrosion, and if they did indicate any problems with RWST, we felt that that -- they would take further action to cover the CSTs.

MEMBER ROSEN: I think your answer is a complete one with respect to external corrosion. But with respect to internal corrosion can you give me some assurance that the internal conditions in the RWST are representative of the internal conditions in the CST?

MR. POLASKI: Let me ask. What's the -- my staff. What's the design on the internal surface? Is that -- Al?

MR. FULVIO: It's got a lining coat or a coating for lining. It's not just steel. It is coated, and that's specifically inspected in the RWST inspection. We also do a specific inspection of that liner condition, and that was also in very good condition last summer when we looked at it.

MR. POLASKI: I think you're not answering his question.

MEMBER ROSEN: How do you --

MR. POLASKI: The question was: are the internal conditions -- the internal design of the RWST and the CSTs the same, I think you said.

MEMBER ROSEN: Yes.

MR. FULVIO: Yes.

MR. POLASKI: Now, are the coolant in the tanks the same?

MR. FULVIO: Yes. It's condensate water. The chemistry parameters are very close. It's essentially demineralized water, you know, with low conductivity and low impurities.

MEMBER ROSEN: In both tanks?

MR. POLASKI: Correct.

MR. FULVIO: In both tanks, yes.

MEMBER SIEBER: You should have a greater throughput and mixing in the condensate tanks.

MR. POLASKI: Yes. Actually, the condensate tank I would expect chemistry would be better --

MEMBER SIEBER: It would be better, right.

MR. POLASKI: -- because if it gets turned over repeatedly the refueling water storage tanks could have a potential to sit there when it's not in use and not out of storage much, because I know that prior to refueling outages we go on the program to clean that up.

So that would be the -- the refueling water storage tank, the chemistry would be the one -- would be the limiting condition, I believe.

MEMBER BARTON: Is this coating a painted coating or is it rubberized, or what kind of coating you have in the tanks?

MS. KHANNA: I can address that. I asked the question. That's actually painted. That's what I was told, that it's painted.

MEMBER SIEBER: So it's a dry coating that was painted on there.

MEMBER BARTON: And have you ever looked inside the CST to see if the coating is intact?

MR. FULVIO: Yes. We have done some inspections over the last ten years, I believe, and yes, at that time the coating was intact.

MEMBER BARTON: But you don't intend to look inside the CST for the next 30 years or whatever?

MR. FULVIO: Not for license renewal. For plan operations that may occur. There's nothing specifically planned at this time.

MEMBER BARTON: Nothing that triggers you to some kind of routine or periodic inspection of the internal of the CST?

MR. FULVIO: That's correct.

MEMBER BARTON: Okay.

MR. POLASKI: Anymore questions on that or?

MEMBER BARTON: No.

MR. POLASKI: Okay.

MEMBER BARTON: We beat that to death, I guess.

MR. POLASKI: Scoping and screening for structures. We scope structures from two viewpoints. One is buildings and the other is structural components. Buildings that support systems with safety-related independent functions were brought into scope, and that was fairly easy part to do, reactor building, diesel generator buildings.

Structural commodities where structural

components that have similar design, materials and environments, and we addressed them on a commodity basis, and that included things like component supports, hazard barriers and elastomers, miscellaneous structural steel, electrical and I&C enclosures and raceways, insulations.

So there's a lot of things in the plant that are structural in nature that we brought them in as a commodity basis.

MEMBER SIEBER: I have a question about that. One of the things that are used a lot in power plants are Hilti bolts, and Hilti bolts are expansion bolts, and you drill a hole in the concrete and you put this sleeve in there and then you tighten it up and it expands the sleeve into the concrete.

But over 60 years concrete changes composition. It changes chemistry. It changes strength and my experience in some really old coal-fired power plants is you can pull the Hiltis right out of the wall.

Or do you have any kind of a testing program, except that which would have occurred during initial construction, to make sure that the Hiltis stay in place and will stay in place during a seismic event or a water hammer?

MR. POLASKI: Well, there are Hiltis, I'm sure, in stuff. I'm going to ask --

MEMBER SIEBER: You must have two million of them.

MR. POLASKI: Yes. Ahmed, can you help us on that one?

MEMBER SIEBER: They're passive.

MR. ONNOU: Again, Ahmed Onnou, with Exelon. We do have Hilti bolts and Maxi bolts, which as you described --

MEMBER SIEBER: It's a brand name.

MR. ONNOU: -- and during the installation you're required to test them. In fact, there used to be a sample, but you do a 100 percent sample and then you do a tension test or a torque test --

MEMBER SIEBER: Right.

MR. ONNOU: -- to make sure that you don't -- they don't release. Hilti bolts generally are not used for vibration -- vibratory equipment. You would use Maxi bolts for that because they're a little more positive connection.

The -- and if you use Hilti bolts, generally the safety factor is very considerable. I mean, it's in the order of five order -- five times. That's all I can say about Hilti bolts.

MEMBER SIEBER: I guess my concern is the change in the properties of the concrete upon which the Hilti and the Maxi bolts rely. And also, there are instances which I have witnessed where you get a water hammer in a pipe that took the hanger off the wall, okay? It just breaks the baseplate away.

MR. ONNOU: Right.

MEMBER SIEBER: Pulls the bolts out.

MR. ONNOU: Absolutely. If you do have an event such as that you might lose the anchors. You might lose structural steel, as well.

MEMBER SIEBER: Yes, a couple pieces here and there.

MR. ONNOU: But we do look, as an outpoint of that we go look at the bolting during the maintenance rule. However, we do not do a tension test, but you look at the bolts, make sure that they're tight and there's none of those components associated with the supports.

MEMBER SIEBER: Actually unless you test it there is no way to inspect or examine a Hilti bolt and determine whether it's going to function or not. Is that -- that's correct, right? You can't look at it and say, boy, that looks good to me.

MR. ONNOU: That is correct.

MEMBER SIEBER: Okay. Is that a concern to the staff, or are you relying that the fact that you installed them correctly and tested them 100 percent for torque and tension, that they're going to be good for 60 years?

MR. KUO: The staff worked at that, too.

MEMBER ROSEN: That's not a Peach Bottom concern. That's --

MEMBER SIEBER: No, that's generic.

MEMBER BONACA: That's a generic concern.

MEMBER SIEBER: That applies to anybody that has them, and everybody has them.

MR. KUO: And the staff will get back to you on that.

MEMBER SIEBER: Okay. Well, I'm curious about that.

MR. KUO: Okay. Yes. I don't have the person here right now.

MEMBER SIEBER: Thank you.

MR. KUO: Thank you.

MR. POLASKI: In scoping and screening an electrical area we scoped systems -- all of our systems initially, including electrical systems so the turnover systems were in scope, just like we did in mechanical.

But once we had gone through that step on electrical, then we moved to the stasis approach where we didn't get into specific boundary definition on electrical systems. But what we did was we included all passive electrical and I&C components in scope on a commodity basis.

And the commodities that we identified that would be in scope were cables, connectors, splices and terminal blocks, including fuse clips. And then the last bullet is electrical equipment that came in scope when we expanded our scoping for station-wide cap to include the offsite power sources.

So that's switch yard bus, high voltage insulators, phase bus and transmission conductors. All of the other electrical equipment was accurate. Most boiler instrumentation was all accurate components and doesn't require aging management.

MEMBER BARTON: Let me ask you a question in electrical. You have some electrical heat tracing system. I saw it somewheres in the application.

MR. POLASKI: Yes.

MEMBER BARTON: But it's not in scope. Is there any way a failure of a heat tracing system could impact the safety-related equipment?

MR. POLASKI: The smoke detectors. Yes.

Well, if it's an active component.

MEMBER BARTON: Heat tracing.

MR. POLASKI: Heat tracing.

MEMBER BARTON: Electrical heat tracing, because it goes on and off as an electrical component.

MR. POLASKI: Yes.

MEMBER BARTON: Forgot about that.

MEMBER SIEBER: That's different than a PWR where you're worried about boron --

MEMBER BARTON: Boron, right.

MEMBER SIEBER: -- solidification. Here, you're worried about freezing.

MEMBER BARTON: Freezing, that's right.

MEMBER SIEBER: And you know, it'd be outdoor tanks with level instruments and things like that where that would be effective. That's --

MEMBER BARTON: That's right.

MEMBER SIEBER: -- I have not seen that stuff be classified as safety-related.

MR. POLASKI: And it's actually components, too. So it's --

MEMBER SIEBER: Well, yes. The operator can pick up a frozen line pretty quick, hopefully.

CHAIRMAN LEITCH: But the standby liquid control system relies upon heat tracing, but there again, you're --

MR. POLASKI: Right. We've got the enriched boron with the lower concentration.

CHAIRMAN LEITCH: Okay.

MR. POLASKI: So you've got to get very cold in the building before you have any problems.

MEMBER SIEBER: You're what percentage? Nine percent or six percent, something like that?

MR. POLASKI: I can't quote the exact number, but when we had to go to the increased capacity the coolant --

MEMBER SIEBER: It was like 60 degrees, right?

MR. POLASKI: Yes. It's -- yes.

MEMBER SIEBER: Okay.

MR. POLASKI: All right.

MEMBER BARTON: Well, if you lose heating and ventilating in a reactor building in the wintertime could you get there? No?

MEMBER SIEBER: Uh --

MEMBER BARTON: There's a head behind you going this way. You turn around you'll see it.

MEMBER SIEBER: I know I worked at LaSalle and they had no service boiler that worked. And when they shut down both units they had piping systems that froze. So I think you can get there if you try hard.

MEMBER BARTON: I was talking about the boric acid in the reactor building.

MEMBER SIEBER: I think -- I think that --

MEMBER BARTON: And you lose the heat tracing there.

MEMBER SIEBER: -- it would get messed up before the lines would freeze, but you're right. But that would be a situation where both units were shut down because just the ambient heat from the plants running would keep the buildings relatively warm, I would think, in the 50, 60 degree range, as a minimum, and probably up in the 100 degree range.

MR. POLASKI: Two areas of special emphasis I'd like to talk about in mechanical scoping. One is boundary realignment and the other was the scoping, the additional scoping we did for 54.4(a)(2), non-safety-related equipment that's impact safety.

The interim staff guides on that was issued in March of 2002 with the NRC's interpretation of (a)(2) scoping, which is different than what we used initially. So we did that additional scoping in the RAI response, and I talked a little bit about that.

So going on to the next one, on boundary realignment, talk about it with five different cases and let me go through each of these. I think this is easier to understand looking at a picture than it is trying to talk about it in words.

So the first one deals with components with containment penetration. So pictorially here, we've got a picture that shows this is the containment boundary. And we've got a system piping that penetrates containment.

There's a valve on either side of containment. Non-safety-related system, not in scope of license renewal for any other reason than this containment penetration. So the question gets into, what do you do with this.

When you look at the current licensing basis for Peach Bottom, this non-safety-related system has no system intended functions. The system intended function is a reason you would bring a system into scope of license renewal.

For example, this may be a service air system which provides service air inside containment for breathing air or operating fulls when you're doing maintenance in there.

These valves in this case normally would be closed when you're at power and operating, but this also could be something like a reactor building closed cooling water system, which provides cooling to components inside containment, but no safety function.

So we get caught in a dichotomy of this system isn't in scope because it has no intended functions, but parts of this system really have a safety rate of function of containment isolation. So how do we address it?

We have two choices. Put the whole system in scope and then shrink it down to just this part where we realign this part of the system from the valve, the piping, the valve and any other piping connections in between, to a system that was our containment isolation system and address aging management of these as part of the system, in that system.

It was a choice we had to make. We chose the second one because we wanted this to be with a system that had an intended function, which in this case was containment isolation.

MEMBER SIEBER: You end up with the same situation, regardless of which way you do it.

MR. POLASKI: You're right. You end up with the same components in the scope, with the same material, same environment and we address aging management only. So it was an issue of how we address it from a scoping basis, from a system basis, not eventually when we get down to the specific components.

MEMBER BONACA: Did you compare the approach with the one used by other applicants for -- you know -- previous applicants for license renewal?

MR. POLASKI: I can't speak for PWRs, but looking at the only other BWR, which was Hatch, they did their scoping on a functional basis. So they said, oh, this -- the function of these valves and plates is containment isolation. So they scoped it into that function. We scoped on a system basis.

MEMBER BONACA: A system basis.

MR. POLASKI: And we ran into this conflict. And so we realigned it to the system that had the function that we were trying -- that it needed the support there.

MEMBER BONACA: Yes.

MR. POLASKI: Okay.

MEMBER BONACA: The reason why it's interesting to me is that most of the applications that come are on a system basis.

MR. POLASKI: Yes.

MEMBER BONACA: And we have not discussed how to handle this.

MR. POLASKI: And I'm not sure if a BWR versus PWR influences a lot of that. For this particular example, initially at Peach Bottom we have a lot of systems that came in under this case.

After we did the additional scoping for (a)(2), non-safety-related, which I'll talk about in a minute, a lot of these systems, like reactor building closed cooling water, dry well chilled water, which had not been in scope, later came in scope for (a)(2). So these would have been treated with that.

Now, the other thing is, when you get this kind of a system design you get a lot of systems with a design like this, core spray, RHR, HPCI, for those, this containment boundary was included right with the safety-related systems.

So it was right there. Okay. And this is case number one. Let's go to case two. Case two is an interface between an in scope and an out of scope mechanical systems. So here's a representation of a safety-related system, which may be high pressure service water, which is river water system provides cooling to our RHR heat exchangers.

And there is a demin water line which attaches to it for flushing and filling purposes. And clearly, this part is non-safety-related. That valve forms part of the pressure battery for the high pressure service water system, but under our plant numbering scheme that valve was numbered with the demin water system.

Demin water system's landscape has no intended function. So what do we do with that valve? We realigned it with the high pressure service water system and we brought all of this in scope, because it's pressure boundary for high pressure service water, and that's where the system intended functions were.

MEMBER SIEBER: A lot of times you end up with the class break where those kinds of valves --

MR. POLASKI: Yes, there may be.

MEMBER SIEBER: -- or is that in --

MR. POLASKI: So the class break would have been here.

MEMBER SIEBER: Right. Well, is that consistently applied? Did you look at class breaks to make sure that you didn't have pieces of piping and valves, valve bodies that probably should have been in scope that ended up because of where the class break was, out of scope.

MR. POLASKI: That was part of what went

into our thought process, but I think the primary driver was, what's the intended function of this system, and we needed to maintain pressure value, which means we needed that value. So that was the primary --

MEMBER SIEBER: So the class break was not necessarily the deciding factor. It was the function that was the deciding factor.

MR. POLASKI: Yes.

MR. PATEL: This is Erach Patel. And what also happens is that besides the class break, that particular valve is safety-related.

MR. POLASKI: Sure.

MR. PATEL: And when we do the component record list downloading, although it's in the demin system it pops up as safety-related, and you pick it up over there and then you realign it so that the class break and the safety-related function goes together.

MEMBER SIEBER: Well, the interesting question is, you know, when you go through this process you're actually auditing the way the plant was built. Did you find any instances where the class break was inappropriate?

In other words, you had lower class piping or values that were inside the pressure boundary? Did you find any of those instances?

MR. POLASKI: I don't know. Erach, can you answer that one?

MR. PATEL: I don't believe we found any case like that. We did find and we did get result as we were going through the drawings that in some cases on unit two it may be showing up differently on unit three, and we would go back one, you know, and get that resolved and put in the system.

So as we went through this process we did find some inconsistencies within the units and we got that resolved and got it done.

MEMBER SIEBER: Okay.

MR. PATEL: But we didn't really find a case where it was safety-related but the class break was on the wrong side.

MEMBER SIEBER: Okay. Well, that's the way you were supposed to build the plant in the first place.

MR. POLASKI: Yes. We did not go into this --

MEMBER SIEBER: So that's a good thing.

MR. POLASKI: -- we did not go into this project with the idea of redesigning the plant. We were just working with --

MEMBER SIEBER: See, you might end up doing that if you found a discrepancy like that.

MR. POLASKI: Yes. And any discrepancies we found, like Erach mentioned, we documented them through our process and turned them over to engineering to be resolved and made sure they were all taken care of.

MEMBER SIEBER: Okay. Thank you.

CHAIRMAN LEITCH: We're getting into just a little bit of schedule trouble, here. Could you try to move the presentation along?

MR. POLASKI: All right. Okay. All right.

MEMBER WALLIS: That wiggly line goes around the valve. It does in our handout. What's in the record from this meeting will show it properly.

MR. POLASKI: Right there.

MEMBER WALLIS: It goes round the valve.

MR. POLASKI: Mark that. Oh, they didn't get the latest change. Okay. All right.

MEMBER WALLIS: Okay.

MR. POLASKI: The third case deals with interfaces between in scope electrical and out of scope mechanical systems. What we run into here is that the numbering convention at Peach Bottom is that the power supply to mechanical component gets numbered with the mechanical component; so a 480-volt breaker that feeds the core spray valve as part of the core spray system.

But we also found that there's power feeds which are safety-related which feed non-safety-related components, and this is for reliability of equipment. And so what do we do with those fuses and circuit breakers.

So we realigned them into the electrical system, but not included them in the non-safety-related mechanical system. And it turned out all those were active components anyway, because of the fuses and relays.

Let's go on to case four and we'll just do it real quick. This is one we got interfaces between systems. The safety-related components would be air supply to main steam relief valve. The normal supply for years was always instrument nitrogen, and that check valve was not there originally in plant design.

And then later, we had to add a safety grade backup gas supply. Two check valves were installed. That check valve right there was numbered with the instrument nitrogen system. So we had to realign it so it's the same thing.

So let's go to Case 5. And Case 5 is one, this is MSIV, instrument air supply, check valve and accumulators. From herein it's safety-related. These are numbered instrument air systems. So we realigned them to the main steam system, but we evaluated them with the environment of air inappropriately for that.

Otherwise, you bring in an instrument air system, which is a monster system. Gives you all kinds of -- a lot of work you need to do isn't worth valued right there. Okay. So let's go on to the next slide down on 54.4(a)(2).

The NRC came out with revised Guidances, a clarification of what (a)(2) meant from a seismic II/I, non-safety-related/safety-related impact initially with a letter in December of 2001, about six months after we'd submitted.

We got an RAI in January of '02. There was additional RAI in February, additional clarification in March. And how did all that came -- we went back and did a reevaluation of what was in scope based on (a)(2), using the interim staff guides provided by the staff.

We submitted that response on May 21st, and our basic criteria was we added into scope any systems previously not in scope that contained a fluid other than air or gas, irrespective of whatever pressure or temperature that was in some spatial proximity to safety-related equipment and we brought it into scope.

MEMBER BARTON: Did that include the piping or just the supports?

MR. POLASKI: We brought the piping into scope.

MEMBER BARTON: You did bring the piping in.

MR. POLASKI: The supports had already been in scope.

MEMBER BARTON: I understand that. Okay.

MR. POLASKI: It was listed --

MEMBER BARTON: I just wanted to make sure I understood what you brought into scope here.

MR. POLASKI: Yes.

MEMBER BARTON: Which was the piping.

MR. PATEL: The piping and components.

MR. POLASKI: And components; so valves, pumps, whatever.

MEMBER BARTON: Thank you.

MR. POLASKI: So basically, anything that could leak or spray and get on safety-related equipment. We did that by review of plant prints and plant walk-downs and determined all that.

CHAIRMAN LEITCH: Go ahead.

MR. POLASKI: And this is a list of systems that were already in scope, but we had to expand them to include additional piping, because parts of these systems were not in scope. One example, control rod drive system.

The original scoping on a control rod drive system was hydraulic control units into the reactor vessel was in scope. The pumps, the water supply piping for the HCUs was not originally in scope. It was on safety-related.

It was added in scope under the safety and scoping criteria, because it could leak and get on safety-related equipment. All right. So we expanded these systems to bring in more parts that had not initially been included in scope.

And then on slide 21, these are systems that were added in scope that had not previously been in scope. So that's what we did, brought these in, and we -- as a supplement to this -- have instituted aging management programs for all of them.

MEMBER SIEBER: I have a question about that. What is it in the water treatment system that you called safety-related and why? That's one of the items here. It's the sixth one down, fifth one down.

MR. POLASKI: Water -- no. These are non-safety-related systems that we brought into scope because --

MEMBER SIEBER: Right. Why.

MR. POLASKI: -- because they were spatially close to some safety-related equipment.

MEMBER BARTON: If they fail they could impact the safety-related components.

MEMBER SIEBER: Okay. Two over one?

MR. POLASKI: Right. Two over one or --

MEMBER BARTON: Two over one issue.

MR. POLASKI: -- they leak and get on the safety-related.

MEMBER SIEBER: Right. I withdraw my question.

MEMBER BONACA: Okay. Excuse me. Just for clarification, you just told me before, service water system was not in scope.

MR. POLASKI: Service water system was not in scope on our original scoping criteria because it was not safety-related.

MEMBER BONACA: That's right.

MR. POLASKI: It was added in under

(a)(2), yes.

MEMBER BONACA: Okay. So you have added it in.

MR. POLASKI: We have added it in, yes.

MEMBER SIEBER: But in the two over one situation you only add in as much as you need to cover the two over one situation.

MEMBER BARTON: Not the whole system area.

MEMBER SIEBER: It would be a piece of --

MR. POLASKI: Well, what we did was -- well, you're right. It could be just particular parts of the system, but when we looked at it from a viewpoint of how much effort it was going to take to go determine that and we looked at how were we going to manage age it.

Well, aging management on a lot of these was a preventive program of water chemistry. Water was going to be represented in one-time samples. We did not expend the effort to go and say, this section of pipes and scope, and on that side of the wall it's not.

We just said, the system's in scope, and we brought it in and we managed -- if it's water chemistry in a lot of these, like chilled water systems or water treatment systems, cloudy water, that applies to all the piping in the system.

MEMBER BARTON: So it is the whole system, then. Okay.

MR. PATEL: What we did was we looked at the buildings, because the reactor building, which is safety-related building, lots of superior components, we took all of the reactor building, closed cooling water in scope. We didn't try to break it up into rooms or anything like that.

MEMBER SIEBER: Yes, I knew that.

MR. HATCHETT: This is Greg Hatchett with the staff. We went out to the plant and walked through the plant with the guys from Exelon. And basically, anything that -- like Erach said, anything that ran into the plant that was part of these systems, even though some parts of it had no spatial relationship, they decided to bring the entire thing into scope.

And we walked through all of the buildings where these systems were and identified those portions that had spatial relationships, as well as identified portions that did not have relationships. But Exelon decided to bring it all into scope as being conservative with respect to this issue.

MEMBER BONACA: Yes. I appreciate the --

you know -- the conservative approach. It's just that it's confusing because when I go to the tables in the applications, some of the systems are clearly stated they're not in scope.

MR. POLASKI: Yes. And when we did the initial scoping, service water and all of these systems --

MEMBER BONACA: Yes.

MR. POLASKI: -- that you see listed there were not in scope.

MEMBER BONACA: That's right.

MR. POLASKI: We added them in, in an RAI response and we brought them into scope.

MEMBER BONACA: And that would be somewhere in your FSAR addendum or where would it be, this?

MR. POLASKI: The FSAR addendum does not include the list of systems in scope, but the programs that manage the aging of these would be in scope.

MEMBER ROSEN: So you'll end up with an inconsistency in your FSAR. It'll say it's not in scope when you really are?

MR. POLASKI: No. The FSAR supplement lists the aging management programs that require this relationship.

MEMBER ROSEN: Yes.

MR. POLASKI: It doesn't list -- you don't put a list of systems in the FSAR of what's in the scope. That will be included in site documentation. And what we're doing is we're going back and revising all of our documentation to show that service water's in scope and the aging management reviews are being updated.

So when we're done with the project there will be a complete package of information that'll show everything that's in scope in the -- book.

MR. PATEL: Yes.

MEMBER ROSEN: And any references to something as being out of scope that really is in scope will be expunged?

MR. POLASKI: Yes.

MEMBER BONACA: But the SER does not necessarily define some of this change, nor is the application doing that. I'm just trying to understand -- again, we're talking about 20 years from now before you step into license renewal.

Here there is a lot of information that you're telling us is going to go into your documentation of the plant, but --

MR. POLASKI: And I'm going to address

that --

MEMBER BONACA: But I don't now how the stuff is keeping a memory of this realignment and everything that goes in it. I mean, it is not in the application and is not in the SER.

MR. POLASKI: Well, with the complete set of information, though, that we've submitted as the application and our responses, all of that is addressed in the SER. So the SER that the NRC issues will include these non-safety-related systems we're doing now. We're going to take all of that and update all of our documentation to show the final result of what's in scope and everything.

MEMBER BONACA: Yes.

MR. POLASKI: So that the scoping package that said -- previously said service water's not in scope is being revised. It says, service water's in scope with criteria (a)(2).

MEMBER BONACA: Yes, but I'm trying -- I'm -- right now, I actually was more asking myself about what the staff is going to do about --

CHAIRMAN LEITCH: Well, the SER has -- that we have in front of us is an SER with open items, right? And this is one of the open items.

MR. POLASKI: Right.

CHAIRMAN LEITCH: This is 2.3.3.19.2-1, and I assume that when we see the final SER without open items this whole issue will be discussed completely. I mean, this was --

MEMBER BONACA: So that this is the open item on methodology.

CHAIRMAN LEITCH: Right.

MR. KUO: And this -- when the open item is closed, this open item will be described in SER.

MEMBER BONACA: But the open item only discusses the methodology, and I hope that you're also including this more than five tables of what is included and what is not.

MEMBER SIEBER: Well, let me ask a question about that. When you build a plant you end up with a Q-list, okay, of what's safety-related and what is not.

MR. POLASKI: Yes.

MEMBER SIEBER: When you finish with the license renewal exercise you end up with another Q-list, which is different than the first one.

MR. POLASKI: Well, its Q doesn't change.

MEMBER SIEBER: Okay. But you end up with a list that is basically license renewal items.

MR. POLASKI: Yes.

MEMBER SIEBER: Because some of them won't be on the original Q-list.

MR. POLASKI: And --

MEMBER SIEBER: And so you're going to keep that as a quality document.

MR. POLASKI: Yes.

MEMBER SIEBER: To refer to all these aging management programs and one-time inspections and so forth.

MR. POLASKI: In fact, the way we're doing that is in our component record list we've added a field for license renewal, which --

MEMBER SIEBER: Yes.

MR. POLASKI: -- is populated as part of it, where indicated --

MEMBER SIEBER: So you can sort on that if you wanted to.

MR. POLASKI: Yes.

MEMBER BONACA: So even if it's non-safety-related --

MEMBER SIEBER: It's complicated.

MEMBER BONACA: Yes. Even the non-safety-related components will have a yes for license renewal in the component record list.

MEMBER SIEBER: And if you're like most

plants you don't have part numbers for pipe.

MR. POLASKI: That's correct.

MEMBER SIEBER: And most of what you're talking about here is pipe.

MR. POLASKI: Yes.

MEMBER SIEBER: So you have to refer to some isometric bounded by components.

MR. POLASKI: Right. Well, we'll have the boundary drawings that show what's in -- you know -- what was in scope.

MEMBER SIEBER: That's right. And PI&D isn't the world's best way to do that, but -- because it really doesn't tell you where it is, you know, Something on a P&ID this long could be a half a mile.

MR. POLASKI: Mile, right.

MEMBER SIEBER: Or vice-versa.

MEMBER BONACA: Well --

MEMBER SIEBER: Okay. Well, that clears up that for me.

MEMBER WALLIS: Can I ask the staff something now? This is quite a big list. Does this create a precedent for future license renewals? Are we going to have all these systems now added for other applicants?

MEMBER SIEBER: No.

MR. POLASKI: I'll tell you --

MEMBER WALLIS: Does the staff know?

MR. POLASKI: Let me speak to the next BWR that's going to be submitted. January next year you'll get a license renewal application for Dresden and Quad Cities, which is our next Exelon submittal. We are incorporating in the initial scoping the uniform state guidance for (a)(2).

So these systems and ones like it won't be exactly the same. Different plant design will be included in the scope initially.

MEMBER WALLIS: Well, will this take --

MEMBER SIEBER: I think Oconee was done this way because they had two over one systems, and you would see it on a P&ID, but the problem --

MEMBER WALLIS: Do it represent a sort of expansion of what's called safety-related?

MEMBER SIEBER: They didn't talk about it as much as Exelon was talking about it. I think that's the difference.

MR. POLASKI: Well, it won't be an expansion of what's safety-related. It'll be an expansion of what's in scope and --

MEMBER BARTON: Of what's in scope, right.

MR. POLASKI: -- what's not.

MEMBER BARTON: Right. Right.

MEMBER BONACA: What we have raised before, however, is the issue of the connotation (phonetic). By the time this process is finished and the contract is written between the staff and the licensee we have an application that is incomplete by the finishers because some of these tables have been added later on, some additional one-time inspections are negotiated or whatever is going to happen.

MR. KUO: Well, the application --

MEMBER BONACA: Some of this information will go in the FSA out of date. Okay. That will solve some of the problem. Some of it will go in the SER, in the final SER and some of it, like tables like which have multiplied, which we normally would see in the application, okay, where are they going to go?

MR. KUO: It will be documented in the RIs and the responses. That's part of the application. So in that sense, the application would be completed.

MR. SOLORIO: And I'd just like to add -- this is Dave --

MEMBER BONACA: So you consider the application, the original application, plus all the RAI responses.

MR. SOLORIO: Correspondence, that's

correct. And in this particular case we've got an RAI -- or an open-item response that's pages and pages because it includes additional tables.

MEMBER BONACA: I'm still, you know, talking about an issue of a member of the public who would like to be followed by some component there and goes to an application and doesn't find it. And then he finds it somewhere else and so.

MR. KUO: Well, yes. I don't think the -- anybody, including the public, will find that, you know, that pieces are separate, they're in different laces. That actually, it will be a document that is the application, plus the RAIs. Okay.

MEMBER BONACA: So really, the information you got, as opposed to an RAI.

MR. KUO: Yes.

MEMBER BONACA: Actually an open item.

MR. KUO: Yes.

MEMBER BONACA: Okay. So in addition to giving you the methodology that they asked for, they also gave you the results of the application that they're involved (phonetic) in.

MR. SOLORIO: That's correct, right.

MEMBER WALLIS: Did you answer my question?

MEMBER BONACA: No, I think they did.

MEMBER WALLIS: Well, the question was: does this represent a sort of step up in the number of systems which are going to be considered in scope over what happened in the past? Is this a change, is this a substantial change in their relicensing process now, with all these new systems that are considered in scope?

MR. KUO: Mr. Butch Williams -- Butch Burton. His first name is William. So I'm sorry.

MR. BURTON: That's all right.

MR. KUO: Mr. Burton will explain the process.

MR. BURTON: Yes. Good morning. This issue of seismic two over one and the treatment of SSCs that meet the 54.4(a)(2) criterion, if you all remember that first came up with Hatch, which was my plan.

In direct answer to your question, I think for perhaps the next couple of plants you may see something similar to this. And it makes sense because as we develop that position, the plants that were in the Q undergoing review at that point or even in preparation of their application, they hadn't -- they were too far gone -- to far along in the process to really address it in the application.

We have to sort these things out through the RAI process, and so we still have a couple of plants that were caught up in that cross-current. So you may see this again. But I think in the longer term, the plants that are a little bit further out, they are incorporating this position into their application right up front.

So what you're going to see is these types of systems are going to be identified in that Table 2.2-1 that lays out what things are in scope and what aren't. So I think in the longer term you're going to see this list shrink.

Does that answer your question? It's -- those are going to be part of the application right up front as plants start to deal with the position.

MR. KUO: The direct answer really is, it is not an expansion.

MEMBER BONACA: No, I understand. But still you understand our difficulty as the committee really views this material, whatever is given to us, you know, I've been -- I'd asked the question of our service water, it really is not in scope.

We discussed it before. Emergency service water is. Now, we discover it is in scope. So becomes very confusing. I mean, you know, we just hang there, depending on --

MR. BURTON: Right.

MEMBER BONACA: -- what step of the process we are discussing at a given time, and we discover different things. And so it's --

MR. BURTON: Yes. And let me speak to that. You're absolutely right. You know, any member of the public who's going to look strictly at the application and then sees this is -- can be -- very easily be confused.

And I think particularly with these what I will call transition applications -- and it applies not just to the seismic two over one and 54.4(a)(2). It also applies to any emerging issue that comes up. There's always going to be a transition time amongst the plans.

And for those issues the best place for any stakeholder to really try to get the entire picture is ultimately in the SER, because that is what's going to reflect what was in the initial application, any changes that came about as a result of the response to RAIs, all of that is ultimately going to get documented in the SER.

So ultimately, for any stakeholder, that is the single best place to try and get the entire picture.

MEMBER BONACA: I understand.

CHAIRMAN LEITCH: I'm still a little confused. If the -- are all of these systems now included in scope?

MR. POLASKI: Yes.

CHAIRMAN LEITCH: Or is it some sub-set of some --

MEMBER SIEBER: Pieces of it.

CHAIRMAN LEITCH: -- portion of this?

MR. POLASKI: These are the systems we added In scope when we did the additional scoping for the -- based on the interim staff guidance related to.

CHAIRMAN LEITCH: Not just those areas where two over one is an issue.

MEMBER BONACA: Yes, they will help in simplicity.

MR. FULVIO: Yes. This is Al Fulvio again, from Exelon. What we did was we identified the structures that contain safety-related components like the reactor building, for instance, and the pump structure, things of that nature.

And we were talking a little bit earlier about service water. Well, service water goes into other spaces that do not contain safety-related components, like for instance, the turbine building areas. So no, those portions would not be in scope.

MEMBER BARTON: Right.

MR. FULVIO: Where there are no safety-related components where they can interact with, okay.

CHAIRMAN LEITCH: Okay.

MR. FULVIO: However, what Greg was talking about earlier was that if you take a building like the reactor building, for instance, it has many, many safety-related components in it, we did not cut and paste, if you will, within that structure.

We said, okay, if that system is in the reactor building then the entire portion of that system in the reactor building will be in scope for license renewal for this issue, and we're not going to, you know, nit-pick about, you know, whether it has the spatial proximity or not.

But for those spaces -- structures where there are no safety-related components, then we just said, okay, there's no credit -- there's no interaction.

MR. BURTON: Right, Mario. So it's not the whole system. It's only in those areas where --

MEMBER BONACA: Within the definition of

the realignment they were talking about before.

MR. BURTON: Right.

CHAIRMAN LEITCH: Okay.

MR. SOLORIO: Does that answer your question, Greg?

CHAIRMAN LEITCH: Yes, it does, yes.

MR. SOLORIO: Okay. Thank you.

MR. POLASKI: Aging management review results. We did our aging management -- the primary part of it was the determination of aging effects, and we did that based on the component materials, the environment, operating experience, both industry operating experience and the Peach Bottom plant specific operating experience, and we used a set of what we call industry tools that are available from EPRI.

There's mechanical tools, civil structural tools and more recently been developed, electrical tools, and so what was used at the time was the Sandia report, which addressed aging management of electrical components.

All this information was used and accumulated to determine aging effects we had in the plant that we needed to address, and then the next step was determine what programs we were going to use.

This slide is an example, a very, very limited example of what Chapter 3 looks like, with a core spray system where we have identified where each of the components that were identified in Chapter 2, the component group, the component's intended function, the environment in which it existed.

In this case, sheltered is the external environment, torus grade water reactor coolant -- the thorough construction, the aging effects, if any, were applicable, and for some like stainless steel, for carbon steel, with a sheltered environment was none, and any aging management activity or program that was in place or managing it.

So this was the presentation of everything that we did as the result of all the work. And just to mention something, it doesn't show on the slide, but in your handout there's references at the bottom to SER sections.

We added those in strictly for discussion purposes today; they relate to those programs. So this is how the aging management review results were presented in the application.

In Appendix B where we list all of our programs -- you'd call them the programs. We call them activities because they range from what I call "big P" programs like ISI programs, to some other extensive programs that are accumulation of a lot of smaller maintenance tasks and surveillance tasks.

Some of them may be very small in scope. Twenty-nine already existed. Some of them did require some enhancements, by they were already existing. There was five new activities, two activities dealing with time limited aging analyses, and of those we've listed here, one-time inspection activities work, the systems we're going to do one-time inspections on.

And these are being done to confirm that the aging effects are already being managed by preventive programs that are in place.

MEMBER BONACA: I was kind of confused a little bit by, what is up with the wooden pole program.

MR. POLASKI: The wooden pole is -- I believe is a new program. Or is it just --

MEMBER BONACA: But you call it an enhanced program.

MR. POLASKI: Well, it is enhanced.

MEMBER BONACA: Because you're committing to performing the inspection during the extended period of operation.

MR. POLASKI: Right.

MEMBER BONACA: That's not an enhancement. It just simply is carrying out the same program during the period of -- is it? Why is it an enhanced program? I don't understand that.

MR. POLASKI: Okay.

MR. PATEL: Well, it's enhanced because the inspection of that is carried out by our transmission and distribution people. So from a Peach Bottom perspective, we're going to enhance it and provide a work order which will come into effect during the license renewal phase, to inform the T&D to make sure the inspections are done.

So it's like -- it's an existing program, but not within Peach Bottom itself.

CHAIRMAN LEITCH: So the enhancement is in the documentation and the formality of it, not so much of the programming site.

MEMBER BONACA: Because in reality, all you're going to do, you're going to exactly what you're going to do now.

MR. POLASKI: Yes.

MEMBER BONACA: And do it in --

MR. PATEL: That is correct.

MR. POLASKI: Yes. I mean, we're not doing anything more than we're just making sure that it gets done on the required frequency that it should be done, because in the T&D world, they schedule them, but budgetary reasons can mean they don't even do them when scheduled. We have to make sure it's getting done.

MEMBER BONACA: I don't see why it's enhanced, but anyway.

MEMBER BARTON: What is the severe weather that's associated with a station blackout event? I didn't know you had to have severe weather to have a station blackout event.

MEMBER SIEBER: Don't have to.

MEMBER ROSEN: You don't have to.

MEMBER BARTON: Well, your application says that this wooden pole has been analyzed to be able to withstand severe weather associated with a station blackout event, and I don't know what that means.

MR. POLASKI: What that deals with is that if -- that was an issue that came up during the design in the NRC review and approval of our station blackout only with AC power source.

MEMBER BARTON: Okay.

MR. POLASKI: And what was reviewed was whether that -- the equipment would be able to supply on an AC during severe weather conditions. It doesn't say that the station blackout is a result of severe weather, but it could be.

So they were -- the NRC was -- staff was concerned. Now, this is not license renewal. This is station blackout.

MEMBER BARTON: I understand that.

MR. POLASKI: With how well that one wooden pole that is part of that system would do under severe weather.

MEMBER BARTON: So you analyze this for blizzards and tornadoes.

MR. POLASKI: Yes.

MEMBER BARTON: And hurricanes and all that stuff? Is that what that means?

MR. POLASKI: From what I understand, that is the most finely analyzed --

MEMBER BARTON: Okay.

MR. POLASKI: -- power pole you ever will see.

MEMBER BARTON: Okay. Well, that's what I figured, why you do a big analysis on a green pole, you know. Okay -- a wooden pole. Now, I understand what the pole is.

MR. POLASKI: I won't even get into that

one.

MEMBER BARTON: All right.

MR. POLASKI: Well, we are going to make sure that for license renewal, the aging of it is properly done.

MEMBER BARTON: I understand.

MEMBER SIEBER: It's a cedar pole.

MEMBER BARTON: No, it's white -- it's yellow pine.

MEMBER SIEBER: Yellow pine?

MEMBER BARTON: Yellow pine.

MEMBER SIEBER: Oh, it's got a bend in it, then.

(Laughter)

MEMBER SHACK: Your FAC program, I noticed that you must have had some failures recently that you had pipe wall thinning that went below ASME minimum or you had leakage. That's what I imply from the DSCR, and I was just --

MR. POLASKI: Yes. I don't know off the top of my head. I can't answer it. But I assume that we had that thing.

MEMBER SHACK: FAC programs are of interest for a variety of reasons.

MR. FULVIO: Yes, we have, you know. One

of those failures that occurred, though, were in non-safety-related portion pipings. However, yes, we have had wall thinning to the --

MEMBER SHACK: Well, the wall thinning is one thing. You expect to have wall thinning.

MR. FULVIO: Right.

MEMBER SHACK: The question is, did you have a failure of the program. Did the wall thinning go below the ASME minimum or did you have leakage, which you're not supposed to have.

MR. FULVIO: Yes, we have had leakage. Like I'll give you an example. On the HPSI/RCSC steam line drains that go to the condenser. They're relatively small pipes, but it's a non-safety-related portion of the piping.

But yes, and they have leaked and we found the leaks and we had to replace that piping. We replaced it with less susceptible --

MEMBER SHACK: Even though your FAC program said you would have been able to get that established without replacing it?

MR. FULVIO: I would say that these degradations occurred before the FAC program stated, and you know, remember now, we've been operating for 25 to 30 years.

MEMBER SHACK: I know. So this is ancient history we're talking about here?

MR. FULVIO: Well, it's old. It's not ancient, but it's old. But currently, yes, we do also find, you know, other degradations.

MEMBER SHACK: Okay. Well, I guess there's another way. Have you had any failures of your FAC program since you've implemented a modern version of it?

MR. FULVIO: Not that I'm aware of.

MR. POLASKI: Well, I'm not aware of any, no.

MEMBER SIEBER: Well, but you don't model everything --

MR. POLASKI: Right.

MEMBER SIEBER: -- down to the, you know, half-inch line in your FAC --

MEMBER SHACK: No, but the question is when you have a failure.

MEMBER SIEBER: Yes. Well, I wouldn't be surprised if some little drip or --

MR. FULVIO: I don't remember any failures in the last five years, but -- I guess not in our memory.

MR. POLASKI: All right. Implementation

of aging management activities. Break this into two sections. All of the activities programs that were identified in the application when we submitted it were incorporated in existing procedures programs, and those commitments were identified in those by September of 2001, about two months after we submitted.

So all of the programs that were identified initially that we did, you know, prior to getting RAIs and expansion, we built those right into our existing programs right up front.

Any additional activities that were identified as a result of increased scope and RAI responses, those have all been identified and the plan is to have all those implemented in the plant by the end of 2003.

MR. PATEL: Incorporated.

MR. POLASKI: Incorporated in the plan in those procedures. One exception to that is that one-time inspections have been identified, what equipment needs to be inspected, what the criteria that we're looking for, those procedures will not be developed until closer to the time of actually doing the inspection so that we're using latest state of the art techniques at that time.

We don't want to go writing a procedure now that won't be implemented for ten years and have to go back and redo it because techniques have changed.

We did this very purposefully because I wanted all this built in. It was a way of getting stations making sure they knew exactly what we were committing to, build it into the process so we weren't going to leave a bunch of work to do for future generations at the plant.

All of this is in our processes. It's on our commitment tracking processes, the changes, the commitments are all annotated. So if somebody picks up a procedure that we had credited part of it for license renewal and wants to change it, it'll be clearly identified in there with those commitments and what part of it is, and they will have to go back through our commitment change process to make those changes.

And it's the same we do on any other commitments, commitments we make on LESS in response to generic correspondence. It's all going into that process, and I think Dr. Bonaca, that was a question you raised before, is we built this in right up front. I didn't want to walk away from the project.

In fact, I told the project team that six months after we get the new license we're all done and out of the Peach Bottom business, we're going to leave a complete package of information for people there, the basis for the application, our scoping packages, or aging management reviews, our boundary drawings.

But all the commitments will be built into the existing systems that we use every day and you can walk away knowing it's all there.

MEMBER BONACA: I had a question regarding the ESW system. On portion of stagnant portions of the ESW, because you had experience of corrosion and leaking, you're going to have biocide treatment, too. That's an enhancement you're making.

MR. POLASKI: Yes.

MEMBER BONACA: Are you going to have it in the period of extended operation or are you having it now already?

MR. POLASKI: Biocide treatment of ESW systems is in existence now. We put those in place -- we had a problem in Peach Bottom 1980 time frame, I believe --

MEMBER BONACA: Yes.

MR. POLASKI: -- significant degradation among the service water system, most of the piping was all replaced and we have treatment of that. We have biocide periodically to keep --

MEMBER BONACA: So that's all right. That has been already in place.

MR. POLASKI: Yes, that's already been in place. We changed the operation system so there's flow through the system now. It's not a dead lake system like it used to be, but --

MEMBER BONACA: So the only enhancement in the problem is really the expanded scope.

MR. POLASKI: Yes. And all that -- and everything -- we monitor the ESW system through our 89/13 program.

MEMBER BONACA: Yes. Okay.

MR. POLASKI: Through the history since we've done the modifications and changed operation, and so we don't have any problems with that system right now. TLAAs, I'm going to let Erach briefly discuss the TLAAs.

MR. PATEL: In the case of TLAAs, we had some generic TLA which normally are considered for all plants at the RPV embrittlement. And in answer to the question that Dr. Rosen had, in the original application, yes, we had not done our upper shelf energy analysis, et cetera, because the methodology wasn't a question from a "G" (phonetic) perspective.

Methodology for the fluence was approved in September 2001. We did the complete calculations and the RAI responded. We sent out -- revised the upper shelf energy information, revised the information for the circumferential valves and the actual probability, et cetera.

So all of that information has been provided to D&S, and the SER reflects that.

MEMBER SIEBER: This is a calculation of the fluence to the wall.

MR. PATEL: Right.

MEMBER SIEBER: The inside of the wall.

MR. PATEL: Inside of the wall, quarter deep.

MEMBER SIEBER: And this is -- I now remember where I got the idea about the shroud. When you do that calculation, General Electric I think ignored the shroud as though it didn't exist, as far as an attenuating factor for the vessel wall. Is that correct? Don't know?

MR. POLASKI: Well, I don't know. That's -- I guess what we can say is that when we initially submitted the application there was no approved --

MEMBER SIEBER: Methodology.

MR. POLASKI: -- there was -- methodology for neutron fluence calculation for the vessel. When that was approved then we had General Electric perform those calculations to do the -- you know -- what's the total fluence at 60 years, upper shelf energy, the T&DT.

And there was also -- part of that was the fluence on the shroud also needed to be considered.

MEMBER SIEBER: Well, the fluence absorbed by the shroud affects the structural properties of the shroud. In other words, will it stay in place? But when you ignore that and say, well, it's really all water there, then you end up with a different number to the vessel wall --

MR. POLASKI: I won't --

MEMBER SIEBER: -- than you do if you modeled it exactly.

MR. POLASKI: Maybe Robin Dyle can discuss that, but --

MR. DYLE: It's Robin Dyle from Southern Nuclear, representing the VIP. I guess what I would like to clarify is the fluence model that Peach Bottom would have used is the new generic fluence model that G.E. developed.

It not only accounted for the shroud. It accounted for the jet pumps and things of that nature.

MEMBER SIEBER: Okay.

MR. DYLE: And it was approved based on the NRC's latest red guide for what criteria it had to meet. So that's what the SE for that fluence model would have been. So it did account for --

MEMBER SIEBER: Okay. So it does include.

MR. DYLE: -- the shroud and the jet pump.

MEMBER SIEBER: It does include the shroud and the jet pumps as they physically exist.

MR. DYLE: Yes, sir.

MEMBER SIEBER: Okay. Thank you.

MR. PATEL: The other DLE's we had were metal fatigue, the environmental qualifications of electrical equipment, containment fatigue. And then we had some specific -- plant specific TLAs. We found the reactor vessel corrosion allowance had a 40-year life associated with that.

So we got that reevaluated for 60 years. We also had the generic letter 81-11 feed water nozzle cracking. That originally was valid for 40 years. We had to reevaluate it for 60 years. Initial, we looked at all of our ISI and PSI work that was done and we found one unit three main steam elbow in the original construction tank.

We had -- that was evaluated for 40 years. We went back and looked at that to make sure it was okay for 60 years, and then the high-energy line break and the crane load cycle limits. So those were the plant specific PLAs that we considered.

MEMBER BARTON: Where are you addressing the upper -- was it upper grid, upper core grid cracking? You -- is that a TLAA or is that somewheres else being looked at?

A PARTICIPANT: Surveillance, vessel surveillance program.

MR. POLASKI: Well, it's not a TLAA.

MEMBER BARTON: But it is an issue, right?

MR. POLASKI: Yes. Barry, you want to speak to that?

MR. KUO: Yes, top guide --

MR. PATEL: The top --

MR. KUO: The top guide cracks.

MR. PATEL: The top guide is a TLA. We considered that as a TLA.

MEMBER BARTON: That is a TLA. Okay.

MR. PATEL: Yes. And the issue there is, we are following the BWRVIP requirement for the top guide.

MEMBER BARTON: Okay. All right.

MR. PATEL: And at ths particular time it's an open issue that is being discussed.

MEMBER BARTON: Okay. Thank you.

MR. POLASKI: Other questions on TLAAs. Now, the last line on future actions, we'll be formally responding to 15 open items by November 29th. Fourteen or 15, we believe, were simply closed and one to go, and that's the top guy we're talking to.

We'll be responding to the 18th informatory items, also by November, and we'll be issuing our update to reflect current licensing dates as changes that affect the application by December. I think Dave had already mentioned that earlier.

CHAIRMAN LEITCH:: We have two clocks here, so we'll start by that one and finish by that one. They're not precisely the same time.

Just before we resume with the agenda, there was a question regarding Hilti bolts, and the Staff has some additional information in that regard. PT, can we ask you to respond to that now, please.

MR. KUO: Yes. Certainly, Dr. Leitch. I have the Senior Staff Hans Ashar here from Mechanical and Civil Engineering Branch. He will address Dr. Sieber's question on the Hilti bolts, extension bolts in general, but is not the specific for Peach Bottom.

It's in general.

MR. ASHAR: All right. I'm Hans Ashar. I'm with the Mechanical and Civil Engineering Branch, and as far as the expansion bolts in general, the Staff's concern has been there since 1979. In 1979, we issued a Generic Bulletin, Bulletin 7902, regarding the expansion bolts. It included not only Hilti, but all types of expansion bolts being used in industry.

All the licensees went through quite a bit of repair and renovation to make sure that they meet the requirements of 7902, though at that time they were made like requirements. And there are safety technos associated with them to take care of certain uncertainty in their function to perform during certain seismic events, et cetera.

Later on, as a part of the USIA-46 Program, which was for the older plants, various equipment being anchored by expansion bolt was one of the big item that most of the licensees addressed at that time, and Staff reviewed in detail what they had done with older plants, because the problem was with the equipment being qualified for the older plants. So expansion bolt, or any kind of bolting was an issue in the USIA-46 resolution. That was completed in around 1992 or so.

During that time, most of the expansion bolts that licensees have installed were being reviewed thoroughly by all the licensees. Our regional inspectors had gone to various plants to make sure that there were adequate programs to make sure that all kinds of bolts have been addressed, including not only expansion bolts, but the cast-in-place bolts, and expansion bolts, all kinds of bolts.

Since that time, a maintenance rule came through, and in maintenance rule, a couple of plants that I, myself, have visited as a part of the baseline inspection, and they had included expansion bolt as part of their maintenance rule, to look at those bolts at periodic intervals. And I would believe during the extended period of operation, all the applicants will be continuing that maintenance rule commitment.

MEMBER SIEBER: Okay. My question really dealt with the aging of the concrete in which the bolt was set, and had that been taken into account. And I guess what you're telling me is that under the maintenance rule, they're going to be inspected or tested somehow or other during this extended period of operation, beyond the 40 calendar years. Is my understanding correct?

MR. ASHAR: That is correct. Now testing

part, I want to address the testing part. Inspection, yes. Testing, only if it is needed. I mean, if they find that there's a problem with particular pipe support connection where there are expansion bolts being used, in that case they might do some testing, or they might pull out something. But testing is not a part of the maintenance rule inspection at this time, because of the extensive program that all the licensees went through during the Generic Resolution of 7902, Bulletin 7902.

MR. KUO And to address your specific concern on the concrete aging, I believe that is really why some of the extension bolts have such high factors there. The safety factor for some of the bolts as high as eight.

MEMBER SIEBER: Yeah. I remember doing a lot of the testing and the safety factor, as I understood it was there because there was some uncertainty about what the seismic response would be, what the forces on the bolting would be, particularly since you test them pulling them, and the seismic forces are lateral, which is a different proposition.

MR. KUO: Yeah.

MEMBER SIEBER: But the answer is you aren't going to test them, and you believe that there is enough margin to take care of concrete aging. And I guess I have to think about that a little bit.

MR. ASHAR: Yeah. I mean, there are a lot of uncertainties regarding the ability of expansion bolts. That's the reason we put safety factors to be required. It was a four or five minimum required, and most of the licensees that had been reviewed later on had much larger than that.

MEMBER SIEBER: Uh-huh. Okay. Well, thank you very much.

CHAIRMAN LEITCH:: Okay. Thanks. We'll turn it back to you then, David.

MR. SOLORIO: Okay. I just want to kind of orient everybody. We're on page 14 in the handouts. With me here to my right is Mr. Bob Pettis and Greg Hatchett. Bob will be presenting the results of the Scoping Methodology Review, and Greg will be doing the scoping review described in Chapter 2 of the SER, following Bob.

MR. PETTIS: Good morning. My name is Bob Pettis, and I'm the Senior Reactor Engineer in the Equipment Instrument Performance Branch of the Division of Inspection Program Management. This morning I will briefly discuss a review of the Staff's input to Section 2 of the draft SER regarding scoping and screening methodology at Peach Bottom Units 2 and 3.

The Staff's input to the draft SER was based primarily on information obtained from the Staff's desktop review of the application, an on-site audit of the applicant's program documentation and implementation, Staff generated requests for additional information, and our findings and conclusions. The Staff's review and subsequent SER input was performed in accordance with 10 CFR 54.4 and the guidance contained in NUREG 1800. This morning I'll provide the Committee with an overview of the Staff's results in these areas.

During the desktop review which was performed at headquarters, the Staff reviewed the applicant's scoping and screening methodology used to identify system structures and components that are within the scope of license renewal, and structures and components that are subject to aging management review. This methodology is described in Section 2.1 of the Peach Bottom license renewal application.

Staff review of the applicant's scoping and screening methodology was to determine if it met the scoping requirements set forth in 54(a)(1) through (3), and the screening requirements set forth in 10 CFR 5421. In developing the scoping and screening methodology, the applicant considered the requirements of the rule, statements of consideration of the rule, and general guidance provided in NEI 95-10. The applicant also considered the Staff's correspondence with other applicants and NEI regarding the development of the methodology.

The team reviewed the license renewal application and supporting information, such as the updated final safety analysis report, existing license renewal program guidance, and system design baseline documents or DBDs. The DBDs are a comprehensive system-level document that provides the system design basis, and addresses system functions, controlling parameters, and design features. The DBDs also identify and discuss regulatory requirements, commitments, codes and standards, and system configuration changes that had an impact on the design baseline of the system for normal and accident conditions.

Based on the Staff's desktop review of the application, the Staff prepared a detailed summary or relevant documentation referenced in the application. The Staff requested the applicant to provide this information to the team during the pre-audit documentation meeting which was held at Exelon's Corporate Office in Kennett Square, Pennsylvania.

During this meeting, the applicant provided copies of the requested documentation, and also provided the team with an overview of the scoping and screening process described in the application. The Staff then reviewed the information in preparation for the upcoming scoping and screening audit which was conducted in December of 2001.

Following the Staff's desktop review of the information obtained during the pre-audit meeting, four Engineering Staff from headquarters performed a week-long audit at the Exelon Corporate Office. During the audit, the team reviewed the implementation process described in the application, which included the review of Exelon reports, procedures, position papers, discussions with the applicant's staff, selected training records, discussions relative to NRC Interim Staff positions, future requests for additional information, applicable design documentation, system DBDs, component record list or cue list, maintenance rule basis documents, and selected system and scoping and screening reports for RCIC system, feedwater and drywall ventilation.

The team selected these systems based on experience gained from previous license renewal audits, and also input from the Division of System Safety Analysis Staff responsible for the review of the scoping and screening results section of the application, which will be discussed following this presentation.

CHAIRMAN LEITCH:: A question here regarding the chronology. This scoping and screening review, was that done prior to the applicant's response to this open item where a number of systems were included in scope based on the II/I issues?

MR. PETTIS: Yes.

CHAIRMAN LEITCH:: It was prior to that.

MR. PETTIS: Yes. The chronology was the application was received by the Staff. We performed a desktop review which is how we refer to it, which is basically an in-house review of the application to try to come up with a feel for what the methodology describes, try to capture any relevant documentation that may be referenced in the application, such as procedures by number, and also gain just a general understanding of the applicant's program.

Following the desktop review, then we send out a request for information and have discussions with the applicant over the phone, and have that information assembled at, in this case the Exelon Corporate Office. A team of one or two people would go up there to gather the information, sit down for about a day. The licensee provided an overview of the methodology process and the relevant documentation. That information was then taken back to headquarters in preparation for the audit, which was conducted in December of 2001. This way, we have an opportunity to review the procedures, understand their methodology, and be able to perform the audit in a much more effective manner.

CHAIRMAN LEITCH:: All right. My question really was whether these systems that were added as a result of this open item, was that work reviewed with the same rigor or thoroughness as the initial work?

MR. PETTIS: Well, the answer to that would be yes, but that review came after, as a result of the seismic II/I RAI that was issued after the on-site inspection in December of 2001. Since that issue was an evolving issue between the Staff and Industry, that RAI or the response to that RAI indicated this additional review, and the additional systems, and the additional boundary expansion.

Actually, that's kind of in the process of being reviewed really at this point. I mean, I think it came in probably about maybe a month or so ago, or two months ago, so we're getting our hands around that response. And I believe in the result section, Greg is going to talk a little bit about the openness of that open item.

CHAIRMAN LEITCH:: Okay.

MR. PETTIS: And I believe it's only item, not because of the methodology, but because of just the docketed correspondence that needs to be obtained by the Staff.

CHAIRMAN LEITCH:: Okay. Thank you.

MR. PETTIS: As a result of the Staff's desktop review of the application and discussions with the applicant's staff during both the pre-documentation meeting and on-site audit, several RAIs were submitted to the applicant in the scoping and screening methodology area. In general, the RAIs requested additional information in the area of scoping and screening, realignment, aging management program attributes, which are discussed in Appendices

A and B of the application, and further clarification as to the extent of the applicant's scoping of non-safety related piping in accordance with (a)(2), or the Seismic II/I issue.

In general, the Staff found the applicant's responses to the RAIs to be acceptable, and consistent with other applications reviewed. The Staff determined that the applicant's approach to this scoping and screening process was generally consistent with the scoping criteria established in 54-4(a)(1) through (3) for both safety and non-safety related system structures and components, and the Commission's regulated events.

The team identified that the applicant's evaluation of the Seismic II/I issue required some additional effort, which was eventually resolved through the RAI process, and the use of the Staff's Interim Staff Guidance provided in this area.

For Seismic II/I considerations, the applicant provided information in the application which discussed the use of an area-based approach to scoping structures and components, and placing them under the scope of license renewal. The applicant also performed a supplemental review of potential (a)(2) structures and components, which resulted in the expansion of the applicant's initial scope. The applicant's evaluation reviewed non-safety related piping which was not connected to safety-related piping but could adversely impact the performance of an intended safety function due to a spatial relationship. This issue will be further discussed in the results section, which will follow this presentation. This, by the way, was the response to the RAI.

The Staff concluded that the applicant's methodology and its implementation were adequate. The scoping process is defined and proceduralized, and the applicant's license renewal team was trained on the implementation process. The Staff's audit of the applicant's scoping and screening methodology provided confirmation of the process and its implementation. As a result, the Staff finds that there is reasonable assurance that the applicant's methodology for identifying system structures and components that are within the scope of license renewal, and structures and components subject to aging management review is consistent with the requirements of 54-4 and 54-21, and therefore, is acceptable. Are there any questions?

CHAIRMAN LEITCH:: Apparently, no

questions.

MR. PETTIS: All right. Thank you.

MEMBER WALLIS: Is that the end, or you are going to move on?

MR. HATCHETT: Good morning. My name is Greg Hatchett, and I work in the Plant Systems Branch as a Reactor Systems Engineer in the Division of System Safety and Analysis. And I believe Bob left all the questions to me, so I'll --

MEMBER ROSEN: He told us the bottom line, but he didn't tell us how you got there.

MR. HATCHETT: How we got there, yeah. The Staff in the Division of System Safety and Analysis, with the assistance of a contractor, was responsible for doing the scoping and screening evaluation for the Peach Bottom plant.

To verify that the applicant had properly implemented the methodology, the Staff focused its review on the implementation results to confirm that there were no emissions of the plant level systems and structures within the scope of license renewal.

As indicated in the slide, the Staff reviewed the applicant's updated final safety analysis report, piping and instrumentation diagrams, license conditions, and its own interim staff guides which reflects emerging issues. One of those emerging issues that we've already talked about to some degree today has to do with 10 CFR 54.4(a)(2), which is the non-safety related system affecting safety-related systems, so we've already discussed that at some length today. So the Staff uses this Interim Staff Guidance to try to ensure that all structures and components requiring an aging management review have been captured.

In the beginning of its review, the Staff focused on the out-of-scope systems in Table 2.2-1 of the application. Several systems identified within the table were considered to be out-of-scope, but had structures and components that were within the scope, and were subsequently included within the boundary of other in-scope systems. Again, today we've talked about that to some degree, and that's known infamously as system boundary realignment.

As described in the SER with open items, systems such as the reactor building, ventilation system, reactor water clean-up system, instrument nitrogen system and instrument air system were not included within the scope of license renewal. However, they were subsequently included as a result of NSR versus SR in some cases. However, specific SCs of the systems were realigned within the boundary of other instrument systems.

CHAIRMAN LEITCH:: Greg, I guess I don't understand why this issue didn't come up previously, or did it, and I just didn't recognize it? I mean, this realignment issue.

MR. HATCHETT: Why didn't it come up previously?

CHAIRMAN LEITCH:: Why did it not come up in other applications?

MR. HATCHETT: Well, again, this is the second boiler that the Staff has reviewed. If you go back and you remember, and reflect on the Hatch application, that was the first boiler. Although I wasn't involved in that review, Butch Burton was the PM for that one. What you'll see is with respect to trying to do system scoping, it may be a little bit challenging for a boiler as opposed to a PWR, so with that in mind, Hatch did functional boundaries. And just as a caveat, they had a primary system in which the primary system represented all those other intended functions that were the reason for bringing the primary system into scope. But there may have been other systems that had the same intended function, that was subsequently considered to be underneath, if you will, the primary system, but it was not listed that way in the application, in the scoping and screening table up front in the application.

Again, what this was, was a methodology again to simplify scoping and screening with respect to a boiler, so Peach Bottom decided to avoid that and try to do more system boundary realignment. And what ended up happening is the Staff in its understanding during the review would come to a point and say well, you know what, we believe the instrument air system should be in-scope because it supports other safety-related functions. So we on the Staff believe that it's a 54.4(a)(2) issue, but they realigned it within the boundary of the supporting system, making it then a 54.4(a)(1) issue. Having said that, those Scs that needed to be captured, were then captured, as a result of the realignment process.

MEMBER BARTON: I think you'll find in the Hatch application that instrument air was in-scope, as I remember.

MR. HATCHETT: But the components for instrument air for the Peach Bottom application that you needed to be in-scope were captured. It was just how it was done.

MEMBER ROSEN: So you're saying the Hatch instrument air system, for example, and the Peach Bottom instrument air system end up at the same point. The components within the instrument air systems for both plants that need to be in-scope are both in-scope, but they arrived at the answer differently.

MR. HATCHETT: Differently. One did functional boundary, and one did realignment.

MR. SOLORIO: Can I just add, Graham, that for Calvert Cliffs, there was a similar situation in terms of realignment. That was a first license renewal application. However, they spent a little more time explaining how they moved components from one system to another for whatever reasons they did, and it wasn't as significant as an issue as it was for these later reviews, so it is an issue that's been identified before with all the previous applicants to a degree. And it really was dependent upon how information they provided in the application, as to whether or not the Staff needed to ask, you know, what number of questions.

MEMBER ROSEN: Does the Staff have a preference now that you've had both ways shown to you?

MR. HATCHETT: Well, what we discussed is that industry has decided not to do this functional boundary thing anymore. I'll say with respect to system boundary realignment, to draw the analogy, if you had to give me directions from NRC to your house using the criteria given to you by the Staff and I got lost, then you probably didn't do a good job in the results and RAIs that you see on the document. So with respect to system boundary realignment, there's nothing wrong with realigning components, because in the end, Staff is trying to determine what systems, what structures and components require an aging management review. So how you get there is not that important with respect to methodology, if you explain it enough so the Staff can have assurance that you did capture all those things necessary, or requiring a review.

MEMBER BONACA: Although we expressed as a Committee, I mean, the preference for the system approach than the functional approach, because we were very confused by the functional approach. For example, one example was typical was ECCS system, I certainly was looking for to be, you know, all the pumps and equipment in the ECCS train, and yet some equipment of that was, since it's used also for core spray, it was under containment equipment or something like that, and so it was very hard to figure out what it was. Depending on the function they had chosen to identify a piece of equipment under, you know, you would be looking in areas where you were not used to look at.

MEMBER ROSEN: I don't think it should be a preference for the licensee in the long run. We're going to do a lot of these with LRAs. If not for every plant, nearly every plant, I suspect, and it seems to me that Staff has a burden under the NRC Commissioner's strategic goals to have a more efficient and effective process. It shouldn't be entirely up to the licensee in the long run for how this is done. I really think the Staff ought to weigh-in, and kind of give through NEI perhaps, but give guidance as to what works best for you guys too, and for us.

MR. HATCHETT: But I think this issue only shows up, or probably only shows up with respect to boilers in terms of trying to fit it into nice neat system boundaries.

MEMBER ROSEN: Yeah. Well, only saying only boilers is saying only a third of the plants, and that's a lot of plants.

MR. HATCHETT: Yeah, I'm just -- but the

idea here is that those are the plants that would have to be addressed particularly.

MEMBER ROSEN: Right. Sure. But I think what I'm trying to give you the message, is that you don't have to stand there and wait for whatever steam comes across the threshold. You could say up front I think through NEI, we prefer you to do this, because it's clearer for us, it's clearer for the ACRS, and it's clearer for public consumptions, other stakeholders.

MEMBER BONACA: The NEI, however, the NEI format is system-based, isn't it?

MR. HATCHETT: That's the format of the standard review plan. It's system-based.

MEMBER BONACA: That's right.

MR. HATCHETT: It's a system-based approach, which is also reflected in the guidance in NEI 95-10.

MEMBER SIEBER: So the message has already been given.

MR. HATCHETT: It is a system-based thing.

MEMBER SIEBER: Right.

DR. LEE: Yeah. We just had a workshop last week, and NEI was a big participant. And then we've gone through -- well, the biggest topic is how to package the application to improve the efficiency of the Staff review. And this topic, the realignment topic, was actually discussed, so we'll continue the dialogue with NEI to address it.

MR. HATCHETT: So again, the Staff met with representatives of Exelon on September 24th, 2001 in Kennett Square to clarify certain aspects of the Peach Bottom LRA, particularly system boundary realignment. The focus of the meeting were problems encountered with Peach Bottom's specific nomenclature and system realignments, which make the scoping and screening of systems structures and components a bit difficult to navigate. Again, system boundary realignment was used to simplify the scoping and screening process.

During that meeting on September 24th, Exelon explained to the Staff that SSCs were divided into four groups. What I'd like to stress here is that what you see before you on the slide behind me, the five cases, were not necessarily clarified at this particular point in the review process.

On September 24th when we met in the Kennett Square offices, the explanation that the Staff received at that time was that the systems were either entirely in-scope, systems entirely out-of-scope, systems that are in-scope with some portions of out-of-scope, and systems that are out-of-scope with some in-scope components are realigned to other in-scope systems, so I think the folks at Peach Bottom understood what they were doing, but in terms of making it clear and understandable for the Staff and for the public in terms of looking at system boundary realignment, it wasn't on the docket yet. And that then made it confusing in trying to understand how they obtained the results they did, and for the Staff to come to some sort of reasonable assurance finding. So during that meeting, the Staff asked Exelon for an explanation of the scoping decisions for systems that were within the scope, but had out-of-scope portions, and some out-of-scope system with in-scope components.

With respect to out-of-scope systems, boundary realignment made it difficult to trace the in-scope components, because the information given for out-of-scope systems was not provided. Again, we go to Table 2.2-1, if the system is out-of-scope, there's no further information for that system in the application.

Having said that, the Staff then looked to the system where those components were subsequently realigned, and looked to see if they could find some connection. And in the portions of the system that were realigned to include those components, there was no explanation, so Exelon acknowledged that this realignment made it difficult to review scoping results starting from a system scoping perspective. So again at that time, the Staff had an understanding with Exelon that it was somewhat difficult to scope the plant components on a system basis.

MEMBER ROSEN: Now this is not the -- Peach Bottom is not the only boiling water reactor that the Exelon Corporation owns and manages.

MR. HATCHETT: Dresden and Quad is coming in `03.

MEMBER ROSEN: How are they doing those?

MR. HATCHETT: PT, do you want to --

MR. KUO: I was going to direct to Fred because he's going to also be responsible for that application.

MR. POLASKI: This is Fred Polaski with Exelon. The Dresden and Quad Cities application in Chapter 2 will present the information again on a system basis. And we did realign components to get them in the right intended function, but part of the methodology will elaborate more fully on how we did that, and how the process was implemented. And in Table 2.2-1, which lists all the systems, where there are systems that are identified as not-in-scope, the components were realigned and will be identified in that table, that a component from System X was realigned in System Y. And the description on System Y will include information about what was realigned into that component.

In that application, you will not see the word
"realigned", but it will -- but essentially it's there, and it will discuss those components that are included in the scope of that system.

MEMBER ROSEN: Yeah, but I understand the Staff's comment and concern is that for systems that are not safety-related, but have components that would "be realigned", they can see what you realigned, but they can't see what you don't, because there's no information about those systems. Is that --

MR. HATCHETT: Yeah, that would be correct.

MEMBER ROSEN: That would be correct so, you know, it creates sort of an impenetrable wall for the Staff with regard to certain systems. And to me, it needs some thought to how you can help the Staff more for those systems, so they can assure us that they have -- that there's some completeness dimension to their review.

MR. POLASKI: I understand.

MR. HATCHETT: Again, the Staff held a public meeting on October 22nd, 2001 to provide Exelon an opportunity on the record to clarify the scoping and screening methodology, particularly as it related to system boundary realignment. The Staff expectations during that meeting were to understand how this process fulfilled the requirements of 10 CFR 54.4 in sufficient detail to complete the review of system scoping results and the methodology.

It was during this meeting that Exelon presented then the five cases that you see behind me, for the realignment and its rationale. However, Exelon did not explain how this translated into the results presented within the Peach Bottom application, and how they were going to clarify that all components requiring an aging management review had been captured.

As a result, the Staff issued a request for additional information on October 30, 2001, and Exelon provided its response on November 16th, 2001.

The RAIs were issued by the Staff as another attempt to flesh out how the results were obtained, and how they could be understood with respect to system boundary realignment.

Again, the Staff had several -- in addition to these meetings, Staff had several telephone conferences with the applicant to again try to understand. What came through very clearly is that the applicant did understand how they attempted to capture all structures and components requiring an aging management review. But as the Staff dealt with this issue in a generic sense, and we issued RAIs that were generic, we got a generic response back. So what ended up happening is the Staff during the scoping audit of December 4th through 7th, Exelon agreed with the Staff that the description contained in Chapter 2.1 of the license renewal application did not contain sufficient information for the NRC Staff to review the actual methodology and procedures used by the Exelon staff. This made it difficult to understand the results of SBR, or system boundary realignment.

Again looking back, Exelon provided the reasons for system boundary realignment, and Staff had already discussed this issue again generically on numerous occasions. As a result, the Staff issued more specific RAIs on January 23rd and March 12th, 2002. As a result, Staff concerns with the LR application, which included, you know, SBR, so those RAIs were not specific to system boundary realignment, but they were the RAIs for the application itself, which included our concerns with system boundary realignment.

The responses provided by the applicant provided additional clarity as a document of how the results were obtained. Again, the responses that we got back then gave us the link between the out-of-scope system, the function of that system, and why the system itself wasn't brought into the scope because it didn't meet the criteria, and then it provided additional tables to show how those components requiring aging management, if there were additional components that were inadvertently omitted in the original application were subsequently modified as a result of the RAI response. So having said that, that then allowed the Staff to complete a scoping evaluation, and making its finding in accordance with

10 CFR 54.4 and 54.21(a)(1).

As spoken to earlier, we had on Dave's early slide in the introduction, we had eight open items. Those open items involve ventilation systems, cranes, and of course the non-safety related SSC interacted with safety-related.

What I'd like to say about that in particular is that the RAI that the Staff sent out on March 12th, and the subsequent response on May 21st of 2002, and then the Staff actually visited the site during the AMR inspection to verify what had been provided to the Staff as part of the May 21st RAI response.

The RAI response, at that time, only gave conclusions. It did not provide details of the methodology itself, so during the site visit on July 10th of 2002, the Exelon representatives provided the methodology. It was broken down into two specific areas. There were fluid-containing systems and non-fluid containing systems, and so the method by which they did the evaluation on a desktop-type thing using the plant CRL database, and then subsequently looking at the plant drawings, and doing a plant walkdown to determine how those non-safety related systems would be included within the scope.

And I was present at that meeting, and I walked down the plant with Al Fulvio, and got an understanding of how they did that, and then verified that, in fact, those non-safety related systems that had special interactions with safety-related components were indeed brought into scope properly.

MEMBER BARTON: Before you move off of the mechanical, are you through with mechanical, the first Bulletin? I had a question, which crops up on several, if not all, the applications as the instrument ventilation systems, and it has to do with HEPA filter housings, fan housings, heating coils within fan housings, that whole subset of issues with ventilation systems keeps coming up. And it seems to me that it's an issue like, you know, II/I, if it's going to keep coming up, isn't there some way to kind of handle this on a generic issue?

DR. LEE: This is Sam Lee. I'm from the license renewal section. Yeah, the housing that you just talk about is actually the interim staff guidance we're trying to develop. We prepare a draft interim staff guidance we issue for comment, and now we're trying to finalize it.

MEMBER BARTON: Okay. I just think it -- you know, instead of fighting this battle at every application, we ought to be able to somehow solve this one across the board, because it keeps coming up.

MR. HATCHETT: Well, the staff guidance was how we, I guess ultimately decided to handle this issue, and it's still out for comment, the way I understand it.

MEMBER BARTON: All right. But you're trying to handle this more as a generic issue?

MR. HATCHETT: Right.

MEMBER BARTON: Thank you. That was my only point. It would help the review process, I think.

MR. HATCHETT: So the Staff has been involved with telephone conferences and fax transmissions back and forth on a preliminary basis to close these open items. And to date, with respect to mechanical systems and structures, we closed preliminarily all the open items, pending formal documentation of those. And as a result, the Staff believes that there's reasonable assurance that the applicant has identified all the Scs requiring an aging management review in accordance with 10 CFR 54.4 and 54.21(a)(1). It there aren't any more questions, I'll turn it back over to Dave Solorio.

MEMBER ROSEN: Well, yeah. I didn't hear

any discussion of those water-tight dike issues.

MR. HATCHETT: Well, we talked about that earlier with respect to the RAD waste system when Mr. Barton brought it up, and I gave the explanation as to the difference between them doing some reflecting on the UFSAR They're going to do a 50-59 evaluation and clear up the inconsistencies in the FSAR to deal with whether it's a 10 CFR 20 issue, or 10 CFR 100 issue. The reason why it was an open item was the Staff saw it as a 10 CFR 100 issue, based on the safety evaluation in Section 9 of the UFSAR. And the licensee dealt with that issue in terms of why it should be in-scope, using other parts of the USFAR and other design-basis documentation. They provided preliminary response to the Staff which the Staff finds to be acceptable, pending a formal submission to the Staff on the docket.

MEMBER ROSEN: Basically a dose argument. Right? That doesn't rise to a Part 100 level of doses.

MR. HATCHETT: No.

MEMBER ROSEN: Is that what I --

MR. HATCHETT: No, it does not.

MEMBER ROSEN: And that's the substance of their argument.

MR. HATCHETT: Yes.

MEMBER ROSEN: Has the Staff reviewed the calculations? Comfortable with that, worst case? It's a Part 20, but it's not a Part 100.

MR. SOLORIO: The response doesn't contain calculations. The response just references design documentation that provides those results.

MR. HATCHETT: Yeah. And that's in the existing SER.

MR. SOLORIO: Yes, sir. And I think the response also points to other design-basis documentation at the plant. And when the open item is closed, the SER will reflect all that information so that you could see it. If you wanted it, we could provide it to your preliminarily also before then.

MEMBER ROSEN: Well, I'm just trying to understand the process to resolve the one remaining structural open item. Okay.

MEMBER BONACA: If it leaks, we just give everybody a little bit of dose. That's all.

MEMBER ROSEN: What's that?

MEMBER BONACA: The leaks would just five everybody a little dose. We don't exceed 100.

MEMBER ROSEN: Right.

MR. SOLORIO: Well, that concludes the

scoping and screening results. Now we're ready to start aging management review part of the presentations. I'm going to thank Greg and Bob for speaking, and ask Meena and Stew to come on up.

MR. BAILEY: Good morning. My name is Stewart Bailey. I guess it's still morning for a little while here. I'm here to discuss the review of the aging management programs. The aging management program review is found in Section 3 of the SER, but aging management programs are found in Appendix B of the LRA.

To review the aging management programs, the Staff relied on the guidance in the standard review plan for license renewal, NUREG 1800 The Staff focus was on the ten attributes of each AMP. These ten attributes are as described in the standard review plan. I won't list them all here. Three of the ten attributes, the corrective actions, confirmatory process and administrative controls were really covered separately from the Division of Engineering Review, and those are reviewed as the administrative controls for the plant, and that review appears in Section 304 of the SER.

The Staff review was really to make sure that the aging management programs presented would provide reasonable assurance that the aging effects would be adequately managed during the period of extended operation, and we had contractors assist us in the review of some of those aging management programs.

Next slide, please. Now in terms of the aging management programs, in the LRA, the applicant had 17 existing programs. These are programs where the applicant decided that their existing plant practices were sufficient to adequately manage aging. One of those programs was deleted during the course of the review, and we'll get to that one later. They had 12 enhanced programs where they determined that some sort of enhancement was needed to their current plant practices. I think as we discussed with the pole, in certain cases that was more of an administrative enhancement, and then there were four new programs. There were two new programs in the LRA, and two programs were added later as a result of staff positioning during the Staff's review.

To clarify the last bullet there, of the two AMPs that were added, one of those was a one-time inspection, and one one-time inspection was included in the LRA. The review was conducted by a number of different branches in the Division of Engineering, and

I will now go into ones that were reviewed by the Mechanical and Civil Engineering Branch.

As you can see, these are the existing programs that were reviewed by the Mechanical and Civil Engineering Branch. Do you want to go to the next slide?

MEMBER SIEBER: Before you leave that area, you rely on the five-year inspection by, I believe it's FERC or the Army Corps of Engineers?

MR. BAILEY: We did rely on FERC for the Conowingo inspections.

MEMBER SIEBER: Did you review the inspection requirements?

MR. BAILEY: Well, what I did in looking at --

MEMBER SIEBER: Or did you just say it's okay with me?

MR. BAILEY: Well, it is the Staff position that we accept the FERC's expertise for the dams that are licensed by FERC. But I did look into that. I did look into their operating manual. It's generally consistent with Reg Guide 1.127. The inspection reports are no longer public documents since 9/11, but I did contact FERC. This particular dam is inspected by a team of consultants every year, as opposed to every five years, and that's because it is one of the first dams that had a certain construction technique, that I won't get into right now. And they have no concerns over the dam at this time, based on their most recent inspection.

MEMBER SIEBER: Okay. I guess I asked the question because you want some certainty that the dam will function, and you trust your fellow agencies or have the --

MR. BAILEY: Well, in fact, when the NRC does dam inspections, we typically contract out to FERC to do those
inspections, so I think we have quite a bit of reliance on FERC for their expertise in this area.

MEMBER SIEBER: That's true. I keep looking at dam
inspection reports over the years that say, you know, this dam is in bad shape, but maybe it'll last another year, and that makes me uncomfortable.

MR. BAILEY: Well, the couple that I've looked at, which were Catawba, McGuire and this one, I did not get that impression.

MEMBER SIEBER: Okay.

CHAIRMAN LEITCH:: Concerning the ISI of certain safety-related systems, there's an open item.

It's 3.0.3.6.2-1, and it says that the applicant should perform inspections either via the ISI program, or one -time inspections to verify the effectiveness of the chemistry control program. Has that open item been resolved?

MR. BAILEY: I believe that Meena is going to talk about that.

MS. KHANNA: I'll address that actually if you want to wait, but yes, actually it has. They have decided to include it in their ISI program.

CHAIRMAN LEITCH:: The ISI.

MS. KHANNA: Such activity will be addressed through their ISI program, but I'll cover that in a few minutes.

CHAIRMAN LEITCH:: Okay. Good. Thank you.

MR. BAILEY: We might have been going back and forth on a few semantics there. They had -- in the chemistry program they had stated that their ISI program demonstrates that the chemistry program is functioning, and yet in the ISI program, they said we don't credit the ISI for verifying the chemistry program, so we needed to get straightened up in the paper trail whether the ISI is credited as a back-up, or if something else is credited as a back-up for the chemistry program, so I don't know that this is as much a technical issue as a dotting Is issue.

CHAIRMAN LEITCH:: Okay. Thanks.

MR. BAILEY: On the enhanced programs, you could see these are the ones that EMEB was responsible for. And I think as we discussed earlier on the Susquehanna Station Wood Pole, the enhancement was more administrative. Under the new programs, the EMEB was only responsible for the torus piping inspection activities. That is a one-time inspection activity that is a back-up to the chemistry programs for the torus. Again, we discussed that earlier also.

MEMBER BARTON: Before you leave that slide, on the emergency diesel generator inspection activities.

MR. BAILEY: Yes.

MEMBER BARTON: In the table under the component -- for diesel generator under component group of vessel, they talk about the fuel oil storage tank.

MR. BAILEY: Okay.

MEMBER BARTON: It's a buried carbon steel tank. The only aging management activity proposed in the table is chemistry control. Now my question is, you know, 60 years, carbon steel buried tank, and you don't even do a one-time inspection before extended operation? And you're just relying on sampling of the fuel oil? You don't do a volumetric once in sixty years on a buried carbon steel tank? I have a problem with that.

MR. BAILEY: Okay. Can I -- let me let the reviewer answer that. That's getting a little beyond my level.

MEMBER SIEBER: It seems to me all these buried tanks are EPA limits as to how much they can leak and where they go. And that may be the overriding authority on it.

MEMBER BARTON: It may be but, you know, if you worry about either water getting into the tank or diesel -- thousands of gallons of diesel oil getting into the --

MEMBER SIEBER: You know that the water gets in there and goes to the bottom of th tank, which is where the corrosion occurs.

MEMBER BARTON: Yeah. Right.

MEMBER SIEBER: And so the bottom is perpetually covered with water in a diesel tank.

MEMBER BARTON: Yeah. That's no problem for 60 years?

MEMBER SIEBER: I never liked it.

MEMBER BARTON: I don't like it either. Okay. Let's listen to the real answer.

MR. RAJAN: Jai Rajan, Mechanical Engineering Branch. There was an inspection of this tank during the `95/96 time frame, and the lowest level of the tank where sediments and sand, et cetera, and water would be expected to collect. And that location was determined through UT examinations and it was found to be .375 inches, which is the original thickness of the tank. And this was after many years of usage, and so we do have a data point that the tank is in good shape, and on that basis the Staff accepted the licensee's evaluations.

MEMBER BARTON: Go ahead. I don't have to like it, but you know.

MEMBER SIEBER: Well, they're actually using mitigating circumstance. If you take a layer of water and then put, you know, 10 or 15 feet of fuel oil on top it, effectively what you've done is eliminated oxygen from that interface, and so corrosion really --

MEMBER BARTON: Is minimal.

MEMBER SIEBER: -- is not likely to occur.

MEMBER BARTON: But I also worry about stuff coming from the outside. You look at the thickness of the tank from anything that's attacking the tank from underneath.

MEMBER SIEBER: Well, underneath the tank is a different ball game. It's the same as --

MEMBER BARTON: As a CST.

MEMBER SIEBER: -- a refueling --

MEMBER BARTON: Refueling water tank. That's right.

MEMBER SIEBER: All those tanks are --

MEMBER BARTON: Because they've got such good soil up there, I guess we don't worry about it.

MR. BAILEY: Well, you're talking about the fuel oil storage tanks. There are tech spec requirements to do the periodic drain-down of the water and whatnot of the tanks, and to do the periodic testing with the quality of the oil for its aging.

MEMBER BARTON: No, I understand that.

MR. BAILEY: Okay. I think our applicants would like to add --

MEMBER BARTON: And there's some experience with this. If you remember the Hatch application, they had a fuel oil, a diesel fuel oil storage tank buried that leaked, you know, so that's why I raised the question. You guys don't want --

MR. FULVIO: This is Al Fulvio from

Exelon. We do have tech spec requirements for -- monthly we check the tank bottom for water accumulation. Okay? And we also have a requirement for a ten year inspection of each of the tanks, so every ten years we empty the tank, we go in, do an inspection. And the data the gentleman was referring to earlier, that was a result of one of those ten-year inspections.

MEMBER BARTON: Okay. I'm satisfied then. Thank you.

MR. FULVIO: They're tech spec requirements. They were always there.

MEMBER BARTON: Okay. Thank you.

CHAIRMAN LEITCH:: I had a question on the previous slide about crane inspection activities. It seems as though some of the rationale for saying the cranes are okay is that many of the loads that are lifted are well below the design capacity of the crane, and I guess my question is, aren't some of the aging activities associated with just the cycles of the crane, rather than the load applied?

MR. SOLORIO: Yes. That's a time limited aging analysis that the Staff identified, that we were going to present briefly later on today.

CHAIRMAN LEITCH:: Okay.

MR. SOLORIO: Section 4.1 of the SER, we talk about ---we asked an RAI about crane load cycles, and whether or not it was TLAA and the applicant agreed. It's now ---

CHAIRMAN LEITCH:: So you'll get into that later.

MR. SOLORIO: Yes.

CHAIRMAN LEITCH:: Okay. Thanks.

MEMBER BARTON: Also, I don't see a request on aging management. In the same area of the LRA, they talk about the main condenser itself, and I can understand the logic on the main condenser. But my issue here is, there's no discussion on the internals of the condenser like baffle plates and things like this where during transients you get, you know, stresses on certain internal components of the condenser, and I don't see that addressed any place. The condenser is just written off as, the way it's built, it's built like any other condenser in the country, and so there's no problem. Nothing addresses internal parts of the condenser.

MEMBER SIEBER: Yeah. What it should say is it has the same problems as every other condenser.

MEMBER BARTON: But it doesn't. It just says, you know, it kind of -- it's like every other condenser so there's no aging program required here.

DR. LEE: George Georgiev from the Materials and Chemical Engineering Branch will address the issue.

MR. GEORGIEV: I was the reviewer for steam and power conversion systems where the main condenser is actually addressed. And the reason the Staff accepted the applicant's arguments that the main condenser doesn't need any problems, and as such, no aging effects were identified, is because the main condenser was pulled into the license renewal because it served two post-accident functions. And other than that, that is really non-safety related item. It's very important but, you know, that's the reason why we went along with the licensee evaluation.

MR. SOLORIO: Can I also add, George, that it's consistent with our GALL aging management review results, so we're using your guidance here, which provides higher operating experience reviews.

MR. GEORGIEV: For the same reason we didn't include it into the GALL report, and on the Hatch application they also had for the Unit 2 listed main condenser for the same post-accident sample, so we have been consistent in our review in this area.

DR. LEE: This is Sam Lee. I don't think the GALL report include the condenser.

MR. BAILEY: All right. Next slide. On the open items where there is -- the safety evaluation report has an open item on the maintenance rule structural monitoring program for detection of aging effects and acceptance criteria for structures and components that were brought into scope. The next bullet says it's resolved, which I means I think we can close that. We are going to get into this in a little bit more detail when we cover structures, so we'll get to that this afternoon.

On the fire protection activities, the open item was related to the aging management of a diesel-driven fire pump fuel oil flexible hose. This one I believe we can also resolve once we see final documentation from the applicant. The applicant had proposed to inspect this hose every five years. That is the frequency where they do major maintenance on that diesel generator.

Staff was questioning whether that was adequate aging management. The applicant decided to credit an annual inspection of this hose, which they do anyway under, I believe it is vendor-recommended maintenance on this diesel, so inspecting that hose on an annual basis, that satisfies the Staff on that.

Next slide, please. Confirmatory items. Again, there's a confirmatory item related to items brought into scope on the maintenance rule structural monitoring program. We will discuss that later. On the HPCI and RCIC inspection activities, the confirmatory item again relates to a flexible hose. The applicant had identified that there was a flexible hose for the HPCI lube oil system. For this, they had recommended an eight-year inspection, which was consistent with when they did a tear-down of the turbines. Again, when the Staff was questioning that, the applicant went back and discovered that there is no flexible hose for fuel oil. This had been one of the pieces of information that was erroneously transcribed into their LRA. That's actually a stainless steel hose for a gland-sealed lead-off with no identified effects, so we're just waiting for that RAI response there.

Other items of interest were the door inspection activities program. They did bring -- as a result of Staff's questioning, they did bring into scope internal doors. In their RAI response, they had stated that the range of humidity and temperature is such that you could have sufficient corrosion of these doors. Brought those into scope.

MEMBER ROSEN: Is this all doors, or just fire protection credited doors?

MR. BAILEY: These are more of the hazard barrier doors, the flood protection doors. I believe these are not the doors --there may be some overlap, but I don't believe that these are all the doors that are credited for fire protection alone.

MEMBER ROSEN: I guess I don't understand which doors they are.

MR. BAILEY: I'd have to get back to you with more detail on exactly which ones they are. My recollection is that these are the flood barrier doors, internal flood barrier doors. Is that correct?

MR. ONNOU: Ahmed Onnou again, with Exelon. In addition to flood barrier doors, we have some doors that are credited for vents, venting as a result of a steam break. We do have some fire doors, and originally this addresses the doors in a sheltered environment. Our original application stated if it's in sheltered environment inside the building, the humidity is such that you're not going to get significant corrosion on the door metal. Staff disagreed with this, and we decided to bring them in scope. But in general, the fire doors are included in fire protection activities, and those are inspected whether they're inside or outside, they're inspected as part of the fire protection activities. But the doors, to answer your question, is flood. There are some outdoor doors basically for secondary containment, such that you don't leak fissional products to the environment. And then there are some doors that we use credit for venting.

MEMBER ROSEN: And all fire doors. Is that what I take from your response?

MR. ONNOU: All fire doors, all of them are inspected.

MR. BAILEY: But under the fire protection program.

MEMBER ROSEN: But that's a program that's credit for aging management.

MR. BAILEY: Yes. The other item of interest would be for the fire protection activities program that the applicant has adopted for volumetric examination of the stagnant piping for wall thicknesses, and this is in accordance with our Interim Staff Guide number 4.

MR. KUO: Meena, just hold on a minute. Stew, is this a good time for you to discuss your RAIs about the containment inspection program in response to Dr. Rosen's question?

MR. BAILEY: Well, we could do that now. That would probably be best left until we discuss some structures.

MR. KUO: Okay.

MS. KHANNA: Okay. My name is Meena Khanna. I'm the Materials and Chemical Engineering Branch Technical Lead for aging management programs. I'll be discussing the remaining aging management programs that the Materials and Chemical Engineering Branch were responsible for.

As Stew had indicated, they were grouped into existing, enhanced and one-time inspections. You can see that these are the existing programs, many of which include chemistry programs. I won't go through the list, but you can look at those. Then there's a list of enhanced programs, and then there's a new program, which is a one-time piping inspection activities program.

Just to make a note, you'll notice in the original LRA, there was a stand-by liquid control system surveillance program, and that was deleted based on questions that the Staff had in regards to demin water and piping inspections that weren't addressed in their original SLC system surveillance program activities. They decided to do similar to what Hatch did, and got rid of the SLC system surveillance program, and included the one-time piping inspections program, and also added the demin water chemistry to the condensate storage tank chemistry activities.

MEMBER ROSEN: We had a discussion the last time, we looked at submerged structures that are subject to attack at the embedded rebar concrete, and the Staff's position was as long as the PH stayed within a given range or a below a certain range, that that was acceptable. Have we got a comparable discussion on this application?

MR. SOLORIO: Later on in the Staff's presentation we will be actually presenting the results of the structures, and we talk about the corrosive -- the soil sampling they've done in this non-corrosive environment, so that's part of your answer. I guess if you -- another part of your question is about just buried piping in general?

MEMBER ROSEN: This question is about buried structures.

MR. SOLORIO: Okay. It's definitely covered later on in a couple of more presentations in 3.5. And if you don't mind, we'll --

MEMBER ROSEN: No.

MS. KHANNA: Okay. I'll discuss the open items and the confirmatory items. We briefly discussed the open item in regards to the verification of the chemistry programs, the verification of the effectiveness of the chemistry programs. Basically as Stew stated, it's more of a semantics. They have definitely got inspection through their ISI program where they're using to verify the effectiveness of the chemistry program. It's basically a linkage problem, but we have conference calls scheduled, and we'll address that. But those are concerns for the reactor coolant system chemistry activities, the condensate storage tank, and the torus water and fuel pool chemistry activities that we wanted to make sure that they do have an inspection activity to verify the effectiveness of the chemistry programs.

MEMBER BONACA: And they do?

MS. KHANNA: They do. In the ISI -- it's hard to explain. In the ISI program, they don't take credit for these activities, so that's the linkage that we're waiting for. But they do have -- in their

RAI response, they indicated that they do have routine inspections for each of these chemistry activities, so it's more like a linkage thing that needs to be taken care of.

MEMBER BONACA: Because it seems to me there is an issue --I mean, the chemistry program is the aging management program.

MS. KHANNA: Right. Exactly.

MEMBER BONACA: But then the inspections are something else. I mean, you're inspecting to see whether or not it's working, so you want to see if there is material loss.

MS. KHANNA: Right.

MEMBER BONACA: Okay. And so you have them where? I mean, I didn't find them --

MS. KHANNA: In the ISI program, what they're doing --actually, we had an open item. I'm sorry, we had several requests for additional information where we asked them, you know, verify the effectiveness of these chemistry programs, do an inspection activity or one-time inspection. They came back and they said that they do routine inspections, and they also did say that they're using their ISI, that these inspections are done through their ISI program. But when you go into the application and you read on the ISI program, they're not taking credit for these. They don't actually indicate.

MEMBER BONACA: That's right.

MS. KHANNA: So that's what we're looking for, is for them to go ahead and, you know, take credit for these through their ISI program.

MEMBER BONACA: So they do it, but it's not described in the program.

MS. KHANNA: Exactly.

MR. BAILEY: Right. They did it, but the program said that we don't credit it. We need something credited to back-up chemistry, so we're dotting that I.

MS. KHANNA: That's the issue that we're dealing with right now.

MEMBER BONACA: So it's not clear to me, so the current ISI program already includes these initiatives. It just simply is not documented in the programs?

MS. KHANNA: Right.

MEMBER BONACA: So we don't need a one-time inspection. I mean, this is going to be done periodically.

MS. KHANNA: Right.

MEMBER BONACA: All right.

MS. KHANNA: And that's Staff's position that's okay for them to do. Okay?

MEMBER SHACK: I mean, they're a sort of noble hydrogen water chemistry plant.

MS. KHANNA: Right.

MEMBER SHACK: You haven't got a generic approval for that. How do you handle crediting that in this particular case? I mean, that's their water chemistry coolant. Right?

MR. POLASKI: This is Fred Polaski from Exelon. For licensure purposes, we did not credit hydrogen water chemistry or noble chemistry.

MR. ELLIOT: Wait a minute. This is Barry Elliot. We're going to talk about when I get up there, about water chemistry, and we're going to talk a little bit more about the BWRVIP program, which there is an impact on when you inspect depending on your chemistry. We'll get to that soon.

MS. KHANNA: Thank you, Barry. I'll go on. There are four confirmatory action items that we have. These were actually based on questions that the Staff had of the applicant during discussions, and they provided answers through those conference calls so, you know, we need them to be docketed. So one had to do with the acceptance criterion parameters for the closed cooling water chemistry activities. Basically, we just asked them what are the parameters for the fluorides and chlorides, and they indicated that's less than 10 ppm. They'll document that for us.

For the outdoor buried and submerged component inspection activities, we asked in regards to the frequency of inspections for the ECW pumps. They indicated that they do that every ten years. And for the refueling, RWST pumps they indicated that they'll be doing those inspections every four years.

For the heat exchanger inspection activities, there was also a question in regards to acceptance criteria. We asked how many of the heat exchangers will be inspected, visually inspected. They indicated that they do all 100 percent of heat exchangers to be visually inspected.

And finally, the last one had to do with the one-time piping inspection activity. The Staff had a concern in regards to when they were going to be actually doing the one-time inspection, and they indicated that they'll be doing it between years 30 and 40 before end-of-life, and those were all found to be satisfactory.

Item of interest, as I indicated before, the standby liquid control system surveillance activities, what they were doing was they were crediting leakage monitoring. They were trying to detect aging effects through leakage monitoring. The Staff had a problem with that. We didn't think that that would address any piping concerns, or we had a concern with the demin water chemistry not being addressed, as well. So as I stated, they deleted that program, came up with the one-time piping inspection activities, and added demin water chemistry to the condensate storage tank chemistry activities to address demin water.

And the last comment is just that one-time piping inspection activities was added to verify the integrity of piping, and to confirm absence of identified aging effects. Are there any questions?

MEMBER SHACK: Now what one-time piping inspection activity are you talking about?

MS. KHANNA: This has to do with standby liquid control. Right. System piping.

(Whereupon, the proceedings went off the record at 12:23 p.m. and resumed at 1:24 p.m.)

CHAIRMAN LEITCH:: Okay, let's come back in session, please. And David I guess it's over to you to begin talking about these various section, 3.1 and following.

MR. SOLORIO: The first slide here, everybody, is on Page 30. The following presentations are going to present the results of the staff's review of aging management activities for Sections 3.1 through 3.6.

I've included this slide to emphasize the format of the majority of the remaining presentations today. While I was tempted to use an equation, I knew I'd get in trouble if I did, so I avoided that.

MEMBER ROSEN: We'd ask you about uncertainty.

MR. SOLORIO: I conducting the review, the staff focused on reviewing the materials, the environments, aging effects, to verify that all the applicable aging effects were identified in the aging management programs credited for these aging effects could adequately manage them.

Once this was determined, the staff could reach a reasonable assurance finding that the intended functions would be maintained consistent with a CLB for the renewal period. In some cases, because there are open items, the staff has qualified the findings.

And we'll be talking about the open items, so I will turn it over now to Mr. Barry Elliot, who will present the results of Section 3.1 and some additional information on BWRVIPs you've asked for.

MR. ELLIOT: Okay, my name is Barry Elliot, I'm with the Materials and Chemical Engineering Branch. The reactor coolant system for this application consists of the reactor pressure vessel, the reactor vessel internals, the RPV instrumentation system and the reactor recirculating system.

The environment is the BWR reactor water environment. It's materials are low alloy steel, stainless steel and nickel-based alloys. The pressure is about 1,055 PSI, and operates in temperatures between 70 and 533.

The Applicant identified the following aging effects, cracking to stress corrosion and cracking and cyclic loading. Cumulative fatigue, loss of fracture toughness from neutron embrittlement and thermal embrittlement.

The Applicant has identified all the aging except for the bolting and the piping, which I'll get into shortly. The applicable aging programs for these aging effects. The first program is the reactor coolant system chemistry program.

In this program the water chemistry is optimized so that the aging effects of loss of material and cracking are minimized. It's controlled while the reactor water chemistry is through the BWR water chemistry guidelines.

And the program relies on monitoring and control of various contaminants below specific pre-established limits. Next slide.

The next program is the in-service inspection program. And this is basically --

MEMBER WALLIS: Are you going to talk about the noble chem part of this?

MR. ELLIOT: Well, I'm not going to talk about noble, but I will talk about hydrogen water chemistry. I won't talk about noble now, but if you have a question on noble metal --

MEMBER WALLIS: Well, it's a relatively new thing, I'm not sure we know how to manage its aging because we don't know enough about it yet.

MR. ELLIOT: Well, I'll get to that.

MEMBER WALLIS: Okay.

MR. ELLIOT: I won't get to noble metal, but I'll get to that. Okay. I think. In-service inspection program is an ASME code in-service inspection program. The pressure vessel, reactor pressure vessels and internal ISI program is basically a program which augments the in-service inspection program.

And chiefly it's supplemented by the BWRVIP program. I'm going to talk about that shortly, in a little more detail. The reactor vessel materials surveillance program, the Applicant plans to implement the integrated surveillance program. I'll give a little more detail on that.

And then the fatigue management activities will be discussed as part of the TLAA, Section 4.3. At the time we put this slide together we had one open item. And the open item had to deal with bolting and instrumentation, piping.

We were in discussions with the Applicant about how, what are the applicable aging effects and what should be appropriate programs. As far as the bolting is concerned, the staff believes that loss of preload, loss of material corrosion, cracking, are applicable aging effects for bolting.

And the Applicant has credited the ISI program for managing these effects. And this is consistent with what we've done in the past for bolting for other plants. The other issue has to do with the instrumentation. Carbon steel piping, concerned about loss of material as a result of galvanic corrosion between the austenitic and the carbon steel.

And the Applicant credits the reactor water chemistry program for managing this aging effect. We were concerned that, we were concerned that there was no inspection here. So we requested they do an inspection.

And they've committed to do a, part of the one-time inspection to look for loss of materials for this piping. And that is also consistent with what we've done in the past.

MEMBER BARTON: What instrument of piping are we talking about here?

MR. ELLIOT: It's carbon, I don't know what particular pipe it is, but there's a carbon steel piping in the reactor coolant instrumentation piping line.

MEMBER BARTON: What's its function, do we know?

MR. ELLIOT: I assume it's push boundary function for instrumentation piping.

MEMBER ROSEN: So when you approve their, are they going to come in with a program and say we're going to do a sample of 21 locations, here, here, here and here, and you know, some kind of statistically significant number of places. Rather than just open up one place and say it looks fine here, close it up and go on.

I mean we're talking about local effects here.

MR. ELLIOT: I'm only concerned about local effects.

MEMBER ROSEN: So you have to look at a lot of places.

MR. ELLIOT: Well, not really. I don't think so. Galvanic effect falls off the further you get away from the interface between the carbon and stainless steel. So if they concentrate their inspections near the interface, they should be okay. Near the interfaces, that should be satisfactory.

CHAIRMAN LEITCH:: But wasn't your question, Steve, with many, with several interfaces. I mean I think you interpreted the question as further down the pipe, so to speak. But I think that Steve --

MR. ELLIOT: I'm talking the interface between the austenitic and the carbon steel. The further you get away from that interface --

MEMBER ROSEN: On any given line.

CHAIRMAN LEITCH:: On any given line. But I think --

MR. ELLIOT: Exactly. Again, they have to take a representative number of lines where there are interfaces. I thought you meant throughout the carbon system.

MEMBER ROSEN: No, no, no. It's got lots of pipes like this, instrument pipes, maybe both ends hook up to austenitic stainless steel. So you need to look, find out how many. If you have 20 lines like that, you need to look at, that's 40 locations. Maybe you need to look at a statistically significant number of the 40 lines.

MR. ELLIOT: Okay, thank you. We're going to look into that.

MEMBER ROSEN: Okay, the point is they just don't open up one connection and say, see, it's okay, close it back up and go on. You need to have a scientific approach.

MR. ELLIOT: I assume they're planning to do a volumetric examination. So they can look at multiple locations.

MEMBER ROSEN: However they do it, they have to prove to you, that's in a statistically significant way, that it's okay.

MR. ELLIOT: Okay, thank you.

MR. POLASKI: This is Fred Polaski from Exelon. Just to clarify, there's only one location that we've addressed, that needs to be addressed.

MR. ELLIOT: Oh.

MR. POLASKI: It's on the bottom head drain line. So there's only one.

MR. ELLIOT: Is it the bottom head drain pipe we're talking about?

MR. POLASKI: Yeah.

MR. ELLIOT: Oh, okay.

MEMBER ROSEN: Well, then they can look at all, complete, they can take a statistically significant look by looking at all of it.

(Laughter.)

MR. ELLIOT: Okay, that's all I have on that part. I'm going to talk about the BWRVIP programs and hopefully answer your question about noble metal. The first one is the BWRVIP-75.

And this forms the technical basis for the revision to Generic Letter 88-01, inspection schedule. Let me give you a little background on 88-01. Generic Letter 88-01, is the staff's position for inspection for piping that are, have had intergranular stress corrosion cracking.

One of the issues that are hot the last couple of years was the summer issue. That was the first instance of, in a PWR, an intergranular stress corrosion cracking occurred.

However, the BWRs, in the '70s and '80s, this occurred all the time. This occurred quite often. And this is the program, 88-01, was the program the staff initiated to correct this situation.

The piping that is involved here is four inches in large enamel pipe diameter and it's any, any piping that is over 200 degrees Fahrenheit. And the material is either austenitic stainless steel, alloy 182 weld metal and alloy 600 base metal.

The Generic Letter 88-01, defines, original Generic Letter 88-01, defines a whole bunch of categories. And it was dependent upon whether a material was resistant and whether the piping had been given mitigation treatment like stress improvement or something.

Since that, since that Generic Letter was issued, many plants have implemented hydrogen water chemistry. As a result of that, we've had experience with hydrogen water chemistry. That has been the main thrust of the revision here, is to change the frequency of the inspections.

And a lot of that has to do with the hydrogen water chemistry. Robin Dyle is here, from BWRVIP. Do you want to add anything to that, noble metal to this?

MR. DYLE: I guess, and this is Robin Dyle from Southern Nuclear. What I would say about noble metal is VIP-75 accounts for inspection schedules based on normal water chemistry and improved water chemistry.

Which would be hydrogen water chemistry or noble metal. The staff is reviewing the basis for what we use to determine the effectiveness based on ECP and things of that nature. So there are schedules in this document that would allow use of normal water chemistry or the other.

And I think the position, I know the position we had on Hatch was for license renewal. We didn't commit to noble metal or HWC for the additional 20 years of service, because we didn't want to make a commitment until we knew how this would play out.

We started implementing this process, it was effective in mitigating cracking, but we didn't fully understand what it would do to fuel and other things. So it was a commitment for license renewal, it's something we're actively using.

We've got multiple programs, fuel inspections and other tests underway to assess the long term effects of it. So that's the generic position from the fleet. And I believe Peach Bottom's position is the same as Hatch's.

That, you know, they're going to use whatever they can to manage to cracking, but they don't want to make a commitment to the additional 20 years for noble metal.

MR. POLASKI: Yeah, that's correct. For Exelon, we do operate with hydrogen water chemistry and we have implemented noble metals on both Peach Bottom 2 and 3. But we did not credited it or going to commit to it in a license renewal application.

We're going to credit our water chemistry and our ISI program.

CHAIRMAN LEITCH:: Was there not a --

MEMBER SHACK: So it would be a separate licensing action to come in then for a reduced inspection schedule, for example.

MR. ELLIOT: Excuse me, the inspection schedule is built into the VIP-75.

MEMBER SHACK: Okay.

MR. ELLIOT: If you implement the hydrogen water chemistry, you have a certain frequency. If you don't implement the hydrogen water inspection, you have a different, more frequent. That's the basic concept between the Generic Letter 88-01, and the

VIP-75.

MR. POLASKI: And what we did for license renewal is we've credited the VIP programs and we've committed to implement the VIP programs.

MR. ELLIOT: And it's up to the individual licensee to implement whatever part of that program that he wants. But we approve the generic program.

CHAIRMAN LEITCH:: So the VIP-75 is no, doesn't indicate noble metals then. It's silent on noble metals.

MR. ELLIOT: I believe so. Let Robin answer that.

MR. DYLE: This is Robin Dyle again from Southern Nuclear. What it allows for is normal water chemistry and improved water chemistry and effective hydrogen water chemistry. And you can achieve effective hydrogen water chemistry one of two ways.

Inject sufficient hydrogen that you have the protection that you need or through the use of noble metals it would allow a much lower induction rate of hydrogen which is beneficial for dose and other things.

So, either way, as long as you get the protection that is necessary by reducing the ECP and lowering the conductivity and keeping everything where we want it, to turn off the crank and, or slow it down significantly, that's what we call improved water chemistry or effective water chemistry.

CHAIRMAN LEITCH:: Okay, thanks. Now it seems to me that Peach Bottom has, in a number of places, installed less susceptible materials. Does the VIP-75 also give credit for that.

MR. ELLIOT: That's part of the original Generic Letter 88-01. You get inspection program based upon the materials and that type of thing. Inspection frequency and sample size is dependent on the materials susceptibility to IGSCC.

That's the material part. Mitigation measures and inspection history and performance of welds. The topical report has no open items. The next issue, the next report was the BWR shroud support and inspection flaw evaluation guidelines, it's VIP-38.

The scope and the aging effects are cracking of the shroud supports. And this is the structure below the core shroud to the reactor pressure vessel inside surface. The materials are alloy 600 base metal, alloy 182 and 82 weld metal and type 304 stainless steel for BWR/2s.

The guidelines provide a basis for

inspection and reinspection and also for evaluating structural integrity. Topical report has one open item, and that is a schedule for implementing inspection for the lower plenum. Currently there is no, well currently there is no tooling available.

They are developing the tooling, and when the tooling becomes available this item will be closed. The next one is the BWRVIP-76, which is a core shroud inspection and flow evaluation guideline.

This is a comprehensive report combining guidelines on VIP-01, VIP-07, BWRVIP-63. VIP-01 is for inspection of the circumferential welds. VIP-07 is for reinspection of the circumferential welds. And VIP-63 is inspection of the vertical welds. 01 and 07 are complete.

The open item is with VIP-63. We expect to finish this item before the supplement for Peach Bottom. And if we do we'll include a discussion on it in the supplement.

CHAIRMAN LEITCH:: So when that is approved, do you expect it to be approved for a 60 year basis?

MR. ELLIOT: Yes, I would think we would be talking about tooling and frequency that could be carried forward for, you know, 60 years easily.

MEMBER BONACA: I had a question on the frequency thing about the shroud. You mentioned the topical report open items scheduled for implementing inspection for lower plenum. The tooling is being developed to perform the inspection.

MR. ELLIOT: Excuse me?

MEMBER BONACA: The tooling is being developed, you said?

MR. ELLIOT: Yes.

MEMBER BONACA: And what's being done in the meantime, I mean if this comes in ten years from now?

MR. ELLIOT: The BWRVIP could tell you what they're doing in the meantime.

MEMBER BONACA: Okay.

MR. DYLE: This is Robin Dyle again. Let me clarify. The open item discussed a concern about being able to inspect in the lower plenum. And it was related to cracking that had occurred at a foreign plant. And that was cracking that had occurred on the bottom side of the shroud support.

There is a separate VIP document which addresses inspections in the lower plenum region itself, as far as the stud tube, CRD housings and things of that nature. So we want to keep those two subjects separated.

What the VIP has gone off and done, is we've done the fracture mechanics analysis, we've done some destructive analysis, based on a unit that was never constructed. Some of that is being reviewed now by the staff.

We've also developed a change to VIP-38, which we believe will address this. The current inspection criteria allowed a visual inspection of one side of the welds. What we're changing the document to require is that you either must do a visual from both sides of the weld.

Which would mean going to the lower plenum and look at the bottom part of the core support structure. Or, do an ultrasonic examination, possibly from the outside of the reactor vessel, where you shoot through the vessel.

You can look at H-8 and H-9, which are the two welds of concern, and see if there's any cracking there. So we're going to leave that option up to the owner, based on the configuration of the vessel, the internals, the age of the plant, because some have better access from the ID and some have better access from the OD.

But that report is been submitted to the staff just recently and it's here for there review. So we believe that will resolve that issue.

MEMBER BONACA: Okay, thank you.

MR. ELLIOT: The next slide deals with the BWR integrated surveillance program. And this is a program to look at the effect of a radiation for a BWR reactor pressure vessels.

The BWRVIP-78 and 86, provide the technical basis an implementation plan for 40 years. The program is being re-evaluated and will be revised by 60 years. We expect to complete this review of the 60 year program in 2003.

We don't expect to finish it in time for the supplement. Therefore, this will probably be, this will be a license condition included to implement either the integrated surveillance program or plan specific program prior to entering the license renewal period.

This morning we talked about one other issue which was the top guide. That was BWRVIP-26. I'm not going to talk about it now. I'm going to talk about it as part of the TLAA later on.

CHAIRMAN LEITCH:: I had a question on the SER on Page 1-7. I don't see a listing there of BWRVIP-78 or 86.

MEMBER SHACK: That list there is representative of what the Applicant, I think, initially told us in the LRA. And in the staff's review, I guess, through RAI process, we've come to learn that they may rely on these reports. So we actually discuss them.

MR. ELLIOT: We subtract, I think, I think Page 83, in Section 3 has a listing of all of the VIP reports that they take credit for. I think 86 and 78. Or in that, and also the accession numbers on the safety evaluation.

CHAIRMAN LEITCH:: Yeah, it is referred to there, but on this particular listing it is not. So I was just wondering if it was just inadvertently omitted or there was some significance to that? This is the SER.

MR. SOLORIO: No, no, I'm looking to see if, I mean what we did there in Chapter 1 was copy what we initially read in the SER, in the LRA. And as a result of Barry's review, we have the additional reports that you see listed in the table he just spoke of.

CHAIRMAN LEITCH:: So this is something that evolved as the work developed then. Page 1-7 is what I'm looking at, Dave.

MR. ELLIOT: He's talking about 78 to 86.

MR. POLASKI: This is Fred Polaski. I believe 78 and 86 would show up on a TLAA, right? Because that's where we credit those programs.

MR. SOLORIO: Yeah, I guess it's just an administrative problem in terms of, well, it's either one of two things. It's either that, perhaps, we left it off and we copied out of the application wrong. That's what we're putting on Page 1-6 and 1-7.

But I think what Barry said earlier is through his review he's come to find out they're relying on that.

CHAIRMAN LEITCH:: It is addressed later on in the application, so it may just be an administrative glitch.

MR. ELLIOT: Section 3 discusses that.

CHAIRMAN LEITCH:: Yeah, right, absolutely, yeah.

MEMBER BARTON: What's the resolution? Your point is it ought to appear as the list of VIPs on Page 6 and 7, right? To make it a complete list.

CHAIRMAN LEITCH:: Yeah, I think it should. I don't, you know --

MR. SOLORIO: I don't see why we couldn't when we revise the SER or issue it as final, include those additional reports there. We'll talk with the Applicant to make sure we got that straight, so it's clear.

CHAIRMAN LEITCH:: If there are no more questions for Barry, I'm going to have Jim Medoff come up here now, thanks.

MR. MEDOFF: Good afternoon. I'm Jim Medoff with the Materials and Chemical Engineering Branch. I was one of the Reviewers for the emergency safety features aging management review.

April Smith and Andrew Szukiewicz also contributed to the staff review of this system. For the Peach Bottom application that are eight emergency safety feature subsystems and they are listed here on the slide.

Next slide, please. Basically the materials of fabrication for the ESFs were carbon steel, carbon steel with stainless cladding or stainless steel. There were some copper, bronze, brass and aluminum alloy components, and the standby gas treatments system does have some neoprene and rubber components.

The applicable environments for the ESFs for steam wetted gas, sheltered air, ventilation air, various treated water, environments such as torus water, condensate storage water, reactor coolant, etcetera, raw water and lubricating oil environments.

The staff identified the applicable aging effects for the ESFs to be loss of material in the mechanisms that most, that led to this effect of general corrosion and pitting FAC. Cracking was an aging effect that was determined to be applicable for certain components.

And for the various heat exchangers in the ESFs, including the pump room cooler, the RHR heat exchangers, lube oil coolers. Loss of heat transfer capability and potential flow blockage were also identified as applicable effects for the heat exchangers.

For the rubber components in the standby gas treatment, the Applicant appropriately identified changes in material properties as an applicable effect. Thermal aging can cause these rubber materials to lose some of their elastic properties.

When we did our review, when we came to an issue on an identification of an aging effect or the ability of an AMP to manage the effect, we asked an RAI. The RAIs that we asked on the ESFs were mainly on the identification of aging effects for moist or humid gaseous environments on applicable aging effects for the heat exchanges.

And as well as the identification of heat, I'm sorry, the identification of aging effects for copper, brass and bronze components. The Applicant, in all cases, provided sufficient technical bases to justify their identification of aging effects in the application.

The Applicant credits a number of aging management programs or activities to manage the aging effects for the ESFs. Most of them were common aging management programs that have been discussed earlier today.

Such as the various water chemistry programs. The torus piping inspection, ISI, IST, oil quality, Generic Letter 89-13 activities which deal with flow blockage of heat exchanger components.

We did have two system specific AMPs that were credited for the program. One was the high pressure service water radioactive monitoring activities. And one was the HPCI, RCIC turbine inspection activities that Stu discussed earlier today.

The AMPs that were proposed for the, to manage the aging effects for the ESFs were determined in all cases to appropriately manage the effects. And therefore, we do not have any open items with regard to the Applicant's aging management review for the ESF components.

Therefore, we concluded that the Applicant had provided reasonable assurance for the emergency safety feature components.

MEMBER ROSEN: Let's talk about the standby gas treatment system for a minute. It's got a duct-like configuration and what did the Applicant say and you agreed to with regard to inspection of the casing of the standby gas treatment system ducting configurative equipment?

MR. MEDOFF: My recollection of the standby gas treatment system was that they did not identify a lot of aging effects for the system, basically, because they had provided a basis for concluding that the operating temperature of the system was hot enough to preclude the identification of aging effects for the system.

For the buried portions of the system they do propose using the outdoor and buried pipe inspection program to look at those components.

MEMBER ROSEN: You said the system operating temperature was high enough to preclude aging effect. Do you mean that it was kept warm enough so that the moisture would not accumulate from condensation or other reasons?

MR. MEDOFF: We basically asked that as a global question for all the ESFs systems.

MEMBER ROSEN: The duct is typically galvanized steel or something like that. So it could become, moisture could collect in pockets and dry out and rewet and dry out and ultimately damage the wall over a long period of time of this.

And what you're saying is moisture won't because of the high temperatures in the system, and moisture won't pocket or collect. I have a hard time believing that. Because the system is shut down most of the time.

And it's not run, although the carbon is kept warm, I think, in some of the systems. Maybe somebody can talk to us about that assumption. The fact that it's kept warm. Is there any more that can be said about that?

MR. MEDOFF: I will have to look further into it. I know, we kept, during the review we kept coming up with the question of what the appropriate aging effects would be for metallic components in moist air systems.

So we asked a global RAI on that and the response that was given back to us by the Applicant was that the ambient temperature for the metal was, I'm sorry, the temperature for the metal was hotter than the ambient conditions.

And therefore, precipitation would not be a concern for the components or the components were insulated. So based on that, that response, that's why we made that conclusion for the ESF components, including standby gas treatment.

MEMBER ROSEN: I guess I need some, somebody to help me understand or substantiate that.

MR. KUO: We'll get back to you on that before the end of the day.

MEMBER ROSEN: Okay, I'll leave it as an open item for me.

MR. SOLORIO: I there are no more questions, I'm going to have Bart Fu present the results to Section 3-3.

MR. FU: Thank you, Dave. My name is Bart Fu, I'm with Materials and Chemical Engineering Branch. I'm the VIP Reviewer for the aging management review of auxiliary systems.

There are a total of 18 systems under this section. They were reviewed by five different members of the staff, April Smith, Andrea Keim, George

Georgiev, Renee Lee and myself.

I coordinated the review activities. In the slide we listed some of the major systems from this section. Next slide. I listed materials and aging effects. Briefly, the AMR aging management review process.

The staff evaluated all components in scope and the materials of construction in this environment, and the aging effects identified. The staff also reviewed the industry operating experience just to make sure the Applicant provided adequate information.

And also make sure all probable aging effects were identified. Next slide. Aging management programs. There are a total of 13 AMPs that are applicable in this section. We listed some of the examples and all of them are common AMPs except the last one.

The emergency diesel inspection activities. This program provides for condition monitoring of the emergency diesel equipment. These components are exposed to gaseous lube oil and fuel oil environment.

And the aging effects identified were loss of material, cracking, as discussed by the staff in the earlier presentation. This program will effectively manage the aging effects. We would like to provide for you examples who this program was used during the AMR, aging management review.

As an example, for the air receivers, they are made of carbon steel, exposed to a wetted gas environment. And loss of materials was identified as an aging effect. And as required by this program, this aging effect would be mitigated by the daily removal of the condensate on the surface of the component.

Another example for the exhaust silencer, also made of carbon steel. Loss of material was identified as an aging effect. This aging effect is managed by the periodic disassembly, cleaning and inspections to ensure its functionality.

Another one, the lube oil and fuel oil systems, also as required by this program, the aging effect of loss of material and cracking would be managed by the periodic inspections. And I recall in the morning's presentation the committee raised a question regarding this.

A concern that water may accumulate at the bottom of the fuel tank. And I remember the Applicant addressed that the performed, you know, the type of periodic inspection. We actually did look into some of the details of how the testing is carried out.

The actual procedure requires that they test every 31 days. So I guess that's a monthly test. And they test a sample at the bottom of the diesel fuel tank. If they detect any water content, you know, they will, the procedure will require that they pump out from the bottom portion of the, you know, the diesel fuel and then retest at the end until they don't have any more water content.

So that's to elaborate a little more. Again, the AMPs form a very important part of the safety, that is to provide reasonable assurance that, you know, aging effect would be properly managed through the extended life of the plant.

I understand the staff discussed all the common aging management programs in the earlier presentation and some of the specific ones. And concluded that all AMPs are adequate in managing aging effects pending the resolution of the open items.

During the review of aging management review of auxiliary systems, the staff identified numerous issues and they were all addressed through the RAI process. The staff, SER summarized the review process and also all the RAIs, the response from the

Applicant, and also the reasons why, you know, they are acceptable.

The SER also documented the conclusions of this review and also documented the technical basis of the conclusions. Again, all issues were resolved, we don't have no open items for the aging management review for the aux systems. Any questions.

CHAIRMAN LEITCH:: Yeah, I have a question about the aging management programs. I'm not sure if it should be in this area or the structural area, but let me tell you my question and then maybe you'd want to hand off to the structural people.

But let me see where it fits. I was reading the NRC web page and I came across, last week, this notice here that happened at one of the plants. It says an open void was discovered approximately five feet deep that exists in the area between the reactor and turbine building walls affecting Appendix R fire separation.

It goes on to say it appears that sand has been moved or eroded away over time. Thus a void beneath the A and B 408 weld switch gear room floors. Do you know anything about that? I mean sand, it sounds like something subsurface has eroded away a big hole.

No, it's John's former favorite station, Oyster Creek.

MR. FU: This is not a part of the aux review. There are different processes.

MR. SOLORIO: I was just going to add, I'm not sure really we've actually addressed this in 3-5. It sounds like an event that just came up. And we will obviously look at it to see if it has an impact for license renewal.

But I'm pretty sure I don't see any of the structural guys shaking their heads no, we don't talk about this apparently. But we'll look into it.

CHAIRMAN LEITCH:: It sounds like something has opened up a big hole. I don't know if the sand has just compressed.

MR. SOLORIO: Can I get that link from you?

CHAIRMAN LEITCH:: Certainly.

MEMBER BARTON: Shifting sands at Oyster Creek. Sixty-nine million dollars, what do you want? What do you want for 69 million dollars? That's what the plant cost.

MR. POLASKI: This is Fred Polaski from Exelon. Just some information with respect to the issue you just talked about. I was just told by our staff that that design feature at Oyster Creek is, you know, applicable at Oyster Creek. That we do not have that kind of design feature at Peach Bottom.

So if there's an issue with sand which forms some separation, we think, between difference electrical cables for separation. So it's probably an Oyster Creek unique design. I'm not sure if anybody else has it. But clearly not applicable to Peach Bottom.

CHAIRMAN LEITCH:: Okay, thanks, Fred.

MR. SOLORIO: Are there any other additional questions on 3-3? If not, I'll George Georgiev present 3-4, steam and power conversion. Thank you.

MR. GEORGIEV: Good afternoon. My name is George Georgiev, and I'm with the Materials and Chemical Engineering Branch. And I was an assigned reviewer for the steam and power conversion system.

The application identified three systems as being part of the steam and power conversion system. Those are main steam, main condenser and the feedwater. Carbon steel, stainless steel, brass, copper and titanium were identified as a material that are included with these systems.

Several operating environment were

identified. The reactor coolant, steam, torus grade water, raw water, sheltered environment, wetted gas and dry gas. And aging effects were identified as a loss of material for carbon steel and stainless steel and cracking for stainless steel.

The review was done along the six column table which basically binds the component type aging effects and aging management programs and the environment. And in doing the review we identified some requests for additional information which pertained to identification of aging effect.

And the reply from the Applicant was that the terminology for the aging effect was the same as the one stated in the GALL report. Then we also needed some clarification about the review of operating experience, and they clarified that the operating experience is accounted within the program itself and they have a separate place where they record the review itself.

Several aging management programs were identified as being proposed to manage the aging effects. And are reactor flow and system chemistry program. The ISI program. The flow-accelerated corrosion program. Torus piping inspection program, and torus water chemistry program.

By the end of our review, we concluded that the aging managing effect were correctly identified in the applications, and that the aging management programs were adequate to manage those effects. So we didn't have open items or confirmatory items.

MEMBER BARTON: In the LAR, under structures, they talk about primary containment, the in-service inspection program. I just have a question. In your inspection program you're looking at the inside of the drywell at the interface of the floor to the metal light bulb, at that seal.

Is there anyway that you can determine at Peach Bottom if there's any leakage from up in the refuel floor, any place that got outside the drywell and down underneath the light bulb?

Do you have any telltales of anything which would give you indication that you've got any leakage on the outside of the light bulb, which would corrode the bottom of your drywell from the outside?

MR. POLASKI: Yes, this is Fred Polaski of Exelon. The design is that that sand pocket is drained. And whatever drains that come off of that, which are checked periodically, once a cycle, I guess, or, yes, once a cycle that there's checks done on that to make sure that there's no water accumulated in that area.

MEMBER BARTON: Okay, thank you.

CHAIRMAN LEITCH:: On your previous slide, you said you looked at the feedwater. I guess I'm confused. How, where, where is the, how far back down the heat cycle, what's the feedwater system defined as?

MR. GEORGIEV: Well, the feedwater --

CHAIRMAN LEITCH:: I mean do you go back to the feedwater heaters or condensate pumps? How far back do you go?

MR. GEORGIEV: That is actually a scoping question. As a courtesy, we do include in our slide a brief description. And --

CHAIRMAN LEITCH:: Yeah, that's really a scoping question.

MR. GEORGIEV: I'm trying to find it out what they said. But as I said, that is a scoping question. And as a material people we generally don't, we assume that our scoping people are, have included everything.

MR. SOLORIO: Well, we can look into that and get back to you today.

MR. GEORGIEV: It says here from the out

most primary containment isolation valve to the reactor pressure vessel. The feedwater system is safety related from the out most primary containment isolation valve to reactor pressure vessel.

CHAIRMAN LEITCH:: Okay, so it's not --

DR. POWERS: Graham, we can, I think Gary can provide some clarification.

EXELON REP: The feedwater system that's in the scope is from the reactor vessel nozzle through the containment up to the first water operated valve on the discharge of the feedwater pump.

And it's in scoping because it provides, the same piping provides the RCIC and HPCI input into the reactor vessel. That's why it's in scoping.

CHAIRMAN LEITCH:: So it doesn't get back the high pressure heaters --

EXELON REP: No, it doesn't go, the pump itself is not in scope either.

CHAIRMAN LEITCH:: Yeah, right.

MEMBER SHACK: Can you explain to me why torus coating doesn't serve a license renewal function. I would have thought the coating was the main reason that I didn't have degradation of the torus.

And yet, you know, it says that the

protection coating does not perform a license renewal function as defined in 10 CFR 54.4(a), and therefore --

MR. SOLORIO: Dr. Shack, the next presenters will talk to that.

DR. LEE: This is Sam Lee. I'm from loss renewal section. Okay, that, what they were talking about was for scoping purposes. Okay, for scoping there is a requirement in 54.4 that says this is safety related or not safety, affect safety or safety related to what the inspection like station blackout for protection.

Coating, that's not their criteria. Coating is part of the aging management program.

MEMBER SHACK: Except at Davis-Besse.

DR. LEE: Okay, it's part of the aging management program. So you see it as part of aging management program, but it's scoping. Okay. Some tests are related to just scoping.

MEMBER SHACK: But it's in the discussion of the aging management programs.

MEMBER ROSEN: I have an outstanding on torus inspection scope and the findings.

MR. SOLORIO: And they are coming up next to answer your question, sir.

MEMBER ROSEN: All right, so we'll talk about torus coating as part of that, I would assume.

MR. SOLORIO: If there are no more questions, we'll get to the structures discussion and we can move into those things.

MR. MUNSON: Okay, my name is Cliff Munson. I'm a member of the Civil and Mechanical Engineering Branch. To my right is Hans Ashar, he is also a primary reviewer for Section 3.5, which is the aging management of structures and component supports.

The structures covered by Section 3.5 are the containment structure, which consists of the primary containment and internal structural steel. The containment is a Mark 1 design. It includes a drywell and torus and ventilation systems.

The other Class 1 structures include the reactor building, the rad waste building, the turbine building, SBO structure, diesel generator building and yard structures. Section 3.5 also covers component supports, miscellaneous steel, barriers and elastomers, raceways and insulation.

The major materials covered in Section 3.5 are concrete, carbon steel, stainless steel, elastomers,. bronze, oh, excuse me. Yeah, bronze, graphite. The different environments are sheltered air, indoor, outdoor, buried, raw water, fuel pool water, torus water.

The aging effects identified for these materials are lost material, cracking, change in material properties, fatigue, loss of mechanical function. The staff reviewed the structural components listed in Section 3.5 to determine if the Applicant adequately identified the aging effects for each component.

In the application, the Applicant did not identify any aging effects for the concrete components in the containment structure reactor building and in any of the other Class 1 structures. So the staff had an RAI concerning concrete aging.

In response to the staff's RAI, the Applicant committed to manage cracking, change in material properties and loss of material for above grade concrete components. For below grade concrete components, the Applicant provided ground water data that showed that the soil ground water environment is not aggressive. Therefore, the staff did not require aging management of below grade concrete components. Since.

MEMBER ROSEN: That's where I come in.

MR. MUNSON: Okay, that's where you come

in.

MEMBER ROSEN: That's where my question comes in. They've provided the data for ground water now. Is there any monitoring of the ground water over the extended period?

MR. MUNSON: We have a slide that shows that. The staff determined that based on the two samples that they had taken, that the pH sulfates and chlorides were well below or above the limits.

And we determined that the ground water monitoring would not be necessary during the period of extended operation.

MEMBER ROSEN: So how long is the period of extended operation? How long does it take you to? What year?

MEMBER BARTON: 2013 to 20 --

MEMBER ROSEN: 2033? So you're going to go another 33 years. You went --

MR. MUNSON: Thirty-one years.

MEMBER ROSEN: You went 32 years between the sample in 1968 and the year 2000, and there wasn't much of a change, right? That's 32 years. Now you're going to go another 30 some years without another sample. No monitoring of any kind.

MR. MUNSON: Well, we have no reason to

believe that those, the ground water chemistry will change over that period of time.

MEMBER ROSEN: You have no reason to believe it won't. What can you --

MEMBER SIEBER: But there's a ton of margin there.

MR. MUNSON: I mean if you look, the values are so far below the limits that, I mean we can, we don't manage for abnormal events. So I don't know what would change the ground water significantly to reach the limits.

MR. ASHAR: Let me add one item that we did consider and certainly they have to manage the ground water. They showed in the application that the ground water chemistry was within the threshold established before.

For example, in Calvert Cliffs case, they came with a number of samples near the containment and auxiliary building area. Where they showed that they were below these limits, except this limit that we had established.

Very close to the intake structure area, because of the vicinity to the sea water and everything else, the fluoride levels were high. So we asked them to monitor those areas. So we did specify in certain applications that they should monitor, they should monitor the ground water and soil characteristics on those areas where there are doubts.

They could go beyond, where the safety factors are so much between what is acceptable and what we are hearing right now. That we didn't see any need to have them monitor.

MEMBER ROSEN: Monitoring implies you're doing it every month or every year. I'm simply suggesting --

MR. ASHAR: Five years or something.

MEMBER ROSEN: -- if you go another 30 years without taking the samples, it seems a little bit extreme. I mean, is this a religious matter between the staff and the Applicant. If so, I'll back away. But it seems to me so easy to do.

And the consequences of going negative or pH down near 5.5 or any change of sulfates and chlorides in terms of the attack on concrete structures below grade that you can't know about are so severe that a simple test, once every period of time, extended period of time,. maybe five, ten years, is hardly a burdensome activity.

And I made the suggestion before. I'm not sure any of the other members of the subcommittee or the full committee would agree with me, but it seems just like an ordinary prudent thing to do.

MR. ASHAR: In a number of areas that we have shown certain concerns and when you try to get a commitment from various Applicants, I think we try to be, trying to reconcile with what is more of concern.

Rather than something of no concern at all at this time. And we're extending something that the water quality can change after ten years, 15 years. I mean it is a feasibility, but on this particular plan that we looked at it, it looked like that it's not going to change because it is an inland plant.

It would cost you to be suddenly not allowing them to do this that way. But in most of the inside areas where they are showing this type of the chemistry, it doesn't seem to us that we should have a commitment from an Applicant to do this kind of thing. By themselves it is a prudent measure that they do it.

MEMBER ROSEN: I'll just change the subject, because I've heard all that before. Why is the word settlement never a question here? Is there no monitoring for a settlement of any of these safety related structures over the period of the extended operation?

MR. ASHAR: Well, during the licensing of the plants there were areas where the soil were bad enough that the staff and licensees agreed on monitoring the settlement on those particular, I remember are the River Bend, Waterford and some other plants where soils were bad enough that they would be monitored.

Now the requirement in the tech spec was that if there's no settlement or no problem occur for first ten years, then they can stop monitoring the settlement for those particular plants.

In the areas where people have their foundations on either solid rock or very, very compacted soil, then there were no requirements for settlement. However, something that we always ask the people to do, and it is in one of the code which is being referenced in structural code.

That any signs of settlement is a part of the cracking of the concrete that they are to investigate. There's a part of ACF-349, which most of the Applicants have committed to when they inspect the structures.

MR. MUNSON: Right. And we have that commitment from the Applicant to inspect for cracking of concrete. That was one of the RAI we asked. So any settlement would show up as a cracking aging effect.

MEMBER ROSEN: But you can monitor settlement without looking for concrete cracking. I mean you can just monitor the positioning of the buildings. Make sure, you know, put a few mark lines on them and with laser sighting nowadays you can detect settlement to very low levels.

MR. POLASKI: Yes, this is Fred Polaski with Exelon, just to clarify. Peach Bottom is built on bedrock. So that settlement, and I think it was checked early in construction days, but it wasn't an issue and we haven't looked at since then because all the buildings are founded directly on bedrock.

MEMBER ROSEN: Okay, well that's a good answer.

MR. MUNSON: Okay. In addition, the staff asked to RAI on some of the carbon steel components that didn't have any aging effects identified. And in response the Applicant committed to manage loss of material for these carbon steel components.

The AMPs, aging management programs that are used to manage the aging effects identified for the structural components are listed. These aging management programs are common aging management programs.

None of them are specific to Section 3.5. The staff did have an open item concerning the structural monitoring program. The open item dealt with the concrete items, components that were added.

The Applicant needed to supplement its acceptance criteria and parameters monitored and inspected to cover the concrete aging effects that they committed to inspect as part of Section 3.5 RAI that we asked.

So the Applicant has shown us what text they're adding to the structural monitoring program or aging management program. So the staff is satisfied with that. Any further questions for Section 3.5?

Oh, excuse me, we were going to address the torus, interior of the torus. Hans is going to address that.

MR. ASHAR: I don't know what exactly the question is.

MEMBER ROSEN: Well, I'll tell you, do you want me to tell you exactly what the question is?

MR. ASHAR: Please, please.

MEMBER ROSEN: What was the scope of the torus inspection, inside, outside, both? At the water line? Above the water line? Below the water line? How many degrees around? All the way around? Or just in one section? Near the SRV discharge lines? Away from them?

What's the scope of the inspection? Where did they look? That's the first question. And second, what did they find? What has been find? Is the liner intact or the coating intact? Not intact? Degraded? Thin?

I mean what is the, this is an important safety related structure, I should think there would be a comprehensive report about this thing. I just want to know what it said.

MR. ASHAR: Yeah, okay. May I give a short background on torus corrosion in general. And then I'll come to Peach Bottom specifically. First the torus corrosion problems were identified during almost late 1980's.

During that time Oyster Creek had corrosion on their drywell also identified. Nine Mile Point had torus corrosion and it was uncoated torus and it corroded heavily in many years.

Based on that we issued three informational releases in late 1980's, ‘89, '88, time frame.

Then afterwards is why specialist concern

BWR Owners Group first the staff came out with their inspection program. Which was discussed with the BWR Owners Group for Mark 1 containments.

Because they would generate problem. And after number of discussions with the Owners Group, what happened was ASME Subsection A and E was also in the process of incorporating the torus corrosion as well and the drywell corrosion as part of this special requirement in the ASME, Section 11.

In 1992, a revision of the code, and the code incorporated a requirement for augmented inspection. The augmented inspection meant that when there was various suspicion of having a corrosion in a particular area, either to the operating experience or creating even a possibility for having some kind of corrosion in a particular area.

They were to have a program for augmented inspection. Now this particular edition of the code became a part of the regulation now. It is in 10 CFR 50.55(a). So all the licensees are, of Mark 1 containments, are required to have inspection programs that would monitor the corrosion of torus in general, outside, inside, everything.

Anyway it can occur, it's a part of the program. And when we ask questions to the Peach

Bottom, to this Applicant, regarding the operating experience, because we knew that torus corrosion is very common in almost all Mark 1 containments.

So they replied and that has been discussed in our SER at length. The acceptance criteria and everything is described very well in the, and what they told us about the operating experience. And based on that we concluded that the program is active, it is going to continue, and what, the kind of acceptance criteria they have utilized, I accepted from all point of view.

MEMBER ROSEN: Okay, you basically told me to go back and read the SER. But I'd like to ask some direct questions, perhaps of the Applicant. Is the torus water inhibited in any way with chemicals, or is it pure?

MR. POLASKI: Torus water is pure.

MEMBER ROSEN: Okay.

MR. POLASKI: Demineralized water.

MEMBER ROSEN: Is there a coating on the inside of the torus?

MR. POLASKI: Yes, there is.

MEMBER ROSEN: What is, what is the coating material?

MR. POLASKI: We believe it's carbyl zinc, but we're not --

MEMBER ROSEN: Carbyl zinc paint?

MR. POLASKI: Yeah, it's a paint type, it's an applied type coating.

MR. ONNOU: If I may just give you some information. Because we, we've done a lot of work on the torus and I think --

MR. SOLORIO: Can you identify yourself?

MR. ONNOU: Again, Ahmed Onnou with Exelon. In response to the RAI that staff issued us, which you would find in the SER, I'm going back in it some research. And we found that we did have initially some degradation with the torus in 1991.

And as a result of that, the entire torus was inspected under water. And the, it was heading that range from 15 mils to a maximum of, I believe, of 40 mils, if my --

MEMBER ROSEN: Forty mils?

MR. ONNOU: Forty, right.

MEMBER ROSEN: What's the thickness of the torus shell?

DR. POWERS: 41.1 mils is what your RAI response says.

MEMBER ROSEN: What is the thickness of the torus shell? The nominal thickness?

MR. ONNOU: The torus shell is 675 or five-eighths of an inch thickness. And again, as a result of the questions staff asked us, what's the projected thickness, assuming you consider the degradation that has occurred in the past.

By the way, we also had another inspection in 1998, for one unit and another one in 1997. And what we found that is that the degradation rate was significantly less than we had experienced in the past.

And we attributed that to improved water chemistry. Again, staff asked us if you assumed the rate as you had, the degradation as you have, what would the expected thickness be at the end of the 60 years.

And we provided some information on that. I think when we calculated, we found that the design thickness is 675. Assuming the degradation will continue as the one from 1991 to 1997 or 1998, the final thickness at the end of 60 years would be something like 610, which is still below, which is still more than what the design requires for the shell.

MEMBER ROSEN: And tell me again what the inspection regimen for the torus shell will be?

MR. ONNOU: Well, the inspection for the shell is, again, we have not made an inspection and there is a visual inspection on the outside. There is a visual inspection of surfaces under water. And on a periodic basis the areas that we had experienced degradation we go back and do the UT and make sure we do have a thickness that's, UT inspection to make sure that the thickness is adequate.

MEMBER ROSEN: Let's focus on the under water inspection for a minute. How often do you do that?

MR. ONNOU: Every six years.

MEMBER ROSEN: Every six years.

MR. ONNOU: Yes.

MEMBER ROSEN: And is this torus inerted?

MR. POLASKI: Yes.

MEMBER ROSEN: I mean the gas space?

MR. POLASKI: Yeah, the gas space is inert, yes. Containment is inerted, yes.

MEMBER BARTON: It's inerted during operation, because you've got the drywell atmosphere.

MEMBER ROSEN: During operation obviously, it's not inerted during shut down?

MR. POLASKI: No, it's not inerted during shut down, which is a very small time period in the overall.

MEMBER ROSEN: And what temperature does the water typically run in the torus?

MR. ONNOU: I believe it's 98?

MEMBER ROSEN: Eighty degrees Fahrenheit?

MR. ONNOU: Yeah.

MEMBER ROSEN: Okay. Okay, thank you.

MR. SOLORIO: Okay, I'm going to be presenting the results of 3.6, Section 3.6. Duc Nguyen was the lead reviewer for this section, and he's on my right. The additional reviewers, Mark Paull and Paul Gill, who are in the audience with us today.

The scope of the equipment covered in this section includes cables, connections, and connections being connectors, splices and terminal blocks. Regarding the station blackout scope of equipment, I think most of you are aware there's an interim staff guidance that's been finalized on that.

The Applicant has committed to include the additional equipment relied on per SBO recovery path, which is consistent with this ISG. The SBO off-site recovery path for this plant that required an AMR are the switchyard bus, high voltage insulators, insulated cables and connections, that again, being connectors, splice and terminal blocks, non-segregated phase bus, transmission conductors.

No aging effects were identified for the switchyard bus, high voltage insulators, non-segregated phase bus and transmission conductors. The materials an environments I've listed up here on the slide.

I'll say the, there's some open items I'm going to talk about in a minute. So I'm going to qualify the statement of applicable aging effects identified. We initially during the inspection, I mentioned earlier today, that during the aging management review inspection it was identified that certain cables with a potential for being wetted and experienced water treeing needed to be managed.

The Applicant initially had told us or has already replaced these cables and told us initially that because they were new they wouldn't be susceptible to this effect for the remaining term. The staff didn't agree with that.

The staff has gone back and forth with some RAIs and on the site to actually talk in detail with the Applicant. Initially the SER calls out an open item on this. As of now, we've got a draft response back from the Applicant that they propose an aging management program consistent with the GALL E3 program.

So provided that comes in under oath and affirmation, we will be able to resolve that item.

CHAIRMAN LEITCH:: I'm just a little confused. You expect the response to this open item to be a commitment to look at the cables?

MR. SOLORIO: Using an aging management program consistent with the GALL E3 program.

MR. NGUYEN: They would test the cable at the end for the year. They would test the cable, conduct a test. So at that time, you know, they will know that the cable have any degradation or not. But the test of program will be conducted every ten years. Every ten years, beginning at year 40.

CHAIRMAN LEITCH:: What voltage, I'm unclear what cables we're talking about?

MR. NGUYEN: These are medium voltage, inaccessible medium voltage. Typically to kilovolt to 15 kilovolt. In accessible, yes. In the conductor or buried.

CHAIRMAN LEITCH:: What about 13KV cables?

MR. NGUYEN: Thirteen kilovolt is considered medium voltage. But let me bring another point that we have a common goal with the Applicant because in the high voltage, you talk about 34.5 kilovolt, they have some cable underground.

That they call the ten seasonal cable that connect from the manhole of Conowingo manhole and then another portion also connect from the manhole from the Peach Bottom. And during the staff visit, the plan during the initial review, we questioned the Applicant whether this cable simply included in the aging management review.

And the answer we got from Applicant that this is not a medium voltage. So it's not subject to the water treeing phenomenon. And we have problem with that. Because we think that the high voltage cable also have problem with water treeing.

So we go back to the Applicant and ask them to include this cable in their aging management program. And yesterday they faxed me the initial response and they include it in the aging program.

So in general any cable, the medium cable or high voltage, if it's underground or buried underground do or the duct band will be managed to this aging management program. But in the SER we put that as an open item and we expect to close that in the final SER.

And we're here to respond from the

licensee, it's just a formality to make sure that they put in the document and then we can close that.

CHAIRMAN LEITCH:: It seems to me that Peach Bottom has had a history of water treeing and these cables.

MR. NGUYEN: Yeah.

CHAIRMAN LEITCH:: I guess for 4KV and the cables surrounding the diesels and up the hill to the substation and --

MR. NGUYEN: I think you're correct that --

CHAIRMAN LEITCH:: -- there's a major cable replacement effort that went on.

MR. POLASKI: Yeah, this is Fred Polaski at Exelon. We did have a major program to replace cables. There was at least one failure due to the water treeing. We had a extensive engineering program that evaluated the cables and the conditions in which they operate and identified those that were subject to water treeing and those were replaced.

Safety related and non-safety related. So our position had been, on the application, that we had replaced with the best cable that was available. The original cable, you know, didn't last the life of the plant, but the industry information is that these new cables, which are EPR cables, were manufactured knowledgeable of the problems they'd had in the past and should last well beyond 30 years.

One of the problems is there's no test or documented testing to prove that they'll last that long because there's no way to do that. And you can't do accelerated age testing on cables for this like you can for EQ.

So we've, I think after a discussion with the staff, we agreed to do testing on them. The one open issue with that right now is that there is no new industry to do that. That still needs to be developed.

CHAIRMAN LEITCH:: That's what I was going to say. What does that testing look like?

MR. POLASKI: There isn't any that we know. We've addressed, we've brought this up with EPRI that we're going to need to develop a test program. But to be honest, initial information is that, you know, there's been work done on that in the past over in the T&D world, underground, and they haven't been able to find any program either.

So, it's an area that's still open to determine what that test program is going to be.

CHAIRMAN LEITCH:: So your response is

going to somehow be couched in terms that you'll keep up with the industry in this regard and do what seems to be state-of-the-art?

MR. POLASKI: We've agreed to do the testing that's developed. And all the previous Applicants that have had this question raised have committed to the same program. Now it's up to us to develop the program.

MR. NGUYEN: It has to be a proven test in the industry. And so I think that, you know, because this is new program, the new test, so at the time go on hopefully in the next 20 years we will have a better test than right now.

But it has to be a proven test. That's the one operating requirement that we have.

CHAIRMAN LEITCH:: Is there a generic safety issue on this? Is this GSI 1, I can't remember all the numbers. But isn't there a generic safety issue related to --

MR. NGUYEN: This didn't come out at the Davis-Besse event or the medium voltage, so that's why when we developed the GALL we had no problem with Davis-Besse service water, if you recall.

They have a lot of problem and the staff, when we developed the GALL, we put the program in the

GALL, the Davis-Besse event.

MR. KUO: Dr. Leitch, this is not part of a generic issue, GSI 168.

CHAIRMAN LEITCH:: That's the one I'm thinking of, yeah. It's not part of that?

MR. KUO: No.

CHAIRMAN LEITCH:: Okay.

MR. SOLORIO: The aging management program specific to this aging management review -- I apologize, you can't see the first one, it's non-EQ accessible cables. and the remaining programs are on the next slide.

The two, earlier today you heard Stu Bailey say there were four new programs. The new programs are the non-EQ cable program and the fire safe shut down cable inspection program.

The, I guess just because it's probably a new term to you, or maybe different from what you've seen in the past. The fire safe shut down cable inspection program involves about 30 cables that are located in the drywell and are all main steam relief valve discharge relying thermal couple wires.

PVC insulated cables will be inspected once every ten years. The first inspection will be performed before the initial 40 year license renewal term. The staff found the program acceptable because the aging management program will detect the cable aging degradation before other loss of intended function.

As I mentioned a moment ago, there were some open items. I talked about one of them. The second open item was regarding visual inspections which may not be effective in detecting aging degradation of neutron monitoring and high range radiation monitoring cables.

The staff, over the last few weeks, and the Applicant has been talking about this. And as a result, the Applicant has now committed to a calibration program consistent with the GALL E2 program.

So the staff is going to consider this resolved, pending formal receipt of that information. And the last thing I'll mention that I have up there is fuse holders. And I have confirmatory item in parentheses after that because it's a confirmatory item in the SER.

And the reason we made it initially a confirmatory item is we understood that, we thought we understood that not only was the Applicant going to submit fuse holders to an aging management review, but they'd also manage aging effects for the fuse holder elastomeric or, and the metal components.

What we subsequently found out is that they have committed to an aging management program for the elastomeric component, but not the metal component. And staff believes that there needs to be one.

I think you're also, or if you're not, this is also the subject of a draft interim staff guidance issue being developed. So we're really in still, you know, trying to work with the Applicant to resolve this, and NEI, so that we can move forward.

So, more to come on this, but I wanted to let you know that this confirmatory item was going to be the subject of more debate.

MR. NGUYEN: Let me ask you some background about the fuse holders. If you recall, we had the issue with the fuse when we reviewed the Oconee. The issue come up of whether the fuse would be active or passive.

And later on it was determined that the fuse be active, and not within the scope of the aging management review. However, at that time we communicate to the industry that we would look this under general issue, because we believe that, we may think, we may think that the fuse problem have any problem.

So we conduct a study by the Sandia Lab, I think last year. And I was the Project Manager for that. They looked at the fuse failure, looked at the LER, and they found that the fuse, very few event that it resulted in fuse failure, very few.

It was very surprised to us. But we also found that a number of events involved a fuse holder. As you recall, when they did a surveillance for the control circuit, they took off the fuse to the circuit to do some kind of testing. And they took it off and on and off and on.

The fuse holder clipping may be loose, not the one that the aging, degradation that this study concluded. The other thing is they found some corrosion in the fuse holder. Because of that, and then in the assembly at Peach Bottom one of the Inspectors found a question whether the fuse holder should be included in aging management review.

Then the staff looked into it and the issue, the interim staff guidance. The reason that this issue did not come up because I think because we find that the fuse holder usually inside the lock assembly, that the fuse holder stand by itself.

So the number is not, not a lot of number or very few. So that's why we issue the interim staff guidance and we were in, our understanding was if you're going to manage the fuse holder, you have to manage the whole thing.

That mean the metallic part and non-metallic part. And NEI industry disagree with the staff. They think that the fuse holder is special after terminal block. And they say have no additional aging effect.

Whatever aging effect of terminal block will be applied to the fuse holder. But we think that the characteristic of the terminal block is different from the fuse holder. I explain to you that the fuse clip, that potentially it can be loosened, you know.

So that's why right now we still have, are looking at what the industry and try to resolve this. And whatever come out will be, go back to the licensee that will approve the license. And then go back and treat it generically.

CHAIRMAN LEITCH:: Can we go back to the Conowingo for just a moment. I guess I'm confused how extensive the aging management program is at Conowingo. I guess first of all, does Exelon still own Conowingo? Is that somebody else?

MR. POLASKI: Yes, Exelon still owns Conowingo.

CHAIRMAN LEITCH:: Okay. Secondly, I guess my question is what's so unusual about Conowingo? I mean a lot of plants have off site power supplies. And, you don't necessarily go back and conduct aging management at every little fossil plant or something that might be supplying power to the, off site power to the nuclear plant.

What's so different about Conowingo? Why are you in that area?

MR. NGUYEN: Let me try to answer that. The reason that Conowingo is subject to aging management is because they are due for the test and blackout alternate AC source. Most other plants they do this, but this plant they do the hydroelectric.

So to be consistent with the rule, you have to include the power supply for the SBO alternate AC. So that's why it's in the picture.

CHAIRMAN LEITCH:: So there's no SBO diesel at Peach Bottom?

MR. NGUYEN: I'm not sure, but I think that's a part of why --

MR. CALVO: Jose Calvo, the Chief of the Electro-engineering Branch. The official history of how the Conowingo is, the station blackout was not the thought. But we were negotiating with the Peach Bottom on those days. They want to do maintenance of the diesel on line and we say what are we going to get in return?

So we say we've got a big hydroelectric unit there, can we use that one. Okay? And we went back and forth, so we allowed them to do on line maintenance of the diesel and extend it for three days to 14 days to see if we can get something else in return.

And that something else in return went to Conowingo line. Okay? Then the question come up of the station blackout. And we feel, I have a question if this was an eight hour coping plan. And we say well you've already got a Conowingo line, you can use it as an alternate AC source of power, pursuant to the station blackout rules.

And then we said we wanted be sure that, that if you lose your site power for whatever reason, you don't lose also the Conowingo feed to the station. So that's when a particular pole in there became so important.

We wanted to be sure that that pole was strong enough to hold it. Because if that pole would go, the whole Conowingo feed would get lost in there. So the Conowingo has that kind of a history.

We've got 60 megawatts allowing them to do on line maintenance, which I thought it was a good swap. Okay, so they did that. We got to dig ourselves in for the risk-informed aspects of it, they can do on line maintenance.

We've got 60 megawatts reserved and we only worry about the person at the commission. So we got that one, it served a purpose to them and also was used for the station blackout was an alternate AC source for us.

Duc is saying because it's alternate AC source, it is part of the aging management program because all the AC sources are. Now keep in mind that's a non-safety related system in the operating world. It's not controlled by the tech specs.

Because we leave it up to the licensee to establish requirements because they do that at the other places.

CHAIRMAN LEITCH:: That's an interesting piece of history.

MEMBER BARTON: You have an aging management program for an old hydroelectric plant.

CHAIRMAN LEITCH:: Yeah, this is a 70 year old plant.

MR. POLASKI: That's correct, and it's the FERC inspection, so we credit. But that hydro unit is in good shape. It makes a lot of megawatts for us, though.

CHAIRMAN LEITCH:: But I thought the FERC inspection would be basically a hydraulic inspection. This sounds like what we're talking here is an electrical aging management program.

MR. BAILEY: I don't know.

MR. SOLORIO: That was what the aging management program is all about.

MR. BAILEY: The FERC inspection covers the power block as well as the structures

(Whereupon, at 2:59 p.m., the meeting was recessed and resumed at 3:16 p.m.)

CHAIRMAN LEITCH: Maybe we are lacking just a few folks here.

MR. SOLORIO: Do you want me to wait or do you want me to start?

CHAIRMAN LEITCH: Yes, why don't you wait. I think maybe I am a little bit ahead of schedule. I was looking at this clock, and some people may be looking at that one. We have to get these synchronized. Okay. David, I think you can proceed now, please.

MR. SOLORIO: Okay. In Section 4.1 of the SER, we summarize the applicable time-limited aging analyses for the Peach Bottom units. We agreed that the TLLAs that they identified were appropriate as you would expect.

We also identify two additional TLLAs. I will just mention that to my bright that Barry Elliott who you have heard from before, and John Fair, will be talking about the reactor vessel neutron embrittlement and the metal fatigue TLAAs.

They are not the only two TLAAs, but they are the two that we have people to make presentations on here today. The other TLAAs didn't have any open items, except for 4.5, which Barry will also be talking about.

As far as the additional time-limited aging analyses, for Peach Bottom, the crane load cycle limit is 20,000 load cycles. They project that the crane will undergo less than 5,000 load cycles in 60 years, and those loads are lower than the rated low capacity.

This was not identified as a TLAA, and an RAI from the staff flushed this out. It has pretty much been an TLAA for prior reviews, and so it is something that you would expect to see.

So they have satisfied the requirements for the time limited aging analyses by meeting the requirements of 54.21(C)(1)(i). The other --

CHAIRMAN LEITCH: That response seemed to me to be based on the fact that many of the lifts were of components that weighed significantly less than the rating of the crane.

But my question was basically whether there were TLAAs associated with just the cycling of the crane, and with the number of cycles, regardless of the load.

MR. SOLORIO: Well, that is the definition of why this is a TLAA. It is based on the number of cycles over -- but I have Renee Li, the reviewer who reviewed this, and has the RAI, and she is going to make some additional comments.

MS. LI: I am Renee Li with the Mechanical Engineering Branch. When I asked for the RAI, I think it is with respect to not only the cycle limits, but also the rate capacity, because in general the design code specifies a specific number of limits, and that would be the limiting cycle.

But it also states what is the rated capacity, and as David mentioned earlier in the original RAI application, the applicant did not identify this as a TLAA, and so we asked for the RAI, and in the response, the applicant stated that the Peach Bottom crane design was in accordance with the criteria of Crane Manufacturer Association of America, the specification number 70.

And that specification specify a 20,000 cycle load limit cycle, and also we didn't get into the detailed number, the quantified number of what is the greatest capacity.

But in the response, in the RAI response, the manufacturer says that they have some type of plant in the scope of license renewal, and among those plants, is the bonding condition. So they further elaborate for that bonding condition what is the project load cycle limit and it turns out to be less than 5,000 cycles.

And they also state that most of the lifting is much less than the rate capacity, and based on these two conditions the Africans determined that the analysis that is associated with the crane design included the load cycle limits specified by the requirements of 10 CFR 54.21 9c)(1)(i).

CHAIRMAN LEITCH: I guess maybe I am not clear on what the definition of a load cycle is. In other words -

MS. LI: In other words, it is the lifting.

CHAIRMAN LEITCH: Is that just up and down or does that mean up and down with the rated load on the crane?

MS. LI: Okay. It's up and down with the load, but the load should be less than the rate capacity. It should be within that limit.

MR. KUO: If I may just to add to what Renee just said, you know, the conditions that Renee just described is consistent with what is required in the AISC specification.

The AISC specification basically specified that allowable stress for the crane, and that allowable stress is based on implicit 20,000 cycles. So basically whether you have a rated load or not, it converts to allowable stress.

CHAIRMAN LEITCH: Okay.

MS. LI: And that this particular crane design specification, especially going to the allowable street, is built in, and it gives a number, like the number of liftings, and the rated capacity, but they, too, are really related.

CHAIRMAN LEITCH: So we are saying that it wouldn't see the rated number or the design number of load cycles, and in 60 years it would not get up to that number of cycles?

MS. LI: Right, because they project a maximum of 5,000 cycles.

CHAIRMAN LEITCH: And this is up to 20,000?

MS. LI: Right.

CHAIRMAN LEITCH: Okay. Thank you.

MS. LI: You're welcome.

MR. SOLORIO: The other time-limited aging analysis was related to pipe break location based on cumulative usage factor, and the applicant indicated that the cumulative usage factor of calculations, which was the basis for the pipe leak postulations, remain valid for the period of extended operation.

We have a confirmatory item for the applicant to include a summary description of this TLAA, and the previous one, in the UFSA supplement.

MEMBER WALLIS: What does this mean, pipe break location? Does it mean that the pipe break location doesn't change over time?

MR. FAIR: This is John Fair. In the initial design of some plants, CUF was used as a basis for postulation pipe ruptures. For Peach Bottom, apparently they did use CUF to postulate pipe ruptures on some of the piping.

For that particular piping, they had recently done a reevaluation for a 60 year operating life, and found that none of those original -- there were no additional identified locations where the CUF was greater than .1, and so they didn't have any additional postulated locations.

MEMBER SHACK: John, didn't at least one of the plants go back and look at the postulated locations, in terms of their real potential mechanisms for pipe failure?

MR. FAIR: I am not quite sure what you are referring to.

MEMBER SHACK: Well, fatigue probably isn't the greatest risk for pipe failure, but the actual pipe break location might be well at the place where you get FAC, or you are more likely to get stress corrosion cracking than fatigue.

Didn't somebody redo the analysis that way, or --

MR. FAIR: You may be thinking of something different --

MEMBER SHACK: And a risk informed inspection kind of argument.

MR. FAIR: Well, we are talking -- and this is the design basis for postulating pipe ruptures, and it was based on the best that they had at the time, which was cumulative usage would be the -- you know, the higher the fatigue usage, the higher your probability of a rupture.

MEMBER WALLIS: But the design basis is not realistic is it? I think that's what we are getting at here.

MEMBER BONACA: So the point that you would be making, Bill, that you would have applied the cycles in a location other than --

MEMBER SHACK: Whatever -- I would look at the mechanism of degradation, and postulate my pipe breaks where I thought it was really most susceptible to failure.

MEMBER BONACA: And you would look at the number of cycles there probably.

MEMBER SHACK: Yes, whatever degradation I was going to pose there, yes.

MR. FAIR: Well, I can't argue with that rational, except to say that is not the design basis, and we are looking here at the TLAAs on the design basis.

MR. SOLORIO: If there are no more further questions, Barry Elliott will present the results of 42 and 45 time-limited aging analyses.

MR. ELLIOTT: My name is Barry Elliott, and I am with the Materials and Chemical Engineering Branch. The first five bullets up here, the first four have to do with neutron and radiation embrittlement, and the fifth bullet has got to do with the radiation corrosion and stress fractures.

First, we are going to talk about neutron radiation embrittlement. With neutron radiation embrittlement, there are two factors; the material part and the methodology part, and the calculation of neutron fluids.

There is two guidance documents, Reg Guide 1.190, is the NRC's guidance document calculating neutron fluence, and as far as material and how to calculate radiation embrittlement, the guidance document is Regulatory Guide 1.99, Rev. 2.

MEMBER SHACK: Barry, is the lower temperature in a BWR, is that sort of ignored in 1.99 Rev. 2, in the sense that I would expect to get more radiation damage per neutron?

MR. ELLIOTT: It is not ignored. I will go into that if you want to go into that. It is not ignored. The guidance in the document is that the radiation embrittlement, that the methodology is applicable between 525 and 575, and as long as you operate your plant in that range, the guidance applies.

If you go below that guidance in the document, and if you go below 525, there is more neutron embrittlement, and the guidance in the document needs to be supplemented. They haven't gone below 525, and so the guidance in the document applies.

The first four items require a valuation of neutron fluence, and the applicant has performed that evaluation using a G.E. methodology, and this methodology conforms with the guidance in Reg. Guide 1.190.

The upper shelf energy evaluation is the first item, and both the first item and the second item are in the regulation, and they are in 10 CFR, Part 50, Appendix G. There is a upper-shelf energy requirement, and a pressure temperature limit requirements in that regulation.

The upper shelf energy requirement is that if you go below a certain foot per pounds, you need to do additional analysis. Peach Bottom did that analysis for the first 40 years, and they reference a

G.E. topical report on this.

For 60 years the BWRVIP-74 revised that analysis, and provided maximum allowable or upper shelf energy drops, which the analysis would apply to. We asked Peach Bottom to go back and calculate their drop in upper shelf energy, and they fall within the bounds of the BWRVIPs criteria.

So the upper shelf energy is satisfied. As far as pressure temperature limits are concerned, this is a licensing amendment question that the applicant has, and we will follow in order to calculate pressure temperature limits, and you follow the guidance in Reg. Guide 1.99, Rev. 2.

And they will follow that, and they will update the pressure temperature limits according to their tech specs. The third bullet is reactor vessel circumferential welds, and this issue has to do with elimination of the inspection for the circumferential welds, and the BWRVIP-05 demonstrated that the failure probabilities of the BWR fleet was low enough so that we could eliminate inspection.

The failure probability is dependent upon the shift in the adjusted reference temperature, and what the applicant did here in their license renewal application for 60 years is that they showed that the adjusted temperature for 60 years would not exceed the values in the guidance document BRWVIP-05.

And therefore they have satisfied that criteria. The fourth bullet deals with --

CHAIRMAN LEITCH: Barry, just before you move on, the first and third bullets, the upper shelf energy and the circumferential welds, in the license renewal application, in both places, it says that Exelon will do calculations after the G.E. fluence methodology has been approved by the NRC.

Did I understand you to say that that methodology has now been approved by the NRC?

MR. ELLIOTT: Yes. What happened was that is what the original application said, and we wrote back to them and we told them that the methodology was approved in September of 2001, and they went back and recalculated all of the fluences and was able to answer all of our questions specifically about these issues.

CHAIRMAN LEITCH: Now, did they just say that it falls within the bounds, or do you have specific data in that regard?

MR. ELLIOTT: Well, they gave us the neutron fluence, and we know that the materials that we calculate, we confirmed the calculation that they fell within the bounds.

CHAIRMAN LEITCH: Okay.

MR. ELLIOTT: And then the fourth bullet has to do with -- it says reactor vessel and failure probability, and this has to do with the axial welds, and again it is similar to the VIP-05, in that in the case where axial welds, and we were looking at VIP-05, the failure probability for axial welds was much too high we thought.

So we asked them to redo the analyses in a more realistic assumption, and they came up with a failure probability for axial welds. Again, that was dependent upon an adjusted reference temperature, and the licensee went back and confirmed that they would be within the bounds of that, and so it met the criteria there.

And we have also confirmed that. The next issue is the core shroud and top guide, and this is a new issue for the staff. BWRVIP-26 establishes screening criteria for radiation assisted stress corrosion cracking.

The only -- the core shroud is below that limit, and in the top guide, the only component that are above the limit projected by the applicant are the top guide beams.

They will exceed the threshold limit. The staff is concerned that if you exceed this threshold limit that there could be multiple failures of the beams, and the staff is concerned that if there are multiple failures of the beams that there could be a loss of function of the top guide.

We asked questions of the applicant on this, and the applicant has responded. Right now the staff has the final position on this, and we are evaluating it. And right now this is an open issue.

MEMBER WALLIS: Why would this be multiple failures? Isn't this the kind of thing where the problem is sort of low and adding up to the limits and something happens, and so they don't all go.

MR. ELLIOTT: Well, the problem -- we have had this problem in Oyster Creek and we had a couple of failures, and then a similar thing as an example, would be about the baffle bolts. When you exceed the limit, you don't automatically fail everything.

But you could fail enough that you could lose the function, and the question is what inspection is required to make sure that you don't lose function, if it is possible to fail multiple of these. And that is the issue that the staff is concerned bout.

MEMBER BARTON: Well, what inspections are being done, for example, at Oyster Creek that does have cracks on the top --

MR. ELLIOTT: They are -- they only inspect it during the -- as part of the -- whatever they look at the internals, they look at it from there.

MEMBER BARTON: And what is so hard at doing that at Peach Bottom?

MR. ELLIOTT: I don't want to prejudge anything.

MEMBER BARTON: I am just asking you.

MR. ELLIOTT: I don't think that is difficult, but that may not be -- and it also depends on -- to me, what does the word multiple mean. If multiple means 2 or 3, then you have a certain inspection program.

If multiple means 25 or 30, or 40 percent of them have to fail, then you have a different inspection program.

MEMBER BARTON: I understand that.

MR. ELLIOTT: And so we have got to get a handle on what that multiple means before we can really say this is acceptable or that is acceptable.

MEMBER WALLIS: Well, don't you notice something before 30 fails?

MEMBER BARTON: You should.

MEMBER WALLIS: You should?

MR. ELLIOTT: Yes, you should, and that may be the answer, and that is all you need to look to see; 30 fails and that is the end of it. But it is something that we have to decide and look into.

MEMBER BONACA: And this is likely to affect other plants, too.

MR. ELLIOTT: I think it will. It is a new issue for the nuclear field for us.

MEMBER SHACK: But even at the end of 60 years, your core shroud doesn't hit the radiation assisted stress corrosion cracking?

MR. ELLIOTT: That is the answer in the RAI said.

MEMBER BONACA: Very interesting.

MR. DYLE: This is Robin Dyle from Southern Nuclear and representing the VIP. Bill, to your question, there might be some plants that the H-3 welds, the mid-core weld, might exceed their fluence limit, but that's going to be on a plant specific basis. It depends on the core loading and things of that nature.

So each plant will have to evaluate that. Should they exceed that limit, there is already inspections in place for that location, and then if you have got flaws, we require the adjustment in the crack growth rate, and dealing with the loss of fracture toughness associated with that irradiation embrittlement, so that you would shorten the time between inspections to account for that change.

In regard to the top guide as Barry discussed, there is one plant that has had cracking. If you consider cracking a failure, then there has been failures, but only one plant has had cracking, and it is the top guide grid structure.

And to date there has been no failures, and what the VIP has put in the document is that we have done an evaluation of those flaws, and it is IGSCC, and it was going very slowly.

We have not seen a need to change the document to require inspection of those areas because you would truly have to have a failure. And in our mind that is a failure where the beam cracks sufficiently all the way through that multiple beams would have to fall down to the core plate, and then the entire core shifts and so you could not insert the control rod drives.

We don't see that happening. One of the things that occurs every outage, at every plant where you remove the head and you are doing in-vessel work, is the top guide is available for visual examination. It is routinely seen by what would be considered a VIP-3.

That in and of itself assures you that you don't have a beam that is broken at one end or several sections of the beam that might have cracked all the way through.

So until that occurs, there is not a safety significant issue. So the VIP hasn't seen the need to describe an inspection requirement for that component as of yet. We will continue to monitor what is going on as we get experience, and if that changes, we would do so.

But that doesn't really address what Peach Bottom is going, but that is what the VIP is doing with that issue.

MEMBER WALLIS: That sounds reasonable.

MR. DYLE: And from an Exelon perspective, we will continue to follow the VIP guidelines, and we had done inspections of the top guide at Peach Bottom, and I am going to ask Rich CIemiewicz to talk about what those have been.

MR. CIEMIEWICZ: Rich Ciemiewicz from Exelon. As we had talked about, we do follow the

BWRVIP guidelines right now with Peach Bottom, and currently those guidelines do not require examination of the beams. We have, however, based on earlier guidelines, G.E. Sills, et cetera, performed some examinations.

And in fact we have performed both UT examinations and visual exams of these grid beams. Back in 1987 and '88, we had performed UT, and found no indications whatsoever.

And then in '94 and '96, we did perform visual exams of some sample cells and found no indications of any cracking. So we continue to follow the VIP guidelines, and if they were to be revised to require examinations, then we would intend to follow those guidelines.

MEMBER BARTON: It sounds reasonable to me.

MR. SOLORIO: If there are no more questions on the 4.2 and the 4.5, John Fair will present the results of 4.3.

MR. FAIR: Section 4.3 covers metal fatigue, and to address metal fatigue, the applicant chose to monitor a sample of high fatigue usage, and locations include the pressure vessel, vessel internals, of course, and the coolant loop piping.

This is similar to the approach that was used by Hatch, with one difference in this particular program, and that is that they are using some automated industry software to monitor detailed cumulative usage factors stresses at a couple of critical locations.

One of them being the feed water nozzle, and another being the vessel support skirt. They also have a couple of cases where the projected CUFs for 60 years may be high, and therefore, I think that is the reason that they are going to an automated monitoring type of system.

One of the areas is the stud bolts, which they project may exceed the CUF during the current operating time based on a conservative projection. But it appears from the responses that they think that the projection is fairly conservative, and that the monitoring is going to show that they are not going to exceed it during the current period.

But they still have a contingency if they do exceed the CUF to either do some more detailed calculations, repair or replace, or as an alternative proposal, to have some kind of an inspection program to monitor for cracks.

And I will get into that further in the

last bullet on this slide. In addition, they evaluated the environment impact effects on fatigue usage.

They originally had an argument that there was enough conservatism in the original design analysis to account for it. We asked for an RAI in this area, and asked them to do a specific evaluation of the six locations that we normally choose for every other plant.

And they responded that instead of doing the analysis right now, they committed to perform the evaluation prior to the period of extended operation for those six locations which are in the staff's NUREG 6260 applicable to BWRs.

We didn't have an open items in the review, but we did have a confirmatory item, which was to get two commitments into the FSAR supplement. One of them is the commitment for the potential corrective actions for the stud bolts where the CUF may exceed one in the period of extended operation.

And the other is the commitment to do the environmental evaluation, and again the corrective actions for the environmental evaluation if they project the usage factor to exceed one in the period of extended operation.

The bullet on license amendment really relates to the third option. If they choose to take some kind of a program instead of showing that they meet the usage factor criteria, and they decide that they want to monitor by some inspection program, we have requested that they submit the details of that program to the staff for staff review and approval prior to them implementing them.

The license amendment is the vehicle in which we are requesting them to do that.

MEMBER SHACK: John, in the cycle counting program, they are computing the CUF from those cycles, with essentially no consideration for environmental fatigue?

MR. FAIR: That's correct, currently.

MEMBER SHACK: Currently.

MR. FAIR: Yes.

MEMBER SHACK: And on the B31.1 typing, where here is no sort of explicit fatigue analysis, is it the staff's judgment that there is enough conservatism in there that you don't have to worry about environmental fatigue in those cases?

MR. FAIR: Yes, I believe that is the position on that, because usually what happens for the B31.1 -- well, let me back up on that, because for

B31.1 plants on the reactor coolant loop piping, we have requested those plants that are designed for B31.1 on the coolant loop to address the six locations, regardless of whether they have a fatigue analysis or not.

And those locations are locations where we expect to get significant fatigue transients. For the rest of the piping systems which are usually considered Class 2 and 3 piping systems, they are designed based on a criteria that is just looking at the range of bending stresses.

And for most cases, they don't see a lot of significant design transients. There have been cases that utilities have looked at particular items that were designed to B31.1 type of criteria, one example being originally on Calvert Cliffs on the feed water nozzle, where you do get some cycling occurring on that particular nozzle.

And they did see fit to actually do some detailed monitoring at that particular location.

CHAIRMAN LEITCH: A question regarding the SER on page 4-3, and under the paragraph of feedwater and control rod drive nozzles. The title is control rod drive nozzles, but the verbiage there refers to control rod drive return line nozzles.

And I am not sure which is correct, but I believe at Peach Bottom that control rod drive return lines used to be just off one nozzle, and that was capped.

I guess I'm just not sure what we are talking about here. Is this the control rod drive nozzles, or the control rod drive return line nozzle? Do you see where I am, on page 4-3?

MR. DYLE: If I could, this is Robin Dyle from Southern Nuclear. That goes back to an old owners' group analysis that was done, and it was done in response to NUREG 0619, which addressed fatigue cracking in BWR feed water nozzle inter-radiuses, and the control rod drive return line nozzle. So that is what it is.

And all but two of the plants in the country have cut and kept those lines and so that has become not an issue going forward.

CHAIRMAN LEITCH: Peach Bottom is cut and capped, right?

DR. POWERS: That's right. Peach Bottom is cut and capped a long time ago.

MR. DYLE: But there was a generic analysis that the owners group did in concert with G.E. that dealt with that that prescribed the inspection programs for this.

CHAIRMAN LEITCH: So this verbiage I think on page 4-3 of the SER needs to be clarified.

MR. SOLORIO: We will look into that. We apologize that the reviewer is not with us here right now.

MEMBER ROSEN: I probably should have asked this question a long time ago, but in some other discussions of this subcommittee, and the full committee even, we talked about would we recommend the extension of the license for just any plant, regardless of its ROP status.

And I think we concluded, well, no, and so I think it is based on that that it is incumbent upon us that we ask that question, even though I think I know the answer.

What is the ROP status of this plant? That is not a question for you, John. Where does this plant stand in the ROP? If I went to the web page what would it show?

MR. SOLORIO: I looked at it and it would show all green at the highest level right now. I am not prepared to go over that with you. I can actually prepare to come back at a later time and meet with you or have a conference call and go over that with you.

MEMBER ROSEN: No, I think that for the full committee that you might make the point about what the ROP status is.

CHAIRMAN LEITCH: And we will go around the room here when we are done and talk about perhaps some of the issues that should be raised. Let me ask one more question here though.

The cumulative usage factors at the end of 60 years for Peach Bottom Number 3 is 1.02, and I guess I am not clear what we are talking about there. It says in the verbiage on page 428 of the -- and now I am in the license renewal application.

It talks about the support skirts, but the table seems to imply that it is the reactor vessel lower head to shell transition.

MR. FAIR: I think there is a footnote, and I will make sure the applicant confirms that says that as an alternate location the location in the table was one of our 6260 locations.

But as an alternate location where they had the more critical fatigue usage that they were going to monitor there, and I believe that is what that usage factor is involved with.

MR. PECAL: Yes, this is Eric Pecal, and we did find one from a calculation perspective on

1.02, and what we planned to do with those areas and program and monitor it, because we believe that there is lot of facilities relating to that number, and trying to redo the analysis is (inaudible) program which over a period of time will reflect where we are going with that thing, and be able to manage on that basis.

That is what the second line item on there reflects, and so we actively support that location.

CHAIRMAN LEITCH: But I guess Eric what I don't understand is are we talking about the lower heads to the first ring of the reactor vessel, or are we talking about the lower heads of the support skirt?

In one place, and that is in the verbiage on page 4-28, it seems to imply a kind of a -- on the second full paragraph on that page, it seems to imply that we are talking about the support skirt.

Whereas, on the table it seems to imply that we are talking about the shell transition. Now, is this a pressure boundary that we are talking about here, or is this a structural boundary?

MR. POLASKI: Our memory on that is that is a location that is on the outside of the reactor vessel. That is the skirt to the vessel location. I remember that because that location is not subject to environmental assisted fatigue, because it is not subject to the reactor water environment.

CHAIRMAN LEITCH: Right.

MR. FAIR: So it is where the support skirt is attached to the lower head.

CHAIRMAN LEITCH: The lower head, yeah. So the words in the table then are incorrect?

MR. FAIR: Yes, they appear to be. They are not the best words to use, yes.

CHAIRMAN LEITCH: Okay. That answers that question. I guess I had another question here. The license renewal application, page 439, I guess I have the impression reading this that the torus penetrations that there is a CUF of .992 for 40 years, and would that mean then that we would be up to like 1-1/2 or 60 years?

MR. SOLORIO: Graham, unfortunately the reviewer who did that review isn't with us at the moment. We had tried to get him over here, and so we could anticipate a question that you would ask on this section. So we are going to have to get back to you with an answer on that question, sir.

CHAIRMAN LEITCH: Okay. Do you understand the question?

MR. SOLORIO: Could you repeat it?

CHAIRMAN LEITCH: I am looking at page 439 on the license renewal application, and at the top there it refers to number two, torus penetration, having a CUF of .992.

MR. SOLORIO: Yes.

CHAIRMAN LEITCH: And the question really is that from the reading of that there that is based on 40 years, but how about 60 years? It would seem to be up near 1.5. Is that acceptable, I guess, is my question.

MR. SOLORIO: Okay.

MR. POLASKI: I guess I could answer that from an excellent perspective. The .992 number came out of the Mark-1 containment study when it was worked on a number of years ago with concerns about the Mark-1 design, and we did a lot of work to beef it up and tie it down, and that analysis was done at that time, and then documented, and you are right.

If you multiple that by 1-1/2, you go above one, and you go above that for a couple of occasions. So the way that we are approaching that is that that fatigue is the result of it opening and closing.

So we are going to be monitoring those locations with our fatigue management program to actually manage what has actually happened, because typically these kinds of calculations are done conservatively, and on straight-on projections, and the operating experience.

And so we are going to actually monitor that location through the fatigue program, and actually determine what the actual cumulative fatigue is at those locations.

CHAIRMAN LEITCH: So I guess my question really is what about in a -- what about in 59, where we have a LOCA. Are we going to be okay in this?

MR. POLASKI: As I understand it. I am not an expert on fatigue, but I have been involved with it for the last couple of years, and in talking to the people that are experts, that if you are at a fatigue -- a calculated fatigue of close to one, and you have a transient, you are not going to have immediate failure of that location.

The fatigue calculations are very conservative, and I talked to the people who do this a lot, and Barry, you can tell me whether you agree or disagree, or John. In one, you don't get cracks. You have got to go above CUFs of one.

And I am not talking about environmental assisted fatigue. But there is a lot of conservatism in the calculations that we use to calculate those numbers.

MR. FAIR: Well, I think what we assume is there is a certain probability of getting a crack initiation in a CUF of one, but that is a crack initiation, and it depends on the type of loading. Once you get a crack initiation, you have some time left to grow the crack and go to failure.

MR. POLASKI: And if you do get the CUFs calculated at one, then there is things that you need to do per the code and other things like that. It can be reanalysis to do the inspections.

So when you get to CUF-1,it doesn't mean that you have got component failure.

MEMBER WALLIS: Well, what does it mean? I mean, it must mean something that is significant, or otherwise we wouldn't do it.

MR. FAIR: Well, the way that the criteria was established was originally there was some testing of some specimen components for fatigue crack initiation, and the test data was then adjusted to account for differences between the specimen tests, and actual components.

And there was some adjustment for data scatter in that, and so if you account for data scatter, even with the test specimens, there is a certain probability of initiation at a CUF of one, but most of the specimens would not crack at CUF equal to one.

MEMBER WALLIS: So what sort of probability is there?

MR. FAIR: Well, Bill is here, but I think some of the studies that were done with the design fatigue curves indicated that the probability was something between 1 and 5 percent probability of initiation of a CUF equal to one.

MEMBER WALLIS: And what happens when it goes to 1-1/2?

MR. FAIR: The probability increases.

MEMBER WALLIS: What is the number? Does it go from one percent to a hundred percent, or one percent to two percent?

MR. FAIR: If you go -- now again we are talking just the adjustment of laboratory data for fatigue and air. If you take the fact that a factor of two was applied to the covered data scatter, you would say that from 1 to 2, if you went up to a CUF of 2, you would probably have a 50 percent chance of fatigue crack initiation, and you would draw some kind of crack curve in between the two.

And actually some of the studies done by Oregon have formulas for calculating that probability of fatigue crack initiation at a given CUF, some of the NUREG reports.

MEMBER WALLIS: So suppose you have a criterion, and if you get above a certain CUF, then you have to act in some way?

MR. FAIR: Well, that is the CUF of one. That is the design criteria.

MEMBER WALLIS: Does that mean that you have to sharpen your pencil when you get to one; is that what you do here?

MR. FAIR: That is what happens a lot of the times. Usually the calculation is done on a conservative basis for simplicity sake.

MEMBER SHACK: I mean, the designer gets it below one and quits. It is good enough.

MR. POLASKI: I think the other thing that you have to consider on this is that the fatigue damage calculations, the CUF calculations, are assuming design transients, which when we are looking at this, we are looking at thermal fatigue damage.

It assumes step changes in temperature, and in reality the transients in the plan are not step changes in temperature. They are less than that. So that when you start looking at the actual transients, you can get reductions in calculated CUF of factors of 13 to 30, to a hundred.

And there is continuing work going on about how much we can credit for that, but from what I have seen, it is a significant reduction in the calculated when you take actual transient data versus the design data.

And the one thing that we are doing with our fatigue pro monitoring program, with the exceptions of two locations, the feed water nozzle, and the support skirt, we are monitoring on a counting basis.

So we are still assuming that it is designed step change transients when we are getting it in close to one, and we take into account more realistic data when we do the analysis on these particular locations.

CHAIRMAN LEITCH: It is not particularly in this section, but while we have the metallurgical folks assembled here, we briefly mentioned, and I can't find the reference now, but we briefly mentioned -- I think it was on Unit 3, a main steam nozzle with a manufacturing flaw. What is the significance of that? An anelbow I should say.

MR. FAIR: Excuse me?

CHAIRMAN LEITCH: A main steam anelbow I think on Unit 3?

MR. ELLIOTT: That was a TLAA and it was evaluated to see what the impact of heat-ups and cool-downs are in 60 years would have on the growth of that flaw, and it was very insignificant.

CHAIRMAN LEITCH: This was a manufacturing issue.

MR. ELLIOTT: Yes.

MR. SOLORIO: Yes, the reviewer gave me a few notes. An embedded, as forged, laminar tear in the Unit 3 main steam flow anelbow material was discovered during pre-service UT inspection. It did not extend to the weld. The applicant performed (inaudible) Section 3 Class 1 fatigue analysis, considering the flaws of local discontinuity, with a high stress concentration factor.

The analysis determined the highest primary, plus secondary, stress was within the code allowable, and in the cumulative uses factor of 0.12 was conservative below 1.0.

Pursuant to 10 CFR 50.21, we made a conclusion that they are managing the aging by the current analysis, or they are meeting the requirements that the TLAA by the current analysis.

I wanted to also add to the question that you asked about 4.6, we do go on record here in the SAR and talk about the applicant will use a fatigue monitoring program to manage aging of that component that you are asking about.

We will get back to you though later with more information on that specific value, but the expectation that I have is that the way they are using the fatigue monitoring program, it is going to be caught before it becomes a problem, and we will get back to you.

CHAIRMAN LEITCH: Okay. Any other questions on this section at any rate? We are at the end of the agenda now, right, or at the end of the presentation part.

MR. SOLORIO: Can I ask one question? I have one IOU in the back of my mind right now. Are there any others?

MEMBER ROSEN: Excuse me, but you have one what?

MR. SOLORIO: IOU. I am going to get an answer on the specific fatigue usage number that Graham just pointed out, and I was just wondering if there were any other questions that we didn't answer during the day.

MR. KUO: Dave, we are going to find out the ROP status?

MR. SOLORIO: Right, the ROP status. Okay.

MR. KUO: And if there is no further questions, Dr. Leitch, this concludes the staff presentation.

CHAIRMAN LEITCH: Okay. Well, thanks. I want to say now that I think that the next thing we should do as a committee is kind of poll the subcommittee here and see what we think the proper disposition of this should be.

Is there any reason for an interim letter right now? We are thinking in terms of no interim letter, but of a verbal presentation at next week's full committee meeting, to be followed by a full committee meeting with respect to Peach Bottom probably in the March time frame, I believe.

MEMBER BARTON: From my perspective, I don't think you need an interim letter. That is just the way I look at this.

CHAIRMAN LEITCH: What I was going to suggest, John, is that maybe we should take 10 minutes, and take a little break, and then come back at 4:15, and kind of poll around the room and see what are the issues that are still -- you know, that are still on people's minds, and we will go from there.

So I want to thank the staff for their presentation, and the Exelon folks for their presentation. I think the presentations today have been very, very good, and very responsive to our questions.

And we will poll the subcommittee here when we resume at 4:15.

MEMBER BARTON: I've just got one question. Why is the "O" in Exelon green?

CHAIRMAN LEITCH: I don't know.

MEMBER BARTON: I wonder if there is any safety significance to that.

CHAIRMAN LEITCH: Let's recess until 4:15.

(Whereupon, at 4:07 p.m., the meeting was recessed and resumed at 4:17 p.m.)

CHAIRMAN LEITCH: Let's come back into session. Unfortunately, we truncated David's presentation, and he has got one more slide to go. So why don't you wrap it up there with that one concluding slide.

MR. SOLORIO: All right. The next steps, we are going to talk about whether you need our support next week, and to what degree. Right now we are going to focus on the remaining open item, and we are glad that you all were able to hear some of the dilemmas that we are facing with that one.

The formal responses to these open items are due on November 29th of this year. I have a date here for the final SER being 3/25/03, but that is when we issue it as a NUREG.

Actually, the date that we expect to be finished with the SER, in terms of closing the open items out, is February 2nd. But it takes a number of weeks actually to get it put together as a NUREG.

So I just wanted to make sure that you all didn't think that we were moving the schedule out, okay? And that is all that I have. Thank you very much, sir.

CHAIRMAN LEITCH: And I think, David, that our wrap-up of this with the final committee is scheduled for the March '03 meeting if I am not mistaken. So that seems to dovetail with the schedule that you have there.

To answer your first question, I don't think we need all the presenters next week by any means, but I do think that it would be good if we had perhaps yourself if that is possible, David.

MR. SOLORIO: Sure.

CHAIRMAN LEITCH: And PT, you may want to be there, too.

MR. KUO: We will be here.

MEMBER ROSEN: I think we should go around the table and see what the issues are, and you might want to think about that after you hear the issues.

CHAIRMAN LEITCH: Okay. So, Dr. Wallis.

MEMBER WALLIS: That's easy. I don't have any issues to raise at this time.

CHAIRMAN LEITCH: Okay. John.

MEMBER BARTON: My questions were basically answered, even though I didn't like the answers to some of them. But I think the important thing here is for the full committee to see the difference between this application and other ones that they heard about, and this boundary concept that they have in their format.

CHAIRMAN LEITCH: By boundary do you mean the realignment?

MEMBER BARTON: Yes, the boundary realignment thing. I think the committee ought to hear that. And I think the main thing remaining is a resolution of the open items to the staff, and the ACRS to their satisfaction. I think that is really where the nuts and bolts are in this application at this point.

I don't have any burning bushes, or major issues from my review, that I think would prevent an extended operation from what I see. So as far as on the full committee, are you are going to have the licensee make a presentation at all or just the staff? Just the staff?

CHAIRMAN LEITCH: Next week, we were thinking not, I believe.

MEMBER BARTON: Just the staff?

CHAIRMAN LEITCH: And I don't even know that the staff is going to make a presentation. I think what I am picturing is making maybe a 15 or 20 minute verbal discussion myself.

MEMBER BARTON: Okay. So you have a real short agenda in the main meeting?

CHAIRMAN LEITCH: With just some support from the staff here in case they are needed. Now, certainly we are not talking about the March meeting now.

MEMBER BARTON: No, I was talking about the November full ACRS meeting.

CHAIRMAN LEITCH: That is assuming that we see no need for an interim letter, and that the cycle is just going to be to make a brief summary presentation to the ACRS in November, and then have the full ACRS meeting in March.

MEMBER BARTON: Well, I think at that point the full ACRS needs to get the subcommittee sense for this application, versus other applications, and what is different about it, and what is good about it.

And what are the open items, and I think that is all that you need to cover.

CHAIRMAN LEITCH: Stephen.

MEMBER ROSEN: I have a number of comments, and they go to different places, and so that I will organize, and let me just hit them. The first one is kind of a reverberation of the point that you have made several times, Graham, about the what you have reviewed for the staff.

Many analyses of the PLAs and subsequent interactions with the staff are deferred until the end of the initial operating period, and that creates this workload that they have a new procedure for.

And I don't think the full committee has heard that, and furthermore, I think that if the full committee was going to write a letter that it might want to somehow communicate to the Commissioners that this is creating a bow wave of work for the staff out in a narrow time window in the future.

And the staff understands the issue, but I think the Commission should be aware of it. So I think that is something that we ought to put in some formal communication to the full Commission. The system boundary realignment --

CHAIRMAN LEITCH: Just for clarification, that is not specifically a Peach Bottom issue.

MEMBER BARTON: No.

CHAIRMAN LEITCH: It is more of a work planning issue for the Commission.

MEMBER BARTON: That's exactly right.

MEMBER BONACA: And it is more of a time when we could proceed with that in a letter that we are due to write in the spring regarding the generic issues, and particularly the adequacy of the guidance document.

MEMBER ROSEN: Yes, it would be very good in that. And the ACRS subcommittee on planning and procedures might want to consider that next week and figure out when we want to interact, and when and where we want to get that message up to the full committee and to the Commission.

CHAIRMAN LEITCH: We have an SRM.

MEMBER BONACA: We do have an SRM.

MEMBER ROSEN: So we have the SRM, and so you are already deciding it, and that's okay. I think that it needs to be communicated.

MEMBER SIEBER: The real issue there is the one time inspections. That's probably where you will get bogged down, but there is a limit. You are supposed to do that within the last 10 years of the 40 year period.

So that it really represents that point in aging life. On the other hand, the aging analysis and that kind of stuff, those kinds of open items, they ought to be worked on and finished up as we go along, and you can start those now.

CHAIRMAN LEITCH: Although I think the one-time inspection is really a burden on the licensee.

MEMBER SIEBER: That's true.

CHAIRMAN LEITCH: I think what we are talking about here is making sure that the staff has the manpower and the resources necessary to inspect to the extent necessary that the licensee has done what they have to do.

MEMBER SIEBER: Well, that's true. On the other hand, if you inspect at the last minute then that burden goes to the staff.

MEMBER ROSEN: That's exactly what we are talking about.

CHAIRMAN LEITCH: That's true.

MEMBER ROSEN: Having an unmanaged deluge of work for the staff.

MEMBER SIEBER: The big issue is going to be when you have about 10 of these plants in a row.

MEMBER ROSEN: Exactly.

MEMBER SIEBER: And then you are going to be running around, and you either are not going to be able to do as good a job as you should, or you are not going to be timely.

MEMBER ROSEN: Right, and I would think that it is serious because a lot of the issues that we have talked about have referred to the demonstration of some sort of something based on the timing of the aging analysis at a point in the future, or some substantive matter.

And the staff will have to interact with the licensees, and maybe inspect, you know, and so I think it is an issue, a planning issue for the staff. So enough of that. I think the system boundary realignment technique that John mentioned, is cumbersome to the staff review, and may be somewhat opaque to the public, and maybe somewhat opaque to the ACRS.

And the staff should interact with NEI to make clear their preference for the scoping approach. That is a message to the staff really. It is not open season over here. I don't think that licensees can do anything the way they want without some net loss of efficiency and effectiveness on the staff, which means that schedules will extend.

If the staff finds a way to do something that is more effective and efficient, I think they need to communicate that clearly with the licensees or for the licensees.

And say, look, if you are going to do it this other way, it is going to take us longer and we prefer you not do it, and so there is a lot of messages there. I don't know where we put that point, but I think John and I -- John Barton and I feel the same way about that one. That is a significant matter.

I didn't get a good -- another subject. I asked a lot of questions, most of which I got I think satisfactory answers for. But I did not get a good answer I don't think to the stand-by gas treatment aging effects.

I guess I don't believe the argument that the components that are kept warm are insulated so that there is no likelihood to be any moisture pocketing effects or effects on the shell of the stand-by gas treatment systems, and the galvanized portions of it.

So I would appreciate some specific further information on that, either before the meeting or at the meeting.

MEMBER BARTON: What is the environment for that system? Is that system in a building or is it outside near the stack, or where is it physically located?

MR. POLASKI: Most of the system is inside. The fans, the flippers, are all in the plant.

MEMBER ROSEN: In the building?

MR. POLASKI: The discharge goes underground though, because at Peach Bottom, the stand-by gas treatment system exhausts to the main stack, which is up on top of the hill behind the plant. So there is underground piping on the discharge going up to the stack.

But the duct work that is in the building is in an environment that -- it is not air-conditioned, but it is a controlled in-door environment, and we have not had any experience at Peach Bottom with water collecting in any of that duct work or any degradation on that duck work.

MEMBER ROSEN: Please understand that I am not so concerned so much about corrosion outside in. I am more concerned with inside out corrosion from moisture condensation inside the duct work and the effect of that on the shell of the -- on the pressurized shell.

MR. POLASKI: I understand.

MEMBER ROSEN: So anything that you can do to help me realize that is not a problem would be helpful.

MEMBER SIEBER: That has charcoal filters in it?

MEMBER ROSEN: Yeah, charcoal filters, and it has even got water piping typically to put out a charcoal fire.

MEMBER SIEBER: Is that the thing that at Perry that burned up and caught fire?

MEMBER ROSEN: I don't know.

MEMBER SIEBER: It was on fire for several days.

MEMBER ROSEN: I don't know.

MR. POLASKI: That was the charcoal I

think in that system.

MEMBER ROSEN: No, I think that might have been in the off-gases.

MR. POLASKI: Yeah, the charcoal and the stand-by gas would not burn for several days. There is not enough load there.

MEMBER SIEBER: Okay. You're right.

MR. KOBETZ: Is then Exelon committing to give us that information then at the next meeting?

MR. POLASKI: I think what we will do is we will work with the staff to get you that information early this week or early next week so you will have it.

MEMBER ROSEN: The staff can just e-mail me a response.

MR. KUO: The staff will be working with the applicant and we will send you an e-mail for before the meeting.

MEMBER ROSEN: Will you say again what you just said?

MEMBER SIEBER: I think we want it in the record, and not as an e-mail.

MR. KOBETZ: So that it will be presented at the next meeting.

MEMBER SIEBER: Yes, we have a transcript of your question, but I think we ought to have a written answer that makes it to the record.

MEMBER ROSEN: And the last point that I had was that I think as a general thing we should have an ROP status of all applicants who want license renewal and license extension, and present it to the full-committee and submit it to the full committee so that we know what is the plant's current performance.

That doesn't guarantee the future clearly, but --

MEMBER BARTON: But that gives us a snapshot right now though.

MEMBER ROSEN: Well, in the past, at least in the past. So I guess we have a commitment from the staff to have that for the full-committee.

MR. KUO: Yes.

MEMBER BARTON: Let me ask you something. What good do you see out of this when you take a plant that we are all familiar with, and that was an info on and was hunky-dory two years ago when the ACRS visited that plant, and all of a sudden things went to hell, and now it is the worst plant in the country?

So what good is this ROP tell you now or in the last 18 months what their performance has been?

MEMBER ROSEN: Well, that is an indictment of the ROP that is so broad sweeping that I don't think that I can respond to it. I think what we have to say is what does the ROP -- the ROP is the agency's current measurement of plant performance.

And when we are considering a licensing action like this, we should have a reading from it.

MEMBER SIEBER: Well, my question is that once you have the information, which each one of us could get off the website if we wanted, what are we going to do with it?

You aren't going to put it in the letter, and you aren't going to withhold your recommendations, because that is all we do. We don't approve anything.

MEMBER ROSEN: I'll tell you what I will do with it.

MEMBER SIEBER: It is not all that clear to me what it is that -- you know, the rule doesn't require it.

MEMBER ROSEN: Can I answer

MEMBER SIEBER: Well, in a minute. And if you have a plant that is mediocre, and is mediocre today and not 15 years from now after some get well program, it is not clear to me what it is that you get out of that.

MEMBER ROSEN: Okay. If the answer to

your question from me is if the plant is in red, or in a seriously degraded state, it's operating experience upon which this program relies is not very good obviously, and I couldn't recommend for this license to be extended.

MEMBER BONACA: I don't think it would come to us.

MEMBER SIEBER: If it is in red and it is not running --

MEMBER ROSEN: It is not running.

MEMBER BONACA: It's a good point.

MEMBER SIEBER: Because if it is in red, it is not running. That's true.

MEMBER ROSEN: It doesn't mean that it can't get its license renewed. I mean, that it can't ask for license renewal.

MEMBER SIEBER: That's right, but it doesn't mean that when you get it renewed that you are allowed to run, okay?

MEMBER ROSEN: Right. It doesn't mean to me that we should spend any time looking at a license application from a plant like that because we don't know what the circumstances are going to be like in that plant when it is finally allowed to operate.

MEMBER BONACA: That's true.

MEMBER SIEBER: Well, I think that is a policy decision that somebody needs to make, and I think we are stepping outside of whatever responsibility there is there.

MEMBER ROSEN: Are you suggesting, Jack, that a question about what is this current plant's ROP is out of bounds?

MEMBER SIEBER: I don't think there is anything that you can do with it once you know the answer.

MEMBER BARTON: I don't think it is out of bounds. I just think it doesn't do much for you to know whether it is green, white, or yellow. Because you know that if it is red, then it is shut down. So if it is green, red, or yellow what are you going to do with it.

MEMBER ROSEN: Well, I leave it on the table. This ACRS member would like to know the ROP status, and it is true that I could go back on the website and look at it, and maybe I have, but the issue is not about what I know. It is about what is on the record to me. That's all I have.

CHAIRMAN LEITCH: All right.

MEMBER BONACA: Well, I think in general that it was a reasonable application. I think that we can renew all the questions, and they were answered. I still have some concern with the documentation, and I voiced this a number of times.

What is documented in the application and what is documented in the review, and what is documented for the future. And the example that I would like to quote here is again in the application the service water system is not in scope.

In the presentation the service water system is in scope. Then we discover that some portions of it are in scope. And this is true of other systems which are listed both in the application and now there is a logic behind that?

We understood that we got a good explanation on the realignment and the system boundary realignment. And we know that all applications have to do some of that. The fact remains that I am still questioning in my mind if there is going to be one place where there is a clear statement of what is in scope, and what is not in scope.

I understand that if we punch up all these documents and we go back now to the RAIs, and we look at the SER, that we can put it all together. But I wonder about those guys will pick up again this application 15 years from now, and try to implement the inspections and so on. It may be more confusing.

So that is just a point that I raised I believe already some months ago, and it is a current issue in my judgment that is not being totally settled. It is not unique to this application at all, and I don't think the in statement regarding this application.

I felt that the SER was a good SER, and that went through pretty well, and I think there was enough information in the SER to come to certain conclusions, and I think the conclusions in the SER were reasonably sound and general.

I liked the presentation that we got from Mr. Elliott and others. They were informative. I feel that we don't have a need for a full discussion at the full meeting.

I think if we prepare it to the chairman that it will be adequate, and I don't think we need an interim letter at this time. That is pretty much my recommendation.

CHAIRMAN LEITCH: Thank you. Jack.

MEMBER SIEBER: I guess I agree that an interim letter is not required. I also agree that the best way to handle the November presentation is as you suggested, with support from the staff. I think that is sufficient.

I don't think there are enough issues out there where we need to have a long presentation and a big contest over the content of the application or the SER. I also agree with Mario that the application was pretty good and the SER was good.

As far as the boundary realignment, compared to the difficulty that I had with the Hatch application, and trying to figure out what was going on, I thought that this was close to heaven.

MEMBER BARTON: It is a lot better than Hatch, and maybe there is a simple way, and it is much better than Hatch.

MEMBER SIEBER: It took me a half-a-day to figure out exactly what it was that they were doing with the help of some drawings, and reading it a couple of times, I thought that the way that their systems are laid out, and the way they numbered things, that was probably a reasonable and with minimum confusion way of doing it.

But I do agree with Steve. There ought to be some kind of a system which I think is part of that SER where we hint to them what things could be firmed up a little bit that would allow us to not read rediscover the world, or rediscover different ways of doing stuff every time one of these comes down the pipe.

I happen to like this, but since I had only see two, plus the PWR, I don't know this one is the best, and maybe somebody will have different ideas.

But I think we know enough now how to do these, both from the staff side and from the industry side, that we ought to be able to settle on a format that would expedite the staff review, and our review, and the licensee preparation and so forth. But as far as I was concerned this was a pretty good one.

MEMBER BONACA: By the way, I would like to just chip in with the fact that I appreciated the presentation that we had on this realignment, because I think it showed us what they did, and we didn't have the benefit of something similar in previous presentations.

MEMBER SIEBER: And I thought that the explanation in the application was good enough for me to imagine what they were doing. But when I looked at the drawings, it was pretty obvious what they were doing, and how they did it, and what criteria they used.

So to me it was a simple leap to convince myself that they had done the right thing, and they probably captured everything that they should. But I do agree that when we respond to the SMR that we ought to make that an issue to sort of drive the BWR owners towards a consistent way of dealing with what is in scope and what isn't in scope.

The other thing I note is that I don't know how to examine scope issues without looking at drawings. For some reason or other, I just can't do it. I know some plants, but I don't know every plant that is out there.

And in particular when there is little quirks like putting a mechanical mark number on an electrical switch instead of an electrical one, and we didn't do that. Our way was that there were more numbers to remember, and at least they were consistent.

You know, everything that you do has to fit the way the plant was built. Among the technical issues, I continue to believe that Hiltis relax over time because of the deterioration of concrete.

I thought that we got an answer, but the answer didn't tell me anything about the future. It told me what had been done in order to ensure that the things had been set properly and had the margin that they were supposed to be set at, at the time that they were tested.

And I went through all of that, and I don't think it was 7902. It might have been, but I don't think that was the right one.

MEMBER ROSEN: It doesn't sound like it.

MEMBER SIEBER: But in any event, I went through all of that and I know how many failures there were, and I have seen transients that pulled hangers and plates out of the wall.

I know that concrete deteriorates, and loses and compresses strength. And I would like to feel more comfortable if there were -- I would feel more comfortable if there was some kind of look at the future as to the fact that these hiltis and other types of fasteners like that maintain their strength throughout the suspected life of a plant.

I would not like to see s seismic event where you end up with a lot of supports that pull out of the building. So to me that is an issue where we got an answer, but I was left with an uncomfortable feeling about the answer.

I think I now understand how the Susquehanna River works thanks to Don, but the explanation in the application was not real good. A picture is worth at least a hundred words, and a drawing was real good, and even the picture on the application cover would have been okay. That would have helped.

So other than that, I thought that it was a pretty good experience, and I learned some more about the VIP program, but not enough obviously. So that would be my comment.

CHAIRMAN LEITCH: Bill.

MEMBER SHACK: I thought it was a pretty good report. Again, I guess I am more optimistic about a number of these issues. I think this is the first BWR done on a system basis, and the guidance for the II over I is now in place and so the next time that we get an application I guess it will be built into the application rather than an add on.

Even the bow wave of work. To me, it seems like you are resolving a lot of the plant dependent issues in the current wave of license renewal of things, and a lot of the open issues will be handled generically.

That is, you will have a comportable report and your issue will be whether you fit in the bounds of that comparable report. So I think it will turn out to be a more manageable problem than it might occur, and I do think that the notion of the way that the VIP is going, and of setting up comparable reports, and handling as many items as you can on a generic basis.

And what the plant has to do is to establish that it fits into those bounds, and makes it much better for the plant, and makes it much better for the staff, and makes it much better for everybody. I like the way that we are going.

On the system realignment, you know, I think there is sort of general agreement that the system approach is the way to go. It fits in the NEI documentation, and so I think we will work out this notion of how to describe the system realignment a little bit better.

So I am a cock-eyed optimist type, and I think that every day and in every way it is getting better and better.

CHAIRMAN LEITCH: Tim.

MR. KOBETZ: One thing that you might want to consider is asking the staff at the full committee meeting is when they get all done, they are going to close out all the open items, but there is going to be a number of commitments, some of which are going to get drawn into the license conditions, and some may not.

You may want to get an understanding of which ones get drawn into conditions and why, and which ones don't and why. And then how those ones that don't are tracked.

And I think that is something that you have talked about a lot at this meeting and at past ones that you are talking about. And then also the second part to that is with the inspection process.

They have had two inspections, and they are going to have a close-out inspection. Then somehow that information has to also feed back into the SER.

And I think I had talked with the staff before and there is a letter from the regional administrator and something like that. But just drawing or tying a bow around everything so that when you get done you know what the commitments are, and which ones are captured because they are more important for safety.

And which ones are maybe just captured in the FSAR and could be changed with a 5059 evaluation or something.

CHAIRMAN LEITCH: That is a comment for the March meeting and not for next week's meeting.

MR. KOBETZ: Correct. That would be for the March meeting, but that is just a recommendation.

MEMBER BONACA: That's a good comment.

CHAIRMAN LEITCH: Yes. Ramin.

MR. ASSA: No comment.

CHAIRMAN LEITCH: Okay. I guess I really had nothing else than that. I think we have -- that almost all of us have referred to the realignment issues, and I guess that really comes in two flavors. There is the five classes.

DR. POWERS: Five cases.

CHAIRMAN LEITCH: The five cases, yes. I think that the five little schematic drawings there made that pretty understandable.

MEMBER SIEBER: The issue there is whether you are going to do it on a system basis or a functional basis. A system basis to me is a more logical way of thinking. But then you are forced into the realignment, and then you need to set a rule. But to me it is just easier to comprehend.

CHAIRMAN LEITCH: Yes, I think that's right.

MEMBER SIEBER: That was difficult.

MEMBER BARTON: That was too hard.

MEMBER BONACA: Well, the application of

the component one by one is not difficult, and the setting of the rule for your employees to do it, that is more of a help for the staff. But I agree that on a system basis that I support that.

MEMBER SIEBER: The functional thing is superior from a philosophical standpoint, because really what you are interested in is function, and you don't care how the system does it.

MEMBER BONACA: That's right.

MEMBER SIEBER: On the other hand, if you are an ex-operator you think in terms of the systems. So I am sort of stuck that way.

MEMBER BONACA: Right.

CHAIRMAN LEITCH: The other case is that maybe realignment is not the right word, but this issue of II over I, and there were a fairly significant list of systems that at least part of which got added into the process.

MEMBER SIEBER: Well, it is more than II over I isn't it? It is pipe whip, and all the high energy line break effects are involved there, too.

MEMBER BARTON: I think we have come a long way on it. I mean, you add more to the scope, but at least I think you now understand what they have done to address that issue throughout the plant. I kind of like what they did.

MEMBER SIEBER: Well, they have a bigger scope than they really need to have for the rules.

MEMBER BARTON: Well, don't tell them that.

MEMBER SIEBER: Well, if it becomes too complicated to figure out you are allowed to throw out, they are probably better off with where they are at. On the other hand, they end up making a bigger envelope to make sure that they fit everything in there, which I thought was a prudent way to do it.

MEMBER BONACA: In that sense, then in many cases they go on a central basis, and therefore they go on an expanded scope, and it may be capturing more work.

MEMBER SIEBER: You may be hitting outside the box all the time.

MEMBER BONACA: Exactly, and the impact that it has on the work.

CHAIRMAN LEITCH: So I guess that those two issues have been up for next week so that the full committee understands at least those two issues. I guess I am not really sure what we are doing to address your Hilti bolt question, Jack.

MEMBER SIEBER: Probably not too much

right now. But I am curious. I don't think it is a show stopper. On the other hand, I think it is an unanswered question. I also think it is generic.

MR. KUO: Yes.

MEMBER SIEBER: And not a Peach Bottom issue.

MR. KUO: If I may add. This is really a current issue, and if anything I would go back to our staff, technical staff, to really present this problem to them as a current issue. Not as a renewal issue.

MEMBER SIEBER: I think that is appropriate.

MR. KUO: And later on if the staff is ready, the staff can come back to the committee --

MEMBER SIEBER: Well, the aging question I think comes from license renewal.

MR. KUO: Right.

MEMBER SIEBER: Because concrete for 30 or 40 years probably isn't too bad, but real old concrete doesn't look too good and react too good.

MR. KUO: Well, generally speaking, concrete aging and the shrinkage, or whatever, would happen probably after one year or two years after it is poured.

The question about Hilti bolt or maxi

bolts losing their strength basically comes from a crack. If there is any crack in the concrete, then you really lose the safety margin there.

MEMBER SIEBER: But if the bolt is used to hold the base plate down, you can't see the cracks.

MR. KUO: I understand that, but that's why I say it is probably better treated as a current issue than as a renewal issue.

MEMBER SIEBER: Well, to me it is -- I don't picture it as a safety significant issue right now. It is more of a curiosity, but it is something that I wonder about.

And if I wonder about it and then say, well, I can accept that, then it sort of goes way. But I haven't gotten to that point yet that I can say that this is not a problem. I would still wonder.

MEMBER ROSEN: If PT is right, it comes from a crack, and the crack occurs randomly in the hilti foundation, it is not a big problem, because you are going to have a failure here and a failure there randomly.

But if it is more generic, and it is just old concrete, then all the hiltis are in old concrete and so now you are going to have a common mode failure of the hiltis in a seismic event, and that is a much more serious concern.

MEMBER SIEBER: Well, the way that they are tested, too, they are tested basically in tensile. But when you load them, in a seismic event, they are loaded laterally, and so there is a bending moment, and that opens the cracks and does different things.

MR. KUO: And that is why that you have a factor of safety of 8 of 4 or 4 to 8. In Southern California, they require the factor safety as eight, and during the 846 evaluation, they require a safety valuation of 6 to 4.

MEMBER SIEBER: How can they establish that there is enough margin and I will go away.

MR. KUO: But what I am really trying to say is that I think that this is really a generic issue.

MEMBER SIEBER: I do, too.

MR. KUO: And it shouldn't be treated in the renewal space.

MEMBER SIEBER: Is it renewal that causes or contributes to the aging?

MR. KUO: Correct. Right.

MEMBER SIEBER: And at least in that sense it is a renewal issue. I wouldn't have thought of it had I not been thinking about license renewal.

MR. KUO: If the cracks come from the aging of the concrete, yes. That might be proper to deal with it in a renewal space. In this case, what I am trying to envision is that we have this aging management program here for concrete, and as soon as there are cracks, hopefully they catch it and they repair it.

And that the loss of strength is often not from the crack, and that eliminates one aspect of uncertainty. There are so many uncertainties involved in this issue really, and that the aging of the concrete like you said would be the crack.

MEMBER SIEBER: Well, the crack is one issue, and a change in chemical composition over time with the concrete is another issue, which causes it to lose strength, especially tensile strength.

MR. KUO: I will take that back and at the proper time we will come back to the committee.

MEMBER SIEBER: I would appreciate that, sir. Thank you.

MR. KUO: You're welcome.

CHAIRMAN LEITCH: Okay. Are there any other comments?

MR. KUO: Yes. Dr. Wallis asked a question earlier about torus administration. Has he left? At that time, we did not have the reviewer in the audience, and he is here now. If the committee wants to hear it, he can talk about it for just a couple of minutes.

CHAIRMAN LEITCH: We didn't quite hear you. Refresh us what the issue is here.

MR. KUO: Dr. Wallis earlier asked about the torus penetration as a CUF equal to .992.

MEMBER SHACK: At the end of 40 years.

MR. KUO: For 40 years.

MEMBER WALLIS: That was following up on Graham's question really, and he was asking the same question, and he was extrapolating the 1.5.

MR. KUO: So if the committee would like to hear it, then we have Dr. Mark Hartzman, who is here.

MR. KUO: Okay. Thank you.

CHAIRMAN LEITCH: Please.

DR. HARTZMAN: I am Mark Hartzman with the Mechanical Engineering Branch. The answer is that this location, the location where the CUF is .992 will be addressed under the fatigue management program.

Any location where the CUF exceeds .4 is included in this program. And the way -- there are various options in the program, and one of which is to reevaluate the fatigue analysis, such that -- to ensure that the CUF remains less than one for the 60 year period.

The fatigue management program tracks cycles, and so therefore this is a means of eliminating many of the conservatisms that went into the original fatigue analysis.

On that basis, it has been -- or I accepted that. So my point is that the CUF of .992 is based on various conservatisms and various assumed cycling histories that will be tracked in practice, and with this they expect to show -- and also with the methodology that they have in the fatigue management program, that a CUF will indeed remain less than one for 60 years.

CHAIRMAN LEITCH: We were trying to understand the significant of one. Is there --

DR. HARTZMAN: One? Okay.

CHAIRMAN LEITCH: In other words, a CUF of one means what?

DR. HARTZMAN: A CUF of one normally means this is where a crack will initiate and start propagating. The low one, there will be no crack. It is not an exact number. In other words, we cannot match exactly that at one that a crack will start.

But normally we accept that.

MEMBER BONACA: Assuming that you go through reanalysis, and you sharpen your pencil and you stay below that, and then at the end of exhausting all these possibilities, you get to a hard number of one. What would you expect at that point?

DR. HARTZMAN: I would expect them to repair or replace.

MEMBER BONACA: Exactly. I'm glad that you clarified that.

MEMBER SIEBER: You keep sharpening until you actually get a crack?

DR. HARTZMAN: I suspect that the pencil is going to be very short.

CHAIRMAN LEITCH: Okay. Thank you. Anything else on that topic? PT, anything else at all?

MR. KUO: Yes, if I can address Dr. Bonaca's concern about the documentation, and as we said earlier, and which Butch Burton also spent quite a few minutes on that, is that we are working with the industry to come up with this new format.

And we just had a workshop last week, and we are going to have another meeting with the industry next week. So I am optimistic that we can come up with a format that is acceptable to most of the applicants, starting from Class '03, and that the industry has indicated that they would be able to come up with some proposal by December of this year.

So if that happens, and then I think that would probably address Dr. Bonaca's concerns.

MEMBER BONACA: Yes, in part. In part, my concern is also due to the fact that we received the presentation like today before open items are closed and before the implementation is completed, and before all the final number of one time inspections are agreed on.

And the earlier that we get this review with respect to the final SER, and the more we get more incomplete information, and that is also why it was my comment the other time that it would be desirable to have a subcommittee meeting when you reach a number, let's say, of 10 open items left and no more than that.

And which is made as part of the commentary as a criterion, because the further we are out from closure, we are going to have more incomplete documentation coming to us with respect to what would be the end of it.

MR. KUO: I understand. I will work with

Tim and Ramim to see if there is any way that we could facilitate better communication between the staff and the --

CHAIRMAN LEITCH: Okay. Thank you. So I am hearing then no sentiment for an interim letter. I will make a brief verbal presentation at next week's full committee meeting addressing these issues, and perhaps one or two others.

And at that meeting, we will have the support of a couple of staff people, but not necessarily have any kind of a presentation other than to support or amplify perhaps what I have to say on any impromptu basis.

MR. KUO: We will be here.

CHAIRMAN LEITCH: So if there is nothing else for the good of the cause, the subcommittee is adjourned.

MR. KUO: Thank you very much.

(Whereupon, at 5:01 p.m., the subcommittee meeting was concluded.)