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.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards Plant License Renewal Subcommittee

Docket Number: n/a/

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

/s/ Rebecca Davis

Rebecca Davis
Official Reporter
Neal R. Gross & Co., Inc.

SUBCOMMITTEE CHAIRMAN OPENING STATEMENT
LICENSE RENEWAL SUBCOMMITTEE MEETING
PEACH BOTTOM UNITS 2 &3
OCTOBER 30, 2002

Good morning. This is the meeting of the ACRS Subcommittee on Plant License Renewal. I am Graham Leitch, Chairman of the Subcommittee.

The ACRS Members in attendance are Mario Bonaca, Dana Powers, Steve Rosen, William Shack, John Sieber, and Graham Wallis.

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

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

Ramin Assa is the Cognizant ACRS 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 22rd, 2002. A transcript of this 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 be readily heard.

I would like to point out that copies of this presentation are in the back of the room. In addition, copies of the 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 call upon Mr. P. T. Kuo, Program Director for the NRC Division of License Renewal and Environmental Impacts, for opening remarks.

Peach Bottom License Renewal SER With Open Items

NRR Staff Presentation to the ACRS
October 30, 2002
David L. Solorio
Office of Nuclear Reactor Regulation

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Agenda

- Opening Remarks.....G. Leitch
- Staff Introduction.....P. Kuo
- Overview.....D. Solono
- Applicant Presentation.....W. Bohlke (sickness)
  .....F. Polaski
- Scoping Screening.....R. Pettis
  .....G. Hatchett
- Aging Management Programs.....S. Bailey
  .....M. Khanna
- Reactor Coolant System.....B. Elliot
- Engineered Safety Features.....J. Medoff

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Agenda (continued)

- Auxiliary Systems.....B. Fu
- Steam & Power Conversion Systems...G.Gerogiev
- Containment, Structures and Component Supports.....C. Munson
- Electrical .....D. Solorio
  .....D. Nguyen
- TLAAs.....D. Solorio
  B. Elliot
  J. Fair

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Background

- Exelon submitted LRA on 7/2/01
- Peach Bottom Unit 2 (BWR/4, Mark1, 3458MWt) license expires August 8, 2013
- Unit 3 (BWR/4, Mark 1, 3458MWt) license expires July 2, 2014
- RAIs (231) issued through 3/12/02
- RAI responses received 5/22/02
- SER with open/confirmatory items issued 9/13/02
- Response due - 11/29/02

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License Renewal Rule

Principles of License Renewal

- **The current licensing basis is adequate** the regulatory process is adequate to ensure that the licensing basis for all currently operating plants provides and maintains an acceptable level of safety with exception of the detrimental effects of aging ..
- **The current licensing basis carries forward** the plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term

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Staff's Review

Process

- Methodology evaluation and audit
  - Provide reasonable assurance that the process identifies structures and components subject to aging management review (AMR) pursuant to 54.21(a)(1)
- Scoping
  - Evaluate systems, structures, and components within the scope of license renewal
- Screening
  - Evaluate which passive, long-lived structures are subject to aging management

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Staff's Review

Process (continued)

- Aging management
  - Evaluate identification of aging effects and management of aging effect to ensure relevant equipment intended functions in accordance with the CLB are maintained during period of extended operation
- TLAAs
  - Evaluate applicant's methods to determine how analyses with time-limited assumptions will be extended/managed for the period of extend operation
- Inspections
  - Scoping and aging management (MC2516, IP71002)

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Inspections

- Scoping and Screening
  - 4/23/02 (2 weeks)
  - Objective. to confirm that the applicant included systems, structures and components required by the license renewal rule
  - Notable findings - scoping of residual heat removal and containment spray subsystems, and scoping of fuse clips

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Inspections (continued)

- Aging Management
  - 8/9/02 (2 weeks)
  - Objective: to confirm that existing AMPs are effective and to examine the applicant's plans for enhancing certain existing programs and establishing new ones
  - Notable findings - cables susceptible to cyclic wetting
- Closeout (12/9/02)
  - Close followup items, annual update, SER OI/CI support

~~bolts~~ in vaults

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Staff Review

Guidance

- 10 CFR Part 54
- Standard Review Plan for License Renewal NUREG-1800 and Regulatory Guide 1.188
- Interim staff guidance
- Generic Aging Lessons Learned Report NUREG-1801 (compulation of operating experience)
- License renewal inspection program
- NRR office letter 805 (style guides)
- Branch technical positions

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Safety Evaluation Report

Format

- Chapter 1: Introduction & open/confirmatory items
- Chapter 2: Scoping and screening
- Chapter 3: Aging management review results
- Chapter 4: Time-limited aging analyses
- Chapter 5: ACRS recommendation - tbd
- Chapter 6: Conclusions

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Open & Confirmatory Items

Categories

- Scoping/Screening - 8 OIs, no CIs
- Aging management review - 6 OIs, 11 CIs
- TLAA - 1 OIs, 5 CIs
- Potential license conditions - 3
  - UFSAR Update
  - Aging management program activities
  - Integrated surveillance program

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Applicant Presentation

- Mr. William Bohlke, Senior Vice-President of Nuclear Services
- Mr. Fred Polaski, Project Manager
- Peach Bottom License Renewal Application
- Exelon Corporation

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Chapter 2: Scoping & Screening

Scoping Methodology Review

- Desktop review
- Onsite Audit December 10-14, 2001
- Requests for additional information
- Findings and conclusions

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Chapter 2: Scoping & Screening

Staff Review Process

- Updated final safety analysis report
- Piping and instrument diagrams
- License conditions
- Interium staff guidance
- Focus on out-of-scope systems, structures, and components

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Chapter 2: Scoping and Screening

Staff Review Process

- System Boundary Realignment
  - Used to simplify system scoping and screening
  - 5 Cases where boundary realignment were exercised
    - Components associated with containment penetration
    - Interfaces of mechanical systems
    - Interface of electrical and mechanical systems
    - Systems with shared components
    - Components supporting intended functions

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Chapter 2: Scoping & Screening

Results

- Mechanical - 7 OIs
  - Ventilation systems, cranes, non-safety-related SSC interactions with safety-related
- Structures and component supports - 1 OI
  - Water-tight dikes
- Electrical - no OI
- Open item resolution

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Chapter 3: Aging Management Review

Aging Management Programs (AMPs) - Section 3.0

- Standard Review Plan for License Renewal, NUREG-1800
- Ten attributes of each AMP evaluated
  - Scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, and operating experience
  - Corrective actions, confirmation process, administrative controls evaluated separately (Section 3.0.4)

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- AMPs
  - Appendix B of LRA
  - 17 Existing programs
    - 1 AMP was deleted through course of review
  - 12 Enhanced programs
  - 4 New programs
    - 2 AMPs (one-time inspections) were added through course of review

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Existing programs (EMEB)
  - Inservice inspection (ISI) program
  - Primary containment ISI program
  - Primary containment leakage rate testing program
  - Inservice testing (IST) program
  - Crane inspection activities
  - Conowingo hydroelectric plant (Dam) AMP
  - Maintenance rule structural monitoring program

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Enhanced programs (EMEB)
  - Ventilation system inspection and testing activities
  - Emergency diesel generator inspection activities
  - Door inspection activities
  - Fire protection activities
  - HPCI and RCIC turbine inspection activities
  - Susquehanna substation wooden pole inspection activity
- New programs (EMEB)
  - Torus Piping Inspection Activities (one-time inspection)

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Open items
  - Maintenance rule structural monitoring program
    - Detection of aging and acceptance criteria for structures/components brought into scope
    - Resolved
  - Fire protection activities
    - Aging management of diesel driven fire pump fuel oil flexible hose
    - Resolved

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Confirmatory items
  - Maintenance rule structural monitoring program
    - Clarification that additional structures brought into scope are covered by this program
  - HPCI and RCIC turbine inspection activities
    - Confirm material/environment of flexible hose
- Items of interest
  - Door inspection activities - applicant added internal doors
  - Fire protection activities - applicant adopted volumetric examination of stagnant piping for wall thickness and loss of material (consistent with ISG-4)

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3 0 (continued)

- Existing programs (EMCB)
  - Flow-accelerated corrosion program
  - Closed cooling water chemistry program
  - Demineralized water and CST chemistry activities*
  - Torus water chemistry activities
  - Fuel pool chemistry activities

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Enhanced programs (EMCB)
  - Lubricating and fuel oil quality testing activities
  - Boraflex management activities
  - Outdoor, buried, and submerged component inspection activities
  - GL 89-13 activities (Service Water System Problems Affecting Safety-Related Equipment)
  - Heat exchanger inspection activities
- New program (EMCB)
  - One-time piping inspection activities (modification to original LRA, one-time inspection)

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Open items
  - Verification of the effectiveness of the following chemistry programs through inspection activity:
    - Reactor coolant system chemistry activities
    - Condensate storage tank chemistry activities
    - Torus water chemistry activities
- Confirmatory items
  - Closed cooling water chemistry activities
    - Acceptance criterion parameters for the chlorides and fluorides (<10 ppm)

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Confirmatory items (continued)
  - Outdoor, buried, and submerged component inspection activities - frequency of inspections
    - Emergency cooling water pumps every 10 years
    - Refueling water storage tanks every 4 years
  - Heat exchanger inspection activities
    - Acceptance criteria
    - Percentage of heat exchangers to be visually inspected (100%)

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3.0 (continued)

- Confirmatory items (continued)
  - One-time inspection activity
    - Schedule of one-time inspection (between years 30-40 - before end of plant life)

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Chapter 3: Aging Management Review

Aging Management Programs - Section 3 0 (continued)

- Items of interest
  - The standby liquid control system surveillance activities program was deleted
  - Condensate storage tank chemistry activities was replaced by the demineralized water and condensate storage tank chemistry activities
  - One-time piping inspection activities program was added to:
    - Verify integrity of piping
    - Confirm absence of identified aging effects

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Chapter 3: Aging Management Review

Review Process for Sections 3.1 through 3.6

- Focus on materials, environments, and aging effects
- All applicable aging effects identified
- Aging management programs adequate
- Reasonable assurance that intended functions will be maintained consistent with the CLB

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Chapter 3: Aging Management Review

Results - Section 3.1, Reactor Coolant System

- Reactor pressure vessel (RPV), internals, RPV instrument system, and reactor recirculation system
- Materials, environment, and aging effects
  - Low allow steels, stainless steel, low nickel alloys
  - 70 °F - 533 °F, 1055psia
  - Cracking due to stress corrosion cracking and cyclic loading, cumulative fatigue, loss of fracture toughness from neutron embrittlement and thermal embrittlement

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Chapter 3: Aging Management Review

Results - Section 3 1, Reactor Coolant System

- Applicable aging effects identified
- RCS Programs
  - RCS chemistry program (Section 3.0.3.2)
  - ISI program (Section 3.0.3.6)
  - Reactor pressure vessel and internals ISI program (Section 3 0.3.9)
    - BWRVIP 38/75
    - BWRVIP 76/78/86

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Chapter 3: Aging Management Review

Results - Section 3.1, Reactor Coolant System (continued)

- RCS Programs (continued)
  - Reactor materials surveillance program (3.0.3.21)
  - Fatigue management activities (Section 4.3)
- AMPs adequate with exception of open item
- Open item
  - Bolting and instrument piping aging management

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Chapter 3: Aging Management Review

Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (BWRVIP-75)

- Scope and aging effect: Cracking of BWR piping (4 inches or larger nominal diameter and temperature above 200 °F) resulting from intergranular stress corrosion cracking (IGSCC)
- Materials: Austenitic stainless steel, Alloy 182 weld metal, and Alloy 600 base metal
- Inspection frequency and sample size is dependent upon materials susceptibility to IGSCC, mitigation measures, inspection history, and performance of welds
- Topical report open items - none

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Chapter 3: Aging Management Review

BWR Shroud Support and Inspection Flaw Evaluation Guidelines (BWRVIP-38)

- Scope and aging effect. Cracking of shroud supports (structure below core shroud to RPV inside surface) resulting from IGSCC
- Materials· Alloy 600 base metal, Alloy 182/82 weld metal, and type 304 stainless steel for BWR-2s
- Provides a basis for baseline inspections, re-inspections, and structural evaluation
- Topical report open items - schedule for implementing inspection program for lower plenum

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Chapter 3: Aging Management Review

BWR Core Shroud Inspection and Flaw Evaluation Guidelines (BWRVIP-76)

- Comprehensive report, combining guidelines in BWRVIP-01 (inspection of circumferential welds), BWRVIP-07 (re-inspection of circumferential welds) and BWRVIP-63 (inspection of vertical welds)
- Review of BWRVIP-01 and BWRVIP-07 is complete
- Expect to complete review of BWRVIP-63 and BWRVIP-76 by December 31, 2002

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Chapter 3: Aging Management Review

BWR Integrated Surveillance Program (BWRVIP-78 and BWRVIP-86)

- Provide technical basis and implementation plan for 40 year surveillance program
- Complete for 40 years and being revised for 60 years
- Expect to complete review of 60 year program in 2003
- License condition included to implement either the integrated surveillance program or a plant-specific program prior to entering the license renewal period

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Chapter 3: Aging Management Review

Results - Section 3.2, Engineered Safety Feature Systems

- High pressure coolant injection system
- Core spray system
- Primary containment isolation system
- Reactor core isolation cooling system
- Residual heat removal system
- Containment atmosphere control and dilution system
- Standby gas treatment system
- Secondary containment system

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Chapter 3: Aging Management Review

Results - Section 3.2, Engineered Safety Feature Systems (continuted)

- Materials, environment, and aging effects
  - Carbon, galvanized carbon, and stainless steels; cast iron; aluminum, copper, bronze, and brass alloys; various; loss of material, cracking, heat transfer reduction, and flow blockage
- Applicable aging effects identified
- ESF Programs
  - HPCI and RCIC turbine inspection
  - High pressure service water radioactivity monitoring
- AMPs adequate
- Open items - none

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Chapter 3: Aging Management Review

Results - Section 3.3, Auxiliary Systems

- Fuel handling, fuel pool cooling and cleanup
- Control rod drive system
- Ventilation systems (various)
- Emergency diesel generator
- Fire protection system
- Instrument gas (various)
- Service water
- Cooling water

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Chapter 3: Aging Management Review

Results - Section 3.3, Auxiliary Systems (continued)

- Materials
  - Carbon steel, galvanized steel, stainless steel, cast iron, aluminum, copper, bronze, brass
- Environment
  - Sheltered, ventilated, outdoor, wetted and dry gases, various fluid systems (borated water, reactor coolant, raw water, lube oil)
- Aging effects
  - loss of material, cracking, heat transfer reduction, flow blockage

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Chapter 3: Aging Management Review

Results - Section 3.3, Auxiliary Systems (continued)

- Applicable aging effects identified
- Aging management programs
  - Outdoor, buried, and submerged component inspection
  - Generic Letter 89-13 activities
  - Fire protection activities
  - Closed cooling water chemistry
  - Emergency diesel generator inspection
- AMPs adequate pending resolution of open item (Section 3.0.3.6)
- Open items - none

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Chapter 3: Aging Management Review

Results - Section 3.4, Steam & Power Conversion Systems

- Main steam, main condenser, feedwater
- Materials, environment, and aging effects
  - Carbon steel, stainless steel, brass, copper, and titanium
  - Reactor coolant, steam, torus grade water, raw water, sheltered environment, wetted gas, dry gas
  - Loss of material, and cracking
- Applicable aging effects identified

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Chapter 3: Aging Management Review

Results - Section 3.4, Steam & Power Conversion Systems (continued)

- AMPs (none specific to Section 3.4)
  - RCS chemistry program, ISI program, flow accelerated corrosion program, torus piping inspection program, torus water chemistry program
- AMPs adequate
- Open items - none

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Chapter 3: Aging Management Review

Results - Section 3 5, Structures & Component Supports

- Containment structure, other Class 1 structures, component supports, misc steel, barriers and elastomers, raceways, and insulation
- Materials, environment, and aging effects
  - Concrete, carbon steel, stainless steel, elastomers, bronze, and graphite
  - Sheltered air, buried, outdoor, and water
  - Loss of material, cracking, change in material properties

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Chapter 3: Aging Management Review

Results - Section 3.5, Structures & Component Supports (continued)

- AMPs (none specific to Section 3.5)
  - Primary containment ISI program, primary containment leakage rate testing program, maintenance rule structure monitoring program, torus water chemistry program boroflex management activities program, fuel pool chemistry program, door inspection activity, fire protection activities
- AMPs adequate with exception of open item
- Open item
  - Structural monitoring program (Section 3.0.3.11)

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Chapter 3: Aging Management Review

Results - Section 3.6, Electrical & Instrumentation Controls

- Cables, connections (connectors, splices, terminal blocks)
- Station Blackout
- Materials, environment, and aging effects
  - Insulation material, aluminum, porcelain
  - Heat, radiation, moisture
  - Loss of material properties and water treeing
- Applicable aging effects identified
- Electrical AMPs
  - Non-EQ accessible cables

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Chapter 3: Aging Management Review

Results - Section 3 6, Electrical & Instrumentation Controls (continuted)

- Electrical AMPs (continued)
  - Fire safe shutdown cable inspection program
  - Conowingo hydroelectric plant aging management program
  - Wooden pole inspection
- AMPs adequate with exception of open items
- Open items
  - Buried cables in duckbanks with potential to be wetted, low voltage cables for neutron monitoring and high range radiation monitoring, fuse holders (confirmatory item)

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Chapter 4: Time-Limited Aging Analyses (TLAAs)

Results - Section 4.1, Identification of TLAAs

- TLAAs
  - Reactor vessel neutron embrittlement
  - Metal fatigue
- Identified two additional TLAAs
  - Pipe break locations
  - Crane cycles
  - Open Items - none

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Chapter 4: TLAAs

Results - Sections 4.2 & 4.5, Reactor Vessel Neutron Embrittlement, Reactor Vessel Fatigue and Embrittlement

- Upper shelf energy
- Pressure-temperature limits
- Reactor vessel circumferential weld
- Reactor vessel weld failure probability
- Core shroud and top guide
- Open item
  - Top guide beams (Section 4.5)

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Chapter 4: TLAAs

Results - Section 4.3, Metal Fatigue

- Fatigue management program
- Evaluation of environmental fatigue
- Open items - none
- License condition
  - Management of fatigue with inspection program

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Concluding Remarks

Next Steps

- ACRS full committee presentation - 11/7/02
- Focus on resolution of open and confirmatory items
  - 1 of 15 OIs remain to be resolved
  - Formal responses due 11/29/02
- Issue final SER 3/25/03

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Peach Bottom Atomic Power Station

Advisory Committee on Reactor
Safeguards Plant License Renewal
Subcommittee Meeting
October 30, 2002

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Participants

- William Bohlke – Senior VP, Nuclear Services
- Fred Polaski – Manager, License Renewal
- Erach Patel – Technical Lead, Peach Bottom LRA

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Purpose of Meeting

- Provide an overview of the license renewal application for Peach Bottom Atomic Power Station
- Report the status of the Draft Safety Evaluation Report Open Items and Confirmatory Actions

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Background

- Application preparation began in March 1999
- Hatch Application submitted in February 2000
- Peach Bottom Application submitted July 2, 2001
- July 2001 final versions of guidance documents (NUREGs-1800 and 1801) received after Peach Bottom Application submitted

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LRA Format

- Section 1: Administrative Information
- *Section 2: Scoping and Screening Results
- *Section 3: Aging Management Review Results
- *Section 4: Time-Limited Aging Analyses
- Appendix A: UFSAR Supplement
- *Appendix B: Aging Management Activities
- Appendix E: Environmental Information

* Sections to be discussed today.

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Scoping and Screening

- 10CFR54.4(a) Scoping Criteria
  - Criterion (1) Safety-Related (SR) SSC
  - Criterion (2) Non-Safety-Related (NSR) SSC whose Failure could Prevent Accomplishment of Safety Function
  - Criterion (3) Regulated Events
    - fire protection
    - environmental qualification
    - pressurized thermal shock
    - anticipated transients without scram
    - station blackout

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Scoping and Screening Data Sources

- Systems and Structures Identified
  - Plant Information Management System (PIMS)
  - Maintenance Rule Database
  - UFSAR (Structures)
- Systems and Structures Boundaries Defined
  - Piping & Instrumentation Drawings
  - Component Record List (CRL)
  - Physical Drawings (Structures)
  - Boundary Realignments
  - Boundary Drawings Created
- System and Structure Functions Identified
  - UFSAR
  - Design Baseline Documents

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Scoping and Screening: Mechanical

- Scoped on system basis
- Boundaries determined by traditional component numbering
- Confirmed interfaces between systems
- Some boundary realignments required
- Screening used CRL data and NEI 95-10 for active/passive

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Scoping and Screening: Structural

- Scoped structures as buildings or structural commodities
- Structures support system safety-related intended functions
- Structural commodities
  - Similar design, materials, environments
  - Commodities include component supports, hazard barriers and elastomers, miscellaneous steel, electrical and I & C enclosures and raceways, and insulation

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Scoping and Screening: Electrical

- Scoped on system basis
- Passive electrical/I&C components screened on a plant-level basis as commodities
  - Spaces Approach
  - Commodities
    - Cables
    - Connectors, Splices, and Terminal Blocks (Fuse Clips)
    - Switchyard bus, High-voltage insulators, Phase bus, and Transmission conductors

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Two Mechanical Scoping Areas of Special Emphasis

- Boundary Realignment
- Scoping for 10CFR54.4(a)(2): Non-safety-related equipment that could impact safety-related equipment

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Boundary Realignment

- Case 1 Components associated with Containment Penetration
- Case 2 Interfaces between In-scope and Out-of-scope mechanical systems
- Case 3 Interfaces between In-scope electrical and Out-of scope mechanical systems
- Case 4 Components shared between In-scope and Out-of-scope systems
- Case 5 Components required to support specific intended functions

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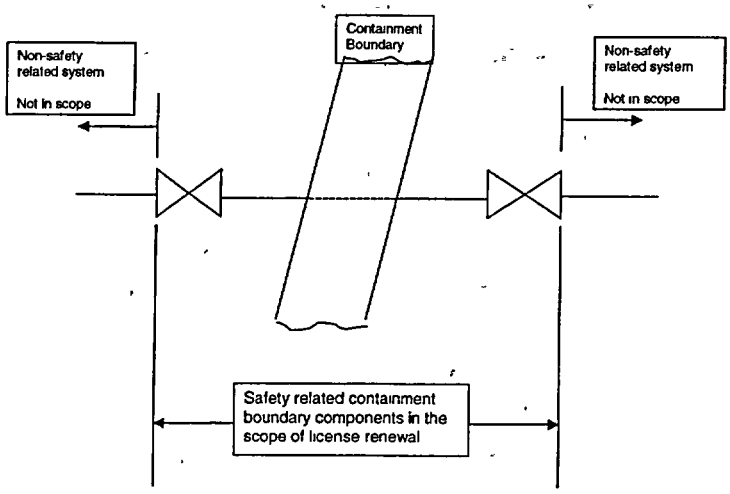
Case 1 – Containment Penetration



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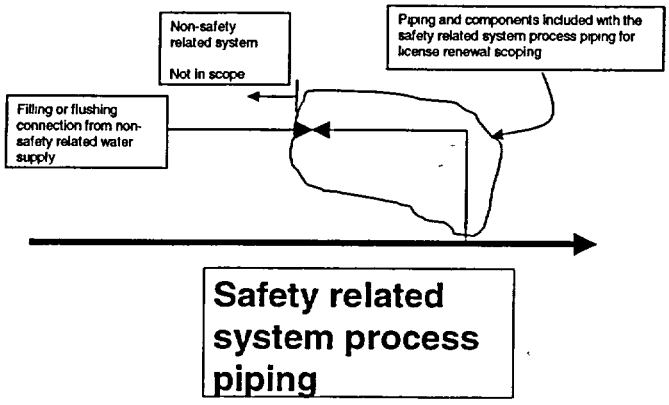
Case 2 – Interfaces Between In-Scope and Out-of-Scope Mechanical Systems



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Case 3 – Interfaces Between In-scope Electrical and Out-of-scope Mechanical Systems

- The CRL often identifies electrical isolation devices such as fuses and circuit breakers as belonging to the mechanical system that they feed.
- This situation is problematic for license renewal when the mechanical system is out-of-scope and the electrical system is in-scope.
- The safety related function of these electrical isolation devices is to protect the power source.
- These electrical isolation devices were realigned to the in-scope electrical system.

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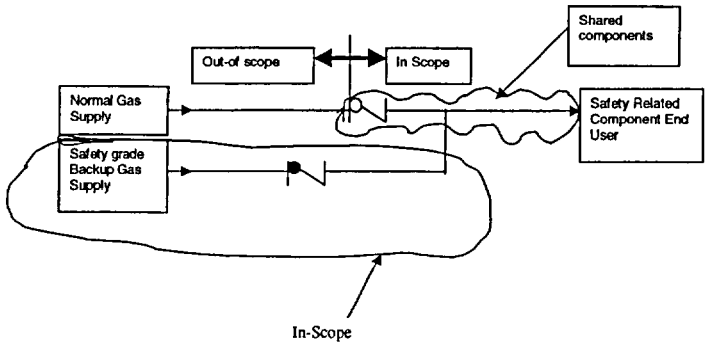
Case 4 – Components Shared Between In-scope and Out-of-scope Systems



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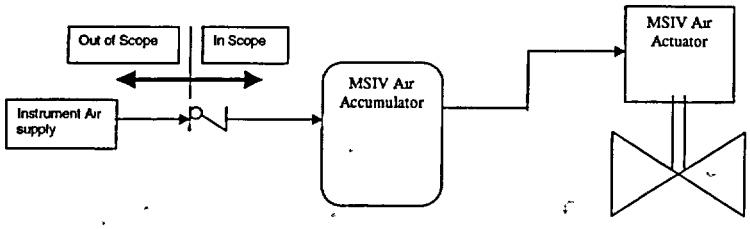
Case 5 – Components Required to Support Specific Intended Functions



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10CFR54.4(a)(2)

- NRC Guidance on Scoping of Seismic II/I Piping Systems Issued on December 3, 2001
- NRC Issued RAI to PBAPS on Seismic II/I Piping Systems and Other NSR SSCs on January 23, 2002
- NRC Issued RAI to PBAPS on Seismic II/I Piping for Auxiliary Systems on February 6, 2002
- NRC Guidance on Identification and Treatment of Structures, Systems, and Components Which Meet 10CFR54.4(a)(2) Issued on March 15, 2002

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Exelon RAI Response Regarding 10CFR54.4(a)(2) NSR to SR Interactions

- RAI response submitted on May 21, 2002
- Systems containing a fluid other than air or gas, irrespective of pressure and temperature, within spatial proximity of safety-related equipment was brought within scope.

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NSR to SR Scoping Results

- Systems with expanded boundaries
  - Reactor Pressure Vessel Instrumentation
  - Reactor Recirculation System
  - Core Spray System
  - Residual Heat Removal System
  - Fuel Pool Cooling and Cleanup System
  - Control Rod Drive System
  - Emergency Service Water System
  - Radiation Monitoring System

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NSR to SR Scoping Results

- Systems added
  - Service Water System
  - Reactor Building Closed Cooling Water System
  - Reactor Water Cleanup System
  - Chilled Water System
  - Water Treatment System
  - Plant Equipment and Floor Drain System
  - Process Sampling System
  - Auxiliary Steam System
  - Condensate Transfer
  - Refueling Water Storage and Transfer
  - Torus Water Cleanup System
  - Post Accident Sampling System

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Section 3: Aging Management Review Results

- Aging Effects Determination
  - Component Materials
  - Component Environments
  - Operating Experience
  - Industry "tools" (documented by EPRI)

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3.2.2 Core Spray System

Table 3 2-2 Aging Management Review Results for Component Groups in the Core Spray System

Component Group	Component Intended Function	Environment	Materials of Construction	Aging Effect	Aging Management Activity
Casting and Forging • Valve Bodies • Pump Casings	• Pressure Boundary	Sheltered	Stainless Steel, Carbon Steel	None	• Not Applicable
Piping • Pipe • Tubing	• Pressure Boundary	Sheltered	Stainless Steel, Carbon Steel	None	• Not Applicable
Piping • Pipe • Tubing	• Pressure Boundary	Torus Grade Water	Stainless Steel	Cracking	•Torus Water Chemistry (B 1 5)*
Piping Specialties • Restricting Orifice	• Pressure Boundary • Throttle	Reactor Coolant	Stainless Steel	Cracking	• RCS Chemistry (B 1 2) ** • ISI Program (B 1 8) ***

* SER Section 3 0 3 5

** SER Section 3 0.3.2

***SER Section 3 0 3 6

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Appendix B: Aging Management Activities

- Existing – 29 activities
- New – 5 activities
- TLAA – 2 activities
- One-Time Inspection Activities
  - Torus piping
  - SLCS
  - Aux Steam
  - Radiation Monitoring
  - Plant Equipment and Floor Drain
  - RPV Instrumentation
  - Reactor Recirculation
  - Service Water
  - Fuel Pool Cooling

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Aging Management Activity Implementation

- Activities that were included in the LRA were incorporated through procedure/program changes that identify commitments.
- Additional activities identified in RAI and SER open item responses are planned to be incorporated through procedure/program changes in 2003.

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TLAAs

- RPV Embrittlement
- Metal Fatigue
- Environmental Qualification
- Containment Fatigue
- Plant Specific
  - Reactor Vessel Corrosion Allowance
  - GL 81-11 BWR Feedwater Nozzle Cracking
  - ISI-Reportable Indications for Unit 3 Main Steam Elbow
  - High Energy Line Break
  - Crane Load Cycle Limit

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Future Actions

- Formally Respond to 15 Open Items by November 29, 2002
- Formally Respond to 18 Confirmatory Items, including updated UFSAR Supplement by November 29, 2002
- LRA update to reflect Current Licensing Basis changes that materially affect LRA content by December 2002
- Region I Final Inspection to close out open items week of December 9, 2002

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