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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE

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MEETING

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TUESDAY

JULY 9, 2002

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ROCKVILLE, MARYLAND

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

PRESENT:

GRAHAM M. LEITCH	Chairman
MARIO V. BONACA	Member
F. PETER FORD	Member
THOMAS S. KRESS	Member
VICTOR H. RANSOM	Member
STEPHEN L. ROSEN	Member
JOHN D. SIEBER	Member
GRAHAM B. WALLIS	Member

ACRS STAFF PRESENT:

JOHN J. BARTON, Consultant

SAM DURAISWAMY, Technical Assistant/Designated Federal Official

Timothy Kobetz, Staff

ALSO PRESENT:

J.N. ADUMN, NRR

RAJ ANAND, NRR

HANS ASHAR, NRR

G. BAGEHI, NRR

G. THOMAS BELLARMINE, NRR

KEN CHANG, NRR

DOUG COE, NRR

STEPHANIE COFFIN, NRR

BARRY ELLIOT, NRR

JOHN FAIR, NRR

RAMILLA FRANOVICH, NRR

GEORG GEORGIEV, NRR

FRANCIS T. GRUBELICH, NRR

J.S. GUO, NRR

WES HELD, NRR

STEVE HOFFMAN, NRR

C. HOLDEN, NRR

PETER J. KANG, NRR

ALSO PRESENT: (cont.)

MEENA KHANNA, NRR

P.T. KUO, NRR

CAROLYN LAURON, NRR

JIM LAZEVNICK, NRR

SAM LEE, NRR

CHANG-YANG LI, NRR

W.C. LIU, NRR

C. LONG, NRR

CLIFTON MARTIN, NRR

JAMES MEDOFF, NRR

CLIFF MUNSON, NRR

S.K. NHITRON, NRR

KRIS PARCZEWSKI, NRR

R. PETTES, NRR

M. RAZZAQUER, NRR

BILL ROGERS, NRR

PAUL SHEMANSKI, NRR

SIMON SHENG, NRR

DAVE SOLORCO, NRR

OMID TABATABAI, NRR

SUNIL WEERAKKODY, NRR

PAUL AITKEN, Dominion

WILLIAM CORBIN, Dominion

MICHAEL HENIG, Dominion

ALSO PRESENT: (cont.)

STUART THICKMAN, Dominion

BILL WATSON, Dominion

LUCKY WRONIEWICZ, Dominion

JERRY PHILLABAUM, Exelon

RUSS WELLS, Constellation Nuclear

I-N-D-E-X

P R O C E E D I N G S

Time: 8:31 a.m.

CHAIRMAN LEITCH: Shall we come to order, please. Good morning. This is the meeting of the ACRS Subcommittee on Plant License Renewal. I am Graham Leitch, the Chairman of the Subcommittee.

The ACRS members present are Mario Bonaca, Peter Ford, Thomas Kress, Victor Ransom, Jack Sieber, Steve Rosen, Graham Wallis, all members of the ACRS Committee, and John Barton, a consultant to the ACRS Committee.

The purpose of this meeting is to review the Staff's Safety Evaluation Report with open items related to the application for license renewal of the operating licenses for North Anna Power Station Units 1 and 2 and Surry Power Station Units 1 and 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.

Tim Kobetz is the Cognizant ACRS Staff engineer for this meeting. Sam Duraiswamy is the Designated Federal Official. 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 June 14, 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 the presentation are in the back of the room. In addition, copies of the North Anna and Surry license renewal applications 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.

I would like to say, by way of clarification, that the ACRS now has two subcommittees considering license renewal application in an effort to help us manage the volume of the work. One is designated Subcommittee A and is chaired by Dr. Bonaca to my left, and I am the Chairman of the subcommittee designated B, and this is the first application that the B Subcommittee is reviewing, and the intention is that from here we would, more or less, alternate

license renewal applications between the A and the B Subcommittees.

I would also like to say that we have just received, hot off the presses, a very nice, glossy brochure depicting the license renewal process, and I will pass these around for your interest, as far as they go. I don't think there's enough copies for everybody in the room, but there are enough for the ACRS members, and other copies will be coming available very shortly. This is just off the presses, and I thought it would be of interest to everybody.

Also, on the very last page there are some photographs, the type of which you normally see in the Post Office with a number under them.

So other than that, I have no opening remarks, and I would like to turn it over to the staff to begin their presentation at this time.

DR. LEE: Thank you, Dr. Leitch, and thank you for ACRS members. My name is Sam Lee. I am the new Section Chief for the License Renewal Branch at NRR, and today Omid is the Project Manager for North Anna and Surry plant. He is going to describe the draft SER that have been issued.

I just want to give also Dr. P.T. Kuo -- He is the Branch Chief. He is on his way. He been

tied up. He is on his way right now.

Today we are going to let you know that we have open items identified in draft SER, but based on information provided by the applicant since the issuance of the draft SER, the staff believes these open items can be technically resolved.

Today we are also going to tell you that after we issued the draft SER, we identified the staff did not complete the documentation of one issue on this seismic two over one issues, and Omid is going to talk to you about that, too.

We are going to address the open items and this item that we missed in the draft SER in the final SER, and then we will report back to the Committee. That's my opening remarks. If no other questions, I'll turn it over to Omid.

MR. TABATABAI: Thank you, Sam. Good morning. My name is Omid Tabatabai, and I am the Project Manager for license renewal applications review for North Anna and Surry, Units 1 and 2.

I will be presenting to you the draft SER that the staff developed based on review of the applications, and --

DR. WALLIS: Excuse me. Do we have a copy of these transparencies?

MR. TABATABAI: Yes.

DR. WALLIS: No. We have a Dominion folder. Graham, I don't have a copy of the transparencies.

DR. FORD: I don't either.

DR. WALLIS: Are they coming?

CHAIRMAN LEITCH: Yes, they're coming.

DR. WALLIS: I'm sorry to hold you up.

CHAIRMAN LEITCH: Okay. Thank you.

MR. TABATABAI: I would like to start with an overview of the application and a little bit of background about North Anna and Surry plants.

Dominion VEPCO submitted two applications for license renewal of operating license of North Anna and Surry. They submitted those applications on May 29, 2001. All four units are Westinghouse 3-loop design PWRs.

North Anna Power Station's Units 1 and 2 are located in Louise County in Northern Virginia, and their operating licenses will expire on April of 2018 and August 2020. Each of those units are designed to generate 2,893 megawatts thermal output.

Surry Power Station is located in Surry County, Southern Virginia, and their operating licenses will expire on May of 2012 and January of

2013. Each of those units are designed to generate around 2,546 megawatts thermal.

On this slide we are just showing a review schedule for North Anna and Surry license renewal applications. Up to this point we have completed draft SER with open items, and today we are having ACRS presentation on draft license renewal -- on draft safety evaluation report with open items.

Draft safety evaluation report consists of four chapter. Chapter 1 discusses general issues, general license renewal issues and background information. Chapter 2 talks about scoping and screening. Chapter 3 we discuss aging management programs and activities, and in Chapter 4 we discuss time-limited aging analyses or TLAAs.

CHAIRMAN LEITCH: Could you comment on processing the license renewal application for two plants, four units simultaneously versus doing them individually? Was that a burdensome effort or do you feel that that was a positive way to approach the situation?

MR. TABATABAI: Yes. I think it was an efficient way to do it, because we wrote -- Actually, the staff wrote one SER safety evaluation report for two applications, and because of the similarity

between the units within the stations, it was possible to do it. It was not that difficult, and staff in its safety evaluation report has addressed -- If there are any differences between the plants, they have addressed those issues.

CHAIRMAN LEITCH: I found that, you know, as a reviewer that it didn't add any appreciable complexity to the review, that the license renewal application was annotated in a very understandable way so that it certainly seemed to flow very freely, and it was clear where there were exceptions between North Anna -- or differences between North Anna and Surry, which in this case were relatively few, but where there were differences, they stood out clearly and I thought the annotation in the presentation was very effective.

MR. TABATABAI: Yes. Yes, indeed.

DR. KUO: Good morning. This is P.T. Kuo. I'm sorry I was a few minutes late, but I just wanted to add a few comments to what Omid just said.

In case of Surry and North Anna, it was relatively simple, because the two are sister units sort of. But we also are expecting other applications come in that will probably be more complicated than this one, like for instance, we have Nine Mile Point,

Unit 1 and 2, that are going to come in next year.

These are two plants -- the same site of two different plant designs. One is BWR-2; the other is BWR-5. We also are expecting the Millstone Units 2 and 3 come in later, and these are again the same site with two different designs. One is Combustion Engineering; the other is Westinghouse.

So in those cases we might expect a little more challenge in case of schedule.

MR. TABATABAI: Thank you, P.T. As Dr. Lee mentioned in his opening remarks, the staff initially identified eight open items and 15 confirmatory actions. As of now, the staff and the applicant, VEPCO, we have resolved all technical issues, and we are just waiting for them to formally submit their responses.

As I understand, it's at the Vice President's desk, and will be submitted to NRC shortly. We are going to discuss all those open items and confirmatory actions later in this presentation, and we'll go into details of those, the nature of the open items and how the staff and the applicant resolved those issues.

One part of license renewal process -- review process is NRC inspections. So far the NRC

inspectors have inspected North Anna and Surry Units twice. They conducted a scoping and screening audit on September 14, 2001, and the NRC Region II staff -- they conducted an aging management review inspection on May 17, 2002, and we have scheduled a third inspection to be conducted in September.

Overall inspection results are very satisfactory. There are not major issues at those plants, those units. There are back-up documentations available at the site for --

DR. WALLIS: May I ask you something? You said the overall material condition of the plant looked good. What kind of things do you see when it looks bad? What sorts of things do you notice in a bad plant?

MR. TABATABAI: As far as aging issues go, that's what we mean by overall --

DR. WALLIS: Yes, but what kind of things? You say it looked good. You must have looked for things.

MR. TABATABAI: Corrosion.

DR. WALLIS: You look for puddles of rust on the floor or something, or what do you look for?

MR. TABATABAI: License renewal inspections are, as far as --

DR. WALLIS: Boron stalactites two feet long? What kind of things do you look for?

DR. FORD: I think what Graham is saying is that your language is saying it looked good. Did you visually look for, for instance, boron stalactites or stalagmites or did you look at the boric acid corrosion program as to its completeness in the records?

MR. TABATABAI: Well, basically, the effectiveness of those programs, like boric acid corrosion is one of the aging management programs that the applicant has in place --

DR. WALLIS: So this is a paper study? I mean, you say material condition. To me, that means the physical reality.

MR. HENIG: If I may add something -- This is Mike Henig from Dominion. The NRC inspection Region inspectors spent a week at North Anna and a week at Surry, and they have covered every part of the plant. They went inside the reactor containment, all the auxiliary buildings, and they started at the top and they worked to the bottom, looking at the material condition of the supports and the equipment --

DR. WALLIS: Yes, but if you took --

MR. HENIG: -- in addition to the

paperwork.

DR. WALLIS: If you took me to a plant, I would look and wouldn't see anything, because I wouldn't know what to look for. I'm trying to find out if these guys know what to look for.

MR. TABATABAI: Yes, they have a plan before they go on inspection. Yes, they develop a plan.

DR. WALLIS: So you weren't part of the inspection team?

MR. TABATABAI: I went there, yes. I did. I didn't stay for the whole week, but I spent for entrance.

DR. WALLIS: So you looked, and you didn't see anything that drew your attention?

MR. TABATABAI: No.

DR. WALLIS: Well, I just wonder what the criteria is for it being good. That's all. It seems a reasonable question, but --

MR. TABATABAI: Dr. Kuo.

DR. KUO: If I may add, for these inspections generally before we go to the inspection, the staff will spend a week on the site to collect information, and then we have also in each of these inspections prepared an inspection plan before we go

out.

In that inspection plan the staff has specified certain systems, structures, and components to be inspected, and when they are on site, they spend a whole week.

DR. WALLIS: That doesn't help me, though. I mean, what do you look -- Give me an example of something you would see which would make the condition bad.

DR. KUO: They will go ahead -- When they are on site, they will look at their programs, and they will go into the plant, do some walkdowns on the systems. They actually, in fact, also look at some of the structures and components that are not in the scope of license renewal to make sure that the methodology is correct.

DR. WALLIS: That doesn't answer my question. I mean, if I were inspecting an airplane and I saw fuel leaking out of a tank or something, I'd say that's a bad condition. I know what is a bad condition. What kind of bad conditions might you see in a plant that you would look for?

DR. KUO: The condition that they are looking for is, for instance, that structures are -- the components are corroded. The instrument that's

monitoring, say, for instance, the chemistry problems, they are indeed working, things like that.

DR. BONACA: I think what he was looking for -- I mean, you would be looking for flanges that possibly are wet or leaking. You would be looking for tags that show the piece of equipment has been out of service for an unreasonably long time. Right?

DR. KUO: Definitely, that's part of the inspection.

DR. BONACA: Well, that's what he's asking for, I believe.

DR. KUO: Yes, and the answer is yes.

DR. WALLIS: Yes, but I want you to give the examples, not my colleague, Mr. Bonaca.

DR. BONACA: If you could give a couple of examples of what you're looking for, I'm saying.

DR. KUO: That's exactly what they are looking for. Yes. The answer is yes. And after the inspection, they write an inspection report documenting all this stuff that they look at.

DR. ROSEN: Maybe what we should be thinking about, Graham, is asking for some photographs of some key things that perhaps we could put a list together ourselves.

MR. TABATABAI: Dr. Wallis, I would like

to clarify that license renewal inspections are different objectively as routine and regular inspections that the NRC inspectors conduct. They look for different things.

DR. FORD: But you will be having input from those periodic inspections that the on-site NRC staff does.

MR. TABATABAI: Yes, operating experience is very important as to making decisions how effective the aging management programs are, because we look at the history of previous inspections and we draw a conclusion if their aging management programs are indeed effective.

MR. BARTON: And what might help Dr. Wallis is you've got the documentation, an example of inspection sheets that were used by the people that went to the site, you know, typical inspection checkoff list or something, and show him exactly what -- That's what he's looking for. You know, in detail what are you really looking for when you go do a site inspection?

So why don't you just show him some of the inspection checklists, and --

DR. WALLIS: Well, this one, I think, is an obvious one top show that it's not an empty

statement. I just want --

MR. BARTON: That will solve it.

DR. KUO: Yes, the staff will provide a typical inspection plan for doing these inspections.

MR. BARTON: Fine. That will solve your question?

DR. WALLIS: Well, it doesn't quite, because it seems to me that someone who really knows what this means could give me an answer without looking it up. That's okay. I'll drop the question right now.

DR. KUO: Let me give you another example. For instance, electrical inspection -- When the staff goes into the plant doing electric inspection, they look at the cables. They look at the jack and see if they were degraded or not.

MR. TABATABAI: We can provide you with the inspection results that Region II issued last month.

DR. BONACA: The question that Dr. Wallis is raising is meaningful, because as long as we are looking at aging effects right now, we are not in license renewal time yet. We are looking for the effectiveness of the corrective action program.

So that's why I mentioned the issue of a

component tagged out for a very long time will give me an indication that the corrective action program maybe is not as effective as it should be. So since we are relying os heavily on commitments, that really the cornerstone of the commitments is really the corrective action program.

You know, that's why we are interested in that question. I think it's a very important question that we understand that the staff looks at those issues and certain attributes which gives us the comfort that, if this company keeps up this program the way they have established right now, they would be good for license renewal.

DR. KUO: That is part -- Dr. Bonaca, that is part of a aging management program. We have ten attributes in the aging management program, and the confirmation process and corrective actions are all part of the program.

So when the inspectors go to a plant and inspects, they will go through these plants, and also we ask them to address the operating experiences. That's where you get confirmation whether the program itself is effective or not. In each case, they find degradation, and they make corrective action, and they have a confirmation process there.

DR. ROSEN: Well, let me try to get at it a little bit differently, quickly. What does the reactor oversight program say about North Anna and Surry? How many white findings do they have?

MR. TABATABAI: Oh, that's not part of license renewal inspection.

DR. ROSEN; I know that. I don't have that.

DR. SIEBER: Zero.

DR. FORD: But I think that's what they are driving at, is that your completeness of the examination has to take into account the whole safety culture aspect of the overall running of the plant. To answer that question would give an indication that was part of the license renewal process.

DR. ROSEN: Would you be sitting here suggesting that we write a letter in agreement with the license renewal for these stations if both of them were red?

MR. TABATABAI: No. That would be indicated. Actually, part of one element of the decision process is the inspection results.

DR. ROSEN: But you don't know what their current status is in the reactor oversight program?

MR. TABATABAI: Dr. Rosen, we will get the

answer for you.

DR. ROSEN: Okay.

MR. CORBIN: This is Bill Corbin form Dominion. Just to try and help things a little bit, when the inspectors were in and they were taking a look at our power stations, spent the week at Surry, spent the week at North Anna, they were looking both from a programmatic point of view at the various programs that we've identified as being aging management programs and are they sufficient, and that gets at the root of corrective action. Has our corrective action program been effective? Have we incorporated operating experience?

They also performed walkdowns in the field, and there they would look for concrete that was spalling. They would look for indications of cracking on cables or conductors. They would look for corrosion on piping systems. They would look at general material condition or housekeeping issues as a way to say are we keeping the environments intact in which we have stated in the application the materials are existing.

So that top to bottom review is really what was -- what we felt we were subjected to by the inspectors when they were there for Region II.

MR. HENIG: That information is documented in -- This is Mike Henig from Dominion -- is documented in the Region II inspection report that was issued, I believe, around the 9th or early June.

MR. TABATABAI: Anymore questions?

CHAIRMAN LEITCH: Just a further question on that bullet. It says the plant looked good. I assume that means the plants looked good? Did you see any difference between North Anna and Surry as far as material condition was concerned?

MR. TABATABAI: No.

MR. CORBIN: But I have to make a clarification. I think there was an issue identified at Surry that was different than North Anna that had to do with the material condition of our component cooling water system, and there was also a pipe chase that was also identified as having some standing water in it. So there's some follow-up actions we need to take care of with regard to those two material condition issues.

CHAIRMAN LEITCH: Okay, than you. Okay, let's continue.

MR. TABATABAI: Thank you. This is actually the first part of my presentation, and I would like to ask Dominion VEPCO to present their

slides at this time.

MR. CORBIN: Again, my name is Bill Corbin. I am the Director, Nuclear Projects with Dominion. I would like to talk to you a little bit about our application. So if you will read along with me, I think you all have the slides in front of you.

My name is Bill Corbin, again. I brought with me a couple of other individuals that are key to the application process. If I need to, I will refer to them. I think Mike Henig has already introduced himself. He is back here, and Lucky Wroniewicz who is also sitting in the audience.

DR. KRESS: Is his real name Lucky?

MR. BARTON: Yeah, did you really need to bring him in because you think you needed luck or what?

MR. CORBIN: Okay. What we would like to od today is give the ACRS and NRC staff an overview of the license renewal applications for Surry and North Anna, cover a little bit about the background, go through a format that we used in the license renewal application, and then work briefly through each of the sections of the application as a way to describe the way we performed our review and the work that we did.

At the very end, we will give a brief

status on the safety evaluation -- draft safety evaluation report open items, and confirmatory items.

If you have questions as I'm going through here, please speak up, as I'm sure you will.

Again, as was previously mentioned, the application was submitted on May 29, 2001. An application for Surry and North Anna came in together, and also as we noted on the schedule as posted, we are either on or ahead of schedule so far in that review of the two applications, combined applications.

The format is consistent with NEI 95-10, Revision 3 and NUREG 1800 which was draft in August of 2000. That was the document that we used as a basis for putting together our application.

The Class of '01, as we refer to ourselves, which consists of Dominion, Duke for his McGuire and Catawba plants, and Excelon with their Peachbottom plant, had a meeting prior to submitting our applications, and agreement was reached with the staff that we would not be reviewed against the requirements of the GALL report.

I would say, however, that we did have a draft version of that report in-house while we were putting our application together, and we did refer to it, I will say, in an informal sense, although we did

not reference the document in our application.

DR. BONACA: That was because the document is still in a draft form?

MR. CORBIN: That's correct, and there were still comments being incorporated. In fact, the final version that came out changed the format and some of the other content changes were there. So we used it to the extent it seemed practical, but didn't feel like we could reference the document.

DR. BONACA: Do you think that, if the document were in a finalized form, it would have helped you, might make the application even more --

MR. CORBIN: Yes, I believe that it would have. I think that we did get a good deal of value out of the draft document. So that having a final document would have only honed those skills, if you will, or made it even better, a little more efficient.

DR. BONACA: Thank you.

MR. CORBIN: Certainly, when we came in, there were a couple of issues that, I would say, turned the corner between the draft and the final that we had to address as RAIs.

DR. BONACA: Sure.

MR. CORBIN: Continuing with the background, We did have one license renewal

application for each station with site information identified. I think we already had a comment relative to whether that was sufficient for reviewers, but that was certainly our intent, was to try and make it obvious where we had differences between Surry and North Anna, and anything that wasn't boxed is really -- in the electronic world is really one document.

We really only had one document, and the boxes were the only places where there were differences. I don't know if anyone tried to do that comparison, but you would have been unsuccessful, I think, in finding differences, because it is one document.

The exemption was also approved for electronic submittal, and we did submit an electronic application.

With regard to the license renewal format, it is consistent, we said, with the standard review plan and 95-10, Revision 3. What I'm going to run through now are these sections as identified here: Section, scoping and screening methodology; section 3 on the AMR results, mechanical, structural, and electrical -- each of those is a little bit different; Section 4 on TLAA; and then run through some of the appendices, UFSAR supplement, Appendix A, Appendix B

on the aging management activities, Appendix C which is optional, but we did decide to include an Appendix C on our methodology we used for the aging management review, and then I will briefly talk about Appendix E which is also included in the environmental report.

First a comment on the IPA process -- Yes?

CHAIRMAN LEITCH: Appendix D, the tech spec changes -- there were none, apparently.

MR. CORBIN: Correct. Right, and we went through a review to determine if there were any tech spec changes, and there were none that we could identify. So decided to skip over that one here today.

CHAIRMAN LEITCH: Yes, okay.

DR. SIEBER: You folks have the new standard tech specs now, right?

MR. CORBIN; No, we do not have integrated tech specs at Surry or North Anna. North Anna is on the threshold of implementing those later this summer, but as yet have not implemented them. Surry is still off in the future.

DR. SIEBER: But it's in the plan? It's your plan to have these four units conform to the latest?

MR. CORBIN: That's correct. In fact, we feel like we are all but there on North Anna. Surry, because it's an older vintage plant and had custom tech spec, very custom tech specs, creates quite an additional challenge in order to get to ITS, but we are working on that, and we do intend to get there eventually.

On the IPA process as defined by 54.21, we went through and identified systems, structures and commodities, which we then broke down into the component groups, the structural members, and the commodity groups that required an aging management review. We performed the aging management review, and then identified the means that we would use to manage those aging effects.

Really, no surprises here. This is pretty standard process that the whole industry and staff are getting used to, I would think.

With regard to scoping, we used the criteria, safety related, non-safety affecting safety, and the five regulated programs. I'm going to talk a little bit more about specifically what we did with regard to criterion 2 and criterion 3 in order to identify the correct scope there. Safety related was pretty easy to do using our equipment database system.

DR. ROSEN: At some point you will talk about especially the station blackout event and what was done there?

MR. CORBIN: Right. We can -- In fact, since you've raised the question on station blackout, our initial thrust in terms of scoping on that was to use our equipment database system and other documents to identify what we felt was station blackout, which included the diesels, because we have a separate full capacity diesel at both Surry and North Anna for handling the station blackout event, and then all the switch gear and everything that brings it into the safety related electric distribution system.

What we didn't include in the application was that equipment that's used for recovery, and that recovery became an industry issue, if you will. NEI got involved, and the staff was involved, and there was quite a discussion back and forth.

The upshot is that we have resolved to include certain components of the switch yard in the scope of license renewal, and from those components bring those into the power station to the safety buses. So that developed as a result of the RAIs and the interaction we've had with the staff, but was not initially included.

Our first cut was to identify the current licensing basis, and our read on the CLB did not include recovery equipment. So we only included that equipment that was specifically designated as station blackout.

DR. ROSEN: When we get to electrical components later today, will the gentleman who is going to brief on that be more specific?

MR. TABATABAI: Yes. This is Omid Tabatabai. Mr. Lazevnick will be discussing that SBO issue and the scoping. He is going to go into detail of that review.

DR. ROSEN: Okay, thank you.

MR. CORBIN: And if we need to, to help clarify that, I think we do have some hard copies of the one-line diagrams that give you a better sense of what equipment was, in fact, included ultimately for station blackout.

Moving on to page 9 then, we see the scoping methodology, the documentation sources. The equipment data system was used. This includes safety classifications. This is a computerized database system. Most plants have them now. It's mark number based. It goes down the left side, and you have a number of columns across the top, but it gives you a

lot of information with regard to both safety related and NSQ, non-safety, affecting safety, for your regulated programs.

So it gave us a good opportunity to identify initially a cut at what should be included and what didn't need to be included in the scope of license renewal.

We also used the Maintenance Rule scoping and the Civil Engineering Structural Monitoring Program. Maintenance rule had its own method of identifying not only what was safety related, but was non-safety-affecting-safety. That gave us a good starting point for understanding Criterion 2, and it picked up a lot of the civil structural elements within Maintenance Rule. That gave us, again, a good starting point to understand what we should include, the civil structural elements, in Maintenance Rule.

We also used our UFSAR and then referenced that in the application. We tried to provide hyper-links to relevant UFSAR sections, where appropriate, use the technical specifications where applicable, and use design basis documents.

We have an electronic system we call DBDLS, which gives us a large library of design basis information about the plant, which is text searchable,

an extensive library. So that also was extremely valuable in seeking out intended functions, for example, and other information about our plant.

We used in-house scoping criteria reports. I think this may be a somewhat unique feature for the way we did our scoping. We actually decided that we would take Criterion 2 and the regulated programs in Criterion 3 and write a separate in-house report that would consolidate various documentation sources into one place so that we had a good definition of what we felt was in the scope for criteria 2, what's in the scope for station blackout, what's in the scope for fire protection, etcetera, and wrote these various reports to try and pull all of that information together.

Finally, we used the plant drawings, which again -- those were provided in the application with appropriate links, so that you could get to and from the drawings to show the boundaries and other design documentation.

Any questions about these sources that we used as the way we put the application together?

CHAIRMAN LEITCH: No. I was wondering if any of these sources would indicate the equipment that was necessary to fulfill emergency operating

procedures or severe accident procedures?

MR. CORBIN: Those reviews had previously been done in-house, and incorporated in order to be included in our EDS system, so that if we go through EDS we could use that. EDS is constantly updated. It's not a once-and-done system. It's a system that is constantly under review. We have an internal document called an EDS car, which is just a change request for the equipment database system.

So reviews for EOPs and other safety documents -- that information had been reflected. So we did not do a specific review of the EOPs. We did not do that.

CHAIRMAN LEITCH: Not for this purpose?

MR. CORBIN: No, we didn't.

CHAIRMAN LEITCH: But EOPs are reviewed and incorporated in the EDS system? Is that what I understand?

MR. CORBIN: That's correct.

CHAIRMAN LEITCH: Okay, good. Thank you.

MR. CORBIN: Any other questions on doc. sources? Okay, moving along then.

As a result of all that work in going through those documentation sources, we developed four tables. You can see. It's a fairly simple system:

Systems in cope, systems not, structures in scope, structures not in scope. Tabulated those results.

DR. BONACA: I have a couple of questions I would like to ask you.

One on the Table 22-2. You have the station blackout diesel, the ASC diesel.

MR. CORBIN: Correct.

DR. BONACA: And diesel service area is not in scope. I don't understand.

MR. CORBIN: Okay. I'm going to ask for a little help from my audience here. Diesel service area, we felt, was not in the scope of license renewal, and I don't know why.

MR. BARTON: You explained that as being a maintenance service item as opposed to a safety item for storing the diesel, as I recall, in your application.

MR. WRONIEWICZ: This is Lucky Wroniewicz. Yes, that's true. The diesel service area is not part of the air start system or part of the start system for the diesel. It's merely in the building for service work.

DR. BONACA: For maintenance support?

MR. WRONIEWICZ: Yes.

DR. BONACA: I didn't see that

distinction. Okay. So I understand. Thank you.

DR. ROSEN: You mean, you use it to power air tools and kind of for clean-up?

MR. WRONIEWICZ: Yes, sir.

DR. BONACA: But you don't depend on it.

MR. WRONIEWICZ: We do not depend on it for diesel start.

DR. BONACA: The other question I had was on the rod position indication, the RPI. These are the control rod position indication?

MR. WRONIEWICZ: Yes, sir.

DR. BONACA: Why would it not be in scope?

MR. CORBIN: Rod position indication is not safety related, as far as I know.

MR. WRONIEWICZ: It's not safety related or not depended on for safe shutdown of the plant.

MR. CORBIN; Right. So when you filter through the criteria, it didn't come out.

DR. SIEBER: In some plants the rod bottom bi-staples are safety related.

DR. BONACA: That's right.

DR. SIEBER: The rest of it is not typically.

MR. CORBIN: Right. And those electronic components then would have been identified if they --

If the rod bottom bi-staples are safety related, they would have then come in as commodities, because we used the spaces approach or commodities approach for electrical components.

MR. WRONIEWICZ: Or in scope as active components and managed by another program, Maintenance Rule.

DR. WALLIS: So is there some other way you know where the rods are?

DR. BONACA: The last question I have was on the fire pump house embankment not in scope. You want to make sure that this fire pump house doesn't collapse and whatever, due to aging. I'm trying to understand, you know, in some of the borderline cases, how the license renewal process takes you in or out, and if it makes sense.

MR. WRONIEWICZ: Fire pump house embankment?

DR. BONACA: Embankment, yes.

MR. WRONIEWICZ: I'm afraid I don't have a quick answer for that.

DR. BONACA: I mean, is it -- Does the structure depend on the --

MR. WRONIEWICZ: I would have to assume that the structure does not depend on the embankment

for support.

DR. BONACA: You got some point, some clarification?

MR. CORBIN; Yes. We will certainly clarify that.

MR. WRONIEWICZ: We will clarify that.

MR. CORBIN: I don't know whether that was Surry or North Anna, too. I'm trying to run through my mind where the two fire pump houses are.

DR. BONACA: This is North Anna.

MR. CORBIN: Okay, at North Anna?

DR. BONACA: Yes.

MR. CORBIN: We will get you a clarification on fire pump house embankment.

DR. BONACA: Thank you.

MR. CORBIN; I think we had a question over here.

DR. WALLIS: I want to call off on the rod position indicators. It would seem to be fairly important to know where your rods are.

MR. CORBIN: It is, but they -- One thing, if they are active components, then they would have screened out.

DR. WALLIS: These are called active?

MR. CORBIN: They would be active, yes.

MR. WRONIEWICZ: Yes, sir.

DR. WALLIS: Well, that's why they are not in scope.

MR. WRONIEWICZ: That would be part of our active instrumentation and would not be in the scope of passive equipment for license renewal. Maintenance Rule, other programs would monitor.

DR. BONACA: That makes sense.

DR. WALLIS: All right. Thank you.

MR. CORBIN: Other questions on Section 2, and we owe a response on that embankment.

MR. BARTON: Yes. I've some on 2, if you're going to jump to 3. In Table 2.2-4 in your structures not within scope -- Maybe this will be clarified. In the LRA you don't have switch yard and associated control house included. Maybe that was before you got into the station blackout issue with the staff.

MR. CORBIN: That's correct.

MR. BARTON: Okay. So that -- some of the switch yard would be now?

MR. CORBIN: Well, some components are now included that relate to the switch yard components and the controls associated with those switch yard components and, therefore, the structural components

that are associated with those controls.

MR. BARTON: Now would be in scope?

MR. CORBIN: Are now in scope for license renewal.

MR. BARTON: Okay. The Met. Tower and station -- I don't understand why that is not in scope, because don't you rely on that for your emergency plan? So why wouldn't the Met. tower --

MR. CORBIN: You do rely on it as part of the emergency plan, but it is not safety related equipment. Again, I'm going to try and run through the criteria. It doesn't fall under criteria 2 as non-safety-affecting-safety, and it's not one of the five regulated programs. So we would not have included it --

MR. BARTON: You don't care whether the Met. tower stands or not?

MR. CORBIN: Well, we do. As a current licensing basis issue, we certainly do, but as a license renewal issue it did not screen in for the criteria.

DR. BONACA: I just had another question, curiosity rather than anything else. You have the IFSSI.

MR. CORBIN: Correct.

DR. BONACA: And that's not in scope, because it is a separate facility and licensed under a different portion of Part 50.

MR. CORBIN: Well, Part 72.

DR. BONACA: Part 72.

MR. CORBIN: Right. As a matter of fact, we have submitted a license renewal application for the Surry ISSFI which is coming up in 2005, I believe it is, or '06. So that is a separate license renewal application. Surry is rolling up on its 20 year anniversary.

North Anna just put their ISBSI in service just a few years ago.

DR. ROSEN: So how was that handled in the staff? That goes through NMSS?

MR. CORBIN: That's who we submitted it to. That is correct.

DR. ROSEN: And ultimately that goes up through ACNW, or what?

MR. CORBIN: Ours is the first of a kind application.

DR. BONACA: ACNW, I assume so.

DR. ROSEN: We are having an internal discussion on how things work in the staff.

MR. CORBIN: We are breaking new ground,

because it is first of a kind. It's new for NMSS, and how it all tracked through with schedule and things, I'm not sure a lot of those things have been determined yet. So it's sitting there, and now what do we do with it?

Other questions on Section 2?

DR. BONACA: Main dam -- Now the main dam at North Anna --

MR. CORBIN: Correct.

DR. BONACA: Is that any use if it's being done to support the plant? I mean, do you have emergency equipment being run by --

MR. CORBIN: No, there is no emergency equipment, but I would explain that the main dam is necessary for circulating water to support the turbine operation, but the service water function is a separate reservoir, separate impoundment which -- pumps block houses and things, and all of that equipment would be, and is, included in the scope of license renewal. But if the dam broke, we would not affect the safety functions of the plant.

DR. ROSEN: Nor affect any of the safety reservoir?

MR. CORBIN: No, because the reservoir is a separate pond that sits apart from the lake.

DR. ROSEN: Apart and upstream so it couldn't be affected by a dam failure on the main --

MR. CORBIN: In fact, it's up on top of a hill behind the plant and separated by some physical distance, if you will, from the lake or lake boundary. The whole drain could leak out, and the reservoir would stay up on the hill.

DR. BONACA: Two more questions. One is the foundations of the main transformers and state service transformers, condensate storage tank and the RSST serial bus bar support structure. I mean, does any of that come into scope because of station blackout now?

MR. CORBIN: The reserve service station transformer foundations and some of their structural components are now in the scope, but main transformers and service transformers are not, although I'm not sure -- Didn't we have to take the buses off of the station service transformers?

MR. WRONIEWICZ: Yes, we took the buses, but we did not take the --

MR. CORBIN: Just to the breaker.

MR. WRONIEWICZ: Yes.

DR. ROSEN: And now we are edging into this afternoon's discussion that I wanted to hear

about and see in some detail.

MR. CORBIN: Okay, very good.

DR. BONACA: And we'll see the scope then.

DR. ROSEN: Yes.

MR. CORBIN: If one-lines are not available, we can certainly by this afternoon make sure some one-lines are available to help facilitate that discussion.

DR. ROSEN: Yes, put up on the screen.

MR. CORBIN: Right, because it is a little bit different at Surry than North Anna. Switch yards are a little bit different. Okay?

DR. BONACA: Yes.

MR. CORBIN: Moving on to screening methodology. In terms of how we did this, I want to talk a little bit about the mechanical screening methodology. Then we'll talk civil/structural, and final electrical and I&C.

So in the mechanical system, what we did is review the documentation sources that identified previously to look for intended functions. Having found those intended functions, then we spent a process to go through and identify those components that were required in order to perform that intended function, and depicted those on boundary drawings,

developed boundaries. So you just keep overlaying intended functions and components associated with them until you arrive at an overall boundary for what's in the scope of license renewal.

Once that was completed, you have both active and passive components in the boundary. We screened through to determine what were the passive components that were in the scope of license renewal.

So that's fairly brief. Intended functions, identified components to go with the functions, put them on a boundary drawing, and then screen it out for passive components. That's the approach we took on mechanical.

CHAIRMAN LEITCH: I was looking at the Figure 2.1-1 simplified scoping and screening process flow chart. It lists all the documentation sources, and coming out of that box you go into the scoping process, but also coming out of that box it looks as though you go directly to the screening process. It would seem to imply that in some cases the screening is done before the scoping.

MR. CORBIN: No, I don't think that was the intent. The idea was simply that those documentation sources were used for both the scoping process to make some functions, to understand intended

functions and what should be in and out, but we also used those doc. sources to help us discern screening elements, what was already identified in some cases as safety related components, for example, without having to drive through intended functions to get there.

So it was just a way that we used those doc. sources for both scoping and screening.

CHAIRMAN LEITCH: I see. Then there is a line from screening back to scoping, which I didn't quite understand.

MR. CORBIN: Right. Well, I mean, that just is a -- You have to understand that's the process that goes through both screening and -- Screening and scoping both feed each other. As you understand what you've got screened in and screened out for safety-related functions, you have to make sure in your scoping analysis that you've picked up everything that you screened as safety-related.

So you really iterate it is what we are trying to say. We're going around and around and around in a circle until we have arrived at what we think is the final complement of components that are screened in. Okay?

So while that diagram may be a little confusing, what we are trying to show there is that we

had to iterate in order to get to a final configuration.

CHAIRMAN LEITCH: Okay.

MR. CORBIN: It wasn't just one pass and done.

CHAIRMAN LEITCH: Thank you.

MR. CORBIN: Any other questions on mechanical? All right. On civil/structural screening overview, what we did there again was working through the documentation sources to identify those intended functions. Then at this point we went straight to the structural detail drawings and used those to identify what structural elements were required in order to support those intended functions.

Again, we had to do a passive -- find passive structural members. Most structural members are passive.

DR. WALLIS: I should think so, yes. Are there any active ones?

MR. CORBIN: We screen very little out that way. We don't want our buildings walking around. We like them to stay right where we put them. But that was the civil/structural process.

MR. BARTON: Foundations -- Equipment foundations covered in the structural screening?

CHAIRMAN LEITCH: Yes.

MR. BARTON: In the table you had the main transformer foundation excluded from the scope, and you explain that as not included, not described in the UFSAR. Is that the only reason that was excluded from scope?

MR. CORBIN: No, it didn't -- Again, you go through the criteria. The main transformer didn't have a safety-related function, non-safety regulated program. So it didn't find its way in, in that direction.

Other questions on civil/structural? Electrical and I&C: In this case we took the approach that some previous applicants have taken, and that is to take the passive electrical/I&C components and take them on a plant level basis as commodities. So we used a commodities approach.

The things that were included as commodities you can see there on the list, cables and connectors, electrical penetrations, and also bus ducts. A point of clarification: There is an emerging issue with regard to fuse holders.

We did include those fuse holders that were discrete components in our commodities review. So I believe that we are in line with the developing

staff position on fuse holders, as far as that goes.

DR. ROSEN: What do you mean when you clarify that by saying those fuse holders that were discrete components? There are fuse holders that are not discrete components?

MR. CORBIN: Correct. An example might be fuse holders that are part of a circuit breakers, which is -- for 95-10 is included as an active component. So as that active component, they would be inspected as part of the normal preventive maintenance that would take place on the circuit breaker as a whole, and that's the distinction, I think.

So when a fuse holder is off to its side like a terminal block is off to its side, they would become passive, and we would include them as commodities.

DR. ROSEN: Thank you.

DR. WALLIS: Would it be appropriate at some later time to ask about what the state of the cables is in this plant? This isn't really part of screening. Are you going to get to -- When you get to Section 3, are you going to talk about the current condition of the cables?

MR. CORBIN: We could or I could just state that, you know, we have done a monitoring in our

plant, a temperature monitoring to identify locations of high temperature, if you will. We know where we have high radiation effects and where we have water treeing as a result of wetted conditions.

So we've done a fair amount of research in that area. There are some cables that have had to be replaced as a result of either high radiation applications or water treeing. They are not in the scope of license renewal, if you will. They are other services, but that operating experience certainly is a part of what we have included in understanding what we need to do with cables.

DR. SIEBER: Do you have any buried cables that are safety-related?

MR. CORBIN: The service water cables at North Anna Power Station come down -- I described the reservoir as being on a hill. They come down the hill into the plant. So those had to be considered, and as a result of going back to do station blackout and bringing the switch yard into scope, we have now had to include some of those cables which are buried. Not all the circuits are buried, but some of the circuits are buried. So those cables are now in the scope of license renewal as well.

DR. SIEBER: What are they, 4 KV cables?

MR. CORBIN: 4 KV, yes. Correct. Everything is 4 KV.

MR. BARTON: I have a question on bus ducts. In the application you talk about bus ducts being in scope and bus ducts being connected to safety-related switch gear enclosures. But the switch gear enclosures are not included.

Switch gear is considered active. I can understand the components within a switch gear cubicle being active, but the cubicle itself -- is that considered active or is that a passive component? You know, the cabinet itself.

MR. CORBIN: Right.

MR. BARTON: And the cabinet itselves aren't included, and I don't know why. Maybe because they are not going to corrode or -- I just don't understand why you don't have the cabinets themselves, the enclosures of the switch gear, included, especially those that are connected to your bus ducts.

MR. CORBIN: I see Lucky is poised to answer that.

MR. WRONIEWICZ: Yes. Lucky Wroniewicz. Actually, we do have the enclosures in scope, but you will find them in the structural, not in the electrical area.

MR. CORBIN: That makes it become a commodity.

MR. BARTON: Thank you.

DR. BONACA: That was an issue that was the -- I mean, the enclosure of those -- Okay.

MR. WRONIEWICZ: Yes, sir. But we feel that enclosures are, obviously, passive in the form of function, but the internal switch gear is active.

MR. BARTON: Thank you. Okay. I've got one more I think you skipped over. I missed it during the mechanical.

MR. CORBIN: Yes.

MR. BARTON: In your application liquid and solid rad. waste and rad. waste systems, there really isn't anything in scope there. My question is aren't there any tanks in there that provide pressure boundary or any valves in a rad. waste system that are in scope? The only component you have listed in your LRA for rad. waste systems is the piping. Now why wouldn't valve bodies be included, because they are included in other systems, but I notice in rad. waste they are not.

MR. CORBIN: The reason -- Well, rad. waste in general is not safety related. So it did not screen in. But we did have some --

MR. BARTON: But the piping did.

MR. CORBIN: -- rad. waste designations because of the way we designate components in the power plant in order to establish a boundary. We did in some cases have to bring rad. waste piping segments into scope without bringing the entire system in. That's just where the line got drawn on the boundary drawing.

MR. BARTON: Okay.

MR. CORBIN: But, in general, rad. waste systems were not included.

MR. BARTON: I just wondered why it was just piping and no valve bodies. Okay.

MR. CORBIN: With regard to screening results then, as we went through those three -- we went through mechanical, civil/structural, and electrical -- how do we depict those in the application?

We've provided a brief description, provided a UFSAR reference where there was an applicable one by hyperlink, included the license renewal boundary drawings, again with the hyperlink, and components subject to an AMR were identified in a table, and that table was then also linked so that you could jump over to Section 3 to see how the aging

management review was done.

If there are no other questions on Section 2, I'm going to move on to Section 3 and get into aging management reviews.

In the aging management review, first of all, just to sort of lay out in terms of how we put the information together. In the text section we had a system component description. We presented the AMR results table. We have a sample of that on the next slide. It's the six-column format.

We did identify a generic topical report, a WCAP in our case, where it was applicable, and identified applicant action item responses, identified the materials, the environment descriptions, aging effects, TLAAs where they were applicable, and concluded with the aging management activities that would be associated with those material/environment combinations and aging effects.

You can see on the next slide then an example of the six-column tables that we put together. This is similar, obviously, to previous applicants, and identifies subcomponents, the passive functions, material groups, environments, aging effects requiring management, and aging management activity.

I think that it should be reasonably

familiar to everyone, because we have duplicated what's gone before here. Any questions on either just how we laid out the text or the tables, either one?

CHAIRMAN LEITCH: Bill, I had a problem identifying the abbreviations used in the passive function column.

MR. CORBIN: Okay, the pressure boundary, PB here?

CHAIRMAN LEITCH: Yes, right. I guess PB was simple enough, but as you go through this there were a number of different categories, most of which I think I was able to figure out, but they are not up front in your list of --

MR. CORBIN: Right. We did have a table in the very beginning of the application that should have assisted with that. If that wasn't clear or obvious, that's a good point for us to recall as we think about Millstone and try to put an application together for Millstone.

MR. CORBIN: Yes. It's just I just didn't see the -- You know, in your table up front that lists all the abbreviations and acronyms that are used, it didn't have things like PB. There was, I guess, eight or so different categories there, most of which you could kind of reason your way through.

MR. CORBIN: RF, restricts flow. Yes, that's not immediately --

DR. ROSEN: The chart you show behind you -- it's a little unfortunate, because it leaves off on the bottom page an area of some current interest. Closure head dome boric acid corrosion surveillance is not shown. I suppose that is because it is on the next page of this table, which you are only showing an example of.

MR. CORBIN: Well, boric acid corrosion surveillance, yes, particularly in light of the Davis-Besse events, and we did include boric acid corrosion surveillance.

DR. ROSEN: But the reason we don't see it on the slide you are showing is because it's just on the next page?

DR. WALLIS: You see it for the bottom and not for the top.

MR. WRONIEWICZ: This is Lucky Wroniewicz. This slide actually shows the internal environments. The boric acid corrosion would be an external environment, I believe.

MR. CORBIN: Well, it says --

MR. WRONIEWICZ: Oh, you're right. I'm sorry.

MR. CORBIN: -- (E) borated water leakage and ISI program for the vessel.

MR. WRONIEWICZ: The ISI program does -- If we use a boric acid program, but the ISI program does a thorough review of the external.

DR. ROSEN: The Bottom Head Dome, top row which is just above that, shows the boric acid corrosion surveillance. So I was just kind of fooling myself and going down and said I ought to see that on the head dome also, and guess what. It's not there.

DR. WALLIS: It's well known not to be a problem.

DR. ROSEN: That's not because you're not doing it?

MR. CORBIN: No, no. Absolutely, we are doing it. In fact, we do --

CHAIRMAN LEITCH: It's an unfortunate choice in the sample page.

MR. CORBIN: Yes, I know that we do that, because we do send two NDE techs down early every outage before we move the heads, and had been doing that prior to the detailed inspections we are doing now. This is some years ago. They were looking for evidence of boric acid.

DR. ROSEN: And what have you found, by

the way, at Surry and North Anna?

MR. CORBIN: We have found evidence of boric acid on the heads and had to do very thorough examinations, both top and bottom, on the heads. We have had to do some weld repairs on heads for Surry and North Anna.

To sum all of that up briefly, we have made it a commitment to replace all four reactor vessel heads at Surry and North Anna, and we will do that as soon as we can. The forgings are already out of the forge, as a matter of fact, but it still take us sometime to complete that activity.

Some of the boric acid that we discovered was related to previously leaking conoseals, for example, which are further up on the head at the head flange area -- or the CRDM flange area, but some of it was the traditional popcorn looking boric acid corrosion that's been identified previously, and that caused us to get in underneath the head and do more extensive UT examinations, visual LP examinations, quite a bit of LP exam done as well, a lot of those. But the heads are in good condition for right now, and we are committed to do those inspections one more time for each vessel head until we can get the new heads in and get them installed.

DR. BONACA: The two -- The four units, they run with -- The head is pretty hot? Is it 600?

MR. CORBIN: I don't know the temperature, but yes, they are hot. They are among the hotter ones in the industry, which puts them much higher on the susceptibility curve.

DR. BONACA: Exactly. Okay.

MR. CORBIN: Right. I think Surry and North Anna four units were all in the top ten in the nation, as a matter of fact.

DR. WALLIS: While we are on this unfortunate example --

DR. ROSEN: Who put this page in here? I would recommend you for the future briefings of the committee to choose a different page.

DR. WALLIS: When I look at cracking, I look at cracking as an aging management effect, aging effect requiring management. The activity on the right for many of them is chemistry control. Well, chemistry control is important to cracking, but it doesn't tell you if you are getting cracking or not.

MR. CORBIN: Right. Well, the examples I see -- and maybe it's not all the way down the page, but stainless steel cracking, at least in the first two example, is coupled with an ISI --

DR. WALLIS: Yes, but at the bottom it's not.

MR. CORBIN: Right, in the bottom head done, we are really relying on our chemistry program. But you know, you would have leading indicators as well.

DR. WALLIS: You would have to have, yes, something else.

MR. CORBIN: Again, if you go into the ISI program, say, up above and we were to see evidence through the ISI program that we did have cracking, our corrective action program drives us to look beyond just the cracks we've got in front of us but to identify where those cracks could also exist, and it may be that we -- I got to think about my geometry a little bit here. It may be that we cannot get to these locations with an ISI program --

DR. WALLIS: That may be the explanation.

MR. CORBIN: -- but it doesn't mean we wouldn't use the ISI program above and the corrective action process that backs it up to drive us to these other locations.

MR. WRONIEWICZ: Another aspect of the chemistry control program is our work control process, too, that provides an actual hands-on look at the --

an inspection of the material when the head is removed.

Chemistry control is primarily a preventive action with work control as a part of the chemistry control when anything is identified, and to provide an inspection when something is opened.

MR. CORBIN: That is a good point, and we did write up work control as part of chemistry, and that is an inspection step.

DR. FORD: I take it, we will be discussing all of the AMR activities when you get to Appendix B.

MR. CORBIN: Yes, when we get to Appendix B, we will run down the programs. So we can talk about them. Yes.

Anything else on Section 3 then, just tabulating the results of the age an management reviews?

All right. Let's talk a little bit about Section 4 on time-limited aging analyses.

MR. BARTON: Excuse me. I got something. On Section 3.6 in the LRA, it's Section 3.9 in the SER, aging managing electrical instrument and controls, I don't see in there your aging management program for medium voltage power cables that have a

potential for being wetted.

MR. CORBIN: This is -- As I mentioned very early in the meeting, we were looking at a draft version of the GALL report. We didn't have the final version. It did have in there some programs, but we did not include cable aging management programs in the application.

As a result of the REI process and the discussions that we have had with the staff, we now do have a commitment to aging management program which looks at both the Echo-1, Echo-2, and Echo-3 portions of the GALL report, which gets into medium voltage cables that are in submerged conditions and also looks at high voltage cables, etcetera.

MR. BARTON: Right. That's got AL-2 and RAI?

MR. CORBIN: Correct.

MR. BARTON: And it's now included?

MR. CORBIN: That program is now in here. In fact, later on you'll see where I mention that program and the fact that it was not originally included in the application, but is now there.

MR. BARTON: Thank you, Bill.

MR. WRONIEWICZ: This is Lucky Wroniewicz. I'd like to point out that that was also an item

identified in the SER as an open item.

MR. CORBIN: As an open item. So it's part of our original SER response.

DR. BONACA: I had a question on the -- with regard to the Class I piping which are covered by the Westinghouse topical reports. You had looked at the small bore piping, and for that you said at this time no small bore piping or socket weld has been designated as significant and so on. So there are no planned inspections. However, you are using some samples of welds in several three-inch lines as part of your ISI, I guess.

The question I have regarding those locations: Are they the most susceptible locations that you have identified or are they just simply some pipe elements of welds that you have in the program, and you are looking at them as leading indicators?

MR. HENIG: Based on review by our materials personnel, these are the most sensitive locations that we feel we could identify.

DR. BONACA: Okay, because the text did not really specify that, but it's important. So they are the most susceptible locations.

MR. HENIG: Yes, sir.

DR. BONACA: And you are using them as

leading indicators?

MR. HENIG: Yes, sir.

DR. BONACA: All right. The other question I have is on void swelling. You really have not made any specific commitment to those. You just commit to do whatever the industry solution may be to that.

MR. CORBIN: That's correct.

DR. BONACA: And there is already an understanding between the NRC and the industry that they will endorse the industry position?

The question I have for the staff is that -- This is a question regarding the void swelling. You know, when I read the application, it says we haven't made any commitment to it except we will commit to do whatever the industry decides to do on this issue.

DR. KUO: Right.

DR. BONACA: Is there an understanding between the staff and the industry that staff will be reviewing the position of the industry and determine whether or not it is acceptable? What is the position?

DR. KUO: Let's see. Can I get back to you on that question?

DR. BONACA: Okay.

DR. KUO: After the break. I want to be sure.

DR. BONACA: That's fine.

DR. KUO: I have some impression, but I want to make sure about that.

DR. BONACA: Because I know there was some understanding, but there is no clear definition of, you know, what is going to be acceptable and not acceptable, and I would like to understand if there is an agreement between the industry and the NRC that the industry will reach a final position. NRC will review it. If you agree, that will be the solution.

DR. KUO: I do believe that's the case, but I want to confirm it.

DR. FORD: It goes beyond that, in fact, because in a quite of your ISI programs, you cite both the MRP progress, for instance, in vessel high penetration cracking and the ISI criteria for that, and also the ASME 11 code conditions. All of that is an ongoing, developing situation.

So what is the agreement for not just your situation but the MRP actions, developments in the ASME 11 codes? What is the relationship to the NRC and the industry on those issues, too?

DR. BONACA: He may want to cover that issue, too.

DR. KUO: I was reminded that we have a staff member here that can talk about the void swelling. Do you want to hear it now or later?

DR. BONACA: Now.

DR, KUO: This is Mr. George Georgiev.

MR. GEORGIEV: Good morning. I am George Georgiev, and I am with the Materials Engineering Branch, and I am scheduled to make a presentation to the Committee this afternoon on the reactor coolant system.

Since the question fits within my area, basically, our staff position is on the issues that are developing, and we don't have the end result. We basically go along with the industry initiatives, and we work with the industry and, in the end, basically, approve what is approved as common condition. We are dissatisfied with the end result.

We do have a couple of the most recent issues that I assume you will ask about, like the reactor vessel head cracking. We haven't come up with a final position on the Davis-Besse event, and the void swelling is one of those we are following. We work with the industry. When the issue is bounded and

resolved, we will rule on it.

DR. BONACA: Some licensee chose the option of inspecting for swelling, one-time inspection, if I remember, or -- yes, one-time inspection tied to the ISI, and they wanted to do internal inspections, and they would be looking for presence of any swelling once, and they would be dealt with and the staff accepted that. We accepted it, too. So that would be an alternative, I guess.

MR. GEORGIEV: Yes. Definitely, but in the meantime something better may come out, and we keep our options, you know.

MR. CORBIN: We are sort of making a commitment in the blind, too, as far as that goes, because we're not exactly sure where the industry and the staff are going to come out on these. But ultimately, you know, that dialogue and that research that will go into making those decisions should prove to be sound in terms of what you have to do to address these issues.

DR. FORD: Before you get onto Section 4, since we've started to ask specific questions about these rather than wait for the Appendices, I've got a couple of questions on Section 3, the aging management programs.

I know this has come up in previous license renewal questions about the validity of one-time inspections. You've got three new programs. One is on tanks. One is on buried pipelines. I can't remember the other one. But they all relate to one-time inspections. Fire protection is the other one.

In those new programs that you have, you say we will do a one-time inspection on a selected part of the piping, for instance. What is your criteria for choosing what section of piping you are going to look at and when?

MR. CORBIN: The answer -- Well, the "when" question first is prior to year 40.

DR. FORD: Oh, and the fire protection is year 50, I think it is.

MR. CORBIN: Well, but we do it again in 50. Isn't that right?

MR. WRONIEWICZ: Yes.

DR. FORD: Okay.

MR. CORBIN: So I think we do it baseline, and then again.

MR. WRONIEWICZ: Yes, still prior to year 40, and then the requirement is --

DR. FORD: And the objective is that you presume you've got, for instance, protection on these

buried pipelines, and you've got no reason to suppose they have failed. You just want to confirm that they haven't failed.

MR. CORBIN: Well, the criteria in terms of what we are going to go look at, we'll look at the various types of materials that we have. So a stainless steel tank is not a good indicator for a carbon steel tank, and we have to look at one of each.

DR. FORD: Sure. Good.

MR. CORBIN: You know, if we have cast iron piping that's buried, then we need to get a sample of cast iron piping and look at that, which is different than stainless steel pipe that's buried.

DR. FORD: But where in the miles of piping you must have in the plant, which part do you look at, and what is the thought process that decides you on that?

MR. CORBIN: The thoughts really have to do with the types of materials. Some of the materials, for example, are pipe that's coated in certain ways or wrapped in certain ways or has cathartic protection. It's to identify those different populations that we have, and really as a matter of course, we are saying the soil conditions are fairly uniform for the buried pipe.

For tanks, we have to look at, you know, are they founded on asphalt or concrete or gravel or sand, to understand those environments, and pick an example of each of those out. But it's going to be opportunistic, to some extent.

In other words, coming up to year 40, if we are in the yard and we are digging a hole for some reason, for some other reason, some other work that we have to do, we will use that opportunity to get down in the hole and see if we have one of our commodities that we need to look at, do our inspection, and write up those results.

That goes into our evaluation that we've committed to as well. We'll do an evaluation of what we found. We use that as a baseline to determine what we need to do in the future, whether it's additional inspections or it gets to something more drastic, up to replacement in some cases.

DR. FORD: Now you presumably questioned on that by the staff.

MR. CORBIN: Yes.

DR. FORD: On that very question, as to what is the criteria?

MR. CORBIN: I was not.

DR. FORD: But somebody was.

MR. CORBIN: Yes.

MR. WRONIEWICZ: Yes. The Region II inspectors questioned what we were doing with all of our --

DR. FORD: And the rationale for where and when?

MR. WRONIEWICZ: Yes, sir.

DR. FORD: For the one-time inspections?

MR. WRONIEWICZ: Yes, sir.

DR. FORD: Okay. The last thing this afternoon. Good.

MR. CORBIN: Anything else on Section 3?

DR. BONACA: Since we are asking questions--

MR. CORBIN: Please do.

DR. BONACA: One question I had for that, you have -- this is an example. You have containment liner on the floor. It's covered by concrete to protect it from -- It's a missile protection thing. As the plant ages and you get into the 40 and 60 years, how do you monitor the liner that is covered, is unaccessible.

MR. CORBIN: It is inaccessible, and what we have indicated is that we would use accessible locations to give us some indication for inaccessible

locations.

DR. BONACA: So you are looking for indirect --

MR. CORBIN: Correct.

DR. BONACA: You probably would have to look also at what could cause that liner to be affected by corrosion of any type.

MR. CORBIN: That is correct. Now we did -- As a matter of operating experience, we did have an opportunity to look at the edge between that concrete and where it meets the side wall at the corner, if you will, of containment and did a little chipping. That operating experience showed us that the liner was really in very good condition underneath the grout, but that again was opportunistic. But using accessible locations -- The basic principle here is that we are going to use accessible locations as an indicator for the condition of inaccessible locations.

CHAIRMAN LEITCH: Were these the -- Is it one of these plants where there was some blistering on the containment liner that, when you investigated, you found it to be lumber, I think it was, that was in the concrete?

MR. CORBIN: That is correct. We did have an instance where we have found lumber in the

concrete, if you will, behind the liner and have had to excavate that. I mean, the corrective action is dig that out and re-grout it, redo the liner, and we have had instances.

CHAIRMAN LEITCH: And the indicator of that was -- Was it blistering on the liner?

MR. CORBIN: Yes. You could see it through the coating. Blistering on the coating was an indicator to us that we had that issue. There's some subsurface issue there. We had to come down, just keep going down until you figure out what's going on.

I believe we did UT examinations, as a matter of fact, through the liner wall to see what in the heck was going on, and discovered this piece of lumber.

DR. SIEBER: Your containments are sub-atmospheric. Correct?

MR. CORBIN: That is correct, sub-atmospheric containment.

DR. SIEBER: So when the plant is running, there is a partial vacuum inside containment which pulls the liner away from the walls?

MR. CORBIN: It would have that effect, yes.

DR. SIEBER: I think that you are one of

the plants or your plants are ones where you map where it's been sucked away from the walls to see how far it's moved. Is that part of your aging management program?

MR. CORBIN: Well, I'm not familiar with that.

DR. SIEBER: There are five Stone and Webster that are built like that.

MR. CORBIN: Well, I think Beaver Valley was one as well.

DR. SIEBER: Yes, we mapped. Farley maps. I presume you mapped, too. Right?

MR. CORBIN: I'm not familiar with any mapping that we do in that regard.

MR. WRONIEWICZ: There may have been some early mapping when the plant was initially started, but we are not, to my knowledge, doing that now.

MR. CORBIN: There's nothing going on in that regard. I mean, we do --

DR. SIEBER: Well, you do have an interesting phenomenon there. You operate the plan, and you're pulling the liner away, and every few years you go and do a containment leak rate test where you pressurize it all back. Now you've got a phenomenon where you're basically flexing this large, very thin

piece of steel. You might want to just think about that f a little bit.

MR. CORBIN: Right. I mean, we do have a time in that aging analysis on containment liner that does talk about cycles, as you are indicating, and making sure that we stay within those limits, the indicated limits for --

DR. SIEBER: Yes. I'm not aware that any liner has cracked because of that. I do know they move, and they move quite a bit.

MR. CORBIN: Right. Yes, when you look at the thickness of the liner relative to the overall area, it is very thin.

DR. SIEBER: Right. It's a membrane.

MR. CORBIN: Right.

DR. WALLIS: Is it tied, I think, to the wall in places? It's not just hanging there?

MR. CORBIN: No, it is tied to the wall. That's correct.

CHAIRMAN LEITCH: I think, rather than getting into Section 4, this may be a good time to take a break. If there are any other questions on Section 3 right now? Then let's recess until 10:15.

(Whereupon, the foregoing matter went off the record at 9:57 a.m. and went back on the record at

10:15 a.m.)

CHAIRMAN LEITCH: We are going to take just a brief interruption here before we move on to Section 4. Doug Coe of the NRC staff is going to give us a discussion of the reactor oversight process as it pertains to Surry and North Anna, and attempt to better answer one of the questions that was raised in the first session.

So we will hear from Doug, and then revert back to the VEPCO presentation at Section 4 then.

MR. COE: I am Doug Coe with the Inspection Programs Branch of NRR. I was asked to just briefly answer two questions, as I understood them. So please correct me if I got these wrong.

I understand that first you would like to know what the status of North Anna and Surry are with the current reactor oversight process performance assessment.

So just before I came here, I went to our external web page on performance assessment results. The results are posted based on up through and including the first quarter of this year. The next quarter will be -- This website will be refreshed with second quarter information as of August 1st, but currently the data is good through the first quarter

of this year, calendar year.

Surry is in the regulatory response column, and North Anna is in the licensee response column. The Surry -- Both Surry plants are in the regulatory response column based on a fourth quarter -- calendar '01 fourth quarter white finding that has to do with a failed number three diesel generator following increasing lube oil contamination.

In addition, a performance indicator for diesel generator unavailability tripped at greater than 2.5 percent unavailability in the first quarter of this calendar year, and on that basis the licensee is in the regulatory response column of the action matrix.

North Anna has green findings or no findings throughout their inspection last four quarters, and PI results are green. So that is why they are in those columns.

Was that responsive to the earlier question?

DR. ROSEN: Tell me again what the first part of the Surry reason for being white was. The second part was greater than 2.5 percent availability of one of their diesels?

MR. COE: That value is the green-white

threshold.

DR. ROSEN; Right, I know, but the other part had to do with a finding on oil?

MR. COE: It was a finding -- a white finding, and it's more fully developed on the web page, but just the brief look that I had of it and kind of the header information indicated that the licensee was deficient in terms of their correction action when increasing lube oil contamination was not effectively responded to and ultimately resulted in failed risk pins and piston carrier bearings on the number 3 diesel generator.

That failure brought to light the earlier deficiencies, which resulted in an NRC finding, and the finding's significance was based on the impact of that diesel generator's unavailability, which was white.

DR. ROSEN: It was the same diesel that had the risk pin failures because of lube oil contamination, and ultimately went to greater than 2.5 percent unavailability?

MR. COE: I'm not -- I can't say that. I mean, it's clear that the unavailability of the number three diesel generator would have contributed to the overall performance indicator for on-site emergency

AC. How much of an influence it had, I would have to look at further. But the performance indicator tripped the green-white threshold in the first quarter of this year. So it was clearly -- That was an input.

MR. CORBIN: I'll just add a note, I guess. The reason the Surry emergency diesel generator experienced this issue was that we did change out the oil that we were using in the machine, and it was the oil that contributed to the problem. As a result, it was not only the number 3 emergency diesel generator. I don't remember if it was number 1 or number 2, but it was one other diesel as well that was affected.

So by the time we got all of the issues resolved and looked at common mode issues, that tripped us out on 2.5 percent unavailability for diesels overall. It all stemmed from the same issue.

DR. RANSOM: That is an issue we heard about at Region II visit, isn't it?

CHAIRMAN LEITCH: Yes, we did.

MR. COE: Okay? So is that responsive?

CHAIRMAN LEITCH: Yes.

MR. COE: The other question that I was asked to discuss was the relationship of the license renewal inspections to the ROP. The license renewal

inspections are governed by a manual chapter that is separate and distinct from the ROP. There is, in fact, a separate budget line that governs or that resources those inspections that is separate and distinct from the ROP.

The purpose of that inspection is not so much licensee performance, because what is really being evaluated is the licensee's readiness to enter an extended license period. So the information that is gathered under inspection procedure 71002, which is available on our website, is essentially information that is useful to the staff in assessing the adequacy of the licensee's programs pursuant to their final approval of a license extension.

Now I will say that the team -- The inspection that is conducted under this procedure is normally conducted by regional inspectors, and it's a fairly extensive team effort that looks hard at the programmatic elements. So from that -- of a licensee's readiness for license renewal.

From that standpoint, it doesn't necessarily fit neatly into a risk informed performance based kind of an ROP thrust, but it is a necessary element of the staff's ability to make a decision or determination regarding a license renewal

request.

My expectation is -- and I don't know that I know of any examples of this, but my expectation is that, if this team inspection were to uncover a current deficiency in the licensee's programs or performance that should be considered in the performance assessment process, that those issues would be turned over to the appropriate inspectors in a different venue, in the ROP venue, for processing or further development.

I don't know that any of those issues have occurred, but my main message here today is that these inspections for license renewal purposes are separate and distinct from the ROP.

DR. ROSEN: And I take it from your remarks that there is no nexus between -- You would extend the license of a plant that was red, just as you would extend the license of a green, if the plant met the requirements of license renewal? There would be no nexus in your mind?

MR. COE: Well, we haven't encountered that situation yet, and so I'm not sure I could speculate. If the licensee was having performance problems of that significance, it may be that those performance problems are reflected in other aspects of

the licensee's programs, including those that are aimed at getting the plant -- or ensuring that the plant is ready to enter an extended license period.

Again, if any issues arise in the license renewal inspection that should be processed by ROP, as I mentioned, my expectation was that those issues would be passed over, and they would be processed by ROP.

The question you raise is the opposite one. If there are issues in the ROP, should they be passed back to the license renewal people to enter into their decision and their determination as to whether the licensee is prepared to enter a license renewal period.

I can't say that there is any examples of that happening either, but I think I would say that my expectation is equal in both scenarios.

DR. ROSEN: Well, I think the definition of red, as I recall, is unacceptable performance.

MR. COE: The definition of red is unacceptable, I believe. Correct. Yes, I think that's the way we've characterized it. So that would be -- But also we also indicated that in certain cases a red finding, in and of itself, may not require the NRC to take, you know, action amounting to a shutdown

order or something like that.

There may be cases where the plant may be allowed to continue to operate. It may be an old design issue that has been subsequently corrected or other kinds of situations that we see arising in which the plant may continue -- be allowed to continue to operate.

Again, I think the question you are raising is, is information available to the license renewal team relative to the licensee's current performance? It would be the expectation that they would utilize that information in making their decision on license renewal and license extension.

Again, I don't have any clear examples of that, but that's certainly an expectation.

DR. ROSEN: Well, this all began with an innocent question by one of the members to a presenter from the staff about what he meant by saying the plant's material condition looked good. The responses were not crisp.

MR. COE: Well, and I don't think that there's any clear standard for material condition looking good. I think the key is that the inspection procedure is really attempting to ascertain whether the licensee is paying appropriate attention to the

right components, the right SSCs, that in fact are subject to aging in the license renewal period, and to which extra attention needs to be paid during that license renewal period.

To some extent, an observation of the plant's material condition might be relevant, but it's only relevant relative to the objectives of that inspection.

DR. ROSEN: Well, I would have expected a crisp answer to be, well, let me show you a picture of something that we look at that's relevant to license renewal and what good condition it's in, and flash up this picture of something and say, by comparison here's one that we didn't think was very good at another plant, and show the difference. That would have been a complete answer, but we didn't get that.

MR. COE: That would be, I am sure, very useful to your understanding. But, clearly, the threshold for what's good and what's not is not a crisp one. I'm not sure that there has ever been a very crisp distinction there.

So it's really the body of all of the observations that combine in the inspectors' judgment and ultimately in the staff's review of the application that bear on the question of readiness to

enter a license renewal period. So this is just one element of that.

Other questions related to the ROP or relationship?

CHAIRMAN LEITCH: Okay, thanks, Doug.

MR. COE: Okay. You're welcome.

DR. KUO: Dr. Leitch, if I may, I just want to add a couple of other comments, that the license renewal staff and our technical staff follow the operating reactor events closely all the time for the purpose of a license renewal, and that we do ask the applicant for license renewal address the operating experiences all the time for any aging management that they propose.

I just give you on example. When we reviewed Oconee plant applications, approaching to the end of that review Davis-Besse had a cable moisture problem, and we promptly asked the Oconee applicant to address that issue.

Since Calvert Cliffs already got their license, we actually went back to them, asked them to address the same issue. That's just some assurance to the Committee that we do follow the operating reactor events.

CHAIRMAN LEITCH: Okay, thank you. Okay,

sorry for the interruption, Bill.

MR. CORBIN: Oh, not at all.

CHAIRMAN LEITCH: Would you resume your presentation/

MR. CORBIN: If I could, I want to backtrack. On the break we tried to follow up on a couple of questions that were raised earlier. The first one on the fire protection embankment: We finally remembered that what we are talking about there is a bladder tank that's on the side of a hill, which is a fire protection enclosure that feeds Warehouse Number 5 for fire protection.

Warehouse Number 5 is not in the scope of license renewal. Therefore, this bladder tank is not in the scope of license renewal. The reason I was puzzled, I kept thinking about the main fire protection system, but this is back over behind a hill. But that's why that particular item is not included in the scope.

Then another question that related back to this chart with regard to why boric acid corrosion surveillance is shown in one location and not in the other. Really, 97-01 had us commit to certain inspections that are more detailed, if you will, and they are carried under the ISI program reactor vessel.

So it really gets us a better inspection than what boric acid corrosion surveillance would get us.

So those two clarifications.

Moving forward then to time-limited aging analyses, they are consistent with 10 CFR 54.21, paragraph Charley, and 95-10. The way we did our time-limited aging analyses search, we would use a key word search for calculations, reports, licensing correspondence, UFSAR, WCAP.

This really is searching for an unknown number of needles in a haystack, and you have to find them all. We spent literally hours and hours of very patient research, and our approach was more to search to exclude an item rather than to include an item.

If we couldn't find a basis to exclude something, then we dug further, and we kept digging on an item until we sure it was not a TLAA, and in this method got ourselves to a point where we believe we did capture the time-limited aging analyses.

We also enlisted the support of Westinghouse, the NSSS supplier, because they do own or keep a number of the calculations that are relevant to the design basis of the plant, and they also performed a search to find time-limited aging analyses.

In terms of how we reported the results, the layout is consistent with the standard review plan format, the same format that was in the draft as well, and we summarized the results in Table 4.1-1, either by (i), (ii), or (iii) as laid out in the standard review plan and the licensing renewal rule.

With regard to what were the time-limited aging analyses that we discovered, the more generic TLAAs included: Reactor vessel neutron embrittlement; metal fatigue, and we included environment effects of fatigue; environmental qualification; containment tendon prestresses was a not applicable section, because we do not have containment tendons at either Surry or North Anna; and containment liner plate and penetration fatigue.

The plant specific TLAAs included the crane load cycle limits, reactor coolant pump flywheel, leak-before-break, spent fuel pool liner, piping subsurface indications -- these were preexisting flaws that we have to continue to follow -- and a Code Case N-481 on reactor coolant pumps for inspection on pump bolts.

So that summarizes then both the generic and plant specific TLAAs. Any questions on time-limited aging analyses?

MR. BARTON: Yes. In environmental qualification electrical equipment --

MR. CORBIN: Yes.

MR. BARTON: There are several areas where -- Well, let me ask the staff, I guess. Has there been final resolution of GSI-168?

DR. KUO: That has been resolved.

DR. ROSEN: 168 is --

DR. KUO: I'm sorry.

DR. ROSEN: 168 is the sump --

MR. BARTON: No, no, no. I think it is the electrical equipment low voltage cable. But there are several sections in your application where you haven't committed to doing anything on certain cables until NRC resolves 168.

My question is has 168 been finally resolved?

DR. KUO: Not yet. I'm sorry. I gave you the wrong answer.

DR. SIEBER: We just wrote the letter on it last week.

MR. DURAISWAMY: John, I think that 168 resolution -- RES made recommendations to NRR. It is with NRR for resolution.

MR. BARTON: Okay.

MR. DURAISWAMY: I think Montgomery looked at the thing and wrote a letter.

MR. BARTON: All right.

DR. KUO: Sir, I have a tech staff here that can answer your question on GSI-168.

MR. BARTON; I don't have any question on 168. The question is where does the application stand on committing to do certain -- you know, AMR on certain equipment, because the LRA now states, you know, until 168 gets resolved -- Well, let me see. No plans exist to extend qualified life of certain equipment until resolution of 168 is finalized. So I just wondered where does that whole issue stand. If 168 is finalized, is there going to be a LRA amendment or, you know, where are we. That's all.

DR. KUO: If you don't mind, sir, we will discuss that in the staff presentation.

MR. BARTON; Okay. Thank you.

DR. RANSOM: How does the leak-before-break come into play under the time limit of the analysis? Most everything here is a component, but that's sort of a generic category.

MR. CORBIN: It is more of a generic, although it does relate specifically to reactor coolant system components. I think I'll let either

Mike or Lucky answer that.

MR. HENIG: This is Mike Henig with Dominion. It deals with the thermal aging of the material. Originally, leak-before-break is strictly material properties that were thermally aged for 40 years, and we had to extend that to 60.

MR. CORBIN: So there was a time associated with our leak-before-break analysis.

MR. HENIG: In the materials aging.

MR. CORBIN: And so now we pick that up and go to 60 years.

MR. BARTON: Bill. You've committed -- For example, on RTDs you committed that certain RTDs would be replaced due to qualification being shorter than extended operating period. I guess my question is to the staff.

How does the staff follow -- That's a statement in the ORA. Now how does the staff follow that to assure that these RTDs are in fact replaced prior to license extension?

DR. KUO: Staff -- Paul Shemanski from the Electrical Engineering Branch will answer your question.

MR. SHEMANSKI: Basically, let's assume that these RTDs are within the equipment qualification

program that is covered by 10 CFR 50.49. As such, they are required to have a qualified life, and whatever that qualified life is -- say, for the RTDs it's 20 years -- then by definition, they've got to be replaced prior to the end of their qualified life. Otherwise, they would be in noncompliance with 50.49.

Now this is not something that the staff regularly checks on. They are required to maintain documentation which gives the qualified life, and then they've got to take action accordingly.

As they approach the end of qualified life, they have two options. They could either replace the component at that point or they may choose to do some additional testing or reanalysis to see if it's possible to extend the qualified life. But that's basically true for all components on the EQ master list. They all have a qualified life.

MR. CORBIN: It's the acceptability of our program then that's being relied on. We have many programs. Our EQ program demands that we change these things out or test or reanalyze, as indicated.

DR. RANSOM: Along that line, why were the four reactor pressure vessel heads being replaced, or you have plans, you said, for replacing all four.

MR. CORBIN: Correct.

DR. RANSOM: And minor repairs have been made, but because they are coming to the end of their life?

MR. CORBIN: Well, you know, as the emerging issue on the susceptibility of these materials has become more evident, it's clear that these reactor vessel heads cannot reasonably be expected to go to 60 years, and so we have made the decision that we are going to replace them.

DR. RANSOM: That wasn't a licensing driven decision?

MR. CORBIN: Certainly, the NRC has had a great deal to say about the inspections and the techniques, but I think the ultimate decision was just a financial one associated with being able to run for 60 years.

We recognize that the best time, if you will, from an EVA point of view, to do heads is to do them as soon as we can. So that drove the decision to do that as quickly as possible.

Now will the material last for 60 years? Probably not.

DR. RANSOM: Well, I was wondering if they would last for the current licensing period.

MR. CORBIN: Will it last for 40 years?

I'm not really prepared to answer that, but my guess is that, no, it wouldn't last for 40 years, but we have reason to believe, based on the emerging issue, that the indications that we have, the fact that we are ranked in the top ten for all four of those units in terms of susceptibility puts us in a fairly precarious position in terms of expecting these things to last even for 40 years.

DR. RANSOM: So that was a decision that you made.

MR. CORBIN: So it's really a current licensing basis decision that Dominion made to go ahead and replace those heads. It really didn't derive out of license renewal, that whole decision making process.

CHAIRMAN LEITCH: In the area of reactor vessel neutron embrittlement, you know, discussed in Section 4, I guess beginning around page 4-3 and following, there is a discussion of upper shelf energy and later pressurized thermal shock and later pressure temperature limits.

In none of these areas is there specificity. For example, I'm looking now at a North Anna specific paragraph that says calculations performed-- This is with regard to upper shelf energy

-- calculations performed in accordance with Reg Guide 1.99 demonstrated that upper shelf energy values for the limiting reactor vessel beltline materials at the end of the period of extended operation are greater than 10 CFR 50 Appendix G requirement of 50 foot pounds.

I guess there are similar statements with respect to pressurized thermal shock and pressure temperature. Greater than 50 foot pounds -- It's good that you say that. I would have been a little more comfortable had I known what the specific value was.

MR. CORBIN: Certainly, our internal documentation, the reports and analyses that we did in-house, are more specific, and that information is available for review back in our facility, but decided that we did not want to be that specific here in the application.

We are really not -- Well, just felt that we should keep that detailed knowledge available, and it is available, if you want answers to questions. What I'm getting at, I guess, is that there is some quantitative back-up --

CHAIRMAN LEITCH: Back-up material, yes.

MR. CORBIN: -- for these statements. It's not just a qualitative statement that, oh, gosh,

we think we are above 50 foot pounds. We can back that up.

DR. BONACA: But did the staff look at the actual value calculated?

DR. KUO: Let me ask the tech staff.

DR. FORD: Well, while the person is coming up, I've got a very similar question maybe he can answer at the same time.

The Surry -- The RTPS value for 40 years was about 245 versus 270 screening criterion. There must be new data to show what the RTPS would be for 60 years, and would that have been looked at by the staff, the details.

You keep hearing about pencil sharpening when you come down to these things, and what sort of pencil sharpening is being done?

MR. CORBIN: All right. I see a member of the staff here.

MR. GEORGIEV: Here is George Georgiev with the Materials Engineering Branch. All these issues are kind of interrelated, the upper shelf, the fracture toughness, the PT limits. The bottom line is fracture toughness of the vessel material.

So we do regulation which covers this Appendix H which mandates that you have a surveillance

capsule that you periodically take out of the vessel and break it, and you have a reference point. And also it do have a screening criteria that all licensees has to meet.

In this case, the applicant stated that he has performed the calculation in accordance with our guidance included in the Reg Guide 199, Revision 2, and it's above our screening criteria.

Over and above, the staff has a reactor vessel database that we do have the limiting materials in this. So we at anytime can go out there and find out which of the vessels if kind of problematic and which is not. The Dominion vessels are not.

DR. FORD: I guess the question is you said you can. Did you?

MR. GEORGIEV: The answer is not. We didn't in this case, but we could --

DR. FORD: So when they say that they meet the screening criterion, that's --

MR. GEORGIEV: That's right.

DR. FORD: -- for not the 60 years, but the 40 years --

MR. GEORGIEV: No, for 60. They do make the statement, and we accepted that statement. Otherwise, that will be the number one request for

additional information, if they haven't done it. But they have done it.

DR. FORD: The fact that Surry had, for instance, an RTPTS for 40 years, 245, plus the screening criterion for 70, suddenly you don't have much of a margin. Now if you go up to 60 years, the margin is even less.

MR. GEORGIEV: Well, but the PT curves do get updated after you get and break capsule. So they do have a valid PT curve at a certain time. When the time approached, they are supposed to come with brand new updated PT curve based upon the data they obtain from breaking the specimens from their capsules, and their operating condition.

So we will get updated PT curves.

DR. FORD: But I think our point is, within the LRA the licensee makes a case that he's all right for going for 60 years for, for instance, PTS or whatever degradation. What you are saying is you didn't double check those calculations.

MR. GEORGIEV: That's correct. We did not.

CHAIRMAN LEITCH: I guess a similar question: The pressure temperature limits. There is a statement there on page 4-7: Dominion has confirmed

that acceptable PTS limits and associated L-top setpoints can be established for the period of extended operation. But the changes in tech specs to support that have been deferred into the future, and I guess the question is the same. To what extend have you independently verified that statement or are you just accepting that --

MR. GEORGIEV: We have not, because we know that when the current PT curves slow their time, a new will have to be docketed with the staff to review, and included in their technical specifications. So when that takes place, we'll take a look then, but we could do the review independently. The question is with time and resources.

DR. SIEBER: Seems to me the PT curves -- they are part of the tech specs, and they are recalculated periodically.

MR. GEORGIEV: Correct.

DR. SIEBER: I recall seven or eight amendments over the years where we resubmitted these things, and so part of the statement that says that you can operate for 60 years and still produce an acceptable PT curve is, to some extent, speculation, but it's based upon the trends of where things are going versus what the limits are.

I don't find that unreasonable.

DR. BONACA: No. In fact, I don't, but I think as a committee we -- I guess we build expectations based on the application from which you get more information. Now the previous one we reviewed for Turkey Point was very specific. It came out, for example, in an RTPTS value. We had a discussion, in fact, about that. Mr. Rosen was concerned about how close the value was to the criterion.

So there, there was an extensive discussion in the SER that is utterly missing from this application, because the application doesn't have the technical detail, and the SER doesn't have the technical detail. So it's a question of how we have been, I guess, spoiled by the previous application with information that we don't have here.

DR. SIEBER: Well, just to follow up a little bit, when we were talking about margin and reduction in margin as the plant ages, the margin is already built into the criterion as opposed to taking whatever your calculated temperature is and saying I want to build a margin between that calculation and the criterion. The criterion has the margin in it.

DR. BONACA: And I agree with that. ON

the other hand, I think it would be --

MR. GEORGIEV: Well, as I mentioned earlier, that could be done. We could do it. I imagine we could have asked for specifics, but it's a matter of time and resources, and we feel that we will address these issues later on when they come with new PT curves. And in fact, this application was reviewed by a contractor, with us, of course, monitoring the contractor. That's an indication that we don't have that many people to do this.

DR. SIEBER: Actually, all these are done by contractors. Right? Usually, the NSSS vendor? They follow an analytical procedure which has been reviewed by the staff at some point in time.

MR. CORBIN: That's certainly the work that we've done in-house.

DR. SIEBER: Right. You have done that in-house?

MR. CORBIN: Well, I mean, I think what he was referring to is a contractor doing the review of the application.

DR. ROSEN: Well, Mario, we'll come back to this in our discussion later, Graham, when the committee has its internal discussion a to what we might want or need before we could go forward.

CHAIRMAN LEITCH: Yes. I think what we are trying to understand here is just what was done, what is the nature of the staff's review.

DR. KUO: We will discuss that later in the staff discussion.

CHAIRMAN LEITCH: Okay. Thank you. Go ahead.

MR. CORBIN: Okay. Any other questions then related to Section 4?

MR. BARTON; Yes. 4.4 ICCM application -- Can you tell me what the function is of the inadequate core cooling system? I couldn't figure it out from the LRA. I wonder why anybody would call anything associated with core cooling as inadequate. And it said it's not a system; it's a bunch of components. Could you please tell me what the function of this thing is?

MR. CORBIN: Well, inadequate core cooling monitor --

MR. BARTON; It calls it a system. That's what is confusing.

MR. CORBIN: Yes. What we are looking at there is when you get into a refueling situation and you're looking at where you are with the refueling canal level, and if you are draining down to midline

on the nozzle, you go up or down with water, you want to make sure that you are maintaining a sufficient inventory of water. So we have a --

MR. BARTON: So this system monitors that. Is that the function?

MR. CORBIN: It's a series of components of some different elements associated with it that give the operator in the control room indication that he can use for verifying that he has adequate core cooling.

MR. BARTON: It's just a strange name. You're talking about inadequate core cooling.

MR. CORBIN: Right. It gets your attention.

MR. BARTON; Yes, it sure does.

DR. BONACA; Well, also isn't there an inadequate core cooling panel in the back of the control room?

MR. CORBIN: Yes. I'm going to say, yes, that's true, although I think we do, for a refueling outage, also drag in a television screen, and we'll put a television camera on an in-place level monitor in the containment and back that up with the electronic indication. So, I mean, there's some different pieces and parts to what we put together for

confirming adequate core cooling. Maybe we should rename it ACCM instead of ICCM.

MR. BARTON: Yes, refueling adequate core cooling indicating system or something. Okay.

DR. SIEBER: You folks do that with jumpers and lifted leads and things like that.

MR. CORBIN: That's correct, and not --

DR. SIEBER: Steam generator level is probably the instrument you use.

MR. CORBIN: Well, actually, we have a separate level indication. It's just a flip flag as one piece of it. We do use steam generator level indication at one element. As a redundant means we have a big flip flag system. That's what we put the TV camera on, and you can see how the flip flags are looking and try and get some different kinds of indication, diverse means of indication.

DR. SIEBER: Have you ever lost suction to the RHR pump?

MR. CORBIN: Have we ever -- We've had some events. You're getting a little off my area of expertise, but I'm sure we've had events where we have had vortexing. We've certainly had vortexing for RHR suction. I'm not sure that we have actually lost a pump. It may be true. Someone here may have

knowledge.

DR. SIEBER: Well, that's what you're protecting with all this stuff.

MR. CORBIN: Correct.

CHAIRMAN LEITCH: Bill, I'm not familiar with this code case N-481 concerning the RCP coolant pump component.

MR. CORBIN: Reactor coolant pumps, right.

CHAIRMAN LEITCH: Apparently, in lieu of volumetric inspection, we are saying we can use fracture mechanics evaluation and visual inspection, and I guess, is that -- you're saying that's valid for the period of extended operation?

MR. CORBIN: Well, we had to reevaluate it. You're talking about the flaw growth now. If you had a flaw and its growth, would that flaw grow to an unacceptable size in 40 years versus 60 years, and you have to look at flaw growth rates and things.

That's why it became a time-limited aging analysis, because this code case was tied to flaw growth, flaw growth rates, which gets you to a period of time. So we had to reevaluate that for a 60-year period of time.

CHAIRMAN LEITCH: And say you really do a visual examination of these impellers rather than a

volumetric examination?

MR. CORBIN: This is the pump bolts, I'm pretty sure. It's not the impellers.

CHAIRMAN LEITCH: Oh, it's not the impellers. Sorry, I misunderstood.

MR. CORBIN: It would be the casing.

CHAIRMAN LEITCH: Ah, okay.

MR. CORBIN: It's hard to get a UT probe on the bolts. They are all round. So we do visual examination, and back it up.

CHAIRMAN LEITCH: I thought it was the impellers. Okay.

DR. SIEBER: It's an ALARA issue, too.

MR. CORBIN: It certainly is.

CHAIRMAN LEITCH: Oh, yeah, sure.

DR. SIEBER: I think most PWRs invoke this code case.

MR. CORBIN: Right. It's used by a lot of utilities. We are not unique in using this code case.

CHAIRMAN LEITCH: Okay, thank you.

MR. CORBIN: More questions on Section 4? All right.

Appendix A: Just a brief statement about what's in there. This was written up as a draft, if you will, of the UFSAR supplement. It summarizes --

provides summaries of the programs and activities that we credit for managing the effects of aging, and it looks at one of the four functions, as identified in the Standard Review Plan, whether it's prevention, mitigation, condition monitoring, and performance monitoring.

I really didn't have a lot of additional comments on Appendix A. What we are going to do with it is use this information and eventually create a new UFSAR chapter that we would put into our UFSARs. In fact, we've gotten a re-draft of that done now where we have put all the information we've gathered over the course of this review back into a new version of Appendix A that will become our UFSAR.

If there's nothing on that, I'm going to go into the aging management activities. The first comment I would like to make is that our aging management activities rely on proven techniques that have been established through existing procedures and programs.

So not only do we use these techniques in the existing programs, but we are applying similar types of techniques to new and upgraded programs. When I say proven techniques, that could be a visual inspection. It could be NDE. It could be chemistry

control. We've tried to use proven techniques as the basis for our aging management activities.

The format of our aging management activity -- You notice, we call them AMAs and not AMPs, because in some cases you are collecting a set of individual activities together rather than a full blown program. But our AMAs have the -- identify the aging effects that are managed.

We provide a list of the applicable systems, structures and components, and then we go through the ten elements, as identified in the Standard Review Plan in terms of writing up or evaluating the program.

DR. BONACA: The question I have on this for discussion here: You talk about rely on proven techniques. Okay?

MR. CORBIN: Right.

DR. BONACA: So one of the central programs you have there is the ISI.

MR. CORBIN: Correct.

DR. BONACA: Now in the mid-nineties Virgil Summer performs ISI of the nozzles -- weld.

MR. CORBIN: Oh, I see where you are going.

DR. BONACA: And they found no indications

in any of the nozzles. Then comes the year 2000. There is a leakage through, which means there is a crack through-wall in a weld on a nozzle, which is significant cracking. It means that it had been there for a long time.

Then they performed UT supported with eddy current. They felt that they had to use eddy current. That was the first time I have seen eddy current with UT, and identified cracks in all the nozzles, which means that the technique, though believed to be proven, didn't work.

DR. ROSEN; It's a question of what the technique proves.

DR. BONACA: Well, I'm saying that -- I'm trying to understand now to what extent you have been alarmed by this situation and maybe revisited the kind of techniques you are going to use. I mean what you believe is proven.

MR. CORBIN: Certainly, we will. I mean, as we go through the -- using ISI now and the in-service inspection program, as you come up on your ten-year intervals, you make a decision whether to go ahead with a new version of the code or not. You have to do that evaluation.

So we do rely on the code to bring to our

attention what are the correct techniques that should be applied for certain situations. The Summer situation -- I don't know that the decision has been made to apply eddy current techniques in the next version of the code that gets issued, but certainly, if that were to be true, we would evaluate that when we come into update for the next interval on the code.

So there is an element here on proven techniques that does allow for growth in the future for the idea that new or better techniques would come out. Certainly, we have some examples in our aging managing activities where we are relying on developing industry positions as a means of trying to identify what the right thing is to do; because it may not be clear in every case right now.

DR. BONACA; Yes. When I reviewed the interactions between the NRC and V.C. Summer on why they were ineffective, they said the reason is that the detector was bouncing on a rough surface. But this happened, evidently, on every rough surface there, and really undermines any confidence for the particular inspection, because wherever there were cracks identified later on, they were missed before. So there was a consistent missing of the cracks.

Now, clearly, there is a judgment going

into whether or not there is a crack there, too. You have some signal, but are you aware of any changes, any ASME requirements or a revisiting of the criteria that are being used? I mean, it still leaves us with a big question about, you know, how comfortable can you be with the current level of testing when you have such a significant effect there.

MR. CORBIN: Certainly, we will have to evaluate any new techniques that are brought forward through the Material Liability Project or other research projects going on, and we will deal with those in the current licensing basis arena, if you will.

So whatever we develop within the CLD world to revise these programs, enhance them, make them better, we are committing to the program. Those techniques would be part of what is carried forward in the period of license renewal.

It does give us pause, though, I mean, to think about whether these techniques are good or not.

DR. BONACA: The reason why I'm pressing this is the statement was made that that crack probably was there from the beginning and that it expanded right through, and it took 20 years, 25 years to get there. Well, that tells me that, if there are

other cracks in other plants, they will come toward -- you know, when the plant is getting older.

So we are going to see more of these cracks coming through the wall, and I think it is important that we have confidence in the techniques being used, that they can identify --

MR. CORBIN: Right. I think the other aspect for Summer, of course, was some materials issues that were there, too, which --

DR. BONACA: That's true.

MR. CORBIN: I mean, that's another method to provide some assurance that you have screened, not strictly relying on your inspection techniques but understanding of materials that were used. There was some -- I don't have the details, but there was some odd buttering that was done on that particular weld.

DR. SIEBER: That's right.

DR. BONACA: Yes. There was buttering on that weld, but the cracks in the other welds were missed, too. So --

DR. FORD: But the point is that you won't do anything proactively, because you are being reactive to what had been developed at MRP. You will wait for the MRP to come out with suggestions as to better inspection techniques.

MR. CORBIN: Well, I would say we play an active role in the MRP. In fact, I would point to a new UT technique that we have developed for looking at socket welds, which has been a bugaboo for the industry on small blow pipe. So we are working it back through the MRP, though, and have shown some success in being able to look ultrasonically at a socket weld, not a widespread technique in the industry yet.

So there's a lot of collegial work, I think. We are active members on the MRP, and sort of through that venue we have come upon new techniques, better techniques.

DR. BONACA: It would be interesting later in the day when we hear the presentation from the staff to know what the staff is doing with regard to the experience of V.C. Summer.

DR. KUO: Yes, sir. Dr. Bonaca, in the later staff presentation, the staff will address the issue of Summer nozzle cracking.

DR. BONACA: Thank you.

DR. FORD: Great.

DR. SIEBER: Referring to the reactor vessel nozzles and safe ends, in this class of plants, it seems to me that inspection requirements are in the

tech specs as an augmented inspection. Is that the case?

MR. CORBIN: That's correct.

DR. SIEBER: And that inspection in plants that I am familiar with require both volumetric and visual examination. When you do the visual, you have to prepare the surface to be able to accomplish it, which -- preparation for the visual exam is typically adequate to provide us an acceptable surface to do a volumetric exam by ultrasonic techniques.

The issue here may be a little different than it was at some other places.

DR. BONACA: I mean, there were ISIs they performed, and they were qualified ISIs.

DR. SIEBER: But this is outside the ISI program. This is an augmented program.

MR. CORBIN: Augmented, yes, but the techniques are similar.

DR. SIEBER: Techniques are similar. That's correct. But it does require a visual, which is the equivalent of ET, because ET looks at surfaces more than anything else. It's not a volumetric exam. So a properly performed visual is equivalent -- A good visual is close to being equivalent to an ET.

DR. FORD: As I read through your

augmented inspection activities in your LRA, it does say quite specifically that they will be applied to the reactor vessel head.

MR. CORBIN: Correct.

DR. FORD: So you will be doing full, 100 percent volumetric examinations on the reactor head?

MR. CORBIN: I'm not sure the extent to which we are doing volumetric on the head. I mean, we are looking at them. I'm looking at Paul back here, but I think we are doing like control rod drive mechanism areas, selected regions, but we are not doing a full volumetric of the whole head.

DR. FORD: Well, maybe when I read "inspections include visual, surface and volumetric examinations," it doesn't mean to say you will do them all. You might do visual, not volumetric?

DR. SIEBER: The volumetric is usually associated with the nozzles only and not the face metal. Base metal is usually done by visual, and it's the second level of visual, and you're basically looking for boric acid.

DR. FORD: Okay. So it should be "inspections include visual, surface or volumetric."

MR. CORBIN: That might be a good clarification. Right.

DR. FORD: Okay.

MR. CORBIN: Other questions on TLAAs? Excuse me, on Intro and Appendix B? We got into the existing activities. We have the list here of 19. You can attempt to count them. I did. I finally got 19 out of this, but basically we have chemistry control, primary, secondary and fuel oil chemistry control; the ISI inspections of various types indicated there; augmented inspections, steam generator, civil structurals, battery racks, cranes, secondary -- we are looking at FAC and that location -- and service water; boric acid corrosion; fire protection; general condition monitoring; reactor vessel integrity management; and work control.

I have to note that the general condition monitoring and work control really is a matter of gathering together sets of inspections that we are already doing or including inspection steps in activities that we are already doing.

General condition monitoring focuses on external inspections primarily of components and equipment; whereas, the work control process gives us an opportunity, when we are inside the plant tearing things down as part of work control, to take that opportunity to do an inspection to see what the

interior condition of equipment looks like.

DR. SIEBER: Before you move on, on the previous slide it referenced the service water system. At Surry about seven, eight, nine years ago, I guess, you found cases of pitting and leakage in the service water piping. Now that piping wasn't replaced at the time. What was done was to have a welder go through and weld up all these pits and then recoat the pipe.

MR. CORBIN: Correct.

DR. SIEBER: So that pipe has got some problems built into it already. Is there anything augmented you are going to do to make sure that you can get another 40 years out of that pipe?

MR. CORBIN: Well, we are continuing to look as part of our Generic Letter 8913 program, which is really what we are talking about here for service water. We continue to do inspections on the pipe.

At Surry, for example, we have a project on the books right now to continue to go through and look at large portions of the CIRC water and service water systems, service water piping, in particular, to do -- continue this method that we have for taking all the gunk off the pipes -- we do have hydroids that grow on the pipes -- and blast it, identify locations, weld repair, recoat. And I suspect that program will

continue ad infinitum through the period of extended operation.

The way we get at it is through this service water inspection program.

DR. SIEBER: Your CIRC water piping -- that's steel piping?

MR. CORBIN: It's a combination. It's a concrete structures, and then we have 96-inch pipes. I'm speaking about Surry now -- 96-inch steel pipe comes into and out of the plant, but it dumps into a discharge tunnel, which is a square cross-section, concrete pipe, if you will. It's not a pipe, because it's got a square cross-section.

Then if I think over to North Anna, it is also a combination of pipe and concrete structure.

DR. SIEBER: Thank you.

MR. CORBIN: Other questions on these programs, either this first page or the second page? I'm looking at either page 23 or 24 on the aging management activities.

DR. WALLIS: Well, the boric acid corrosion surveillance -- I read that section. It seemed to rely on walkdowns.

MR. CORBIN: Yes.

DR. WALLIS: Is that really good enough?

MR. CORBIN: Now when we do the walkdowns as the unit is coming, is ramping down at the end of a cycle and as we are entering into a refueling cycle, we do send teams, people out to do boric acid walkdowns. What they are looking for is any evidence of the white crystals.

We believe that that is a very effective way of finding where we have leaks. Many times, we find that that leak leads back to a flange.

DR. WALLIS: They can see all the places that they need to see?

MR. CORBIN: They can see what they see in that walkdown, because its temperature -- it's very hot at that time. All they do is they tag. They literally use pieces of tape, and they tag things with a card where they found the boric acid.

DR. WALLIS: They have to be able to see, and they can see all the places they need to see?

MR. CORBIN: They do. They crawl through the loop rooms. They get inside the containments.

DR. WALLIS: Do they use mirrors and things like that?

MR. CORBIN: They do use mirrors where they need to. They work fairly quickly, because it is a high dose activity, and there's a fairly high

temperature at that time as well. But they do get in the techniques.

Now what I don't want to mislead you on, a lot of this stuff has suitcase latch insulation on it at the time, and all they are finding is the location of the leak. Once the unit is shut down, now you start chasing the leak, and you know, you pull the insulation off and you find that you may be, you know, many feet away along the pipe before you get to the leaking flange.

DR. WALLIS: So you could have boric acid sort of leaking into the insulation for a while before there is anything you can actually see.

MR. CORBIN: At those pressures and temperatures, you know, it tends to show up fairly quickly, particularly out of the primary systems that are operating. And we do find evidence of leakage when we go in. Those become work orders. They get worked.

DR. WALLIS: But you haven't had big deposits or stalactites or the things we have --

MR. CORBIN: On some occasions, we have had, you know, substantial buildup on certain flanges. In particular, I am thinking of on the RHR flaps, as we call them, as we refer to them. We have had

indications of some leakage that did make an accumulation of boric acid that we then had to clean and go back and rework flanges.

As I mentioned earlier, we have also -- This is really more of the 97-01 inspection, but it also looks for boric acid. You get in on the head, and you can find evidence where a conoseal has leaked, and you can see the boric acid trails that run down the pipe and then across the top of the head.

Many other cases, you just see where it is coming out of a suitcase latch joint, and you have to go back and work your way back to where the leak is. Mechanical closures in almost every case, occasional seal weld.

Other questions on the existing programs, on the 19 existing programs? Moving forward, we also have four new programs: The buried pipe and valve inspections; infrequently accessed areas.

I should comment on infrequently accessed areas. This is an inspection program that leads us into pipe tunnels, selected manholes where we have in-scope equipment, intake structures that might be high radiation areas, areas where we typically don't get an opportunity to go in; and infrequently accessed areas will give us a focused look at those areas of

the plant that we typically don't enter.

Tank inspections, and then cable monitoring is noted here, "added after submittal." I think that was the question earlier. We do now have a cable monitoring program that was added after the application was submitted.

DR. FORD: The top three are all one-time inspections?

MR. CORBIN: Correct. And the idea, because we really haven't had an opportunity to draw any kind of baseline on buried pipe, infrequently accessed areas, and tanks, we need to do that first. That would be this one-time inspection that would then lead to whatever the correct evaluation says. Is that inspections on an interval? Does it lead into a replacement schedule? It's not clear what that is going to be yet, but we would do that prior to year 40.

MR. BARTON; Well, you've got some experience. I think reading the application, either there or the SER, where you've had -- I think it was on fire protection system, the valve work, that you had to go down. You did some valve and pipe inspection on fire protection buried piping, I believe.

MR. CORBIN: Yes, we have.

MR. BARTON: You do have some history there on at least fire protection system buried piping.

MR. CORBIN: Right. On the cast iron pipe. It actually looks very good, as a matter of fact. What we didn't do as well as we could have, and will in the future, is document the results of that inspection. This was just someone peering in a hole.

MR. BARTON: During maintenance or something, you did the work, but you didn't document it. Okay.

MR. CORBIN: And we're back to, hey, it looks good. What does "looks good" mean? So we need to be opportunistic. The next time we get in, we have a valve or a flange leak or something and we dig a hole, we need to document what we looked at. That would be part then of this buried pipe inspection.

MR. BARTON: All right. Thank you.

MR. CORBIN: It's what we don't have. We don't have that documentation.

DR. ROSEN: I'm a little -- still remain a little concerned about that whole discussion, the opportunistic approach. It's certainly useful and a plus because you are down subsurface doing something

else, and that's clearly a good thing to do. But it seems to me a more first principles approach would be more satisfactory from an engineering point of view, and that you could then factor in the opportunistic data as well. But you need to start off by saying we need to establish with a certain degree of confidence that our buried pipes and valves are in satisfactory condition, and we know what the system is, and we know where it is, and here are the things we need to look at, you know, around the table with some engineers who know what they are doing.

We need to look at this, we need to look at that, we need to look at this elbow, we need to look at this place where it descends and goes under another service. More of a first principles approach, other than just saying, well, whenever we dig a hole, we'll have a look at it.

MR. CORBIN: Yes. I need to clarify, I think, that as we march up to year 40 and we have not yet uncovered or had an opportunity to look at certain locations, we will do exactly what you're talking about. We need to cover -- We have a laundry list of everything that we need to look at.

This is the first principles approach. What is everything we need to look at? And if we

haven't covered all those up to, say, year 38, then we will take a very deliberate action to go and look at all the remaining things on our list to make sure that we have looked at everything that does need to be looked at. But that's very manpower intensive and expensive.

So if we can knock some things off the list ahead of time, we are going to do it that way.

DR. ROSEN: Yes, but that is likely to be a small percentage of what you ultimately need to do.

MR. CORBIN: We dig holes in the yard fairly often. It's not an unusual activity for us to be digging in the yard.

DR. ROSEN: But you are digging in a place where it may or may not matter.

MR. CORBIN: True, but there's an awful lot of stuff that is buried in the yard. In order to get at pipe A, I typically have to go around duct bank B and pipe C, D and E. So there are -- We've felt there are a number of opportunities, have been a lot of opportunities.

It's kind of unfortunate that we didn't document our recent history on excavations we have had in the yard, because I believe we would have knocked off a lot of things on the list by now, just but from

that method, just by waiting for the holes to come up.

DR. SIEBER: It seems to me that, if you looked at the yard area around a power plant, that's usually select fill. It's placed during construction, and the piping is underneath it. If you expose a piece of the piping, it's reasonable to assume that the fill is consistent all the way along. So the chemistry is reasonably consistent in the groundwater.

That actually does tell you something, give you some indication of the condition of the whole pipe.

MR. BARTON: Right.

MR. CORBIN: I would also say that, even though we haven't documented the inspections, our experience is in digging holes in the yard that the pipe looks pretty good, but there I'm back again to a very subjective thing. It's not analytical or not documented, but it gives us some confidence (a) that the frequency of digging holes is fairly often, and (b) that what we anticipate we are going to find and document is going to show that the pipes are in reasonably good shape, not that we don't have to do something to get to 60 years, but that from here to 40 years is a reasonable expectation to run this program as a one-time inspection.

DR. ROSEN: Well, I've made my point of view relative to first principles approaches versus opportunism fairly clear, I think. My other point on that is that, when you use a first principles approach, it also says not only what you are going to look at but how you are going to look --

MR. CORBIN: Exactly.

DR. ROSEN: -- what inspection tech. It's not okay to say, well, we dug down there and had a look, and it looked okay. To me, that's a wasted opportunity. You need to have gone down, cleaned off the outside of the surface of the pipe, applied a known in-service inspection technique both at the top of the pipe and underneath it, gone all the way around, looked at the weld, looked at the adjacent materials adjacent to the weld, and used some real -- documented well what you found

MR. CORBIN: And that certainly is the intent of the tank inspection, buried pipe and valve inspection, that we have identified in the AMA the techniques that we will use, and those examinations will be performed using first principles.

The only thing that is opportunistic here is that we dig a lot of holes in the yard. The rest of it is -- you know, has been prescribed: This is

what we are going to look at; this is how we are going to look at it; this is how we are going to document it. All of that is written down.

DR. ROSEN: And in my engineering company, if it turned out that that hole just happened to be where I had previously decided to go look or in an equivalent position, then I would -- and in fact, had done the inspection in a qualified way, then I might use the data. Otherwise, I'd say, well, that's interesting; now let's get on with this other discussion, the one we came to talk about.

MR. CORBIN: Well, that is our intent, is that we will -- We have our list of where we are going to look and how we are going to look and how we are going to document. Now we are waiting for a hole to be dug in the yard. If it doesn't get dug, year 38 we are going to be digging a lot of holes, because we got to cross everything off the list, got to look at everything.

Getting into some of the tanks raises some of those other issues, too. It's very challenging to get into some of the tanks that we need to look at.

DR. ROSEN: Well, the license doesn't give you -- What you say in the license renewal application doesn't give me a lot of confidence. It talks about

this buried pipe and valve inspection. It says we'll get down there and look in a few places. It doesn't give the clarity that this interplay we've just had provides.

DR. RANSOM: Do you do any leakage and pressure testing of these components when they are available?

MR. CORBIN: Well, on the buried piping systems?

DR. RANSOM: Right.

MR. CORBIN: On fire protection, I know we -- Periodically, I believe we do some kind of a drop test or a leak test on the fire protection system, certainly. Whether we do specific hydro tests or drop tests on, for example, quench spray or service water -- I guess we do in-service leak tests. Right? Yes, we do in-service leak tests on a lot of those systems.

DR. SIEBER: Those aren't buried. Well, the fire system -- you usually time how often the fire pump starts, because fire systems always leak, for some reason or other.

MR. CORBIN: Well, and the other systems that are safety-related buried commodities -- I mean, we actually pull in in-service leak tests. That will let us know where we've got an issue.

Other questions on the new activities?

With regard to the aging management activities themselves, we did include operating experience, obviously. Both industry and in-house operating experience has been incorporated, and we do that through the correction action process.

That is a normal, ongoing process that's in the power plant to pull operating experience in and make sure that it is incorporated. But in addition to that, the second bullet here, we did operating experience reviews specifically performed by the license renewal team to look at specific aging issues to make sure that we pulled that operating experience out and taken advantage of that in preparing our application and writing up our programs.

Also with regard to the quality assurance program, three elements are featured in each of our aging management activities. They are the corrective action, confirmation process, and administrative controls.

I think a point that we need to stress is that those are applicable not only to safety-related but to non-safety-related structures, systems, and components. So it's uniformly applied to both safety and non-safety-related systems.

We also include in Appendix B the aging management activities associated with time-limited aging analysis. Those are the environmental qualification program and the transient cycle counting program.

CHAIRMAN LEITCH: Bill, as far as operating experience is concerned, I just noticed an event reported on the NRC web page a couple of days ago, and it describes a situation at Columbia Generating Station, cracks in concrete due to abandoned concrete anchors and shrinkage cracks in the reinforced concrete floor.

Now my question is more about process than the specifics of this incident. These concrete floors were coated or they're uncoated, and the coating had cracked, and there was a problem related to fire seals and flood protection.

I guess in this operating experience, would you expect to pick up this kind of thing? In other words, this idea of shrinkage cracks in the reinforced concrete floor sounds like it might be an aging management issue, and would your operating experience tend to pick up this thing and someone would say, hey, maybe this is something we haven't thought about before, and factor it into the program,

or just how would that work?

MR. CORBIN: Again, you're asking a process question. Yes, we would get the operating experience report that would come in from Columbia, and understand the details of it. Typically, from the way we handle those in-house, they are screened by an OE coordinator who helps determine who that should go to.

In this case, it would go to the civil/structural group, and they would evaluate that to determine if it's applicable to our plant or not, and if there are any actions that we need to take in order to address the issue.

That's ongoing as part of our current licensing basis team. If I'm going to segregate my license renewal team over here, it's something that we would have to evaluate as part of an annual update, for example, but it's not something that we would specifically get involved in, because the team is going to go away.

So the process that works and will continue to work through the period of extended operation is through the OE coordinators, farming those out to the right people, having them evaluate them, write up the corrective actions, if applicable,

and incorporating those.

CHAIRMAN LEITCH: But it's not as though the license -- In other words, I guess, if there is a new aging effect that that implied --

MR. CORBIN: Oh, I see where you're going.

CHAIRMAN LEITCH: Let's say this is one, and I'm not sure that it is, but this concrete shrinkage business. In year 38, to use your number, is that somehow factored into this program?

MR. CORBIN: The answer is yes. As this project winds down, we will give birth to a program, which is the license renewal program which will be staffed by coordinators at Surry, North Anna and Innsbrook. At least, right now that looks like the staffing that we are planning to use.

That program will also be captured in a -- Well, we call them DNAP. It's an admin procedure that describes the program elements. And also what it does most importantly is it puts hooks in our whole system of doing business for change control. All right?

If anyone is going to make a change in the plant, then they are going to have to review aging management issues as they are associated with that change. Okay?

IN terms of operating experience, that

would come in if actions are required. Those actions have got to be reviewed in light of aging management issues. They would have to be looked at by these program coordinators in that light.

So it's the implementation of license renewal that is likely to continue to look for operating experience that deals with aging management. That's where we are going. We are thinking and working long and hard right now in terms of getting our implementation program put together.

CHAIRMAN LEITCH: Okay. As smart as we think we are now, there may be some aging effects that will develop in the future that we haven't thought of yet.

MR. CORBIN: And what we have to have, just like we have an Appendix R program, an EQ program, a heavy loads program, there's going to be a license renewal program, and that wills be a living program that will go on right through the period of extended operation.

CHAIRMAN LEITCH: Thank you.

MR. CORBIN: Where am I? Page 29, licensee follow-up actions: This was a special feature that we put into Appendix B as Section B4.0. What we did was we tried to facilitate the commitments

that we were making and the follow-up actions that we were taking as a result of the whole application, to put that in a handy table, if you will, listed the actions required to effectively managing the aging effects.

It includes our commitments for program/activity changes where we had to change the program, and most of these were intended to be completed before the end of the current operating license. This is the one-time inspections, for example, we plan to do prior to year 40.

So that was also included in Appendix B. Moving over to Slide 30, what we've done now is we have taken what was in Appendix A, which was a draft of what a UFSAR supplement would look like -- We have incorporated that.

We've brought these licensee follow-up action items. We have distributed those among the appropriate programs, and a number of the SER confirmatory action items also related to the programs, and we have appropriately injected the SER confirmatory action items also in this chapter.

So we've collected all three pieces together, Appendix A, our table that was in Appendix B, and now the SER confirmatory action items, and all

that is in a draft of what the UFSAR supplement will look like.

Appendix C: Again, not required. It was really provided as a reviewer's aid. I think not very many applicants have done this, but we felt it would be helpful to the staff.

It provides a grouping of the systems, structures, and components, identifies short-lived components and consumable and our methodology, also the methodology around aging effects and mechanisms.

In addition to that, it also identifies Westinghouse Generic Topical Reports that we used. You can see the four there that we did specifically reference.

So that was a reviewer's aid. Hopefully, that was helpful. I'm not sure if it was or not.

CHAIRMAN LEITCH: For this reviewer, it was. I thought particularly the table on page C-2 was helpful in understanding the process.

MR. CORBIN: All right, very good.

Jumping ahead, just briefly on Appendix E, the environmental report: Obviously, that was included as a separate volume in the hard copy, and it follows the guidance of 10 CFR 54.23 which invokes, in effect, 10 CFR 51. We did it in accordance with the

NEPA guidelines, also used the GEIS.

Severe accident mitigation alternatives were reviewed. The results were incorporated. We also used some additional guidance as provided through Supplement 1 to Reg Guide 4.2 and NUREG-1455. Perhaps most importantly, we did quite a bit of review of previous applicants in terms of what they had gone through and done with their environmental report to make sure we took advantage of everything that they had done previously.

CHAIRMAN LEITCH: Just to go back to Appendix C for just a moment, on page C-6, identification of short-lived components and consumables, it indicates that the plant procedures are being credited for managing the effects of aging.

I guess my question there is: Is there a control mechanism that plant procedures are not inadvertently changed or that these commitments don't get dropped out of plant procedures?

MR. CORBIN: If it's part of EQ, that's true. Is that what that is referring to, Mike? I don't have the page in front of me.

MR. HENIG: Yes. This is Mike Henig. Just as an overview, we are going through and identifying plant procedures. For example, in our

work control process where we have procedures that identify to the maintenance personnel when they open up piping, that they look around and inspect.

We are identifying those procedures to give them some clarification to look for cracking and wastage and rust. Those further guidance will be identified in the procedures as license renewal commitments. So prior to changing that document or making any changes to those further guidance for the maintenance folks, as Bill indicated, we are going to have license renewal coordinators at the station, and they will have to verify and bless off that change before any of those commitments are changed in the procedures.

MR. CORBIN: That's true, if that's where you were going. I mean, we will -- Our procedures have a -- All our procedures have a commitment section in them, and if license renewal is a commitment, then that would be so annotated in the procedure such that you couldn't change it out of the procedure without first reviewing it through the coordinators, which might ultimately, depending on the change, bring us all the way back to the NRC, depending on what we were doing.

CHAIRMAN LEITCH: Okay. So there is a

system to capture what part of procedures are commitments.

MR. CORBIN: Certainly, this will be part of our Appendix B requirements. I mean with regard to Part 50 requirements, that is. So, I mean, we could invoke 50.59 for changes, but within the guidance of 50.59 we would have to follow that process.

CHAIRMAN LEITCH: Sure. Okay, thank you.

MR. CORBIN: On page 34, I think, is where I am, the other features about the environmental report. We did use subject matter experts. We did a new and significant information process. We involved the environmental agencies, organizations, and public, obtained industry peer reviews, and frequent, clear and open communications with the NRC as part of that review. That's the other major portion of our application.

The final results are that the impacts were small, and smaller than reasonable alternatives, as indicated in the draft site environmental impact statement. So we believe we are on the right track with the way those two environmental reports came together. There was one for Surry and a separate one for North Anna.

I'd like to turn for just a second -- I'm

not going to cover these in detail unless you have questions on specific ones, but with regard to the safety evaluation -- the draft safety evaluation report, there were eight open items identified.

There is one on station blackout scope, three that dealt with aging management of cables. Additional information on environmental effects of fatigue were two of the questions, and containment liner design cycles were two more of the questions.

We have had dialogue with the staff on each of these eight and, as was reported earlier this morning, we believe we have come to closure on exactly what we need to do for each of those eight open items.

On the 15 confirmatory items, you can see the bean count there: 13 associated with UFSAR supplements which I indicated previously, we are going to incorporated those as part of our UFSAR -- our new UFSAR chapter; one on drawing updates; and one on confirmation of open items.

Again, we have had dialogue with the staff and believe that we have come to closure on what we need to do with those 15 items, and believe those will be reported on in this afternoon's session.

DR. SIEBER: What do you plan to do with the containment liner design cycles open item?

MR. CORBIN: Okay. I think we simply provided a clarification that the cycles would be applied for 60 years. I see Lucky shaking his head back there. Is that correct?

MR. WRONIEWICZ: Yes. What we did is we provided a clarification in the UFSAR where they indicated expected operating cycles. We have reported in the LRA the design cycle. So we are making a clarification in the UFSAR to note that.

DR. SIEBER: So there's some analysis that says the liner can withstand your new count of cycles?

MR. CORBIN: That's correct.

MR. WRONIEWICZ: Yes. The analysis is there. We had some confusion in the numbers that were reported in the LRA versus UFSAR. We clarified that.

MR. CORBIN: I think it was the anticipated versus design. I think that was some of the confusion on that particular item. So some numbers looked like anticipated cycles. Others were design cycles. What's all that look like?

DR. SIEBER: Okay. Thank you.

MR. CORBIN: Glad to clarify that. What we've done -- I guess I would just summarize this. In any event, we have submitted to NRC Project Manager in

draft form a response to the eight open items and disposition of the 15 confirmatory items.

We are also currently doing a technical accuracy review of the safety evaluation report, and plan to submit comments on the SER, both technical which there were very few technical comments that we had, and also a number of editorial remarks, just things to clean things up and make sure references are proper and that, if there's a list, that the list is complete, etcetera, make sure that the document is accurate. Overall, it looked good.

Closing remarks: I guess I would note that we do have a number of follow-up letters that are in the works to try and close items. We hope to get those done by the end of next week, get those out, dealing with the SER open items, the formal submittal of that letter on open items, on confirmatory items.

We have an annual update letter. We want to get the SER comments to you. So those letters are in the works and should be signed out here by the middle of July.

I want to tell you that I appreciate the opportunity to speak to you. If you have any final questions, I'd be happy to do that. But that concludes my formal remarks.

DR. ROSEN: I just have one question about whether you are going to stick around for our discussion later this afternoon.

MR. CORBIN: Absolutely.

DR. ROSEN: There may be some things that come out of the committee discussion that you might be able to help ups with before we get to an ACRS letter before the end of this year.

MR. CORBIN: We would be happy to stick around, plan to stick around all day.

DR. ROSEN: Good.

MR. CORBIN: Right. And we have some back-up information with us, too, that if that becomes helpful, we could put on the table if you need it.

CHAIRMAN LEITCH: Any other of the members have comments?

DR. RANSOM: I have a curiosity on the new heads that you are going to put on these plants. Some of the plants, the heads were built in such a way that they were not easy to inspect in that they had some of the head support assembly, I think, that was pretty well closed.

Are these new ones being built in such a way that inspection is going to be possible over the head?

MR. CORBIN: We currently haven't signed a purchase order for the head assembly upgrade package, HAUP, but that's something that we are going through right now.

One of the features that we are considering is in the lower section near the dome, the lower section of the upper head assembly, to include doorways, just inspection hatches so that we would facilitate the ability to put the moveable visual camera that everyone is using these days to crawl through all the CRDMs and look for evidence and inspection.

So we are considering putting that feature in the head and making sure that the head insulation package is raised up off the head, again to facilitate ability to get in there.

So while we don't expect that these heads are going to be susceptible -- we're certainly not trying to build something that's going to be susceptible to these issues -- we are going to build in some features or we are considering in features that will facilitate that kind of inspection work in the future.

DR. RANSOM: I know from the Davis-Besse one of the problems there was they delayed putting

these inspection ports in the upper head assembly. Obviously, if they had been done and probably put in when they were scheduled to be put in, they might have found this kind of problem earlier.

MR. CORBIN: Yes, that's correct, and there are other geometries that don't lend themselves well to head inspection. That pretty much forces you, if you can't go over the top, to get in underneath. You have to put it on the head stand, and then you got to come in underneath to do your inspection from the underside.

DR. SIEBER: But your current heads are accessible now. The insulation is not resting on the top of the head.

MR. CORBIN: We've had some good success with the ability to go over the top, although we've had some trouble with the device where there was evidence of boric acid. Sometimes we gum up the wheels. It would get into a mess or get stuck, and you had to go retrieve it. But from an access point of view on a perfectly clean head, it was possible.

DR. SIEBER: It's like driving through snow.

MR. CORBIN: Correct. Sticky snow, too. It just clings to the wheels.

DR. SIEBER: Right.

CHAIRMAN LEITCH: Okay. Any other comments, questions? Bill, thanks very much for your presentation.

We will be recessed now until 12:45.

(Whereupon, the foregoing matter went off the record at 11:45 a.m.)

A F T E R N O O N S E S S I O N

Time: 12:46 p.m.

CHAIRMAN LEITCH: Let's get back in session now, and we will resume with the balance of the staff's presentation.

MR. TABATABAI: Good afternoon. For the afternoon session, we are going to start with Chapter 2 of the draft SER. We are discussing scoping and screening of structures and components subject to NAR.

In this section we are going to talk about the methodology of the screening and scoping. Basically, we don't have -- The staff has not identified any open items. We just want to start from the conclusion part. We don't have any open items in this section.

Starting with conclusion for this part, the applicant's methodology and implementation has been robust. Scoping process was well defined, and procedurals. License renewal team was well trained. Audits provided confirmation of process and implementation, and the NRC staff finds that there is reasonable assurance that the applicant's methodologies for identifying structures and components that are subject to AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR

54.21(a)(1). Therefore, it is acceptable.

The staff actually used several means to evaluate that scoping and screening methodology. They reviewed on-site documents, license renewal applications, updated FSARs, design basis documents. They had on-site audits, engineering reports, procedures, design documentation and discussion with the Dominion staff.

As far as findings for scoping and screening, the applicant's evaluation of criterion 2 required some effort, and we resolved it through REI process. The applicant applied the preventive approach to scoping of additional non-safety-related systems, structures and components.

The applicant's supplemental review of potential A-2 structures and components resulted in expansion of the scope of license renewal.

This is basically my -- This presentation was prepared by Mr. Galletti. He is at Fort Calhoun, and he asked me to present it for him. If there's any questions on scoping and screening -- If not, I am going to ask Mr. Li to continue the presentation.

CHAIRMAN LEITCH: I guess I did have one question. On page 2.11 of the SER in the center paragraph the report described the process by which

only certain non-safety-related SECs are brought into the scope, if the failure of those non-safety-related SECs is postulated in the current licensing basis or their failure would result in loss of safety-related function.

I guess I am not sure what types of things are being excluded or what is the intent there in that paragraph? It sounds like things not in the current licensing basis are just excluded. Is that a reason for exclusion?

MR. TABATABAI: I don't have actually an answer to this question, but there are two aspects of non-safety systems over safety-related systems. One relates to spatial orientation, and that was the discussion between the staff and applicant, to bring more systems into the scope because of the spatial.

There were no connection between the non-safety-related pipings and safety-related, and as a result of that spatial relationship within the non-safety, they included more systems into the scope of license renewal.

MR. BARTON; Is this a seismic tool 1 issue?

MR. TABATABAI: Yes.

DR. SIEBER: Or high energy line breaks,

too.

MR. TABATABAI: Right. Seismic tool 1 is a subset of this issue. As I mentioned, there are two aspects of non-safety-related systems over safety-related systems. One, non-safety-related systems have connections to safety-related systems, and spatial relationships are for the cases that there is no connection between the two.

MR. BARTON: Okay, thank you.

MR. TABATABAI: You're welcome.

MR. LI: My name is Chang Li. I am with Parent System Branch. I'm the SSA lead reviewer for scoping and screening of mechanical systems and structural. We have a total of 55 mechanical systems and 12 structurals. We have eight reviewers for mechanical systems and two reviewers for structurals. Some of them are here to support, if you have questions for them.

We reviewed five reactor coolant systems and five engineering safeguard systems, 38 auxiliary systems and --

DR. WALLIS: By five reactor coolant systems, you mean five parts of the reactor coolant system?

MR. LI: Five parts of the reactor coolant

system. Actually, reactor cooling is just one of these five. The others are like reactor vessel, reactor vessel internal, and so forth.

DR. WALLIS: So the piping would be one part, and the casings is a part, that sort of thing?

MR. LI: In terms of systems, you have pump -- Maybe one system covers piping and pump, reactor coolant system, which have the reactor cooling system piping runs.

We have 38 auxiliary systems and seven steam and power conversion systems that we have reviewed. We didn't identify any open items in these review areas in terms of scoping and screening, but --

DR. WALLIS: Were there any systems that you had significant questions about?

MR. LI: In our SERs we have identified several things. We went through the process, and after we discussed with -- through our REI process, we added additional questions.

DR. WALLIS: There is no other system you want to tell me a story about?

MR. LI: Nothing very specific. If you want me to bring some examples, I can, but I don't know whether if that's --

DR. WALLIS: No. I just wondered if an

example might illustrate what you did. That's all.

MR. LI: I can give example, illustration, but I don't see -- I don't know whether there is a significance, because when we did that review, we concluded there is no open item, which means that we didn't identify that significant --

DR. WALLIS: Nothing very interesting showed up?

MR. LI: That's right. If you want to give example, then I can -- I have example I can give.

MR. TABATABAI: There are some items of interest coming in the other sections.

DR. WALLIS: Good. Thank you.

DR. BONACA: Right now this portion is on the identification of the systems in scope?

MR. TABATABAI: That's right.

MR. LI: Only scoping and screening.

DR. SIEBER: How many RAIs did you issue overall?

MR. TABATABAI: Specific to this chapter or overall?

DR. SIEBER: No, overall.

MR. BARTON: Eighty-seven.

MR. TABATABAI: Eighty-seven.

MR. LI: In the structural areas we

covered 12 structures. We also don't have open items in that area.

CHAIRMAN LEITCH: When you say none, do these include some of the eight issues that have since been resolved or there was never any open items?

MR. LI: None of those eight items, open items in this area. We do have one confirmatory item, but that's resolved.

MR. TABATABAI: Any questions on scoping and screening? Anymore questions? Thank you.

MR. LI: Thank you.

DR. KUO: Dr. Leitch, I just want to add one more -- one remark on this scoping section. As we discussed before this morning that we did not include the scoping results on the seismic 201 issues, and some of the structures and components aging management review is ongoing. We will include those results in the final safety analysis report and report to the Committee.

MS. KHANNA: Good afternoon. My name is Meena Khanna. I was the technical monitor for the materials review of the aging management programs. Cliff Munson here was the technical monitor and coordinator for the mechanical portion of the review.

Well, first of all, I will tell you that

we actually contracted the aging management programs to Brookhaven National Laboratories. So we served as the technical monitors, and we did keep a few in-house, a few aging management programs in-house that we were comfortable with.

Okay. As stated earlier, there were 19 existing aging management programs. These are listed here, and four new aging management programs that were indicated earlier as well.

We didn't have any open items. However, I will state that, as an item of interest, there was a Davis-Besse event that I'm sure you all are aware of, and that had to do with boric acid corrosion with the reactor pressure vessel head.

In regard to that, there was a Bulletin 2002-01 that was issued, and to date we have reviewed the 15-day responses, and we haven't found any issues that were applicable to Davis-Besse, you know, which caused any problems. We didn't find any issues at North Anna and Surry that were concerned to Davis-Besse, but that's an ongoing issue.

DR. FORD: On the four new aging management programs, what was your thought process? You had a comment this morning about the concerns about one-time inspections.

MS. KHANNA: Right.

DR. FORD: When you were looking at their plans, what was your thought process as you went through?

MS. KHANNA; We did have RAIs. I guess the basic thing that we thought -- We were okay, because what they are doing is they are doing a one-time inspection, and from the results of the one-time inspection they will -- it will go into their corrective action program. They will come up with a plan. You know, if they find significant degradation, they will take action to do more inspections, everything like that. So --

DR. FORD: But you had the remarks about the opportunistic nature of those one-time inspections.

MS. KHANNA: Right.

DR. FORD: But did that come into your thought process?

MR. MUNSON: I think this application is unique in that they are using what they call a work control process, which, like you say, is an opportunistic look at the interior of components, and we did have several RAIs related to the work control process.

In response to our RAIs, the applicant did commit to do an audit of all the components that are covered by the work control process to ensure that they will be covered for the period of extended operation, and also to do an audit during license renewal period.

So there will be coverage of these components. So even though it is opportunistic in nature, they did commit to doing these audits, I believe, on a five-year interval.

DR. BONACA: But I don't remember the other applications to be less opportunistic. They were pretty much the same approach.

MR. MUNSON: Actually, this is the first application we have had where a work control process type aging management program has been applied to such a large number of different components.

DR. BONACA: I'm saying that, for previous applications, we saw even less of a commitment at times, because there wasn't a well defined scope. They simply said, if we happen to uncover some area, we are going to test that wrapping around a piping or -- So --

MR. MUNSON: That is usually the approach that is taken for buried piping, for inaccessible

components.

DR. ROSEN: So our assurance of the integrity of this piping depends upon whether they dig or not? I don't think that's what the licensee means. I think what we heard this morning is that they will inspect representative locations and have a plan for that, and that if they happen to dig in an area and it's on the plan, well, then they won't have to do that again.

MR. CORBIN: That's correct.

DR. ROSEN: Which is a more accurate characterization. Is that correct?

MR. CORBIN: That is correct.

DR. ROSEN: And that is for external, and they will have plan for looking at what is it they do when they get down into the pipe, and it will be thorough and look 360 degrees around the pipe, and be well documented. That's for external.

For internal, they won't dig pipe up and cut it open, which wouldn't be too wise, but they can look at that same piece of pipe internally in the plant when they open a valve or something like that.

MR. CORBIN: Again, that is correct. That's how we cover both internal and external portions of those pipes.

DR. ROSEN: There is no reason to expect the internal piece condition of a system would be different whether it's buried or whether it's exposed in the plant.

So what I'm left with is only the question of how comprehensive will the plan be. This is important piping. It's risk significant piping. It is accessed to the ultimate heat sink piping, and I don't have a feel for that except the licensee's assertion that it will be representative.

So that's my residual questions, how representative it would be, and trying to get a feel by looking at the application of that is not all that comforting. We just get the assertion that it will be, but that's all I have.

DR. SIEBER: There actually is not a lot of buried pipe, is there, that's safety-related and in scope? Service water?

MR. CORBIN: By numbers of systems it's not a lot of different systems, but by linear feet we actually do pile up a fair amount of pipe.

DR. SIEBER: Right.

DR. ROSEN: And it's exposed to an aggressive environment, I presume.

DR. SIEBER: Depends on the soil

condition.

DR. ROSEN: That's true. That's true.

MR. MUNSON: Actually, in regards to the groundwater soil environment, in the application they identified that it was nonaggressive.

DR. WALLIS: Is it monitored in case it might become aggressive at sometime?

MR. MUNSON: Right, and I will cover that later in my presentation, but we did get them to commit to do that on an annual basis.

DR. ROSEN: To do what on an annual basis?

MR. MUNSON: To monitor the groundwater.

DR. WALLIS: This item of interest you cite here, it says the staff reviewed, the staff found. Is that you or some other staff?

MS. KHANNA: That's part of the material conclusions.

DR. WALLIS: So that's some other staff?

MS. KHANNA: A part of the NCD, but yes.

DR. WALLIS: So what did you do with this item of interest?

MS. KHANNA: We are aware of the issues. So just to keep abreast of everything. It has to do -- It came into the place with the boric acid corrosion prevention program, and actually our Section

Chief asked us to address it just to make sure that we are following up on it.

DR. ROSEN: So you concluded that their boric acid surveillance was okay?

MS. KHANNA: It's okay for license renewal, and anything that comes out of this will be handled separately.

DR. ROSEN: So you are satisfied that they can detect these leaks?

MS. KHANNA: Yes.

DR. ROSEN: By looking?

MS. KHANNA: Yes, and we had a couple of questions on inaccessible areas --

DR. ROSEN: What happens when there is insulation over the area you are looking at? Insulation -- you have insulation over the area, covers it up so you can't look at it.

MS. KHANNA: What we do is we actually rely on visual inspections for the insulation. We are told that, if there is a leakage, that we would be able to see it.

DR. ROSEN: What happens if there's a leak that goes into the insulation? You can't see that area.

MS. KHANNA; Then I was told that

eventually we would see it.

DR. ROSEN: Well, that's what they said this morning, but I wasn't quite clear how long eventually would be.

MS. KHANNA: I think, before there's a problem -- I have talked to several staff members, and they felt comfortable that we would see it visually, you know, before there's a problem, that it would be detected.

DR. ROSEN: That's what we felt before Davis-Besse.

DR. KUO: Stephanie Coffin, Section Chief in the Materials Engineering Branch, would like to comment, make a remark.

MS. COFFIN: I just want to comment. Meena is not the reviewer for Bulletin 2002-01. So she doesn't know all the details.

As you all know, we are relooking at the basis for licensee's Generic Letter 88-05 programs, and we are certainly asking that question on removal of insulation. This is a current licensing basis issue, a current day basis.

What the licensee has now is their standard 88-05 program, which does not require insulation removal unless you probably find a leak.

The you need to chase down the source of that leakage. This is a code requirement. That's all. That's all required, and this is something that we are going to be chasing down as we close out Bulletin 2002-01.

DR. SIEBER: I think one of the problems with leakage under insulation is where the deposit appears or the liquid appears is often remote from where the leak is. So when you start to remove insulation, you may end up removing a lot of it before you get to the leak. And if it's on the coolant system or boric acid, it's usually pretty radioactive, which is the --

DR. WALLIS: In order to make it through the insulation and drip down somewhere else, it presumably has to maintain its liquid state, whereas it's trying to dry up all the time.

DR. SIEBER: That's true.

DR. WALLIS: But you think then this will be covered by this bulletin 2002-01 resolution rather than as part of license renewal?

MS. COFFIN: It's not unique to license renewal, the issue. So we are going to close -- That's how we are pursuing closing out this issue.

DR. FORD: I guess that's what worries me. We are going through the process to say, well, it's

not in this program, it's in another program. It's likely to -- I think this is the first license renewal we have had since the whole BHP Davis-Besse thing has occurred, from my memory, and I'm hearing exactly that. It is not part of license renewal. It's part of an ongoing current license condition. It just makes me feel uncomfortable that this process never really came into the discussions for this particular plant going on for license renewal.

MR. CORBIN: I would comment, however, that we are not doing nothing, if you will, about it. We do have a vessel inspection program. Whether the techniques that we are using are exactly what will come out of resolution of 2002-01 is not clear, but since that is a program that we are referencing for aging management, it is a current licensing basis program.

Anything that comes out as a resolution of this issue will change our program, and that will go forward in the period of extended operation in that changed form to address this specific issue.

DR. SIEBER: It seems to me that the vessel head leakage issue is still under development by the staff. They requested information, had some near term actions, but the long term fixes are not yet

specified either by the MRP, the code committees or the staff.

So I'm not sure what we would require an applicant for license renewal do differently than what the rest of the industry is required to do right now.

DR. BONACA: What will happen as a result of these activities would become part of the current licensing basis for this plant.

DR. SIEBER: That's correct.

DR. BONACA: And the license renewal intent is one of assuring that the plant submits its licensing basis -- current licensing basis during the period of extended operation. So otherwise, we will be searching for what a solution may be and asking them to commit to a solution that doesn't exist yet. So there's some division in the process.

DR. FORD: So we are recognizing that the current ISI methodology for the vessel head is not adequate. It is being addressed, and --

DR. BONACA: That's right.

DR. SIEBER: I think it's adequate for the time being. On the other hand, I think that there is some more data gathering to be done by the industry and the staff, and additional consideration as to what the ultimate fix is, and a lot of utilities are buying

new vessel heads.

DR. BONACA That's right. This utility, too. They are changing the head already. So they are addressing something in the materials issue, and so even the frequency with which this kind of degradation may come up --

DR. FORD: So you think it is appropriate that the license renewal inspection staff, these guys addressing this particular issue right now, there is no need for them to have thought about the risks associated with this emerging set of events? They shouldn't necessarily have worried about it?

DR. BONACA: Well, I mean, I think they should be worried about it right now.

DR. FORD: Okay.

DR. BONACA: -- short term concern, and it will certainly become a long term one if it's not resolved.

DR. SIEBER: If they don't change their heads, I think Surry was -- Construction began in the early Seventies, 1970 or thereabout, and it's susceptible. It's a hot head plant. So that puts them right on the high frequency for inspection, and maybe some developments will occur to make inspections more effective or easier to do, but that's yet to be

seen.

MR. CORBIN: We are, as a matter of fact, committed to doing inspections one more time on each head. I think I mentioned that this morning. So we just have to do it one more time.

DR. SIEBER: So far.

MR. CORBIN: So far.

DR. BONACA: Now since we discussed the level of repair or information provided this morning, I feel differently about time limited aging analysis where you have a component that we do not intend to replace and for which they could be in arrears already hard numerical data that the plant has determined. I would like to see that data, because that would allow me to understand the margin billed to those components as they come close to 60 years of life, and make a judgment from that.

I bring it up because it falls into the same category of, you know, not enough detail in the application. For this kind of thing, you know, I don't have a concern. I have a concern more for the time-limited aging analyses where they have extended the life of the components. We would like to know how close you get to that criterion as you get close to 60 years, and we haven't seen the information in this

application.

DR. WALLIS: Can I ask you another question? There is an item here called fuel oil chemistry program. What fuel oil is that?

MS. KHANNA: I think that one is diesel.

DR. WALLIS: It's not an oil burning plant.

MS. KHANNA: It's diesel.

DR. WALLIS: Emergency diesel generator. I assume it's the -- I just don't want to put words in your mouth. This is for the diesels?

MS. KHANNA: Yes, diesel.

DR. WALLIS: I don't see anything here about lube oil. Lube oil is used in all kinds of places, and there was a problem with the diesels, because they had bearings and the pistons that wore out because of some poor lubricating oil. There is no lube oil program. I just wondered why you have a fuel oil chemistry program and no program for lube oil, which is used all over the placed in rotating machinery.

Presumably, if it deteriorates, it could ruin bearings. Why is there a fuel oil --

MR. BARTON: Are you addressing that to the staff or the applicant?

DR. WALLIS: I'm just trying to get a question to see what was going on here, and I just noticed fuel oil chemistry, and I had heard earlier today about a lube oil problem. Why is there a program in fuel oil and not in lubricating oil? It's a naive question.

MR. CORBIN: The fuel oil chemistry program really relates --

DR. WALLIS: Probably for you. It's for the staff, but maybe --

MR. CORBIN: Oh, okay. Well, I'd be happy to answer it.

DR. WALLIS: I know, but you've been answering all morning.

MS. KHANNA: We didn't review lube oil. We concentrated on the diesel fuel.

DR. KUO: Meena, can you speak to the microphone, please?

MS. KHANNA: Yes. Actually, we only reviewed the diesel fuel oil.

DR. WALLIS: So you reviewed what is already there.

MS. KHANNA: Right.

DR. WALLIS: And it didn't occur to you to ask why isn't there a lube oil program. It was a fuel

oil program.

MS. KHANNA: Exactly, and maybe I can --

DR. WALLIS: So it's only someone like me who might have the idea to ask the question.

MS. KHANNA: I've been involved with aging management programs and never noted lube --

DR. WALLIS: I can't hear you.

MS. KHANNA: I'm sorry. I haven't noticed lube oil. I've never seen lube oil discussed with the fuel oil. So I have never asked that type of question. The contractor didn't ask that question, and we didn't identify it.

DR. SIEBER: Maybe I could help a little bit. There are regulations that require specific properties of diesel fuel. One of them is water contamination. So most utilities will sample each truckload that comes --

DR. WALLIS: So it's in the regulations. The answer is one is in the regulations, and one is not. Is that the answer?

DR. SIEBER: The other one -- Lubricating oils are not covered by the regulation specifically. Secondly, oil failures which start equipment failures are pretty rare, in my experience anyway. It's usually the oil gets messed up after the equipment

fails, you know, as the bearing comes apart and so forth.

MR. BARTON: Sometimes it's the other way, too, but each utility has a lubrication program.

DR. SIEBER: Right.

MR. BARTON: And which specifies the lubricants for each piece of equipment. But it's not required by regulations. So I think that's the difference.

DR. WALLIS: So I guess the answer that I'm trying to get -- because I'm asking the staff, not you guys -- is that --

MR. BARTON: Sorry about that, Graham.

DR. WALLIS: -- these 19 items are here because they are in the regulations, and other things that might occur to some naive observer like me aren't here, because they are not in the regulations.

MR. MUNSON: It's because they are associated with the management of passive components. The aging management of these passive components are covered by these 19 programs.

MS. KHANNA: And these are what's within the --

DR. WALLIS: And there doesn't happen to be --

DR. SIEBER: The fuel oil is stored in a passive -- in a tank.

MR. MUNSON: But it's stored in a tank.

DR. WALLIS: Well, I guess the question is sort of to see if there's a comprehensive activities and if someone has made an effort to assure themselves that these 19 are a comprehensive catalog of what the activities should be. How does one get some sort of assurance of that?

MS. KHANNA: We have -- I mean, there's a scoping review that occurs, and our assurance -- What we do is we have these seven elements, the program scope is monitored. So what we do is we evaluate what the applicant provides us against the GALL report, and get a reasonable assurance.

DR. WALLIS: And you use the GALL report to assure yourself that it's a comprehensive set of activities?

MS. KHANNA: Yes. And the GALL report is very explicit in telling us for each parameter.

CHAIRMAN LEITCH: Isn't the answer that these aging management activities, such as the fuel oil chemistry program, are used to detect degradation and systems that are within the scope of the license renewal effort, namely, passive systems, that is, that

are not normally inspected.

So the fuel oil chemistry program is credited in piping systems, to the diesel, the diesel storage tank, the diesel day tank -- there's a day tank? I assume there is -- all that kind of thing. When you ask the question, how are you managing the aging of that system, it's by this fuel oil chemistry program.

DR. WALLIS: Well, lubricating oil also has tanks and pipes and whatever.

CHAIRMAN LEITCH: And the lube oil system, the components are active in that there are bearings and so forth.

DR. WALLIS: The tanks and the pipes are not anymore active than they were with the other.

CHAIRMAN LEITCH: But they are inspected periodically.

DR. WALLIS: Well, I don't want to pursue this, if it's not going to help. But I'm just trying to see -- yes, to get some assurance that this is a comprehensive list.

DR. KUO: If I may -- Let me, Dr. Wallis, try to see if I can alleviate somewhat your concern about whether it's comprehensive or not.

There are two steps here for the review,

two major steps for the license renewal review here. The first part is the scoping and screening. Based on that result, whatever the structures and components that are within the scope of the license renewal will be subject to aging management review, each and every one of them.

You see that 19 aging management programs that are grouped together, and some of them are common to many structures and components. Others may be component specific. But the point is that each and every structures and component are being reviewed for aging management effects -- aging effects, in the aging management program.

DR. WALLIS: Each one that was identified in the scoping?

DR. KUO: Right.

DR. WALLIS: Right.

DR. RANSOM: Kind of along that line, I guess an interesting question would be does the fuel oil management program include emptying the tanks and replacing the fuel oil periodically? You would think that, if you are going to manage fuel oil, you would periodically clean it out and put new in, you know, as it degrades with time.

MS. KHANNA: They monitor their fuel --

They monitor the chemistry of their fuel, but I don't think that they are emptying them out at all. They are not emptying or taking the fuel oil.

DR. WALLIS: Anyway, they are managing it.

DR. SIEBER: From an aging management standpoint, what you are protecting is the tank, not the diesel, because the diesel is active.

DR. WALLIS: So you're concerned about water corrosion?

DR. SIEBER: It's water. It's fungus.

MR. BARTON; Microorganisms.

DR. SIEBER: And you do periodically skim the bottom of the tank, because that's where the water ends up, to minimize that, and the pipe that brings the fuel oil out of the tank is not on the bottom. It's raised about six inches or so.

But then the other thing is, in the anti-fungal, anti-bacteriological additives you put in there, you take samples to see what's growing, what contaminates you have. But that's how you protect those.

DR. WALLIS: But then you're answering the question.

DR. SIEBER: I don't think I did.

DR. WALLIS: The question really comes,

BNL would be the people who did all the work on this. So you relied on their report?

MS. KHANNA: That's true. Yes, we reviewed them. I mean, the whole thing with the chemistry program was that they are monitoring. They want to see if there's any impurities and things like that, but they definitely don't replace the oil. We didn't see anything like that.

DR. RANSOM: It would be interesting to ask the plant people. How long does the diesel fuel sit in a tank?

MR. CORBIN: You know, we do run weekly diesel periodic tests, and so there is a continuous use of the oil in the underground fuel oil storage tanks, which are the safety-related tanks. So we are turning the volume over slowly, but we are turning the volume over in those tanks.

DR. RANSOM: How long would it take to turn over the volume in one of those tanks?

MR. CORBIN: We have to have a 30-day supply, I believe it is. I'm not entirely sure, but I think that's correct. We have to have a 30 day supply in order to meet our commitments for LOCA.

DR. RANSOM: But with your periodic running, how long would it take to recycle that 30-

day supply?

MR. CORBIN: It might be -- Well, it won't be that, because you would only run --

DR. ROSEN: But they keep it topped off.

MR. CORBIN: You only run the diesel for a few hours every week. So I've got to divide all that out, and am I out to a year? I don't know. We can do the arithmetic.

DR. ROSEN: You don't empty the tank as you go. You run enough to top it off. Right?

MR. CORBIN: That is correct.

DR. RANSOM: What I was asking, though, is how long would it take with that process to have effectively replaced --

MR. CORBIN: Forever.

DR. RANSOM: You can't replace every molecule, but you would have gone through one tankful in some period of time.

MR. CORBIN: Right. Now we have made a commitment in here with the tank inspection program to look into those tanks, and that will cause us to empty them, and we have in the past completely drained those tanks to do inspections and look at them. So those activities are not routine, but they have occurred, and they have given us an opportunity to look inside

these tanks.

With regard to the question on lubricating oils, we really don't count on lubricating oils as an inspection program. We're counting on work control as a means for inspections of other diesel components. Lubricating oils and greases and those other things are considered consumables, and as consumables are not included in the scope of license renewal, and we really don't consider them any further. I certainly don't consider them in the light of being an aging management program.

MR. BARTON: But you do have a lube oil management program.

MR. CORBIN: Correct, we do.

DR. WALLIS: You do?

MR. CORBIN: There is a program, yes. It's just not referenced here as part of license renewal.

DR. WALLIS: So while we are talking, service water then that cools bearings would be part of -- The system that supplies that is part -- is in scope, but the lubricating oil system that supplies the lubricating oil for the bearing is not part of the license renewal scope. Is that the way it works? But the bearing ought to work is really key to the

functioning of many important parts of the system.

CHAIRMAN LEITCH: But it's not in scope.

DR. WALLIS: Okay. But the system that supplies the lubricating is another consumable.

MR. BARTON: A 65-gallon drum in the warehouse.

DR. WALLIS: No, it's not as simple as that. Pipes and valves and all kinds of things.

DR. SIEBER: And the pump itself is active. So it's out of scope and covered under the regular maintenance program.

DR. WALLIS: It's an interesting game, this putting things in and out of scope.

DR. SIEBER: It's what the rule says.

MR. GEORGIEV: My name is George Georgiev, and I am with the Materials Engineering Branch. The review of the reactor coolant system was performed by Brookhaven National Laboratory, and I was the technical monitor for this effort.

The review the reactor coolant system followed that application, the breakdown, basically. The reactor coolant system is broken down to the reactor coolant piping, the reactor coolant internals, the vessels, steam generators and the pressurizers.

The material for the reactor coolant

system is basically stainless steel for the pressurizer, the reactor vessel, and the primary side for the steam generator is alloy steel clad with stainless steel overlay.

This applicant and application identified aging effects associated with these materials. In operating the reactors some of these aging effects are cracking in stainless steel, loss of materials, and carbon steel, cracking in the nickel alloy and so forth, and we do list each and every one in the application.

So I'll address these five major areas, the topics. For the reactor coolant piping, basically, the application identified the several aging management programs that will manage these aging effects that were identified, and they are the chemistry control program, the boric acid corrosion surveillance program, the in-service inspection program, augmented inspection activities, and they have a plant-specific work control process program which basically earlier this morning was talked by the applicant.

The review also for the whole application followed up the guidance that is specified in the Westinghouse owner's Group report, and there are

basically three reports. One is for piping. One is for the pressurizer, and one is the for internals.

We have reviewed -- The staff has reviewed these reports. We have approved them with certain stipulations. Each and every one of these stipulations was addressed in our review, and the bottom line is that this application is bounded by this report with certain qualifications, and we do list each and every one of the applications.

Some that come to mind is like the topical report doesn't credit the chemistry control program for managing certain effects. The application credits this program. The floor is -- in orifices and not addressed by the report. The application addressed them, and so forth and so on.

We didn't have open item issues with the piping. Another important issues that you are probably aware with this piping for this plant, the ISI inspection will convert, if not to a risk based inspection, and we did approve earlier the use of -- but that doesn't change anything.

The reactor pressure vessel internals: There are basically two type of materials, stainless steel material and nickel based alloys.

DR. WALLIS: Can I ask you about the

piping?

MR. GEORGIEV: Most certainly.

DR. WALLIS: With discussion this morning -- I guess you were here this morning.

MR. GEORGIEV: Yes.

DR. WALLIS: -- about why was it that at Summer they didn't detect the cracks in the main pipe, and then a year later there was a major leak. Are you satisfied that the method of looking for cracks in reactor coolant piping at these plants is adequate?

MR. GEORGIEV: Yes, we are. Otherwise --

DR. WALLIS: On what basis are you satisfied that it's adequate?

MR. GEORGIEV: Well, because we can't recommend anything better. You can't --

DR. WALLIS: You can't recommend anything better?

MR. GEORGIEV: Yes. Other than that, we do have efforts on our part and also industry efforts that are endlessly working and improving the detection methods. A lot of money is spent on this effort, and I'm sure in the future we will get better in detecting these. But basically, that is the short and honest answer.

DR. BONACA: Well, yes, and this morning

we asked for additional information to come from you, and so we ask you the question.

MR. GEORGIEV: I wasn't here for the discussion.

DR. BONACA: I mean, I know it's the short answer, but here we are, and we are asking V.C. Summer, every outage, to go back and inspect again these nozzles and the welds to see if there is any growth in those cracks that they identified, etcetera, etcetera. That's because they failed once.

Now we have no confidence that other plants out there don't have the same problem. They could have had the same team performing the ISI or company doing it, missing all these indications, could have the same situation, and they are not doing, you know, repeated inspections because they didn't find anything yet.

Certainly, I mean, I'm sure there is some -- I would like to know what is going on in the industry to try to address this issue, and why is the NRC confident or comfortable that there is sufficient progress in addressing this issue that we can wait and hope that there will be some better inspections? I don't think we can just --

MS. COFFIN: George, I can talk to this a

little bit. This is Stephanie Coffin, and again, you know, when Summer happened, I think initially the industry reaction -- and I'm not an expert in the Summer event, but my understanding is the initial reaction was this was a plant-specific problem.

Staff does not agree with that. We asked EPRI MRP to take an active interest in pursuing the generic implications of the Summer event, and the staff was working independently along the same path. Then Oconee and Davis-Besse happened, and I think resources -- To be frank, resources got diverted to addressing those two issues, which are fairly related PWSCC Alloy-600, 82, 182 weld metal.

So I think we are getting back on track, but again this is another -- Not that this makes Dr. Ford feel any better. This is another current day issue that do I feel confident, does the staff feel confident their ISI programs are completely adequate to cover this PWSCC issue. I would have to say no. But do we know what to tell them to do? No.

DR. BONACA: My concern is this, though. The Davis-Besse event was significant enough, and there is a lot of focus on it, and I am comfortable with what is going on, because I know everybody is looking at it.

The V.C. Summer event -- I am bringing it up. Nobody talks about it, and yet we know that most of these cracks you see, they were probably present from Day One, and now they are being put back into the welds, and they were missed at V.C. Summer. If the same situation occurred at other plant, we may have a population of plants that approach the time when some of these cracks may happen, and we have to commit to identify this before the cracks occur.

We have to be aware of the fact that, in fact, we are addressing aging here, and aging is going to bring some population of plants to the threshold where the failures may occur.

So I think there has to be some commitment on the part of the industry and the staff to give us more comfort on what the inspections are capable of doing, and we are not getting that.

I mean, I just don't see that coming yet, and I understand this is an issue with current licensing basis versus future program. Well, that makes it even more urgent, because it seems to me that we don't have to wait ten years before we worry about that. We worry about it today.

DR. WALLIS: Moreover, the license renewal is a time when you have to leave or when you might

actually apply something to the applicant to get them to do something better. There hasn't been news. It's a point where the decision can be made one way or the other.

DR. BONACA: I know there is comfort on leak before break and those other things, but still, I mean, it is an issue that -- and I'm seeing here that so much of this depends on the ISI.

DR. WALLIS: The answer that there is no better method doesn't really answer the question, though, is the present system adequate. What would a method have to be in order to be adequate would be the first thing I'd like to sort of know, and then, if there isn't a system, how can we get one?

DR. SIEBER: Well, just dealing with Surry and North Anna, I guess I'd like to ask a question. Plants of that vintage were -- Coolant piping was centrifugally cast stainless steel; whereas, I'm not sure that Oconee is that. The weld configuration is different, and the materials, I think, are different -- of the weld metal.

So is there any basis to say that this issue is generic to PWRs or is it restricted to Oconee by itself, or -- they are what, combustion units?

MR. BARTON: B&W. Oconee units are B&W.

DR. SIEBER: Yes. How do classify that? Is every plant susceptible to that? If so, where is the program to manage it?

DR. BONACA: I'm not asking about other problems. I'm talking about the technique by which you inspect. And the whole license renewal depends on the credibility of programs to inspect, identify, and correct. If you inspect and do not identify, well, you got a problem.

DR. SIEBER: But that's part of the augmented inspection and tech specs for these plants.

MR. GEORGIEV: Well, one thing, we can all agree that the inspection methods have improved. The sensitivity of detection or likelihood of detection has improved through the years.

What years ago, 10, 15 years ago, you couldn't detect with existing UT metal, now you could. We did send out to EPRI NDE center. We qualified people. A lot of things have changed for the better. Is it enough? I --

DR. BONACA: One thing they did at V.C. Summer, they use eddy current, as I said, because eddy current is going to identify superficial indications, and then they went after indications with UT. So they have already implemented an enhanced inspection

process.

MR. GEORGIEV: Well, the same thing North Anna has done for their reactor pressure vessel nozzle inspection. We have went into extra effort to list the result, the inspector results. In the safety evaluation they have used combination of eddy current, UT, visual and, I believe in some instances, liquid penetrant inspections. So people are trying.

DR. RANSOM: Does the piping system program for aging management include like flow assisted corrosion monitoring?

MR. GEORGIEV: Not for flow accelerated corrosion, not for the reactor coolant system. They do have a program, but that's for the steam --

DR. RANSOM: Well, what about the steam lines, for example? You included the steam generators.

MR. GEORGIEV: Well, that's a different system, and I happen to be the presenter for this. It's under steam and feedwater system. They do have a program that monitors for this.

DR. RANSOM: It's not included in the steam generators?

MR. GEORGIEV: And it has a different name. It's not a flow assisted corrosion. They call

it something else. I have to look up. In fact, I have to do that to my section chief when we are all down there. But they do have flow accelerated corrosion program in place, but they call it something else.

DR. ROSEN: I think we shouldn't just leave your concern, Mario, hanging out there. I think it's a valid concern.

DR. BONACA: I think we should -- We will have a presentation once the FSAR issues -- the open issues are closed. Right? That will be in the fall?

CHAIRMAN LEITCH: September.

DR. BONACA: September. I think we should hear about that.

DR. KUO: Dr. Bonaca, we will come back to the Committee.

DR. BONACA: And I'm not concerned about North Anna alone. I'm concerned about what the NRC's expectation is for an enhanced ISI that will give us the comfort. We don't need to have it tomorrow. We need to know that you have a plan, or the industry, to address this issue in a way that solves the concerns with the adequacy of inspection.

MS. COFFIN: But that's exactly what we are working to, working with the MRP and EPRI,

because, you know, there are -- and that takes time, if you want to go about it deliberately. But I understand your comment, and it's very valid.

DR. BONACA: Maybe you could come when we have the final review and give us a report on what is going on with EPRI, in fact, how is this issue being addressed. We don't expect to have a resolution of it tomorrow.

DR. FORD: That hinges on something mentioned an hour ago. This particular team, if they are examining the LRA -- and I get the feeling it's almost a pro forma exercise -- do they have an aging management program to come back to address this particular issue, whatever those issues are?

Generally, because we have had so many license renewal applications going through, the answer is, yes, there is an AMP. The question is never asked, is the AMP process adequate? In certain -- Of course, in many cases it is, but in certain evolving areas such as ISI, the cracking, it's not. That takes it outside the purview of this group into the NRC, NRP, utility interaction. It's outside their -- and that's what worries me.

DR. BONACA: They work in a project mode. When it comes down to asking a question about whether

or not the mechanical program is appropriate, they go to the Mechanical Branch. Right? That's the way you do the review. So that individual should be also up to speed on quoting license and bases and resolution of these issues, and so we should be able to hear it from this presentation.

DR. KUO: And, yes, we will.

DR. FORD: But just because the industry as a whole -- by industry, I mean the industry, NRC as a whole -- have not grasped the ISI network strong enough, does that mean to say that we turn to Surry and North Anna and say, no, you can't have your LRA?

DR. ROSEN: Be very careful now, because Jack Sieber will jump all over you if we start using individual licensees as a means for transmitting generic questions to the Commission. Am I right, Jack?

DR. SIEBER: Absolutely.

DR. FORD: And I agree with it.

DR. SIEBER: It's called victimizing.

DR. ROSEN: On the other hand, I don't share his -- entirely share his views on that. I think it might certainly get read if you said we agree, for instance, that North Anna and Surry should get their license extended; however -- and then you

could put the caveat. There is this issue that will have to be managed in the license renewal term of North Anna and Surry as well as all the other PWRs which we have concern about.

DR. SIEBER: We've done that.

DR. ROSEN: That's the kind of language I could tolerate, and you would ask, Jack, I know -- you'll say, well, what are Surry and North Anna going to do about that, and why lay it on them?

Well, I don't expect Surry and North Anna to do anything specific except be part of the industry resolution process, which they are already part of.

DR. SIEBER: Well, the Chairman of the NRP is an employee of Dominion. So --

DR. ROSEN: Oh, is he? Okay. I mean, that's something we can talk about later, but I certainly think that's an important enough issue that we ought to come back to it.

DR. KUO: And we will come back to the Committee also in the next SER Committee meeting. We will give you some explanation of what the staff position is.

DR. ROSEN: Well, I think you could do that, but we are really more interested in what the resolution is, how we're going to resolve the issue

that apparently one can be operating these machines with cracking progressing, and you may not be able to detect it with the current methods.

DR. KUO: Yes. We will have some story for you.

MR. GEORGIEV: Okay.

DR. WALLIS: And you are relicensing them. So within some public forum, people could ask you questions about how can you do that, isn't this a step of faith, and then by the time you have relicensed ten of them without resolving the issue, maybe the issue gets sort of resolved through the back door.

DR. ROSEN: Well, we have defense in depth here, I think, is part of the answer to that question. We do have leak before break. We think these pipes will, when they get in real trouble, before they break they will announce the fact that they are in trouble. But that isn't good enough.

DR. BONACA: But it's interesting. You're absolutely right. In the early times of license renewal, two or three years, and we ask the question, is ten-year ISI still adequate when the plants are older. I raised this question because -- and I made the example. I said, when I was a young man, my insurance company would never have justified a check-

up more than once every ten years. Now they allow for me one every two years. Okay?

So isn't it true -- And the answer was, oh, no, no, one every ten years, perfect, no problem at all. If that is the case, okay, we have to really believe that at least the inspection which you perform is insightful enough to identify cracks that may develop over the ten years into a leak.

Now I agree with you that we have leak before break, and we have this and that. But you are still staying with a long interval between inspections. So you have to be really dependent on that. Otherwise, you have to make them more and more frequent.

DR. ROSEN: Well, we don't intend to write a letter on Surry and North Anna at this meeting. We have something like six months to five months before we write a letter. So we have time to hear some more.

DR. WALLIS: We will ask the question again. We'll ask the question again next time.

DR. BONACA: We heard, you know, that we have a commitment to hear from the staff on what's going on right now. That may give us sufficient comfort that there is attention being paid to it, and there is an effort to improve the inspection

processes.

DR. KUO: And also I believe this issue and Davis-Besse issue will take probably a long time to come to a resolution. However, but we will come back to the Committee on how we are going to deal with it in the interim.

DR. BONACA: Realize, however, Davis-Besse we heard were replacing the heads. I mean, that's a heck of a solution there. We don't have to worry about it much anymore, at least in the short term. Here for the ISI since two years ago I haven't heard anything, and we were at Region II just three weeks ago, and I asked a lot of questions about that, and there is no -- Nothing has come out of that yet. It just seems the issue is being forgotten, and I don't think it should be.

DR. KUO: But in terms of the frequency of ISI, that's a much more generic question than, you know, the North Anna and Surry.

DR. BONACA; Oh, yes. I am not putting it on their back at all.

MR. GEORGIEV: Anymore questions on the piping? That's enough.

I'll go ahead with the reactor coolant internals. There are only two types of materials used

for internals, basically stainless steel and nickel alloys, and there are two problems, the reactor -- The chemistry control problem and the reactor vessel internal inspection problem proposed to manage the aging effects associated with the reactor coolant internals -- the reactor vessel internals. Basically, we didn't identify the issues with this area.

The next area was the pressurizer.

DR. FORD: Can I ask a question, just how you set about approving -- It says the applicant stated that the RCS components, etcetera, etcetera. How much examination did you do -- Okay. They've got an aging management program, sheet of paper, that says it. How much examination did you do of that piece of paper or that procedure as it applies to their particular plants, their materials, their fluence level, etcetera, etcetera?

MR. GEORGIEV: Procedures per se? We don't look at procedures. We do look at programs. Each program is supposed to have ten elements that, if you adhere to, will end up with adequate program to manage the effects that your review identifies.

IN this instance for the internals, they are proposing -- You do have the ISI of the reactor vessels. We can correlate to that. We know what is

required, what is the acceptance of the reactor chemistry control program.

We also know nowadays the EPRI guidance documents. We work with the industry on the established parameter to control the industry. So--

DR. FORD: So could you have a situation that, as we go down the line with all these further plants, if they've got a piece of -- a procedure on the table that says this is what I'm going to do for this particular component, then you could tick it off?

MR. GEORGIEV: Well, basically, that's the way the plant does it, but here we don't do that. We just review the program. If the program is acceptable to manage this, we say, you know --

DR. FORD: And how do you define acceptable?

MR. GEORGIEV: Well, to detect the problem will be. Like for internals, what do you do? They identified cracking of the internals. How do you detect them? You go and look visually or with a PUC examination or something else. If you can see it, you can identify it, you can repair it. If you don't see it, then it won't happen. So that is the procedure and the process of accepting something.

MR. ELLIOT: George, this is Barry Elliot,

Materials and Chemical Engineering Branch.

I was one of the reviewers of the WCAPs, and the WCAPs -- What it does is it gives a list of components and materials that are a part of that component, and then for each of those materials and components it identifies whatever the aging effect is, and then from that a program is identified.

When we say in here that it bounds -- the plant bounds the WCAP, what that means is that the applicant has looked at the materials and the environments that are in the WCAP and has determined that they are applicable to their components.

Then they look at the aging management programs to determine if their programs meet that. Now as reviewers, we at the NRC, we review the six-column table, and in the six-column table it has the materials that would be on these components, and we just look at those tables to see whether or not they would comply -- are complying with the WCAPs, and to that extent.

MR. GEORGIEV: Yes, but I understood that there was actual mechanic were go or no go kind of thing. But anyway, yes, that's --

MR. ELLIOT: That's the procedure, basically, we follow as reviewers, is to review the

tables to see if they are in compliance with what's in the WCAP.

DR. KUO: And in addition to that --

DR. SIEBER: You reviewed the WCAP for vessel internals?

MR. ELLIOT: Yes.

DR. SIEBER: I can think of two issues in these plants, this type of plant that were significant. One of them was the guide tube studs and nuts that were breaking off. Is that in the program or not?

MR. ELLIOT: I don't remember all the details. I remember that -- I think that was a -- The guide tubes were the vibration. Wasn't that a vibration problem, when they started up? John, do you remember that? No?

DR. SIEBER: And the other one was baffle bolts that were breaking.

MR. ELLIOT: Yes.

DR. SIEBER: Is that covered under the WCAP program?

MR. ELLIOT: The baffle bolts -- There's a program in there, but we are -- You know, that has been supplemented by -- The internals program has been supplemented by the MRP program in many cases, and

they are developing more inspection guidance through the MRP program. It's not fully resolved as far as the WCAP is concerned.

DR. SIEBER: But the SER doesn't require anything beyond what the WCAP requires?

MR. ELLIOT: I believe the applicant is committed to the MRP program, and -- Isn't that true?

MR. CORBIN: That is correct.

DR. SIEBER: But they don't have an answer. Right?

MR. ELLIOT: Well, we are still looking at how to -- There's a whole bunch of aging effects that we're talking about here, void swelling, reduction in fracture toughness, IASCC. All these aging effects take a long time, and they are not going to occur tomorrow. They are going to take a long time to occur, and so that the program is being developed prior to the license renewal period and will be implemented during the license renewal period.

DR. FORD: I think what we're saying is I think that baffle bolt cracking -- I mean, that's nothing new.

MR. ELLIOT; No. No.

DR. SIEBER: And neither is the guide tube studs. I know a plant that had some broken ones.

DR. FORD: Your contention is that some of those programs exist to address this.

MR. ELLIOT: Yes, that's true. But here is our baffle bolt person.

MR. GEORGIEV: Actually, I did find it in the SER. We did talk about that baffle bolts.

MR. GRUBELICH: With regard to the -- Frank Grubelich, Mechanical Engineering Branch, NRR.

With regard to the baffle bolts, the baffle bolts on the Westinghouse plants -- they were first -- I think, as you all know, the cracking was discovered over in the foreign plants, and initially what was said -- what was told here is that we've never seen it domestically.

Of course, we've never seen it domestically, because the inspection is visual, and the crack in the bolt was between the shank of the bolt and the head of the bolt. Visually, when you look at it, all you are doing is looking head onto the head of the bolt.

Westinghouse and the Owner's Group then got into doing UT inspections.

DR. SIEBER: Through the head.

MR. GRUBELICH: Through the head.

DR. SIEBER: Right. I remember that.

MR. GRUBELICH: And out of the four plants that they inspected, they found cracking in two of the plants. They have developed an analytical program in which they went back and they looked at what the stress levels were. In that, they developed an inspection program for which they go in and inspect the bolts, and they replace a certain pattern of bolts. And out of the something like 1,000 bolts, they really only need for the blowdown loads, and that's essentially what the program is -- they need some very small portion of those bolts.

They have identified the patterns of the minimum bolting that they need, and they have gone in and in those plants that they inspected, they replaced those bolts.

The MRP is developing an inspection program, and that is what the industry utilities have committed to, that they are in fact going to comply with the inspection requirements, the type of inspection, and what minimum number of bolts have to be replaced.

DR. SIEBER: Now if you replace the minimum number of bolts, that allows the blowdown loads to be --

MR. GRUBELICH: To meet the blowdown load,

is what I'm saying.

DR. SIEBER: To meet the blowdown load, but it doesn't necessarily keep the baffles straight. So you end up with baffle --

MR. GRUBELICH: Well, if you don't put in all the bolts, you have a problem of keeping those plates flat so that during refueling, if you have a fuel assembly that bows and the plate bows, you have an operational problem getting that fuel assembly out.

DR. SIEBER: Yes, you do.

MR. GRUBELICH: So no one is -- In all the meetings that I have had, none of the utilities have ever suggested that they were only going to put in the minimum number of bolts.

DR. FORD: So as far as this LRA process is concerned, because North Anna and Surry have committed to following the development within the MRP and NRC, you have approved that particular ANP related to --

DR. SIEBER: Well, this is the same as a number of other current operating issues, I think, which really isn't a part of the license renewal process. Even if you don't renew the license, they still have to comply to continue to operate.

MR. GRUBELICH: Correct.

MR. ELLIOT: That is a current operating problem.

DR. FORD: The only reason why you would know is if there was a physical reason why going for the extra 20 years that the program that MRP are going to come up with and which they would comply with would be physically impossible, like getting to a critical clearance level.

DR. SIEBER: Right, for the vessel.

DR. FORD: Correct.

MR. ELLIOT: There is one other issue, and that is this occurred on the very early plants, and on the early plants the way they were designed, they had what is called downflow in which they introduce the coolant at the top of the baffle and then down, where all the later plants were upflow. In that case --

DR. SIEBER: A lot of the downflow plants converted by drilling holes and putting plugs in.

MR. ELLIOT: Some of them. Not all of them. There are a few that haven't done that.

DR. FORD: Well, let me ask the next question. That approach should be perfectly adequate, provided there wasn't a physical reason why you could not take these programs on for another 20 years and still not reach some physical fluence limitation.

DR. SIEBER: Right.

DR. FORD: That sort of thing can go on as you examine these programs. Did you go through the mental process, well, the MRP program is fine, but there's a limit to the fluence --

MR. ELLIOT: The utilities have committed to do an inspection on the bolts, UT inspection, prior to entering the 20-year extension and, if they find that they've got cracked bolts, of course, they are going to have to --

DR. KUO: The answer to Dr. Ford's question is yes, that we do go through that kind of a mental process.

MR. ELLIOT: I've very carefully gone through this baffle problem.

DR. SIEBER: I presume -- and correct me if I'm wrong -- that it depends on what the fix is. You replace the bolt. Then the new bolt probably is just as good as the original and can probably go 30 years.

If you do something else that falls short of replacing the part, then you have to figure out how long that fix will last. If you don't know the solution yet, then you don't know what analysis to do. But in the baffle bolting problem, I think the

intention is to replace the bolts.

MR. ELLIOT: Correct.

DR. WALLIS: You are having the longest presentation of the day.

MR. GEORGIEV: Ah, I appreciate the interest and the help.

CHAIRMAN LEITCH: Can we move on to pressurizers now?

MR. GEORGIEV: Yes, the pressurizer is the next area. Basically, it's cladded alloy steel, over-welded with stainless steel. As it turned out in one of the pressurizers in Surry, they had a furnace sensitized stainless steel, and that's what is identified as an aging effect, correctly so. But through the fact that there were no problems identified today, basically, the overall conclusion for the pressurizer is that the aging management program for the identified aging effects are adequate to manage the degradation effect.

CHAIRMAN LEITCH: Does this discussion --

MR. GEORGIEV: And again I do have listed in the evaluation each and every aging effect and each and every management problem. But, you know, it would take two days to run through the list.

CHAIRMAN LEITCH: Does the discussion

about pressurizers include the pressurizer surge lines?

MR. GEORGIEV: The surge lines, yes.

CHAIRMAN LEITCH: And what is the issue there? There seemed to be quite a bit of discussion about the pressurizer surge lines and differences between North Anna and Surry. What's the issue there? I wasn't quite sure I understood that.

MR. GEORGIEV: Well, they do have a sensitized three or four stainless steel.

CHAIRMAN LEITCH: In the surge lines?

MR. GEORGIEV: In the surge lines.

CHAIRMAN LEITCH: At both plants?

MR. GEORGIEV: In one of the Surry plants. Basically, it's the sensitized steel. You know, it's susceptible to stress corrosion, cracking. So that the concern is all this, you know, when it will crack,and that's why we do -- It's been considerable discussion about that. But basically, with the exception of this line, the rest is standard material, alloy steel --

CHAIRMAN LEITCH: Standard material being?

MR. GEORGIEV: Alloy steel overlaid with stainless steel, and they do have some cast material above that is specifically were addressed as in

concern with the reduction to aging. But the overall conclusion was that the existing problem -- we'll manage that.

So the bottom line is there is no open items identified with the pressurizers.

DR. WALLIS: In operation, the pressurizer level stays constant or does it cycle?

DR. SIEBER: It stays constant.

DR. WALLIS: How active is the level in the pressurizer in normal operation?

DR. SIEBER: It stays constant. You always have flow in the surge line, because you run some level of heaters in the spray valve.

DR. WALLIS: Yes. What I'm getting at, if you have heaters in the spray and there's a problem, is there some sort of thermal cycling?

DR. SIEBER: It's not thermal cycling, but there's a thermal gradient.

DR. WALLIS: Does that thermal gradient move up and down?

DR. SIEBER; No, but it runs along the length of the surge line.

DR. WALLIS: So there isn't any kind of thermal fatigue problem at the surge line?

DR. SIEBER: No, but if you trip the

plant, there's --

DR. WALLIS: Oh, yes, but you don't do that very often. With the normal cycling, normal operation, there is some sort of cycling.

DR. SIEBER: Yes, but it's small.

MR. GEORGIEV: Okay. The next area, the reactor vessels, and there is a basically difference for the two plants. At North Anna the base material was forged materials weld overlaid with -- 3 or 4 stainless steel, and for the Surry they used plate material welded.

The reactor vessels, as earlier was discussed, they are covered with regulation, Appendix G and Appendix H. Appendix G pertains to fracture toughness, and we do have a screening criteria that we discussed earlier. They do meet -- The applicant went and calculated the fracture toughness for the 60 years and came out that they meet our screening criteria, which is 50 foot pounds at the end of life.

Basically, the existing problem which, of course, the chemistry control problem are listed adequate to manage the identified aging effect.

For the steam generators, steam --

MR. BARTON; In the reactor vessel, where are the nozzles covered? In the ISI program? ISI

covers the nozzles on the vessel?

DR. SIEBER: Some plants have augmented tech specs which require visual inspection.

MR. GEORGIEV: Steam generators are relatively new. They have been replaced at both plants. So the old type steam generator problem like denting the support were not present in this plant, and they do have existing problem for the primary chemistry, the secondary chemistry, and the steam generator inspections, which include, you know, the tube inspections and loose spot and other.

DR. SIEBER: It seems to me that the tubes in the replacement steam generators for Surry were Alloy 600 or 690? Six hundred, I think.

MR. GEORGIEV: I'll let the applicant answer that. I actually don't --

MS. COFFIN: I think Surry was one of the first plants to replace. So I'm sure they have 600 thermally treated.

DR. SIEBER: Right. That's what I thought.

MR. GEORGIEV: Yes. Actually, the first was in the late Seventies.

DR. SIEBER: Well, Turkey Point, I thought, was the first.

MR. GEORGIEV: The Surry, yeah.

DR. SIEBER: Surry was right behind them. North Anna was fairly recent.

MR. GEORGIEV: Yes.

DR. SIEBER: So the Alloy 600 problems don't go away.

MR. CORBIN: It is Alloy 600.

MR. GEORGIEV: Thank you. And basically, the bottom line is through the review, the other preexisting issues are enveloped and addressed into the SER, and those two relatively new issues that this morning was talked about it.

We went with the effort to identify what the story is with North Anna and Surry, and specifically for the nozzle issue which is dealt with in 2001, inspection has been performed. In two of the units, they didn't find any cracks. On the other two units, they did find, and we list the numbers.

They were repaired, and they used a combination of inspection techniques, visual, UT, ERICA, and liquid penetrant to identify these flaws. For the Davis-Besse issue, which is dealt with in 2002-01, it doesn't apply to North Anna. They don't have the same problem.

CHAIRMAN LEITCH: These cracks, were they

through-wall cracks?

MR. GEORGIEV: I believe they weren't. They were just flaws. But the answer is no, they weren't. They were flaws. One, I remember, was a crack which was fabrication -- was existed, but the rest were characterized as flaws that developed through operation.

DR. ROSEN: Now we heard earlier today that they used a tracked vehicle to look around, and it got stuck in the mush. Tell me more about that? Was it ultimately -- That was, obviously, boric acid that came down from above. That was later cleaned up. How did you leave the heads at Surry and North Anna? What is the current condition?

MR. CORBIN: When we left the heads, they had been cleaned, so that we would be able to establish a good baseline for our next inspection. Next time we go in, we expect to see them clean again.

DR. WALLIS: What was cleaned off them?

MR. CORBIN: We cleaned the boric acid off.

DR. WALLIS: And the boric acid came from a leak up in the guide tube somewhere?

MR. CORBIN: Up on the guide tubes. Correct. Conoseal leak.

DR. WALLIS: And it didn't contain oxides of iron in it?

MR. CORBIN: No, not that we were aware of.

DR. WALLIS: Or enough that you were aware of it?

MR. CORBIN: Right.

DR. ROSEN; But there was enough of it to stick the vehicle?

MR. CORBIN: That's correct. Didn't take much, but it was enough. They have since improved the crawler device where it --

DR. WALLIS: Shouldn't you fix those leaks so that there is no boric acid on the head?

MR. CORBIN: Yes, there are no leaks on the head at this time.

DR. WALLIS: No, but I mean it is coming down from above. Fix the leaks up above. It's in a seal in a joint or something?

MR. CORBIN: We have fixed those leaks.

DR. WALLIS: Oh, so there is no leak anymore?

MR. CORBIN: Correct.

DR. SIEBER: It's a welded device.

MR. CORBIN: What wasn't done in the past

when we had a conoseal leak is we repaired the leak. We did the weld repair, but we didn't clean the head. Now we have cleaned the head.

DR. ROSEN: On both plants, both Surry --

MR. CORBIN: All four units.

CHAIRMAN LEITCH: Okay, George, anything else?

MR. GEORGIEV: Well, I can't think of anything that this committee didn't ask.

CHAIRMAN LEITCH: That's good.

DR. WALLIS: I'm sure we could, but we haven't asked it.

CHAIRMAN LEITCH: We are falling a little bit behind schedule, but let's come back at 2:30, have a little recess now, come back at 2:30, and pick up the pace a little bit.

(Whereupon, the foregoing matter went off the record at 2:17 p.m. and went back on the record at 2:31 p.m)

CHAIRMAN LEITCH: Pick up the discussion with the Engineered Safeguard Features. Jim?

MR. MEDOFF: Good afternoon. I am Jim Medoff. I am a Materials Engineer with the Materials and Chemical Engineering Branch of NRR.

I was assigned the task of reviewing the

engineered safety features for the Surry-North Anna application.

The engineered safety features include: The quench spray, fuel pit cooling, recirculation spray, residual heat removal, and safety injection systems.

When we did the review, we reviewed the systems as a commodity group due to similarities in the materials and the environment for the components in the systems.

We did issue four confirmatory type of RAIs with regard to a few of the aging management programs that were proposed and some regarding identification of aging effects for the components.

I need to emphasize that the engineered safety feature materials and environments were similar to those identified in other applications, specifically Oconee and Turkey Point which we used for comparisons, Oconee based on the fact that it is a sister facility for the applicant, Turkey Point because it was the first Westinghouse facility which we issued a safety evaluation report for.

Most of the components in the engineered safety features are carbon steel or stainless steel materials, and they are exposed to either treated

water internal environments, and external controlled air environments.

The applicant answered and resolved all RAIs to the satisfaction of the staff. The applicant proposed acceptable aging management programs to manage the effects of aging in passive engineered safety components within the scope of license renewal.

Answers to the RAIs satisfactorily clarified why the applicant was proposing different aging management programs for some components that seemed to have similar materials of fabrication and operating environmental conditions.

Based on our review, we determined that the applicant's aging management reviews for the North Anna-Surry ESFs were sufficient to identify both the effects of aging for those ESF components within the scope of license renewal, and the aging management programs that will be used to manage the effect of aging that were identified by the applicant.

We did not have any open items or confirmatory items with regard to the engineered safety features.

CHAIRMAN LEITCH: Comments, questions? Okay, thank you, Jim.

MR. LAURON: My name is Carolyn Lauron.

I am a reviewer in the Materials and Chemical Engineering Branch. I am one of four reviewers who reviewed the auxiliary systems. Along with me is Jim Davis, Arnold Lee and John Sau, all of who are not here today.

At any rate, the systems that we reviewed are the auxiliary systems and essentially consisted of primary process systems,the open water system and closed water, air and gas, ventilation and vacuum system, drain and liquid processing systems, vent and gaseous processing systems, and fire protection and supporting systems.

These systems are delineated more specifically in the six-column tables that the applicant provided, and may include portions of piping and/or components that are found in several other systems. For example, the primary process system includes portions that are described in chemical and volume control system, high radiation sampling system, the in-core instrumentation system, refueling purification system, and the sampling system. That's just one example.

So for each of these, you may find descriptions for specific components in other portions of the LRA under scoping and screening. The aging

effects for the various components in each of these systems varies, depending on the material and/or environment combination.

Both internal and external environments were considered, and the staff found appropriate aging management programs discussed earlier this afternoon to be adequate for managing the various aging effects listed in the six-column table.

So we didn't find any open items. If there are specific components you would like to discuss and/or aging effects, we can certainly go through the tables and see if I could find them.

DR. WALLIS: Does ventilation include control room habitability considerations? Does that come under ventilation?

MS. LAURON: I believe so. Let me look real quick. Ventilation -- The ventilation system includes the containment vacuum system, leakage monitoring, secondary vent system, vacuum priming system, and the heat ventilation system.

DR. WALLIS: How would something like control room habitability come in?

MS. LAURON: Control room habitability?

DR. WALLIS: Where would that come in?

MR. CORBIN: Just to come in, yes, control

habitability systems are included.

DR. WALLIS: Under what heading would they be?

MR. CORBIN: They would be under ventilation.

MS. LAURON: The heating and ventilation system? Is that 2.3.3.2.1?

MR. CORBIN: I's heating and ventilation system, but as far as the title right here it's under ventilation and vacuum system, as noted here. The specific system is a heating and ventilation system.

DR. WALLIS: Well, we are talking about aging management.

MS. LAURON; No, we are talking about the aging effects for --

DR. WALLIS: Yes, presumably the seals, whatever it is, that controls air, egress/ingress and everything, to a control room, subject to wear, deterioration.

MR. CORBIN: The actual seals in the walls would have been treated as part of the structural commodities associated with the walls.

DR. WALLIS: So you wouldn't be prepared to answer specific questions about the control ventilation aging management?

MS. LAURON: Program?

DR. WALLIS: Would you be prepared to answer?

MS. LAURON: I don't know anything.

DR. WALLIS: No?

MS. LAURON: No. If you have something specific, I could certainly take that down and come back.

DR. WALLIS: No. I guess our duty is to ask questions, and your job is to answer them. I'm trying to find a question I can ask.

MS. LAURON: I have no life lines present.

CHAIRMAN LEITCH: Well, I have one. There was some discussion with previous applicants regarding the housings of fans. That is, the fan rotating assembly and ventilation system is obviously an active component, but there was a differentiation made between the fan rotating assembly and the fan housing.

The fan housing -- In some of these critical systems like control room ventilation, is the fan housing in scope?

MS. LAURON: I believe they are. They are in scope.

DR. KUO: I believe fan housing is part of the passive system that the staff is looking at.

CHAIRMAN LEITCH: Okay.

DR. WALLIS: How does How does a fan housing age?

CHAIRMAN LEITCH: Well, it can get holes in it. It can --

DR. SIEBER: It gets corroded. It rusts through. The same way with the ductwork. It vibrates and --

DR. WALLIS: It's a humid -- It's a wet environment or something? Why does it corrode?

MR. BARTON: Environment. It's usually outside. Fans are usually outside.

DR. WALLIS: Oh, those kind of fans. Okay. So it's the weather that gets after them.

MR. BARTON; They are in the table. The fan housings are included in the table.

CHAIRMAN LEITCH: Okay. Any other questions for Carolyn?

DR. WALLIS: Well, I guess Carolyn is telling us that you reviewed these, and everything is fine.

MS. LAURON: Yes. There were no --

DR. WALLIS: Our job is to find out whether we believe you.

MS. LAURON: Right.

DR. WALLIS: So how can I ask a question that helps me. Well, maybe I can't. Maybe I just have to give up.

MR. BARTON; In the fire protection table, there are four sets of things listed, and some of them require aging management. Some don't. I can understand where some are in an air or gas environment but may not require aging management. There are other things in the table that are in an air environment that do have an aging management program.

So I don't understand the rationale here on the fire protection tanks.

MS. LAURON: Okay. For those tanks that are carbon steel and low alloy steel, those are given either -- They are coupled with fire protection program and the tank inspection activity. I believe the tank you are referring to is the stainless steel tank.

MR. BARTON: It's carbon steel, and that's in table 3.3.9.1 on page 3.2.3.3. of the LRA.

MS. LAURON: Is that North Anna or Surry?

MR. BARTON: North Anna Station, Units 1 and 2. Right. There are four sets of tanks listed, and they are all carbon steel and low alloy steel. Some of them in air and gas environment. So aging

effects requiring management are none. I guess I can understand that.

But there are other tanks in that column that are in an air environment that do have a loss of material concern and are under the program. I don't understand why. It's not consistent. For some in air environment, no program required. Some in air environment, a program is required. What's the difference?

MS. LAURON: The difference is the amount of humidity present in that air environment, and each of the environments have a --

MR. BARTON: E or I?

MS. LAURON: Superscript. There should be a superscript, a 1 or a 2, that is defined later. I'm looking at the Surry table, and mine has a 1 listed. It either talks about a moisture or an intermittent wet environment.

MR. BARTON: I don't see that. Okay. All right. Well, if that's the difference, I understand it.

CHAIRMAN LEITCH: Anything else on auxiliary systems? Okay, thank you, Carolyn.

MS. LAURON: thank you.

CHAIRMAN LEITCH: Okay, George, steam and

power conversion systems.

MR. BARTON: Make it quicker this time, George.

MR. GEORGIEV: My name is George Georgiev, and I was assigned to report the steam and power conversion systems.

Steam and power conversion systems for this application includes seven systems: Auxiliary steam; blowdown; condensate; feedwater; main steam; steam drains; and steam generator water treatment.

Aging effects that were identified with those systems were cracking of carbon steel, low alloy steel, stainless steel, in treated water and steam environment, cracking of nickel based alloy and copper alloys in air, loss of materials from carbon steel and low alloy steel in treated water materials.

The application proposes ten different aging management programs to manage the aging effects, and those ten aging management programs are augmented and services station activities; boric acid, corrosion surveillance program; chemistry control program for primary systems; chemistry control program for secondary systems; general condition monitoring activities; infrequently accessed area station activities; ISI program component; components of post-

inspection; secondary piping and component inspections, and that is the flaw accelerated production treatment for this plant; tank inspection activities; and the work control processes.

As you can see from this, some are newly identified problems, like the tank inspection activities earlier. There were some considerable discussion about the new problems.

We reviewed the problems and reviewed the aging management effects, and the materials basically are carbon steel and stainless steel, and you do have some nickel based alloys for the instrumentation end of it, like flaw monitors and some brass and copper alloys.

In our judgment, the aging management programs are adequate to manage the effects for the proposed extended period of time.

DR. WALLIS: Where do the steam drains com from?

MR. GEORGIEV: The steam drains. That's a system question. I would have to look it up. They are identified in the table 3.4.2 for steam drains, but basically it's only one item, pipe.

DR. WALLIS: Where does it come from? Where does it go to?

MR. GEORGIEV: I don't know, sir.

MR. CORBIN: They go to Con-C system or to condensers.

DR. WALLIS: Whenever you take steam out of somewhere and it condenses, you worry about water hammers. Do they have condensate traps and things like that?

MR. GEORGIEV: Yes,they do.

DR. WALLIS: And is there some way of monitoring whether or not there was a water hammer in this line?

MR. GEORGIEV: Well, they do have three problems listed to manage this piping --

DR. WALLIS; Well, I know. They always have management programs. Do they have some way of knowing whether these lines are subject to water hammer, and if water hammer occurred?

MR. CORBIN: The steam drains that are in the scope here have not been subject to water hammer. If you look for like main steam traps, those have been subject to water hammer but are not in the scope of license renewal. Okay? So here we go with the scoping question again. So we have to look where the boundary is drawn.

DR. WALLIS: But the trap is attached to

a drain? What is this main steam trap attached to?

MR. CORBIN: It's part of steam drains, if you will, but --

DR. WALLIS: So if there were water hammer, it would propagate up the drain from the trap?

MR. CORBIN: No, it would not reach the portion of the system. We have to look -- Steam drains is a huge system. It's all over everywhere. It's an octopus. We are only capturing certain pipe segments of the steam drain system in order to establish a boundary.

Now we are not particularly interested in the steam drain system as a system associated with the scope of licensing renewal.

DR. WALLIS: This boundary is because you have drawn a boundary -- because you've got some systems in it, which you know you have to worry about.

MR. CORBIN: Main steam.

DR. WALLIS: And this happens to be inside that boundary, just by chance?

MR. CORBIN: Correct. It's a pipe spool, but it doesn't reach to other portions of steam drains where we have had some experience with water hammer types of issues.

DR. SIEBER: I guess an example is that

you all have a pot and drain line and a trap with a valve on either end, maybe going to the condenser; and when you heat up a steam line, which is a sort of precarious situation, you use a bypass to emit a little bit of steam, which condenses, goes to the trap, and the trap, if it's a bucket trap, will dump into the condenser. And sometimes the water hammer or steam hammer occurs in the main line, sometimes in the drain.

If you would break them off, other than filling the room full of steam, it wouldn't make any difference to the safety of the plant.

DR. WALLIS: I guess I'm just being a naive observer and saying steam drains, aha, water hammer. All he's talked about is cracking, loss of material. Is someone worrying about other causes of damage?

MR. CORBIN: The other --

DR. WALLIS: Apparently, this isn't a concern because, for reasons I don't quite understand, the path where the water hammer might occur is outside the scope.

MR. CORBIN: Water hammer is an event, and as an event driven issue, it's not considered within the scope of license renewal. It may cause damage,

but it's a damage as a result of an event that occurs as opposed to damage as opposed to aging.

DR. WALLIS: But if you have lots of events over a period of time, that causes cumulative damage, which might be even in the scope of aging.

MR. CORBIN: It would be considered as part of the event. It's event driven.

DR. WALLIS: So this would be caught by you tracking down sort of the cause of the event and so on.

MR. CORBIN: That's correct.

DR. WALLIS: So it would be part of some program but not -- It wouldn't fall under the scope of license renewal.

MR. CORBIN: That's correct.

DR. WALLIS: Do you accept that that doesn't fall within the scope of license renewal?

MR. GEORGIEV: Well, our group does not review the scoping. We do the aging effect and materials of the construction and the aging management program for adequacy by identifying management defects.

What we did -- in this case, me -- I looked at the table. One pipe is identified. The external environment is air. The internal is steel.

Those are the problems. They have the aging material, loss of material because it's a carbon steel.

They identified three programs which are managing these aging effects. Water hammer is not listed there. So I assume that this portion of pipe is not an issue.

MS. COFFIN: If I could comment. I think the staff position on water hammer is that it is usually related to a design problem or an operational problem or both, which is not --

DR. WALLIS: It's a what problem? I'm sorry.

MS. COFFIN: A design problem, an operational problem, or both, some kind of configuration control problem. It's not an aging effect brought about in --We don't consider this an aging effect, and we expect the licensees -- Usually, if they have water hammer, want to take care of that issue right away, because it's pretty catastrophic.

DR. WALLIS: Although a succession of water hammers would presumably be an aging effect.

MS. COFFIN: If they decided to live with a system with water hammer, they would have to come in with an aging management program. I have not seen that yet.

DR. WALLIS: Okay. Thank you.

DR. RANSOM: I have a question. Your review reviews whether or not they have a program for aging management in these components, and then you say there are no open items. Does that mean that all of their aging management programs for these components are acceptable?

MR. GEORGIEV: That's what it means, yes.

DR. RANSOM: And satisfied the NRC licensing requirements?

MR. GEORGIEV: Satisfied the staff that they are adequate to manage those effects. That is correct.

DR. RANSOM: Could you give just a brief example on this accelerated corrosion? What does a program consist of?

MR. GEORGIEV: I know they have put a unique name on it. They don't call it flaws with corrosion, but in general terms after we put out the Generic Letter, each and every utility went and came up with a flaws assisted corrosion monitoring program.

We here in headquarters didn't review the program. The regions reviewed the programs for acceptability. and they are not comprehensive. They are going to look at the pipe configuration where they

would have valves, T's, elbows, and they don't look just at welds. They go and take a thickness checks periodically on certain occasions.

DR. RANSOM: What do they check?

MR. GEORGIEV: Well, they -- mainly thickness thinning.

DR. RANSOM: So they measure the thickness?

MR. GEORGIEV: The thickness, to monitor it this way.

DR. RANSOM: Periodically?

MR. GEORGIEV: Periodically.

DR. RANSOM: A couple of times a year?

MR. GEORGIEV: That's correct, and --

CHAIRMAN LEITCH: Do they use the CHECKMATE or CHECKWORKS program?

MR. GEORGIEV: They do. They do.

CHAIRMAN LEITCH: That prescribes the frequency.

MR. GEORGIEV: That prescribes the frequency. That looks in the design, kind of predicting which area you could expect problems and which you can't. Through the years, basically, you know, the experience shows that it's working. We haven't experienced or heard of problems.

DR. FORD: But you say you didn't check CHECKWORKS' validity.

MR. GEORGIEV: I myself, not. But we do have a reviewer who happens to be here, who makes a living out of that. He basically checks the CHECKWORKS. So if you have questions --

MR. PARCZEWSKI: My name is Kris Parczewski. I am in the Material and Chemical Engineering Branch. I understand the question is concerning the degradation due to corrosion problems.

In the steam system, main steam, of course, dry steam does not produce erosion corrosion. So there must be water, you see. All the systems which are prone to erosion corrosion usually should be in the program, erosion corrosion program, which includes prediction of the erosion corrosion and eventual measurement using UT.

So that in this way protects it, if they found, obviously, that they are that degraded, they have to either repair or replace.

DR. RANSOM: I assume it is kind of like the steam turbines that we saw at Watts Bar. You know, they suffer corrosion.

MR. PARCZEWSKI: They do, especially -- yes, extraction steam does that. They are two-phase.

It produces -- Yes, it produces high erosion corrosion degradation. So those lines pretty often have to be replaced.

Generally, they are replacing the -- in most cases, at least -- material which is prone to corrosion, you know, which has a little bit of crumb. You know, one percent of crumb is enough to make it minute on the corrosion.

DR. RANSOM: I guess the steam turbines are really not part of the aging management program, because they are active components, I guess, that are, in effect, repaired periodically.

MR. PARCZEWSKI: That's right.

MR. GEORGIEV: Yes. The turbines does need to be repaired periodically.

DR. ROSEN: So what is the experience at Surry and North Anna in terms of flow accelerated corrosion? I am, obviously, very sensitive to it, given the catastrophic event they had back in the Eighties where actually people were killed. Several people were killed.

DR. RANSOM: Were they the ones who had a steam line --

DR. ROSEN: They were the first place they were opened up, yes. So what's been the experience

since then in terms of managing flow accelerated corrosion?

MR. GEORGIEV: Well, we never heard of any other problems.

DR. ROSEN: There's no corrosion?

MR. GEORGIEV: No, they do. They do. What are the numbers in terms of thickness for certain lines, I can't tell you. For this, the licensee or the applicant has the data.

DR. FORD: I guess our question really is: Surry has had a problem, serious problem. The CHECKWORKS program from EPRI on the books is used to manage the problem. Our question is did you look at the validity of the CHECKWORKS program, i.e., observation versus theory, for Surry and North Anna?

MR. GEORGIEV: I did not.

MR. PARCZEWSKI: I would like to add that the program -- Usually, the programs for the plants are based on EPRI documents. They have a description. They follow pretty closely to this particular program, as described in the document.

DR. ROSEN: I know all about the program, and I know a lot of folks are -- CHECKWORKS. What I'm asking is: At Surry and North Anna, have they had significant flow accelerated corrosion in these

systems and, if so, where has it been?

MR. GEORGIEV: To the best of my knowledge, I don't know --

DR. ROSEN: To the best of your knowledge, you don't know of any?

MR. GEORGIEV: -- of any significant erosion corrosion at Surry or North Anna. But the applicant is here. Maybe they will add to that.

MR. CORBIN: I would add that, you know, we do run the CHECKWORKS program, and we know about the program. We do replace components every refueling outage. There are some number of components that we do discover that are not necessarily below min wall, but where we do not predict that they will go an additional cycle or two and, therefore, we replace those components.

DR. ROSEN: Which systems?

MR. CORBIN: Many of those systems, you would find it on feedwater condensate, extraction steam, which is not up there because it's not on the scope, but those would be the main systems where we would find evidence of flow accelerated corrosion that is causing us to replace components. We do replace components. It's a continuous program.

DR. WALLIS: I think the question that my

colleagues are asking is trying to determine how the NRC staff satisfied itself that these CHECKWORKS and whatever programs were adequate.

DR. KUO: When the program was introduced, we had all these things. Several plants -- I don't really believe Surry was one of them, but naturally, we found in most cases the programs were -- in a proper way. So we felt this is probably -- it's applicable to all the plants.

In addition, all the utilities belong to so called CHECKS program, which is sponsored by EPRI, and they exchange the information among themselves, operating experience.

DR. ROSEN: Well, now we are talking about aging of Surry and North Anna, and what we hear is that there has been lots of changeouts of piping due to flow accelerated corrosion. Can we see some data? How much? Where? Are we dong more and more of this or less and less?

I would think you would be doing less and less, because as a given location turns out to be prone to accelerated corrosion from flow that you would replace it with a material which has got a little chrome in it, and that would then thereafter not be a problem. So over time we would expect to see

this decrease, but there is no data. Data is good. Data might even tell us something.

MR. CORBIN: Our CHECKWORKS program does have all that data, and you're correct. We have a lot of our material with chrome and actually chrome moly material, which is material that is -- and even some stainless material that is less susceptible to erosion corrosion.

A lot of our major -- by major, our large pipe sizes, large bore piping we have replaced with enhanced materials. But we don't rest. It continues. We continue to protect and predict where we may have concerns, and continue to do inspections every outage to validate those concerns.

DR. FORD: That's great news. It's good. What's disturbing is that the NRC don't know that.

MR. CORBIN: In that regard, we do have regional inspections that come in and really evaluate our flow accelerated corrosion program periodically.

DR. ROSEN: Well, maybe when you come back, you can just provide a little data for us.

MR. CORBIN: Certainly.

MR. GEORGIEV: Yes. That data we also would like to see. But I would like to remind the members how it works. You do have a pipe component

that -- design rules. It requires certain wall thickness. So now you have this program which manages the thickness.

As you start approaching this minimum design, if you go below, you will be in noncompliance. You have to come to the Commission for relief. So, basically, there is a safe contained mechanism for us to ascertain --

DR. ROSEN: I am aware of that, George. What I am concerned about is, is the situation getting worse at Surry and North Anna or is it getting better? That is, flow accelerated corrosion corrective actions are precluding recurrence, and that as time goes on we can expect to see fewer and fewer cases of piping that needs replacement due to flow accelerated corrosion. It's a simple question.

MR. GEORGIEV: Acknowledged.

DR. WALLIS: That would really help the public, if the public could be told that, as a result of aging management, something is getting better. Things are getting better, because the impression is that as things get older, they get worse, and it isn't always the case.

MR. CORBIN: Well, we have agreed that we will provide facts. The facts are illuminating, and

I believe we've got that all collected. We'll get an opportunity to put it together. We will certainly submit it to you. I think the facts will tell the story.

MR. GEORGIEV: Well, for power uprates we are very -- you know -- demanding on this issue, because --

DR. ROSEN: Power uprates?

MR. GEORGIEV: For power uprates, yes, we do ask them a question, give us the numbers which are the most susceptible.

DR. WALLIS: We have seen them. We've seen some of dramatic numbers sometimes.

MR. GEORGIEV: For sometime, yes. I imagine that's where the question came from, but for license renewal we haven't really asked these details. Maybe we should.

DR. WALLIS: Well, but for power uprate the concern is that uprating the power you accelerate the rate of flow.

DR. FORD: On that issue, do either of these four -- or any of these four stations plan on going to power uprate?

MR. CORBIN: We are currently looking at the power uprates associated -- Appendix K type power

uprates. Yes.

DR. FORD: Will there be increased flow rates in some of these systems, presumably?

MR. CORBIN: Yes, there will.

DR. FORD: And they will be managed by CHECKWORKS?

MR. CORBIN: That's correct.

CHAIRMAN LEITCH: Okay. Anything else, George? Any other questions?

MR. GEORGIEV: No, sir.

CHAIRMAN LEITCH: Thank you.

MR. MUNSON: For the structures and components support components for the AMR, we contracted out to Brookhaven National Lab, and I was in charge of putting together their final submittal to us.

The components that the applicant did the AMR for were in containment, other structures, NSSS equipment supports, general structural supports, miscellaneous structural commodities, and load-handling cranes and devices.

In the application for the containment, the applicant identified aging effects for steel and elastomers. The applicant did not identify any applicable aging effects for containment concrete

components.

So the staff requested in an REI that the applicant commit to -- the applicant justify their not identifying aging effects for concrete components. So in their response to the staff REI,the applicant committed to managing aging effects for all accessible concrete structural components.

For below grade concrete, the applicant committed to monitoring the groundwater on an annual basis to check for chloride sulfates and pH during --

DR. WALLIS: Is that good enough? Aren't there seasonal variations in groundwater? If you always do it in December, you don't catch -- Maybe there aren't in this area.

MR. MUNSON: I think for the serious type of chemistry that we would expect to actually degrade concrete, I don't think seasonal variations would be significant enough in terms of affecting the pH, chlorides in sulfate.

DR. WALLIS: The salinity? You don't have the New England fall and the leaking of the salinity of the Connecticut River being in August, all the runoff from the salt deposit there on the roads. They are not getting that kind of seasonal variations in Virginia? You don't?

MR. MUNSON: I don't expect --

DR. WALLIS: Acid rain is more prevalent at certain seasons?

MR. MUNSON: And it also would have to get deep below grade. I mean to where these structures are.

DR. WALLIS: I think there might be seasonal variations in the groundwater.

MR. MUNSON: I can check on that.

For structures outside containment, the applicant identified aging effects for steel, concrete in soil and water, elastomers, and soil embankments. Once again, we asked them to justify not having aging effects for all accessible concrete components, and in their response they did commit to managing cracking, loss of material, and change of material properties for concrete components.

For the NSSS equipment supports, general structural supports, and miscellaneous structural commodities, and load-handling cranes and devices, our review -- or, actually, Brookhaven's review showed that the applicant AMR adequately identified the aging effects for each of these components in these structures and systems.

DR. SIEBER: Why isn't a crane considered

an active device?

MR. MUNSON: I think the crane itself -- It is the rails and --

DR. SIEBER: The rail and the hook?

MR. MUNSON: Yes. It's the support for the crane.

DR. SIEBER: I also recall for this class of plants that there was a question maybe 20 years ago about the strength of the bolts that hold the supports for the steam generators.

MR. MUNSON: We had several RAIs on that issue. The applicant has --

DR. SIEBER: So they are doing something special for that?

MR. MUNSON: Right. They have -- They are managing cracking and -- I think cracking and loss of materials -- is that correct? -- for the bolts, NSSS, and they are currently using a VT-3. Is that correct?

DR. SIEBER: Visual?

MR. MUNSON: Visual to identify the cracking. Initially, we felt that might not be adequate, a VT-3, to detect cracking.

DR. SIEBER: Well, the crack occurs in a place where you can't see it. You know, you have a stud coming up out of the floor through the foot of

the support, and you screw a nut down on top of it. The crack is going to be somewhere between the nut and the base mount. So I don't know -- I'm not sure how visual does much for you there.

DR. KUO: That would show up in the loss of loads. If there are cracks in the supports, that would show up in the loss of loads. The load bearing capacity will decrease.

DR. SIEBER: Well, everything in the support is under compression. So it's not going to change shape unless it gets some dynamic load like a blowdown, a LOCA or something like that. I'm not quite sure I understand.

DR. KUO: Because of the crack, the loads carried by the bolt would be less. It's getting loose.

DR. SIEBER: I'll have to think about that. If it's sitting there, it is not going to go anyplace. Does this include snubbers and struts and things like that?

DR. KUO: Scrubbers are active components. We only look at the supports.

DR. SIEBER: That's considered active? But a strut would not be an active component?

DR. KUO: The scrubber itself is active.

The strut, yes. The strut is passive.

DR. SIEBER: It's active?

DR. KUO: No, passive.

DR. SIEBER: Passive? All right. When they started taking out snubbers by seismic recalculation, they would replace some of them with struts. So I presume that the struts are in there.

MR. MUNSON: Are there any further questions on structures?

DR. WALLIS: I was wondering how Brookhaven determines that the AMR adequately identified -- Does Brookhaven make its own list and compare it or do they look at the list and check it off and say we couldn't think of anything else or how do they know that they adequately identified everything that matters?

MR. MUNSON: They use the GALL report for guidance.

DR. WALLIS: And how did the GALL report know? I know the GALL report is immense. This is a combination of everybody's knowledge about what matters in nuclear plants that you have to worry about?

MR. MUNSON: Right. The aging, right.

DR. WALLIS: So Brookhaven made a

comparison between the GALL report --

MR. MUNSON: And the application.

DR. WALLIS: Okay. Thank you.

CHAIRMAN LEITCH: Okay, thank you, Cliff.

MR. MUNSON: Thank you.

MR. LAZEVNICK: Good afternoon. I am Jim Lazevnick from the Electrical Instrumentation Branch of NRR, and I was the reviewer for the electrical and I&C components in the North Anna and Surry application.

CHAIRMAN LEITCH: Sir, could you use the microphone, please.

MR. LAZEVNICK: Yes. I am -- Can you hear me now? I am Jim Lazevnick from the Electrical Instrumentation and Control Branch, and I was the reviewer for the electrical and I&C components in the North Anna and Surry license renewal application.

There were relatively minor license renewal differences between the two plants. I have identified some of them here. The bus duct material: Aluminum bars were used at North Anna, copper bars at Surry; the service environments were slightly different at North Anna and Surry.

The underground cables were different. There was only one safety related cable at North Anna.

There was none at Surry, but there were additional outside power system cables, underground cables, at both plants.

Overhead bare distribution conductors: There was one at Surry. There was none indicated for North Anna.

These differences were all accounted for in the license renewal application and appropriately addressed.

In our review in our draft safety evaluation, we had a number of open items identified which we have more recently discussed with the applicant and have resolved in his draft responses.

The first item dealt with the plant system portion of the off-site power system. That was not originally included in the scope of license renewal.

CHAIRMAN LEITCH: You might want to change your -- Thank you.

MR. LAZEVNICK: Yes. That first open item there is the off-site power system. That was not originally included within the scope of license renewal. We identified a position, final position, in April, indicating that we believed the off-site power system should be included as a result of its reliance under the station blackout rule for recovery from a

station blackout event.

The applicant subsequently included the applicable portion of the off-site power system's structures and components within the scope of license renewal, and the appropriately identified the aging management programs that would have to be included with these structures, systems, and components.

CHAIRMAN LEITCH: Jim, how far out does that off-site power structure go, or how far out -- under boundary there?

DR. ROSEN: Let's have a look at the drawing. We offered the opportunity this morning.

MR. LAZEVNICK: Right. This is the one-line diagram for the Surry power station. What you see there, the lines -- the dotted lines indicate those portions of the electrical circuit that was brought into the scope under the off-site power system station blackout issue.

Basically, what it includes -- In this bottom portion here, we have some transfer buses that are connected to the safety-related buses. A portion of those were included under the original scope, because they dealt with the alternate AC power system portion of the station blackout event, which the licensee did include.

A portion of them were not included, because the were not utilized for that purpose, but they are utilized to bring in your off-site circuit. The circuits go up to the 34.5 KV bus located in the switchyard. So essentially everything between that 345 KV bus and those transfer buses and a portion of the transfer buses are included within the scope.

CHAIRMAN LEITCH: Is it 345 KV?

MR. LAZEVNICK: Yes.

DR. ROSEN; No. It's 34.5.

MR. LAZEVNICK: It's 34.5 KV.

DR. ROSEN: Now you say all the dotted stuff was not included before and is included now. Is that right?

MR. LAZEVNICK: That is correct.

DR. ROSEN: So starting up at the 34.5 bus, why don't you just track down and tell me what those components were?

MR. LAZEVNICK: Okay. Coming down through here, you have a disconnect switch for your circuit breaker. You have a 34.5 KV circuit breaker, another disconnect switch. You have the connections up here to the 34.5 KV bus. I believe those are primarily -- there's some copper or aluminum tubing associated with that.

From the 34.5 KV breaker, you come down to the station service transformers.

DR. ROSEN: Which had not previously been included, but now are? It's a little hard to tell whether those are dotted or not dotted.

MR. LAZEVNICK: Yes. Those are included, but -- They are included within the scope, but they essentially fall out, because they are considered -- Transformers are considered to be an active component. So they ultimately are not included in the scope.

This includes both Class 1-E as well as --

DR. ROSEN: It just sits there, Jack.

DR. SIEBER: It hums, though.

DR. ROSEN: It hums. Oh. Forgot about the hum. That's what makes it active. It sits and goes mmmmmm.

MR. LAZEVNICK: This was an issue addressed generically with the industry prior to license renewal, and this is applicable to all the designs. Transformers are not included, have been determined to be an active component and are not included within the scope of license renewal.

DR. ROSEN: How many cycles? If it's under 30 cycles, it wouldn't be active. Well, forget about it.

MR. LAZEVNICK: From the transformer we go down to the 4 KV circuit breaker and then connect to the transfer buses. So it's that portion of the circuit. The applicant identified various combinations of cabling, solid conductor and underground insulated conductor as portions of the off-site circuit.

DR. ROSEN: Now what about the supports for all of that stuff?

MR. LAZEVNICK: Those are all included. The supports, the structures included with that, cabinets, control wiring. There were about four or five pages of structures identified with that circuit.

MR. BARTON: How about the foundations?

MR. LAZEVNICK: Those were included. The licensee identified four or five pages of structures and included things like switchyard bus, disconnect switch, cross-arms, cable supports, switchyard breaker, circuit breaker supports, caulking and sealants, cable trenches, duct banks, control house slab on grade, control house masonry block walls, control panels, cabinets, control house structural steel, battery racks, manholes, cable pull boxes, electrical conduit, cable trays --

MR. BARTON; We get the picture.

MR. LAZEVNICK: Okay.

DR. ROSEN: I almost get the picture. What about batteries, switchyard batteries?

MR. LAZEVNICK: Battery racks are --

DR. ROSEN: Battery racks. You said that. What about batteries?

MR. LAZEVNICK: Battery racks are included. Batteries have been determined by the staff to be an active component.

DR. ROSEN: Oh, there's that hum.

DR. SIEBER: No, they don't have a hum.

DR. ROSEN: They don't hum. But there's something in the battery that moves?

DR. WALLIS: They pump electrons.

MR. LAZEVNICK: I'll just quickly show the North Anna design. Similar to the Surry design, there were some additional circuits included in that, that weren't included in the Surry design. Basically, it's the same effect there. The dotted lines indicate the portion of the off-site circuit that was scoped in that wasn't originally scoped in.

Again, it's the portion between the 34.5 KV switchyard bus and the transfer buses down in the plant, the 4 KV transfer buses in the plant.

CHAIRMAN LEITCH: Does the generator feed

onto the 34 KV bus? Where is the main generator?

MR. LAZEVNICK: No, it doesn't. The main generator -- Those are -- Yes, the main generator feeds through its own step-up transformer into the switchyard itself, which is rated at --

MR. CORBIN: 500 KV at North Anna.

MR. LAZEVNICK: 500 KV. Thank you. The drawing is extremely small. I can't read it. It generates essentially to the switchyard which is upstream in the 34.5 KV buses. there is another circuit from the 34.5 KV buses that take you through transformers and ultimately connect to the 500 KV switchyard, and it's at that point that the generator is powered.

CHAIRMAN LEITCH: Does the main generator have an auxiliary transformer or a station transformer.

MR. CORBIN: There are station service transformers. You can see in the bottom here, alternate here to normal Charley, alternate to normal Bravo, alternate normal Alpha. Those breakers on the other side of those breakers connect back to station service transformers.

CHAIRMAN LEITCH: Okay. Got you.

DR. SIEBER: You have a blackout diesel

there?

MR. LAZEVNICK; Yes.

DR. SIEBER: So you have five diesels, two per unit plus a blackout diesel?

MR. CORBIN: At North Anna. At Surry there are three diesels plus a blackout diesel.

DR. SIEBER: Okay. With a cross-connect. Right?

MR. LAZEVNICK: That's correct.

MR. CORBIN: That's correct.

DR. SIEBER: Is any part of the blackout diesel in scope?

MR. LAZEVNICK: Yes. The blackout diesels or the alternate AC sources, as we call them, are within scope, and the applicant included those --

DR. SIEBER: Just the switch gear and foundations and things, not the diesel itself?

MR. LAZEVNICK: That's true. That's true. Actually, the diesel itself isn't included, but all the structures and electrical components, cabling associated with that is included.

DR. ROSEN: Very good.

MR. LAZEVNICK: Are those the questions on the station blackout? Should I move on to the next open item here?

The next issue dealt with the disposition of low voltage, low signal level instrumentation circuits. We addressed those as a separate category from other circuits. The guidance in GALL indicates that calibration may be the best way to determine whether there is a problem in those particular circuits, and there has been an ongoing discussion between ourselves and the industry whether visual inspection of these kinds of circuits is sufficient or whether you should include calibration.

Previous applicants used the calibration approach, and that's the approach recommended in the GALL report.

With regard to the low voltage, low signal level instrumentation circuits, we agreed that those particular circuits probably would be acceptable candidates to use a visual inspection approach on, given that the disposition of those circuits, if you visually found some degradation, considered the potential for moisture in the area, the anomalies.

The philosophy there was some amount of cracking could be handled by a cable if it wasn't a dry environment and the cracks were filled with dry air. There was evidence in the literature to indicate that this was the case, but if indeed it was in a

moist environment and those cracks were filled with moist air, then you could get low insulation resistance level cracking and eventual breakdown of the cable.

DR. WALLIS: It becomes moist in a LOCA.

MR. LAZEVNICK: These -- Oh, excuse me. This review I'm speaking about is all non-EQ, all non-environmentally qualified cables. So we are not talking about cables that are in a LOCA environment. These cables are all essentially located in a mild environment.

What we are looking for in these programs are cables that are subject to localized adverse environments, essentially hot spots and the like. The licensee indicated that the general ambient for all these components was acceptable, but we indicated early on in our review that we felt he needed to address localized adverse environments. So these programs are aimed at cables in those kinds of environments.

DR. SIEBER: In general, would you say that low voltage signal cables use voltage levels as the medium, or current?

MR. LAZEVNICK: I think they -- We specifically didn't look at that, but generally they

will use a combination of one or the other, depending upon the transducer and the type of sensing system used.

DR. SIEBER: The current type are better when you consider cable degradation, you know, because the transmitter will continue to put out as much as it needs to, to overcome whatever resistance builds up. But the voltage type is more subject to air.

I think, in this class of plants, most of the transducers are the current types.

MR. CORBIN: We have a lot of 4-20 milliamp circuits.

DR. SIEBER: Yes, right. That's pretty typical for that area.

MR. LAZEVNICK: The next item was kind of a subset of the same category, and it dealt with whether the visual inspection approach was appropriate for high voltage neutron monitoring instrumentation cables and radiation monitor cables.

In looking at the literature on this that was developed for these aging management programs, we found that these cables were looked at separately in terms of the kinds of failures that they produce, because they typically -- the sensors themselves typically operate in the relatively high voltage

range, 1000 volts to 5000 volts.

We felt that these may not be good candidates for the visual inspection, because we felt that at these high voltages and very low signal levels, you could develop leakage currents through the insulation before you could actually see some visual evidence of it. The open item was to address this.

The applicant resolved this issue by essentially relying upon the calibration test, which is consistent with the guidance in the GALL report, to determine whether there -- The applicant utilized calibration tests essentially to determine -- in his aging management program to determine whether there would be any age related degradation of the circuits.

This was consistent with the guidance in the GALL report. So essentially we believe this will resolve that issue.

DR. RANSOM: What does the calibration consist of?

MR. LAZEVNICK: The calibration consists of typically a couple of things, a LOOP calibration as well as a sensor calibration or other --

DR. RANSOM: What do they measure in a calibration?

MR. LAZEVNICK: They are typically looking

at signal levels. They put in a dummy input and look at the signal level of the circuit to determine if, given the input put in, the output is essentially reading where they would expect it to read, and then they will calibrate that to make sure it does indeed do that.

DR. RANSOM: Are those more instrumentation cables you are talking about or what about a bus, for example?

MR. LAZEVNICK: No, no. This whole category is a subset of instrumentation circuits only, and specifically very low signal strength.

DR. RANSOM: Oh, I thought you were talking about like the main buses in the plant.

MR. LAZEVNICK: No, not this particular--

DR. SIEBER: High voltage through the wire.

MR. LAZEVNICK: Yes.

DR. RANSOM: Yes.

MR. LAZEVNICK: Right. Yes, that's perhaps where maybe I misled you. It's high voltage, but it's in an instrumentation circuit. It's kind of an oddball in that sense. It's not high voltage in the sense of a power circuit, but in this case the detectors -- the neutron monitor detectors do operate

at these high voltages.

DR. RANSOM: Oh, yes, I was thinking previously you were talking about the aluminum and copper buses through the plant. Now weren't those the main power buses?

MR. LAZEVNICK: Yes. Those buses are the transfer -- Those are bus ducts.

DR. RANSOM: You mentioned calibration with regard to, you know, the aging management of those components as well.

MR. LAZEVNICK: I didn't think --

DR. RANSOM: I thought.

MR. LAZEVNICK: I don't know how you calibrate that. No, I think I just indicated that these were some differences between the North Anna and Surry design. They are aluminum in one design, copper in the other design, and there were no aging management effects identified that needed to be managed for the extended term for these bus ducts.

DR. RANSOM: Are there no connectors or anything that would degrade with time?

DR. SIEBER: They are typically bolted together.

DR. RANSOM: They are bolted?

DR. SIEBER: Yes, they are.

DR. RANSOM: Well, don't they corrode?

DR. SIEBER: If they corrode, they fail, but you can pick that up with just in normal operation.

DR. RANSOM: But there is no specific program to watch for those sort of effects, I guess, huh?

DR. SIEBER: Some people do.

DR. RANSOM: Thermal vision kind of a program?

DR. SIEBER: They use that thing that looks like a rifle that reads the infrared.

MR. CORBIN: Thermal vision.

CHAIRMAN LEITCH: So you can see those hot spots.

MR. LAZEVNICK: The final open item that we identified in our draft safety evaluation record had to do with the periodic testing of inaccessible medium voltage cables exposed to significant voltage and moisture.

These are essentially underground cables that, if exposed to significant voltage and moisture, could be subject to a water training type of effect that, in the past, is found to cause failure of these particular kinds of circuits.

The issue we had there early on was the definition of, in particular, significant moisture. The guidance in the GALL report indicates that cables that are subject to moisture for more than a few days, for example, normal drain and rain conditions should be considered to be significant moisture.

Early on, we had a lot of discussions about whether they could be subject to moisture for longer periods of time. This item was eventually resolved. The licensee -- As part of that GALL program guidance, part of the prevent actions under the GALL program is to try to keep the moisture off the cables.

If the cables are not subject to moisture, then there are no problems associated with the particular water training effect. So one of the first things the GALL program looked at was, in terms of preventive actions, whether the cables are kept dry. If they are kept dry, then this is really not an issue.

That is primarily the approach the applicant is relying upon in his program. He has sump pumps. He has drains. He has periodic inspections to determine whether he finds any cables in standing water in the manholes and, if he does, he has

indicated as part of his program, if he did find cables in standing water that he determined were subject to moisture for more than a few days, then his disposition of those cables would include testing to determine the amount of degradation on the cables and to ultimately determine the disposition of the cables, whether they needed to be replaced or whether they just simply need to be monitored on a continuing basis.

That type of an approach is also consistent with the guidance under the GALL program, and that would resolve the staff's concern in this area.

DR. ROSEN: So what is the experience in terms of -- at North Anna and Surry, in terms of whether or not these cables in underground vaults, for example, have typically been exposed to standing water or not?

MR. LAZEVNICK: There have been problems identified in the past. The applicant indicated that he has corrected those problems. I think, in some cases, cables have been replaced, and he is now relying upon essentially a condition monitoring and the fixes made to the sump pumps, the drains, etcetera, to keep the cables dry. And if he

determines through his inspections that it is not doing that job, then they will be subject to the testing requirement.

DR. ROSEN: So there is some way that the staff will be able to keep track of whether or not these active components now -- the sump pumps and things like that -- are keeping the cable vaults dry enough so that you don't have to go into a testing program? I mean, because if they don't happen -- if that doesn't happen, then you trip into a testing program.

I'm trying to determine how you would know that the testing program is now required.

MR. LAZEVNICK: Well, the staff doesn't have an ongoing program. There potentially could be audits in the future. We are relying upon the applicant's aging management program. He has indicated in the aging management program that indeed the attributes under that program would indicate that they would be subject to the testing requirements, if they found cables that were exposed to some significant wetting.

CHAIRMAN LEITCH: Just to add to that, I guess, all of the aging management programs that we have will become part of the current licensing basis,

such we will need to maintain the programs and the program elements and the equipment associated with those program elements in a condition to satisfy the requirements of the program. So it will be auditable and inspectable and enforceable.

MR. LAZEVNICK: Is there any other question?

CHAIRMAN LEITCH: Okay, thank you, Jim.

There is no break called for here, but I think we could use one. Why don't we come back at about ten to four. A short break.

(Whereupon, the foregoing matter went off the record at 3:42 p.m. and went back on the record at 3:50 p.m.)

CHAIRMAN LEITCH: Back in session then, and we are on time limited aging analysis.

MR. FAIR: Good afternoon. I am John Fair with Mechanical Engineering Branch, and I have with me Meena Khanna from Materials Engineering, and we are going to go over the time limited aging analyses.

What I have got up here on the first slide is a listing of the time limited aging analysis, same one that the applicant showed earlier. I just want to make one comment on this list. This was the list that was identified by the applicant.

We asked one question on the identification of these time limited aging analyses relative to pipe break criteria, because at North Anna they had used fatigue usage as a criteria for postulating pipe breaks.

The applicant responded to that question by saying that the number of design cycles that they used in the original postulation of pipe break would not be exceeded during the period of extended operations. So we considered this an adequate TLAA, and do consider the pipe break criteria time limited aging analysis when it is based on fatigue usage.

What we are going to do with these is just cover the items that had open items associated with them and what the open items are, discuss what the open items are.

So the first one of these that had open items was the fatigue issue. There were two open items associated with fatigue. One of them involved the evaluation for environmental effects.

What we have done on all license renewal applications is ask applicants to evaluate a sample of components, evaluate it for fatigue for the effects of the new environmental data that wasn't considered in the original design.

The applicant did that evaluation. As part of their evaluation, they at first were intending to use some of the staff's study evaluations that we had done in NUREG-6260. We asked them questions on the applicability of those studies, because the particular items of interest, which were the safety injection and charging nozzles, we had done detailed, finite element analyses in our study analysis, and we wanted to make sure that they had the same type of geometries, etcetera, to make these analyses applicable to Surry and North Anna.

After several rounds of discussion, the applicant decided to go back and actually do detailed analyses for North Anna, because of the differences between their nozzles and the ones in our study NUREG, and they have submitted something later describing this analysis that is satisfactory to the staff.

DR. WALLIS: What kind of environmental fatigue are we talking about here?

MR. FAIR: Well, the effects of the reactor water environment and temperature on fatigue.

DR. WALLIS: It's a thermal fatigue?

MR. FAIR: It's thermal fatigue.

DR. WALLIS: Is it because there's cold water on one side nearby and there's hot water in the

loop?

MR. FAIR: No. This was a generic issue that had been identified a number of years ago. The original ASME code-designed fatigue curves were developed from specimen tests done in air -- in an air environment, and there were adjustment factors of 5 to those to account for the difference between specimen testing and actual components.

Later tests performed in reactor water environments done by the Japanese originally, a lot of the testing, and then later by Argonne National Lab found that maybe these adjustment factors weren't large enough to account for the decrease in fatigue life that you could get in reactor water environments.

So there have been a number of NUREG reports published giving some correlation factors based on the testing in reactor water environments, and the way this has been handled in reviewing these in license renewal is to take the original fatigue analysis and apply some adjustment factor derived from these later correlations, and see if you still have an acceptable usage.

DR. WALLIS: So why is there temperature fluctuation at these nozzles?

MR. FAIR: The transients that cause

fatigue are generally thermal shock type transients when you have a change in flow or something like that.

DR. WALLIS: So it's actually cold water flowing through the nozzle? Doesn't happen very often, does it?

MR. FAIR: It happens every time they get an injection event. I guess there's a number of events in charging systems that occur that give you these --

DR. WALLIS: Particularly charging, safety injection probably less, less frequently.

DR. SIEBER: Yes, pretty much so.

MR. FAIR: The only other open issue in this area was just an updated of the FSAR to describe this environmental evaluation, plus there was also an evaluation done for underclad cracking in which they took credit for a generic evaluation in the Westinghouse topical report.

The only issue was for the applicant to add that into their FSAR update that they were basing it on that topical report, and they agreed to do that.

DR. ROSEN: Before you go away too far from reactor vessel embrittlement, would you just cover it in a flash there?

MR. FAIR: I didn't, but all right.

DR. ROSEN: Earlier our Vice Chairman commented that the license renewal application simply says that there's been an evaluation done, and it will meet Appendix G, the vessel. So the comment was that's nice, but what kind of margin is that.

So have you looked at that?

MS. KHANNA: I'll try to address that. For the RTPTS, we did -- we ensured that they met the 50-61 criteria, and for upper shelf energy -- We don't have the values for RTPTS. I can ask the applicant to provide those values. We actually do not have the values for RTPTS. We do know that they are below -- they fall below the 50-61 screening criteria.

DR. ROSEN: How could you not have the -- How could you know that without having the values?

MS. KHANNA: Basically, like what George has said earlier, you know, that was done through the RCS review, and you know, it was --

DR. ROSEN: If somebody is supposed to meet 50 foot pounds, and you say they meet it, then I say, okay, well, how much was it. But you say we don't know the values. I don't --

MS. KHANNA: Okay. Well, for upper shelf energy for North Anna and Surry, the applicant projected the upper shelf energy using REG GUIDE 1.99

Rev 2. Okay? For North Anna, they found that the upper shelf energy was found above 50 foot pounds, which is in accordance with REG GUIDE 1.99 Rev 2.

DR. ROSEN: And it was?

MS. KHANNA: And that's found acceptable.

DR. ROSEN: And it was above 50 foot pounds, and its value was?

MS. COFFIN: We don't know the specific value. They meet the criteria that's in our regulations, which is to be above 50 foot pounds.

DR. WALLIS: Now this is equivocation, isn't it? What's the real answer?

MS. KHANNA: We don't have-- The real answer is we do not have the values.

DR. WALLIS: So someone told you it's above?

MS. KHANNA: Right, and they used -- What we are doing is we are evaluating it against the criteria of REG GUIDE 1.99 Rev 2, and for Surry it was found to be below, and they used the equivalent margin analyses, which is found acceptable to the code.

Now if we need values, we can get them for you through the applicant. We have already spoken to them and asked them for the values, but they were not asked for previously.

DR. ROSEN: So you accepted their assertion that it was okay?

MS. KHANNA: Yes. The staff did.

MS. COFFIN: If they say under oath and affirmation that they meet our regulations, yes, we agree. We also know there are plants where -- I mean, they cite the right process. We've reviewed the methodology.

There are plants that we pay particular attention to, because we know there are plants that have -- you know, Calvert or Oconee or Palisades, we know they have embrittlement issues, and that's a plant that we might dig a little deeper and ask for a lot more detail and do confirmatory calculations. Do we do it in every case? No.

DR. FORD: But, for instance, Oconee, the RTPTS value is not that high toward the screening value. Whereas, at Surry they are 20 degrees away from the screening criteria for axial cracks, and so here's a situation where the margin, if you like, between the RTPTS value is not that much below the screening criteria for 40 years.

So the question that we are asking is have you done the checking to make sure that, when they say they are all right for 60 years, the values are

reasonable defensible calculations? That's what we are asking.

MS. KHANNA: I understand what you are asking, and that would have been done through the RCS. It was not done, because they did not feel the need to do it. You know, we accepted their word.

DR. WALLIS: Well, I guess the message is that, when you come back, we'd like to see the real numbers.

MS. KHANNA: Okay. That's fine.

DR. ROSEN: For the Appendix G upper shelf entity -- Be sure you know what we are asking -- for all four plants, and the RTPTS value, ductility transition temperature for all four plants. Right, Peter?

DR. FORD: Yes. They are still below the screening criteria at 60 years, and especially for Surry.

DR. SIEBER: At what point do you want this? At what point in time? Sixty years, 40 years?

DR. ROSEN: Sixty years. I mean, that's what they are asking for a license.

DR. WALLIS: If they are close to the criteria, maybe you should let us know how uncertain their predictions are, and what sort of errors you

expect in their prediction.

MS. KHANNA: Okay.

MR. CORBIN: We'll certainly support that effort.

DR. WALLIS: I'm not sure that the fluence is that well calculated, for example. Seems to vary, depending upon the method used, and we get people who say, ah, we've now got a new method for calculating flence, and it's gone down, you know. So that indicates that there is some uncertainty in calculating it.

DR. ROSEN: Well, you know, that's reasonable. I mean, if it doesn't matter -- I mean, if you are so away from the screening criteria --

DR. WALLIS: But they are so far away.

DR. ROSEN: -- then you can do some sort of conservative analysis. But if you are close, yes, you have to do a better job, and there are ways to do a better job.

MR. ELLIOT: This is Barry Elliot. I just want to separate out the two issues first off, the upper shelf energy and the PTS issue. I want to explain to you how we do an evaluation of upper shelf energy.

If a plant is below -- It uses a REG GUIDE

1.99 to determine whether or not they are above and below 50 foot pounds. It's only a screening criteria. If you go below the 50 foot pounds -- We didn't require the applicant to do what's called an equivalent margin analysis. We have generic -- receive generic evaluations from the industry of, if you go certain distance, certain foot pounds below the upper shelf energy, certain foot pound energy.

They have done the analysis generically for all plants, and we know that, as long as you stay above those upper shelf energy evaluations, then you meet the equivalent margin analysis. This plant has done that. They have demonstrated that, and that's all we need to know, as far as the upper shelf energy.

Now as far as the PTS is concerned, I agree. We should have RT. We should have specific values, but I think in this case you are going to see that -- I don't remember this as being one of the plants that's near the screening criteria, but we'll check that and give you that answer. But as far as the upper shelf energy, it is only a screening process which leads to equivalent margin analysis, which then leads to evaluation with respect to generic evaluations, which they have already done.

DR. FORD: And I think Surry is one of

those plants which is not that far off for axial cracks for the screening criteria at 40 years.

MR. CORBIN: Unfortunately, I wish I had a table of all of the information that's just been requested, because it does exist.

DR. FORD: Oh, it does. I've got it here.

MR. CORBIN: But we don't have --

DR. FORD: Surry is 245.

MR. CORBIN: Right. We don't have all of the answers with us here today. I'm not sure the 245 is a 60-year value, though, right?

DR. ROSEN: These are the kind of answers that seems like you ought to just -- All plants all to come in and tell us those answers, so we can build a table up, and we would know what it is we were recommending to the Commission that they approve.

Maybe the staff knows, but we're just dealing with -- Unless we have that, we're just saying, well, the staff told us it's okay. So we said it's okay. If that's what the Commission wants, they want to know whether the staff told us it's okay, that's one thing. But I think they really want more than that.

The Commission wants to know what we think, and unless we have data, we don't think

anything other than what we are told. It's sort of a trivial answer to say we were told this to the Commission.

CHAIRMAN LEITCH: Well, this whole issue is discussed on page 4-4 through about 4-7 of the application, and I guess there are three pieces of information. I'm not sure whether you are saying that we are not going to get the first piece. One is the upper shelf energy. Two is the pressurized thermal shock. Three is the pressure temperature limits.

MR. ELLIOT: I think the applicant in this case has said that they aren't going to give you pressure temperature limits until they need them. What happens is the tech specs --

CHAIRMAN LEITCH: That's true. That's what they did say, yes.

MR. ELLIOT: The tech specs -- We have tech specs for pressure temperature limits, and the tech specs are based upon criteria and methodology which are in the regulations, Appendix G.

What they have said is they will meet the tech specs for how long the current pressure temperature limits are. I'm not sure how long they are, but they update them periodically, and that they will give us before they enter the license renewal

period pressure temperature limits that are applicable for the license renewal period.

That's how we handle tech specs. When the existing tech specs run out, you put new tech specs in and upgrade them, and this is consistent with how we've always done business with tech specs.

CHAIRMAN LEITCH: Okay.

DR. ROSEN: I didn't ask about that.

MR. ELLIOT: Okay. I'm just explaining --

DR. ROSEN: You understand I didn't ask about that.

MR. ELLIOT: I understand you. You want upper shelf energy and pressurized thermal shock.

DR. ROSEN: Right.

MR. CORBIN: We will be happy to provide the information and get that out in front of everyone.

MR. ROSEN: Good. Simple.

MR. FAIR: The next area of the time limited aging analysis we had open items regarding was the containment liner plate analysis, and this is a relatively simple issue.

In the evaluation of this, they did a simple extrapolation of the number of cycles by a factor of 1.5 and specified the number of cycles in the license renewal application.

When we went back and checked the FSARs of the Surry and the North Anna facilities, we found the number of cycles in the Surry facility, but we couldn't find the reference to that number of cycles in the North Anna facility. So what we did was ask them to clarify that as part of the open item, and also to be specific in the FSAR update as to the number of cycles used in the design.

The applicant has come back and said that there was a little confusion in the North Anna FSAR which they intend to update and correct, and that they had done -- for both facilities they had used the same number of conservative cycles and, therefore, their extrapolation for the time limited aging analysis was also a conservative extrapolation.

MS. KHANNA: Okay. 4.7.3 is leak before break. We didn't have any open items. However, there was an item of interest which we have discussed before, which was the summer main coolant loop weld cracking event involving Alloy 82/182 weld material.

Basically, now we -- You know, we've made a note to ourselves that we will always consider the effect of primary water stress corrosion cracking, and we will address it in the SERs for all future leak before break evaluations for license renewal.

I can tell you that for Surry, we noted that they do not have any welds made of Alloy 82/182 material. So this was not a concern. However, for North Anna they do have steam generator primary nozzles to safe end welds in the primary loop piping.

What they have done is they have committed to follow any industry/NRC initiatives, and that will also be done through the MRP. What we have asked them to do and what they have agreed to do is track those through the FSAR Supplement. So they have made a note in their FSAR Supplement, and we will check that through that supplement for North Anna.

CHAIRMAN LEITCH: Okay. Any other comments?

MR. FAIR: That was it. That's the open items.

DR. WALLIS: This MRP gets referred to so often that I hope that they come up with really good results from their studies and recommendations.

CHAIRMAN LEITCH: Okay. Thank you all. I think at this time then we are scheduled to go into a Subcommittee discussion unless there are some other general comments.

I think the status of the SER at the moment is that the SER will be revised, closing these

open items and some other changes to the SER. We need that about a month before we have our full Committee meeting on this topic.

We had hoped that that may occur -- that we may get that by August, mid-August, which would allow us to have a committee -- just sit down with this on the full Committee agenda for September.

It's now not 100 percent clear that we will have that by mid-August. It may slip a little bit. So exactly when this full Committee meeting on this topic will come up is a little unclear. It may still be September. It could be October. We will just have to see how that develops.

I guess I've polled the members who have had to leave for one reason or another, and none of them saw any reason for an interim letter on this topic. I guess I would like to go around the room and ask the members if they see any reason for an interim letter.

Assuming there is not then, I guess what we need to do is to just summarize and clarify the main points that we want to hear about when we come back with the full Committee meeting. In other words, what are those major open items that are still in your mind with respect to the full Committee meeting.

DR. WALLIS: I don't think we need an interim letter, if that is the question.

CHAIRMAN LEITCH: And are there issues --

DR. WALLIS: Do we want to be on the record with all our comments? Should we be on the record or off the record? What's the situation now?

CHAIRMAN LEITCH: I'm not sure what the protocol is.

We don't need this on the record. So we are done with the transcription then.

(Whereupon, the foregoing matter went off the record at 4:12 p.m.)

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