Official Transcript of Proceedings ACRS T-3146

NUCLEAR REGULATORY COMMISSION

ORIGINAL

Title: Advisory Committee on Reactor Safeguards
Plant License Renewal Subcommittee

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

Docket Number: (not applicable)

Location: Rockville, Maryland

Date: Thursday, February 22, 2001

Work Order No.: NRC-081 Pages 1-177

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

TR04

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

+ + + + +

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

PLANT LICENSE RENEWAL SUBCOMMITTEE

+ + + + +

ARKANSAS NUCLEAR ONE, UNIT 1

LICENSE RENEWAL APPLICATION

+ + + + +

THURSDAY,

FEBRUARY 22, 2001

+ + + + +

ROCKVILLE, MARYLAND

+ + + + +

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

COMMITTEE MEMBERS:

MARIO V. BONACA, Chairman

GEORGE APOSTOLAKIS

THOMAS S. KRESS

WILLIAM J. SHACK

ROBERT E. UHRIG

NRC STAFF:

H. ASHER

R. AULUDE

LEE BANIC

W. BATEMAN

W. BURTON

JIM DAVIS

T. EATON

BARRY ELLIOT

J. FAIR

Z. BART FU

GEORGE GEORGIEV

CHRIS GRIMES

GREGG GULLETTI

M. HARTZMAN

STEVE HOFFMAN

A. KEIM

THOMAS KENYON

C. LAURON

ANDREA LEE

S.K. MITRA

A. PAL

K. PARCZESKI

ROBERT J. PRATO

J.H. RAVAL

NRC STAFF: (CONT.)

J. RAJAN

OMID TABATABAI

CHANG-YANG LI

Y.C. (RENEE) LI

OTHERS PRESENT:

RAYMOND BAKER, Southern Nuclear

RICK BUCKLEY, Entergy

RICHARD HARRIS, Entergy

NATALIE MOSHER, Entergy

JEFF RICHARDSON, Entergy

MARK RINCKEL, Framatome

CHARLES WILLBANKS, Scientech

GARY YOUNG, Entergy

I-N-D-E-X

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

(8:30 a.m.)

DR. BONACA: The meeting will now come to order. This is a meeting of the ACRS Subcommittee on Plant License Renewal. I am Mario Bonaca, Chairman of the Subcommittee. ACRS members in attendance are George Apostolakis, Thomas Kress, William Shack, and Robert Uhrig.

The purpose of this meeting is to discuss the license renewal application for the Arkansas Nuclear One, Unit 1, and the associated NRC staff's draft Safety Evaluation Report. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for the liberation by the full Committee. Sam Duraiswamy is the Cognizant ACRS Staff Engineer for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting, previously published in the Federal Register on January 29, 2001. A transcript of the meeting is being kept and will be made available as stated in the Federal Register Notice. It is requested that the speakers first identify themselves and speak with sufficient clarity and volume so that

they can be readily heard.

We have received no written comments or requests for time to make oral statements from members of the public regarding today's meeting. We will now proceed with the meeting and I call upon Mr. Chris Grimes, of the NRR, to begin.

MR. GRIMES: Thank you, Dr. Bonaca. I am Chris Grimes, Chief of the License Renewal and Standardization Branch, and we're here today to present the results of this staff's safety evaluation with open items for the review of the license renewal application for Arkansas Nuclear One, Unit 1.

As you may recall, this is a B&W unit, and our review followed very closely the Oconee license renewal application. And in order to make this most useful for you, the staff's presentation has been organized to highlight differences and uniqueness of this review over other license renewal reviews that we've presented to you, in order to focus on what was special about Arkansas Nuclear One in terms of the conduct of this staff's review.

I would like to introduce Robert Prato, who is the license renewal project manager for the ANO-1 license renewal review. And he'll go over the license renewal application and the main part of the

presentation. And then we have other staff members who will cover other topics in our agenda today.

As the Subcommittee, or the full Committee, I can't recall now which, as you requested, we've also arranged to present a brief overview of the environmental review, in order to familiarize you with the parallel activity that the staff had ongoing related to the review of the environmental report and the preparation of the supplement to the generic environmental impact statement. And that's arranged later in the agenda.

Unless there are any questions that you have for me, I'll turn it over to Bob Prato, and we'll get started with the presentation.

DR. BONACA: We can start.

MR. PRATO: Thank you. Good morning. Again, my name is Bob Prato. I'm the -- should I go ahead? I'm the Project Manager for Arkansas Nuclear One License Renewal Application. On slide two is a listing of the topics, and the presenters of those topics.

Now, I'll begin with the overview. On slide -- we'll start on slide three if we could, please. Unit description: ANO-1 is a two-unit site consisting of a Babcock and Wilcox pressurized water

reactor and a combustion engineering pressurized water reactor located in Pope County in central Arkansas on Lake Dardanelle.

Lake Dardanelle is a man-made lake. It was constructed around 1960, in the very early '60s. On February 1, 2000, the applicant, Entergy Incorporated, submitted a license renewal application for ANO-1, Arkansas Nuclear One, Unit 1, the 2,568 megawatt thermal Babcock and Wilcox pressurized water reactor.

Unit 1 construction began in 1968 and went commercial in 1974. The current facility operating license expires in May of 2014. This facility is similar to ONS in the interpless design aspects. Comparing ANO-1 site with the Oconee nuclear facility, Oconee nuclear site is a three-unit site.

It has a stand by shut down facility, which is not only a difference between Oconee and ANO, but it's unique to the industry. And Oconee uses a keowee hydroelectric dam to provide emergency power, which again, is unique to that site.

The difference between ANO-1 and Oconee is ANO-1 has an emergency cooling pond as an alternate ultimate heat sink. With respect to the applications, you need to understand that Oconee submitted its

application prior -- or developed this application prior to issuance of the standard review plan.

As a result, their outline was considerably different than was anticipated in the standard review plan. The outline for the Oconee SER application was -- Chapter 1 was the introduction. Chapter 2 was scoping. Chapter 3 was aging effects. Chapter 4 was age of management programs. And Chapter 5 was time limited aging analysis.

The ANO-1 application was more consistent with the SRP, where we had Chapter 1 was the introduction. Chapter 2 was scoping, and Chapter 3 was the aging management review, which is combined Chapter 3 and 4 putting in the Oconee application. Chapter 4 was also a TLA.

As far as the safety evaluation reports, the SER was out in time for the staff to develop the SER for Oconee consistent with the SRP. And therefore, both applications are very similar. There is a couple of extra chapters in the Oconee application.

I believe it's Chapter 2 is -- I'm sorry -- Chapter 2 is aging effects from mechanical systems, and I believe Chapter 3 is containment. They separated out containment from the rest of the

structures. The ANO application, a safety evaluation, starts with an introduction, goes to scoping, goes to aging management review, and goes to time limit aging analysis.

There is a unique feature about the ANO application, the Chapter 3, is what they call the mechanical tools. This chapter is what they use to develop the aging effects for mechanical components. This -- understanding that this is a separate focus of the applicants will help us later on in presentation.

What we did to try and provide you a comparison of the two applications was we took the open items from Oconee and ANO, and we identified the differences in the application for those items. So we're going to begin with scoping.

ANO-1 safety-related criteria is based on the more current definition consistent with 10 CFR 54.4(a)(1) and (a)(2). That is that the safety-related criteria is based on the safety-related criteria and a non-safety-related criteria for scoping for license renewal.

Oconee's safety-related criteria was considerably different. Their definition was based on very deficient products, and that caused some contrast between what the staff was used to and the rule

itself. And we spent quite a bit of time trying to rectify the differences in ensuring that the scope was complete for Oconee.

We did not have that difficulty for ANO. We'll begin the presentation on the scoping methodology here a little bit later. ANO-1 spent fuel pool cooling was not included within the scope of license renewal. This was consistent with the Oconee conclusion that the -- Oconee's recirculating cooling water system was not required because the spent fuel pools are similar designs. Neither one were required for being within the scope of license renewal.

ANO-1 chilled water was not excluded from --

DR. BONACA: Excuse me.

MR. PRATO: Yes, sir.

DR. BONACA: But Oconee had an emergency make-up to the pool that is a part of the aging management programs. And I believe, also, Arkansas has an emergency make-up capability, right, to serve this water.

MR. PRATO: Yes, sir. And both of them are required to keep their fuel full, and rather than requiring emergency cooling, it's just required to keep the materials in the fuel -- spent fuel pool covered.

DR. BONACA: Yes. And you tell us also about the liner, because there is a one --

MR. PRATO: We will cover that a little bit later as well when we get down into the specifics.

DR. BONACA: Yes. Was the Oconee application -- did it include the liner as part of the components under -- in the scoping?

MR. PRATO: Yes, sir.

DR. BONACA: Okay.

MR. PRATO: Yes, sir.

DR. BONACA: Do you also want to discuss the boron flux issue?

MR. PRATO: Yes, we will. We will. We will get to that as well.

ANO-1 passive long-lived skidman equipment were not excluded from an aging management review and the license renewal application. ANO-1 structural sealant, water stops and expansion joints were not excluded from an aging management review as well in the license renewal application.

DR. BONACA: The chilled water system. You didn't -- I interrupted you at that point.

MR. PRATO: Yes, sir.

DR. BONACA: Did you have any comment on that one? You have a bullet here.

MR. PRATO: I thought I added that. It was included within the scope of the license renewal in the application. You'll find out as we go through this presentation that ANO took considerable advantage of the lessons learned from Oconee.

And a lot of what issues were raised during Oconee, the great majority of them were resolved right in the application. And that's really the theme that we're trying to bring out here, is a lot of what we identified early on for Oconee was resolved.

DR. BONACA: Among the comparisons here, I would like to talk about also the reactor vessel level measurement system.

MR. PRATO: Okay. I'm not sure we were prepared to go into detail on that, but if you'd like --

DR. BONACA: Well, I would like to hear about that. I understand it's been excluded from the scope --

MR. PRATO: Yes.

DR. BONACA: -- of the application. And I can't remember if we excluded it for Oconee too. It probably was excluded.

MR. PRATO: It's just one of the measuring

devices. I don't believe that all of them were excluded. They have --

DR. BONACA: When you go through the scoping, it will be interesting to understand the logic for excluding the reactor vessel level measurement system.

MR. PRATO: Okay. And we'll try to prepare for that. I'll go back. I believe that presentation is probably scheduled for after lunch.

DR. BONACA: Okay.

MR. PRATO: The applicant is going to be here as well, and you may be able to get the details if you need, as well, from them.

DR. BONACA: Good.

MR. PRATO: Structural sealants, water stops and expansion joints were included. Electric cables were not excluded from this scope. They were included and required an aging management review for Arkansas Nuclear One.

Initially, in the application there were some contradicting statements with respect to Lake Dardanelle and the Turbine Building, and as to whether or not they were included within the scope. Those were straightened out in the RAI process, and it was straightened out prior to issuing the SER.

ANO-1 ventilation sealants were also included within the scope, and an aging management review was performed on those. ANO fire detector cables were also included. ANO aging effects discussed and accepted by the staff were consistent -- were consistently applied throughout the application.

This is where that Appendix C came into play. Because they had tools and they applied those tools consistently across all their systems, they didn't have the problems that arose in the Oconee application with applying aging effects consistently across the different systems.

ANO-1 buried pipe were included within a scope, and an aging management review was performed in the license renewal application. And ANO-1 committed to 10 CFR Part 50, Appendix B, for corrective actions, confirmation, processes, and document control activities were both safety-related and non-safety-related.

Oconee had only committed it for safety-related, and they applied different techniques to resolve those for non-safety-related. ONS just committed to Appendix B for all components within the scope of license renewal.

MR. GRIMES: Excuse me, Bob, are you on

slide six?

MR. PRATO: Yes, I am.

MR. GRIMES: Is slide six up? Thank you.

MR. PRATO: The last two items on that page are the two items that are open items for ANO-1 with respect to scoping. The staff identified in the FSAR that one of the full control offices was required to control the injection of sodium hydroxide for pH control.

The applicant included that orifice within the scope of license renewal, but solely for pressure boundary. And the staff requested that they justify excluding it for full control. The other item, which is the item that right now is the center of our focus for proceeding with the -- final safety evaluation -- is the fire protection system.

ANO-1 was built prior to 1968. They were not subject to all of Appendix R, just the three subsections they were back fitted to. They, at that time, they were not submitting specific components for fire protection. They were doing it in general terms. The staff were reviewing them in general terms.

There was some confusion as to whether or not they were ever within the applicant's CLB. In the mid-'80s, they did a design basis reconstitution to

convert their safety-related definition from Fischen product barriers to event medication. And when they went through that process, they identified all the components on site.

And then they made a determination whether it was safety related, whether it was required for fire protection, ATWS, et cetera. When they were done with that evaluation, they had what is known as the ref list, which is the fire protection list.

And there were a number of components that were not included on that list that the staff feels should be included. And we're in the process of evaluating whether or not those components need to be added to their current licensing basis. If it is decided that it needs to be added, they are going to be required to submit an aging management review on those components.

The components in question is the fire protection jockey pump. The carbon dioxide system, fire hydrants, the water supply to the low level rad waste building fire protection system, and the piping to the manual hose stations -- are they components that are within question.

There will be a staff meeting on that. Right now, we're trying to figure out a final date for

that meeting. It's going to be a public meeting. It's currently scheduled for the 7th. There are some scheduling conflicts, and we're trying to work those out as well.

MR. SHACK: Does this report sort of follow the NEI suggested format? That is, is this close to a template for what we expect future license renewal applications to look like?

MR. PRATO: Their application did basically follow the NEI template. They did something unique. They incorporated a lot of tables. And the staff had mixed feelings about that. Having the tables were really helpful. It had a lot of compact information that sat in front of you and it helped you do your evaluation a lot quicker.

However, it being in table form, did raise some questions on the details. And we had approximately 250 REIs as a result of the application review, which is less than our predecessors. However, if you take a look at them, about 90, 95 percent were questions on details that the information really was contained in the tables, but it wasn't clear.

The staff is not discouraging the use of the tables. We're trying to get a balance between the tables and the detailed information that we need

writing the application.

DR. BONACA: I didn't see any, you know, extensive reference to the GALL2 report. Was it just because of timing, the GALL2 came after the application was essentially submitted, or was it just because the GALL would be mostly referenced by the SER?

MR. PRATO: The GALL hadn't been issued during the development stage. They followed a lot of it, and the staff requested a lot of information. And the applicant made a lot of adjustments to be more consistent with GALL.

DR. BONACA: Okay. So they played the role, although maybe less a role just because of the timing.

MR. PRATO: I believe it played a role for the applicant as well as the staff.

DR. BONACA: Okay.

DR. SHACK: Well, the B&W topical reports also had a tremendous impact, just to cover huge chunks of stuff --

MR. PRATO: And that's another difference between Oconee and ANO. A couple of the topical reports were not issued when ANO were developing their application. And that generated a lot of open items.

And a lot of those open items were just not applicable to Arkansas because they had incorporated the requirements in those topical reports.

DR. SHACK: One other general comment, just as you're coming up on the aging management review, I didn't see really do a -- I didn't see nearly as many one-time inspections. Is that correct, or am I just -- that there's not a call out as one-time inspections as there were for Calvert Cliffs or Oconee?

MR. PRATO: There were a couple one-time inspections, but I think you're right, because I've worked both on Calvert and Oconee's.

DR. SHACK: Plus, there were like 30 of them or something.

MR. PRATO: Yes, yes, sir. And a lot of those were as a result of open items, and it was a resolution to a lot of the open items. I'm not sure why there aren't as many as at ANO, but I believe the reason is is because they were aware of the fact that they were open items.

And instead of trying to address the resolution of the open items, I believe the applicant tried to address the issue itself. And as a result, some of those one-time inspections just materialized.

DR. BONACA: But you performed a comparison with the previous applications to make sure that of one of the reasons a one-time inspection is because there is a different commitment that fulfills the need anyway.

MR. PRATO: We did not do a specific evaluation to verify that itself. I think we did -- and I think a large part of that is because we had different reviewers. Again, another unique about Arkansas is that a lot of the review is done by laboratories.

We had staff personnel overseeing it, making sure it was complete, making sure that it was consistent, that we weren't recreating the will, if you will, for Arkansas. But I think as -- because we got different reviews involved, there wasn't that focus.

Another thing is I don't think the staff wholesale accepts one-time inspections. We, in general, request them to justify the use of that if that's what they want to use. It has to make sense, and it's the applicant's responsibility to provide a justification for that.

DR. BONACA: But as you go forth, I mean I imagine that although you have different reviewers,

you will want to capture lessons learned from individual -- this, by the way, is one of the reasons why we have a presentation that we discuss with Mr. Grimes, which includes some comparison.

Because we are trying ourselves, as a committee, to gain from previous experience.

MR. PRATO: Don't misunderstand me. There's a big effort and a lot of focus on lessons learned between plants. And not only with the staff itself, but with the industry.

The industry meets quite often internally to themselves, and talk about what they've learned and where the problems are, and why is it a problem here and it wasn't in another place, and what is a good solution for it? And a lot of that work is going into GALL, I believe.

MR. GRIMES: As a matter of fact, I wanted to point out that I think that you say fewer one-time inspections here, primarily, because some of the uncertainty associated with the treatment of potential aging effects in Calvert Cliffs and Oconee has been resolved in the work on GALL, that has either determined where there is no need to verify the existence of an aging effect, or the effectiveness of a program.

And I think also my sense was, as we were going through the review of the Arkansas safety evaluation, I got the sense that Entergy put more reliance on existing programs and periodic inspections to determine the existence of aging effects, where Calvert Cliffs and Oconee look more to the one-time inspection to check for the existence of aging effects.

DR. SHACK: I notice they even opted for a periodic pressurizer cladding inspection, whereas you accepted a one-time inspection and a topical report, which struck me as a considerable improvement.

MR. PRATO: Yes, well -- and we thought so, too.

DR. BONACA: Yes, at some point, Appendix B on the application has at least seven -- I believe seven new problems. Among those are a couple of one-time inspections. And at some point, we will get an overview of those programs?

MR. PRATO: Not as a separate presentation. But if you'd like, I'll be glad to propose one.

DR. BONACA: No, you don't have to, but as long as we get it sometime today from the licensee or from you.

MR. PRATO: Okay. We'll do what we can.

DR. BONACA: Well, I mean, some of them I'm sure you're going to go through, because --

MR. PRATO: Absolutely.

DR. BONACA: So there might be a couple extra, but I would like to review them a little bit to understand.

MR. PRATO: There are a number of them that are common aging management programs, which we're going to cover that as a separate entity as well. So you'll get most of them. We weren't prepared to do those by themselves, and I'm not sure if the applicant is prepared to do that.

But if there are any --

DR. BONACA: Well, we just have a few questions. I'm sure you are cognizant enough to provide some answers.

MR. PRATO: Yes, sir. As for aging management, the plant differences ANO-1 did not exclude the heat transfer as an applicable intended function for heat exchangers. And they use performance monitoring consistent with generic letter 8913 to manage the following itself -- 8913 is the service water generic letter.

ANO-1 performed an aging management review

of all the piping in the service -- all the piping within the scope of this service water system regardless of the materials. Oconee limited their initial evaluation just to carbon steel piping.

ANO-1 did not perform an aging management review of the tendon galleries in the license renewal application, which is consistent with the previous two applicants. They weren't required to do that.

Continuing with the aging management review, this is specific to the reactant coolant system aging effects. ANO-1 pressurizer spray head was not included within the scope of license renewal, because it's not required by the current licensing basis. They don't use it for design basis events accident analysis.

ANO-1 addressed void swelling in its license renewal application as an applicable aging effect for the reactor vessel. And manage the related aging using the reactor vessel internal aging management program consistent with the topical report BAW-2248 and the Oconee lessons learned.

Next slide is on reactive coolant systems aging management programs. ANO-1 heater bundle penetration welds are designed differently than Oconee's heather bundle penetration welds. ANO-1

heater bundles are all stainless steel and consist of a stainless steel heater sheet weld directly to a stainless steel diaphragm plate.

Oconee Unit One contained alloy 600 heater sheets. And the design was a heater sheet to sleeve, plate weld to a heater sleeve, to a bundle diaphragm plate weld. ANO-1, in this license renewal application, committed to examine heater bundles upon removal consistent with the lessons learned from Oconee.

DR. BONACA: Now, in the application, however, it states that if Oconee performs the inspection and doesn't find anything, then they would not perform an inspection in Arkansas. But in the SER, I didn't see the exclusions. So is there some agreement that you reached through some communications?

MR. PRATO: Yes, I don't believe there's an open item on that issue at all. The agreement was that when they replace it, they're going to inspect it. There's not going to be any specific inspection, unless when Oconee does its inspection, they find a problem.

Is that correct?

MR. YOUNG: Gary Young with Entergy.

We're going to follow the Oconee work and they're going to follow our work. So what we're going to do is compare notes. If we do our heater bundle first, then the results from that will be factored into the Oconee program.

And if they do their heater bundle first, then we'll factor that result into our program. Though, it's really more of a B&W program to look at, you know, both units together. That's why it's stated the way it is. And the staff, if they have any problems with that --

DR. BONACA: Okay. Yes, because the application is clear on that issue, but the SER did not -- assuming the SER says that Arkansas would perform in any event, an inspection of the heater bundle, which in turn, it means that it may not, in case Oconee does it first.

MR. PRATO: Right.

DR. BONACA: And I think it's fine.

MR. PRATO: If the Oconee comes out, you know, with no problems whatsoever, and there's no benefit from doing a subsequent inspection in Arkansas, that's what that section was all about.

DR. BONACA: And that was part of the B&W topical.

MR. PRATO: Yes.

DR. BONACA: That kind of --

MR. PRATO: Dr. Bonaca, I have a note here, and we will go through the SER again and in our revision and in our final version, we'll make sure that's made clear.

DR. BONACA: Okay.

MR. PRATO: ANO-1, in its license renewal application, included cracking as an applicable aging effect for reactor vessel internal non-bolted items. And the identification of limiting components when considering irradiation embrittlement in its reactor vessel internal's aging management program. This is consistent with topical report BAW-2248 and the Oconee lessons learned.

DR. BONACA: Now, Arkansas-1 experienced thermal shields and cobarold bolt cracking, right, as experienced in the past.

MR. YOUNG: Yes, that's right.

MR. RINCKEL: This is Mark Rinckel from Framatome, and that's correct.

DR. BONACA: And so as part of the internal inspections, it would be also -- probably you have a periodic inspection of those components.

MR. RINCKEL: They are in the reactor

vessel internal as aging management program. Yes, that's correct.

DR. BONACA: And that program involves a one-time inspection, right?

MR. RINCKEL: It could be one or it could be more.

DR. BONACA: But now, if I remember, that inspection is also tied to an Oconee inspection.

MR. RINCKEL: That is correct, yes, and the application.

DR. BONACA: Okay. Which means if Oconee performs the inspection first, then you may not perform the inspection for Arkansas?

MR. RINCKEL: It's possible. I think it's in the application we are committing to doing some type of inspection, but I -- you know, I think there will be lessons learned from the Oconee inspections because they'll be first.

DR. BONACA: Yes, the reason why I'm asking that question is, since you've experienced already the cracking of the bolts, in both the thermal shields and the wiring, why would you consider the experience from Oconee applicable to our -- or, let me just put it the other way, which is why would you consider Arkansas to be -- you know, I mean, you have

experienced the problem.

Wouldn't you want to see -- don't you have already the inspections to look at those --

MR. RINCKEL: We do, not necessarily biometric inspections. But if you remember back in the original issue, they thought it was stress erosion cracking, and a lot of it with the fabrication, you know, overtorquing and so forth.

And so they've replaced those. And now what the issue is, is possibly a radiation assisted stress erosion cracking, which is more of an aging phenomena as opposed to a fabrication type issue, so it's kind of something different now with regard to aging, even though it's the same component.

DR. BONACA: Okay. But you are tracking the issue?

MR. RINCKEL: Yes.

MR. PRATO: Next page, we're going to continue with reactant coolant system. ANO-1 included IASCC as an applicable aging effect for baffle bolts in its license renewal application consistent with topical report BAW-2248 and Oconee lessons learned.

ANO-1 evaluated reactor vessel internal cast components. In this license renewal application, for reduction of fracture toughness by thermal

embrittlement and a radiation embrittlement consistent with the EPRI technical report 106092.

This is also consistent with the topical report 2248 and the Oconee's lessons learned. ANO-1 included vent valve bodies and retainer rings in its reactor vessel internal's age and management program and its application.

DR. SHACK: Just let me get back to the -- the cast stainless was a sort of a extended topic of discussion for Calvert Cliffs and Oconee. And this one -- it just -- I mean, it did go smoothly, right? I mean, they incorporated acceptable plans from the lessons learned, basically, from line one, or was this another exchange before we iterated to a successful solution?

MR. PRATO: I believe it went so smoothly at ANO because they followed the topical report. Is that correct --

MR. YOUNG: Yes, Bob. They -- and we also followed the lessons learned from Oconee. We just basically incorporated what the staff determined to be acceptable. And you have to remember the CASS includes the retical and pump casing, valve bodies, and those we follow the same solution that Oconee did.

And then the rad vessel internal's CASS,

you had not only thermal embrittlement, but irradiation embrittlement. And we address those by putting them in our rad vessel internalization management program, which is consistent with Oconee.

MR. PRATO: And the last item, ANO-1 identified cracking and loss of material of letdown cooler tubing, and loss of material for external ferritic surfaces due to boric acid wastage as applicable aging effects in the license renewal application, which is consistent with the lessons learned for Oconee.

That completes the RCS aging management review. We'll go on with the rest of the system's aging management review. ANO-1 did not consider vibration loading as an applicable aging effect for the HVAC system in its license renewal application consistent with the staff's determination that caused similar concerns on Oconee.

ANO-1 included an acceptable scope for the aging management review of the reactant cooling pump motor oil collection system inspection program. There was some questions as to whether or not Oconee included the entire -- enough of the system based on lessons learned from Oconee. ANO included the appropriate evaluation boundaries for the system.

DR. BONACA: If I remember, for Oconee, the only inspection was for corrosion due to water intrusion in the --

MR. PRATO: Wet system.

DR. BONACA: -- in the drain, for the drain in the tanks, collection tanks. And now, so the Arkansas has included in the piping of the system and any other component?

MR. YOUNG: Yes, we included the oil collection pans and the piping that went down to the drain tank, the whole system.

MR. PRATO: ANO-1 spent fuel concrete thermal exposure is limited to less than 150 degrees Fahrenheit, which is contrary to the Oconee. They experienced temperature of up to 183 degrees, and being less than 150 degrees is less than the threshold for potential cracking and changes in properties of the concrete.

And the applicant addressed this directly in the application. ANO-1 considered results of inspections and instances of reporting unusual event in this demonstration of aging management programs in the license renewal application. In general, part of the demonstration was operating history.

The staff had a number of questions as to

whether or not they considered operating history, and in a couple of cases, the applicant had to go back and take a look at it. But in general, they did include operating history, both industry and on-site history for demonstration.

ANO-1 primary and secondary shield wall is reinforced concrete without any tendons, and therefore, monitoring of applicable forces is not needed. And there was a question with Oconee's monitoring of tendon forces in the secondary shield wall.

ANO-1 consistently considered applicable aging effects with cable trays and conduits located inside and outside of containment.

DR. SHACK: Want to flip your slide?

MR. PRATO: Oh, I'm sorry. The last two items there on this page common to both ANO and Oconee, ANO meets -- and these are two of the -- two of the six open items. ANO-1 needs to provide additional summary description for a number of their selected program descriptions in the FSAR supplement.

And a second item is ANO-1 needs to identify an aging management program for buried medium-voltage cables exposed to ground water that are within the scope of license renewal and subject to an

aging management review. This was an issue both for Oconee and ANO, and the applicant is developing a program similar to what ANO resolution -- I'm sorry, similar to the resolution for Oconee.

DR. UHRIG: Are these primarily load carrying cables, or are these there for emergencies?

MR. PRATO: It's load carrying.

DR. UHRIG: Load carrying.

MR. PRATO: Yes, sir.

DR. UHRIG: So they would have heating?

MR. PRATO: Right. That's part of the problem, that along with moisture causes a number of aging effects to occur. Slide 13. Time limit aging analysis. ANO-1 did provide a discussion on the cumulative effects of fatigue for the containment liner plate and penetration in the application.

ANO-1 provided an adequate TLAA for the reactive coolant system to address environmentally assisted fatigue concerns for operation beyond 40 years in the application. ANO-1 committed to 10 CFR Part 50, Appendix B, for all -- for corrective actions for all components within the scope of license renewal, including Section 11.4 evaluations.

ANO-1 addressed the reduction of fracture toughness related to susceptibility of the reactor

vessel internal -- internals under loss of coolant and seismic loadings. And its reactive vessel internals aging management program consistent with the topical report BAW-2248 and Oconee lessons learned.

ANO-1 addressed the applicability of flow of growth in accordance with the ASME boiler pressure code Section 11 ISI requirements in the application consistent with topical report BAW-2248 and Oconee lessons learned.

The last two items are ANO open items. These are the last two of the six open items that exist right now in the safety evaluation. The first one has come to both Oconee and ANO. ANO did not demonstrate the adequacy of the existing pre-stress forces in the containment tendons by providing the trend lines for the containment post-tensioning system for the period of extended operation.

There were some questions as to how they described their program in the application. They used the same aging management program that they used in Chapter 3 for managing the aging of those tendons. The staff wanted something more for the time limit aging analysis, more trending, more than was required by the code itself and the applicants in the process of developing that.

And the last item is the boraflex monitoring program. The ANO monitoring program is similar to Oconee's monitoring program. However, sometime between the time they submitted their application and during the staff review, they collected additional data. They plotted that data, and they found out that the boraflex is not going to last much more than five years.

Therefore, they had to do something under Part 50. Because they felt that it became a Part 50 issue, they turned around and told the staff instead of sending additional description, as the staff requested in the REI, they turned around and said, "Look, we have this problem. We have to fix it prior to entering into the period of extended operation. Therefore, we don't consider it a TLAA anymore."

Initially, the staff accepted that. But as we thought about it more and more, it was a difficult concept for us to accept that we were going to give them a license for 60 years without knowing whether or not they have sufficient boraflex to maintain the shut down margin.

We spoke with OGC. OGC said it's not -- if you look at the definition for TLAA, there's one item that says as defined by the current licensing

term. They said that does not necessarily need to be interpreted as 40 years. In other words, if it was a TLAA in the initial application for initial licensing, we can still consider it a TLAA in the license renewal process.

So the applicant is working out a resolution. The resolution is targeted for late 2002. What we're going to do is we're going to insist that they maintain their boraflex monitoring program until the resolution is not only developed, reviewed, and approved by the staff, but implemented as well.

That completes the overview. Next item of topic is scoping of systems.

DR. SHACK: I think it's -- when you say they handled the environmentally assisted fatigue in the application, that means basically, it came in in an acceptable form, and you weren't negotiating back and forth the way you were with Oconee and Calvert Cliffs?

MR. PRATO: That is correct. After resolving Oconee and Calvert Cliffs satisfactorily, the information was out there. And they took advantage of that, and they took the lessons learned, and they submitted. That's not to say the staff didn't have any RAIs on this subject.

If I remember correctly, we had a number of RAIs, but they responded satisfactorily.

MR. YOUNG: Bob, in that regard -- this is Gary Young again with Entergy. We did have a number of conversations with John Fair, and we had originally proposed what we felt was a complete solution to the environmentally assisted fatigue involving in-service inspection

But we couldn't come to terms on the interval for the inspection, the ten year interval. So we wound up, through their RAI process, revising our commitment to deal with whatever comes out of the changes that may occur with the definition of flaw growth tolerances for environmentally assisted fatigue.

And also open the possibility that we might go back and do analysis once the methodology is established for doing analysis for environmentally assisted fatigue. So there was an adjustment made, but it was through the RAI process.

MR. PRATO: Are there any more questions for me?

MR. GRIMES: Actually, before you go on to the next topic, Dr. Bonaca, I would like to emphasize that in describing these differences between Oconee

and Arkansas, I don't want to leave the impression that we were Oconee bashing in some fashion.

Bob referred frequently to deficiencies in the Oconee application, and given that they were flying blind as one of the first two license renewal applicants. I still think it was remarkable that we only had, I believe, it was 48 or 49 open items on Oconee.

And the purpose of Bob's presentation was to explain how Arkansas was issued with six open items. So we got from 48 open items to six open items. And I think that if you went through and counted the number of times Bob referred to, consistent with lessons learned from Oconee, the Arkansas application did reflect a lot of the experience from Oconee and also incorporated the resolution of a number of the Oconee open items.

And that was the vast majority of the reasons for the difference between the number of open items. You also heard reference to a number of B&W programs that were resolved and a staff evaluation was issued at about the same time that the Oconee safety evaluation was issued. And so we took advantage of that.

And then there were a handful of

circumstances where Bob explained that there were plant unique features, plant unique environment. There were only a few cases where unit differences between the Oconee site and Arkansas site accounted for the basis for the differences.

So those are the categories of differences that we described. You also will observe that there were -- there are a handful of these open items that will probably always be open items. The content of the FSAR supplement is always going to have to have a finishing touch to it. And there are going to be open items in the scoping area where there -- we're trying to pin down the precise nature of the current licensing basis.

So you can expect that future license renewal safety evaluations are going to have open items that look like that, but they're going to vary from plant to plant based on the differences in the current licensing basis.

DR. BONACA: Thank you. I must say at least I didn't get the impression that there was any bashing of Oconee. I mean, I recognize the fact that Oconee was the second -- one of the first. Anyway, the first two coming through the gate. And they had to really start from scratch.

I mean, so clearly, there were many more open issues. I think what we're seeing here for Arkansas is encouraging. However, the lessons learned are being clearly implemented and used. And the issues are closed before they are opened. That's good. Okay, thank you.

MR. PRATO: Okay. Next presentation will be on scoping. Greg Galletti will make that presentation. The next presentation is supposed to be Entergy. I apologize.

DR. BONACA: Yes, okay.

MR. PRATO: We're just getting a little ahead of ourselves.

MR. YOUNG: My name is Gary Young, and I'm with Entergy. I'm the Project Lead for the license renewal project. And one thing I'd like to make you aware of is about 22 years ago, I was part of the ACRS staff. I worked as an ACRS fellow for one year, and then as an ACRS Staff Engineer for one year.

And that was in 1979, 1980, and 1981 time frame. So I'm glad to be back, and especially in the context of presenting license renewal as the subject. So that's a very nice subject to be talking about with the ACRS.

To my right is Natalie Mosher, who is our

Lead Licensing Engineer for the license renewal project. She's been doing all of the interfacing and coordinating with the NRC staff as we've gone through this process. I've also got several members of our staff here.

Reza Arabli is from our structural group. Jeff Richardson worked on our electrical portion of our application. Mark Rinckel, who spoke earlier with FDI, helped us a lot with the Class 1 and the mechanical portion of the work.

Rick Buckley was our Environmental Lead and did a lot of work in that area. And Richard Harris, who worked on our SAMA portion of our environmental application. So we brought all these people here to help address any questions you might have and help facilitate your review process.

DR. BONACA: I'll have a number of questions about specific components in scope. I don't want to interrupt your presentation. So you tell me when is the best time for me to ask questions.

MR. YOUNG: At any time. At any time. Yes, I'd rather you ask at the point that the question comes up, and then we'll try to address it right then.

We'd like to than the ACRS for the opportunity to come here, and to go through this part

of the process. We're anxious to answer your questions and to help you facilitate your review. We'd also like to thank the NRC staff, because we -- this process, although it's been somewhat grueling to go through all the questions and the RAIs, and the site visits, and the meetings, we think that the end product justifies all the work that we've had to put into it.

And we know the staff has put an awful lot of work into it, too, because getting down to just six open items was -- I mean, we'd like to take all of the credit for that, but we don't deserve all the credit. The NRC staff did a lot of work in order to get the list down to just the six open items.

Okay. Next slide. Now, Bob covered a lot of this, so I'll skip through a good portion of this and try to move on. Again, we're located in Russellville, Arkansas. We are similar to Oconee, a B&W 177 fuel assembly plant, a 2,568 megawatts thermal. Our current license expires May of 2014, and with license renewal, we will have the option to operate until 2034.

And again, one issue that we always like to make clear, is that by getting this renewed license doesn't mean we will operate for 60 years because

economic factors will dictate how long we operate even if we go beyond 40 years.

But by getting this license, it gives us that option that if economic factors are good, then we can continue to operate. Now, you know, two is not included in this application or this review. It's a combustion engineering unit, and so, we're going to have to submit a separate application for ANO-2. And we plan to do that by September of 2003.

The ANO-1 effort, too, is going to set the platform for all the subsequent Entergy applications. And we have a number of other plants that we plan to pursue license renewal on. So we'll use this as our template, and the lessons that we learn from this. And we have learned a lot of lessons going through this process. We plan to apply to the other units, and then hope to come in with even cleaner applications in the future.

Next slide. And again, as mentioned earlier, we did follow Oconee, and we tried to apply as many lessons learned as we could. The timing of our application was very good relative to the resolution of a lot of the issues on Oconee, and the completion of some of the topical reports.

Those were completed at a point where we

could take advantage of them in our application. And as mentioned earlier, there's a lot of credit to be given to that for reducing the number of open items.

We did participate with the B&W owners group in developing generic aging management reports, which were the topical reports we talked about earlier. But in addition, we developed, or participated in the development, of mechanical and structural guideline documents to help actually do the aging management review.

And those things are sometimes referred to as mechanical tools and structural tools. We took full advantage of those, and that's part of what is described in Appendix C of our application. Also, we looked at the RAIs that had come out on Oconee, and tried to incorporate as much of that as we could.

I certainly cant' say that we incorporated all of the RAI resolutions from Oconee, but we did try to incorporate the ones that we felt were the more significant ones. And then also, we got few back from the NRC prior to submitting our application on what kind of format they would like to see.

And this was what became known as the standard format for license renewal application. It was published a few months before we were to turn in

our application. So again, we took advantage of that, and formatted our application to the standard format that was draft at that time.

In addition, we had some conversations in meetings with the staff to discuss some of the details, and got some direction there. In fact, some of the tables that you see in our application were worked out with the NRC staff ahead of time. Now, again, it was the first time that we tried to use those kind of tables.

There were some problems with them as far as, maybe, level of detail. But again, I think we've learned some lessons from that and we can apply them on the next applications. In addition, we worked with NEI to obtain industry input. During the final stages of our application, we actually had a peer review of the draft application with several other utilities through the NEI License Renewal Task Force. And we get a lot of benefit from that by getting the perspective of other utilities on our application. Next slide.

This slide shows the hierarchy of the documentation that exists to support the application itself. The application is the top box on this slide, and then all of the other documentation below that

represents on-site engineering reports that were create to support the license renewal project.

The first grouping of documents is what we call the Class 1 mechanical. These are the ASME Class 1 or the RCS related components. In this grouping, we had eight reports that were created, eight on-site engineering reports. And these benefited from the generic topicals that were done by the B&W owners group.

And four of those had received prior NRC approval so that we could actually reference those in our application. And that was on the reactor vessel, reactor vessel internals, the pressurizer, and the RCS piping.

The second grouping of documents is the non-Class 1 mechanical. There were 25 system reports generated, and these were on systems such as the high-pressure ejection system, and the emergency feed water and main steam. For this grouping of documents, we used the mechanical tools to guide us through the evaluation process.

And those mechanical tools, at the time, were B&W report. They've now been transferred to EPRI and they're being published as an EPRI document so that the whole industry can use those and reference

those.

In the structural area, we had seven reports that were broken into major structures on-site and commodities. For example, we had one report on the reactor building, one on the OTS building, and one on the intake structure. And for these reports, we used the structural tools, which at that time were also B&W document, which has also been transferred to EPRI and is now an industry document.

And then the electrical area, we had ten engineering reports on the cables, connectors, terminal blocks, et cetera. And these were generated using the Sandia Spaces approach, which is also a more or less an industry document that we -- that the whole industry can use to do their review on electrical equipment the same way.

Then we had separate reports on the environmental issue, TLAA's, our program's document, and an EQ. We separated EQ out, simply because of the volume of work that was required to go through a reevaluation on our EQ components.

Region 4 has just recently been at Arkansas on site, performing a review of these engineering reports as part of this review process. And they're having an exit meeting on the results of

that on, I believe, it's March the 9th. So we think that went fairly well.

We haven't got the full results from that inspection yet, but it seemed to go quite well as they went through and reviewed the details of these reports.

DR. BONACA: In the phase of scoping, you know, the documentation shows that you were pretty much helped by the fact that you have -- you included all the supports in the system, and those include a lot of support systems that somebody else could not call them until later, actually.

MR. YOUNG: Yes.

DR. BONACA: So you have a pretty comprehensive scope. You all do list in the application the -- your design basis events that you considered as the basis, I guess, as the source of this information. Since you have a pretty extensive definition, you know, not the minimum requirement definition of safety-related, I was kind of surprised a little bit regarding the reactor vessel level measurement system. And I can see how you don't have any specific design basis event that would reference that and become, therefore, excluded. On the other hand, I mean, that's a true -- the only function of

the system is to provide a safety function of some type, which is under certain conditions to measure level.

What was the logic for excluding it that you presented that was then accepted by the NRC?

MR. YOUNG: Okay. The reactor vessel level instrumentation was added as a post-TMI modification. During the development of our emergency operating procedures, which is where that component comes into play -- first of all, in the safety analysis, we take no credit for vessel level monitoring.

It's not something that we include in any of our safety analysis as credit. On top of that, in our emergency operating procedures, they're based on maintaining a sub-cooling margin in the core. And that is the safety source of information. And as long as we can maintain the sub-cooling margin, then we don't get into any vessel level problems.

As the staff went through and reviewed the Entergy staff in developing all of these emergency procedures, they realized that the vessel level monitoring system is a good piece of information for the operators to have, but they don't take action on that information. They take action solely on the sub-

cooling margin in keeping the core cool.

DR. BONACA: But once you lose sub-cool margin --

MR. YOUNG: Again, that piece of information is available to the operators, but they take action based on losing sub-cooling margin, not based on vessel level.

DR. BONACA: Okay. Now, what's the consequences of not including that system? Does it mean that --

MR. YOUNG: Really, a lot of -- one of the things I think is important to understand is by not having it in the scope, license renewal doesn't change how it's treated. It's still treated as a full quality requirements PBX type inspections, surveillances. It has specifications on if it's out of service, how long you can continue to operate, or what you do if it goes out of service.

There's a number of requirements that still exist because of the post-TMI commitments, and those have not changed. And they will continue through the extended term.

DR. BONACA: Yes, that goes to the commitments issues. What I mean is that, on the other hand, you could change commitments regarding the

system and not have a linkage to the commitments of the license renewal. I mean --

MR. YOUNG: Yes, all of that, though, would have to go through a 5059 review process. And depending on the outcome of that, you know, possibly having NRC staff approval before we can make any changes to it.

DR. BONACA: Okay.

MR. YOUNG: Another factor that would probably be important to point out here is that we did include the pressure boundary portions of the vessel level monitoring system, since that is in the scope of license renewal.

DR. BONACA: Yes, I saw that.

MR. YOUNG: And most of the other instrumentation would have been excluded anyway because it would have been an active component. So I doubt that even including it would have changed very much on how we would have handled the aging management review. Because most of it is just electrical thermal couples and so forth, inside the reactor vessel.

DR. BONACA: Okay. But certainly, I mean, right now you may have some guidelines that says that if it fails, you have some commitment on how long you can stay with the system failed.

MR. YOUNG: Yes.

DR. BONACA: And, you know, you can change that?

MR. YOUNG: Well, those, I believe, are tech specs. So we would have to go through NRC review and approval to change that. They're not -- they're not just commitments. They're actually in our tech specs.

DR. BONACA: All right. Thank you.

MR. YOUNG: Okay. On the -- again, on the scoping, I think we've talked about most of this. The first, we used NEI 95-10 as our guidance document for doing the scoping review. And the guidance documents that were available from the NRC in the form of the rule and the draft and the review plan.

Safety-related definition we have -- was mentioned earlier as component level Q-list, and also a summary level Q-list that's in the SAR. And those were the basis for determining what equipment was in the scope of A-1, which is the safety-related category.

A-2, which is the non-safety-related components that can prevent a safety-related function from being performed. At Arkansas, most everything that would really fall in this category, we had

already classified as Q, or safety related. The history on that was simply that at the time that we were building the plant and licensing it, was that if you had a support system that was needed -- for example, a cooling water system to a pump.

And that cooling water system was needed to make that pump operable, we'd call that Q, safety related. We didn't call it non-Q that could affect safety related. So we had very little equipment that fell into the A-2 category. We did have some, because it is an older plant, and there were a few things like seismic category two over one, that fell in this category.

But the majority of equipment was actually falling in the category of A-1 for us. Next slide. The A-3 category, which is sometimes referred to as the regulated events category, included the fire protection, environmental qualification, pressurized thermal shock, anticipated transits without scram and station blackout.

We simply used the design documentation for those events to come up with a listing of what was in scope. And as was mentioned earlier, fire protection is one that we still have an open item on. We're working through that. You know, we have what we

defined as the scope of our fire protection equipment.

And the -- I think it was four or five sets of components are being evaluated right now with the staff on whether or not they should have been included. And we're going to have meetings on that in another week or two.

Okay. On the next slide, going into the screening process, after we had scoped -- we scoped at the system level, the system and structure level. And then we went in to do screening to identify the passive long-lived components that were within those structures and systems, that had a function that required an aging management review.

And this was, I guess, the second major step in the process before you got into aging. And this again, was using the guidelines of NEI 95-10. Next slide. The -- once we got into the scoping and screening work, again, we split it up into mechanical, electrical, and structural, and did those pretty much in parallel with separate activities.

All of this work, of course, was done on a plant specific basis. But for the Class 1 mechanical equipment, we did have the benefit of the generic B&W topical reports to use, and that was a tremendous benefit, because when we started into the

site specific, we could basically take those topical reports and simply deal with the site specific differences.

So most of our actual on-site effort was in the areas of the non-Class 1 and the electrical and structural. We didn't have any generic or topical type reports that we could rely upon. I think that's all we have on that slide. Next slide.

Okay. The aging effects. Again, the mechanical review was done on a system basis. We went system by system, and did and evaluation for the Class 1. Again, we used the topical reports. For the non-Class 1, we used the mechanical tools to help us go through that review process.

On the electrical side, we used what's called the spaces approach, which is based on the Sandia aging management guidelines. And then on structural, we used a commodity and a building approach. We looked at major buildings, but then within those buildings, we took commodities basically, steel and concrete, and just did an aging review on those commodities.

And based on that, we identified the aging effects that required management. Okay. Next slide. After we had identified the aging effects that

required management, then we'd identify the aging management programs. And as was mentioned earlier, we had -- well, first of all, we had about 30 major groupings of programs that we've identified.

Now, there's probably about over 100 actual specific programs, but we grouped them, such as our preventive maintenance program, which has a lot of individual preventive maintenance activities that we credited. We just put it in the category -- one category called preventive maintenance. Same thing with our chemistry.

But in the aging management programs, we have a group called the new programs, and then a group called the existing and modified programs. And there were seven major categories for new programs that didn't exist before.

And I've listed a few of them here, our buried piping inspection program, our electrical component inspection, certain pressurizer examinations, reactor vessel internals aging management, which was a B&W topical issue, and our Smithfield fuel monitoring programs.

DR. BONACA: I have a number of questions on these programs. And is it a good time to ask?

MR. YOUNG: Yes.

DR. BONACA: On the buried pipe inspection program, you know, when I go back to Appendix B, and I'm looking at what it says, it says that the program consists of, you know, whenever you have an opportunity to expose one of these pipes because of maintenance or a design change, you will look at the pipe.

MR. YOUNG: Right, right.

DR. BONACA: And how different is this program from what you do right now?

MR. YOUNG: The main difference is that right now, when we expose the piping, it's really up to the individual work group doing the activity to do an inspection, so what we want to do is formalize that and give them criteria so that when they uncover one of these pipes, they know what to look for, what sort of things we were concerned about.

We went back in history and looked at the times when we have exposed buried piping, and we found that in most cases, they did do an inspection beyond just the location they were either doing a repair on or doing instruction. But there was no requirement for them to do that.

So we felt like that because of the review that came out of the license renewal, that we should

formalize that into a set of activities or inspection criteria, that then they would document those results, and we could watch for trends. So that's the main difference.

DR. BONACA: The other question is just on the top of your head, what's the frequency of, you know -- I mean, how many times in the past 30 years you had an opportunity to --

MR. YOUNG: Yes, we've got about 26 years of operation now, something like that. And we didn't go all the way back to the beginning, but we found that in the last ten years or so, we've had about, I think, two or three situation where we've had to dig up piping for various reasons.

So we're thinking that, in general, it's about once every five years. Sometimes more, sometimes less.

DR. BONACA: Okay, thanks. Second question I had was on the heat exchanger monitoring problem.

I thought you have core problems, which I'm looking at performance. I think it's --

MR. YOUNG: We do. That's a little confusing, the title of that program is a little confusing, because what we have is our service order

integrity program, which is an existing program. And it looks at service water heat exchangers.

But what we found in doing our review, there were some heat exchangers that were not covered by the service water integrity program. And in fact, the issue that we're dealing with on the heat exchanger program is actually a cracking or loss of integrity, primarily from a seismic viewpoint. So that gets into things like doing some sort of non-destructive testing, like maybe 80 current, or something like that.

So those -- it's a very limited set of heat exchangers that fall under what we call this heat exchanger program, because the majority of the heat exchangers on site are already covered by the service water integrity program. So they work hand in hand. We gave it that title, and we found out later that even the staff questioned us on that, is why are there so few heat exchangers in your heat exchanger monitoring program?

The reason is we have what we call the service water integrity program that covers most of them.

DR. BONACA: Yes. The third question I have, probably you already answered, I mean, you're

not augmented, because you already have extensive pressurizer examinations --

MR. YOUNG: Yes.

DR. BONACA: -- to perform as part of the ISI, right?

MR. YOUNG: Right, right. These were some new commitments on very special locations. And so we went ahead and called it a new program, just to kind of, you know, add to the visibility of it. We, in fact, could have put it over into the category of an existing ISI program that was just augmented.

But we felt like it was worth making this one more visible in our report.

DR. BONACA: Okay.

MR. GRIMES: Dr. Bonaca, if I could add, this is Chris Grimes. And I think that there is still a certain degree of controversy over the clad integrity inspections, and the need for them, and the conduct of them. So, you know, Arkansas has called it out. They have proposed to do more than we've been able to negotiate on a generic basis.

But that will continue to be an area where I think there's ongoing dialogue with the industry.

DR. BONACA: Thank you. On the -- let's see -- on the reactor vessel internal aging management

program, the application did not specify at all the time when you would perform the one-time inspection. But the SER states specifically, I can't remember now, it refers to some kind of periodic time when it will be done?

MR. YOUNG: Yes.

DR. BONACA: What's the commitment there?

MR. YOUNG: Okay. I might turn this over to Mark Rinckel. He's the one that has helped us develop that program. Mark?

MR. RINCKEL: Yes, this is Mark Rinckel. I think the commitment came through the RAI reposes to do one inspection towards the end of the fifth interval. So that would be, you know, towards 45 to 50 years. But also, realizing that Oconee will have already inspected probably Oconee Unit 1. And we're going to certainly incorporate lessons learned.

Now, there is, you know, a question as to whether or not we will have to inspect Unit 1 and O-1, once Oconee has, but, you know, we are -- made a commitment to do an inspection towards the end of the fifth interval.

DR. BONACA: So that the fifth interval?

MR. RINCKEL: Yes, the fifth interval is between years 40 and 50. So it's towards -- I believe

it's towards the end of the fifth interval is when we made the commitment. Now, I'm going by memory here, so --

DR. BONACA: I couldn't understand, in fact, what I was referring to. I only know that clearly they were specified, although it was not specified in the application.

MR. YOUNG: Yes, at the time we wrote the application, I think they were still developing some of these details in the reactor vessel internals program, and we coordinated with Oconee in coming up with this inspection. Because obviously, this really is a generic B&W inspection effort.

So whatever we find, we feed to the other plants. Whatever they find, they feed to us. So we tried to coordinate our commitment on when we would do an inspection so that we wouldn't wind up doing two inspections at the same time. We would sequence them with Oconee.

DR. BONACA: Once you have all these agreements in place, will you amend the application for your own purpose, I mean, to include these descriptions?

MR. GRIMES: If I could answer that. It is our expectation that by drawing a conclusion on the

proposals and the commitments that have been made, and then are codified in changes in the FSAR, we would expect that after issuance of a renewed license, that commitments could be changed in accordance with 50.59 and 50.71 E.

And that -- and much like the vessel surveillance program this internals program relies on a sharing of information that we would expect would feed the different B&W plants, and cause them to reflect on whether or not they need to make changes in these programs. And whether or not they trip the threshold of 50.59 that would warrant a license amendment.

MR. YOUNG: And we do plan to document that inspection frequency in the SAR supplement that will be, you know, issued with the new license. So it will be documented.

DR. BONACA: I just wanted to point out, at this stage, a reader like myself who come in cold --

MR. YOUNG: Yes.

DR. BONACA: I went through the application first, and I found a lot of open issues, vague -- not vague, but simply they were specified for, in this case, it will be one inspection.

Then I go to the SER and I find there is a timing of the inspection stated, and everything else. So it seems as if something has been negotiated in between that is not reflected in the application yet.

MR. YOUNG: Yes, we don't plan to amend the application, but in the commitment itself would be contained in the SAR supplement.

DR. BONACA: In the supplement?

MR. YOUNG: Right.

MR. PRATO: A lot of this was discussed on the RAI process. It's documented in the RAIs and their responses.

MR. YOUNG: Yes, right.

MR. GRIMES: Yes, Dr. Bonaca, this is Chris Grimes. Now, I would like to emphasize that we're at that stage in the review where we expect to have more dialogue with the applicant in order to resolve the open items. And then, before we draw a final conclusion on it, a renewed license, we'd present the resolution of the open issues along with any clarifications to the safety evaluation, and it would feel warranted.

And then those would be reflected in changes to the SAR supplement where appropriate. But

the whole record will consist of the application along with all the correspondence since the application was submitted, in support of the final safety -- the safety evaluation, the FSAR supplement, and those will be the two case in terms of having a consistent explanation of the treatment of these issues.

DR. BONACA: One last question I had on the problems was -- well, on the spent fuel pool monitoring, I think already we talked about that. But I had a question regarding the mineralizers heat exchangers in part of the scope?

MR. YOUNG: No.

DR. BONACA: They're not? Because they're not included in the cooling pool?

MR. YOUNG: Right.

DR. BONACA: Just the emergency addition from the service water.

MR. YOUNG: Yes, right.

DR. BONACA: And the last question I had was, when I was reading about the program of wall thinning inspections, specifically the major portion of the description, you know, regarding application, Arkansas claims that visual inspections have been effective in maintaining the integrity of the walls.

When I look at the SER, the SER states

that ultrasonic testing will be neutralized in wall thickness.

MR. YOUNG: Yes.

DR. BONACA: Again, there is a disconnect, and I don't understand.

MR. YOUNG: I believe that we got an RAI on that, and that was actually an error in our application. We meant to say that in service inspections, instead of visual inspection, and it does include volumetric inspection.

DR. BONACA: So you will go to --

MR. YOUNG: Yes.

DR. BONACA: Okay, thank you. I think that's pretty much it. Thanks.

MR. YOUNG: Okay, this next slide is just a summary listing of the 22 existing programs that we had. And of course, these are some of the major programs that all plants have, a Section 11 program, chemistry program, preventive maintenance program, and so on.

One of the things we did find that literally, probably 95 percent of all of the components and equipment, that need an aging management program, already have one. And the new programs are really covering a limited set of

components. So most everything we need, we already had in place.

DR. SHACK: Your risk informed ISI, you referred to as a -- translate that for me. Is that every risk informed, or the Westinghouse?

MR. RINCKEL: That is, as Mark -- it's the EPRI, EPRI method. And I think they'll get into that later, but those application numbers from form ISI, and essentially resolve the small buried piping issue, which is a good precedent for future applications.

MR. YOUNG: Right. Okay. The next slide here is on the time limited aging analysis, and here I've just listed some examples of the TLAAs that we had and evaluated. This was done separately from the rest of the review process. Our list of TLAAs was very similar to Oconee's, and of course, similar to other utilities. I think we're all coming up with very similar lists on our TLAAs.

And we've already talked a little bit about the boraflex issue. That was something that we thought was going to last for the full 60 years, but as we got into the review, we got some test results back showing that it would not. So we're working with the staff now to deal with that as far as getting our license renewed.

Next slide. Yes, that's the end of the discussion on the application on aging management. Now I'm going to move into the environmental report. In the environmental report, again, we --

DR. BONACA: How long do you think you'll need for this portion here?

MR. YOUNG: About five minutes.

DR. BONACA: Well, let's go through it, and then we'll take a break so we are on schedule.

MR. YOUNG: And the reason I say that, the environmental review is going extremely well. We've really had no problems in that area. Again, we used NEI and NRC guidance documents. We incorporated lessons learned, primarily from Oconee. We looked at what they had done, and tried to adjust our environmental report accordingly.

We did a new insignificant information review to confirm the adequacy of the category one conclusions that were in the generic environmental impact statement that the NRC staff credits for license renewal.

Next slide. The environmental impacts in all areas were identified as small, which is I guess, an EPA definition meaning that there are no significant impacts. There were no unique plant

characteristics that would effect the environment based on license renewal. And we had no threatened and endangered species present on site.

In the area of SAMA, Severe Accident Mitigation Alternatives, we identified 169 alternatives to be considered. This was based on the Calvert Cliffs and Oconee work that had been done previously. Eighty of those were screened out as either being not applicable or already having been implemented at ANO.

And then 89 were subject to benefit cost evaluation. Of those 89, we only found one that was actually cost beneficial. It dealt with a training program -- or -- yes, a training item that dealt with the operator switchover when they're going from the water storage tank to the sump during ECCS recirculation mode.

That was the only on that turned out to be cost beneficial. As we looked into it further, we determined that the training program had been appropriately modified, and there was no further action required there.

No SAMAs were identified that were age related, including the one that was cost beneficial. Tom Kenyon, our NRC Project Manager on that, has done

a very good job, I think, of going through and doing the review. We had a couple of public meetings. Those went quite well.

And we're now, I think, in the final stages of getting the supplemental environmental impact statement issued and published. And then the last slide, just a quick conclusion, again we utilized a number of the lessons learned from Oconee and the industry to get to where we are.

We appreciate that support that we got from the previous applications, and from the NRC's previous reviews. We were able to reduce the number of RAIs during the review process, as was mentioned earlier. I think Oconee had over 350 and we had pretty close to 250.

Of course, we'd like to get that number down even further and later applications, but still that was quite an accomplishment. And we also reduced the number of open items down to six, with taking benefit from those lessons learned. In our opinion, the license renewal process is stable and predictable. We, as well as the other utilities that we're working with on the NEI group, are building our applications off of each previous application.

So I think you'll see that the

applications, for example, Turkey Point, that has come in fairly recently, used a lot of lessons learned from our application as well as Oconee. And hopefully, they'll come through with a lot of the issues we're dealing with, and our RAIs will already have been dealt with in their application. So that's all I had.

DR. BONACA: Thank you. Any additional questions from the members? I thank you for your presentation. I think we will hear about the specifics in this scoping methodology, and design basis events, and open items after the break. So let's take a break now until 10:15.

(Whereupon, the foregoing matter went off the record at 9:59 a.m. and went back on the record at 10:16 a.m.)

DR. BONACA: Let's resume the meeting, and we now can proceed to the next presentation on the agenda.

MR. GALLETTI: Good morning. My name is Greg Galletti. I'm an operations engineer with Nuclear Reactor Regulation, Division of Inspection Performance Management. I'm in the Equipment Quality and Performance Branch, and our Branch had the responsibility for the screening and the scoping methodology review for the license renewal

application.

What I wanted to go over today was quickly give you an overview of the methodology review that we performed, that was both done in-house and as an on-site audit. And then get into some of the findings from that review, our conclusions from that review and then we'll switch over and discuss a little bit about the plant differences between the Oconee and the ANO review.

With respect to the scoping methodology, the staff's mandate was to review the license review application to ensure that the information provided in the application was consistent with the 54.4 regulations. In order to do that, the staff implemented a two-tiered approached, one being the in-house review of certain design documentation. Specifically, what we looked at was the license renewal application information and some of the supporting information that was provided by the applicant.

Some of that supporting information we had already in-house, for instance, the updated final safety analysis report, which we used quite heavily; the B&W ATOG, which is their emergency procedures guideline documentation, which the licensees have used

to generate their own site-specific EOPs. And we had the benefit of using the applicant's summary report from their IPE.

The basis for our doing the desktop review was, as I mentioned, first, to ensure that their application documentation was consistent with the regulations, that it encompassed all of those aspects of 10 CFR 54.4 that were required. And then, secondarily, the supporting documentation provided the staff some additional insights as to how the applicant had implemented their procedures and processes to ensure that their final product was consistent with their LRA application.

In addition, some of the background documentation, like the updated final safety analysis report and the EPGs, provided the staff some better understanding of the design basis, certain design basis events that the licensee basically was responsible for reviewing, and gave the staff some additional understanding of some of the CLB issues.

In addition to the desktop review, we had the opportunity to do an on-site audit, and that was performed by three staff members over a period of about three days, and that was done on-site at the engineering facilities of the licensee, the applicant.

The purpose of the on-site audit was initially to verify that the documentation provided in the LRA, in terms of the process used to generate the scoping methodology, was consistent with the actual application in the field; that is, that what they described in the LRA was consistent with the actual application of the engineering procedures and the process that they -- the implementation process the licensee used at their own facility.

Secondarily, what the on-site audit provided us is an opportunity to look at some products from their LRA implementation process to ensure that there was consistency in those products; that is, the different reviewers, different engineers that were involved in the review basically had the same level of detail, same analysis approach, same processes used to generate their final reports.

And thirdly, the on-site audit provided us an opportunity to look more specifically at the implementation guidance of the licensee. Their engineering reports, that Gary had mentioned earlier, we got to look at some of the detail associated with those reports, and we got to look at their actual implementing procedures; that is, what specific guidance, if you will, and operating procedure, if you

will, for this purpose, specific guidance that the engineers had at their disposal that governed what sort of information they looked at, how they approached the process of developing the LRA, the scoping methodology and the results.

DR. BONACA: This on-site visit was three days, you said?

MR. GALLETTI: Yes, sir.

DR. BONACA: Okay. Because in the application and also in the NCR there is a lot of statements regarding the fact that the applicant stated that or has stated that. So that was the extent of the verification process.

MR. GALLETTI: The initial verification process, which was done in-house, which was to review the LRA and make it very clear what the applicant provided to us.

DR. BONACA: Okay.

MR. GALLETTI: In addition, the on-site audit provided what I would characterize as a verification and validation process for the staff. That is, we were able to verify that the process used by the applicant matched very well with the description that was provided in the LRA.

And in terms of verification -- or in

terms of validation, again, we got to see the end results. We got to look at the specific design documentation that the applicant used. We got to understand the scope of that design documentation, and that was quite important, because what we wanted to set out to do was establish that the licensee had done a credible job of reviewing their CLB and ensuring that they went, certainly, just beyond like accident analysis or just design basis events.

DR. BONACA: One statement regarding the involvement of the staff was that you took some systems or some components that were not included in the scope by the application, and they were borderline. And for those, you verified that in fact the contention of the applicant was correct.

MR. PRATO: This is Bob Prato. That's part of the scoping inspection.

DR. BONACA: Yes.

MR. PRATO: What Greg is talking about is the methodology review.

DR. BONACA: Okay.

MR. PRATO: We actually spent an additional -- there was seven us I believe. And we actually did a verification that what they actually included within the scope of license renewal was

consistent with the methodology, the application and the SER.

DR. BONACA: Okay. So there were two visits then to the site.

MR. GALLETTI: Right, right.

MR. PRATO: When we do that scoping methodology, we do it in really two stages. The first stage is we pick a number of systems that we feel are important, that can be important, that were not included within the scope of the license renewal, and we verify that those systems do not meet the criteria. And once we do that verification, we have a comfortable feeling that they've included all the systems within the scope, and then we go into the screening and the actual scoping activities.

DR. BONACA: All right. Two visits there, and this was meant.

MR. GALLETTI: Correct, yes. The purpose of our audit was to ensure that the methodology that's been outlined --

DR. BONACA: I understand.

MR. GALLETTI: -- in the engineering documents is consistent with the regulations.

Basically, one of the things that we did in the on-site audit was to review some of the design

documentation as the results of the LRA application. In essence, we looked at what's called the upper level documents. These ULDs are essentially a library of documents that cover systems, structures, events, if you will, design basis events, as well as additional topics. And by looking at those ULDs, as well as looking at what Gary brought up before, the Q list development process, the staff was able to come up with reasonable assurances that the process implemented by the applicant was consistent with 54.4.

If I could go on to the specific findings, as a result of our in-house review, as well as our on-site audit, we did find that the applicant's approach was consistent with 54.4 in terms of defining what safety-related equipment was consistent with A-1, understanding their consideration for non-safety-related equipment.

And what's been brought up already is the fact that many things we would characterize as non-safety whereby the virtue of the licensees desire are already safety related. And those things above and beyond that, such as the seismic two over one or some internal flooding types of systems and components were brought into play as a result of the review.

And, finally, we did verify that the

regulated events, if you will, the ATWS, the station blackout, those sorts of events were well analyzed by the applicant. There is sufficient design documentation available to us to ensure that they had done a credible job of reviewing those events and scoping in the proper equipment components and structures necessary.

What we found is that their scoping process was very well defined in their engineering reports, and that the implementation of those processes was very consistent. The audit also provided confirmation that the process implementation was consistent with the descriptions provided in the LRA and also consistent with the specific engineering procedures that the licensee had been developed for that purpose.

In conclusion, the staff made a safety finding that the applicant's methodology and implementation was sufficient to develop and we believe maintain the scope of the license renewal application over the period of extended operation.

If I could, I'd like to -- if there's no specific questions on those areas --

DR. BONACA: Well, I have two questions on scoping that you and you with the applicant may

answer, if I could ask them now.

MR. GALLETTI: Certainly.

DR. BONACA: Because we're going to be getting into section three, which is more of the aging management problems, right?

On scoping, I have just a few questions. One is, I was looking at page 217 of the SER where it talks about the fact that Arkansas included components not addressed in the B&W 2243(a). And I was -- one thing I was aware of is that some of the B&W plant experienced letdown system pressure breakdown, orifices failures. Are those included in the scope?

MR. YOUNG: The orifices are included from the viewpoint of pressure boundary, but they don't -- I don't believe those particular orifices perform a safety function, so they weren't in there for flow control or anything like that. But they were in there for pressure boundaries, so they were included.

DR. BONACA: Pressure boundary. So they are for pressure boundary.

MR. YOUNG: Yes.

DR. BONACA: Okay. Thank you. The other question I had was -- maybe this is just a confusion on my part -- in the section that speaks about the steam generator, there is a reference to the fact that

the auxiliary feed water in the piping is not in scope. But then when I look at the SER, and specifically it talks about the emergency feed water system, it seems to be in scope, the piping. And I am confused. I mean do you have two different systems, an emergency feed water system and an auxiliary feed water system or is it the same system and then these connect?

MR. RINCKEL: This is Mark Rinckel. I believe that was an error in the original application. There was an RAI on that. That piping is in the scope. I've got a picture of it here if you want to see it. But it's the riser piping that goes from the header into the generator.

DR. BONACA: If I could see that?

MR. RINCKEL: Sure. Oh, wait, let me make sure I brought it.

DR. BONACA: So you don't have two systems. Because also I found at times it's referred to as auxiliary feed water system; at times it's an emergency feed water system. I think the application is auxiliary, and the SER is emergency. So I thought maybe they're two different systems. I wanted to understand.

MR. RINCKEL: I apologize, I didn't bring

the picture of the generator.

DR. BONACA: All right.

MR. RINCKEL: But what it is is there is a main feed water header, there's two of them, and there's riser piping that goes up and attaches to the shell of the generator. And all of that's in scope. And emergency feed water has a similar application, but I think it goes almost all the way around, it's a header, and there's riser piping that goes up and attaches to it. All of that is in scope.

DR. BONACA: Okay.

MR. RINCKEL: And what was in the application was an error. That was clarified in RAI response.

DR. BONACA: All right. Is the mechanical seal package of the reactor coolant pumps in scope?

MR. YOUNG: Sorry, what?

DR. BONACA: The mechanical seal package in scope for the RCPs?

MR. YOUNG: No. The seals are replaced based on --

DR. BONACA: Because you have periodic replacement.

MR. YOUNG: Right. So they don't have a long life.

DR. BONACA: All right. One question I had was regarding the reactor vessel head leakage monitoring piping, which was excluded, and the staff accepted that on the basis that Arkansas estimates that the leak flow would be within the capacity of the makeup system. Could you explain to me what estimates mean?

MR. YOUNG: Well, first of all, the head leak-off path is after the first o-ring in the reactor vessel head, and it does have an orifice in it, or a small opening that goes into the piping. So what we did is we did a review on what would happen if that was orifice was exposed to the full RCS pressure and how much flow we would get out and could we handle it with our makeup capacity? And we found that we could. But in reality the path to get there is so torturous that the flow would actually be much lower than that.

DR. BONACA: Okay. But still you performed the calculation.

MR. YOUNG: Yes.

DR. BONACA: All right. So it wasn't just a judgment.

MR. YOUNG: Oh, no; you're right. Right, we did some analysis on it.

DR. BONACA: Yes, I was just questioning

the word "estimates."

On the emergency room drains there was a request for additional information, and then you said that there is a drain there that is a 10-inch drain, I believe, that will allow you to prevent flooding. What prevents the drain to be clogged, I mean, and to have the flooding?

MR. YOUNG: The drain that was being referred to there is actually a pipe. I think 10 inches, is that what --

DR. BONACA: Yes.

MR. YOUNG: It's a fairly big pipe. It's actually a hole in the wall.

DR. BONACA: It's a 10-inch pipe, yes.

MR. YOUNG: It's an exterior wall, and it's just a straight pipe right through the wall, so there was no aging mechanism or anything that could come into play.

DR. BONACA: So it's not a question of aging. It's a question of -- no, I understand.

And I had one more question. It was of the auxiliary building hitting a ventilation. They have a function of maintaining 60 degrees during winter. Now, I don't know, maybe you never get below 60 degrees in America, but the question I had was do

you have -- are the heating components in scope?

MR. YOUNG: I believe the way that's handled, pressure boundary components are in scope. So any portions of the system that had pressure boundary would be. I don't believe we had -- you're talking about electrical heating elements?

DR. BONACA: Yes. Because the 60 degrees contingent is to prevent components from freezing.

MR. YOUNG: Right. The electrical equipment, like heating elements and so forth, are considered active, because they have to be energized in order to perform their function. So they were excluded upon that basis.

DR. BONACA: Okay. I agree with that. Okay, thank you.

MR. GALLETTI: Okay, if I could, I'd like to switch to a quick discussion of the differences between the Oconee review and the ANO review with regard to the scoping methodology, specifically looking at the design basis events, which I understand from previous discussion was a topic of concern.

With respect to ANO, clearly, as part of their scoping methodology, they looked specifically at their Chapter 14 accident analysis events. But far in addition to that, as part of their Q list development

process and as part of this ULD development process that we discussed earlier, the applicant went far beyond Chapter 14, clearly looked at all of the FSAR as it related to the events, and then went beyond that still to consider the current licensing basis.

And if you look at that supporting documentation, the ULDs and the Q list development process, when we went through that as part of the on-site audit, we were able to take a look specifically at the types of information that the licensee had employed for those reviews.

In doing so, we confirmed that they had looked at operational experiences, they had looked at commitments they had made to the NRC regulations, they had looked at exemptions that were made to the license. So they really encompassed all of their CLB, as far as the definition was concerned, in those reviews. And it was a major difference between the two right off the bat.

The second difference which was brought up had to do with the definition of safety-related. For the Oconee review, they relied on, basically, three barriers to the release as their definition. For ANO, as was brought up, they relied on basically the 54.4 A-1 definition -- A-2? And A-2 definition for what

constitutes safety-related.

So in that respect, we were aligned from the very beginning with ANO-1 in terms of coming to a formal and agreeable definition.

DR. BONACA: Now, the difference in definition between the Oconee application and the Arkansas, did it lead to significant differences in the equipment that is in scope?

MR. GALLETTI: I don't believe it really led to a change in the equipment versus led to an understanding of if the requirement was that you look at these three criterion, instead of doing that you looked at these criterion, what was the nexus? How could the staff make a safety finding that in fact by using these other criteria, that you were using the same approach or was going to have the same effect.

DR. BONACA: I don't want to reopen the issue of Oconee. We know that was a difficult scoping process. But as we go forth, for similar plans, I would expect that once we make a determination that certain components had to be scoped, that logic should extend to sister plants. And I'm not saying that they'll identical these plants, but they're very similar.

MR. GRIMES: Dr. Bonaca, this is Chris

Grimes. I think Greg has struck on it more from the standpoint of our ability to understand the current licensing basis and the associated intended functions that are relied on is going to be easier when there's a process and a methodology associated with maintaining that Q list that is as comprehensive as the one that Entergy employs at Arkansas.

Our struggle at Oconee was more from the standpoint of understanding their licensing basis. With the resultant set of components, we would expect to see only minor differences in plant licensing basis. So it really gets to our ability to understand and have reasonable assurance in the scoping process that is benefitted by a process that maintains the licensing basis with such clarity.

MR. GALLETTI: And I guess to close out this discussion, the final change, or difference, between the two applicants was that with the Oconee review, initially they looked at their accident analysis design basis events and then included natural phenomenon and external events. And one of the areas of concern or issue was the anticipated operational occurrences and defining what those are and scoping those in. And there was a lot of discussion between the staff and the licensee on doing that.

With respect to Arkansas, we didn't see the same issue arise, again, as a result of their Q list development process and their ULD development process. Those anticipated operational occurrences were in fact considered during those review programs.

In conclusion, there were two open items as a result of the scoping methodology. The first is the applicant needs to provide a technical justification for not including in-line flow orifice flow control intended function to ensure proper sodium hydroxide injection rate for pH control.

The second open item we currently have is to have the applicant provide a technical justification for not including fire protection jockey pump, carbon dioxide systems, fire hydrants, the water supply to the low-level rad waste building fire protection system and the piping to the manual hose station as being within the scope of license renewal and subject to an AMR. I believe both of these issues have been previously brought up today.

DR. BONACA: As part of this open item is the question also about fire water storage tank. Is there a fire water storage tank or is the source of water --

MR. YOUNG: The source of water is our

service water system, the lake, so it's an infinite source.

DR. BONACA: Okay. Thank you.

MR. GALLETTI: That concludes my presentation. Thank you.

DR. BONACA: Thank you. Any other questions for Mr. Galletti?

MR. PRATO: Next presentation will be "Common Aging Management Programs," by Meena Khanna.

MS. KHANNA: Good morning. My name's Meena Khanna. I'll be talking about common aging management programs, and I guess I'll go ahead and start.

A common aging management program, as you already may know, is a program that covers and manages the applicable aging effects of two or more systems' inner structures. Entergy identified 12 common aging management programs in their ANO-1 LRA, and these include the Chemistry Control program, the QA program, structures and system walkdowns, the Heat Exchange Monitoring program, buried pipe inspection, Wall Thinning Inspection program, Boric Acid Corrosion Prevention program, flow accelerate corrosion prevention, leakage detection and reactor building, oil analysis, Reactor Building Leak Rate Testing

program and the ASME ISI program.

The staff and the contractors evaluate the Aging management program against the following elements, as discussed in the standard review plan. These include scope, preventive actions, parameters monitored, protection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, admin controls and operating experience.

Now, there's three of those that are covered under the Corrective Actions program, as was stated in the LRA. For ANO-1, the elements involved corrective actions, confirmation process and admin controls are all discussed in the Corrective Actions program, so we don't address those elements in the SE under those.

Okay. For open items, there were no significant open items. However, there are a few minor FSAR supplements that will be needed to be done by Entergy. They're listed in the SE. We don't have to go into those, because they're not really important. They're just basically summaries that need to be beefed up in the FSAR supplement.

Okay. Plant differences. If you compare the ANO-1 LRA to the Oconee, basically, with respect

to the common aging management programs, Entergy's description of the aging management programs were written very closely to those for Oconee. And we noted a few differences. If you compared the elements to those of the SRP, there are some differences; however, we were still able to do a parallel review. So, basically, you know, we didn't have a problem in reviewing those programs.

ANO-1 applied many of the lessons learned in determining their aging management programs. That was the difference with Oconee. And, finally, the aging management programs for ANO-1 were very similar to those for Oconee. There were only a few deviations, and those were due to site-specific differences or limitations, such as the Buried Pipe Inspection program.

DR. BONACA: Okay. Of this common aging management programs, some of them are the new programs, right, like the Buried Pipe Inspection program --

MS. KHANNA: Right, exactly.

DR. BONACA: -- Heat Exchange and Monitoring program. And some of them are existing programs.

MS. KHANNA: Exactly.

DR. BONACA: Okay. Now, okay, we have some questions about the new programs. And you use the ten elements of the SRP.

MS. KHANNA: Right. We look at the SE. That's how we actually evaluate them against those ten elements.

DR. BONACA: That's right.

MS. KHANNA: A couple of them were a little different the way they were written up, but you could still get the same information if you read the LRA.

DR. BONACA: Okay. For example, the Flow Accelerated Corrosion Prevention program, that's a standard programs or existing program --

MS. KHANNA: Right.

DR. BONACA: -- that's being used. In fact, those, in the evaluation, it's referring to standards that are in place already.

Okay. Any questions for members regarding this? Thank you.

MR. PRATO: "Reactor Coolant System," Andrea Lee.

MR. LEE: Good morning. My name is Andrea Lee, and I work in the Materials and Chemical Engineering Branch. I was the technical monitor for

the contract to review the RCS and also the lead reviewer.

And in terms of an overview, there were several topical reports for the RCS system. There was one for the reactor vessel, for reactor vessel internals, for piping and also for the pressurizer. And there were several applicant action items in each of those reports, which license renewal applicants have to respond to.

Most of the applicant items were addressed in the initial application, but through the request for additional information process, we got expanded information and additional clarifications, which allowed us to draft the safety evaluation report with no open items.

In terms of differences in Oconee and some of the other applications, one difference was the Alloy 600 and Alloy 82/182. The applicant is monitoring the locations that are most susceptible to cracking during the period of extended operation. And the method used to identify these locations was a susceptibility model. That model is similar to a model that was accepted for the CRDMs, and that was based on an EPRI model.

And just as a summary, the model that was

used, there was a reference Alloy 600 item that was picked. And that item was the pressurizer instrumentation nozzle, and that is a nozzle that was found leaking in 1999 -- or excuse me, 1990. Once that item was selected, there is a relative time to crack initiation that was calculated for the item. So to extend that to the other locations, a susceptibility factor was calculated.

And throughout the process there was a comparison of material parameters and other items, such as chemistry, in order to extend that reference to the subject component, Alloy 600 component that was being compared. Once that process was done, there was a susceptibility factor calculated for the new item. And in terms of the items that were determined to be most susceptible, they were all piping components in the pressurizer.

Another difference was the way small bore piping was handled. And just as background, small bore piping, as you probably know, is piping that's less than four inches nominal pipe size. And also as background for the ASME code, any piping that's between one inch and four inches, there's no requirement for volumetric examination. There's just a surface. And for any piping less than one inch,

there's no volumetric or surface requirement.

So in light of that, and the final safety evaluation for the piping topical, the staff suggested that all applicants do a one-time inspection. And ANO was unique in that they implemented a risk-informed process. And through that process, they picked the most susceptible locations. And from that, they're going to do an ongoing program. And this was already approved for the current license.

So it was just extended into, and the materials and the parameters were looked at for the period of extended operation. So because of that extension, it negated the need to have a one-time inspection. This is an ongoing program, which is an improvement than just doing the one-time inspection.

And the --

DR. BONACA: If I remember now, the previous applications we had one-time inspection in a susceptible location.

MR. LEE: Yes.

DR. BONACA: Right? So this is now a periodic inspection.

MR. LEE: Well, for the -- if I'm not mistaken, for the other applications it was one-time inspection for a susceptible location.

DR. BONACA: Yes, that's right.

MR. LEE: And just as a matter of interest, the susceptible locations were the pressurizer spray line, make-up and purification lines, letdown lines, and cold leg section drain lines. And these are all one and a half- or two and a half-inch lines.

And during the course of the request for additional information process, we got very detailed in asking, "Well, this is a good procedure for between one and four. Is this extended to less than one?" And throughout the process, it's the same materials and the same kind of considerations, so that was rolled into the evaluation for all of small bore piping. So we didn't have to keep making the distinction between less than one and between one and four.

DR. BONACA: Okay.

MR. LEE: And that's all that I prepared, unless you have any more questions.

DR. BONACA: Now, there are no Class I piping fabricated from CASS-1 at Arkansas-1; is that correct?

MR. LEE: Pardon me?

DR. BONACA: There are no Class I piping

fabricated from CASS component?

MR. LEE: No.

DR. BONACA: In Arkansas. Now, the SER refers to five leaks associated with RCS small bore piping --

MR. LEE: Yes.

DR. BONACA: -- which have been identified in the past? And there's a comment that says that the applicant states that all leaks and cracks were caused by vibration of fatigue due to design problems. And how far back in time -- oh, yes, I can see that. As late as 1998, however, it occurred.

MR. YOUNG: Yes. Right. What we found was all of those leaks that occurred before, when we did our root cause evaluation, identified some sort of a vibrational problem or a support problem or a change in the way we operated the plant. And the solution in all those cases was to do a design change to correct the problem that caused the cracking.

DR. BONACA: Okay.

DR. SHACK: I guess I had one question. I'm a little surprised to find that everybody believes Alloy 600 is the more limiting component over the Alloy 82/182, and so that when you look at the most susceptible Alloy 600, you've bounded the 82/182. And

I just wondered if any rethinking of that since the summer incident?

MR. LEE: That may be a better question for --

MR. RINCKEL: Yes. This is Mark Rinckel. The program that -- Alloy 600 program that Arkansas has relies upon the B&W Owners Group program. And it includes all the Alloy 600 items and all of the Alloy 82/182 weld locations. Up until this point, it was pretty much expected that the base metal would be the more limiting item. Recent events may change that.

DR. SHACK: Certainly in my laboratory tests I wouldn't believe that.

MR. RINCKEL: Well, it was because of the stresses and the way it was fabricated, at least our components and what we had seen before. You know, the nozzle that cracked at Arkansas was the base metal; it wasn't the weld. And so for the B&W design components, that's what we had seen.

But this is a living program, and they're going to have to go back and see how this new information affects the ranking. And the ranking was done for ANO, as well as Oconee. Oconee used a similar type ranking process, and identified the top five locations amongst the three. But the program

will evolve, you know, as they get more operating data and so forth.

DR. SHACK: Yes. It's hard to look at one without looking at the other.

MR. RINCKEL: Yes. So to answer your question, every weld and every Alloy 600 item is catalogued and is in the program. It's how it's treated, you know, will evolve and will change. And it may result in focusing on different locations for inspection.

MR. ELLIOT: Barry Elliot, Materials and Chemical Engineering Branch of NRR. As far as a weld, 82/182 welds, that's a current problem. We're evaluating -- the industry is a proposing a program right now to evaluate the entire -- all welds in the reactor coolant pressure boundary that are 82/182. And whatever program we come up with for those welds will carry forward into the license renewal term.

DR. SHACK: I guess I had one other comment too, and that was in the SER, there was a -- they were evaluating the program for thermal fatigue, and they were taking credit for the primary water chemistry. Now, I'll yield to nobody in my dedication to good primary water chemistry, just how much it buys you in terms of thermal fatigue, I'm a little

skeptical.

MR. ELLIOT: We agree. And that's why we have the Small Bore Piping program.

DR. SHACK: Well, but if you read the SER, it's a preventive factor for thermal fatigue.

MR. ELLIOT: Yes. And that's why we have inspections, to find that out.

PARTICIPANT: I don't believe that's the only aging management program.

DR. SHACK: No. It was just under one of the ten element assessments. I agreed that it certainly does -- you wouldn't want bad water chemistry on top of thermal cycling. Good water chemistry isn't going to save you from thermal cycling.

MR. GRIMES: When we go back -- this is Chris Grimes -- when we go back and address the open items in the final safety evaluation, we'll check to make sure we haven't overstated water chemistry.

DR. BONACA: Now, my understanding is that for this presentation it includes the reactor vessel and pressurizer, right?

MR. LEE: Yes.

DR. BONACA: Not the TLAA portions. They'll be later.

MR. LEE: That will be later.

DR. BONACA: And I guess for this component, it's pretty much B&W document supply.

MR. LEE: Yes. The only component that did not have a topical was the pump. There may have been another one, but from my recollection, the reactor coolant pump did not have a topical.

DR. BONACA: Okay. And there is a specific description here of the programs to manage aging.

MR. LEE: Yes.

MR. RINCKEL: This is Mark Rinckel. The other component that did not receive or have a topical report was the steam generator, the OTSG. And, again, the review of that was very similar to Oconee, since they have the same OTSG.

DR. BONACA: Any comments on that, Bill. You had some comments yesterday.

DR. SHACK: I looked at that again. I have no idea -- what is the status of the steam generators at ANO-1? Do they show degradation? Are there plans to replace them or they're still marching along?

MR. YOUNG: They're still marching along fairly well, but we are in the early stages of doing

an evaluation for possible replacement because of the industry experience and the Oconee experience. So I think at this point it would be safe to say we don't expect them to last the full 40 years, but they haven't started degrading to the point that we have to make any definite plans for replacement. We're just doing some preliminary plans at this moment.

DR. BONACA: Okay. Thank you. Any other questions for Ms. Lee? No, so thanks a lot.

MR. LEE: Thank you.

DR. APOSTOLAKIS: Speaking of risk-informed stuff, what is the core damage frequency at ANO Unit 1 from the IPE?

MR. HARRIS: For the IPE, it was 3.47 E --

DR. BONACA: Please introduce yourself.

MR. HARRIS: This is Richard Harris at Entergy. For the IPE, I believe the core damage frequency was around 3.67 E minus 5. I may be off a little bit, but it was a net in that area.

DR. APOSTOLAKIS: You say from the IPE. I mean have you done anything to it afterwards?

MR. HARRIS: Yes. We have done a couple of revisions to --

DR. APOSTOLAKIS: And what is it now?

MR. HARRIS: The current core damage

frequency is around 5.6 E minus 6.

DR. APOSTOLAKIS: Went down by, wow, almost --

MR. HARRIS: There are some specific reasons that for. One of the dominant contributors to risk in the IPE was the station blackout sequences lost that power. Since that time, we've put in a SBO diesel, which took us from around 3.6 down to about 1.90 minus 5. And then our small break LOCAs became a pretty dominant contributor after that revision. We've since gone to new reg 57.50. We're initiating the frequencies. And that's not the small break LOCA frequencies. Our contributor's down significantly. And there's some other changes included in that, and those are addressed in the environmental report, but those are the main things that took the core damage frequency down.

DR. BONACA: And this is only internal events, correct?

MR. HARRIS: Yes.

DR. BONACA: And you've done the IPEEE as well?

MR. HARRIS: Well, we have done IPEEE. We did a vulnerability assessment for fire and a seismic margins method for that portion. We haven't

calculated a core damage frequency for our fire analysis.

DR. BONACA: But you will?

MR. HARRIS: Well, at this point, we'll see where we're going with that. The intent of the IPEEE effort was to identify vulnerabilities and weaknesses in your operation system, et cetera. And we've done that. And we've met the intent of IPEEE. But there was no requirement to generate a core damage frequency in that effort. And although we did use our PSA models and fire methodology to do screening, we didn't calculate an absolute core damage frequency for fire.

DR. BONACA: Well, I guess that's not a question to you, but I'm really curious now how one can find vulnerabilities without calculating the core damage frequency.

MR. HARRIS: Well, you can -- what you can do, or what we did, and I think most of the industry did, was we did a screening analysis. By removing those components within the zone that would be affected by a fire in that zone, you can then quantify and determine what your CDF is. And if it's below 1E minus 7, it screens, you're done. If it's above 1E minus 7, then you go in and you look and say, "Well,

is this -- does this really fail or does this really impact this equipment? What are the circumstances?" And you work on it until it either screens or it doesn't screen.

And once it gets -- if it screens, you stop. If it doesn't screen, then you work on it a little bit more until you get to a point where you feel comfortable that you've adequately assessed that zone. Then you go to the next zone and you do the same thing. But you're not really trying to determine an absolute core damage frequency for each and every zone. You're simply doing a screening analysis.

DR. BONACA: Okay.

MR. PRATO: The next presentation is on "Engineering Safety Features," by Bart Fu.

MR. FU: Again, my name is Bart Fu. I'm with EMCB NRR. I'm also the tech monitor for the ESF section during ANO's license renewal process.

Just a brief overview of ESF system. They consist of ECCS actuation part of it. That's the LPI/HPI. And core flood. Then it also includes reactor building spray, reactor building cooling, purging, isolation. There are a few more: sodium hydroxide system, hydrogen control system. So they're designed, again, for the engineered safeguard purpose

in case of a LOCA, in case of -- well, during shutdown you use them to cool the core.

Most of the components are made of stainless steel and carbon steels. In a few systems, we've seen 90/10 carbon nickel and also inc alloy 800. And they're exposed to air, ambient air, water and borated water. Those are the environments.

Aging effects identified. Major aging effects are pretty much a loss of materials, cracking and fouling. Aging management programs. I believe Meena discussed the common again management programs a little earlier. For a few of the systems, they have specific aging management programs just for the specific aging effects identified in the process.

We don't have any open items. There is one item that was added to the supplemented FSAR. That items calls for a one-time inspection of the piping in the sodium hydroxide system. But all issues are resolved at this point.

I was told to focus on the plant differences. Really, as you all are aware of, they're sister plants with Oconee, and even the process is pretty much similar. The way I've seen, you know, they've got, I think, a little bit more streamlined in their process. The few differences that I know of,

one is the hydrogen control system. It was identified and reviewed as part of the auxiliary system in the Oconee's process but as an ESF system, part of the ESF. In ANO's process, under the same -- it should be listed the same system.

Under this hydrogen control system, no aging effects were identified for the Oconee's review process, but at ANO, fouling was identified as an aging effect. That was the only difference for this system. And it's actually fouling at the external surface for the EP changers. They're exposed to a gas air environment.

The other difference, halide impurities. The concern was raised during the process, and we talked to the plant engineers about the -- we called it a little bit too high of impurities in the sodium hydroxide system -- or sodium hydroxide. And we addressed this issue. And it resolved the item I mentioned that was added to the supplemented FSAR that calls for a one-time inspection of the system.

DR. SHACK: I mean there was some difference in the specification for the purchase of the sodium hydroxide that would let you expect more halide here?

MR. FU: I'm not sure about Oconee, but at

ANO that was the case, yes, because they may have purchased sodium hydroxide from different sources. But when I reviewed the Oconee's SER, this concern wasn't raised. So it could be the sources, but I'm not so sure.

DR. SHACK: What temperature is that system? I mean that stuff sits around at room temperature, basically?

MR. FU: Right. Ambient air. So we're talking about 90-some.

DR. SHACK: Oh, so it's -- yes.

DR. BONACA: Much of this piping is exposed to boron, right?

MR. FU: Boron streaming.

DR. BONACA: I'm sorry? Many of the systems are exposed to boron.

MR. FU: Right. Or to water or boron.

DR. BONACA: Yes. So I guess -- so this must be controlled by some kind of -- oh, yes, boric acid, corrosion --

MR. FU: Right.

DR. BONACA: -- carbon. Is this problem looking at piping inside and outside only or just simply focusing on the internal corrosion of piping?

MR. YOUNG: Are you referring to the Boric

Acid Corrosion Prevention program?

DR. BONACA: Yes, yes.

MR. YOUNG: It's external piping carbon steel and components. So the program is basically a walkdown inspection looking for boric acid crystals. And then if we find them, we trace them back to the source and see if it has contacted any carbon steel components. And if so, corrective action is taken.

DR. BONACA: Okay. Now, this piping typically sits there standby with boric acid diluted in the water. And what prevents internal corrosion, I guess, is lining of the piping?

MR. YOUNG: All of the piping that has borated water in it is stainless steel. There is no carbon steel, right. The only time we get boric acid on carbon steel is if it leaks out and gets on another piping system that is carbon. But all internal surfaces are stainless that have borated water.

DR. BONACA: So mostly you're looking at joints, you're looking at --

MR. YOUNG: Yes. Flanges --

DR. BONACA: Flanges.

MR. YOUNG: -- and valve packing and things like that.

MR. FU: And just to add to your point,

when there's a leak, you see on the external surface of carbon steel, and then they have maintenance rules and other programs to catch it.

DR. BONACA: Yes. And so -- I mean this is a standard program, but you come back and there are no changes to it for the extended period of operation.

MR. YOUNG: That's correct. That's correct. It's the existing program.

DR. BONACA: Okay. Thank you.

MR. PRATO: Any additional questions? Thank you.

The next presentation will be on "Auxiliary Systems," by Merrilee Banic.

MS. BANIC: Good morning. My name is Lee Banic, and it's a pleasure to be here to present our safety evaluation of the 13 auxiliary systems. As the lead technical monitor for the contract on the auxiliary systems for the Materials and Chemical Engineering Branch, I'll be making the presentation. Assisting me is Renee Lee, the technical monitor for the contract for the Mechanical Engineering Branch and Jim Davis of the Materials and Chemical Engineering Branch. Our contractor, Idaho National Labs, performed the review.

The ANO-1 auxiliary systems consists of

the following 13 systems: spent fuel, fire protection, emergency diesel generator, auxiliary building sump and reactor building drains, alternate AC diesel generator, halon fuel oil, instrument air, chilled water, service water, penetration room ventilation, auxiliary building heating and ventilation and control room ventilation.

We reviewed the application to determine whether the effects of aging on the system components were adequately managed. There were many kinds of components. They include pumps, piping, valves, drains, screens, tanks, cylinders, fans and filters, among others.

The environments were water, meaning borated, treated and well water, external buried, external ambient, internal ambient and fuel oil. The aging effects were cracking, loss of material, loss of mechanical closure integrity and fouling.

Of the programs we reviewed, most were existing programs proven by operating experience and common to the industry. Many apply to more than one system. The programs are: reactor building leak rate testing, maintenance rule, Oil Analysis program, preventive maintenance, buried pipe inspection, ASME section 11, ISI inspections and augmented inspection,

chemistry monitoring programs, primary, secondary and auxiliary systems, Boric Acid Corrosion Inspection program, spent fuel pool level monitoring, service water, Chemical Control program, fire suppression water supply system and sprinkler system surveillance, fire water piping thickness evaluation, control room halon fire system inspection, emergency diesel generator testing and inspections, reactor coolant pump oil collection system, alternate AC and AC diesel generator testing and inspection, Diesel Fuel Monitoring program, instrument air quality, wall thinning inspection, Heat Exchange and Monitoring program, Service Water Integrity program and testing of the penetration room and control room ventilation systems.

We had no open items. We found that ANO has shown that the effects of aging on the auxiliary systems will be adequately managed so that there is reasonable assurance that the systems will perform their intended functions in accordance with the current licensing basis for the period of extended operation.

For items that are unique or different from Oconee, we had the Buried Pipe Inspection program. This is a new program. ANO's program is

consistent with programs acceptable according to the Generic Aging Lessons Learned Report.

DR. BONACA: Okay. I had a question regarding the alternate AC generator. The starting receivers, are they in scope? That wasn't clear if they were in scope.

MR. YOUNG: Yes.

DR. BONACA: They are in scope.

MR. YOUNG: Yes. Everything associated with the, we call them the station blackout diesels, or the alternate AC diesels, were in scope.

DR. BONACA: Part of the pressure boundary.

MR. YOUNG: Yes.

DR. BONACA: The other question I had was instrument air. Now, the passive components or elements of the compressors, are they in scope?

MR. YOUNG: No, not the compressors. The only portion of the instrument air that was in scope were the portions that connected directly to a safety system or were part of a reactor building isolation system. But the actual instrument air system itself is not safety grade.

DR. BONACA: So you don't have any passive component that you had to look at. I mean you're

looking at it as an active component.

MR. YOUNG: Well, the passive equipment that we looked at were pressure boundary on the tubing and the piping and certain valves that we credit to ensure that we don't have a loss of air on those systems that require air. The compressors themselves are not -- we don't depend on them. We have air accumulators for those systems that have a safety function that requires an air supply.

DR. BONACA: Okay.

MR. YOUNG: Yes.

DR. BONACA: All right. Okay. Thanks. On the -- one thing I noticed in many of these programs, some of them make reference to preventive maintenance as a program that supports it; some of them don't. And yet it seems to me that preventive maintenance is part of those components too. It's just an oversight or --

MR. YOUNG: No. You're right. Preventive maintenance is a part of every system in the plant. But what we did is on those systems that required some sort of aging management program, we looked to see if we had a preventive maintenance activity that we could credit for that.

DR. BONACA: I see.

MR. YOUNG: So the ones you see in the document there are those that we specifically credited for an aging management review.

DR. BONACA: Because they do perform an aging management role.

MR. YOUNG: Right.

DR. BONACA: All right.

MR. GRIMES: Dr. Bonaca, this is Chris Grimes. And I'd like to add that Safety Evaluation explicitly considered in each of the programs whether or not we felt there was a need to credit some form of preventive maintenance.

DR. BONACA: All right. So I understand now. We really have a benefit from it that you can claim for the aging purposes. Otherwise you don't reference that.

MR. GRIMES: Yes. The important part is whether or not we felt that was a need to credit a preventive maintenance activity specifically for the purpose of managing the aging effect.

DR. BONACA: On the control room, this is part of the system, yes. Are the door seals and other penetrations in scope?

MR. YOUNG: Yes. All of the pressure boundary for the control room was in scope.

DR. BONACA: Okay. And I had a question here. I think we discussed it before, the buried piping for the extent on the environment. My question was more like you've had experience with it, because you already set it on a frequency of once almost every five years. Did you have any problems you identified through these inspections in the past?

MR. YOUNG: As far as aging problems?

DR. BONACA: Yes.

MR. YOUNG: The problems that we've found in the past have primarily been associated with some sort of an event.

DR. BONACA: Okay.

MR. YOUNG: For example, we had an acid leak that was routed through some abandoned piping and got down into some buried piping and ate away the coating and the pipe until a leak occurred.

DR. BONACA: Yes.

MR. YOUNG: And so as we went down to repair that, we inspected the piping in the area seeing if the acid had exposed any other piping.

DR. BONACA: Outside of those kind of failures that you have seen because of root cause -- I mean here you have a cause that --

MR. YOUNG: Yes.

DR. BONACA: -- have you had any experience of failures of buried piping that you did not expect?

MR. YOUNG: No, no. We haven't found any instances where the -- all of this piping is coated with a tar-type coating.

DR. BONACA: Right.

MR. YOUNG: And the only time we've had problems so far has been when that coating was damaged for some reason, such as the acid leak. So as long as the coating is in tact, we haven't seen any problems.

DR. BONACA: Okay. Thank you.

MR. PRATO: This is Bob Prato. During the inspection, the aging management review inspection, we thoroughly reviewed the Buried Pipe Inspection program. We looked at all the operating history, and we have an extensive write-up in the inspection report, which should be issued in about 30 days.

DR. BONACA: Okay. Oh, yes, on the Emergency Diesel Generator Testing and Inspection program, it's interesting that, you know, the frequency of tests and visual exams are managed by plant procedures. Now, question, just for learning purposes, you know, if you make a change to those procedures at some point in the future, for example,

by stepping down the frequency of the inspections or tests, okay, how does that tie up to be accident of the aging management commitments?

MR. YOUNG: In the diesel, the emergency diesel case specifically, what we found was that the current inspection intervals, which are normally a major inspection every 18 months and then some more minor inspections during the surveillance period, which may be quarterly or monthly, was far more frequent than what's required for aging management. So we went ahead and committed to those programs simply because they're existing programs.

But if we were only looking for aging effects, we would have much longer intervals than what's required for the active function of the system. So we're crediting something that is looking for active failures, but we're also finding it would see any evidence of corrosion during those inspections.

DR. BONACA: Yes. In some cases, that may not be the case, however. You may have instances where -- I'm trying to understand now, you have commitments in the FSAR addendum, and I understand that. But you must have a configuration management program of some type that ties commitments you made for existing programs tied to aging, to the LRA, so

that you can flag it through that.

MR. YOUNG: Right. The way that will work is we will have the commitment in the SAR that changes, the SAR supplement that comes out with the new license. And then that will tag those specific procedures as being associated with a SAR commitment. And then any changes that we would want to make will have to go through the full 50.59 review process to determine if we -- that we're meeting our commitments.

DR. BONACA: Yes. Okay, thank you. I don't have any other questions of this issue. Thank you. Any other questions?

MR. PRATO: Next presentation is "Steam and Power Conversion System," by George Georgiev.

MR. GRIMES: This is Chris Grimes. While George is getting settled in his chair up there, I'd like to mention that we're embarking on an effort here to get about three hours ahead of your schedule. And so for your planning purposes, I think we now have all of the staff representatives to cover the afternoon materials. And so we're going to continue to try and march through and cover the safety evaluation topics hopefully before lunch.

DR. BONACA: Now, there is a presentation scheduled also, "The License Renewal Environmental

Review Process."

MR. GRIMES: Yes. We can get Mr. Kenyon here. He's not here. He was here. But we can bring Mr. Kenyon in if you want to cover that before lunch.

DR. BONACA: Anyway, let's -- why don't we just proceed about half an hour and see where we're going at that point. And then we'll make some decision of how long this meeting will last.

Okay. So now we are down to "Steam and Power Conversion Systems."

MR. GEORGIEV: Yes, good morning. My name is George Georgiev, and I was the technical monitor for the steam and power conversion system, and ARGON National Laboratory did the actual review.

The steam and power conversion system includes four subsystems: Main steam, main treated water, emergency feed water and the condensate storage and transfer system.

The materials for those subsystems are mainly carbon, steel. It does include some stainless steel, bronze and copper. The environment in which these systems operate is mostly treated water, which is a high purity water and steam, and the external environment is ambient, inside building environment in the reactor building turbine and the auxiliary

building.

There are 11 aging management programs identified in the application. As example, some of them are Flow Accelerated Corrosion Prevention program, ASME Section 11, inspection -- Wall Thinning Inspection program, maintenance rule and some others.

The components for those systems are standard piping components: piping, valves, pumps, feedings, there are some coolants and heat exchanges. And it's nothing unusual.

The aging effects that the application identified with these systems is general corrosion, selective leaching involving CASS and peeling and stress corrosion. Again, those are expected degradation effects for these type of materials and environment.

We did not identify any open items. And as far as plan differences and Oconee and Arkansas one very minor. Like, for instance, in the materials area, in the Oconee application, there was copper nickel for tubes used here. They have something else. They do have copper tubes in some of their coolers. As far as the aging management programs in this plant, there are 11 aging management programs and Oconee's, there were only four aging management programs

identified to control aging effects.

And that's basically it. That concludes our presentation.

DR. SHACK: When I read the report, I was sort of interested in the flow-assisted corrosion, that they had done 900 inspections and replaced 125 components. That seemed to me a larger number. But I assume all that was really in the secondary system, by and large.

They're relying on check works, which, as I understand it, would monitor sort of the most susceptible regions, and then you would do an analytical thing to sort of assure yourself that you're okay. Are they actually directly making ultrasonic measurements on any part of the feed water system or the main steam or those would all rank low in the susceptibility and so they're monitoring something else directly?

MR. GEORGIEV: I believe that the latter is the case in the system, including the steam and power conversions and the lower side. However, they do have a Wall Thinning program, which is separate for the steam and power conversion system. They take measurements of the management and compare, you know, how it is to what it was before.

DR. SHACK: So there are direct wall thinning measurements then, for example, in the feed water system?

MR. GEORGIEV: That's right, yes, there is. But it's more in conjunction with the wall thinning problem. See, in this plant, they have subdivided. They have 11 programs, and Oconee, they have four. And part of the reason, I believe, was explained earlier.

They went back to their procedures, their way of doing business. And whatever they can use within these programs and procedures that could be used to do an aging management, they use it. And in doing that, I guess, they ended up with 11 programs. They also have more of Section 11 type of inspection in this steam and power conversion than Oconee had. And maybe I should let them explain better why they set it up the way they set it, but that's how it is. The staff believes it's --

DR. SHACK: Yes. Somehow I had interpreted the wall thinning as some sort of -- you're looking for general corrosion, but I wouldn't have thought that you were doing that on systems that you were monitoring for flow-assisted corrosion.

MR. YOUNG: That's correct. The Flow

Accelerated Corrosion program deals with those systems that have that potential effect, and we do do ultrasonic inspections in certain locations to measure the actual loss of material and then to trend it to see if we have a situation where we need to replace the piping or just continue to monitor it.

Then there were some other piping systems that were identified in this review that could be subject to wall thinning for reasons other than flow accelerated corrosion. That's the Wall Thinning program that was referred to. So it does not include any systems that have flow accelerated corrosion problems, because that's covered under that program, under the FAC program.

DR. SHACK: So, again, coming back to my question then, is any part of the feed water system directly monitored under the DFAC program or it's one of the less susceptible ones, and so you're looking at something else as the lead component?

MR. YOUNG: I'm not familiar enough with that program to say which one is the lead. I know we do a lot of ultrasonic inspections during an outage, but I can't tell you specifically which system is included in that at this point. We can try to get an answer for you, though.

DR. SHACK: It just seemed to me on sort of a risk-informed perspective, I'd worry a lot more about losing that feed water system than I would many of the other pipes that you're probably directly monitoring.

MR. YOUNG: Well, I know that the way the program was set up, we're looking for those areas that are the most susceptible to FAC, and it has to do more with geometry and the way the system --

DR. SHACK: Right, rather than risk.

MR. YOUNG: Right. Yes. In fact, I don't think risk even comes to play on the FAC program.

MR. FU: Are you satisfied, sir?

DR. SHACK: Yes.

DR. BONACA: Any other questions? None, so thank you.

MR. FU: Thank you.

MR. PRATO: Next presentation is going to be on "Structures and Structural Components," by David Jeng.

MR. JENG: Good morning. I am David Jeng. I'm a member of the Mechanical Engineering Branch in Division Engineering. And being there was for us to perform the review of the structure sections. And I participated in the review after the submittal.

I'm here to provide you an overview of the structures and structure components review. The applicant adopted so-called commodity grouping approach in which they put together some materials and environment items in different buildings as one commodity group in just the aging management.

So among the commodity groups, they have presented to us the steel structure -- concrete, prestress concrete, threaded fasteners, fiber, and as an embankment elastomas integral. These are the sibling categories. They categorized, and each of them they addressed their aging effect, their environment, and how they propose to manage -- they are proposing aging management programs.

The materials. Among the key materials are structure steel, carbonized steel, standard steel, concrete precision wires, fire protection material like receiving for the penetrations, elastomas, neoprenes, careful material and PVC water stopped.

With regard to the environment, I think that, yes, so-called protected environment, unprotected environment, high humidity, high temperature, environments and high radiation environment and also some roll water, baronated water, or boric acid concentration and concrete environment.

These are the key environments which we have developed.

Income of aging effects. The major aging effects are the loss of material, cracking and also the change of material properties. And also, in the case of prestress concrete component, we have a loss of prestress due to reaction and cracks of the preceding wires.

And we have not identified any open items. As regard to any difference between the Oconee and the ANO plant, there are a few minor differences. In the case of Oconee, they used Keowee dams and the hydraulic unit to provide power. ANO, we did not have that kind of need. Also, Oconee had the so-called safe-shutdown facility, which is sort of unique, as compared to ANO-1 situation.

And in the case of ANO-1, they have adopted so-called emergency cooling pond, which is the major supplier of water for emergency situations. And they had to perform annual inspection to make sure the pond is maintained. And what they do is they do an inspection to check the pond water and make sure the volume is there. So this is sort of unique in the case of ANO-1 compared to Oconee.

And there are other differences, such as

the trash racks in the infrastructure, which in the case of ANO-1 was not within the AMR domain. And in the case of the Oconee, the turbine building -- they are part of the turbine building susceptibility, so they had to address that portion. And this is the difference between the two plants.

So these are the key differences between the two sister plants. And my presentation concludes at this point.

MR. GRIMES: Actually, I think they're first cousin plants, but --

(Laughter.)

MR. JENG: First cousin plants.

DR. BONACA: Now, under the structural steel portion, there's always a reference to an aging effect being loss of material for the reactor building liner plate. I just have a question regarding the steel liner of the containment. Are there concerns with any corrosion of steel liner outside of the steel liner plate that has been addressed?

MR. JENG: In so far as the particular issue, in the section of the steel liner operating floor, unless there's some expansion allowances, in the past history many plants did encounter some difficulties, corrosion, due to seepage of the waters.

But staff has paid attention in this area. In past LRA evaluations, we asked applicant to talk about their previous experience. In the case of ANO-1, I think they have not encountered this situation which we're concerned. So they are maintaining a good shape of these interfaces.

DR. BONACA: So you have a program to look at it? I mean are you walking down, typically, those locations?

MR. YOUNG: Yes. All of the reactor building liner drills are subject to a visual inspection on a certain frequency. And then we if see any sort of signs of degradation that could indicate that there may be problems with the buried part of the liner, or the embedded part of the liner, then we would have to come up with some evaluations of programs to deal with that. But we haven't had any problems.

DR. BONACA: Because the steel liner goes into the concrete --

MR. YOUNG: Yes.

DR. BONACA: -- and that ties into the liner plate.

MR. YOUNG: The base.

DR. BONACA: So there is a portion which

is not visually accessible.

MR. YOUNG: Yes. Right. But if we don't see any signs of any problems at the surface, where the water or whatever might get into it, then right now that's our program to determine that there shouldn't be any problems further down.

DR. BONACA: Okay. Regarding the concrete, I was looking at page 232. There was a request on the part of the NRC regarding aging effects in an accessible area. And the response from Arkansas was that the concrete used in those inaccessible areas was a high cement contained, low water cement ratio and proper curing. And that's the reason why the applicant stated that we don't have to have an aging management program, and the staff accepted that.

I was kind of -- I mean that kind of claim could be made about any component which is not accessible. And I'm not an expert in concrete structures, just I wanted to understand how you got the confidence that in fact because of these assertions, you don't need to look at these inaccessible structures.

MR. JENG: Okay. In the issue, really, most concern the situation where in a containment it's the basement level. The liner is about two feet deep

of concrete. And the concern was if there was some significant cracks on this two-foot concrete and the water may seep in to become the agent for causing degradation of the liner underneath that.

The staff originally pulls the requirement that applicant should have an aging management program. But soon the interaction and discussion under the context of the LAR report discussion, most of the staff and the applicant comes to a conclusion that if you are ever to conclude it's of high quality, low probability --

DR. BONACA: I see.

MR. JENG: For this reason -- on top of that, they had the maintenance program to perform the regular inspection, as required by the program. And this, too, we come to the conclusion that --

DR. BONACA: Okay. I understand. And you have solid records that shows that you have high cement contained to low water cement ratio and proper curing?

PARTICIPANT: Yes, we do.

MR. YOUNG: Yes. We went back to our construction records to document that.

DR. BONACA: Again, on the effects of aging on the building, I guess, in the tendon gallery,

there's a statement that says, "The applicant states that they have not observed abnormal levels of humidity during four contaminants in the tendon access gallery." And then there's a statement that says, "Corrosion was identified in components during a ten-year and 15-year in service tendon inspections. But this loss of material did not adversely effect the intended function of these components.

Now, I can agree that you had not enough corrosion to affect the function. What does it give you the comfort that we don't need to look at it in the future?

MR. JENG: We do look at it in the future, according to the tendon program. Yes, it is power. It's on the side of the anchor of the tendon --

DR. BONACA: Yes, that's right.

MR. JENG: -- which is part of their regular movement. So it's to be looked at --

DR. BONACA: Oh, so it's back to the program already. The inspection and of course there will be corrective action if he gets to the point.

MR. JENG: Yes.

DR. BONACA: Now, you still have an issue of criteria for corrective action on the tendons that you have an open item on, right? I thought there was

an open item.

MR. JENG: That's only --

PARTICIPANT: On TLAA, sir.

DR. BONACA: Okay. All right. Thank you. I have no further questions on this.

MR. JENG: Thank you.

MR. PRATO: Last presentation on the aging management review will be by Duc Nguyen on the electrical systems.

MR. NGUYEN: Good morning. My name is Duc Nguyen, and I am a technical monitor in the electrical system performed by the INEL, Idaho National Engineering and Environmental Lab.

Today, I'm going to present the aging management program for the electrical system. The applicant yielded commodity component to identify the long-lived passive electric component. That required the aging management review. And you know most electrical components are active, and therefore only three commodity time will identify.

The first one is the connector, terminal block and the cable. The environmental -- this can affect the aging of this component, including the radiation environment and the potential humidity environment and chemical environment.

Also, cable and connector also subject to the frequent manipulation. When you disconnect and connect them more than once, many times, it can create a problem, especially to have a very low voltage current, low voltage implementation cable and connector. That can create a problem. That is sensitive to small variation.

Talking about the aging effect, the aging effect of the connector it would include the potential aging. Aging mechanism will be the corrosion of metal, electrical tresses, water, humidity effect, mechanical tresses and thermal radiation, aging of the organic components. However, the corrosion is not expected because the connector usually in the -- not so bad on dry condition, not in the humidity condition. So it's not supposed to have any corrosion effect.

And mechanical tress is not significant, because, you know, connector does not provide any mechanical support. So the mechanical tress is not the problem. And electrical tresses. Usually, connector can handle lots of current, so electrical trussing not a problem. I had the applicant identify the number of splices that can have the moisture and the temperature effect. And to manage that, they do

the Component Inspection program to manage that.

Also, the applicant also identified connector that is subject to frequent manipulation, like the multi-pin connector screw terminal and the battery terminal post. The effect of frequent manipulation can create wear, loose fitting, cracking, and this can be detected by visual inspection. So they do the good maintenance practice. That means when you disconnect or connect something, they use a good maintenance to check the resistance of that connection.

And connector that are the terminating impeding sensor circuit also has been identified by the applicant. Oxidization and corrosion of the connector pin could interfere with the operation of these circuits. And in order to ensure this does not happen, Electrical Component Inspection program will be established to periodically inspect this connector.

And about a terminal block, the only thing that can affect the aging of the terminal block is the frequent manipulation. But the applicant identified that, you know, the procedure will call for lifting of the lead from the terminal block for testing purpose. This will be to control the aging effect of frequent manipulation.

And the last one is the cable. Cable can have potential aging mechanism due to corrosion of the conductor electrical tresses. Water and humidity affect terminal degradation, aging and mechanical tresses. About corrosion of the conductor, I think it's not a problem, because, you know, conduction usually covered by insulator. So corrosion of the conductor is not a problem.

Electrical tresses can be a problem, because the omit hitting can be significant for the cable. That I wrote in they're continually open with a high current, relative to that and past the limit. However, most of this component, you know, only ruling the normal operation, this component had very low current. Only during the action condition then they can create a high current. But it doesn't happen very often.

Another concern is exposed to the wet environment can be significant aging effect for the medium or high voltage cable, especially the medium cable that you have buried in the conduced. This can have significant effect.

Chemical attack of the organic material also can be potential effect of this cable. Radiation tests are not significant because this is not a cable.

So the radiation tests for this is less than one to the eight rad, so it's not a problem. To manage this aging effect, the applicant does the Component Inspection program. They use the Inspection program to manage the aging effect of this component.

Right now I would like to talk about an open item that we have. We have the concern about the unacceptable cable, because in the Component Inspection program, there's only visual inspection. And there's only visual inspection with acceptable cable, not unacceptable. And they view the acceptable cable to compare to with unacceptable, and we think that's no comparable, because you cannot do visual inspection for inaccessible cable. And we have a concern with that one. So that one is an open item right now.

DR. BONACA: The concern is that the environment may be --

MR. NGUYEN: Different from the acceptable.

DR. BONACA: -- different from what they should assess.

MR. NGUYEN: Yes, yes. Especially water tree, you know, moisture intrusion, and it can crack the insulation of the cable.

DR. BONACA: This is a separate issue from GSI 168.

MR. NGUYEN: Yes, different.

DR. BONACA: Yes. And Arkansas has committed to essentially meet the requirements of GSI 168 once that is resolved?

MR. NGUYEN: That, let me ask Arkansas. Maybe they can answer that question.

DR. BONACA: For medium voltage cables, irrespective of accessible even. The concern which has been raised through GSI 168 is the ability of maintaining, for example, the environmental capability once they are heated and in wet condition for a long time. I mean because there has been testing that has shown that under LOCA conditions, for example, they would fail in a gross fashion. Has this issue been addressed here?

MR. GRIMES: I'm going to attempt to explain that the resolution of GSI 168, as I understand it at this point, is being treated on a manufacturer basis; that is, that the testing results raise some question about the qualification techniques by -- manufacturer now escapes me. But we're pursuing those results primarily from the standpoint of reflecting on the lessons learned from the testing.

But otherwise, I believe that when GSI 168 is ultimately concluded, and my recollection is it hasn't been concluded yet, that it's still in a process of trying to draw the generic insights.

But we still rely on compliance with EQ rule as an acceptable way to establish a qualified life. And the process by which one maintains qualified life to reflect on testing insights and whether or not the qualification basis needs to be revisited at any point, either in the current term or the extended period of operation.

DR. BONACA: The reason I asked that question is that, first, the issue of GSI 168 is pretty high on the agenda of this Committee of the ACRS. And second, for Oconee, if I remember, we had an implicit discussion in the SER regarding the in fact medium voltage cables.

MR. GRIMES: Non-EQ medium voltage cables.

DR. BONACA: And the need for walkdowns of those components. Yes, I agree with you, that the EQ program requirements are sufficient to --

MR. NGUYEN: Wait, wait. This one is not EQ. We talk about the non-EQ cable. GSI 168, I think they talk about EQ cable, so that's a different issue here. We're talking about here a non-EQ medium

voltage.

MR. PRATO: Cables found outside, exposed to the environment, buried.

MR. NGUYEN: Yes, buried.

MR. PRATO: And could be exposed to groundwater.

DR. BONACA: Sure. And I can see this, and you're asking for a program.

MR. GRIMES: If I could suggest, this is equivalent to the open item that we had on Calvert and Oconee and are still pursuing in generic aging lessons learned in terms of establishing some consistent basis for concluding that on the treatment of the potential for moisture intrusion on medium voltage buried cables.

DR. BONACA: Yes. Well, the reason why I raised that issue was only because of the characterization of buried cable. I thought that the open issue for Oconee was all medium voltage cable.

MR. GRIMES: No. It was inaccessible, whether the inaccessibility comes through being buried or being hidden in a conduit. But the issue is referred to both ways, as buried or inaccessible. But essentially it's the same issue.

DR. SHACK: But didn't Oconee have a

program to look for sort of warm temperature --

DR. BONACA: That's right.

DR. SHACK: -- or radiated conditions on the medium --

DR. BONACA: Absolutely.

DR. SHACK: It was non-EQ, but it was a general kind of --

DR. BONACA: They offered the program, and the program essentially was addressing all cables. They had pictures of cable they had identified in locations where clearly it was accessible, because I took pictures of it, and it was showing the damage of high heat and water intrusion on the jacket of cable.

DR. SHACK: That's what I recall. They looked at the cabling and then they looked where the cabling would be in a high temperature, high radiation area, and then they would do inspections there.

DR. BONACA: Right.

MR. NGUYEN: We talk about inaccessible cable, and I believe at Oconee they committed to test everything for this kind of cable. Look at the manhole to see if the water collects so they can make a comparison to see how the inaccessible cable -- but they commit to do the test.

DR. BONACA: They committed to do

walkdowns and inspect and repair the cable that showed clear degradation. That's all they did.

MR. GRIMES: But my recollection is Dr. Shack is correct, that it's not simply water intrusion by itself that causes a concern about potential degradation of the cable insulation. It's the condition of buried cables or inaccessible cables that also are exposed to other stressors that might cause -- that would provide a basis for you to infer from conditions of accessible cables the point at which buried cables would become in jeopardy and would need to be explicitly checked. And that was the nature of the program.

MR. YOUNG: If I may here, as far as the Arkansas situation, we have committed to an Electrical Component Inspection program that's similar to Oconee for the accessible cables in high temperatures and so on. So we are on the same path with them there. This open item dealt with those limited set of cables that were buried or inaccessible, and we are working on writing a resolution on those that will also match the Oconee resolution which is to do some sort of testing on these cables that may be exposed to that kind of environment.

DR. SHACK: Is this testing a leakage

current thing or something?

MR. YOUNG: It's somewhat undefined at this point, and -- yes, Jeff, go ahead.

MR. RICHARDSON: Yes. This is Jeff Richardson with Entergy. Right now, the way the electrical component -- our response to this particular issue is being formed. The test is non-specific. There are several different tests that have been proposed, including power factor type testing. We're not going specifically. It will be condition driven based on the cable and the situation. But the test --

DR. SHACK: But you'll do testing of some sort.

MR. RICHARDSON: Yes. The plan at this point, or the direction we're taking at this point is to follow Oconee's lead into the medium voltage inaccessible cables that are within the scope. Where appropriate, where they're exposed to either extended periods of being exposed to water and also in conjunction with thermal stresses such as high system voltage, greater than 25 percent system voltage for a period of time, then those would be subjected to some form of testing to be determined as appropriate for those conditions.

DR. BONACA: So there is a commitment you said, and that's going to be in the FSAR.

MR. YOUNG: Yes. We've already got a commitment to the visual inspection portion of it. And in response to this open item, we'll make a commitment for the varied cable portion.

DR. BONACA: Let me just make an announcement outside of schedule here. I've been told the Agency will close at 12 noon, which is now. Because, I guess, of weather conditions, they're sending people away. I would like to propose the following here: We don't have much left on the agenda, and I think we can condense the overview on the license renewal and environmental review process. So I would like to do is to continue. Just take five minute break right now and then continue this meeting for next half an hour. That should be allowing to go to discussion, and then end the meeting. I think we can do that.

MR. GRIMES: Dr. Bonaca, the staff is ready, willing and able. We want to march through the time limit at aging analysis. I sent a runner to try and track down Mr. Kenyon so that we can try and get through the environmental review as well.

DR. BONACA: Well, let's try to do that.

MR. GRIMES: Okay.

(Whereupon, the foregoing matter went off the record at 12:00 p.m. and went back on the record at 12:08 p.m.)

DR. BONACA: We want to review the TLA. I believe that's the next step of the agenda.

MR. ELLIOT: My name is -- my assistant here is not here. My name is Barry Elliot. I'm with the Materials and Chemical Engineering Branch of NRR.

There are ten TLA issues that cover mechanical areas, materials areas, corrosion areas. So it covers a broad spectrum of Division of Engineering functions. People who have reviewed these area functions are Hanz Asher, Carol Lauron, John Fair, Cliff Munson, Amar Pal, Mark Hartzman, Andrea Lee and Jay Rajan.

The first TLA is reactor vessel neutron embrittlement. There are two regulations that are reviewed with respect to this issue. They are the PTS rule, which is 10 CFR 50.61 and Appendix G of the regulations, which establishes upper-shelf energy requirements.

In this case, the applicant did a plant-specific PTS evaluation. And as far as the upper-shelf energy, it would be a plant-specific upper-shelf

energy evaluation. And it turns out that as far as the upper-shelf energy, all the forgings would be above 50-foot pounds at end of license, end of renewal license. However, the welds would not -- and an Appendix K analysis was done to show that it had adequate safety margins. These methodologies are the same as those used by Oconee, the only difference being the plant-specific variability.

The next issue is metal fatigue. The applicant evaluated the impact and environmental effects on the reactor coolant pressure boundary components. And the evaluation indicated that the surge line and the high pressure injection make-up nozzle and safe ends may exceed a cumulated usage factor of one during the period of extended operation. As a result, the applicant proposes a program which will include one or more of the following options: refinement of the fatigue analysis, repair, replacement and management of the effects of fatigue by a program that would be approved by the staff.

Essentially, this is very similar to what Oconee did. The difference is that Oconee is counting the cycles and may have to perform corrective action similar to ANO-1. ANO-1 already extrapolated a number of transients in 60 years and has identified the

potential locations with usage factors that may exceed one.

DR. SHACK: But they also do a monitoring program, don't they, so they'll be able to actually --

PARTICIPANT: Count.

DR. SHACK: Yes, count.

MR. ELLIOT: Yes, they do that.

MR. FAIR: This is John Fair with the staff. They haven't proposed to do this by a monitoring program similar to Oconee, but they do have a cyclic -- they do keep track of cyclic transients. But they don't propose to use the program to manage the effect. So they did an up-front calculation, whereas Oconee is going to monitor cycles.

MR. ELLIOT: The next issue is environmental qualification. The applicant evaluated environmental impact of extended operation on all long-life, passive and active electrical components within the scope of the rule. And the components either had analysis that remained valid for the period of extended operation, had analysis that projected to the end of the period of extended operation or had a program to reanalyze or replace components prior to exceeding the qualified life of the component. This is very similar to the program for Oconee.

Next issue is concrete reactor building tendon prestress. The applicant indicates concrete reactor building tendon prestress that we've managed during the period of extended operation, using ASME code, Section 11 In-Service Inspection program. This is an open issue for us, because although this is similar to Oconee, in the case of Oconee, they have addressed the program in sufficient detail and given us sufficient characteristics to approve the program. In the case of ANO-1, they have not, and they must address the attributes and characteristics that are in this overhead. And then we'll be able to resolve this issue.

The reactor building liner plate fatigue analysis. The applicant had demonstrated that the original fatigue analysis is valid for the extended period of operation. In this case, the methodologies used by Oconee and ANO-1 are the same. Individual plant-specific transients may be slightly different.

Next issue, aging of Boraflex and spent fuel pools. Boraflex is a neutron absorber. It is used to maintain subcriticality margin in the spent fuel during storage or transfer of fuel. Tech specs require applicants to maintain the subcriticality margin. The applicant has determined that the

Boraflex has degraded more rapidly than expected and will not last through the current 40 years. They've done an analysis, and that's the results.

As a result, in order to satisfy the license renewal rule, they're going to have to propose a program to monitor the aging of the Boraflex. This is an open issue at the moment for ANO-1. They have to propose a program. Oconee has already a defined program, and that's the difference.

Next issue, as far as reactor vessel underclad cracking, the issue here is that when B&W fabricated the vessels, the course grade forgings had cracks in them during fabrication, intergranule separations during the cladding operation. We're talking about defects on the order of a tenth of an inch. This was evaluated in the first 40 years, and in the next 60 years the evaluation goes to higher neutron fluences and also more fatigue crack growth.

The analysis was a fraction mechanic analysis, and it was determined to be acceptable by the staff for the 60-year license. Both Oconee and ANO referenced the B&W topical report, which contained analysis applicable to both Oconee and ANO-1.

Next issue is the reactor vessel instrumentation nozzle. The applicant has evaluated

the impact of flow-induced vibration on reactor vessel instrumentation nozzles. Analyses have been projected to the end of the period of extended operation. The flow-induced vibration stresses are below the extrapolated fatigue limit. Oconee and ANO-1 used the same methodology in evaluation of flow-induced vibration -- well, ANO-1 used the same methodology as used in Oconee reactor vessel internals.

DR. SHACK: Do they do this because they've actually had a flow-induced vibration problem or is this just part of their basic design?

MR. FAIR: This is John Fair again. This is part of the basic design on this. They just extrapolate out the originally designed for -- what is it, 12 cycles or something like that? And they extrapolate it out in order of magnitude, very conservative extrapolation.

MR. RINCKEL: This is Mark Rinckel with Framatome. There were problems with the original end core modern system design. There were three-quarter-inch on 60 pipe that went at the bottom of the vessel. Those cracked off at Oconee at one, and then they built them up and repaired them all. And then this fatigue analysis that John's referring to was with regard to the new design.

DR. SHACK: So you basically just beefed the up enough --

MR. RINCKEL: We beefed up, yes.

DR. SHACK: -- so the stresses are very low.

MR. RINCKEL: Yes. They were not designed proper to begin with, and that was corrected.

MR. ELLIOT: The next issue is a leak before break. The applicant did a -- there was a leak-before-break analysis done in the first 40 years. The applicant has evaluated the impact of fatigue crack growth and thermal aging on leak-before-break analysis of the reactor coolant system, main coolant and piping. The floor growth analysis remains valid for the period of extended operation. And the flaw stability analysis used lower bound casts, fostering a stainless steel fracture toughness properties for the reactor coolant pump nozzles in adjacent welds.

And the adjacent wells will have adequate fresh stuff at the end of the period of extended operation. That's the result of the analysis. Oconee and ANO-1 used the same basic approach.

The last issue is the reactor coolant pump motor flywheels.

DR. SHACK: Excuse me, that must be a

postulated flaw assumption, right?

MR. ELLIOT: Yes, it is a postulated flaw.

DR. SHACK: What's the postulated flaw?

MR. ELLIOT: It's a leak before break. You have to have a leakage size.

DR. SHACK: Oh, okay, okay.

MR. ELLIOT: It's criteria. There's leakage-size flaw, and then there's a stability flaw. There's two size flaws, and that depends on the leakage and the size of the pipe and everything. So there's not one flaw; it's a through-wall flaw.

DR. SHACK: It's a through-wall flaw.

MR. ELLIOT: It depends on the size of the pipe and --

DR. SHACK: They're not just counting to go through the wall. They're actually looking at the through-wall flaw and making sure it's stable.

MR. ELLIOT: Right. That's for the stability analysis. For the fatigue analysis, it starts with a small flaw.

And then the final issue is the reactor coolant pump motor flywheels. The applicant has evaluated the impact of fatigue on the growth of cracks in the reactor coolant pump flywheel bore keyways. This is another postulated flaw. There is

no flaw there. And the analysis is projected -- growth remains acceptable for the period of extended operation. There is nothing unique about this analysis. This is standard fatigue crack growth analysis.

Any questions?

DR. SHACK: Is that in a standard design procedure for all coolant pumps with keyways? Do they have to do this?

MR. ELLIOT: No. There is a different here, now that I think about it, a little different. They did the analysis -- in the case of Oconee, they proposed a program. Instead of doing the analysis to the reactor pumps, they do inspections, periodic inspections. So you have this alternative. You can either do analysis or you can do inspections. And at ANO-1 they chose the analysis, and Oconee chose the inspections. And this is a continuation of each of their licensing bases. The ANO-1 licensing basis was the fatigue study, and the Oconee licensing basis was the inspection program.

DR. BONACA: Okay. One last question I have is regarding the Boraflex. So the expectation is that there will be a solution needed prior to entering the 20 additional years of life.

MR. PRATO: In reality -- this is Bob Prato -- in reality, they had submitted a program that was consistent with Oconee. We asked for some additional description in our RAIs, and that's when they found the data would -- that the Boraflex would not last the current licensing term.

DR. BONACA: All right.

MR. PRATO: They did not respond to our description. They said it's no longer TLAA. Staff took exception. So, basically, what they're going to provide is that same program they had initially with the additional information we requested in our RAI. And from the staff's perspective, that should resolve the issue.

DR. BONACA: Okay. Thank you.

MR. ELLIOT: Thank you.

MR. PRATO: That concludes the safety inspection review. Tom Kenyon, for the environmental evaluation review, will give his presentation at this time.

DR. BONACA: And the plan we have right now is to have a brief overview of this environmental review process, maybe ten minutes or so. Then I would like to just have a brief discussion among the members here, and then a decision on how we're going to

address this at the full committee next week.

MR. GRIMES: Yes, sir. Dr. Bonaca, this is Chris Grimes. I would like to introduce Tom Kenyon, who's the Environmental Project Manager for Arkansas. I would like to remind you that the staff made presentations to the Committee about the regulatory guide and the standard review plan for the environmental process. Tom's going to just basically run through the main features of the review process and our NEPA obligations. And he should be able to do that in about ten minutes.

DR. BONACA: Okay.

MR. KENYON: I'll try. My name is Tom Kenyon. I'm an Environmental Project Manager with the Generic Issues Environmental, Financial and Rulemaking Branch. I've been asked to make a presentation regarding the environmental review process that we undertake under the license renewal reviews.

I plan to talk a little bit about the statutory requirements. We'll focus on the National Environmental Policy Act. I'll be talking about the review process that we go through and give you an idea of the schedule. My goal is to just kind of put into perspective the environmental protection activities that we undergo for license renewal purposes. And the

presentation is for information only. We're not asking for a letter in this area. Of course, you always have the option, if you want to, to provide your views.

DR. BONACA: We don't intend to write a letter on this now.

MR. KENYON: Thank you. Some of you may recall that Barry Saltman had made a presentation like this a couple years ago, and I think it's safe to say right now that not a whole lot has changed, other than we've implemented the process, we've completed the review on two plants, Calvert Cliffs and Oconee, and we're undergoing a review right now of three additional plants.

As you well know, the NRC is governed by the Atomic Energy Act and the Energy Reorganization Act of '74. There are a number of other statutes that define our mission in terms of the environmental protection mission as well, but I'm going to focus on the National Environmental Policy Act.

This slide gives you -- it's a slide of all of the -- the entire license review process. The top path shows the path that you're used to working in. The Part 54 review includes the inspection activities, it includes the safety review that Mr.

Prato is involved in, and of course, it includes the ACRS' review as well. Now, the bottom path is the path that we follow as part of our Part 51 review. And I'm going to go into more detail about each one of these steps as we go through this presentation.

Now, I'm going to give you a bit of background on the National Environmental Policy Act. It was enacted in 1969, and it requires all federal agencies to use a systematic approach to consider the environmental impacts of certain decisionmaking proceedings. It's a disclosure tool that involves the public and involves the process in which we gather information, we document the findings that we have and then we invite public participation to evaluate it.

The NEPA process results in a number of different documents, but the one that we're going to focus on is the Environmental Impact Statement, which describes the results of our detailed review, that is the environmental impacts for major federal actions that have the potential to significantly affect the quality of the human environment. And the NRC has already determined that NEPA -- I'm sorry, that license renewal is just such a major federal action.

Now, to implement NEPA, the staff has its regulations in Part 51. And the regulation describes

the process that we undertake, it outlines the contents of the Environmental Impact Statements, and it also defines the objective of our review. And I'm going to have to read this, because it's a big unwieldy. Our objective is "To determine whether the adverse environmental impacts of license renewal are not so great that preserving the option of license renewal for energy planning decision-makers would be unreasonable."

Now, that's a quote from the regulations. It's Part 51.95. I prefer to just think of it as we're trying to determine whether or not the additional 20 years of operation is acceptable from an environmental standpoint.

Now, if I could go back to the previous slide for a second. Early on when it was decided -- when we were developing the license renewal process back in the '80s and '90s, it was recognized that the original Environmental Impact Statements that were developed to support the construction permits and the operating licenses about 20 or more years ago would have to be updated to reflect the additional 20 years. And so the NRC undertook a rulemaking effort to modify Part 51 and to have it reflect the license renewal process.

As part of the rulemaking effort, the staff developed a generic Environmental Impact Statement, known as the GEIS, which took a systematic look at the thousands of hours of operation of the nuclear power plants to help us identify where our potential environmental impacts could occur. In addition, the staff developed regulatory guidance, the Environmental Standard Review plan, and a regulatory guide.

Now, the GEIS was used, as I said earlier, as a supporting document for the Part 51 rulemaking, but it's also an integral part of our review process, and so I wanted to go in a little bit of detail as to what's enclosed in that document. The GEIS was published as NUREG-1437 and was issued in 1996. During the development, the staff met with the states, the Presidential Council on Environmental Quality. They met with the Environmental Protection Agency and other groups, and they had a series of public workshops to develop the final GEIS.

And suffice it to say that during this period the staff was trying to identify what environmental impacts needed to be reviewed in license renewal. And we identified a total of 92 issues. When the staff evaluated those issues, they found that

some -- noticed that some of those were generic in nature; that is that they are common to all plants or a class of plants regardless of where they're sited. And so the NRC wanted to kind of categorize them differently, and so we came up with this Category 1, Category 2 scheme, Category 1 being, of course, generic issues, and Category 2 requiring plant-specific review.

Now, I did not mean that we do not look -- well, I'm trying to figure out what I can skip through. An example of Category 1 issue is a the off-site radiological impacts. And the staff took a look to see if whether or not it was likely that there would be an increase in off-site radiological impacts due to the increased operation. So they did a historical review and determined that the public -- and determined that the doses to the public have been maintained below those allowed by the regulations.

And staff has not been able to see any reason why the doses would increase due to the extended operation, provided that the control programs and the monitoring programs are maintained and implemented acceptably. So because the expected radiological impacts apply to all plants in a similar manner and that the impact is considered small at all

the plants, the staff concluded that this could be addressed on a generic basis.

Now, that does not mean that we do not need to look at this issue anymore. What it means is that we look only to see if there's significant new information that would cause us to change the conclusions that we made five years ago. As you can see, there are 69 issues that were resolved in this manner, considered generic issues, and the remainder of the 23 issues that were identified need to be addressed on a plant-specific basis.

Now, when the staff completed the GEIS in '96, we evaluated it to determine their impact significance, in terms of whether or not their environmental impacts are likely to be small, moderate or large. And what we determined was that the generic issues, the Category 1 issues, all had a small impact on the environment, and that the impacts of Category 2 issues could range across the full gamut, from small to large, depending on the particular site and the particular issue. I guess I don't know need to show that slide.

Now, this slide shows a little more detail about the NEPA process. There are certain steps that we have to follow, and these steps are consistent for

all Environmental Impact Statements that are prepared by federal agencies for any major federal action. The first step is the notice of intent. It lets the public know that we're going to prepare for an Environmental Impact Statement. It is issued in the Federal Register shortly after the acceptance review is completed.

To prepare for our reviews, we've assembled a team of NRC staff with backgrounds in a specific technical and scientific disciplines that is needed to do these reviews. We have people with backgrounds in biology, ichthyology, zoology. There some people with human health backgrounds. And they have generalists like me, project managers who coordinate the reviews.

In addition, to supplement the expertise of the staff, we've engaged the assistance of various national laboratories to ensure that we have a well-rounded knowledge base to do these reviews. For every review, we put a team together of about 20 people.

The next step is the scoping process, during which we tried to narrow down the scope of the Environmental Impact Statement for the plant that we're looking at. And we solicit public input. The scoping process runs for about a minimum of 30 days

and could be as long as -- what we've been doing, because we have to gain some experience, we've been allowing for a 60-day comment period. About midway into the comment period, we have two public meetings near the site where we describe what we do, and we try to solicit public input. We also perform a site visit, and we obtain information from the applicant during the site visit and from federal, state and local authorities.

Now, during this time, we seek information to define the scope of the plant-specific Environmental Impact Statement and determine what needs to be studied in detail and what is not appropriate to address. We start with the potential list of 92 issues that came from the GEIS, and then we try to determine which ones are applicable and which are not.

In addition, we require the applicant to submit an evaluation and to let us know whether or not they're aware of any new, significant information that could affect our conclusions on Category 1 issues. And during the scoping phase, of course, we take a look and see what the members of the public have to say and other federal, state and local authorities. And if something new and significant information does

arise, then we review it on a plant-specific basis. And if not, we adopt the generic conclusions from the GEIS, and we incorporate those conclusions into our plant-specific review.

Category 2 issues, of course, we look at at the plant, and we obtain information during our site audits. And finally, we also try to find out if there's any new issues that we hadn't considered in the GEIS five years ago. And if a significant new issue does come up, then we would review that as if it were a Category 2 issue.

The most important thing about this slide that I wanted to point out was that -- I'm sorry.

MR. GRIMES: Tom, if I could suggest, if you'd go to 15, because you basically covered what the process steps are, and just flash 15 and 16 for the areas review.

MR. KENYON: And then finish up.

MR. GRIMES: Yes.

MR. KENYON: Okay. This gives you an idea of the ecological issues. The next slide shows you the kind of issues we look at in terms of social economics and environmental justice.

DR. APOSTOLAKIS: How do you do social economics?

MR. KENYON: Well, we have a sociologist, and we go out and we interview a number of different people, like the local businessmen; we talk to local charities; we try to get a flavor for what would be the impact of the plant not being there, in terms of what it would do to their tax base, that sort of thing. It's kind of a different kind of review.

When you're talking to the people who run the charities, you know, when they think of the plant leaving, in some cases there would be a significant impact; in other cases, these people that they take care of are probably not likely to be working at the plant to start with. Okay?

DR. APOSTOLAKIS: Okay.

MR. KENYON: I'll just breeze through this real quickly. There are issues that are not considered in the environmental review, such as the need -- this is by regulation. The other important thing I wanted to point out is that we don't look at the safety-related issues. That's left up to Mr. Prato, and we don't get involved in his review.

DR. APOSTOLAKIS: So let me understand this. A coal fire plant is not licensed by the federal government; is that true? Are they licensed by the federal government?

MR. KENYON: I don't know that they're licensed by the federal government, but there's a number of environmental statutes that they have to meet, and they're covered by the Environmental Protection Agency.

MR. GRIMES: We have to be careful with our choice of terms, because I would contend that there's an EPA permit requirement that is not like our licensing process, but it is a federally imposed restriction. Hydroelectric facilities are licensed by FERC in a process that looks very much like ours.

DR. APOSTOLAKIS: So, ultimately, everybody does an Environmental Impact Statement.

MR. GRIMES: Yes. Ultimately, everybody does an Environmental Impact Statement but with a particular focus.

MR. KENYON: And that concludes my presentation, unless you have any other questions. I did provide you with the document of the last Environmental Impact Statement that we produced on Oconee just to give you an idea of what we do.

DR. BONACA: Thank you; appreciate it.

MR. GRIMES: I'd also like to add that Tom made a point that during the process that they go through, they reach out to the public in order to find

out what the public's interests are. But the environmental review does not address safety-related issues. So if safety issues are brought to them, they refer them to the safety review, and Mr. Prato checks to make sure that they're being covered as part of our review process. But we don't necessarily tailor a safety evaluation to address the public's interest in issues like waste or so forth. But we do keep the two trains separate during the review process.

DR. BONACA: Thank you for the presentation. And I would like to thank also the applicants and Framatome's support for the presentations; very informative for the application that was -- well, I'll comment on that. And also the staff for the presentations we received.

And I would like to go around the table and ask the two surviving members of the Subcommittee here if they have any additional insights to whatever they provided me before regarding the presentations.

I would like to just make a few comments. One is that I spent quite a bit of time reviewing the application as well as the SER, and I thought that the application was effective. I thought the SER was complete and effective. I thought that definitely there were a lot of lessons learned that were used to

make this application and the review more complete. I think that it was easy to trace the issues.

And I also appreciate the staff's willingness to make this presentation on a comparison basis. It was helpful for us, because I mean we spent quite a bit of time on Oconee, and it was a profit for us to benefit from the experience in our review of Arkansas, and that took place.

I felt that the scoping process was thorough and part was helped by very effective quality listing that already Arkansas seemed to have. That was quite helpful. We didn't go through the pain and suffering that we had in previous applications. That was good. I thought that it was pleasing to see that there wasn't too much of a focusing on legalistic narrow limits in the extent in which management programs were implemented.

There was some expansion to give proper consideration to important items, and that was important. And because of that, I feel that there are very few open items. That's one of the reasons. And I don't think those items are contentious. The way I see it there is no measure of contention there. So I don't see any show stoppers from a perspective of the review of the staff, as well as a review of the CRS.

What I would recommend is that we do not have an interim report. And I would like to have your thoughts, Chris, regarding this.

MR. GRIMES: My view is we don't need one. I think that we've benefitted from your review, and the level of detail that you've gone into is evident, and the feedback is helpful, and we're going to reflect on ways that we can improve the safety evaluation just based on the exchange that we'd had. But unless you have any particular views on the issues, we don't need an interim report in order to proceed, and we'll plan on coming back to the Subcommittee again to report on the resolution of the open items and --

DR. BONACA: And we will plan to write a letter at that time.

MR. GRIMES: Correct.

DR. BONACA: We will write just one letter. That was part of our plan, in fact, when we go to a second and third review of a similar type plan, unless there are major issues to which we can contribute observations, then we'd have simply a final report, which we plan to have on this plant.

What I would propose, then, is that I'll report these conclusions to the full committee next

week. That will take probably 15 to 20 minutes, maybe half an hour at the most. And I would request that the staff supports me maybe with a couple of people there present in case there are any specific questions from the members of the full committee. And that's what I would like to do.

So for that presentation we do not need applicants present, right, at this stage. We will plan to have you come at the final -- when we receive the final SER with the closed open items. And then we will have a full presentation in front of the Committee at the time, and then we'll write a full report.

So if there are no disagreements, that's pretty much what we're trying to do. We will somewhat change the schedule --

DR. APOSTOLAKIS: How much time are we scheduled for?

DR. BONACA: We're scheduled for an hour and a half, George.

DR. APOSTOLAKIS: But we will take only half an hour?

DR. BONACA: About half an hour, yes. We'll take a half an hour and --

DR. APOSTOLAKIS: We'll do something else.

DR. BONACA: Oh, yes. We've got a lot things to do.

DR. APOSTOLAKIS: We can finish the safety research.

DR. BONACA: No. With that, I'm pleased to see that even our review was facilitated by the lessons learned. So with that, if there are no further comments --

MR. GRIMES: Dr. Bonaca, I have a couple of questions, though, that I'd like to pose before you adjourn. The first is I'd like to ask -- you mentioned during the course of the presentation several times that you had some questions: The question on the reactor vessel level measurement device --

DR. BONACA: Yes.

MR. GRIMES: -- the nature of the seven new programs, the clarity of the SER as it relates to the B&W integrated internal's activities. Dr. Shack asked about impurities in the sodium hydroxide and FAC on the feed water. And I wanted to know whether or not there were any of those questions that you'd like us to pursue further and get back to you?

DR. BONACA: Not for my part, no. I was satisfied that it was more like I needed

clarification. In many cases -- in my case, it was the point I made that the application said something and the SER contained resolutions of issues that were not reflected in the application.

MR. GRIMES: I understand. And as I said, that was useful for us, and we'll reflect on that when we close the open items to see if we can improve the clarity of the SER in those areas.

The other question I had is the style of this presentation was largely built off of Oconee, but I would expect that when we bring Hatch to the Subcommittee at the end of March that we do something that largely focuses on BWR uniqueness and perhaps the particular issues that we felt were challenging because of the boiling water reactor. So in that sense, we would have a presentation that would be organized in much the same way, allow about the same order and level of detail, and highlight unique BWR challenges rather than differences from previous reviews.

DR. BONACA: I agree with that. That seems to be a positive approach. The thing that I would like to make sure, of course we have not reviewed the BWR/VIP documents; we're reviewing them now.

MR. GRIMES: We have a separate meeting scheduled for the VIP, the day before.

DR. BONACA: That's right. I was referring to the full committee meeting we have the week after that. So if I understand it, the SER for Hatch will be very much based on -- okay, but we're saying we're going to deal with them separately.

MR. GRIMES: Right. We would attempt to try and cover as much of the VIP during the first meeting as possible so that the focus of the second meeting would largely be the same kind of format as today -- scoping -- our methodology, scoping, aging management programs in each of the areas. And then wherever VIP occurs, we'd refer away from that and concentrate on the other aspects of the Hatch review that were unique and challenging from an aging management perspective.

DR. BONACA: And I agree with that. Actually, that would be helpful for another reason, that although we think of these plants very differently, but in many of the support system we find similarities. And to the extent to which you can capture the experience we have for those similarities, that helps. I mean, clearly, emergency systems and the steam -- well, not completely, but many portions

would be singular.

Any other questions?

MR. GRIMES: That's everything I need. Thank you.

DR. BONACA: Questions or comments from members?

DR. SHACK: I like the format of the license renewal report. I thought it was rather helpful to get through it. It was easier reading than the first two that we went through. For the SER, how about a list of the initialese up front. For those of us that ULDs don't slip off our tongue, and when I come back in two weeks I forget what a ULD is again.

MR. GRIMES: Acronyms up front, right behind the executive summary.

DR. BONACA: If there are no further comments, I'll adjourn the meeting. Thank you very much.

(Whereupon, the Subcommittee meeting was concluded at 12:49 p.m.)

CERTIFICATE

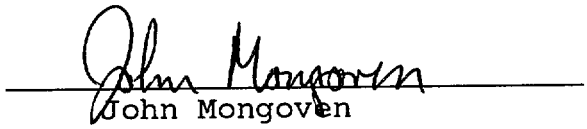
This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: ACRS Plant License Renewal

Docket Number: (not applicable)

Location: Rockville, Maryland

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



John Mongoven
Official Reporter
Neal R. Gross & Co., Inc.