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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

FEBRUARY 24, 2000

The contents of this transcript of the proceeding of the United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on February 24, 2000, as reported herein, is a record of the discussions recorded at the meeting held on the above date.

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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MTG: PLANT LICENSE RENEWAL

Clemson University

Madren Conference Center

Room III & IV

Madren Center Drive

Clemson, South Carolina

Thursday, February 24, 2000

The above-entitled meeting commenced, pursuant to notice, at 8:00 a.m.

MEMBERS PRESENT:

MARIO BONACA, Chairman, ACRS

ROBERT SEALE, Vice-Chairman, ACRS

THOMAS KRESS, Member, ACRS

DANA POWERS, Member, ACRS

WILLIAM SHACK, Member, ACRS

JACK SIEBER, Member, ACRS

ROBERT UHRIG, Member, ACRS

P R O C E E D I N G S

(8:00 a.m.)

CHAIRMAN BONACA: This is a meeting of the ACRS Plant License Renewal Subcommittee. I am Mario Bonaca, Chairman of the Subcommittee. The other ACRS members in attendance are the Vice Chairman of the Subcommittee, Robert Seale, Thomas Kress, Dana Powers, William Shack, Jack Sieber, and Robert Uhrig.

The purpose of the meeting is to meet with the representatives of the NRC staff and the Duke Energy Corporation to discuss the staff's resolution of the open and confirmatory items identified in the Safety Evaluation Report related to the license renewal of Oconee Nuclear Station, Units 1, 2 and 3, and related license renewal activities. Our Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for deliberation by the full Committee.

Noel Dudley 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 13, 2000.

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 are readily heard.

We have received no written comments or requests for time to make oral statements from members of the public.

Yesterday, the Subcommittee toured Oconee Nuclear Station and meet with representatives of the Duke Energy Corporation to review the details of how Duke conducted the license renewal scoping and aging management review processes.

Before we proceed, Jack Sieber of the Committee needs to make a statement.

Mr. Sieber: Thank you, Mr. Chairman. I would like to place on the record the fact that under Federal Ethics Laws I am not eligible to vote on matters effecting Duke Energy Corporation because I am a stockholder of Duke Capital Corporation, and, therefore, my non-voting should be construed in that light. Thank you.

CHAIRMAN BONACA: Thank you. We will proceed now with the meeting and

I call upon the Duke staff to begin. Good morning.

MR. GILL: Good morning. Thank you, Dr. Bonaca. My name is Bob Gill. I am on the Oconee License Renewal

Team. I'm here to start our presentation. And on behalf of Duke Energy, the Team, and, of course, Oconee Nuclear Station, we welcome you to the upstate South Carolina area. Hope you've enjoyed your visit, your short visit although it may be.

We have several presenters today to go over topics of interest that have been identified. Before I do that, let me go through just a little bit of a background before we get into the first topics. I'm going to cover briefly the project status, where we are. This is a very important meeting, because it is leading up to the recommendation by the staff in the next couple of weeks. There were three open items that the Committee decided they would like to review in depth; the resolution of scoping methodology, electrical insulated cables and connecters, aging management program, and vessel internals. We have presentation prepared on each one of those.

Briefly, on the status, the current status as we understand it is that the Recommendation Letter to the Commission will be sent by the staff by April 14. There are a number of milestones that have to be completed before then, many of which have already been done. The Facility Operating License, the new draft, has been provided us for review. We have a meeting scheduled on March 19th with the staff to go over that.

There were no technical specifications or changes identified.

The Final Safety Evaluation Report, which we have copies on the table, have been published by the staff. We were very welcome on that. A lot of good work has gone on both sides there.

The UFSAR Supplement, a draft, was provided to the staff and the staff is reviewing that. We intend to formally submit a revised UFSAR Supplement by the end of March so the staff can have that as part of the package. We are expecting a Region II Recommendation Letter by the end of March. There is a site inspection scheduled for next week, with a Public Exit Meeting the end of next week announced.

Final Supplemental Environmental Impact Statement was received in December. That closed out all the environmental reviews associated with renewal of the license for Oconee. We are expecting your recommendation Letter in a couple of weeks, after the full committee has a chance to review all the issues.

And for the final piece was the Indemnity Agreement, which was required by the regulations to be looked at. We did not identify any changes. I believe the staff has concurred in that.

So, those eight pieces are the total package that

we needed to renew the license.

The purpose of this morning's discussion is for us to provide additional information to the members of the committee on the resolution of three open items, and the insights that we used to do that. We will follow the handout that is in here.

The first item that will be discussed is the Scoping Methodology, with Rounette Nader.

Second, will be Paul Colaianni talking about the Electrical Aging Management Program on cables and connectors.

And, finally, Jeff Gilreath from our corporate office staff. And you see a couple of models here and diagrams of the vessel internals. That will be our last presentation, and we will be able to answer any questions the staff has on that.

Are there any questions at this point in time on what we are covering? I turn it over now to Rounette Nader, who will go over the Scoping Methodology validation that we did late last year.

MS. NADER: Thank you, Bob. I'm Rounette Nader with Duke Energy. I'll be discussing the Scoping open item. On slide number seven, we have the issued defined and the resolution, all here together at the beginning. But the issue really evolved into from the scoping open item was, is

the set of events that was considered by Oconee license renewal scoping methodology sufficient for scoping.

The issue was resolved by case study. Ten events identified by the NRC. Duke researched the licensing basis of the ten events, and the end result was that the scoping methodology had identified all the appropriate systems, structures and components for license renewal.

On slide number eight, really the next three slides, eight, nine and ten, are a chronology of some of the things that occurred between Duke and NRC on this issue. I'm not going to go through each of these. It is really more just to show the rigor of what really went into this issue. You can see that Duke submitted the license renewal application in July of 1998. And in October of '98 the NRC staff, several members traveled to Charlotte to look at the internal documentation related to scoping.

Several meetings occurred. The request for additional information was issued in December. Several meetings occurred the first half of '99. On slide number nine you will see the second half of '99 were more meetings. The SER open item was issued.

On slide number ten, on October 28th of 1999, which was a year and a day after our first meeting, Duke and NRC had a meeting to discuss resolution of the issue.

Duke submitted the response in November and the

SER that was issued just this month closed the open item. To really understand the technical basis behind the issue, on slide eleven begins a presentation of, really of the Oconee scoping methodology for license renewal. The methodology for all three disciplines combined, we have boiled down into seven steps. The first four steps were the mechanical steps for mechanical scoping.

So the first step was to identify functional flow paths, mechanical functional flow paths required to mitigate design basis events for Oconee.

The second step was to add pressure boundary to these flow paths. Passive pressure boundaries required before you could impact the flow paths.

The third was to identify physical interference commonly known as two over one, any piping whose failure could interfere with a safety related or a central system. On slide twelve, the fourth step, was to capture any other safety related or seismic equipment at the plant that had not already been identified. Because of Oconee's design there were some incidences where there were safety related piping that didn't get identified in the first three steps. They got identified in step number four.

From a structural standpoint starting with item number five, class one structures meet the 54.4(a)(1) criteria. Class two structures meet the (a)(2) criteria.

Those were scoped by looking in the UFSAR for those definitions.

Step number six was electrical in nature. You heard about the spaces approach. All electrical components were initially assumed to be within scope, and then the screening staff screened out active equipment.

In step seven was to meet the 54.4(a)(3) criteria, which was to look at the licensing basis of the five regulated events that are in (a)(3) and include those systems, structures and components within scope.

So upon completion of these seven steps, the scoping for license renewal was complete for mechanical, structural and electrical.

On slide thirteen we did a graphical representation of the methodology and really the results. You can see on the pie chart the structural pie piece, the electrical pie piece, the 54.4(a)(3), the regulated events pie piece. On the top piece of the pie is the mechanical methodology. It is broken into the four steps that I just mentioned.

The first step, the input into the first step, is really the issue of the open item. The first step was accomplished by identifying the functional flow paths required for design basis events. What are those events, that's how the issue got identified. So with design basis

events, the passive pressure boundary, the seismic two over one, and the other safety related in seismic. So we felt like the focus of the issue was really -- is there anything, any little bump in this pie that should be added. The NRC had concern that there were other events that Oconee should have considered when scoping for license renewal.

So what did Duke consider as a design basis events. Design basis events are as the term that is used in 54 for scoping. Oconee's UFSAR, Chapter 15, is the accident analysis chapter for Oconee. The first sentence, the introductory sentence for that chapter, is the following: "This section details the expected response of the plant to which the spectrum of transients and accidents which constitute the design basis events." So, historically, this is

the -- the Chapter 15 accident analyses are the events that Oconee has considered the design basis events.

Modern day regulations get written very similar to the way 54.4 is written. When applying these regulations to Oconee, it is important to recognize that Oconee's design really preceded the regulation that defines these on-basis events today in 50.49. We had our definition that was on the previous slide, on fourteen. We did institute a project in the early 90's to really confirm since all the regulations that were coming out really used this new type

of methodology and new approach. To confirm Oconee's licensing basis and design, and they really confirmed that the UFSAR Chapter 15 events are what constituted the licensing basis for Oconee as the design basis events.

In addition, this project said, the end result of the project said, you know, really since original licensing there have been some other events that have come up through licensing that are really important. When you are scoping these regulated programs you should probably consider these additional events. A license renewal was an issue that did that. We call them scoping events. It goes beyond the Chapter 15 licensing basis, design basis events.

On slide sixteen, the definition of the scoping events that was used by Oconee for license renewal scoping. For the design basis events in Chapter 15. Natural Phenomena Criteria, which are in Chapter 3 of the Oconee UFSAR. The Post-TMI Emergency Feedwater Designs, the scenarios associated with that. And the Turbine Building Flood, which is mitigated by the Standby Shutdown Facility. You saw that in your tour yesterday.

So the Chapter 15 events, plus these other three criteria, were the scoping events set that was used by Oconee scoping.

So throughout the year as Duke and NRC had our meetings and our correspondence on the issue, we finally

came down to Resolution, the NRC Perspective, as you see on slide seventeen. It is the staff believe that more events should be considered, and should have been reviewed in order the insure the functions identified in 54.4(a)(1).

So the resolution was for Duke to conduct a case study of ten additional events that were identified by the staff and given to Duke, and to research the current licensing basis and these five documents: Commission regulations, license conditions, Commission orders, the UFSAR, and exemptions.

On slide eighteen, the purpose of the case study was to really validate the scoping methodology that had been performed by Oconee, the seven steps that we just spoke of. That those seven steps as executed identify all the SSCs required to be within the scope of license renewal for 54.4.

On slide nineteen you can see the results of the case study. The assessment performed by Duke revealed that the current licensing basis associated with those ten events did not identify any additional systems, structures, or components that met the license renewal scope that met the criteria of 54.4.

The final SER that was issued earlier this month agreed with that, the Duke assessment. That no additional SSCs needed to added to the scope of license renewal.

So slide twenty is the conclusion from the case

study. The Oconee License Renewal Scoping Methodology is described in the Application in that you saw in the seven steps that we just described, identified all systems, structures and components relied upon to remain functional, to insure the functions identified in 10 CFR 54.4.

The case study provided the validation for Duke and the NRC, that the methodology that was employed by Oconee, by Duke, was indeed sufficient. And the NRC could use that validation in making their finding that the scoping methodology was sufficient and that the results were sufficient.

The final SER, as I mentioned before, did resolve the issue. It closed the open item related to the scoping issue. It does talk about the validation that was done, the case study that was done, and that the NRC gave reasonable assurance that the set of events that were used in the scoping methodology were sufficient to get all the important SSCs in the plan, and all the SSCs that met the license renewal scoping criteria 54.4.

We feel good about our scoping methodology. We've felt good about our scoping methodology for awhile. Our project that was instituted at the beginning of the early nineties, like I mentioned before, did a validation of Oconee's licensing basis, and design basis. We felt good because we felt like we were consistent with our current

licensing basis. You saw the statement of the Chapter 15 of UFSAR. We felt like our scoping process was really applied in accordance with the rule. We read the rule, we read the SSCs. We felt like the methodology we employed was a good one.

We were also consistent with other regulations, regulations that used the same type of wording, such as maintenance rule, in-service testing, scope, motor operated valve testing scope. Other regulative programs that have been instituted in the last decade or so that used the same kind of words, the license renewal scoping methodology was very consistent with those. And traditionally when you look at the plant, you look at Oconee, you pull out the drawings to see what is in license renewal scope, we feel like we really captured all the important systems, structures and components. Just a gut feel. All the SSCs that we traditionally view as important to a plant, we really feel like we've got them.

Questions?

CHAIRMAN BONACA: One of the main events that you reviewed for the items, and you yesterday described to me that was a study that was done -- could you tell me the dates when it was done? At least to the extent that the review that that accident evolved?

MS. NADER: That's true. One of the events that

was researched in the case study was a high energy line break event that Oconee had done a report on in 1973. It was based on a Jim Bouso, Mr. Jim Bouso letter that was issued really after Oconee Unit One was licensed, but before Oconee Units Two and Three were licensed. The report that was conducted looked at the susceptible locations of high energy lines, where they might break, and what sort of safety related components it may impact.

There were some resultant actions that came out of the High Energy Line Break Report. There were several modifications that had to be done to the plant in order to insure that the plant could be safely shut down in the event of a high energy line break as such.

One of the ten events was the high energy line break. We did review the report. We had Duke and the NRC, we had some guidelines on what sort of things should be reviewed. The UFSAR talks about the high energy line breaks. The licensing basis associated with the high energy line breaks were the -- there was actually a license condition on Unit One to get the modifications performed. Units Two and Three, we did the modifications before they started up.

So we looked at the licensing basis associated with high energy line break and determined that the systems, structures and components that were within the licensing

basis for that event were in the scope of license renewal.

CHAIRMAN BONACA: I guess the question I have is from the perspective of ACRS and the review you performed. There should have been a scope, a review of that particular event, right? Because, I mean, it is part of your licensing basis and I was curious to know why in your going through the first six events that we went through did not include that one. I'm sure that one already was reflected in your piping systems. You showed us those diagrams. I'm just trying to understand for future applications the fact that why you would not have included that specific event as one that you used originally.

MS. NADER: That event is discussed in the UFSAR. It is in Chapter 9, I believe, of the UFSAR. It is not one of the Chapter 15 accidents in the UFSAR. It is not traditionally considered a design basis event for Oconee. It was used as part of the design for Oconee, a design criteria to insure that you don't route high energy lines over safety related switch gears. But as far as having an accident analysis, you know, such as a safety analysis on this event, we traditionally don't treat this event as a design basis event that is included in scoping. Like I say, if we modified the plant correctly the way we were supposed to according to the license condition, and we perform our modifications like we should, and we don't route the high

energy lines over safety related piping, then there is really, there is really ---

CHAIRMAN BONACA: Certainly. But shouldn't beginning the scope that you cover to include more than Chapter 15 events. In fact, on the list of items in which you gave us, I believe, they would be on that.

MS. NADER: That's true.

CHAIRMAN BONACA: I'm not questioning the scope of which you have

covered today. I'm only asking questions about these events in my judgment should have been part of the original review. And it would fit within the categorization that you've described here which say Chapter 15 events plus, TMI, and I can't find it now.

MS. NADER: It is on slide sixteen. There were several reasons for identifying the plus; the Natural Phenomenon, the Post-TMI Emergency Feedwater scenarios, and the Turbine Building Flood. Some of them were based on risks. The biggest thing I think that really went into the plus events, if you will, is the fact that they bring in important parts of the plant. If you exclude the plus, for example, you will not have the standby shutdown facility within scope. You saw it yesterday. It is a pretty impressive facility. It is safety related. But it would not come in the scope for a Chapter 15 event because it was

all in post-licensing. It was not an event that was added to Chapter 15.

CHAIRMAN BONACA: And, again, on slide number sixteen you have expanded the basis from Chapter 15 with other things. You showed us diagrams yesterday, and I'm sure that the high energy line break locations for physical interactions I think have been identified in some of the diagrams already.

MS. NADER: That's right.

CHAIRMAN BONACA: Okay. For the purpose of to get license renewal in general, that to me is an understanding of where the staff was going and I think that it was good that this was done as part of that.

MS. NADER: And I think that's the thought process that went into these, the plus events, was that if you really did scope using Chapter 15 and these plus events, you have bound things like high energy line break. That's what we found out from the validation and from the case study.

Any other questions? Comments?

CHAIRMAN BONACA: None, thank you.

MS. NADER: Okay.

MR. GILL: Next up we will have Paul Colaianni, who is our electrical lead engineer on the license renewal project. He will discuss in detail the Insulated Cable Aging Management Program that we've added, that was not part

of the original submittal. That was added to the program late last year.

MR. COLAIANNI: Hello.

CHAIRMAN BONACA: Good morning.

MR. COLAIANNI: All right, we will start out, basically this open item was opened up after the original review of plants UFSAR came out. It came out of the on-site inspections, and basically a review offered experience, showed that, indicated that something was needed. The items basically fell into two categories that are generated via the program that came out of this. And, basically, to resolve the item, basically Duke committed to initiate a cable aging management program. I will go through the details here.

We pretty much included all the verbiage in these, we tried to make them readable so you'd have all the details. So, we will take the two separately then, thermal/radiation aging versus moisture aging. So, this is the thermal/radiation aging.

Basically, what was found was insulated cables in a small number of localized areas in containment were identified in station problem reports as exhibiting accelerated aging due to their proximity to this high equipment.

Corrective actions, these, of course, showed up in

the problem investigation reports. Corrective actions at the time tested the cables and they were all functional. So that confirmed that. Future surveillance was also put into corrective actions. Modifications to eliminate the adverse environments were to be evaluated. That's the corrective actions that came out of it. Yes?

DR. SEALE: Have you got any indication based on the initial examinations where things were still functional, that down the road you might expect a deterioration in performance and that was the reason for the future surveillance item that is in that bullet?

MR. COLAIANNI:

Yeah. There were not -- if the cables look in a condition that they seem to accelerate at that same rate, you might have a problem.

DR. SEALE: Okay.

MR. COLAIANNI: Yeah, that was the reason for continuously monitoring of the area. The evaluation of the modification, I mean, the ideal situation where you can actually eliminate it. One case was where they had routed some cables over a large feedwater line. The ideal would be to fix it, shield it, so that you no longer have that design feature in that area. So that's the thought process behind that.

DR. SHACK: How were the problems identified?

That's basically visual inspection, saw degraded cables, or functional problems?

MR. COLAIANNI: No. Visual inspections. Some of them were actual dedicated walkdowns, but these same areas were also found just by maintenance people walking around doing their jobs and they would notice something and report it back. Then an engineer would come out and evaluate it. But it turned out that many of these got identified more than once, so you had more than one PIP on the same area simply because the area kept being noticed by maintenance people. But walkdown inspections, just visual indications were what was noted.

When these are identified in the early stages of license renewal review, this is like 1996 time frame. This is the walkdowns I told you about yesterday, that I went over. A lot of these were initially noted in PIPS at that time. The problems were judged to be design installation problems and not relevant to license renewal. That may seem, on hindsight it kind of looks strange to say that, but at the time what we were thinking was, you know, we were trying to draw a distinct line between design problems, or maintenance problems, versus actual aging problems. So that was the judgment that was reflected in the original application, that these were design issues that should be dealt with more in the modification area to alleviate the

problem rather than an aging issue that should be part of license renewal. So, that is kind of what got reflected in the original application.

CHAIRMAN BONACA: But you may have a design feature, not from a cable but from the environment that is causing the aging problem.

MR. COLAIANNI: Right.

CHAIRMAN BONACA: So the environment is part of the license renewal, but not from the aging then because you can just make the same application, eliminating that environment.

MR. COLAIANNI: Right.

CHAIRMAN BONACA: So, you are addressing that?

MR. COLAIANNI: Yes. Yes. And as you will see in the next slide the progression that went on, basically, in what we realize now is that if you have a design installation problem that you don't fix, then basically then you've got an aging problem that is part of license renewal. But if they went ahead and fixed it so to alleviate the problem and it goes away, then it is not an aging problem. So it is kind of a progression of thinking through the process.

So, as I was just describing, basically in 1999 now that we did the on-site inspections, the problem reports were identified by the staff. The problems the staff

identified as indications that aging management was needed, which was a good call because the areas had not been modified to alleviate the problem. So that is basically what this explains here. So we agreed at that point since the areas had not been modified to alleviate the problem then aging management was needed. And, basically, these sort of lessons, I call as lessons learned. I tried to, you know, the incident I told you about yesterday, give them this type of lesson meaning, you know, if you discover in walkdown something that you can label as a design and replace the problem. If you don't ever fix it, then you better include it in the license renewal program, because then it becomes an aging problem. If you are going to fix it, take care of it then and you won't have to worry about it. So, that is one of those lessons to learn going through this process the first time. It is always a challenge to label something.

CHAIRMAN BONACA: Say that you didn't go through license renewal till you find some cable like that, what would you do? I mean, you would just have the decision to either remove the cause of the problem by corrective action, or just simply monitor. That depends on if they have built it in the system, right?

MR. COLAIANNI: Right. Yeah, and it may depend on a particular situation. But, the continued surveillance of

that particular area would go on and either we'd modify it or continue to be surveilled down the road. License renewal just more or less made that process a commitment to make sure that that actually does get done as part of the program.

CHAIRMAN BONACA: But it is not different from what you normally would do?

MR. COLAIANNI: No.

CHAIRMAN BONACA: This is just establishing some specific commitment that you would do it?

MR. COLAIANNI: Right.

CHAIRMAN BONACA: An alternative to just simply moving the environment that is caused by the design problem?

MR. COLAIANNI: Right. Now even in this stage, even though those areas will be wrapped into the program, if they actually do modify them in the future to alleviate the situation, the adverse environment, then basically they can be brought back out of the program. Then there would be no need to have them in there.

CHAIRMAN BONACA: Yesterday you showed us some very aggressive inspection on your part, which I think should be commended. You wrote down a lot of systems, and you showed snapshots of areas where there were indications of challenging the equipment. Is this just a one- time initiative, or is it going to be part of this aging

management program, which you are going to have walkdowns with some frequency?

MR. COLAIANNI: The inspections that are envisioned, even though we found in specific areas, basically around the steam generators and pressurizers revealed some hot pipes we found specific areas. The inspections themselves are going to be enlarged to basically say, you know, basically we are going to look around all areas that the steam generators where you have cables to see if you have these things. In a three or four foot proximity all around the pressurizer is where you might have cables. Those are the areas that are most prone to where these problems would pop up. So it should make sense to just include the whole area around the steam generator and pressurizer in the inspection program.

CHAIRMAN BONACA: So you really haven't identified, or you will in

the aging management program of cables with specification location which are regulated by the aging program?

MR. COLAIANNI: Right. And one of the elements you will see in there, because those fall close to hot equipment basically, you've got that similar adverse environment from the cables and those similarities. So that would also be included.

CHAIRMAN BONACA: Okay.

MR. COLAIANNI: I've already covered this. Next slide.

Mr. Sieber: While you are doing that, there are some cables, power cables and control cables that you can't visually inspect. Those are ones that run in duct lines or conduits. What steps are you taking with those types of cables to insure that their condition is satisfactory?

MR. COLAIANNI: In our Reactor Building we have very few cables in conduit, basically because we have the armored construction cables. So that is really not a problem. In most places we have very limited use of conduit for areas that would just be subject to heat degradation. Now, the moisture degradation issue is covered, and I'll be covering that in some later slides for medium voltage cables exposed to moisture.

Mr. Sieber: All right.

MR. COLAIANNI: So what we came out with, this is the part of the program specific to the Thermal and Aging, Radiation Aging Effects. Basically, all in-scope cables installed in adverse, localized environments will be inspected. And those adverse localized environments basically, since they sort of did it on a spacing approach, basically we are going to be inspecting areas looking at cables and areas as opposed to specific identified cables.

And, again, because of the way the rule is set up, these do not include the acute program cables. They are already in an adequate program. The staff found that to be adequate for managing the aging of those cables. They've already been through a lot of pre-testing for their environments. So, this program itself does not explicitly include EQ cables, although in the inspections you are not really determining whether something is in or out of EQ, but this is more of a programmatic statement.

Accessible cables in these areas will be visually inspected every ten years. Basically what you are going to be looking for is cable surface anomalies to be used as an indication that something is going on with the cable. You obviously can't see the actual installation, that installation, which is the thing that really matters. But you are looking for surface indications that something is going on with the cable. So, these are the types of things you would look for in addition to other things. We've got a guide that I can show you that gives a lot of information on what kind of things to look for and where to look for them.

Unacceptable indications found during the inspections will be investigated further by engineering. So, basically where something is found either by a maintenance person, going through and identifying something, or an engineering problem itself, finding something, if it

looks, and depending on how it looks, further investigation would be done and it could include testing and any sort of corrective actions that seem appropriate.

MR. UHRIG: In the armored cables are you looking for dents

in the armor? What kind are you looking for?

MR. COLAIANNI: Actually, in a lot of cases there are some cables in the Reactor Building that just have the armor on the outside. But there are quite a lot of cables. In most cases you are more concerned with control of the cables. Those do have jackets that you can see, or they have a braided armor and you can actually see the jacket underneath the braided armor, or you can see deterioration of the braid. But you can actually see it. There are those pictures I showed you yesterday. You can actually see there is some deterioration that is going on. Although we do have armored cable, it might seem kind of strange to look for surface dents, but there are indications that you can see. This was found in the PIPS. Basically, a lot of things can be seen. A lot of things have been seen as time goes on.

So now we will move onto the Moisture, Medium-Voltage Cable Moisture Aging Effect part of the program. The history is basically on the outside inspection reviews. Areas of particular concern to inspectors were water collection and cable trenches and potential

degradation of direct-buried cables. To answer those concerns during the inspection, basically Oconee cables installed in trenches are designed for a rain and drain type exposure. The inspection reports for the direct buried cable tests, as also documented in the inspection report, do not show, do not indicate ongoing degradation. So, we feel good about at least the rate of whatever mechanism involved with those cables.

We did have one LER of a medium voltage cable back in 1980, where the cable failed. The documented root cause of that was their moisture intrusion due to improper installation, due to damage of the jacket during installation, or improper installation where water was allowed to intrude into the end of the cable. But those were the documented root causes in the LER itself. But that's the only instance that I'm aware of of medium-voltage cable failures with the conduit at Oconee.

CHAIRMAN BONACA: How was this failure identified?

MR. COLAIANNI: It was identified as part of testing of the motor. It might have been a mega test, but I'm not positive, but they were testing the service and found an indication and narrowed it down to the cable itself.

CHAIRMAN BONACA: So there was nothing to -- it was just part of a test?

MR. COLAIANNI: Right. So based on the site inspection, the staffing concluded that aging effects for medium-voltage cables exposed to moisture were applicable to Oconee and that aging management was needed.

So here we have the program elements pertaining particularly to this aging effect. Basically the program includes an inaccessible in-scope medium-voltage cables installed in adverse localized environments in conduits and direct-buried. Water collection in manholes will be monitored to prevent cables from being exposed to significant moisture as a preventive action. Inaccessible medium-voltage cables exposed to significant moisture and voltage will be tested at least every ten years. Now, basically when we talk about significant -- I use the term significant moisture and significant voltage. Those are defined as part of the program. It depends on the particulars of the cable itself as to what to submit. We do have the framework of definition. If you are not real sure of what your cable is capable of withstanding when we talk environments, we have sort of a threshold value in there. But a lot of it depends on how the cable is designed, what environment it is designed for. You could have a submarine cable which is designed for a hundred percent exposure, a hundred percent voltage all the time. So that does depend on the cable itself.

MR. UHRIG: What kind of testing are you talking about there, measuring the resistance, the pulse transmission?

MR. COLAIANNI: Right now, and because the first testing under this program will not be done for another decade, didn't specify what type of test. Basically, before the test is performed, the cable engineer with the help of our NGO cable engineer, would determine what is the best type of test performed and to give him the best information on the individual cable. But that really won't need to be determined, won't be determined till another decade before the test. And hopefully, you know, mainly because there could be new test arise between now an then. A lot of the test that we will replace now, that may not look good now, maybe customized down the road. So we didn't want to specify and lock into any particular type. But it would be something that would give the cable engineers a good confidence about the condition of the cables.

CHAIRMAN BONACA: But you plan to do the testing? You've committed

to some testing by what?

MR. COLAIANNI: The first test would occur sometime before the end of the Unit One initial period of operation.

CHAIRMAN BONACA: And you would have a bona fide

program at the time, of course problems can change as you learn more, or something different.

MR. COLAIANNI: That's correct. The program would be fully in place before the first test would be performed. So this is the reason we are talking prior to each test, the specific type of test performed along with test acceptance criteria will be determined.

The criteria will depend on the type of test, and what are the particulars at the time, and the particular type of cable. The cables not meeting the test acceptance criteria will be investigated further by engineering, be it testing, be it replacement, whatever seems to be corrective action.

All right, so those are the particular aspects to each of those types. Now, there are aspects of the program that deal with both thermal aging and moisture. These are basically that a determination we made as to whether an identified unacceptable condition or situation is applicable to other accessible or inaccessible cables. So in the case of thermal or radiation, of course you can't see cables in the middle of a bundle. So if you see some indications on the surface of the ones you can see, you know, an evaluation would be determined whether is that a condition applicable to other cables that I can't see. And the same thing for the moisture. They find some cables and they do a test and

they find an unacceptable condition, an evaluation would be done. Is this occurring on other units with the same configurations, but that would be applied. The initial inspections or tests would be completed by February 6, 2013. That is the end of the initial four year period for Unit One.

And to use as a guidance, there is a new document posed by EPRI now that gives good walkdown guidance. Here are some of the kind things we look for, here is a good way to organize your activities related to these things. And it will be used as guidance to the process of completing the program.

I think that is it. Any questions?

With this we feel confident that we will be able to manage the problems that were seen by the staff in that whole process of license renewal.

CHAIRMAN BONACA: Thank you. Any questions? Thank you.

MR. GILL: Jeff Gilreath will come up now and he'll talk about Vessel Internals. We have a display over to the side.

Do we want to bring that up before here so you can use it here, Jeff?

MR. GILREATH: People can look at it there.

MR. GILL: Okay. So on the break perhaps we will

talk more, if that is all right, Dr. Bonaca. We do have some backup slides that will give the details on each specific location. Jeff has been involved for several years in industry efforts of vessels internals. He is well-versed in the current activities. They are ongoing, not only at Duke but also in Anderson.

MR. GILREATH: As Bob said, my name is Jeff Gilreath. I work in Materials, Mileage and Piping group for nuclear engineering section.

The purpose of the presentation today is to review how Duke Power addressed the open items concerning reactor vessel internals. Directly, there were six open items that we needed to address on certain reactor vessel internals. One had to do with potential void swelling, potential changes. The second had to do with potential cracking due to radiated assisted stress corrosion cracking, radiation embrittlement. And basically the 3 and 4 materials, reactor vessel internals, the third had to do with cracking of the baffle former bolts. So there has been some cracking identified in industry on back about baffle former bolts to date and the potential effect that could occur in the license renewal period. The fourth had to do with the embrittlement of cast austenitic stainless steel. The concern there was that we knew that there was thermal embrittlement, and we know that there is potential for

radiation embrittlement. But is there any synergistic-type effect and do we have the material properties to evaluate that.

The fifth had to do with the thermal embrittlement of the vent value. And that, too, is just that a vent value has a castaustenitic stainless steel body and it has a retained ream that is a martensitic stainless steel.

And then the last had to do with the reduction of fractured toughness of the internals to the radiation embrittlement. Duke resolved these issues in the end by committing to an inspection plan to inspect what are the effects of these particular mechanisms, and also to participate in industry and research and to report our program at it matures and evolves over the next few years. On slide 34, just to point out different components of the internals. In the internals, and there is a picture over here, and even our model, you can look at that later, it is really made of two sections. It has a plenum area that is removed when we defuel every outage. In the plenum area assembly there is a sixty-nine control rod guide tube assembly. Within these control rod guide tube assemblies, there are actual spacers, ten spacers in each assembly as of castaustenitic stainless steel. So, therefore, we were asked to address those components.

Also, there is your core support assembly. Your

core support assembly is actually made up of three components that are bolted together. You have your support shield. In your support shield area you have some vent values. Well, we just mentioned vent values. And also the, on unit three there are outlet nozzles that are castaustenitic stainless steel.

Then your core barrel assembly. This is really where most of our focus is, because in the core barrel assembly there is high levels of radiation. There are the baffle bolts that we've been addressing. There are also the baffle plates, former plates, your core barrel itself. So there is a lot of research going on right now evaluating those components.

And then in your lower internals assembly there, too, in the encore guide tubes there is a spiral right in this area that is castaustenitic stainless steel and we will have to evaluate that.

DR. SHACK: Are your baffle bolts 3.04?

MR. GILREATH: Yes, sir.

DR. SHACK: And no coal work?

MR. GILREATH: No coal work.

DR. SHACK: So you are relatively unique that way in B&W units?

MR. GILREATH: Yes, sir. Which may, actually, you know, we think we can use that to our advantage because the

bolts themselves, you know, we obviously could remove those in an inspection and do further studies that would reflect how pretty much the whole internals would be behaving, because that would be your lead component. And, so, we think that is going to really help us.

DR. SHACK: It could be more susceptible to swelling, too.

MR. GILREATH: Well, Frank Gardner has mentioned that to us also, and he is helping us develop a program. He has looked at our internal design, and a few things about the internals are unique to B&W. Let me just point those out real quick. This is a backup slide. When Frank was evaluating -- you know, this is just first shot discussing how our internals may perform. He noticed that in our baffle plates we have some holes that are drilled throughout the plates, or bypass flood holes, pressure relief holes. And also in the plates there are big slots. And so the deferential pressure against the baffle plate is very minor, but even to a more concerned with swelling is that the cause of all the interchange of water and the heating effects are not going to be as high on these particular bolts and plates as you might see an internal design does not have all the flow holes. Next slide.

CHAIRMAN BONACA: I have a question. You mentioned before we got into different -- that is pretty

unique to B&W design. And you mentioned martensitic steel for that?

MR. GILREATH: Well, the vent valve itself, this is a drawing of the vent valve. The valve body is castaustenitic stainless steel. Then the retaining wedge here is a 15.4 participate hardening stainless steel. Those particular items have been known to thermal embrittle. And so what we want to do is make sure that with -- there is not much radiation in that area, but it may get to the 10.17th, neutrons per centimeter square range. So, therefore, we just need to evaluate how that will effect the toughness of the material.

MR. UHRIG: Will it be a theoretical evaluation or will it be a measurement?

MR. GILREATH: Well, presently we do an active test on these valves every outage. We will do an analysis. But in that analysis what we hope to do is to actually take castaustenitic stainless steel from a plant that is shutting down that has a high level of radiation on that component so that we can get some real material properties. Because today there are not many out there in the industry on this item.

CHAIRMAN BONACA: The reason why I'm asking is that just the hinges on there. I mean, the valve is supposed to open freely.

MR. GILREATH: Yes. Sure.

CHAIRMAN BONACA: So you have just hinges there. I'm just not familiar with the size of them, but certainly embrittlement would be a concern that it could drop if we had a failure in there.

MR. GILREATH: And that will be evaluated in our program, and we will be inspecting it. But we do inspect those every outage even today, the activation.

CHAIRMAN BONACA: That specifically is in your program?

MR. GILREATH: Yes, sir.

CHAIRMAN BONACA: Well, how do you inspect them now, I'm just curious. You do push it to see if it opens?

MR. GILREATH: It is a functional inspection. No visual inspection of cracking or anything.

MR. GILL: There is a visual inspection. They lower a tool valve and lift it, and they measure the force of lifting. It is a strobe test, basically. These are considered to be check valves for Section 11. There are about four, I think, for each internals, for us eight. But it is unique to B&W design. It is actually a strobe test that they can visually look at it with a camera sticking in so they can see physically if there is any other

abnormalities you can visually look at. This is actually replaceable with the jack screws. You can actually replace the valve itself.

DR. SHACK: Now, you look at it with a camera. Did you actually do a visual inspection?

MR. GILREATH: Yes.

CHAIRMAN BONACA: Now, you mention martensitic steel for those hinges. Is there any specific reason why there was a different kind of material?

MR. GILREATH: Not for the hinges, but for the retainment. I'm not sure what material it is for the hinge itself.

Mr. Sieber: Well, that would interfere, if it broke off it would interfere with the vessel wall so you would have damage to the vessel wall to some minor extent that it would not be floating around inside the vessel. It would interfere with rod drops.

CHAIRMAN BONACA: No, it would be on the outside.

MR. GILL: You would probably hear it, too.

Mr. Sieber: Probably would.

CHAIRMAN BONACA: Okay, thank you.

MR. GILREATH: Initially, our approach to resolving these open issues had to do with license and a process. In our reactor vessel internals aging management program we were evaluating the aging effects of the

internals. We were characterizing those. We were looking to see if any of these particular mechanisms may effect our internals, trying to perform an some analysis on critical crack sizes, developing methods for particular inspections. The NRC raised a concern that most of those studies, which there are quite a bit -- a few studies are going on, both at Duke and in the industry -- that most of those studies will be over the next five or six years. What they were concerned with was what if a mechanism may not show up until late in the license renewal life, would you be able to detect that. And so they said why don't you go ahead and commit to an inspection program that assumes all these mechanisms occur, and then if you can prove through your evaluations and your analysis that these, the effects of these mechanisms will not impact the function of your internals, then you can make a submittal for us to review and take that particular part of the inspection out of the inspection plan. And, so that was acceptable to us. So through working with NRC we did commit to an inspection plan, and basically took the processes that we were already performing and incorporating them in our inspection plan to help mature the elements of the plan, like the acceptance criteria, the method of inspection, things of that nature. We committed to specific timings. Instead of doing them early in the license renewal life, that we would do some

early. We would do some in the middle and some later in the license renewal life to assure that we've been able to monitor any type of aging effect. Also, we would participate with the industry in doing research and trying to better characterize each aging mechanism and we would report that to the NRC. And so we agreed we would commit to an inspection plan, but that inspection plan would mature over the next five years as we go through our process, and as we go through all our research. And so the program itself, the elements in the program will be modified or maturing or evolving over the next few years. As we get more industry data -- we are doing a lot or research in the industry -- and also as we perform some of our analysis. If for any reason that we felt that we could remove any part of the inspection plan, we would have to make a submittal to the NRC for them to evaluate the basis for that removal and come to some resolution at that time.

What we came up with in our inspection plan is actually three inter-related inspections. One had to do with inspecting the baffle bolts. We would propose performing a volumetric-type inspection of baffle bolts. There were a lot of aging effects that the baffle bolt may actually see a cracking due to irradiation assisted stress corrosion cracking. Reduction of fracture toughness due to irradiation embrittlement, and dimensional changes due to

void swelling. This is an inspection that we will plan to do early in the license renewal life, in the middle and in the end. During that inspection as we evaluate how we might utilize some of those bolts, we may be removing some of those for further analysis.

We committed to a, we expect our castaustenitic stainless steel inspection will assist with some type of visual, one type of visual about the enhanced DT-1 or DT-3. What we are going to do is perform an analysis, and first we've got to come up with some material property data. Once we do that we are going to perform an analysis, come up with a critical crack size, and at that time we will be able to determine what method we want to use for an inspection.

With the other components in the internals there are quite a few; the baffle plates, the former plates, the core barrel bolts, different components. We have planned to perform a visual inspection of all the other items, and also in this area we will be looking at material properties of three or four different plates, for instance. That will be critical crack sizes, so that we can determine what size crack would effect the function of the internals and develop our inspection program around that.

We will probably be using some of the baffle bolts to lead items on potential change and to avoid swelling, but that could change once we do an evaluation. We are really

where the gamma heating effect is. Apparently, the gamma heating effect and irradiation are the two concerns that need to be addressed with swelling.

We've got an ongoing program right now with our core barrel bolts and thermal shield bolts that we have done volumetric exams in the past. We are doing visuals now every outage. We've got a program in a BWOG that is evaluating what would be the best method of inspection in the future. We are kind of waiting for the deliverable there from BWOG to determine exactly how we'll inspect those bolts.

DR. SHACK: What is your dose map look like? How much of this core is really in a kind of a high EPA state, kind of a radiation system track point of view?

MR. GILREATH: Let me see if I have a backup slide for that. In the area of the fuel itself the dose rates, or the accumulated affluence are pretty high. They can see as high as 10 to the 23rd neutrons per centimeter square. But it falls off pretty quick. The core barrel itself, I think, is more like 5 times 10 to the 21st. That's a ballpark number. I'm not quite sure about that core barrel. We knew that if we could get the lead component, three or four material, developing an inspection planned around the lead components we will be able to pretty much map out the effect to the whole internals.

DR. SHACK: Where do you say go below 10 to the 21? How high up would you have to go?

MR. GILREATH: The map that I've seen, basically, they do not go -- we do not have maps that go up into the plenum area. Therefore, you know, we were wanting to be able to say, for instance, the spacers may be below 10 to the 20th, and wouldn't be concerned of radiation embrittlement, but there are some people that believe even though you may be below that particular threshold, is there a synergistic effect. So, what if you only have 10 to the 18 neutrons per centimeter square, will that, coupled with thermal embrittlement, effect the spacers. So we do not have maps right now that go up real high into the upper internal, but here it is pretty even across the core. This area would be like 10 to the 21st, and come all the way down to the 10 to the 23rd, and then come back off 10 to the 21st, 10 to the 20th, in that rank. So, pretty much the length of the core you are going to have maximum affluence.

As I have mentioned before, instead of committing to one inspection, we have committed actually a minimum of three inspections. One, early in the license renewal period. The second one would be in the middle. The third would be in the third period of license renewal period. However, it would be prior to our last year of operation. We expect that this particular program, we'll be able to

utilize it for other plants that have the radiations out that far. So, you know, we are pretty much committed to this inspection plan.

I just want to mention a little bit -- I don't know how much you know about all that industry is doing in this area, but we have committed to participate with the industry. Primarily, a B&W owners group has a reactor vessel internals aging management program with quite a few elements in it looking at Oconee specific, or the B&W specific internals, and we are going to be utilizing a lot of the programs coming out of there. To give you just an idea of that schedule, just an idea of some of the tasks we are doing, we are doing studies on swelling and gas. Pretty much everything we've discussed today, the B&W owners group is addressing. We have a five year plan to come up and to evolve or mature all the elements in the inspection program, utilizing industry data. So at a particular time we will be submitting a program to the NRC for review before at least two years prior to our first inspection.

Also, we are working with other groups. EPRI has a large group, material liability program issues task group. In that group we've got some of the same elements and other elements working with the whole industry and addressing or trying to characterize the aging effect. And, two, the job program, or joint baffle bolt task team. That's a program

that went out and looked at the international programs, tried to find out where we thought the most work was being performed. We found EDF with a very large program. And so we are funding some of that work and we've submitted our materials also to be integrated with their program. And just in the job itself there are over a hundred and forty deliverables that are already part of the contract.

The reports I mentioned, our first report to the NRC was the topical report, BAW-2248, that addressed the effects of reactor vessel internals. We just received a SER on that in December.

Other reports that we are committed to, as our program evolves we are going to submit reports to the NRC every time we complete a significant milestone for review. And then our first report will go in within one year of receiving a license. Then our last report will be two years prior to our first inspection, when we will have all our inspection methods resolved or committed to and what the acceptance criteria will be, things of that nature.

Are there any other questions?

CHAIRMAN BONACA: I understand you have to report to the NRC and the two years, it will be two years before the end of the current cycle.

MR. GILREATH: The first report will be within one year of receiving a license for licensing, for extended

license.

MR. GILL: Sometime next year.

MR. GILREATH: Sometime next year. And then our last or final report will be two years prior to our first inspection. So it will be pretty much when license renewal begins, that period.

CHAIRMAN BONACA: And that report, focusing on that one, that one will really contain much of the detail that you are going to gain from all the activities you have with EPRI, and with the ---

MR. GILREATH: Yes. It is really essential that we get that material property data, and we will be submitting that to NRC. As a matter of fact, we are going to Washington in April to go over the whole industry program with the NRC, the EPRI program, the BWOG program, and others.

CHAIRMAN BONACA: It will be interesting because there is a lot of activity going on. Okay, thank you. We are running a few minutes ahead of time. We can take a break now.

MR. GILL: That concludes our morning presentation.

[Recess.]

CHAIRMAN BONACA: Okay. So let's resume the meeting, and we have representation from the staff now

regarding the SER and the closure of the open items.

MR. GRIMES: Thank you, Dr. Bonaca. My name is Chris Grimes. I'm the Chief of the License Renewal & Standardization Branch. And by way of introducing Joe Sebrosky, who is the Project Manager for the Oconee License Renewal Application. I would like to compliment the committee on holding a meeting here at Oconee, providing an opportunity for more access by the interested public, and also bringing the renewal activities to the site so that the plant people can see the licensing process. I think that is a good move on the Committee's part, and we will plan for that for future renewals.

With that, Joe is going to go through and present the staff's presentation and we are prepared to respond to any questions that you have about the staff's safety evaluation basis.

MR. SEBROSKY: Good morning, my name is Joe Sebrosky. I'm the project manager for the safety review for the Oconee License Renewal Application. I would just like to point out that we have several members of the staff in Washington that are standing by to support the meeting. They have copies of the slides. So, I am going to be calling out the slide numbers just so they can keep abreast of where we are at.

As far as the presentation, I'd like to just give

you a brief overview of where we were and where we are at right now regarding the safety review aspect of the license renewal application. And then discuss the resolution of the open and confirmatory items, some discussions that were added to Oconee SER since the last version was published in June of '99. And then a summary of the license renewal application review activities that are to be completed before Duke gets its renewed license.

The last time we made a presentation to the subcommittee was based on a June 16th, 1999 version of the SER. We had a meeting with the ACRS Subcommittee over two days on June 30th and July 1st, and we also interacted with the full committee on September 1st. Since that time we provided the ACRS with an update to the SER on February 3rd of this year.

The February 3rd version of the SER contains several updates to the June version of the SER. Specifically, it closed the open and confirmatory items contained in the June version of the SER. There were forty-three open items and six confirmatory items that were closed in the February 3rd version. There were also new evaluations that were added due to license renewal application update or because of a Duke response to an SER open item. I'll point those out towards the end of the meeting, specifically what added evaluations were put into

the SER as a result of those.

And, finally, we did make changes to the SER based on technical comments that we received from Duke. Back in October when they provided the responses to the SER open items they also gave us technical comments that resulted in some changes.

On to slide five. I'd like to -- we are modeling this presentation over the presentation that we gave to the ACRS for Calvert Cliffs. And, specifically what we are doing is we are breaking down the open items based on the division responsibilities within the Nuclear Regulatory Commission.

There are four divisions that were involved in the review of the license renewal application. The division that I'm in, which is Regulatory Improvement Programs, the Division of Inspection Program Management, Division of Systems, Safety Analysis, and finally, the Division of Engineering.

For the Division of Engineering open items, since they had the majority of the review, I've actually, we've broken those items up into the respective branches. And as far as going through the presentation for each of these divisions, what we tried to do was tell you what the top issues were, and then also have a discussion of all the other open items. Doctor Bonaca, Noel indicated to me that

you may have some questions that may not necessarily be in the top issues. I'll try to call those out when we come to those slides.

As far as the top issue that was resolved within my division, that was, we had an open item regarding the content of the UFSAR. That was open item 3.0-1. Currently right now we are in the process of reviewing Duke's draft UFSAR supplement that they have updated because of the SER and because of changes that have been made to the application as a result of the review. We intend to have that review completed and reach an agreement on the UFSAR supplement before we go forward with the commission recommendation.

So, the basis for the resolution was basically that the staff would review the detail content of the UFSAR supplement, and prior to going forth with commission recommendation agree on a resolution.

MR. GRIMES: I would like to add to that. Since we issued the draft revised UFSAR supplement to the staff, along with guidance explaining what the content changes are, pursuant to 57.1E, and the guidance that has been developed and relative to changes in 50.59, so that the staff would be able to view the contents of the UFSAR in the context of the regulatory process that is going to maintain the licensing basis in the future. And any issues that stem from the

staff's review of the UFSAR supplement, we would intend on identifying and tracking in the same way that we identified and tracked resolution of open items in the UFSAR itself.

MR. SEBROSKY: The next division was the division of inspection program management. The branch within that division that was involved with the review was the quality assurance branch. They were the lead on the scoping issue that was discussed this morning with Duke, and also on several other items.

This slide, just on a high level, provides an overview on the basis for the resolution of the open item, and it reiterates what Duke presented this morning, the fact that we asked them to look at ten additional events, and based on them not identifying any additional systems, structures or components, we felt comfortable and it gave us a reasonable assurance that the scoping was done properly.

CHAIRMAN BONACA: On a genetic basis, but we are talking about the SOP, etc. It is better for the older plants in need of being more specific than just -- I'm not sure that 50.54 specifically felt this is all Chapter 15.

MR. SEBROSKY: We don't, we didn't agree with the view that design basis events. It says narrow as the way that Duke explained that they maintained the licensing basis. But we do agree that the end result, by virtue of the overlapping scoping techniques, captured all of the

necessary systems, structures and components that are relied upon to prevent or mitigate events that are described in the licensing basis. That is how we selected the ten additional events to evaluate. And I would expect that we would take that experience and feed it back into improved guidance for the standard review plan, and possibly even we can work something out with the industry group, guidance for the industry guide 95.10 that would explain how to review plant capabilities in a broader way.

I'd also mention that after the generic aging lessons learned, an SRP update, we have a commitment to the Commission to the consider rule-making, and I would expect that if there is an opportunity for us to clarify the language in part 54 that describes scoping, to make it more consistent with the evolving design basis description under 50.2., and the other language that describes design basis events. And 50.49, for environmental qualification. And the maintenance rule. There's a maintenance rule workshop that was just held two days ago. As all that experience comes together it is conceivable that we can clarify that the expectations for future renewal applicants.

CHAIRMAN BONACA: Good.

DR. SHACK: Does the latest revision of 95.10 incorporating this? I mean, would you expect to see the future applications discussion?

MR. SEBROSKY: 95.10 addresses scoping and addresses methodology, but to the extent that it doesn't get into this what is a design basis event, and how is the definition of current licensing basis in part 54 intended to be applied to a current licensing basis, that is still an area where these other activities going on in 50.2 with the industry. There is guidance there. There is guidance for 50.59. There is guidance for the maintenance rule. All of those things sort of surround this thing. If we could bring some more focus to it, I think that would make the process more efficient and predictable in the future.

Go on to other issues that were resolved for the quality assurance branch under slide number eight. We did have an open item relative to the corrective action for non-safety related systems. The resolution for that is basically the UFSAR supplement. Duke is identifying under one of their attributes corrective actions, specifically what process will apply to both safety related and non-safety related systems.

I'd like to move on to DSSA, which is slide nine. Basically, as far as the top issues go within this division, they are the division that did the scoping. The systems groups looked at the scoping to make sure that the boundaries were appropriate, and also challenging in some cases whether or not systems should be within scope.

The top issues that I identified for the division were the ones that added additional system structures of components. We had three open items that did that. There was the -- we challenged the chill water system, which is the heat sync for the control. As a result of that Duke scoped that in and we reviewed that, performed an Aging Management Review. So you will see added discussions both within Chapter 2 of the SER, and also within Chapter 3 where we asked the Division of Engineering to look at the Aging Management Review for that.

Also, the other two open items were associated with the ventilation sealant material, and one was with the passive long-lived equipment excluded from AMR. If you go back to the tour that the ACRS took yesterday of the standby-shut down facility, this one issue dealt with skid-mounted equipment, which the diesel was considered to be skid-mounted equipment. The question that the staff had was were the boundaries that Duke originally drew appropriate. When they drew those boundaries, skid-mounted equipment, like some of the heat exchanges that were on the skid were excluded from an aging management review. We didn't agree with that. We challenged that. Duke subsequent to the initial application provided aging management review from its components.

And lastly, under one of the top issues that was

resolved for DSSA, there was an issue that came up late in the Calvert Cliffs review regarding ECCS piping insulation and whether or not that should be within scope. The staff asked a question about that and Duke gave us justification for their design as to why the piping insulation, they did not need that to meet any of the criteria in 54.4A1, A2 or A3. We agreed with that, but there was an additional evaluation and exchange of information that was done. You also see that in the SER.

MR. GRIMES: I would like to clarify. That was insulation on 4A water system piping and whether or not the insulation was necessary in order to insure that the sufficient statement and solution. So it wasn't insulation in a broader context, it was for that specific functional capability.

MR. SEBROSKY: The next slide is other issues that we resolved within DSSA. I didn't plan on talking about each one, but there was one, Dr. Bonaca, that you had indicated some interest in, and that was on the recirculated cooling water system, which is the heat sync for the spent fuel pool. We have the staff available if you have any questions about that.

CHAIRMAN BONACA: No. I think with the review of yesterday in the afternoon, I think that we recognized that what you did, which really is not part of the licensing

basis, the current licensing basis for the plant. We still have questions regarding the loss of spent fuel cooling event as a basis for the pool. Clearly it is not the basis for cooling. We heard that the makeup water system is circulated. It can be used to make up water in case the cooling system is lost. That was the basis for your cooling, I believe. I believe that the membership accepted that yesterday as recognizing that as a means of cooling the pool and making up the water.

DR. POWERS: I guess I would characterize the members have heard that. I would characterize it as saying the members heard that.

CHAIRMAN BONACA: Yeah.

DR. POWERS: I wouldn't say that there was any endorsement.

CHAIRMAN BONACA: True. True.

MR. SEBROSKY: But I would also like to add that was one of the areas that we explored very carefully in making sure that we understood what the licensing basis was. And we did consider it very carefully, and DSSA affirmed that was the way that a number of plants are currently designed and licensed. We considered whether or not there were any risk insights that warranted pursuing that separate from licensing. Mr. Gratton explained in the conference call that we had that their understanding of the licensing

basis were prepared to pursue that separately with the ACRS if you like.

CHAIRMAN BONACA: Before you move that, I had a question regarding the open item 2.2.3.7-2 regarding active equipment in storage, if I remember. I understand that you agreed not to include that equipment in scope. I personally agreed with that. The only question I have is that because Duke said that they are routinely inspecting and testing their equipment, so therefore it is maintained in a way that -- but it seems to me that in any event the equipment is being inspected, tested, installed and then tested when it is installed anyway. Why would you consider possibly in scope? I'm trying to understand, you know, for example, how will you address this issue? Do you still have a requirement that this be ---

MR. SEBROSKY: The way that the issue came up was that there was equipment that is warehoused that has passive elements, and whether or not the passive features of that equipment need to be managed while over time because the aging effects are the same whether or not the equipment is being used or in storage. It is more the process by which the equipment that is taken out of storage and then put into service is verified as suitable for service that provides us with a process assurance that if there are any applicable aging effects, if they are not managed or at least checked

before the equipment is put in and then subjected to the routine inspection program. So, that's the way the issue started to evolve. It was, well, do we need to have an aging management program for this equipment while it is in storage. And we concluded that by virtue of the process that certifies spare parts for use, that provided sufficient assurance that if there were any aging effects they would be identified and then checked before the equipment is actually put into service.

CHAIRMAN BONACA: Yeah, that point I made, I totally agreed with that, with the conclusions that you made regarding that. I just believed that those conclusions are pretty genetic because the process is by which the utilities install the spare parts. It is very similar. You have to set the specific requirements and go through, which would include the inspection and the testing, and then selection testing.

MR. SEBROSKY: The reason that the issue came up for Oconee is if you look at the scoping criteria one of the criteria is regulated events, 54.4A3. There is an appendix R. As you noted yesterday on the tour, Oconee has some unique features. For example, the turbine building, that's where the emergency feed water pumps are located. They are not located in the ox building, so there is a vulnerability to a fire in the turbine building. That's why they added,

one of the reasons they added the standby shut down facility. So, when you go their Appendix R requirements, they rely on a lot of cabling that is in storage. Also pumps and breakers that are in storage to help recover from a fire in the turbine building. The staff looked at that and they noted that Duke had looked at the passive components, the cables, and did an aging management review and determined that the cables were in a benign environment. But we asked about the active components, and that was the reason for that open item.

So, it is somewhat related to the unique nature of Oconee's licensing basis. That is why the question was asked.

MR. GRIMES: I'm sorry, I didn't respond to your specific question. Yes, I would expect to add guidance in the standard review plan that explains why we do not need to be concerned about aging management programs for equipment that's in storage.

CHAIRMAN BONACA: Okay. Good.

MR. SEBROSKY: I guess as far as the top issues, I'd like to move to the Division of Engineering. We've broken it down by branch here. For the materials in the Chemical Engineering branch, the top issues that we identified for this branch, if you go to slide 11, are those associated with the reactor vessel internals. And if you go

back to Duke's slides this morning, this slide is consistent with that as far as the open items that were associated with the internals.

Are there any questions that the ACRS members have of the staff?

CHAIRMAN BONACA: I think that we saw a very comprehensive program that addresses a lot of the issues from the swelling to others.

MR. SEBROSKY: The first issue on the next slide, slide twelve, really involves a reactor vessel internals component. Again, that was talked about this morning. That's the vent valve bodies, internal reactor vessel.

The next set of open items dealt with CASS components. Finally, there was a new issue, this 3.4, 3.3-9 that was added after the SER was written in June, and that had to deal with reactor vessel monitoring line. The staff questioned whether or not that needed an aging management review. Are there any questions on that?

As far as other issues that were in this branch, they had the majority of the open items. There are several items on this slide, Dr. Bonaca, that Noel has indicated to me that you might have questions about specifically on the pressurizer heater sheath-to-sleeve plate, open item 3.4.3.3-2. The buried piping, the standby shut down facility HVAC coolers, and the standby shut down facility

heat exchanges.

CHAIRMAN BONACA: Yes. I had some questions on the pressurizer heater, we discussed it yesterday with the applicant. I understood, the question was more relating to the nature of the one time inspection where you would not have an inspection unless you have a failure to the heater, so I thought that we had characterized one time inspections somewhat differently. Essentially, the inspection that you performed to get a confirmation that in effect is not occurring. Or if it is occurring it is a benign factor. And, so, you know, that was more of a clarification than anything else that we got from the applicant. Everything was fine with that.

On buried piping, the questions I have was in several instances, two instances on this. All the inspections for the buried piping of the Kewanee facilities are not really done there. I mean, they are referring to the inspections at Oconee as being indicators of the aging management at the Keowee facility. The reason is that the materials used supposedly are the same between Keowee facility and Oconee facility. I had some questions about two things. One, the environment. It is, in any case did you look at the differences in environment and possible aging effects resulting from it. And second, the Keowee facility was not really under Appendix B program until now.

And so, therefore, there maybe -- do you have enough records to say that, yes, you have the same material, the same conditions, and therefore the inspections that would be for Oconee are also indicative of the conditions you would find at Keowee?

MR. SEBROSKY: I guess our lead reviewer, and I'm hoping he is on the phone, was Jim Davis. Are you there?

Mr. Davis (via telephone.): Yeah, I'm here.

MR. SEBROSKY: Jim, I was hoping that you could respond to Dr. Bonaca's questions.

Mr. Davis: Well, basically, what they are concerned with is the soil corrosion of a pipe, and with carbon alloy steel you don't see much difference in corrosion rate. Basically what they are doing is they are doing an internal inspection, eleven foot diameter pipes, which counts for about eighty percent of the piping that they have. That's not the recommended way to do things, but we found it acceptable. If there was an oil or gas line, it would be totally unacceptable.

The downside is it is going to cost them a lot of money when they see a leak because they are going to have to replace all that piping, probably. But that is their decision to make. They are inspecting eighty percent of the pipe. I see no difference in the, or significant difference in the corrosion rate from soil anywhere that you have

buried pipe.

MR. GRIMES: And, Jim, correct me if I misstate this, but I think that the way that you described that we would say they were not relying so much on the identical nature of the piping, but more that the inspections that they have provide a bounding circumstance by which any indication would cause them to go look at the effected piping and, as Jim points out, if they find a problem then they are going to do a lot more digging than if they had a more focused inspection activity because of the benign, relatively benign nature and the expectation that they are not going to see a problem, this constitutes sort of a bounding approach to be issued.

DR. POWERS: It would be interesting to see the data that suggests that the carbon steel piping corrosion is fairly independent to details of soil conditions.

Mr. Davis: Typically, you know the NBS in the old days and this now did a very detailed study of corrosion in soils of steel or alloy steel. They found that the average life is twenty-eight years. This pipe is coated, but it is not cathodically protected, which normally would make it worse. If you are not going to cathodically protect it, you should leave it bare, and then after thirty years replace it all. If you cathodically protect it is good forever. So, I'm not quite sure what there logic is of not cathodically

protecting it. But basically, once they see problems they are going to have problems everywhere. They are just going to have to go in and deal with it.

DR. POWERS: I guess we would be interested not just in the average life time, but the variable around that average.

Mr. Davis: It all depends. It depends on a lot of things. If you find a section of pipe that corrodes through, and you replace that section of pipe, the new pipe will last about six months, because it acts as an anode and cathodically protects the rest of the pipe. So, you get into a real serious problem if you don't use good engineering practice, which a lot of the nuclear industry doesn't, and that piping is not under, there are no rules or regulations to control it. But if they see problems they are going to have to go in and look at all their pipe.

DR. POWERS: I guess I'm more interested in the data that led to your conclusion, that there was a fair insensitivity to this type environment.

Mr. Davis: It is kind of hard to predict. The variance probably plus or minus ten years, their soil is pretty benign. They could do a soil conductivity measurement, and that would give them a good indication of how corrosive it is. Usually if it is a high resistivity, five thousand centimeters, then the soil is not considered

to be very corrosive. But if it is a lower resistance then it is considered to be very corrosive. The program that they propose to go in and inspect periodically, they are going to find leaks if they have any, or depending on the inspection time it takes.

MR. GRIMES: Jim, did you mention where those studies are found?

Mr. Davis: Yeah. They are NBS and the National Institute Science and Technology did the big studies.

MR. GRIMES: The National Institute of Standards and Technologies?

Mr. Davis: Yeah. It used to be the NBS when they did the -- but, you know, and the type of soil they've got there, I would expect it to be close to a thirty year life.

CHAIRMAN BONACA: You also made a statement before that I don't understand the answer. You said that you would be concerned if in fact the environment was not water, but oil or gas.

Mr. Davis: If you have oil and gas pipelines, that falls under Title 49 of the Code of Federal Regulations, and it says, "If you bury a pipe and you've got oil or gas in it, you must coat it and you must cathodically protect it, and then you must monitor it using pipe to soil potential measurements like Calvert Cliffs does.

Oconee has chosen not to do that.

DR. SHACK: But then Oconee is not transporting oil or gas interstate through cities and ---

Mr. Davis: Yeah. And they are not required by law to do it. If they want to replace their pipe every thirty years they have the right to do that.

CHAIRMAN BONACA: I understand. Okay. Thank you.

DR. SHACK: I guess the other argument is you don't really expect the soil to be terribly different at Oconee and Keowee, so whether it is average soil or not, there doesn't seem to be a reason to believe it is terribly different.

Mr. Davis: That's right. You normally expect the higher corrosion rates if you have brackish water or something like that. That is not the case for Oconee, so you wouldn't expect to have a very corrosive soil there.

DR. POWERS: I'm going to have to comment on the technical basis for the staff's decision, and I just don't understand the technical basis for this. I guess I understand the technical rationale, I just don't see the data. As far as the variability of soils I think I can see places where soils vary dramatically over the course of a few feet. I don't know whether that's the case here. I don't have enough information on the site to ---

Mr. Davis: Normally you would expect to see large

variations. What we are relying on here is that they are inspecting eighty percent of a total surface area of the pipe on a regular basis. If they have a problem, they will detect it.

MR. GRIMES: And take appropriate corrective action.

Mr. Davis: Right.

MR. GRIMES: But we can provide the, we can provide the NIST reference, the N-I-S-T references, in terms of the data that lists the variability of corrosion for buried pipe. But otherwise our technical basis is based on inspection and corrective action, not necessarily managing the aging effects that are applicable to the buried surfaces of the piping.

DR. POWERS: I think this gives us an opportunity to highlight before the Commission the approach that is adopted here.

I think it is an opportunity for us to point out to the Commission that the approach is here. Okay, they've taken the strategy, the strategy will work, because if they find a problem they will have to dig and replace things. You've got some confidence that there is detection because they are doing eighty percent of the tech things, and the other twenty percent we think is much like the remaining eighty percent. But I think we have to have an

understanding of the technical rationale for that. We have to see the technical rationale. If it is an engineering guess, that's an engineering guess. If it is based on a careful analysis, it is based on a careful analysis. It is just a matter for us to point it out to the Commission.

CHAIRMAN BONACA: Well, actually we are hearing that they are going to inspect and if there are problems they are going to fix them. That's pretty much what I hear. The other issue, you know, it is more regarding the bounding of all systems of the Keowee from Oconee systems.

And that ---

DR. POWERS: But it is not a random eighty percent they are inspecting.

CHAIRMAN BONACA: That's right. It's ---

DR. POWERS: It is a distinctly unrandomed eighty percent.

CHAIRMAN BONACA: Right. So that would be right.

MR. SEBROSKY: Well, I'd just point out on this slide, before we leave this slide, there were two other items, 3.2.12-1 and 3.2.12-2.

CHAIRMAN BONACA: I had a couple questions of this. One was for the SSF HVAC coolers. You had a question regarding the need for providing both floor measurements and measurement to assess if there was any measure of loss of material, for example, that would effect the changes. I

believe the resolution was that the frequency of testing is such that the flow measurement can be relied upon to detect if there is any change. I didn't understand. There was no specific explanation in the SER why lack of identity allows you to get that assessment and the field loss.

MR. SEBROSKY: Our reviewer for that is Stephanie Coffin. Stephanie, are you there?

Ms. Coffin (via telephone.): Yes, I'm here.

MR. SEBROSKY: And did you hear Dr. Bonaca's question?

Ms. Coffin: Yes, I did. The answer is they do measure across those heat exchanges. Not as part of their, in response to open item what they propose with the new preventive maintenance activity that we reference in closing out this open item. And in that PM activity they do measure it across the heat exchangers.

CHAIRMAN BONACA: Okay. That is not what is documented in the SER, but that is fine. So I'll take it as the answer to this question. And I had one more question regarding the 3.2.13-2. That's where carbon steel inspection indicate, a user indicator of conditions of known carbon steel components. And the specific question was that the carbon steel inspections are used as lead indicator of conditions such as, for example, a MIC attack. Or other that it may cause pitting. And the position was that this

type of corrosion does not effect the destruction of any of the components. Okay, if you have a MIC attack you typically have a pin hole leak and therefore you can't identify it ahead of time. I wanted to hear more about that, because for my limited experience with MIC attack, I've seen pipes literally devoured inside by MIC attack. There was a pin hole leak, but the pipe was ready to go. And maybe even in a more -- so I would like to hear the technical phases for concluded that this is a --

MR. SEBROSKY: And Stephanie before you give the answer I guess I just wanted to make sure I -- that, if I understand correctly, it is actually on slide fourteen, and the question that you have is on 3.2.13-2, correct?

CHAIRMAN BONACA: Yes.

MR. SEBROSKY: I think I had the wrong slide up. Stephanie, did you understand the question?

Ms. Coffin: Yes, I did. The basis for closing out this open item was Oconee's operating experience with their service water system. They have been doing these inspections for close on twenty years now, and they have not found any, not had to replace any kind of piping due to corrosion concerns. They haven't documented any indications of problems with MIC, or very localized degradation with problems that they've seen in their service water piping is general corrosion for the techniques they are applying are

acceptable. That doesn't mean that this isn't a concern to the staff, and what the licensee, and the licensee recognized that and they committed to following more closely the results of those service water inspections as well as other, say, specific materials to document any times that they have a degradation due to a localized corrosion phenomena and consider its relevance to the service water, service water piping inspection and factor that into how they are approaching maintaining the integrity of their service water piping.

MR. GRIMES: Another way I would put that is, the general, the inspection activities associated with general corrosion and plant conditions will identify if MIC becomes a concern in the future, or any other aging effect for which there hasn't been any present evidence warranting a specific aging management program. So it goes beyond just a particular concern about microbiologically induced corrosion. I thought I'd say what MIC is, because you have to say it so slowly. So in that sense this conclusion is very general for us. If there hasn't been any evidence of a particular aging effect, we still rely on the general programs to reveal and deal with any evidence if it occurs in the future.

MR. SEBROSKY: We've actually moved onto slide fourteen. There weren't any other questions that I noted on

slide thirteen. But since we've moved onto a new slide, Dr. Bonaca, Noel indicated to me that there was also a question that you had regarding 3.2.13-3 on the relationship of the program to Keowee, and also on 3.2.13-4 on the UT inspection capability, located degradation.

CHAIRMAN BONACA: Yes. The first one we already discussed. That was related to the same question that we had before, relationship between inspection for Oconee and Keowee. And the other one ---

MR. SEBROSKY: I guess the question that I had from Noel was regarding 3.2.13-4 is, "What is the staff's basis for finding the applicant's justification acceptable?" Some localized degradation mechanisms may not be bounded by inspection for general corrosion and may result in pipe failure.

CHAIRMAN BONACA: Yes. That was UT test, which are not very effective to identify. That was the point I had. There are none, as far as I understand it, where you are effectively localizing, identifying localized pitting, and microbiologically induced corrosion. And so I would like to hear more about that.

MR. SEBROSKY: Again, the reviewer for this open item is Stephanie Coffin. So, Stephanie, if you could respond to that.

Ms. Coffin: The reason why open item 3.2.13-4 is

related to closing out 3.2.13-2 and because the staff accepted that general corrosion with the limiting degradation note for this service water piping, UT is an acceptable technique to use. If they have to change their program in response to finding the localized pitting or mix, they have committed to changing their techniques to use one that is qualified for the application, which means it won't be UT, it will probably be a visual inspection. I can't think of what much else you could use. I don't know if you heard, did you hear what Jim Davis ---

MR. SEBROSKY: No, we did not hear what Jim said.

Ms. Coffin: Jim also pointed out that they also have their

heat exchanger performance testing, which would also tell you that you may have a MIC problem because you would getting fouling. So that is sort of a secondary measure in place to let you know that may be of a concern in your plan.

MR. SEBROSKY: The rest, if that answers your question, the rest of these open items on this slide dealt with TLAA's and some -- TLAA's being Time Limited Aging Analysis -- and also some confirmatory items. Were there any questions on those? I didn't note any. On the ones that are left on the slide, Dr. Bonaca, I didn't note any that Noel indicated. As a matter of fact, I believe that of

all the questions that Noel forwarded to me that we addressed all the items.

CHAIRMAN BONACA: But I have more.

MR. SEBROSKY: I understand. I understand. I guess, moving on, the next group is the mechanical engineering branch within the Division of Engineering on slide fifteen. Our reviewer for this was John Fair, and I'll just give a high level overview and then ask John to address the specifics. John, are you there?

Mr. Fair (via telephone.): Yes, I'm here.

MR. SEBROSKY: And basically, I guess, what I wanted to say as a high level overview is we presented three options to Duke, and they chose an option that is a plant specific option, similar to what Calvert Cliffs chose. So the resolution for Calvert Cliffs and Oconee for this issue are the same. And, John, is there anything that you wanted to add?

MR. FAIR: The only thing I wanted to add is that the resolution for both Calvert Cliffs and for Oconee is consistent with the recommendation that came in on GSI-190, which was to do something to monitor the effects of fatigue cracking due to environmental concerns. So it is consistent with the GSI-190 resolution.

CHAIRMAN BONACA: Did Duke use the same locations for monitoring that the GA used? I know they identified

them from the regs 60-260 or so. That's fine by me.

MR. SEBROSKY: John, did you hear the question?

MR. FAIR: Yes, I did. They are essentially the same as were used by Calvert Cliffs, and the ones from Duke are out as new regs 60-260. Several of the new regs 60-260 locations were addressed in the topical report on the vessel. And the remaining ones that weren't addressed by the topical report on the vessel, Duke is going to evaluate the GSI-190.

CHAIRMAN BONACA: Okay, and that is responsive to the recommendation that you are giving on the closure?

MR. FAIR: That's correct.

MR. SEBROSKY: Were there any other questions on that?

CHAIRMAN BONACA: No questions.

MR. SEBROSKY: As far as the rest of the issues that were in this branch, there weren't any that were identified to me before hand. The issues that we had open items on were: containment tendon anchorages; letdown cooler thermal fatigue; aging effects of HVAC sub-components; the reactor coolant pump oil tank inspection plan; spent fuel pool temperature. And then we also had several related to structures and the secondary shield wall. Were there any questions about how those were dispositioned?

CHAIRMAN BONACA: No. We discussed the secondary

shield wall yesterday, the pre-stressing tendons, that the aging issues that are different than the ones for the containment.

MR. SEBROSKY: That's correct.

CHAIRMAN BONACA: And it was explained to us that the program that is being utilized to manage the tendons in containment is different from the one for the shield wall. But it seems to be like a comprehensive problem, also the one for the secondary shield wall.

MR. SEBROSKY: And, finally, slide seventeen finishes up the issues that are within this branch. These relate, again, to time limited aging analysis, and also some confirmatory items that we had. Were there any questions on that?

CHAIRMAN BONACA: Yeah. There was a time-limited aging analysis to do with the tendons, right? But they have chosen not to just before the inspection, so that is why they are gone? And that closes the whole issue?

MR. SEBROSKY: Hans -- yeah -- our reviewer on that is Hans Ashar. Hans, are you there?

Mr. Ashar (via telephone.): Yes, I am here.

MR. SEBROSKY: Did you have any comments on Dr. Bonaca's observation?

Mr. Ashar: No, I think his observation is correct. We had hoped to have enough data that can provide

a tendon drain line based on the previous data, and the drain line so that the forces are good enough for sixty years. But in the case of Oconee, that was not possible because they did not have random sampling data earlier. So they chose a management program. They are going to comply with the regulations regarding the drain line and not meeting the second requirement in the drain line requirement.

CHAIRMAN BONACA: I understand now they've gone from sampling the same nine tendons to sampling random samples?

Mr. Ashar: That is correct. Yeah. That is correct and they are going to implement a subsection item for section 11, a project tendon inspections.

MR. SEBROSKY: If there aren't any more questions on slide seventeen I'll go ahead and move to slide eighteen. This is in our Electrical and INC branch within the Division of Engineering. Paul Colaianni gave a discussion on it this morning. The issue was actually added as a result of an inspection. Caudle Julian and Vic McCree from region two are here. And as a result of the second inspection, they identified that there were aging effects with the cabling. As a result of that we added an open item. Duke gave us an aging management program that we reviewed and found acceptable.

Our lead reviewer on that is Paul Shemanski.

Paul, are you there?

Mr. Shemanski (via telephone.): Yes, I'm here, Joe.

MR. SEBROSKY: Was there anything that you wanted to add to that discussion?

Mr. Shemanski: No, not really. I thought Paul Colaianni gave a

pretty good description of the overall program. I guess the only thing I would like to point out though is that this is a new program for Duke. When the application came in they identified basically three potential aging effects; radiation, thermal and moisture. In the application they concluded that none of these were basically applicable aging effects. And as a result of our inspection we found some evidence that the staff felt, you know, we recommended or felt we needed an aging management program for cables. Subsequently, Duke came in and we worked very closely with them on the attributes of the program. Since, again, this was a new program, so I think we are satisfied generally that the proposed program would be acceptable. It is based primarily on inspection. That is basically what I have to say.

MR. SEBROSKY: Were there any questions on this item?

I guess that ends the discussion about the open items and the confirmatory items. What I'd like to move on to is just to point out to the ACRS members the added discussions that were put into the SER from the June version. I have several slides on this.

The first slide just identifies responses to open items that resulted in SER sections. The majority of these were identified in the June version, but as we said you will notice that there is one on insulated cables and one on reactor vessel monitoring pipe that were added after the June version.

Regardless, as a result of the open items that are on this slide, scoping was done by DSSA, Division of Systems Safety Analysis. An Aging Management Review was done by the Division of Engineering. And sections were changed in both Chapter 2 and Chapter 3 for the Oconee SER for these as a result of the NRC open items.

The next slide, slide 20, and I apologize on missing a nine here, but on the September 30th, on September 30, 1999, Duke gave us a license renewal application update that is required by 10CFR 54. They identified several new system structures or components that were added as a result of changes to the current licensing basis. This slide just details those things such as the essential siphon vacuum system, portions of the component cooling water system being

expanded and portions of the low pressure service water system being expanded. The staff did a review and again made changes to the SER based on this.

The next slide just provides details of what Duke's technical comments were. If you go back to the October 15th letter that Duke gave us, in that letter they provided us all the written responses for the open and confirmatory items, and they also gave us this list of ten items to look at. In some cases we identified that there were no changes necessary to the SER and we discussed that with Duke. But in other cases, for example, we added the discussion about the leak before break, that was about a page long. And we've clarified some other things as a result of Duke's comments. Are there any questions on that?

Then I guess the final slide is basically a schedule of where we go from here. This just identifies the end gain, including the sub-committee and the full-committee meetings, and also the ACRS letter. But we have several actions that we have to complete, including issuing the new regs in SER. Caudle and Vic have to do ---

MR. GRIMES: Issuing the SER as a new reg.

MR. SEBROSKY: I'm sorry, issuing the new reg as an SER. Sorry. Anyway, Caudle and Vic have to do the final inspection and get the Region 2 administrator letter. The schedule was to forward the Commission paper with the staff

recommendation by April 14th, then it is in the Commission's hands.

MR. GILL: The engage schedules are presumptive. We presume that the ACRS will write a favorable letter. We presume that the follow-up inspection won't identify any issues that can't be readily resolved. And we presume that we will work out the details of a renewed license to present to the Commission in order to meet those milestones. But, we've been able to fulfill that kind of schedule on Calvert Cliffs, and I have a recommendation pending before the Commission that they are going to discuss on March the 3rd. That's why we asked you to move the full committee discussion of Oconee to March the 2nd. So, we are playing both end games in parallel and we'd expect to follow this same pattern for Oconee.

That ends my presentation, unless there are any questions.

DR. POWERS: I'm wondering how comfortable we are with all of this, this rush to completion.

CHAIRMAN BONACA: I'm sorry?

DR. POWERS: How comfortable are we going to be, how comfortable is the full committee going to be with this rush to conclusion.

CHAIRMAN BONACA: Well, I mean, I think we would like to have a discussion now of the sub-committee and talk

about also that issue there. And then my sense is that at the end of the discussion we will then define for the staff and for Duke what we would like to hear next week. So, why don't we just start and go around the table and see what general perspective there are, and comments regarding what we heard in the past couple of days and the closure of open items in the SER, and where we are right now as far as having our meeting next week and where we think we are going to be with the committee.

Why don't we go around the table and see if there are any specific comments. We'll start with you, Bill.

DR. SHACK: No, I don't have any particular problems. The big open issue that we sort of had was the reactor vessel internals. It seems to me they've addressed that with a fairly comprehensive program. You don't have all the answers, but, obviously, if you are inspecting you will identify problems and can address those. And if you can make some of those go away by analysis after further research, that's fine. So, updating that.

The questions on scoping I thought were reasonably well addressed by the discussions we had yesterday and today. So, I don't see any real show-stoppers here from my point of view.

CHAIRMAN BONACA: Tom, your feelings?

DR. KRESS: I agree with Bill. I don't see any

real show-stoppers either. I think they did an excellent job of addressing the scoping question. I just wonder how that will play out on the next review. I think we need to look into how we are going to review the scoping issue for the other plants.

But the items I had on my list to review for open items, I think the resolution and the closure was very appropriate and acceptable.

CHAIRMAN BONACA: Bob?

DR. SEALE: I was certainly impressed with the thoroughness, and really the enthusiasm with which the applicant has plowed new ground here. I guess the old story is that only the lead dog gets to see the change in scenery. And, certainly, you are seeing a lot of change in scenery as you go through and do this analysis.

I have one concern that just struck me that as you went through you in some cases referred to some rather vintage analysis, even things that were done before TMI. And I wonder if those vintages are perhaps all they are cracked up to be. Are there things that have been learned since then. Clearly there has been a very extensive amount of engineering work addressing some of the issues in the TMI realm that might cause one to ask whether or not those conclusions were completely true. And I guess, Chris, I guess that is something your guys want to take a look at.

MR. GRIMES: Actually, I'll address that by saying that as we present the results of these license renewal findings, we emphasis that the underlying principals for license renewal; the first of which is reliance and the regulatory process to maintain plant safety. Wherever there were lessons learned over time regarding whether the Three Mile Island lessons learned, or other specific events, the regulatory process has identified bulletins, generic letters, and other actions by which vintage analysis, or vintage designs are back fit to more modern standards. We may have learned some lessons that we conclude did not warrant backfitting, but that does not necessarily mean that the utility has not taken that experience and reflected that in their vintage analysis. We rely on them to do, to reflect on those things and go above and beyond with the backfitting requirements. So that reliance and the process gives us the confidence that whatever vintage features needed to be upgraded, have been upgraded.

CHAIRMAN BONACA: Mr. Uhrig?

MR. UHRIG: I, too, am impressed with what I've seen the last day and a half. My major concern had to do with the cable aging, and I think that was very appropriately addressed yesterday, and summarized here again this morning. I don't have any reservations on that.

The one surprise that came out this morning is the

lack of cathodic protection. But, again, it is not an issue as far as license renewal is concerned. I'm just surprised. I had understood this was always pretty much standard procedure, but it is not an issue as far as the relicensing is concerned. Thank you.

CHAIRMAN BONACA: Dr. Powers?

DR. POWERS: I'd like to first just comment on absence of cathodic protection. I think there are probably more instances in this world over cathodic protection than cathodic trouble, whereas it is protected, there are some serious problems with ground loops and things like that. But it can occur on a complicated site. So, the fact that there is no cathodic protection doesn't bother me very much. I work with some sites where it is just a nightmare trying to cathodically protect things.

I think it is important that we be able to write a letter that is fairly parallel to the one that we wrote on Calvert Cliffs. So it is important to make sure we have the information that can do that. Now, clearly, there are sites specific, but we ought to have a certain parallelism to the extent if we can. On the other hand, we do have to recognize that we are talking about methodology and setting a pattern that is going to be adopted in the future.

So, I don't think we should hesitate to comment on

methodological issues in the sense that they've been proven out here at Oconee.

DR. KRESS: Do you see the scoping methodology they use as being generally applicable to other plants? That was the concern I had.

DR. POWERS: I think that I would take from their scoping methodology, if I were a different plant, to be, the lesson learned there is to be imaginative in your approach on scope rather than trying to follow somebody else's line of script. That's the take home lesson I would get from that.

There is a question in my mind on how much we want to speak to the technical issues of information to the Commission, and particular on the, what I would say betting on the aspects of this, since we've gotten explicit questions from the Commission on the issue of one-time inspections. I'm wondering if in our presentation for the full Committee it might not be valuable to have a little more discussion of philosophy on that one-time inspection. Why do they think that this is a good way to look at something. How can you set the time frame for when it would be useful to do and when it is not useful to do.

CHAIRMAN BONACA: Yeah. And it is not set by the program.

DR. POWERS: Just because it is clear that is a

question that is on the mind of the Commission. Enough for them to write us and ask us a question about it.

DR. KRESS: Well, their basis that they used was, I thought it was strictly pragmatic; how can we fit it into the remaining shutdowns we are going to have between now and the end of the original license.

DR. POWERS: I think there is nothing wrong with that, and I'm not objecting to it. I'm trying to understand why ---

DR. KRESS: Understand why that's good enough?

DR. POWERS: Why that is good enough, yeah.

DR. SEALE: And what the circumstances might be under which one inspection wouldn't be adequate.

DR. POWERS: That's right, because there is, one of the things that is going to happen is you are going to set a precedent here, and you may well have to find, come up on occasion where you have to undue that precedent. And so you want to make sure that precedent is cast in the right light, so that somebody can't come back and say, "hey, you let these guys do this and I want to do the same thing," or it is almost the same thing, and now you are not letting me do this.

CHAIRMAN BONACA: And the other thing is that clearly we understood the philosophy of the NRC in accepting one-time inspection as a confirmatory inspection that in

effect is not occurring. That in of itself has a logic behind it that says you should wait and allow for time to give yourself time to make sure that you give it time to this improbably effect to manifest itself.

And so, then we had some communication that says, well, you know, there should be no restriction when you do it. Well, you have twenty years behind you. It doesn't make all sense. I think it would be good to have that discussion with the staff planned for next week.

DR. KRESS: Well, my concern with that, Mario, is that I'm afraid it is an unanswerable question.

DR. POWERS: And I think that is an acceptable response from the staff.

CHAIRMAN BONACA: That's fine. Sure. Okay.

DR. POWERS: I think you, if the staff came in and said, "Look, here is what we are trying to accomplish." You are trying to respond to a negative hypothesis. You are doomed to failure here.

DR. KRESS: Yeah. You are doomed to failure, yeah.

DR. POWERS: So you are looking for plausibility, and that's

all we've sought is plausibility here, and a program that has these characteristics to us is plausible and the ones that have these characteristics is implausible

to us, I think that is an acceptable answer, because that is pretty much the answer we've given the Commission on that, this plausibility document.

CHAIRMAN BONACA: We never gave a communication we expect to establish a criteria, but we said that this seems appropriate to the extent possible that you would delay as much as you can. They go in cycle. And that's why, I mean, I think it is important we understand why not, or there is a different criteria. One is, you know, can you perform a one-time inspection when your license the new plant. He says that he can do that. So, that's an issue we should hear about.

DR. POWERS: I think it's that I personally would like to see, understand a little better, the technical underpinning for the decisions on the sampling of piping for the ground corrosion.

CHAIRMAN BONACA: Yes.

DR. POWERS: I don't know that it is wrong.

CHAIRMAN BONACA: No. But to hear the criteria

DR. POWERS: In other words, a little more details on this so that I would be in a position to defend it, as well as the staff.

CHAIRMAN BONACA: Okay, Mr. Sieber?

Mr. Sieber: As you know, I'm recused from voting

on the application with Duke Energy. On the other hand, I'm not recused from assisting the committee in making its investigation, reviewing the items that were assigned to me, and commenting on those. I have done all of those. Along with Dr. Uhrig, I was assigned to look at the electrical issues here. But there are other items that I was particularly interested in. As a general conclusion I believe that there is nothing that bothers me to any significant extent that would prevent the issuance of an extended license. I would point out that in my discussions with individual Duke employees, they were very forthright and honest, and very willing to tell me everything that I asked them, or volunteer information straight from the shoulder, and I think that that's a prime and essential ingredient to being able to maintain a safe plant. But I got that impression while I was here and I would encourage them to foster that amongst all the people that are involved with Oconee.

CHAIRMAN BONACA: Thank you. In my impressions -- first of all, I would like to just make some comments regarding the interim SER as we received it, and the final SER. There are some big differences in my mind, and that's mostly for the issues we sought. Scoping. I think that the extended review by the staff was important in my mind because it gave us further assurance that in a pretty cloudy

definition, as we have for an older plant like Oconee, they have gone the extra mile to verify that there are components out of scope. I think that by looking at a number of additional, particularly the high energy line break, which really spans the whole gamut of the plant. When you cover that and you find no additional components, that gives a good feeling that really you have covered the scope issue reasonably well, or well.

The reason the reactor, RVI-AMP, which is Reactor Vessel Internal Aging Management Program, I think is a significant commitment. And I think that -- you know, so many of the issues we had regarding fatigue, regarding swelling, is really captured by that program. I really like to see that program is so tied in with the initiatives of the industry to aggressively go after these issues because the industry has not addressed those issues. So that is really their -- it has to be that leadership.

Also, I was satisfied about the closure on the issue of attendance, because that is a program where inspections, you know, you are not relying any more on those that, you know, we had other questions on when we met for the interim review.

Also, the cables. What I appreciated the most was the initiative of the plant to go out and look at locations and take pictures and be candidate with us, and that we

could see and then to respond. It means that they intend to take care of it.

I was impressed by the physical conditions of the plant. Most of all, by the fact that I didn't see a difference between the components which are going to be aging and those which are not, which it is telling me that there is a tendency to look at all components and take care of that.

One statement though, I'd like to make, has to do with more an impression, the reliance on established CLB. That is part of the rule. But my feeling is always that there is a rule and then there is we want to run a safe plant anyway. And so I, and I'm not saying that Oconee would not in fact look outside of the rule, but you -- particularly when the CLB is very old, you have to be alert to all components that you know by other means or any means that are important to safety. There will be some that you didn't capture in that CLB, and some that you captured, for example. And, so, I know that we have discussed this with the staff, these questions that got raised, and I believe again that the scope is adequate, but I think it is important that we all always recognize that, you know, we know as much as we, you know, our tools give us to know.

DR. KRESS: Mario, do you think the addition of the additional events to look at following this Chapter 15

is almost like doing a PRA? If you add enough of the events in ---

CHAIRMAN BONACA: Let me give you a feeling for what -- let me just give you -- I mean, this is a high energy line break analysis done most likely in the early 70's. I heard 1973. You know, there were computer codes used at that time. You don't even recognize it was for heat, but you blow super heat inside certain rooms at times and you get significant effects. And, so, you know, as in a PRA, what you know is as good as the methods you use. And, so, and there is nothing wrong with the licensing base of older plants, but the fact is, you know, they are more limited and we have to recognize that. Now, that is really what I meant.

DR. KRESS: All right. I was encouraged that the staff was able to add additional, what I would call design basis events, into this.

CHAIRMAN BONACA: Yes.

DR. KRESS: Because I think that sets a bit of a precedence that even though we can't see how to work the PRA, and that precedence to me does give a way to make sure the scope does cover all safety significant to the components of the system. That was encouraging to me.

CHAIRMAN BONACA: Yeah. And to me, too. It was significant, you know, cross verification of scope. And I

agree with Dr. Powers that we should hear something about one-time inspection, the initiative as being somewhat belabored. Again, the perspective of the committee is not one that we should impose any requirement as being done the last day, but one that says it is prudent to do it. Later and earlier because you want to keep a chance for this effectively.

DR. KRESS: I realize there is pragmatic and practical consideration there. It takes so long to do an inspection. You can't do it all at once, even though it is a one-time inspection, and it ought to be spread out over time. My thought there is that I think there is a need to prioritize. Which ones do you do first and which ones do you do last, and not worry too much about the timing, but the order in which you do it. I haven't seen much discussion on that.

DR. POWERS: I think what you are looking for is some language, some thought on a question of detectibility and sizing. Clearly, you want to inspect for those things that are most easily manifested and most easily detected, most easily sized earliest. And the most difficult latest. And in that, that maybe all the guidance you can offer.

DR. KRESS: I haven't seen any guidance.

DR. SEALE: Well, in this case, in this case, too, there is going to be the additional attraction, if you

will, and advantage perhaps of having an extended outage or two having to do with steam generator replacement that is going to sort of open the plant up for perhaps more detailed examination of some things than others. It would be a shame to not be sure that the tough ones that needed time to do, or to gain access to, were ignored when that opportunity arose. But you can't count on that every time. Not everybody is going to do that, but serendipity does come up and bite you every once in awhile.

CHAIRMAN BONACA: My thoughts on what to put in the letter. I agree with some of the comments that Dr. Powers made in the beginning, but as we, I would like to use the same format we used for Calvert Cliffs. I would like to highlight in that letter some of the problems which have been instituted in this list of open items, which I mentioned before. We were very significant, I mean, the reactor vessel programs, the containment commitments, and the cable problems. I would like to address the closure of GSI-190. I think that is important because this comes right after we close another genetic basis and we have a licensee who has responded and has essentially committed to certain specific inspections to deal with additional concerns that really, they could take our position on that and say, "Well, we are not going to do it because GSI-190 is closed." So I think that was something I wanted to identify in the letter.

I would like to put something regarding one-time inspection just to clarify the committee perspective on that. We may have been misunderstood in the past, or they may have believed that we were trying to impose some kind of specific requirements, which we never intended to.

Dana, you mentioned before the importance of communicating some of the methodology that the staff is using to accept closure of open items, and said to me the one of corrosion of carbon steel pipes. It is a good example. And, so, we will ask the staff to give us, you know, a very brief summary of the logic as they go through that we heard today verbally, and I would like to further summarize that just for information for the Commissioners. That was pretty much, I mean, there may be additional items that seem to be important enough for them to put in the letter for comment anyway, for your review. But that would be the bulk of where I would like to go. And I will hopefully have a firm draft for you before we travel to Washington so that you can take a look at it, because we have a very short time table.

DR. KRESS: Well, once again, I was impressed with the depth and comprehension of the staff's review. That gives you a lot of comfort to know they do a really good job on this.

CHAIRMAN BONACA: Yeah, likewise. I was very

impressed with their work. I was very impressed with Oconee. Unfortunately, and I say unfortunately, it gives us a benchmark as we did for Calvert Cliffs, and sets up expectations at least on our part for the next applications, and we hear about people coming in groves and groups and lumping together. We will have to really be watchful of the process that Oconee is going through to identify components of established programs. We will be with them for a long time, because they are taking the time to look at it, inspect it, and hopefully as well will happen on the next applications.

We have identified a couple of things I would like to hear for a full committee meeting, and it seems to me that from Oconee, from Duke, we would like to hear about the three items represented today, which is scoping, cables and the Reactor Vessel Internal Aging Management Program. Any other items you would like to hear from Duke?

DR. KRESS: Well, their plans for the one-time inspection.

DR. SEALE: Yeah.

CHAIRMAN BONACA: Okay. Plans for the one-time inspection, and maybe just some basic information regarding their embedded pipes corrosion inspection so we can understand that philosophy.

And on the part of the staff, we need to hear

pretty much the summary of closure of open items with -- I will expect special focus on the three areas that are being presenting by Oconee, which is scoping, cables and reactor vessel internal. Also, explaining their philosophy and accepting some of, you know, the approach for example on the corrosion of embedded piping.

And they heard us today talking about one-time inspections, so if there is any additional information that, or other perspectives that you are to give us, that would be the place for us to receive them so we can possibly address them in the letter.

MR. GRIMES: Dr. Bonaca?

CHAIRMAN BONACA: Yes.

MR. GRIMES: Just so that I make sure we are clear, Duke is going to make a presentation of the full committee that is going to describe scoping, cables, reactor vessel internals, their one-time inspections, and the buried piping?

CHAIRMAN BONACA: Yes.

MR. GRIMES: And the NRC staff is going to provide a summary of the closure of open items, and will specifically emphasize -- I'm going to start first with the reliance on the CLB and the regulatory process in terms of what the scope or renewal is. One-time inspections, both philosophically and in terms of what our expectations are,

and then how we do them in the change to the licensing basis. And then the buried piping issue, in terms of the illustration of the

staff's approach to evaluating aging management programs. Is that correct?

CHAIRMAN BONACA: Correct.

MR. GRIMES: Thank you.

CHAIRMAN BONACA: Okay. Do we have any other comments? Any comments from the public?

MR. TUCKER: My name is Mike Tucker. I'm Executive Vice-President for Duke. I rarely miss the opportunity to get up in front of a microphone. I would just like to thank the staff very much for the work that you have done in reviewing the Oconee application. I think you are correct, the NRC staff has done a very rigorous review of this topic, and our staff has certainly put a lot of effort into it. Doctor Seale, we very much appreciate your view that the view is only different as a lead. This team has done a good job and we look very much forward to the review next Thursday, I guess, with the full Committee moving on this project, so we have an opportunity to bring some more to you in the future.

CHAIRMAN BONACA: Thank you. If there are no other comments, we will ---

DR. SEALE: We do need to get to visit plants a

little more often.

CHAIRMAN BONACA: I agree.

DR. SEALE: I think you learn a lot.

DR. POWERS: We've got one coming in June.

DR. SEALE: I know.

DR. POWERS: I would personally like to thank the Oconee staff for the hospitality and the fine tour we had.

CHAIRMAN BONACA: And for the lunch that was delicious, I must say, and plentiful, too. Okay, so with that I think we can adjourn the meeting. The meeting is adjourned.

[Whereupon, at 11:15 a.m the meeting was concluded.]

REPORTER'S CERTIFICATE

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

NAME OF PROCEEDING: MEETING: PLANT LICENSE RENEWAL

CASE NUMBER:

PLACE OF PROCEEDING: Clemson, SC

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.

D. Brown
Official Reporter
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