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NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

Title: MEETING: 470TH ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

MARCH 2, 2000

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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MEETING: 470TH ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

U.S. Nuclear Regulatory Commission
11545 Rockville Pike
Room T-2B3
White Flint Building 2
Rockville, Maryland
Thursday March 2, 2000

The above-entitled committee met, pursuant to notice, at 1:02 p.m.

MEMBERS PRESENT:

DANA A. POWERS, ACRS Chairman
GEORGE APOSTOLAKIS, ACRS Vice-Chairman
THOMAS S. KRESS, ACRS Member
MARIO V. BONACA, ACRS Member
JOHN J. BARTON, ACRS Member
ROBERT E. UHRIG, ACRS Member
WILLIAM J. SHACK, ACRS Member
JOHN D. SIEBER, ACRS Member
ROBERT L. SEALE, ACRS Member
GRAHAM B. WALLIS, ACRS Member

P R O C E E D I N G S

[1:02 p.m.]

CHAIRMAN POWERS: The meeting will now come to order. This is the second day of the 470th meeting of the Advisory Committee on Reactor Safeguards.

During today's meeting, the Committee will consider the follow: Technical components associated with the revised reactor oversight process; nuclear power plant license renewal application; proposed final amendment to 10 CFR 50.72 and 50.73; proposed final Revision 3 to Regulatory Guide 1.160; assessing and managing risk before maintenance activities at nuclear power plants. We will also discuss proposed ACRS reports.

The Committee met with Commissioners between 9:30 and 12:00 noon today in the Commissioners Conference Room, One White Flint North, and discussed items of mutual interest.

The meeting is being conducted in accordance with provisions of the Federal Advisory Committee Act.

Mr. Howard Larson is the Designated Federal Official for the initial portion of the meeting. We have received no written statements or requests for time to make oral statements from members of the public regarding today's session.

Transcripts of portions of the meeting are begin

kept, and it is requested that the speakers use one of the microphones, identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

Before we initiate the discussions, do any members have any comments that they want to make at the opening of the meeting?

[No response.]

CHAIRMAN POWERS: Seeing none, I think we can proceed then with our agenda. The first topic that we're going to discuss is the technical components associated with the revised reactor oversight process.

Mr. Barton, I believe you're going to direct our process through this most interested topic.

MR. BARTON: Thank you, Mr. Chairman. The purpose of today's session is to continue dialogue with the staff regarding the revised oversight process, and I think, specifically discuss preparedness for rolling out the process for the initial implementation program, and also some discussion on the significant determination process which we didn't have time or weren't ready or something to discuss the last time we met with the staff.

So at this point, I'll turn it over to the staff. Who's got the lead? Frank, do you want to say anything?

MR. GILLESPIE: No, it's Bill's.

MR. BARTON: All right, Bill, you've got it.

MR. DEAN: Good afternoon, gentlemen. I'm Bill Dean, the Inspection Program Branch Chief from NRR. And with me today are Alan Madison and Doug Coe from my staff.

We're here to talk to you about exactly what Mr. Barton addressed. Basically this is a continuation of our February 3rd meeting where, basically, we were only able to get through the performance indicator portion of the discussion.

So we wanted to pick up where we left off and talk to you about the significance determination process.

I would like to mention a few things that have happened in the interim. Of course, we have developed and submitted our Commission paper, SECY 0049, to the Commission, which I believe you all have copies of, and hopefully you've had a chance to start to peruse that document.

That certainly provides what we believe the basis is for why we feel that going forward with initial implementation in the near term is the right thing to do.

CHAIRMAN POWERS: Why is that?

MR. DEAN: Well, there are a number of reasons. Of course, we watch with interest, your presentation to the Commission today, and some of the comments that the Commissioners made in the closing remarks, I think are pretty much in line with where we believe we're coming out,

based on the results of the pilot program.

And that is that the pilot process allowed us to learn a number of issues regarding the efficacy of the revised oversight process. It allowed us, during the course of the pilot program and in the interim between the end of the pilot program and now, to make appropriate changes and modifications to the process and improvements that would allow us to be able to enter into the next phase, which is basically -- and I think Commissioner Merrifield kind of described it best; that really it's an expansion of the pilot process to 103 plants.

You know, we believe that we've learned enough information that gives us a good comfort level that this program is an improvement in all the areas that the Commission directed us to improve in, and I think that we've demonstrated that.

I think we have also demonstrated some areas that we need to continue to monitor closely and gather additional information in, and that after the course of the first year in implementing this process at all 103 sites, it will give us the added information that we need to do to better refine this program and get it closer to the perfection that Commissioner Merrifield noted; that this was not a perfect process.

It was not expected to be a perfect process. It

is a much improved process, but, obviously, there is going to be continued improvements that will be needed.

CHAIRMAN POWERS: You said 103 sites.

MR. DEAN: Plants.

CHAIRMAN POWERS: Is this being applied anywhere besides nuclear power plants?

MR. DEAN: No, I meant plants.

CHAIRMAN POWERS: Okay.

MR. DEAN: Sorry. We do appreciate the endorsement that we heard regarding your belief, universal belief that this is an improved process.

But we also recognize that we may continue to agree to disagree on certain aspects of the program, and that perhaps more effort is needed on the part of the staff to either continue to discuss certain issues or aspects of the program with the Committee or individual members, and certainly we're willing to do that.

Before we get started, I do want to note one thing in terms of schedule. I know that you also have other parts of this afternoon to listen to other presentations, but we do have a briefing for the Chairman at 3:00 this afternoon, so hopefully we can adhere pretty closely to the schedule.

CHAIRMAN POWERS: Oh, we've got him where we want him now. Let me ask you a question.

MR. DEAN: Yes, sir.

CHAIRMAN POWERS: When you presented last time, a document that had a series of questions posed about the pilots, and then you got a grade from some people that did some grading for you on that, in many cases you got an incomplete.

And the answer was that I can't answer whether this criterion had met; the thing didn't go on long enough. Have you had a chance to get back to your graders and say now we're going to go in to this second phase where we have a pilot involving 103 plants, and ask them, how long does this have to go on before you can give us something besides an incomplete? Either pass us or fail us.

MR. DEAN: I believe -- I think the Commission paper addresses that as part of the rationale for moving forward into initial implementation, but also recognizing the fact that after a year of initial implementation, we need to do a thorough self-assessment, much like we've done in the pilot program, and report back to the Commission again.

And that would incorporate getting feedback from all of our stakeholders, much as we did in the pilot program, soliciting public feedback, industry feedback, internal stakeholder feedback, on, you know, now that we've experienced a year of this process, you know, what does that tell us about, for example, some of the issues where, you

know, there is still some discomfort out there about the capabilities of this process to do certain things that people believe it should.

And, you know, it's having the chance to experience this process over the course of the year. Does that help in that regard? Has that helped to alleviate some of the concerns in that area?

I think a lot of the discomfort or concerns on the part of both internal and external stakeholders about this process, a lot of it is based on just not having enough experience with enough diverse plant performance issues to be able to really feel fully comfortable with it.

And that's what we hope this initial implementation phase will do; it will allow us to gather additional insights from a wider spectrum of plants and different performance levels and performance issues, so that we can fully exercise all aspects of the process.

Okay, what we'd like to do with respect to the agenda, is spend most of the time hopefully talking about the significance of termination process, and Alan and Doug will take the lead on that.

I do have some discussions, hopefully at the end, on some future initiatives, and perhaps update you a little bit. There were some questions, for example, today, on performance indicator thresholds.

And one of the things we've done over the past few weeks is take a look at the historical information that we gathered from all plants from the submittal in late January. And that has allowed us to gain some further insights about some of those thresholds.

And we have made some adjustments or plan on making some adjustments to some of those thresholds on a going-forward basis. So, hopefully at the end, we'll have some time to talk about that.

Otherwise, unless there is any other further question, I'd like to turn it over to Alan and to Doug to start talking about the significance of the termination process.

MR. MADISON: Good afternoon. This is a brief overview of the significance of the termination process. And as has been mentioned before, it's really not just one process; it's multiple processes.

And I'm sure we'll get to the details that are of interest to you, based upon your questions.

But just to review, the principal objective of the significance determination process was first in characterize the significance of findings, to provide a relatively simple tool to provide to inspectors so that they could make an approximation within an order of magnitude of the significance of inspection findings.

We realize that we've said before that it is more difficult than the processes they've used in the past, from their engineer expertise to determine what the significance of characterizing a finding, but it's not quite as difficult as doing a PRA analysis.

There are some shortcuts and we can discuss some of those if you wish. But it uses similar risk metrics to what were used to determine the thresholds the performance indicators.

And therefore we have a way of correlating the significance of inspection findings to crossing the threshold in the performance indicators.

DR. WALLIS: I don't quite understand. What metric are you using? The PI seems to me to be in different plane from the usual risk metrics.

MR. MADISON: For the yellow, the white/yellow, and the yellow/red thresholds on all the performance indicators --

DR. WALLIS: There is a PRA.

MR. MADISON: -- are set at Delta CDF, the metric for --

DR. WALLIS: The green/white?

MR. MADISON: The green/white threshold is set at, as we've talked about in the past, to identify outliers. However, we've done just a gross check to make sure that we

are within the vicinity of a threshold of 10 to the minus six, and we're still pretty close there.

DR. WALLIS: Ten to the minus five in Appendix H. It's not ten to the minus six?

MR. MADISON: Ten to the minus five is your white/yellow.

DR. WALLIS: But that's what it says in Appendix H.

DR. SHACK: It's a typo.

DR. WALLIS: It's a typo? Because I have been puzzled by that/

MR. MADISON: It must be a typo if it actually says that in Appendix H, because the intent was 10 to the minus five for the white/yellow, and --

DR. WALLIS: It also says for white/green, which really puzzled me, because it's the same number. Anyway --

MR. MADISON: It was meant to be 10 to the minus six. Now, of course, that's not possible with some of the non-reactor thresholds, because you don't have as clear a correlation to risk as you do with the reactor safety.

DR. WALLIS: I think you really need to clarify this typo, if it is a typo.

MR. MADISON: That should be clarified with the new information that we have out on the significance determination process. And it also will be incorporated

into the procedures that have been written to describe the significance determination process.

CHAIRMAN POWERS: In your viewgraph, you say with similar risk metrics. Does that mean that there is no significance in the determination process associated with findings in connection with security and safeguards?

MR. MADISON: I'm afraid I don't understand the question. We have a significance determination process for safeguards issues that uses relative risk, and then goes into the reactor safety SDP to actually correlate it to change in core damage frequency.

CHAIRMAN POWERS: But we don't have any --

MR. MADISON: But in the inspection finding arena, we have what we think are relative significance in a qualitative manner from one inspection finding to another. If you have an inspection finding in the reactor safety arena and a white inspection finding in the safeguards area, they should have the same qualitative significance.

And we have tested that through doing feasibility reviews on each of these where we have involved the staff, as well as industry.

CHAIRMAN POWERS: But I have not seen something that tells me here's how I think I got to the idea that this white finding in the safeguards area is relatively the same as this white finding in initiators.

MR. MADISON: And that's because we haven't written about it yet. You haven't read that part, but we've done that, in doing, as I mentioned, feasibility reviews on each of the significance determination processes.

And the one on the safeguards significance determination process was just recently completed, so that report is not out.

But that was the objective, and actually that was one of the clear criticisms that we received in the lessons-learned meeting on the week of January 10th; is that that wasn't transparent to industry or to the public, that there was that correlation; that a white or red finding in safeguards was the same in EP as it was in reactor safety.

And so we tried to make that correlation clear, and by doing the feasibility reviews on each of those, we've tried to validate that, that that is, indeed, the case.

CHAIRMAN POWERS: It remains obscure to me.

DR. SHACK: What is the basis for that? It's an expert opinion thing? You get a bunch of industry people and NRC people in?

MR. MADISON: With the exception of when you go beyond white in the safeguards area, and when you go from the fire protection. Those both feed into the reactor safety SDP, and so there is a clear tie to each of those.

I didn't bring the diagram. I don't know if you

have the diagrams for the new, but they are in, I think they're in the document, the new SDPs for both safeguards and fire protection.

They clearly feed directly into the reactor safety SDPs, so that if there is areas of concern or issues of concern, the issue is characterized finally through the reactor safety SDP. So you get the same tie, the same equal tie there.

CHAIRMAN POWERS: I have a document that described the SDP, and, in particular, for fire. Has that changed?

MR. DEAN: Yes. We're developing, as part of the guidance documents that we're developing for implementing this program, we're developing an inspection manual chapter on the significance determination process which will provide all the information associated with all of the various processes that we use for determining significance.

And it will incorporate all of the lessons learned and revisions that have been taking place over the last several months as we've refined those based on lessons learned.

And the fire protection one is one that we have tested out, as a matter of fact, over the last several months. We've had a couple of issues at several plants that have allowed us to gain some insights, as well as in the meeting we had February 15th and 16th with NRC and industry

to talk about fire protection.

So we're in the process of revising that.

MR. MADISON: I can tell you the major changes on the fire protection SDP. We tried to clarify that that was a feed into the reactor safety SDP.

The output of the fire protection SDP goes into the reactor safety SDP. That was one change. I wasn't clear. That was the intent all along, but I wasn't very clear in the procedure.

And there -- what we also tried to do is show that the input to that SDP should be the same as the input to any other SDP. Whatever comes out of the Guidance in 0610* as far as describing the threshold for findings.

CHAIRMAN POWERS: Let me exercise memory a little bit on what that SDP process is. I have to go in and make an assessment on whether the degradation in the fire suppression capability, both manual and hardware-wise, has been degraded significantly, a medium amount, or not very much.

And from that I derive a parameter. Is there something that tells me what a lot of degradation is versus a medium amount of degradation, versus very little degradation?

MR. MADISON: There are some concepts that are incorporated in the training that the inspectors receive in

that area, yes.

And let me add this, too: That portion of the procedures is actually to be used only during the triennial inspection or by a fire protection safety engineer. The screening portion of the tool is designed for the resident staff and the normal inspector, Regional Inspector that would go out to the site and identify small issues out at the site.

So the expertise is available at the time when the finding -- to come to that type of conclusion.

MR. DEAN: But I think to answer your question more specifically in terms of criteria that say what is low, medium, and high, that's one of the issues that we have identified in using the significance determination process, and that's one of the areas that we do have to improve in terms of providing --

CHAIRMAN POWERS: It's totally capricious and arbitrary right now.

MR. MADISON: It could be.

CHAIRMAN POWERS: And having done that, if I succeed in doing that, I find I'm given a parameter. And I take that number and I add it. It says to the frequency of fires, but I think you really mean the logarithm to the frequency of fires.

And where did that parameter come from?

MR. MADISON: From EPRI studies.

CHAIRMAN POWERS: EPRI studies? Okay, so this comes out of five?

MR. MADISON: Yes.

CHAIRMAN POWERS: Ah, now I understand better, thank you.

MR. MADISON: We had a long discussion over where a lot of those numbers come from on the -- during the 15th and 16th workshop with industry and the public.

And J.S. Hyslop was very good at describing that and defending his terms to the point where industry was accepting of the numbers that were in there, the relative significance of those numbers, although they did express concern about the age of those numbers, that some of those numbers were quite old and that maybe new studies should be done to update those numbers.

CHAIRMAN POWERS: You've got -- the industry funds a research program attempting to better develop fire risk assessment capabilities. Why don't you use that?

MR. MADISON: We took that as a point to look at. There are a couple of phases. I guess part of what we wanted to do was to try to describe, just basically, the significance determination process as far as the phases of the significance determination process.

And with that, I wanted to use the next slide. It

talks about Phase 1, 2, and 3 of the process.

Phase 1 is more of a screening device where the issues that are identified by the inspector. And there are some questions that the inspectors ask to clearly identify or represent whether or not this is a very low risk-significant finding, or does it have the potential be a higher risk-significant finding?

If it doesn't have any potential to be a high risk significance finding, then it is colored as green. It is directed to the licensee's Corrective Action Program and documented in the report. If it is, then it goes to the Phase 2 screening, which is more complicated.

CHAIRMAN POWERS: Here's the step that I never really could understand from the description of this process. Suppose I have a finding that affects both the containment barrier and the RCS barrier?

MR. MADISON: It automatically goes to a Phase 2 review. If it affects more than one cornerstone it automatically goes to a Phase 2 review.

CHAIRMAN POWERS: Okay, so does it go through both of these little flow paths here?

MR. MADISON: No, you go straight to the Phase 2 review or if it affects both the barrier -- we would look at both of those, that's correct. We would look at all the action scenarios and we would try to pick -- not try to, we

would pick the most conservative call.

CHAIRMAN POWERS: You might want to make that clear in the documentation, because you make heavy use of this kind of flow chart in the description of the significance determination process. That is the one that just hits you immediately is -- even some of your examples. You even have an example in there, I think, where it affects two or more cornerstones, and it doesn't tell me in the flow chart what do I do.

MR. MADISON: You do both.

CHAIRMAN POWERS: You go through both?

MR. MADISON: You do both and you take the highest call.

CHAIRMAN POWERS: I was pretty sure that you went with the highest one, but it didn't say that.

DR. WALLIS: You say "we" -- who is "we" when you say "We" do these things?

MR. MADISON: The inspector does this.

DR. WALLIS: The inspector does all of this?

MR. MADISON: The Phase 2 review is done by the inspector. During the initial implementation phase there will probably be necessary for the regional SRAs to help out in some cases, although the inspectors have received training on this.

DR. WALLIS: The inspector has enough knowledge to

run the PRA and make these --

MR. MADISON: Doesn't have to run a PRA --

DR. WALLIS: -- run the licensee's PRA?

MR. MADISON: The work sheets provide kind of a quick method for him to estimate the risk --

CHAIRMAN POWERS: The prebuilt sheets are pretty clear, I think.

MR. MADISON: It's plug and chug in a lot of cases.

CHAIRMAN POWERS: Well, I think that overstates it. I don't think it is plug and chug.

MR. COE: We don't want it to be plug and chug. We want it to be a thinking process that entails the accumulation of risk insights. That is what we want the inspector to gain as well as an answer.

MR. SIEBER: Are these work sheets plant-specific?

MR. MADISON: Yes, they are. We were going to talk about that in a little bit.

MR. SIEBER: That's the work sheets you have been sending to plants --

MR. MADISON: That's correct.

MR. SIEBER: -- for right now.

DR. APOSTOLAKIS: What is the logic of the sheets being plant-specific and the thresholds not?

MR. COE: The logic is that we are trying to

assess an affected accident sequence, what the remaining capability is if you take away -- if you assume automatically some of the capability is already removed because of the problem that you found, so we have to judge for that particular plant how many other mitigation systems are needed to get to core damage that will remain for that sequence, and that is how we try to determine --

MR. MADISON: And the sheets are going to walk you through that.

MR. COE: And again it's a rough, it's an approximation within an order of magnitude so we are not drawing a bright line. The thresholds are not -- as you said, they are a fuzzy line. They are not a bright line.

DR. APOSTOLAKIS: Well, this analysis is plant-specific.

MR. MADISON: Pardon?

DR. APOSTOLAKIS: This analysis will be plant-specific?

MR. MADISON: Yes, based upon plant-specific information and within the limitations of what is represented on the work sheets.

DR. APOSTOLAKIS: All right.

CHAIRMAN POWERS: One of the things I didn't understand about the work sheets, I got the impression if we were to look, say, 10 years from now that it might well be

that work sheets were actually made by the inspector himself, rather than supplied. Is that the case?

MR. MADISON: That is not the intent, no.

DR. APOSTOLAKIS: Now if you have a model of the plant that maybe comes from the IPE with some improvements and so on, on the Sapphire code would that be an appropriate model to run to see this, the remaining protection?

MR. COE: It could be, and we would hope that if the SDP indicated that there was a potentially risk-significant situation that had been identified that if there was any value in doing those further detailed studies we would want to do that, and we have set aside --

MR. MADISON: It's likely going to fall though into the Phase 3 review and not necessarily in the Phase 2 review. The Phase 2 review is more to identify with a conservative call whether or not there is significant risk characteristics with an inspection finding, to then increase the dialogue if necessary with the licensee.

DR. APOSTOLAKIS: Now my understanding is that one of the national laboratories is working under your sponsorship, not "your" -- this particular group -- but the Agency sponsorship to put on Sapphire all the IPEs that have been submitted to the Agency, so now if I have a Sapphire model of the IPE of the plant, why can't I completely bypass these sheets and go there and --

MR. MADISON: There's some advantages to having these work sheets rather than just having just a computer model where you do really plug and chug. You plug a number in and it spits out a number. Doug will be one of the first ones to tell you this. It actually forces the inspector to thing about what is important at his site, what are the important characteristics of that train and what are the important components I should be worried about in that train. It makes them stop and think about that and maybe go look at those more frequently because that's where he is going to find the most significant issues.

A computer program doesn't necessarily do that for him. It is almost a training tool as well as a calculational tool.

DR. APOSTOLAKIS: I think there is great value to that. There is no question about it. You don't want just to push a button and get a number out, but I think you can also get similar information maybe by minimal modification of the existing software.

MR. DEAN: Yes. I mean that's a good point and we have had that discussion almost from Day One about computerizing the model. I think one of the things that we feel is important about the significance determination process is that in order to utilize it the inspector has to make some assumptions about things.

This process clearly calls out what those assumptions are, gets those out on the table, so that the NRC and the licensee can discuss the appropriateness of those assumptions and whether they really are applicable or not, and that is the real strength of this process.

CHAIRMAN POWERS: That comes across very well on your documentation.

DR. APOSTOLAKIS: I have no -- I don't object to any of this. It's just that we have bad experience in other situations where methods were developed for a quick and convenient calculation and then they took a life on their own. The precursor analysis -- there was a period of time when it was advertised as being an alternative to PRA. I don't think anybody in his right mind would say that now.

MR. MADISON: We have been very cautious. There was an early attempt to utilize the SDP, by industry to utilize the SDP to prioritize maintenance, and we said no, stop doing that, that is not the intent, and we have said and we have made it very clear to industry that its only intent is as a tool for inspectors to characterize inspection findings.

DR. APOSTOLAKIS: I think that if there is hope that in the future, in the near future, these computerized IPEs will play an increasing role in this, I think that will be a good development.

MR. MADISON: I think they already are in some of the other aspects of the program too. If you have read the discussion about event response, we initially looked at utilizing the SDP to characterize events. During our feasibility review we came to the conclusion that that was not appropriate, that there were better tools to do that characterization and they were available to the SRAs, to the regions, and they should use those tools, not the SDP.

The SDP was still the right tool to use for characterizing inspection findings, but we thought using the models, the Gem model, the Sapphire, were more appropriate for characterizing events.

DR. WALLIS: Does Sapphire come in at Phase 3 here?

MR. MADISON: The Sapphire may come in in Phase 3.

DR. WALLIS: Phase 3 starts after "Yes" -- that's not that clear from your --

MR. MADISON: I beg your pardon?

DR. WALLIS: Phase 3 starts --

MR. MADISON: Phase 3 is you have made a determination out of the Phase 2 --

DR. WALLIS: It starts at "Yes."

MR. MADISON: Yes, that's correct. You have a determination out of Phase 2 that you have a white, yellow or a red finding, and then you go into the Phase 3. Now I

said that it increases the communication between the licensee and the inspector, because all along during Phase 2 there should have been communication about what are my assumptions, what are the things that I am considering, what was the condition of this piece of equipment in your estimation at the time of the evaluation.

One of the other objectives, major objectives, of the tool is it's a communications tool. As Bill said, we lay out on the work sheets and on the report what our assumptions are, what are the considerations we are making during the analysis of the issue.

That's all out in the open. That's all part of the discussion with the licensee, and it is information the public and other stakeholders have to evaluate our work doing the SDP.

DR. SHACK: You take that you miss programmatic failures. You know, if I have a valve failure because I have a bad maintenance program, but the valve itself is not very important, I am going to end up green. But the fact that I have a problem with my valve maintenance program may well be significant. Do I miss that with this process?

DR. BONACA: I had a question, in fact, that I posed last time and I don't see a change here, so I was wondering if you are considering it, which goes in the direction, which is, do you have a repeat event that may not

make it to Phase 2, but may be significant in and of itself because it indicates something? For example, say that you have two events, or three events, they may something about the maintenance program or something else that may be significant just because -- not because you meet some kind of risk criterion in and of itself, but the repeat event in and of itself has a significance.

MR. DEAN: Yes. And what you are talking about, and there was some discussion of this this morning with the Commission and your presentation in terms of corrective action programs, or what we have characterized as the cross-cutting area of problem identification and resolution. And one of the reasons why we have embedded into the oversight process, to the baseline inspection program a substantial element of looking at the licensee's problem identification and resolution performance, and that incorporates in each inspectable area some element of that effort should be looking at licensee's efforts and problem identification and resolution, as well what we have right now, which is an annual inspection to look at problem identification and resolution activities, with the annual inspection probably focusing more on corrective action, extent of condition type activities.

Whereas, in the inspectable areas, you are probably looking more at, how well is the licensee doing

problem identification? Are they identifying issue in that particular area and getting those in a corrective action program.

DR. BONACA: You see, I think that this belongs right here. You have a box with corrective action program there. If your corrective action program cannot deal with events that repeat themselves time and time again, this reliance on the box becomes meaningless. I mean you have a chart here. I would like to see inspection issue involved in the condition, the first box. Does the issue clearly -- and you have a "yes" down. The next question is -- is this a repeat finding?

MR. DEAN: Yes. And what I was going to get is one of the elements of the annual inspection is to look at, for example, what has been in the licensee's corrective action program and in addition to what we have see through our inspection findings over the course of the previous year or so in terms of what sort of issues have emerged that have been characterized with some significance. You know, green issues are not good issues, they are issues of very low but some risk significance.

Do we see any patterns or trends? That is one of the purposes of doing that annual inspection is to look for patterns and trends and to look at see what the licensee is doing in terms of evaluating the body of information in

their corrective action program to see if they indeed recognize if there is any patterns or trends.

DR. BONACA: But this is the Significance Determination Process. Anything which is not identified in the Significance Determination Process is, by definition, not significant, it seems to me. I mean, to me, in a risk analysis scenario, although it may not be quantifiable, repeat events have significance. Okay.

We may not be able to quantify them. But the fact that you have, you know, misalignment after misalignment after misalignment is significant issue from a risk standpoint.

MR. DEAN: And we would believe that if you have misalignment after misalignment, then you are talking about impacting things like safety system availability. You are going to have unplanned availabilities.

DR. BONACA: Other systems.

MR. DEAN: And, so, a basic premise of this program is that if you see programmatic breakdowns in areas like valve maintenance or things like that, then they will evince themselves in either issues that will be captured through increasing trends in the performance indicators, or we will come up with a number of inspection findings, some of which may trip a risk significance threshold, or which there may be an accumulation over time that would cause us

to identify a trend or pattern.

And, so, you know, this --

MR. MADISON: The finding is still identified as green. It is still identified, it is documented in a report and it is required to be addressed by the licensee's corrective action program.

But I will say this, this is something we are watching closely during initial implementation. We have a working group set up to look at the problem identification resolution, actually, all cross-cutting issues, but focus first on problem identification resolution issues. And we will be looking at this and making sure that the initial assumptions we are making with the program, the premises of the program, are valid.

DR. BONACA: Yes.

DR. SHACK: That is the majority conclusion that that hasn't been tested yet.

MR. DEAN: That's correct.

DR. BONACA: Yes. And, again, I suggest you look at this fact because this says, this is the safety Significance Determination Process.

MR. DEAN: Yes.

DR. BONACA: And, so, I think you have to look at all the aspects, because, by definition, since you have put the definition here, that is -- you know, anything which is

not here is not being considered.

MR. DEAN: I guess not to be too much longer on, you know, repeat issues, you know, in our enforcement process, under the current oversight program, you know, that is one of the things that we look at, but that is something that we also struggle over. You know, what is the time period between one issue occurring and another issue occurring that that really is a repeat issue? And are there different aspects about the issue that really it is a different element that caused this issue to occur?

And, so, that is an issue that we struggle over a lot in the current process in determining, you know, is this really a repeat issue or not?

DR. POWERS: Did I get an answer to Dr. Shack's question about, do you catch programmatic failures?

MR. DEAN: Well, I guess in kind of a long-winded way. I think what we tried to get across was that we believe that if there are programmatic issues that affect equipment or activities of risk import, that you should see that over time evince itself in thresholds being crossed.

Now, is this something that has been proven out? It hasn't. I think it is something that we certainly recognize in the Commission paper, that this is something that, you know, time will really tell, and is one of the motivators really for getting into initial implementation

and getting more plants involved so that we can hopefully prove out the theorem that we believe that this process has embedded in it, that we will see those programmatic issues emerge and thresholds being crossed and significant issues.

MR. MADISON: But his question was, do you miss the programmatic findings? No, you don't miss the programmatic findings because the programmatic findings have an impact. They can be measured through the SDP and if they come -- they will come out at least green, if they get into the SDP. And, again, they are documented, they are identified and they are required to be corrected by the licensee.

We are, as we mentioned earlier, the process relies on the site -- the reactor safety process relies on site-specific work sheets, and they are being developed for each of the plants. As you mentioned, we will be mailing them out to the sites.

We are planning on making visits out to each site, and the SRAs from the Region will also be supporting Doug, and others from headquarters will be going out to each site and validating that the information is correct, because the information originally was based on old IPE submittals and there may have been some major changes. But it would have to be a fairly significant change to the facility because of the conservative and the fairly simple nature that the work

sheets do. So if they added a diesel generator that wasn't incorporated into the program, then we will have to make a change to the work sheet.

DR. POWERS: Yeah, that would change the work sheet. Yes.

MR. MADISON: And we will do that. We actually have learned some good insights in going out and doing this during the pilot. We found out some non-conservative calls we were making with regard to turbine-driven pumps versus electrical driven and we made some changes to the program based upon that review. So it has been a real good review.

DR. POWERS: If I was real nice, maybe didn't ask any more questions, could I get the copy of the work sheets for Davis-Besse.

MR. SIEBER: It is in ADAMS, I saw it.

MR. MADISON: It should be no problem.

DR. POWERS: That is the question I asked, I asked could I get a copy of it.

[Laughter.]

MR. MADISON: Yes. You will get a copy. Anybody else?

DR. UHRIG: Do you have training?

MR. MADISON: We do have a course for the inspectors that we are training them on called G-200 that talks about the entire process, but it focuses at least a

full day on the Significance Determination Process where they do examples of both BWRs and PWRs, some actual examples from the field.

DR. POWERS: I would think, having looked at your example sheets, that if I were an inspector I would be pretty enthusiastic about those sheets. Is that -- have you got in --

MR. COE: Initially, there was some, you know, kind of the initial shock of, oh, gosh, I have got to figure out this whole new system. But we found I think that after they do a few examples, they begin to see how it all comes together, it becomes an interesting tool that really allows them not only to get an answer but to see the relative influence of the various assumptions that they make, and the influence of changing those assumptions.

DR. POWERS: Yes, I think that certainly comes across nicely in your documentation. That is one thing you don't need to change in the documentation, just what you say. Laying the assumptions down and seeing that they have an influence on the answer you get was nicely done.

MR. COE: Right.

MR. MADISON: Again, I mentioned this earlier, I just want to highlight it again, we have done -- we did a feasibility review on the initial development of the SDP, that was documented in 007A. But we have since done a

second feasibility review that was tied to the event response on the reactor safety SDP, that is documented in 049 that you have before you.

We have done feasibility reviews on all of the SDPs, which have involved our staff running through real examples from the field, in some cases with, for example, the safeguards SDP, as many as 30 or 40 examples that were run concurrent with staff and industry to make sure that we were coming out with a similar answer, at least understood where our differences if we came out with difference answers. We feel fairly comfortable that was a good test at least at the beginning of the process for each of the SDPs.

Ongoing work, as I mentioned earlier, we need to continue to do the site visits to make sure that we have consistent application of the work sheets.

There we go. We expect to continue work on those through May of this year to try and complete those. We are getting them in a little slower than we had expected from our contractor but we are mailing them out to the licensees as soon as possible and then to our Staff so that they get them right away and then we will follow up with site visits and try to complete those.

We have developed a containment significance determination process that we feel at least at first blush after the first read looks pretty good. It is tied to a

change in LERF, delta LERF, and then ties back into the reactor safety SDP, the existing one.

We expect to do a feasibility review of that with the Staff at least the week of the 13th of March.

We have a shutdown screening tool that also seems to show promise and we are going to try to do a feasibility review of that the same week. We think both of those should be ready to run some time early in April, to actually implement into the new process and watch them closely again as we are with this whole process, but those especially.

One of the lessons learned that came out of the workshop, the January 10th workshop and actually before, through the pilot program, was that external events weren't well taken care of within the significance determination process. As sort of a stopgap measure we're developing an external events screening tool to look for where external events may be a significant impact at individual sites and to flag those sites then for extra effort by the SRAs and Headquarters staff when issues are identified there to ensure that external events didn't play a large part in that issue.

CHAIRMAN POWERS: When you use the term "external events" here, are you distinguishing them from fire events?

DR. BONACA: No.

MR. MADISON: No.

CHAIRMAN POWERS: So fire events are included?

MR. MADISON: Fire events are considered an external event.

CHAIRMAN POWERS: Think they are a peculiarity to a site?

MR. MADISON: Yes -- to the best of our knowledge they are. Again, this is something we are looking at. We are going to continue the process of developing corrections, necessary corrections to all the SDPs to incorporate these lessons of external events issues into all the SDPs but that is going to be some time beyond April.

With that, we get into the changes that we have made, if there aren't any other questions on the SDP.

CHAIRMAN POWERS: I would like to go back and have a little better understanding of Phase 3.

MR. MADISON: Okay.

CHAIRMAN POWERS: My irreverent characterization is that is where we find out why the industry thinks you're wrong.

MR. MADISON: That's true. That's a good analogy.

DR. BONACA: You put the gloves on.

MR. MADISON: We told them, we laid it out for them with the Phase 2. We put it in the inspection report that this finding has, we think, a significance of white or greater. These are the assumptions we have made. This is

why we think it is significant.

We offer the licensee the opportunity to either send us information or come to a regulatory conference and give us the information. In some cases we feel that there may be a need that we'll request information because we don't have enough information to make that final determination and that will be part of the Phase 3.

Once we take that information in and understand where their objections are, where their differences lie, we make the final call on what we figure the significance of the finding is, and again I revert back to what I said earlier. It is not a bright line. It gets more into the qualitative area of what do we think the significance is based upon the best available information we have, including that provided by the licensee.

MR. SIEBER: Now --

DR. SEALE: Go ahead.

MR. SIEBER: There is a subjective part that goes into that by the regional administrator, the regional staff, is that true or not?

MR. COE: That's true.

MR. SIEBER: What factors do they take into account that would alter the quantitative outcome of all of this?

MR. COE: I wouldn't necessarily say it's

subjective. I would say that this process does not obviate the need for judgments to be made.

MR. SIEBER: That's better --

MR. COE: But what it does do, it forces the Staff and it obligates the Staff to make those judgments clear so their effect and influence is obvious as to how it did influence the outcome.

If they were to deviate from the process, they would have to document why they deviated from the process.

MR. SIEBER: Nonetheless they have the authority to deviate from the process.

MR. MADISON: Certainly.

MR. COE: With justification.

MR. MADISON: With justification, but we also during at least the initial part of, the first year of implementation as we did during the pilot we have an oversight group that includes Doug and myself and others that we collect this information.

The information comes in from the field on what the Phase 2 review found, and we provide kind of that consistency monitor to make sure they have applied the process correctly and we would have come to a similar determination based upon the assumptions they made.

MR. SIEBER: And that is done before the imposition of civil penalty or whatever else?

MR. MADISON: Well, there is no civil penalty with the new process on things that go through the SDP, but yes, it is done before it is actually documented in the report.

DR. SEALE: In your first year of piloting, adjusting, and so on, are you going to essentially do sensitivity studies by toggling the yes/no determination at the end of Phase 2?

MR. DEAN: Well, I'm not sure. One of the things we did in during the pilot program is we did an independent review of all the issues that were identified by the regions that were classified as at least green by the significance determination process and did an independent assessment with risk analysts to ascertain whether they would have come to a different judgment.

I believe in all cases they said that they made the right call. I think they felt that one of the regions might have been too aggressive in one case, that they wouldn't have even classified the issue as green, but that is the result of I forget how many issues, Doug, sixty or seventy issues?

MR. COE: The pilot total was about 99 issues, total, in the pilot.

DR. SEALE: Well, you'd expect about one out of that, but that's a call within your flexibility as this review group too, isn't it? I mean if you see one where you

would like to see what happens if you took it to Phase 3 you could ask for that?

MR. MADISON: That's true.

MR. COE: Yes.

MR. MADISON: And these oversight panel reviews are fairly challenging. The individual has to come fully loaded to discuss the issue at the oversight panel. We have tied that now to enforcement actions, to the enforcement panel, so it directly flows from the oversight of the SDP into what are the enforcement aspects of that.

CHAIRMAN POWERS: If I am a licensee and you guys have got a finding that says I have a fault right down in my security and safeguards area, okay? You have got your little work sheets and you told me just how we came out, and I said, no, you're wrong. I have run the conflict code on this particular incident and I find out there's only a delta risk of loss of material of 10 to the minus 6th here. What do you do?

MR. MADISON: I don't understand what the conflict code is --

CHAIRMAN POWERS: Oh, that's because you haven't read the literature on safeguards and security.

MR. MADISON: Probably -- I don't have a high enough security clearance, I guess, but we as the NRC, based upon the -- you know, we will have to look at our procedures

to see if there is any fatal flaw based upon that information, but we as the NRC retain the right to make the final call. That is our job.

But I think the first question we have to ask is what is the basis for this result out of this conflict code, what are the modeling assumptions, and the assumptions we have made in our model -- how do they compare to ours.

CHAIRMAN POWERS: I could point you to 16 papers in the literature of facility defense that says the conflict code validated, works well, boy, this is a great code.

MR. COE: But that doesn't answer the question. I think it's going to be the burden of the licensee in a case like that to come forward and say we understand how your SDP arrived at your answer but our answer is different for the following valid reasons, and item by item convince us that there is an alternative perspective that should supersede our own.

MR. MADISON: One of the other reasons for doing the feasibility reviews besides to verify that we were on the right path with the SDPs was to ensure that industry was on the same path and was on the same page with us, and industry has agreed that these are the right significance determination processes, that they come up with answers that they can agree to.

We have identified issues that have significance

and they have agreed to the significance if characterized appropriately.

MR. GILLESPIE: Alan, something that we also have to keep in mind: Independent of what this grades it as, compliance is still required. If they're in deliberate noncompliance because they don't think it's important, that throws us into an whole other avenue.

And you're outside this system, and now you're in wrongdoings space. So there are other boundary conditions that are fixed. So the idea that someone can have a totally generation of security, and have it be a red, would be -- I think that would be actually difficult to occur, unless it was connected with some weird kind of event that both killed all the guards they need for compensatory measures and destroyed all the barriers and detection systems.

I mean, I'm not being -- it's just, you know, probably unrealistic to think we could actually have a red in security, quite honestly, without having seen something earlier.

MR. MADISON: A red in security, unless you can show a change of core damage frequency through the reactor safety SDP, the highest defining security is going to achieve is white.

CHAIRMAN POWERS: I understand that.

MR. MADISON: As far as significance within --

CHAIRMAN POWERS: I took security as an example, because I wanted to understand what happens if the licensee comes into this Phase III with superior technology to what you have.

MR. MADISON: Well, I can relate to the case of the Sequoia findings. The licensee continued to try to bring in additional information, additional analyses, and in some cases, new analyses, to prove their case.

We still took the position that based upon the information that we had at the time, that we were making the right call through the SDP.

MR. COE: It would be their burden to demonstrate. You made the comment that the premise was that they had superior technology. And I guess what that means is, a more refined view, a better basis, more detail, et cetera, that sort of thing.

And it would be incumbent upon them to demonstrate to us why that is and why we should utilize those assumptions, versus our own assumptions.

We have to be careful to be clear that anytime the licensee comes forward to bring us information that would influence a regulatory decisionmaking process, it needs to be docketed up front, on the table, publicly available, and in some cases, when they're talking about sophisticated analyses, reviewed to some level of detail by our own staff.

So in many cases, I think we're going to find that it may be that the effort, both their's and ours, to resolve the question of are we white or green, may be far beyond the effort needed to fix and for us to verify whatever problem it is.

MR. MADISON: Absolutely. That was the point we were trying to make to Sequoia, that they probably spent $100,000 responding to that issue that would have cost them 14 hours of inspection. And they had already fixed the problem.

And the other aspect of that is, too -- and this is why, again, we're not drawing a bright line -- we see no difference in the significance determination process between .9 and 1.1. It's the same number as far as we're concerned, because it has the same relative significance.

MR. DEAN: I think that over time people will come to appreciate the sensitivity. We have been trying to promote the fact that a green issue is not a good issue, but by the same token, a white issue is not the end of the world.

And so I think that over time, as we get more of these issues emerging, and these things play out, I think, overall, both internally and externally, there will be a greater understanding of what the various colors mean in terms of risk import, and what it entails in terms of what

the NRC's reaction is going to be.

MR. MADISON: We do have some new information for you. As we promised, we are going to look at the performance indicator thresholds, based upon the historical information submitted to us January 21st.

We have made some adjustments to some thresholds. I don't know if you want to talk about that.

MR. DEAN: Yes. First of all, this is a result of ongoing analysis. We took the opportunity with the historical data submittal in January from all the licensees to take a look at the validity, if you will, of some of the thresholds that we had established on a going-forward basis for the pilot.

I want to really emphasize the fact that if you go back and look at SECY 99-007, where we talk about performance indicator thresholds, we were very clear in that document that these thresholds would be something that we would be looking at through the pilot program, and we would gather more information, and there would be some need to refine these thresholds on a going-forward basis, and not that we're going to, on an ongoing basis, every year, look at these thresholds as industry improved performance and continue to move the thresholds upward and upward.

Okay, but it is to establish at least on a going-forward basis, for initial implementation of this

program, an adequate set of thresholds that do, indeed, meet the stated goals, at least at the green/white threshold with respect to identifying George's favorite issue, the 95 percentile deviation from nominal industry performance.

DR. WALLIS: Was the criterion for moving these, the 95 percent or was it a risk-based criterion?

MR. MADISON: It was primarily an analysis done of how many outliers we would have identified, dependent upon the threshold set. In several cases, for example, the scrams with loss of normal heat removal, had we left the threshold at four, no licensee would have been identified over a three-year period, to have crossed that threshold.

DR. WALLIS: So you wanted five out of 100.

MR. MADISON: A rough number of five. Again, you know, seven is okay; three is also okay, some rough number of five, an approximation of identifying the significant outliers of performance, significant deviation from nominal.

DR. WALLIS: Well, it doesn't imply any kind of risk evaluation whatever.

MR. MADISON: Again, we looked at that earlier, and we felt that we were close with a 10 to the minus six, and that was -- again provided significant safety margin.

DR. WALLIS: That was a small sample. The 10 to the minus six was not everybody, so you may be really unfairly treating some plant. We've said this before.

MR. MADISON: Yes, you said this before, but again, we felt there is significant safety margin at the green/white threshold that we have.

What we're trying to identify at the green/white threshold are those licensees whose performance has slipped to the point where we need to get more engaged. We felt that was the right type of threshold, a set, of those outliers, those folks that are deviating from nominal performance. Those are the ones we want to focus our attention on.

CHAIRMAN POWERS: A couple of questions come to mind on this: Is there going to be at some time, a document where I can go in and look at it and say, okay, here's the database that they looked at and here's why they came up with two. I mean, I could do the statistics myself or something like that?

MR. MADISON: We've answered this question before, because you have asked it before, and, yes. We have to write that document. But, yes, that is in the plan to document that during the coming year.

MR. DEAN: We will borrow, for example, from Appendix H of SECY 9007 that goes into a lot of discussion about.

CHAIRMAN POWERS: I hope you do it better than they do, because I can't follow their logic in there. But I

see the numbers.

MR. MADISON: Maybe the same author, but we'll make an attempt to do a better job with it.

CHAIRMAN POWERS: Let me ask one other question about this: Everybody has concluded that somebody has crossed the green/white threshold. And you say, okay, we've got to get more engaged.

And so that means that you come to somebody and say, okay, I need more resources and more manpower to go look at Oconee, not more than we planned at the beginning of the year.

And he says, guys, you can't do it; I've got my money out, already done; you're going to have to wait till next year, but we'll sure enough put it in the budget for next yea and you're up.

MR. BARTON: That's not going to happen.

CHAIRMAN POWERS: The question is, are we confident that the gear up to get more engaged, occurs sufficiently quickly that what crossed the green/white threshold will not have crossed the white/yellow threshold by the time we get there?

MR. DEAN: That's a good question and let me take a first crack at it, and then Alan or Doug can jump in.

I guess to real briefly talk about what the supplemental inspection approach is for additional

inspection when a threshold is crossed -- and let's go through a performance indicator. We get -- let's take -- we're going to get a report April 21st, okay?

The industry is going to give us their input from the first quarter of 2000, and we'll get that April 21st. It will take us about a week to get that so we can see what it say.

We say, okay, we've got this plant here that's crossed the threshold. Okay? Now, let's look at why is it that they crossed the threshold?

Is it something simple like, well, gee, last quarter, they had two additional scrams, okay? Well, that's a pretty easy one.

Or you may have something that's a little bit more, a safety system unavailability where you've got to look at why was it unavailable?

But the purpose of supplemental inspection as you cross from green to white is to allow the licensee to do their root cause evaluation, root cause review, and then go in and look and say does what you did make sense? Did it appear that you did the appropriate extended conditions reviews?

It's basically for us to go in there and follow in behind them. So there may be some time period there from the time that that PI cross the threshold, before it's the

appropriate time for us to do our followup inspection.

If you were to then cross a threshold from white to yellow, the supplemental inspection there requires us to be involved in more of an independent diagnostic approach.

So in that case, you would probably see us engage a lot more quickly to capture information as to why was that threshold crossed, and do more of an independent review of why it is you are where you are in that stage.

So, do we have the case where we could shift quickly from green to white to yellow over the course of a couple months? I don't think so, unless you have a situation where you have, for example, an important piece of safety equipment that's out for a large period of time.

And that would have been something that would have gotten our attention and the licensee's attention pretty quickly anyway. So, Alan?

MR. MADISON: There are other aspects of the program, too, that would respond to significant conditions or events on an real-time basis.

But I think the strength of the program is that you don't have to guess about what we're going to do; we're telling you what we're going to do in the action matrix, based upon inputs.

I think if the stakeholders, the public being the one that we're driving that at, sees that we're not

following our processes, they're going to call us on that. We have to justify why we've deviated from our processes.

CHAIRMAN POWERS: I think the take-home lesson I get is that it's entirely possible that before you get more heavily engaged, it could be for -- continued deterioration of performance. But you don't think so? You think that would be really unusual? I guess I'm content to think that probably it would be.

MR. MADISON: I wanted to highlight some of the other PI thresholds. The reasons why we changed them are pretty much the same in doing the review.

But I wanted to mention that the safety system unavailability performance indicators, we've reverted back to what we initially proposed in SECY 99-007.

Now, we had initially changed those during the pilot program to take into account, the two-week allowed outage time on EAC that some licensees have. And that's why we changed that from 2 to 3.8. That took into account and allowed outage time considerations.

We'd also changed some of the other PIs to greater than -- to being two, because of industry goals that had been established by INPO and others being at that two level. And the ones that we had initially proposed were tighter.

We ran -- we agreed to run those through the pilot program and test it out. In looking at the pilot program

data, and looking at the January 21st historical data, we find that the numbers that we had originally selected were more accurate representations of what actual performance was during that time period, and we have decided to go back to those numbers and implement those for initial implementation.

DR. APOSTOLAKIS: I have a question, Alan. The number of scrams that you will use to enter the determination process is over what period? What period of time?

MR. MADISON: Which one, the normal scram? It's for 7,000 critical hours. It's basically one year of operation. This one is over a three-year period.

DR. APOSTOLAKIS: Over a three-year period, so are you observing, say, three above the limit, the new limit?

MR. MADISON: Yes, greater than two scrams, complicated scrams, loss of normal heat removal.

DR. APOSTOLAKIS: Right. Now, for the safety system unavailability, how many tests am I supposed to look at and calculate?

MR. MADISON: This is measuring the unavailability of that equipment over a one-year period.

DR. APOSTOLAKIS: Over one year?

MR. MADISON: Four quarters.

MR. DEAN: It's a three-year rolling average.

MR. MADISON: But it's a three-year rolling average over a four-quarter period.

DR. APOSTOLAKIS: What does that mean?

MR. COE: It's not demand failures.

MR. MADISON: Yes. It's not demand failures. It's not a reliability indicator.

DR. APOSTOLAKIS: What is it?

MR. MADISON: It's an unavailability indicator. It measures the time the piece of equipment was out of service for maintenance, or because it was broken or was intentionally taken out of service for other reasons.

DR. WALLIS: A three-year rolling average takes a long time to change if it's been very good and then begins to go down.

MR. MADISON: I don't think that's a three-year rolling average.

MR. COE: That's a one-year number.

DR. APOSTOLAKIS: It is a three-year rolling average. Why don't you say it isn't in unavailability?

MR. MADISON: It's not a reliability number.

DR. APOSTOLAKIS: It's not available.

MR. COE: It's a one-year number. It's a four-quarter rolling average, but you can get, if you have old information -- one of the things that we found -- it's a one-year rolling average.

MR. MADISON: One of the things we found was that you had with design issues, though, you can really flavor that PI and stay with it for a long time. And we've tried to make some accommodation for that in the guidance, that if a design issue, as far as measuring the unavailability time, to make sure that that doesn't happen, and if it does happen, to be able to remove that biasing if the event has been on for at least four quarters and if the event -- or if the number has been in there for at least four quarters and has been corrected by the licensee, we've reviewed it and agreed to the correction is adequate, and we'll allow them to pull that number out of the calculation.

MR. DEAN: Don, Don Hickman, is there any clarification on the SSU?

MR. HICKMAN: The safety system unavailability indicator is the ratio of the total hours the system was unavailable during the past 12 quarters.

MR. MADISON: Twelve quarters, yes.

MR. HICKMAN: Divided by the total hours it was required during the past 12 quarters.

MR. MADISON: So it is three years.

MR. HICKMAN: It is a three-year average.

MR. MADISON: I'm mistaken then. But the reliability number that you were talking about, the measure of when it fails, that's something we are working on with

research to try to develop that.

DR. APOSTOLAKIS: But it's not included here.

MR. MADISON: It's not included. That's why we include fault exposure time in this performance indicator, so if -- and that's why, again, a design issue would have a large impact on this performance indicator, because we would count the fault exposure time all the way back to the day one.

And also if you have an error that you have discovered in between surveillance, you would count half the time back to the last time it was known to have worked. If we had a reliability number, we'd have an indicator that -- an unavailability number, we wouldn't have to worry about fault exposure numbers.

DR. APOSTOLAKIS: I remember, again, the former AEOD. I don't know their new title. They presented a nice table where they had the unavailabilities of all sorts of safety systems across the 103 units.

How do these numbers compare to those unavailabilities?

MR. MADISON: I don't know. Don?

MR. HICKMAN: You are referring, I guess, to the system performance studies that AEOD did? That's a good point.

We've not really checked these against that. And

we should do that. I guess by way of sort of validating their results, they made a lot of assumptions when they did those studies, obviously.

DR. APOSTOLAKIS: They tell us that this is the real world. I mean, they are based on data.

MR. HICKMAN: That's right.

DR. APOSTOLAKIS: And that's why you have been perplexed all this time, Garrett. Why don't you use the plant-specific numbers. There is a table that has all that stuff.

MR. MADISON: Don actually worked with some of those issues.

MR. PARRY: If you've looked at those numbers, actually we've done some checking, okay? The HIPSI results and the RIPSI results are pretty much consistent with these thresholds; they don't vary that much.

DR. APOSTOLAKIS: If you come here with one viewgraph that will have these distributions, and you will support the argument that you have, I will have no problem. I will buy you a beer, a coffee, whatever.

But you're always giving me this argument as an afterthought.

MR. PARRY: No, no.

DR. APOSTOLAKIS: Yes.

MR. PARRY: No, we're not. You have to be a

little -- you have to think back a little bit, too, of we're getting the data from the industry. The industry has presented us the data that went into the determination of the thresholds.

That's what we start with. That's how the program is going. The AEOD results were a look over an extended period. But that's not going to be updated all the time, and the numbers are, as Don said, calculated in a slightly different way.

They're more focused on PRA-type information than the data that we get from the licensees.

DR. APOSTOLAKIS: What counts eventually is the PRA documentation.

MR. PARRY: I agree.

DR. APOSTOLAKIS: You want to know what -- you don't care whether it was a rolling average or if it was -- is it going to start or not? And these data that those guys showed us, address that issue. They actually go one step beyond.

I think they tend to support your argument that you don't need an individual number for each plant.

MR. PARRY: I think they do.

DR. APOSTOLAKIS: But you have to do it right.

MR. HICKMAN: One thing to keep in mind is the AEOD studies were done primarily with data from 1987 to

1993. A few went to '95, but most of them were to '93, and we're looking at more recent data.

We should see some consistency, though, I guess, some sort of relationship.

MR. MADISON: We'll take the criticism and we will document the look in our rewrite of this.

DR. APOSTOLAKIS: Good. I will really appreciate that. If you have picked up those reports, and you will see that you will get a lot of support for what you are doing, plus one member here will tend to be more quiet.

[Discussion off the record.]

MR. PARRY: Can I just add a comment here? I think we'd also get support for these thresholds by looking at the typical numbers that you find quoted in IPEs for unavailabilities. They are not very far off these unavailabilities.

DR. APOSTOLAKIS: The argument you're giving me makes perfect sense to me.

MR. PARRY: Good.

DR. APOSTOLAKIS: It's just that I have to ask you to get them. I don't understand that.

MR. MADISON: I want to also note the occupational exposure control threshold. It's actually the measure also changed. We had originally proposed a two-tiered type of PI that would measure a three-year number and a one-year

number.

During the initial discussion with industry and our folks, the feeling was that it was too complicated to do it that way, and let's choose one. They chose the three-year to test during the pilot. It wasn't very satisfactory during the pilot, so we're using the one-year going forward.

And that changes the threshold then from five and three to two and one.

DR. APOSTOLAKIS: Right.

MR. MADISON: We have increased a couple of the thresholds, relaxed a couple of thresholds.

If you look at unplanned power changes, safety system functional failures for BWRs -- pardon me; I'm sorry -- safety system functional failures and security equipment performance index, we have actually loosened those.

That is, again, based upon going back and looking at the actual data that we got in. We realized, for example, in security equipment performance index, we did capture a few more than we had intended.

The safety system functional failures captured significantly more plants that we had intended to capture with that threshold, so we have loosened those thresholds up to, again, identify the real outliers, the folks that are really deviating from nominal performance.

MR. DEAN: Okay, good. The last topic we wanted to talk about is some of the things that we see. We talked about the need for further refinements and improvements, and this page here, this slide here talks about some of the major things that we're going to be working on over the course of the next year or so.

The first item there is develop additional performance indicators, and this last discussion we had on safety system unavailability, and the fact that we don't have a reliability indicator, we feel that it would enhance the program to have a reliability indicator.

It's one area that we identified quite some time ago. We have engaged with the Office of Research to look at developing a reliability indicator.

Another area here, the example I have here is containment performance. We really don't have --

MR. BARTON: You eliminated that one, didn't you?

MR. MADISON: We eliminated the one that was proposed.

MR. DEAN: Containment leakage.

MR. MADISON: It looked a --

MR. DEAN: Well, I'm sorry, that's true. The containment leakage we have. The containment leakage performance indicator was one that we deleted because it was just fraught with issues that just made it very difficult to

get at consistent figure across the board.

CHAIRMAN POWERS: One of the people that I have to report to reminded me that there is a third component to all of this process, and he drew my attention to the corrective action program.

Are you going to have performance indicators on the corrective action program?

MR. MADISON: That's a good question. We do have a working group looking at what we can do better in the corrective action program, or if there is necessary improvements we can make to the process based upon that.

We have advertised all along from the beginning that that was an important component of this program. We said that was a major portion of the baseline inspection.

Ten to 15 percent of all inspection activity out at the site is done in the corrective action program. There is a major inspection done on an annual basis at each site that looks at the corrective action program on a rollup type basis.

So we've always advertised that as a major portion, a major component. We have relaxed our documentation requirements to allow inspectors to make qualitative judgments about the effectiveness of a corrective action program, barring significant findings.

Even if they don't have significant findings, they

can make a qualitative judgment of the effectiveness of corrective action programs during that annual review in the report.

And we've also included consideration of that and other cross-cutting issues in the assessment part of the program where the assessment report on an annual basis, as well, as the mid-cycle report, semiannually can look at these issues and make qualitative judgments about the effectiveness of the program in those areas.

CHAIRMAN POWERS: I'm surprised at your emphasis on the qualitative nature. It seems to me, since I was in the business of looking at DOE facilities, that one of the first things we asked them was, you know, what was the backlog in their equivalent of a corrective action program, and how long was the average lifetime of an item in their equivalent of a corrective action program?

It seems to me we have an intuitive feel for some quantitative numbers here.

MR. DEAN: Yes, to build on where you're coming from, Dr. Powers, is that one of the things that we attempted to do early in this process was engage industry in some discussion over what would be the criteria that we would use to judge the effectiveness of a corrective action program? And it dealt with things exactly like what you're talking about: Size of backlog, timeliness of correcting

issues.

And so industry took that onboard, and actually INPO volunteered to look at developing some criteria.

MR. BARTON: In fact, INPO has a standard out now or a guide for self-assessment in corrective action programs.

MR. DEAN: Right. That's a fairly high level principle document.

MR. BARTON: It just came out.

MR. DEAN: Right. And that resulted, I think, a lot from our discussions early on about what can we do to establish criteria? As Alan mentions, that looks at self-assessment/corrective action, but probably at a higher threshold than to get after, perhaps, what an inspector would be more interested in, in looking at the actual effectiveness in dealing with some of those quantitative type issues.

So, what we plan on doing is looking at taking on this issue ourselves, and trying t establish some more standardized criteria by which we can judge the effectiveness of a corrective action program, and being able to look at things like that.

As you mentioned, a number of licensees trend that type of stuff already as a measure of their effectiveness.

So what we'll do is look at that and then work

with industry to try to come to some consensus as to what we all agree are good criteria. Hopefully we can use that on a going-forward basis, but that will take us some time, I think, to develop that, but we do have a group in place that's starting to look at that issue.

MR. MADISON: And if you want to talk about some of those individual PIs with me, I used some of the same type of indicators doing diagnostic evaluations as well. But that's more down at a lower level in some cases than we want inspectors to look at.

CHAIRMAN POWERS: You could guys could get on my good side today because you would have saved me from getting a lecture from my boss for performance indicators on this corrective action thing. Then I would have remembered that it's a key -- I wouldn't have been chastised and been in a much better mood.

MR. MADISON: I'm sorry. It's been in the written material from the beginning.

[Laughter.]

MR. GILLESPIE: Let me emphasize that we had a meeting actually with INPO and NEI, Ralph Beedle and Mark Pfeiffer from INPO who came up, who has now moved up the chain at INPO a little bit.

Besides that document, that higher level document, they actually have the next tier down. They call them

how-to's, where they're looking at a whole process where they would go out and do periodic evaluations.

The licensee would do annual evaluations that they's share with us. In fact, at the meeting we had, we shared the thought about is there something to be learned from how we deal with the training program that we might learn from this?

If they're going to do periodic evaluations, could we go and observe four or five or six of them a year? Plus, have the inspectors then getting an annual report which is a self-assessment.

And the industry has taken this seriously enough that what Mark said was, for only the third time in history, they have asked every utility in the country to report back to them on how their programs match up against that higher-level program as a starting point.

So, the idea that the cross-cutting issue is corrective -- problem identification, corrective action programs, has really taken hold.

I'll say we're tiptoeing a little bit because we're on that threshold of regulation versus excellence. Their focus is to try to make sure that their facilities have the wherewithal, procedures, and the ability to identity problems to keep us out, quite honestly, to keep their performance in that band.

I think that's going to be a big plus for safety, if we can be a catalyst to see that happen. So that process has started.

The working group that Bill mentioned will be interfacing with them, and INPO said that probably their process will gel enough that they can really talk to us about something, probably towards the end of April or so.

So, there are a lot of people working it, and a lot of high level attention is now getting paid to it, problem identification and corrective action. So, it's not just that one document. There is a whole bunch of stuff that's going on underneath it.

DR. SEALE: Mr. Chairman, do you think there would be something of interest in that product of around the end of April that the Committee might be interested in?

CHAIRMAN POWERS: I am willing to bet money that there is, but I'm also willing to bet money that they're not ready to come talk to us about it.

DR. SEALE: Well, whenever.

CHAIRMAN POWERS: But in May.

MR. GILLESPIE: Yes, they were kind of viewing it as that kind of timeframe, because they're trying to get this report in from everybody, and then get their thoughts together. For instance, how often would INPO go out, like parallel to the training accreditation visits. And then

licensees would do something annually, so they have actually put some real thought into how this whole thing links together.

And we would then observe this whole process kind of as an integral. We just have to see how that comes off in the next year.

MR. COE: I'm not sure a working group would be prepared to come to you at that point.

CHAIRMAN POWERS: Okay.

DR. UHRIG: There was a recent report I saw where Dr. Vesely of the Fussel Vesely fame, commented that only about ten out of the 2,000 or 3,000 items in the backlog corrective action list were really important to safety, and that these should be addressed first.

Would that, if implemented by the utilities, have an impact upon the kind of evaluation of that program that you're considering?

MR. GILLESPIE: Absolutely. Bill was working for a couple of utilities, but we also put some seed money into that same project. And it was a kind of neat frequency distribution, sorted by important sequence with systems versus flaw, which allowed you to get that kind of focus.

We would expect that anything that comes out of this would have to take consideration of exactly that point, because we really want to focus on that top two or three

percent being worked.

So that would be kind of a performance characteristic we'd see being factored into a good corrective action program.

MR. COE: We have actually done a couple of exploratory types of inspections along those lines to see if there is a way to develop a tool or whether it's worth pursuing. At about the time we completed those inspections, Vesely came out with his thoughts and ideas.

And we have had an ongoing dialogue with Research as to the viability and the possibilities of such a tool.

MR. MADISON: We see it right now, what's been developed, as very time consuming and resource-intensive. And we need to develop something that is going to be much more simple and much more less impact on our resources.

DR. UHRIG: One other thing that I ran across recently was a NEI publication that characterized this process as four levels of the green, white, yellow, and red levels, and the green was satisfactory, the white was characterized as being deserving of a utility attention; the yellow was characterized as deserving of NRC attention, and the red is unsatisfactory.

Is this a fair characterization?

MR. DEAN: No. I'm not sure -- I don't know exactly what document that is that you're referring to.

DR. UHRIG: It was one of the NEI leaflets. I may be paraphrasing this.

MR. DEAN: One of the issues that we're concerned about a little bit is that people take -- and this may be a criticism of the process that we need to look at -- is that people take, you know, the green, white, yellow, and red characterizations of performance indicator results or inspection findings, and then try and translate that to an assessment of the licensee performance.

And really what you to go to is, you have to go to our action matrix. The PIs and the inspection findings serve as an input to that. And then there are various categories in there, depending on the impact on various cornerstones and how many cornerstones are affected and to what level.

And that defines what action we take. So that's something where people fall into that trap a little bit, of, you know, they're a white-performer or a yellow-performer, and we have to be careful that we don't make that connotation.

So you might be referring to something that might have been sent out early, because our own document, 1649, NUREG 1649, kind of mischaracterized that approach early on when we were first developing the pilot program.

DR. UHRIG: This was headlined something like

proven evaluation process being implemented, as I recall the headline.

MR. DEAN: We'll have to ask NEI to see if we can get a copy of that.

MR. BARTON: Are you through with this slide?

MR. DEAN: Yes. Well, we're about 2:30.

MR. BARTON: I was just wondering if you had any more and if there were any questions. NEI was going to make a presentation, but I don't think NEI is with us this afternoon. That's why I allowed the staff to go another 15 minutes.

If the staff is finished with their presentation, are there any other questions of the staff? I think this was an enlightening further discussion on where you're going.

I think it will make a lot of good improvements in the program in getting it ready to roll out.

Any other questions?

[No response.]

MR. BARTON: Thank you very much.

MR. DEAN: You're quite welcome.

MR. MADISON: Thank you.

MR. BARTON: Mr. Chairman, I send it back to you.

CHAIRMAN POWERS: I thank the staff also for this presentation. I hold you in great admiration. It's

unbelievable, all you've been able to do.

MR. DEAN: Thank you.

CHAIRMAN POWERS: I think we're excited about it, and it's very evident to us that the Commission is very excited about this program. So while we interrogate you closely, it's just because we want to learn all we can about it.

MR. DEAN: We appreciate that. Like I said, you know, the offer, if any individual members feel like they'd like to have some discussions with us, certainly any time you want us to come back and talk to you, certainly as we go through the pilot process, you're going to want updates.

CHAIRMAN POWERS: I think we'll need fairly frequent updates, but we don't want to do it till you're ready to come update us. Thank you very much.

DR. SHACK: If you can quiet George, I'll buy you a beer.

[Laughter.]

CHAIRMAN POWERS: I'll recess us for 15 minutes till quarter of.

[Recess.]

CHAIRMAN POWERS: We'll come back into session. The next item on our agenda is to discuss license renewal at Oconee, but before we get started, I'll recognize Jack Sieber.

MR. SIEBER: Thank you, Mr. Chairman. I need to put on the record that I will recuse myself from voting on the Oconee matter, due to a conflict of interest in owning Duke Capital stock.

CHAIRMAN POWERS: Okay, we'll pay no attention to you whatsoever then.

[Laughter.]

CHAIRMAN POWERS: Oh, you mean just for this item. I'm sorry.

Dr. Bonaca, do you want to lead us through this set of presentations?

DR. BONACA: Yes, Mr. Chairman. As you know, last week we met at the Oconee facility. We had an open Subcommittee meeting that most of the Committee members attended.

We reviewed the closure of open items in the SER and the final SER provided for Oconee. We had representation on the part of the licensee, and also on the part of the NRC staff.

We had a number of issues. We asked both of them to come and to present to the Committee. Specifically for Duke Power, we asked to talk about the scoping methodology, cables and connections, reactor vessel internals, and also one-time inspection, their philosophy of application, as well as buried piping, and how inspections from Oconee apply

to the Keowee facility.

We also asked the staff to address the same issues in their presentation to us for the SER.

I would like to remind both presenters that we have only one hour and 15 minutes scheduled for our agenda, so we will try to be pretty quick through those presentations and to leave a few minutes for us for discussions.

With that, I'll introduce the Duke personnel.

MR. ROBINSON: Thank you, Dr. Bonaca. My name is Greg Robinson, and it's nice to be with so many of you who were with us at Oconee last week.

I'd like to introduce with me today, Jim Fisicaro from Duke Energy, and also Jeff Gilbreath who will be presenting our reactor internals information. Jim?

MR. GILBREATH: I just wanted to say a few words of thanks. Mike Tuckman wasn't able to be here today. He had a death in his family earlier this week, so actually the license renewal folks actually work for me, and on behalf of Duke Energy, I just want to thank Dr. Bonaca and his team for last week's effort.

I think that was a very good interchange amongst both sides. I think we both learned some things, and do appreciate the support that the ACRS has given this. We appreciate the NRC staff for their review.

We are meeting schedules, and I think everybody knows that this is a very important piece to Duke Power Company, so we appreciate your efforts. So thank you very much.

MR. ROBINSON: And with that, thank you, Jeff. These are the five issues that you just laid out, and I'll move quickly into the first one:

We have spoken briefly about the scoping methodology last year when we had a chance to meet, and we did spend a good bit of time at Oconee going through the details of the scoping process, including the engineering records that captured the scoping results.

The SER open item was associated with a definition or struggling with the definition of design basis events and the timeframe that that definition was used at Oconee.

There was a concern or the issue was whether the set of events that we did identify associated with the scoping of the plant, was sufficient for scoping for license renewal.

We went through a number of meetings and a number of discussions with the staff on this issue, and in order to resolve it, we conducted a case study and looked at ten additional events, and the licensing basis aspects at Oconee for those ten addition events.

And we were able to conclude from that study that

there were no additional systems, structures, and components identified by those ten events that were not already within the scope of license renewal.

And we felt very good about the validation efforts of that study.

DR. BONACA: Just a question: Seven of those events, you conceded; the other three you did not find them in your design basis. The question I have is, do you consider those seven additional events part of your current licensing basis?

MR. ROBINSON: The seven additional events, in some aspects, part of our current licensing basis at Oconee. They are not, however, part of our design basis events set of materials.

Again, to change that definition would require significant changes to other aspects of the plant. But as far as finding them, we did find aspects of those seven events that you've spoken of in the current licensing basis of Oconee.

DR. BONACA: Okay. I appreciate the fact that you covered them and addressed them. I just was left with that question in my mind as to whether or not you would consider that part of your current licensing basis.

CHAIRMAN POWERS: I wonder if the process of identifying these ten additional events has any translation

to whether -- this particular -- restricted to Oconee.

MR. ROBINSON: I don't know that I'm qualified to speak about others' designs, but I imagine that things that were designed in the time period when the definitions of terms such as design basis events were being put forth, you're going to find uniqueness in the late 60s designs in the United States.

CHAIRMAN POWERS: That's why I'm interested in the process and not necessarily the details.

DR. BONACA: I would expect that when we come to the staff we'll ask that question, and we'll hear that it would be, in my judgment -- that's why I asked the question about current licensing basis, because that's what I believed happened there, although I recognize that it wasn't part of your original design. But you were asked by the staff for a number of issues that came like TMI action items and so on, to address additional issues. Although they were not part of the original design basis, they are part of your current licensing basis.

MR. ROBINSON: Yes.

DR. BONACA: Okay, thank you.

MR. ROBINSON: I will move on and summarize the second issue on our list now, which was the insulated cables and connectors issue.

A little background on this issue: When we

originally did the reviews, aging management reviews for license renewal at Oconee, we found several instances from field walkdwn work where we had cables and connectors that were in locations that were in high temperature areas or high radiation areas.

And in a number of instances, we were able to relocate those cables, to move them out of those areas. Using that thought that we perhaps could make modifications to the plant and not end up with any cabling in a very, very aggressive environment, we went with the idea that we would really not need an aging management program if we modified the plant to the extent where the hardware was not being exposed to these environments.

However, because a number of the cables had not been moved out of their aggressive environments, and may not be moved due to budget restrictions or other things, there was a feeling during the inspections that it may be better to go ahead and plan for an aging management program for those cables.

We can still relocate them, still modify the plant, which would eliminate the problem. But for those areas that we did not eliminate the exposure to the aggressive environment, we wanted to go ahead and put a programmatic action in place. We called that the insulated cable aging management program.

We did work with the staff to develop the aspects of that, so there was a good understanding. In particular, a number of members of the staff and Duke were involved in IEEE efforts on aging effects, and they applied their knowledge to this program.

The focus of the program is on the cables and connectors, and the adverse localized environments, including radiation, temperature and moisture environments, in particular, conduits.

And we did have an opportunity when we were at Oconee to see some of the areas that we had gathered information from, a number of the cable banks that were there in the buildings, and they will be the types of areas that this program will be focused on.

DR. BONACA: In containment, you had also some areas where you had synergistic thermal/radiation effects.

MR. ROBINSON: Yes, we did, in containment. One of the things we did do as a part of license renewal efforts to gather information in containment is, we instrumented the inside of several of our containments to gather thermal data, so we could do thermal mapping and profiling to begin to understand what kind of thresholds we were actually exposing the hardware to.

We used that as insights to us in noticing the aggressiveness of the environment. Along with the thermal

monitoring, we did some radiation monitoring, and that's where the idea of the synergistic effect did come in.

DR. BONACA: Thank you.

MR. ROBINSON: So that is a summary of the insulated cables item that we dealt with.

DR. BONACA: The program, however, that you presented, is broader than just thermal/radiation. You have the moisture concern, and issues being addressed also for buried cables and in-tray cables, right?

MR. ROBINSON: Yes, they are, especially the cables in the conduits. I'll make note that we've spent some time -- we are in our third inspection at Oconee, our Regional inspection this week, and one of the items in the electrical area was to go back in the plant and reinforce the aspects of this program versus the physical layout of the plant, in particular, conduits in areas that may be exposed to moisture or maybe could collect moisture, which would also be a part of this program.

CHAIRMAN POWERS: Do you have an idea of what the chemistry is that causes a coupling between the moisture and the thermal processes?

MR. ROBINSON: No, sir, I don't.

CHAIRMAN POWERS: I could imagine why the radiation would couple with the moisture, just because you build up a little peroxide and some free radicals in there.

MR. ROBINSON: To my knowledge, the areas that could be exposed to moisture are typically in the lower parts of the building and away from bigger, hotter, equipment, so there is probably less of the synergistic effect there, if there is any.

CHAIRMAN POWERS: What you say is there is this coupling of thermal and moisture, not radiation and moisture, as far as I can remember in your documentation.

MR. ROBINSON: Okay. The next area is the one that Jeff Gilbreath will cover, and this is where we're moving into our reactor vessel internals area.

MR. GILBREATH: The reactor vessel internals had six open items that we had to address. Those six open items basically captured all of the aging mechanisms that we identified in our topical report, and also how those aging mechanisms may affect or potentially affect the reactor vessel internals.

Specifically, those were -- they are listed: dimensional changes due to void swelling; cracking of internals -- this was primarily looking at radiation stress cracking; thermal embrittlement of the plates and formers, non-cast items.

Then we evaluated the cracking of baffle bolts due to ISCC. Also we were to evaluate embrittlement of cast components and reactor vessel internals; thermal

embrittlement of the vent valve, and reduction of fracture toughness.

Just to point out some of the components that we're addressing, our internals basically are two components: the plenum, which is upper internals area, which houses your control rod drive mechanism. In that mechanism, there is actually ten spacers or guide cards, and those ten spacers are made of cast and also made of CASS austinated stainless steel.

Then there is your core support area, which is actually three components bolted together. Your core support shield on the very top actually has the vent valves, eight vent valves in it, and also on Oconee Unit III, you have a CASS austinated stainless outlet nozzle.

Then our primary focus is actually in the core barrel region where the radiation is the highest. You have your baffle bolts, your plates, your former and baffle plates, and also your core barrel region.

And then your lower internals have an in-core guide tube which has a spotter assembly made of CASS austinated stainless. So those were the components that have been identified as needing further studies.

DR. SHACK: Just out of curiosity, why are the baffling plates perforated?

MR. GILBREATH: I have a better drawing of those.

[Pause.]

The baffle plates actually form the geometry of the core, support your assemblies but at the same time these particular plates have a pressure relief holes in those for interaction of water from the bypass region and also the normal core region. There are some slots in the plates, actually in the center of the plates in this area that also allow some cooling interchange.

With this particular design, the Oconee, it's an upflow design, bypass flow design, and they have tried to maintain pretty much a zero differential pressure on one side of the plates versus the other. Some designs are different.

DR. SHACK: Have you estimated your gamma heating then in there?

MR. GILBREATH: We have a program to actually do that. Some utilities have -- EDF has done some studies in that area like the gamma heating effect there could go as far as an additional 50 degrees but that is something that as part of our program we will be doing over the next three, four years.

Initially our approach that we took to reactor vessel internals, we have developed an aging management program. That program really was a focus on the process -- what we need to do, what we need to learn to manage the

potential effects of all these different aging mechanisms, since most of these particular effects may have never been seen before in the industry.

In doing that, once we have completed our analysis, our studies in the industry as far as testing certain surveillance materials, we would put together whatever inspection programs would be needed to manage the effects to the internals.

The NRC in reviewing our proposal, I think their concern was that a lot of these aging mechanisms may not show up until late in life and if you are developing your program now, they weren't sure that there was a real commitment I guess to doing inspection in that period that the aging mechanism may show up, so they suggested that we assume that these effects do exist and commit to an inspection program and in doing that, if, for instance, once we do our analysis and our evaluations we can prove that that will not affect the function of the internals at that time we can make that submittal.

They will evaluate it and we can maybe change the elements of the inspection program. That was acceptable to us, so basically what we did, we submitted an inspection program. We rolled in all the different process that we're already working on in the inspection program to help develop the different elements.

Basically there we have 12 elements in the inspection program and things such as acceptance criteria, the inspection method, corrective actions, different things, we still have to develop, and so the commitments we made with the inspection program -- one, we would inspect all three internals and we would do this in a time when we wouldn't just do it all in the early part of the license renewal period but we would do one in the early part, one in the middle and one in the latter, not being the last year of the renewed term.

We also committed to work with the industry, particular the B&W Owners Group, Reactor Vessel Internal Aging Management Program. They have quite a number of tasks that are really supporting us in doing the evaluation and performing the analysis we need, not only the BWOG but also EPRI has a program called Materials Reliability Program, which they have an issues task group on reactor vessel internals and that task group is managing or trying to coordinate all the different activities in the U.S. on reactor vessel internals aging effects.

Also, they have another group called the Joint Baffle Bolts Task Team or the JOBB you may have heard, and that particular group said look, who's the leaders internationally? Who is actually doing the work out there in the world on reactor vessel internals that we might could

participate with, learn from what they have done and also incorporate some of our materials? We formed the JOBB and actually found that EDF has done quite a bit of work in this area.

So we have taken materials from both the Oconee internals and also materials -- well, the Westinghouse groups have done the same -- and we have sent those to EDF and asked -- they have already set up contracts and all to irradiate their materials at different places -- and we have asked if we could irradiate ours and do some studies in that way. We are working with them -- as a matter of fact, we have a meeting with them in April to go over some of the findings in the initial irradiations.

There's a lot of industry participation going on that we have committed to. Lastly, we have committed to give reports to the NRC on a routine basis, the first report being within one year of receiving a renewed license and then later reports over the next 10 years, and the final report being about at the end of the present license but within two years prior to our first inspection, laying out the basis for our inspection program and developing our aging management program at that point.

I guess the last bullet we have already covered. Obviously modifications of this program are going to exist as we learn more.

The inspection as it exists today, our inspection program, really consists of three items. One is the baffle bolt inspection which we plan to do some type of volumetric inspection on the baffle bolts. That is one area that we have actually seen some cracking in the industry. I know the EDF has had cracking and there's been a few baffle bolts found cracked in the U.S.

In that program there's been quite a bit of work in the industry already, developing inspection methods for that, so there is not a lot of work to do in that area except to say that we are doing analysis to see how many -- there's different internals for different designs but like the Oconee design there's approximately 1400 baffle bolts or baffle former bolts. What we want to know is how many of those baffle bolts we need to maintain the function of the internals and we are doing analysis to determine that today.

Also, the CASS austinated stainless steel, you know, the real concern there, we knew that there was a thermal embrittlement effect and we knew that there's an irradiation effect, but never really have seen any kind of synergistic effect of the two and so we are trying to develop now or we are developing a program today not only to do an inspection but to do an analysis to determine a critical crack size so we can figure out what type of inspection we will have to do to detect a crack in that

particular component. Most of our CASS austinated components are in a compressive state.

Also we have pretty much the other components that capture the rest of the internals, concerns with our core barrel and shield bolting is X750 material. You could have a stress corrosion cracking issue there that we need to monitor, and we have a program today that we do an inspection of those bolts.

Also on the plates, former plates and baffle plates, I guess a concern has come up through this evaluation -- what is swelling, is there a potential for swelling, and how might it affect the reactor vessel internals, and so we really try to focus in on where the gamma heating effect may be the highest, because where your highest temperatures are and your highest irradiation, that is probably going to be your limiting area as far as swelling or the first place you would see swelling and so we are developing a program to perform an inspection for swelling also.

That's kind of where our focuses are today. As we said, this program may evolve. You may see that group that says "other components" become two or three bullets, two or three different types of inspections, depending on what mechanism or what effect we are looking for.

It could be volumetric if we are looking for

cracking, if we are looking for dimensional changes -- it could be quite a few things and those we are going to still have to work out.

CHAIRMAN POWERS: It isn't obvious to me that the plant's temperature region would be the region of maximum swelling.

MR. GILBREATH: The direction we have been given in studies that we have looked at, I guess we have utilized some of Frank Gardner's studies and contracted him to help us -- he seems to believe and has shown with the results he has had I guess in the vessels he has looked at where the maximum temperature is and fluence, a combination of the two, are really your two drivers for swelling.

If the temperature drops a little, you may not have any effects, so where that threshold is, it's still really unknown with PWRs.

CHAIRMAN POWERS: I would assume that the temperature effect can't be linear. It has got to go through some maximum glib to get it high enough. I will anneal out -- if I get it hot enough. I don't know what hot enough is though.

DR. SHACK: Yes, but he is on the other end of the curve.

CHAIRMAN POWERS: Okay.

MR. GILBREATH: Yes, it seems that higher

temperatures in this case are not good.

CHAIRMAN POWERS: Yes, you are going upslope.

MR. GILBREATH: Yes -- which is actually good for PWRs since we do not operate at the temperatures that the swelling has been seen in the past.

MR. ROBISON: Thank you. I appreciate Jeff going through that. We had quite a lengthy discussion at Oconee last week on the very same subject.

It is a very broad subject, and in fact that is the area, as several of us have discussed, that we believe is sort of the new area that license renewal has moved into, is reactor internals and the maturation of this program from when we started in 1996 until today is pretty amazing. You see how far we have come and then the timelines and plans that have been laid out. It speaks well for the hard work Jeff and others have done.

The last two items on our agenda today would be the one-time inspections and then the buried piping overviews.

I just have one slide on the one-time inspections, calling out that we make sure we know what we are talking about when we are talking about one-time inspections. They are aimed at verifying the aging effects are not occurring. This is the check to make sure that things are not happening. We could not absolutely say something was not

going to be an effect that would cause a problem over a longer period of time, so we said what we really need to do is go look.

We have almost 30 years of operating experience now. Somewhere between here and 2013 we had planned to do, before the end of the initial 40-year period, we would have had 30, 35 perhaps even closer to 40 years of operating experience or exposure of this set of components to the environment, and something that was going to reveal itself should be revealing itself somewhere in that timeframe.

What I have listed here, and I won't read through them, you can read through them, but these are the nine topical areas for the one-time inspections. You can see they range from carbon steel type components to stainless steel type components to things that are exposed to oil and air and moisture, to systems that are exposed to very clean chemistry, chemically controlled items, but we just could not quite make judgments that they were going to be fine so we are going to go look.

CHAIRMAN POWERS: Your reactor coolant pump motor oil collection tank inspection, that's because you are afraid you may get acids in this motor oil that gets collected?

MR. ROBISON: It's even simpler than that. When we dump the oil in it, there's a chance that when we spray

down in the reactor building you are getting water in this tank.

It's a carbon steel tank inside. We don't know what is going on.

We assume there is a coating of oil inside that will remain even when you drain the tank out. You will keep a film in there.

We don't know, and what we would like to do is go take the manway off and go in there and take a look just to convince ourselves that that coating of oil is protecting it and we are not inadvertently spraying down the building, getting moisture in this tank and having the tank perhaps in a degraded condition so it couldn't catch the oil in the case of needing it in a fire event.

It just seemed like a good, common sense way rather than trying to analyze our way out or guess our way out we would go into the plant and take a look.

DR. UHRIG: Some of the inspections have to do with specific pieces of equipment and others are materials. Take the first couple -- cast iron selective leaching inspection. Is there any particular place that you will do this or is there a sampling of places?

MR. ROBISON: There were a number of pump bodies in treated water systems and raw water systems that we felt like could have a progressive leaching effect occur if it

were going to occur. We do disassemble those pumps for maintenance periodically and what we hope to do here is plan some intrusive type inspection while maintenance is in there doing work on the pump for other reasons.

DR. UHRIG: On the galvanic susceptibility inspection, does that have to do with buried pipe, or is that in addition to the buried pipe?

MR. ROBISON: That is in addition to the buried pipe. From my past experiences, we have put bronze and stainless and carbon sort of intermixed as replacement items. We certainly did that for corrosion or erosion issues and I am not certain of the long-term effects of welding all of that together.

I asked my metallurgist here and he gives me some insights and some I understand, some I don't. I am going to go look and make sure that we are not creating a situation in the plant -- I don't think we are.

DR. UHRIG: How about the condensers? Are you using different materials in the condensers or you have all the same?

MR. ROBISON: Up to now we have had the same. I don't if we have retubed any of Oconee's condensers. I can't remember off the top of my head. I know we have done some work at some other plants, other of the Duke plants.

DR. UHRIG: I remember having four sections with

four different materials one time at Turkey Point.

MR. ROBISON: Oh, boy.

CHAIRMAN POWERS: If your metallurgist is like my metallurgist, he'd probably give you the galvanic corrosion potential good up to a sign.

MR. ROBISON: Yes.

CHAIRMAN POWERS: And these complicated system --

MR. ROBISON: They handed me the book and said you can figure it out. Find your metals on the thing and just be careful with which ones you pick, so it seemed more practical to go take a look, so we are going to go do that.

DR. BONACA: Assuming you have corrosion on the oil collection tank, you have a leak from that, they'll look at it from inside the containment, right?

MR. ROBISON: Yes.

DR. BONACA: And so you will have really a spillover on the floor?

MR. ROBISON: Yes, sir. Yes, and that certainly is a concern, and that is why it seemed more prudent to go look than to try to make an assumption that we dump the oil frequently enough to keep a sheen in the tank itself.

CHAIRMAN POWERS: I would think that the worry about water, that's a good one. I hadn't thought about that one, but I would also worry about, you know, you put those hydrocarbons in there and they are nice good hydrocarbons in

theory but as they age and get older you can get carboxylic groups in there and they become acidic and they can do some corrosion, even when you don't -- it's oil and old oil is not always very protective.

MR. SIEBER: There is boric acid there too.

MR. ROBISON: Right, yes. I think the Staff will speak more to the one times.

The last subject area I will overview for us is the buried piping area. We had some discussions on it. I thought I would begin with a graphical illustration. I'm told that I am supposed to start with graphics and then go to words, but I did it opposite today. My wife is a schoolteacher. She told us that.

The 132 inch diameter piping represents the condenser circulating water system at Oconee, which is actually a large cave underground. The 18 inch line is meant to represent or illustrate the largest size line anywhere else on site that is buried or at Keowee. One of the discussions topics that came up was how do we make it an equivalency between Keowee buried lines and Oconee buried lines when in fact the entire site was disturbed together at the same time and all the lines were installed together with a similar technique, and I have illustrated that here.

Surface preparation of coating and wrapping the lines was the same, the standard specification of how we

prepared the piping when we put it in the ground. The interesting thing about the 132 inch line is we actually go in that line and inspect from the inside, so every few years we are able to dewater one of the units' lines -- there's two lines coming into each unit -- and go through the lines and inspect internally for areas where the coatings and wrappings may have had a holiday in them, creating a galvanic cell with the soil and you would end up with a hole in the line.

We have three that we were able to find in the operating literature, operating history of the plant. Typically when you find it, you will UT around the area. You will go in and make some type of repair on the spot.

Interestingly though, to lose function of that line would require many, many, many holes. In our situation here, finding many, many, many holes would tell us the behavior of the piping material and the whole system, the soil, the piping, the coatings and all had progressed to the point where something needed to be done. That is the indication that we are after, not the one hole or the other hole but the general behavior of the setup.

You can see if you look at the square footage that we are reviewing here, it is roughly the area of 10 football fields that we are surveying, and that is quite a lot of surveillance data.

CHAIRMAN POWERS: That's a pretty good sampling.

[Laughter.]

MR. ROBISON: That is a pretty good sample.

MR. BARTON: Are you surveying by internal -- UT from internally?

MR. ROBISON: We are visually looking internal, internal to the lines, for areas where the coatings may not be doing their job, because typically what will happen is a galvanic cell will establish itself between the soil and the carbon steel piping and it will lead to a whole in the line.

This was meant to introduce you. I don't know if you have any other particular questions here, but it was a solution. I would even look closely at our other nuclear units to see if this type of technique will work, but I do know that we feel very good about the technique we have here.

When we have had those several leaks and we've UT'd large areas around those holes, they have been very specific, location-specific, and the remainder of the piping is at or above the mil spec that it was purchased at, so we have good belief in the quality of what's there, the behavior of what's there.

DR. UHRIG: Do you do any repair from the outside?

MR. ROBISON: If we can dig to it. The last hole we had was 35 feet underground, and it would have been

difficult to dig down because we were out on the discharge end. We would have to have gone and dug down from the upper parking lot down to the line, so that is the reason we have developed, tried to develop more focused internal inspections, because of the locations of these lines.

You said the soil is pretty much identical between the Keowee facility -- because one of the issues was that you are inspecting the Oconee piping then inferring the condition of the Keowee piping from the Oconee inspection.

MR. ROBISON: Yes, and I was unable to bring the photograph but I did find a photograph in an old book that we had onsite where the entire site had been disturbed. The soil on the entire site had been disturbed literally from the riverbed -- for you gentlemen who are able to go to Keowee -- from the riverbed where the hydro plant is located all the way over to the nuclear station in its location. All of that was disturbed, so the piping at the Keowee facility was put into the same moved soil and moved earth that the big lines at Oconee were, so we would have a good feel that all of that soil had been mixed and moved around and should be similar in characteristics.

CHAIRMAN POWERS: There is nothing, given your location, you don't have any problems where the Keowee could be saltier than the Oconee soil?

MR. ROBISON: To our knowledge, no. When we went

and looked back through our records and talked to our engineering folks, our civil engineering folks, they could see no reason why there should be any behavior different between the two. They are in the river valley.

CHAIRMAN POWERS: The classic one is that we've got a parking lot that gets deiced with salt and that affects the soil around it, and of course 50 yards away there is no salt.

MR. ROBISON: I understand.

DR. BONACA: Now you said this piping is wrapped on the outside, so there is some level of protect. Could you describe that?

MR. ROBISON: It's epoxy or coal tar type --

MR. BARTON: Bitumastic tape?

MR. ROBISON: Yes, yes -- and then a wrapping, a careful prep -- and I made sure I checked with our civil engineers. I said you didn't just backfill it with gravel and knock holes in your coating and wrapping? -- and they said no, we even had specifications on the soil and how we put the soil back in around the coatings and wrappings to make sure that we left it in a good as-prepared condition.

I think that has been evident in the very few leaks that we have seen over time.

DR. BONACA: Any other questions?

CHAIRMAN POWERS: I guess we did go and check the

cited reference on the effects of soil and found that soils do have an effect on the galvanic corrosion -- five orders of magnitude is the corrosion potential --

[Laughter.]

CHAIRMAN POWERS: The point is if they are all the same then it's the same.

DR. BONACA: Plus again I mean your inspections to date have not revealed any general widespread defects. You found isolated, localized effects that are indicative of cells rather than -- you know.

CHAIRMAN POWERS: And it would take a pretty heroic type failure to cause a problem.

DR. BONACA: I think so too. Yes.

CHAIRMAN POWERS: You could probably see the ground washing away before you --

MR. ROBISON: Yes.

DR. BONACA: Yes. With those type of pipes, yes.

MR. ROBISON: I had one other item. I wanted to bring word from our Region II inspection for you. You knew it was going on this week.

DR. BONACA: Yes.

MR. ROBISON: We concluded the inspection items last evening and checked all the checklist items and I think there are going to be some general plant tours and some regional management onsite today, but I wanted to let you

know that we did finish those. We do not believe, Duke does not believe there are any open items remaining. We were able to close them all.

CHAIRMAN POWERS: So you got a good close-out?

MR. ROBISON: Got a good close-out and we have a formal public exit tomorrow morning.

CHAIRMAN POWERS: Okay.a

DR. BONACA: Okay. I have just one more question, which is in October when you had still an open item on GSI-190, you offered to the Staff to have -- to meeting either the plant-specific approach or to commit to a generic closure of GSI-190. Later, in November I believe, the NRC presented a resolution on GSI-190 and set the requirements.

You have committed to a plant-specific resolution of GSI-190. Am I correct?

MR. ROBISON: Yes, sir, we did commit to it.

DR. BONACA: You already have defined the program and the NRC has recognized that in the SER at this stage, so it is not anymore an option which way you are going to go.

I just want to make sure of that.

MR. ROBISON: Yes.

DR. BONACA: That I understood it correctly.

MR. ROBISON: Yes. It would be our intent to follow the outline of what has been laid out in the SER, follow another approved process if the Staff finds one, or

use the latest technology and thought processes that were available in industry as people continue to develop the math models associated with environmentally-assisted fatigue.x

DR. BONACA: But if I understand, you took one of the NUREGs in which there were six locations which were specifically inspected and you chose the six locations for your inspections.

MR. ROBISON: Yes, we did.

DR. BONACA: And you are still committing to those?

MR. ROBISON: Yes, sir, we are.

DR. BONACA: Thank you.

MR. ROBISON: Thank you.

DR. BONACA: Any other questions? No questions. Thank you for the presentations.

MR. SEBROSKY: I am Joe Sebrosky. I am the Project Manager for the safety review for the Oconee license renewal application. I would just like the other members of the staff to introduce themselves.

MS. COFFIN: Stephanie Coffin. I am a Tech Reviewer, Division of Engineering.

MR. DAVIS: Jim Davis, a Tech Reviewer in the Division of Engineering.

MR. GRIMES: And I am Chris Grimes. I am the Chief of the License Renewal and Standardization Branch. We

are here to talk about these four things -- the resolution of the open and confirmatory items in the SER; reliance on the current licensing basis and the regulatory process; our perspectives on one-time inspection; and also buried piping.

MR. SEBROSKY: If you look at the next slides, Slides 3, 4 and 5, they simply list the open items and just a brief one-line description of what the open items were, and the purpose of listing them was to make sure that the ACRS members didn't have any questions or comments that the Staff could respond to.

DR. BONACA: Actually, isn't it the same open times that you have in the SER and that you closed there, that you presented last week? Correct?

MR. SEBROSKY: The answer to the first question is it is almost the same as the list of the open items that were in the SER in the June version. As Duke pointed out, one of the open items that we added after the SER in June was issued was the electrical insulated cables, so we added that open item. We also added some discussion on ECCS piping. We added some additional information because Duke updated their license renewal application, so the SER changed not only because of the closure of open items and confirmatory items but for those other reasons.

The answer to your second question is, is this the same information that we presented to the subcommittee, the

answer is yes. So unless there aren't any questions from Slide 3, 4 or 5, I guess I would like to move on to Slide 6 and turn it over to my boss, Mr. Grimes.

MR. GRIMES: I propose that because of the nature of this question and also the dialogue that you had a moment ago regarding the definition of design basis event and what it means relative to the licensing basis, I wanted to just go back to the fundamental philosophy of license renewal.

We had an original attempt in 1991 to establish a review scope for license renewal that would attempt to try and identify unique aspects of the licensing basis, but even at that time there was a vision that the renewal review process would use the current licensing basis, and continue it, and that we weren't going to attempt to try and modernize plants, but we discovered in that effort that isn't anything unique about aging effects, that Mother Nature does not subscribe to the 40-year life principle --

[Laughter.]

MR. GRIMES: -- that was established in the Atomic Energy Act, so in 1995 the rule was amended and it extracted a definition that is contemporary in its explanation about how a licensing basis is established. It refers to design basis events, and by inference to 50.49. It describes it in terms using design basis event as a term, but as we learned at Oconee and as I expect we will find as we add

clarifications to the guidance, for some plants to say design basis event means an analyzed design basis event, but our purpose in license renewal was also to get systems, structures and components that are relied upon to perform functions associated with the licensing basis that might not be an analyzed design basis event -- capital "D" -- capital "B" -- capital "E" but like earthquakes, like loss of decay heat removal, like high energy line breaks.

To the extent the design has evolved over time, there are implied capabilities to cope with events and so we overcame our linguistic problem by talking about using scoping events and we explored 10 events as Duke described in order to identify structures and components that were relied upon to prevent or mitigate those events without calling them design basis events or anything else -- there is a capability in the plant design and we needed to make sure that the structures and components that are going to be subjected to an aging management review fit in that box.

We found, as Duke pointed out, that everything was subjected to an aging management review that needed to be, and I expect that we will run into that again in the future but from a broader perspective I will also say that maintaining the integrity of the current licensing basis and carrying it forward is a fundamental principle of license renewal.

After reflecting on it philosophically, whether or not for example other nonsafety capabilities like the cooling loop for the spent fuel pool or some of the other things that the plant design does not live up to a contemporary plant, we are still comfortable that the process has its built-in protections so as the licensing basis evolves in the future we will continue to have programs that manage aging effects for those things that are relied upon and we look into risk space as well to test that theory, and I am very comfortable that that underlying philosophy is still a sound one.

DR. BONACA: I just asked that question before however because at some point I believe when you come to the SRP definition or somewhere you will want to capture a process that has some definition in current regulatory space rather than having to say, well we look to the other -- let me just give you an example.

When Oconee was designed and licensed it had one auxiliary feedwater pump per plant and they were interconnected. Right now the plant has three auxiliary feedwater pumps per unit. In addition to that, because of TMI action item I imagine, there was automatic initiation of auxiliary feedwater in the plant -- I imagine as seen in the other plant.

I assume that those requirements which were

imposed for whatever reasons by the NRC and were installed are part now of what we call the licensing basis for the plant, so that if Oconee will come with the original SAR, Chapter 15, with only one pump starting at a given time and not automatically but by operator action, you would contend that the current licensing basis incorporates a different design which captures three pumps and an automatic start.

That is what I meant by -- am I correct? I am trying to understand if I am correct or not in calling that current licensing basis. I am trying to learn.

MR. GRIMES: Well, the simplest answer that I can give you is throughout this process we raised questions about why is the plant licensed the way it is licensed and when we get into circumstances like that and we ask the question and we can't find the answer, it goes back to we will put that into the space of determining whether or not the current licensing basis needs to be changed.

Now I am trying to draw back on the SEP experience. There are plants that don't have certain capabilities and if that is the way the licensing basis is, then that is the way that we will evaluate it for --

DR. BONACA: I understand that, but I think there is a fundamental difference between the SEP, which was a way of reconciling certain lacks of components, with new requirements imposed. I imagine those three auxiliary

feedwater pumps per plant at Oconee all fall under the Appendix B program.

I don't think that only the original one is on the Appendix B and the other two are not.

MR. GRIMES: And that is where I'll hesitate because I wouldn't make that presumption. The way that we went through the scoping events is we said the ground rules for evaluating the current licensing basis are you go find a statement in the FSAR that describes a reliance on a particular component or a statement in the regulations, but some of the TMI action plan stuff got resolved on a plant-specific basis and then through the inspection process we looked to see whether or not the FSAR captured those things that were relied upon to resolve those issues.

So we still rely on the process ultimately to have identified changes in the licensing basis, and that is the way that we screen the events. I don't know the specific answer to your question and the Systems folks who we didn't bring today could -- might be able to answer that.

MR. MATTHEWS: I might be able to --

DR. BONACA: I think for Duke we are satisfied that the scope --

MR. MATTHEWS: I was just going to provide a clarification that, in answer to your first question, I think the answer is yes. It would be in the licensing basis

of the plant, but they wouldn't necessarily be scoped as design basis events in the traditional terminology.

DR. BONACA: You know, I don't want to belabor the issue with Oconee. I think we have seen it enough and the fact that they have verified this and no additional components were identified is comforting.

MR. MATTHEWS: And I do think, as I mentioned, we will probably have to go through a similar exercise against future applications and we have even talked about the fact that as a result we may have to come to a rule change eventually to address this, to remove this confusion that exists with regard to the terminology used.

DR. BONACA: It is confusing. The point I am making is more for the preparation of the SRP, which should provide some clarification and hopefully will in this particular area because it is confusing.

MR. MATTHEWS: Yes.

DR. BONACA: Okay, thank you.

MR. SEBROSKY: That was David Matthews, by the way.

DR. SEALE: You still are.

MR. MATTHEWS: Still am.

[Laughter.]

MR. SEBROSKY: Moving on to the next slide, Duke made a presentation about one-time inspections and this

slide basically reiterates and has one additional thought.

Duke has nine one-time inspections and as Duke, as Greg Robison mentioned, the purpose of the one-time inspection is to verify that aging effects are not occurring such that an aging management program would be required.

The last bullet is just the basis for the Staff's acceptance. If you go to our SER, you will find that we found it acceptable because at present the aging effects are expected to be slow-acting and can be resolved by the established corrective action process.

That is our basis for acceptability.

The last issue that we were going to discuss today was buried piping and if you to Duke's application, the aging is actually managed by two preventative maintenance activities. Greg mentioned one, the condenser circulating water system internal coating inspection.

There is also another one. As you know, there is a standby shutdown facility that has a buried diesel fuel oil tank and there is also an internal inspection associated with that.

If you go again to our SER and the basis for the acceptability we mentioned the condenser circulating water system, 11 foot diameter pipe, accounts for 80 percent of the surface area of the buried pipe.

So that is all we have for presentation today.

Were there any questions?

DR. BONACA: Any other questions from the members

CHAIRMAN POWERS: Pretty straightforward. No.

DR. BONACA: Thank you for the presentations.

I would like to go around the table and see if there are any additional comments from members regarding all we have seen. Most members were at Oconee last week. Not all of them, so any questions you have we should discuss here.

CHAIRMAN POWERS: I see no particular questions. I think we learned something from going and looking at Oconee. It is a plant from an older era and I think we need to give some thought to what we have learned from their example on how it might be applicable to other plants. I think they did a particularly impressive job.

I think it might be worthwhile to look and see if there are areas that we can profitably curtail based on the experience there, areas and methods that we could profitably highlight.

DR. UHRIG: Some of that might be related to the results of the inspection but they may not be done in time.

CHAIRMAN POWERS: Okay, thank you very much.

DR. BONACA: Any additional questions from the members?

[No response.]

DR. BONACA: Well, thank you very much. I turn it back to you, Mr. Chairman.

CHAIRMAN POWERS: I have a problem. I am unable to start the sessions on 50.72 until 4:15, so we will recess until 4:15.

[Recess.]

DR. APOSTOLAKIS: We are back in session.

DR. SEALE: We've got a quorum at the forum, eh?

DR. APOSTOLAKIS: Yes. The next item is proposed final amendment to 10 CFR 50.72 and 50.73. The cognizant member is Dr. Bonaca. I will turn it over to him.

DR. BONACA: Okay. During the February 3 to 5, 2000 ACRS meeting the Staff presented its proposed final amendment to 10 CFR 50.72 and 50.73. At that meeting the Nuclear Energy Institute stated that the proposed amendment would be beneficial for licensees and should be issued as soon as possible with the exception of the following new reporting requirement -- any event or condition that required corrective action for a single cause or condition in order to ensure the ability of more than one train or channel to perform its specified function.

The Staff and the industry met on February 25th, 2000 to discuss this requirement. The Staff agrees that there are problems with the requirement. The Staff plans to meet on Monday, March 6, 2000 to decide on a course of

action and they plan to brief the ACRS on the resolution of this matter on April 5-7, 2000 ACRS meeting.

I believe we have representatives of the Staff here that can explain to us what the issue is and what you expect to see as a closure and if also you believe that by the April meeting we will be able to hear a report and write a letter. Thank you.

MR. BARTON: You have got to come up front so we can take a shot at you.

MR. ALLISON: My name is Dennis Allison. The issues that arise with this criterion, which were really unexpected to the Staff -- but assume you have a routine monitoring program for heat exchangers to check for fouling and you find that they are fouled, they are operable, but there has been some fouling and you decide to clean two heat exchangers.

That could be considered to fall under this definition. It wasn't what was intended but it could be considered a corrective action to ensure operability, so it needs to be clarified and I would expect we'll clarify it one way or the other.

I think at the meeting the licensees showed us lots of things that we didn't want to be reported that would be, so one could list a long list of exceptions. That is not --

DR. BONACA: Could you give us an example of what you would like to be reported and then an example of what the industry is concerned that you agree that should not be reported?

MR. ALLISON: Yes, sir. The kind of thing we would like to be reported would be, say, you find a valve stem that is cracked nearly through, so that 75 percent -- I think there is an example in the package to that effect.

DR. BONACA: Yes. I remember that.

MR. ALLISON: Because you used the wrong material in a plant modification, so it is corroding rapidly. You decide that you need to replace the valve stem in the other train as well, even though it might not be so bad yet, but you are going to replace them with new material.

The reason we would like to see something like that is that there is a little lesson there. Now in this particular case that probably wouldn't end up in a bulletin, but there is a lesson there. That is, if you use this material you get rapid corrosion in this situation. Maybe it is something we don't know about. So that is what we would like.

I don't think there's a problem with that. That is, I don't think the industry really objects to reporting that situation.

Something that we wouldn't want to hear about is

the example I just gave of routine maintenance. You clean two heat exchangers -- it could be considered.

A suggestion that licensees throughout the last minute at the meeting and it seemed like it would work would be to say something like the following -- an event or condition that as a result of a single cause or condition could have prevented fulfillment of the safety function of two trains.

That is kind of a hybrid between two existing requirements that they know how to interpret. They know how to interpret the term "could have prevented fulfillment of the safety function" and they know how to interpret the term "as a result of a single cause or condition." So that is another possibility.

DR. BONACA: But they agree that there is a category of issues that should be reported?

MR. ALLISON: Well --

DR. BONACA: At least they are willing to entertain that?

MR. ALLISON: Yes. I think industry is mostly concerned with clarity and clarity can be interpreted to mean unintended consequences, like a whole lot of situations that shouldn't be reported.

They are also concerned about the process. They don't want to have to review every deviation report,

thousands of things, all the maintenance things they do in the plant for reportability. They would like something that is a little easier to recognize and is clear.

DR. BONACA: Although it seems to me that I mean for an event like the cracked stem you would have, you know, a root cause evaluation most likely and that would end up in the corrective action program with a pretty high level.

MR. ALLISON: I would think so, yes.

Now one of the things -- a technical point. I am not sure that you want to get into it, but a technical point is when we drafted that guidance we said that this applies only to significant conditions adverse to quality as discussed in Criterion 16, but in turns out there's a lot of variability in QA programs and at one plant they have a specific definition of that in their program that would be about right and so by its terms this criterion would be about right for that plant, but at another plant everything they do to correct the problem is just a corrective action. They don't make that distinction.

DR. BONACA: Do you believe that you will be able to resolve this issue by the April meeting?

MR. ALLISON: Yes, sir. I have recommended that we take a little more time -- I don't know if that will be approved -- to try to make sure we get a criterion that does not have unintended consequences and if that is approved I

will have it resolved by the April meeting. If it is not, then it will be resolved sooner.

DR. BONACA: Okay. We are not going to write anything until this issue is resolved.

DR. SEALE: Not until we have something to comment on.

DR. BONACA: Because I mean we already commented favorably regarding the changes that you were proposing to make to 10 CFR 50.72 and 73 and the only issue of significance to come up was this one, and so we will wait until we hear from you. Okay?

MR. ALLISON: Now I guess there is a possibility that we would decide to proceed rapidly by some means like using this or deleting it or something and go ahead. There is that possibility but it doesn't seem like a realistic one to me.

DR. BONACA: Okay.

MR. SIEBER: Would this be one of those issues that one would call a process issue as opposed to a technical issue?

CHAIRMAN POWERS: I don't know.

MR. SIEBER: If it's really truly a process issue, then they can go ahead without us.

DR. BONACA: Well, yes -- you mean without our review?

MR. SIEBER: Yes.

MR. DUDLEY: The technical issue involved with this is that they did delete the requirement to report conditions outside the design basis and there is a subset of events that would have been reported that's trying to be captured by this new criterion which are those events that could lead to an inoperability, more than a train, looking for a common cause failure.

It would be of interest to the rest of the industry.

MR. SIEBER: So we have to see it before they can go beyond that?

MR. DUDLEY: That's correct.

MR. SIEBER: In your opinion.

MR. DUDLEY: In my opinion it is how they finally resolve the issue and the wording that is used because the industry was saying with this reading every time they went in to calibrate a piece of equipment, they would be undertaking a corrective action due to instrument drift on several instruments --

MR. SIEBER: That's true.

MR. DUDLEY: -- and would have to report it, and taking it a little bit further, they were concerned that every corrective action that they took within the plant would need a root cause analysis to determine whether it

could result --

MR. BARTON: Reportable.

MR. DUDLEY: Whether it was reportable, and the industry felt comfortable if they were already doing a root cause analysis that they would already have that information and that was probably an appropriate level to report.

MR. SIEBER: Thank you.

DR. BONACA: For our part I mean we need to have a final resolution before we can make a judgment on other resolutions so we will wait until we hear and we will not write a letter now.

MR. ALLISON: Okay. Is there anything else?

DR. BONACA: Any other comments regarding this issue or questions?

MR. BARTON: No questions, no comments. Thank you.

DR. APOSTOLAKIS: Okay. I understand the Staff is here for the next item.

MR. BARTON: But can you start before the posted time?

DR. APOSTOLAKIS: A Federal employee told me I could.

MR. BARTON: A Federal employee told you? Did you believe him?

[Laughter.]

DR. APOSTOLAKIS: The next item is proposed Final Revision 3 to Regulatory Guide 1.160, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.

The cognizant member is Mr. Barton, so he is in charge.

MR. BARTON: Thank you, Mr. Chairman.

The last time we met with the Staff on this issue was in November and at that time the committee recommended that the proposed Rev. 3 to Reg Guide 1.160 be issued for public comment.

We did have an additional comment though, and we requested that our issue or definition of "unavailability" be addressed.

During the comment period and resolution of the comments. The comment period is over, the staff and industry have I think reconciled the minor differences they had on this Reg. Guide and the staff is here to present to us how the guide has finally been resolved and to, I guess, talk about the definition of unavailability, which will close out this issue for the Committee.

DR. APOSTOLAKIS: This issue again?

MR. BARTON: Well, George.

DR. APOSTOLAKIS: This is one of the simplest concepts, reliability.

MR. SCOTT: Okay. Good evening, I guess, almost.

MR. BARTON: Just about.

MR. SCOTT: Mr. Chairman and ACRS.

DR. POWERS: It hasn't even gotten good and started yet.

MR. SCOTT: My name is Wayne Scott, I have been acting since Rich Correia, who you all known and love, moved on to NRR Projects back in November. As you said, Mr. Barton, we have been through all these steps along the way. We hope we have satisfactory resolution for your ears today, and maybe this is our last time.

I want to point out one thing, by the way, that we have said all along we were terms of Revision 3 to Reg. Guide 1.160 and what we have really decided to do instead to issue what the Reg. Guide people call a companion guide. At this point in time the guide is called 1.XXX. It will have a number different from 1.160. It will specifically address the change in the rule and will endorse NEI's Section 11 of their NUMARC 93-01 document.

So, rather than putting out a whole new Reg. Guide and opening all the Pandora's box there and having them do the similar thing with 93-01, they are issuing Chapter 11 uniquely, as well as a couple of pages to their appendices that we will talk about, and we are endorsing it through a separate Reg. Guide that is called the Companion Reg. Guide.

Our assumption is that shortly, you might say

maybe within a year or so, we will issue Revision 3 of Reg. Guide 1.160 which will fold in more clarifications from the baseline inspections and from inspections and changes in oversight policy, program, all that sort of stuff, as well as the issues with respect to the new (a)(4) into -- that will be into Revision 3 of Reg. Guide 1.160 at a later date.

So, with that, I would like to turn over the program to Dr. See-Meng Wong. Dr. Wong was the author, the principal author of the NRC's initial Regulatory Guide in this area before NEI decided to participate, so I think it is appropriate that he take the floor.

MR. WONG: Good evening. I am See-Meng Wong from the PSA branch and --

MR. BARTON: Welcome back.

MR. WONG: Thank you. Since we have been scheduled for this last presentation for today, I thought it was appropriate, this may be the end of the road for us. But --

MR. BARTON: We can't afford to burn out any more engineers, that is for sure.

MR. WONG: Right. I just want to briefly bring up to date the Committee on what has transpired since the last briefing to you on November the 4th. Essentially, on November the 10th we provided a briefing to the Commission on the status and the development of the Reg. Guide and

informed the Commission on the objectives. Our objective was to endorse acceptable industry practices and also to define an optional scoping criteria.

As a result of that briefing, we provided the guidance package to the Commission for information on November the 30th and sometime in December, we issued it for public comment in the Federal Register. As of January 10th, we have completed our 30 day public comment period on the draft guidance.

The next slide, essentially, is probably where most of the discussion is today, is on the public comments that we received. We received comments from seven utilities; from one state agency, which is the Illinois Department of Nuclear Safety; Winston & Strawn, which is a legal firm representing several utilities; and NEI.

The specific comments that we have gotten from all these organizations essentially was to request an extension of the 120 day implementation period. The requests varied from 240 days to about a year. And, in fact, the request from the utility that wanted a one year extension was so that they could go and try to upgrade their program.

In fact, they provided a very detailed timeline of what they have to do to scope, you know, the SSCs that they need to be part of the (a)(4) assessments, the procedures, the training and the testing of the program, and also a

self-assessment to make sure that they have got a good program in place before the inspectors show up.

The second specific comment, this came about actually from NEI, and it is really an industry proposal to try to define a clear boundary between where the 50.65(a)(4) and 50.59 interface. And in the package that we have submitted to you, this will be on page 3, on Item 6, and also on page 17 on Section 11.3.8.

The industry proposal is that they want to make sure that for competency measures that address degraded conditions prior to the performance of maintenance be subject or be under the purview of the 10 CFR 50.59. And if the competency measures is being used as part of risk management action during the maintenance activity, they want it to be subject to the (a)(4) assessment. What they are trying to do is they want to avoid two assessments for probably the same change in the conditions.

So, subsequent to the package that they have provided to you, and I want to show you the language that they have added which is not in your package, just for discussion purposes. This is not in your transparency. On page 3, in Section 11.3.2, they have added a note which says that "If, during power operation conditions, the temporary alteration associated with maintenance is expected to be in effect for greater than 90 days, the temporary alteration

should be screen, and, if necessary, evaluated under 10 CFR 50.59 prior to implementation."

And in Section 11.3.8, at the end, very end of the second paragraph they have added the sentence, or the statement after the last sentence which said, "Since the competency measures are associated with maintenance activities, no review is required under 10 50.59 unless the measures are expected to be in effect during power operation for greater than 90 days."

This issue was discussed and presented to the Commission by the people -- that are involved in the development of the 50.59 regulatory guidance. Questions were asked, why did you take 90 days? And the answer that was given was it was arbitrary, they chose it at this time without any good basis. Yes?

DR. APOSTOLAKIS: I have just a question a clarification.

MR. WONG: Yes.

DR. APOSTOLAKIS: Could I take Regulatory Guide 1.177 which deals with outage times, --

MR. WONG: Yes.

DR. APOSTOLAKIS: -- and have some bounds on the probability, the incremental probability of core damage and so on?

MR. WONG: Yes.

DR. APOSTOLAKIS: Could I take that one and come to you and argue that, you know, for 90 days or 100 days, the incremental probability is below the limit, so I shouldn't have to do this? Am I allowed by all this to do this?

MR. WONG: Okay.

DR. APOSTOLAKIS: I mean this is a temporary configuration, right?

MR. WONG: Right. The temporary configuration they are talking about are these like scaffoldings that they have in place.

DR. APOSTOLAKIS: So they are below the PRA consideration.

MR. WONG: Below, right. It is probably not modeled in the PRA.

DR. APOSTOLAKIS: Or maybe not at all.

MR. WONG: That is correct.

DR. APOSTOLAKIS: So why 90 days, why not a year?

MR. WONG: Well, if it is a year it is too long, and -- well.

MR. BARTON: He said it is arbitrary, I don't know why the 90.

MR. WONG: Right. Right.

MR. BARTON: But there is a requirement now, if you gave a temporary modification, you have to do a 50.50.

Now, all of a sudden we are saying if it is only for 90 days, I don't want to do a 50.59. Is this what this is saying?

DR. APOSTOLAKIS: Yes.

MR. WONG: Yes. Yes. This is what --

MR. SCOTT: If it is specifically --

DR. POWERS: For the maintenance.

MR. SCOTT: -- related to and required by the maintenance activity. Basically, they are getting a little bone here. And what we are talking about is, as See-Meng mentioned, if they have to put up some scaffolding, if they put some shielding in perhaps.

We even talking about tearing down maybe a little wall or opening a door that normally is not open. If they have to do that in order to perform the maintenance, then the concept is they do, perform the maintenance, and then put it back like-for-like, like it was, and if they can get all done within arbitrarily chosen 90 days, and so far that seems to be flying all right, because Gary Holahan basically was one of the principal players in the decision to come up with that 90 days. And he assures us that what we are really talking about here is stuff that is not covered by tech specs, it is not in a PRA, it is really of relatively very low safety significance. So --

MR. BARTON: It is a temporary modification to the

plant.

MR. SCOTT: Well, --

MR. BARTON: Yeah, it is. Right?

MR. SCOTT: Yeah, except we had -- listening yesterday at the Commission -- was it yesterday?

MR. WONG: Two days ago.

MR. SCOTT: Two days ago at the Commission meeting, Harold Ray from San Onofre took exception with Tony Pietrangelo talking about temporary alterations, temporary mods, temporary changes, and what he really said, basically, is if it is for maintenance and you it back like-for-like, it is not a change, it is not an alteration, it is not a mod. I don't know what the right word is, but it is a temporary -- I looked through the thesaurus today in my word processing system trying to find a better word to put into this last piece of the Reg. Guide that is up there. But it is a temporary --

DR. APOSTOLAKIS: But expected perhaps.

MR. SCOTT: Yeah.

DR. APOSTOLAKIS: Temporary expected activity.

MR. BARTON: To me it is a temporary, whatever you want, if I put scaffolding up in the plant, I have got to a safety evaluation of scaffolding. So all of a sudden I can do all this stuff in 90 days and don't have to do it. I am with you.

MR. SIEBER: A temporary mod could be a hose, a hose or a jumper or a lifted lead.

MR. SCOTT: The idea is that --

DR. APOSTOLAKIS: Are you saying, John, that they should do it?

MR. SCOTT: Yeah. As part of --

MR. BARTON: I am saying I don't understand why all of a sudden the same thing I would do if I didn't do maintenance, but put scaffolding up for a mod I am going to do later, or some change I am going to do to the plant, I have got to do an evaluation because it is a temporary modification, I am going to have it in there for a while.

MR. SCOTT: The evaluation does not disappear, the evaluation, however, is done under the aegis of the (a)(4) safety assessment and management of the risk as opposed to through the process of 50.59. That is really the change. The assessment we expect, the NRC's expectation is the evaluation of whatever they evaluate when they put up scaffolding, that evaluation will nonetheless take place, an engineering evaluation of hanging lead shielding on a pipe or whatever they do with that sort of stuff. Those kinds of things will still have to be done, but they won't have to go through the formal 50.59 process, they will be handled through the maintenance risk assessment and risk management process.

DR. APOSTOLAKIS: So Mr. Ray disagreed with the 90 day?

MR. WONG: No, no, he didn't.

MR. SCOTT: No, he didn't. No, he just said, basically, it is not a temporary alteration if it is something you are going to do for maintenance and then put it back in place. A temporary alteration is something of long-term that is actually altered like the lifted leads.

DR. BONACA: Or like lead shielding. I mean I know of some cases in the past where I have seen that the safety evaluation helped identify some significant issue that maintenance people totally missed.

MR. SCOTT: Sure.

MR. WONG: Sure.

DR. BONACA: And so it was useful in that sense because it focused the evaluation on some significant issues you had to consider. So I am not as comfortable as other people seem to feel, but --

MR. WONG: Well, given the slight discomfort, this is what we attempted to put some clarification statements in our Reg. Guide in the implementation section, and this is what we have crafted, that the assessment does not relieve the licensee from obligations to his license or the regulations, and the exemption requirements in 10 CFR 50.90 remain effect, and the intent here is to eliminate

overlapping requirements for assessments which could be considered to exist under 10 CFR 50.65(a)(4) and 10 CFR 50.59. This clarification applies to temporary alterations directly related to and required to support a specific maintenance activity being assessed.

DR. BONACA: Okay.

MR. WONG: There is also the thought that we will see how it is being implemented. If there is going to be an abuse, we may just make a revision and maybe shorten the time or rescind this.

DR. SEALE: What are you guys going to do if the scaffolding suddenly shows up two weeks after it has been taken down after being up for 90 days?

MR. SIEBER: A violation.

MR. SCOTT: Well, we thought about that, and one of the issues in that area, we think that what is going on in the industry these days is a real stretch for profitability, and we have discussed that specific issue. What if they take a door out and then -- for 89 days and then they put it back in and take it back.

We don't really expect to see that for the simple reason that it costs money to take that scaffolding down and put the scaffolding back up. So it would seem to us to be a lot simpler process, if they are going to leave that scaffolding up and they want it up for a longer time, that

they should go right to the 50.59 in the beginning, or at least as soon as they recognize that they are going to pass the 90 day barrier.

And it is our opinion, I think that the cheaper method is to do the 50.59 than to go through all the rigmarole of tearing down the scaffolding and putting it back up.

MR. SIEBER: That's true. I guess one way to look at it, though, is if you are going to do a temporary mod inside the boundary of the equipment you are working on, let's say you are going to overhaul a pump, okay, and your mod puts scaffolding around the pump, you know, you could put that right into 50.65(a)(4) without any problem at all.

But if your modification affects some other independent piece of safety-related equipment, it seems to me to be more pertinent to do a 50.59 because now you can take two trains out, where you can take two alternate pieces of equipment out if the modification is incorrect or it fails.

MR. SCOTT: Well, that should be, in my opinion, that should be part of the overall assessment that the licensee makes.

MR. SIEBER: Under (a)(4).

MR. SCOTT: Under (a)(4), integrating all those aspects of the activity.

DR. POWERS: It sounds to me like they are making a first step toward a risk-informed 50.59 here in this one narrow area.

MR. SIEBER: That's true. In some plants, though, it is maintenance people that do the (a)(4) evaluation versus engineering and operations that do 50.59, so it is two different levels of expertise and I am not sure they are equivalent.

MR. SCOTT: Well, we expect that is going to have to change, other people getting involved.

DR. POWERS: You suspect it is going to have to change because of the language of 50.65(a)(4)?

MR. SCOTT: Sure.

MR. SIEBER: All right.

MR. WONG: Okay? Our other comments are essentially very, very minor comments. In response to Mr. Barton's questions, there were comments on unavailability, but I think we have essentially beaten that to death, and the definition that is provided in your package has been agreed to by all the organizations that we know of except WANO.

And when it was first proposed I really Professor Apostolakis wanted to burn away that definition, but we made an attempt to try to come up with the best that we could have, and to try to clean it up so that it addresses

specifically the practical aspects of what we are trying to use the definition for, which is to track the unavailability of the equipment for the purposes of maintenance. So other comments essentially are just choice of words, adjectives and we have had a meeting with NEI to come to agreement with what the words should be so that it provides clarity in the guidance. Okay.

DR. APOSTOLAKIS: Now, let me understand this definition in Appendix B.

MR. WONG: Okay.

DR. APOSTOLAKIS: When you say planned unavailable hours plus planned -- unplanned unavailable hours divided by the required operational hours, what exactly does unavailable mean? I mean this is a definition of unavailability. Does it include -- is it only the time that you took it out to do something to the equipment?

MR. SCOTT: In Maintenance Rule space something is not available if it is unable to perform the function that got the SSC in the Maintenance Rule in the first place.

DR. APOSTOLAKIS: So this is only for maintenance, this definition? The fact that it may be available in this sense, but fail during the demand is not included here.

MR. SCOTT: I reckon that is true.

DR. APOSTOLAKIS: And that is --

MR. SCOTT: We are really looking at treatment of

systems in the Maintenance rule where, you know, the rule is monitoring the effectiveness of the maintenance. And, so, as you pointed out in your letter, it depends on whether it is a standby piece of equipment or continually running, and that sort of thing.

DR. APOSTOLAKIS: You actually read it. Good.

MR. SCOTT: A couple of months ago I had it memorized, sir.

[Laughter.]

MR. SCOTT: We have, on this subject of availability, we have had -- gracious, we probably have our own TAC number for unavailability. And we have had people going to national conferences and international conferences. This is not just something that we just made up, you know.

DR. APOSTOLAKIS: No, I realize that.

MR. SCOTT: Right.

DR. APOSTOLAKIS: But I would be much happier if you explained that this is a definition that applies, you know, to these issues. I mean I guess it is understood because you continue and talk about -- I mean you go on and talk about maintenance activities and testing and so on.

MR. SCOTT: It also is involved very much in the new performance indicators. I assume you have been involved in all that.

DR. APOSTOLAKIS: Yes, and I have the same problem

there.

[Laughter.]

DR. APOSTOLAKIS: Let's see, what are we doing here, Mr. Barton? Are we going to approve this?

MR. BARTON: Well, that was the intent, yes.

DR. SHACK: Now, what is the status of that language? I mean that is -- the staff is now proposing to approve the NEI document with that language added to the sections and you are going to add that language to your Reg. Guide and that is now staff approved and you are asking us to approve that?

MR. SCOTT: We are at the point right now where we have a Regulatory Guide -- oh, you are talking about this?

DR. SHACK: Yeah.

MR. SCOTT: Yes.

DR. SHACK: The Regulatory Guide plus that language and the NEI guide that we have in our hand, plus that language.

MR. SCOTT: Exactly right. That is the package.

DR. SHACK: You have approved that and now the question is, are we going to approve it?

MR. BARTON: That is the question.

MR. SCOTT: Right. Exactly right.

DR. APOSTOLAKIS: Is it possible to add three words here somewhere, or is it too late? Unavailability due

to maintenance operations is defined as follows. That is correct, if you put those words "due to maintenance problems."

MR. SCOTT: I am sure when you ask that question you really don't have a good feel for what it would take to make the change, not just in our Reg. Guide, that is not the issue, the issue is -- is Don Dickman here? No. Throughout all the apparati that collect unavailability data, that have been set up, the data systems, the performance indicators, the agreements with INPO and -- truly, I haven't been to those meetings, so I don't know how all those other people are, but to make a modification like that would be, for our purpose, for this purpose, would be correct, but no easy thing to do, sir.

MR. GILLESPIE: George, let me make sure I understand, because we collectively may not be communicating. The unavailability here is the same as oversight, it is not just unavailability from maintenance. If you have a demand failure and you find something inoperable, that downtown also counts on the unavailability. It is exactly the same unavailability that we talked about a little earlier when the oversight group was here.

DR. APOSTOLAKIS: Yes, but, again, that is a little different.

MR. GILLESPIE: It is not the reliability, it is

not the demand failure, but if you demand it and then find out it is inoperable, --

DR. APOSTOLAKIS: Yes.

MR. GILLESPIE: -- that time of inoperability then starts accumulating as part of the numerator of the fraction. So it is not the same as what you just so.

DR. APOSTOLAKIS: No, I understand that.

MR. GILLESPIE: Okay.

DR. APOSTOLAKIS: Let's say you are testing something every first of the month, for example.

MR. GILLESPIE: Right.

DR. APOSTOLAKIS: And you find out that the first of February -- first of January was okay, first of February was not. And then somehow you find out that it had been failed for six days.

MR. GILLESPIE: Yeah.

DR. APOSTOLAKIS: So that, those six days will be part of the unplanned unavailable hours.

MR. GILLESPIE: Yes.

DR. APOSTOLAKIS: Okay. But that still does not account for the fact that it may have been available for all this period, but it failed due to something that happened during the demand.

DR. SEALE: Yes.

DR. APOSTOLAKIS: That part is not here. And all

I am saying is, if you say that this is due to -- I mean we have to find the words. You are right, it is not just maintenance.

MR. GILLESPIE: Yeah, and this is why we are groping now in working with Research to try to find the corresponding reliability or demand measure that goes with this as a set, and we are just not there.

DR. APOSTOLAKIS: If we could put an asterisk there, put at the end something that this is not the unavailability that we are talking about in PRAs, this is not the unavailability we are talking about in reliability, this is not the unavailability that you will find defined in a book. This is not it. There is nothing wrong this.

MR. GILLESPIE: You're right.

DR. APOSTOLAKIS: As long as you make it clear that you are talking about this particular thing. You are saying, administratively, that is not easy.

MR. WONG: Well, we can suggest it to NEI, because that is there document.

DR. APOSTOLAKIS: Well, they know what it is, right.

MR. WONG: Yes.

DR. APOSTOLAKIS: Yes.

MR. WONG: I think we can try to do that. Okay.

MR. BARTON: Let's go back to the definition of

the -- I am tired of unavailability, the other one, the 50.59 issue.

MR. WONG: Okay.

MR. BARTON: I need to see the words again. Let me ask you something.

MR. SINGH: I will get a copy.

MR. BARTON: I am going to do a refueling outage, I am going to do 489 maintenance items, and I am going to erect scaffolding all of the place, take doors down, put shielding all over the place.

MR. SCOTT: There is a caveat that says this is issue is an at power issue.

MR. BARTON: It is a what?

MR. SCOTT: At power.

MR. WONG: At power.

MR. SCOTT: We are not trying to change the licensee's outage.

MR. BARTON: That is why I wanted to see this again, because I have got a lot of concerns if I just want to do 50.59, I can do all kinds of modifications, and put all kinds of stuff in the plant and leave it there for 90 days.

DR. BONACA: But even at power, 90 days, now they were doing, they are making changes every day pretty much, taking out some systems, components, putting them back in.

So now you have all the scaffolding and you are not evaluating the impact of the scaffolding on -- are you evaluating the impact every day as you do it?

MR. SCOTT: Every time there s a change. That is the issue with the (a)(4), when there is a change in the configuration of the plant, then there should be a reassessment.

DR. BONACA: A reassessment, and that reassessment will include the temporary modifications that are in place?

MR. SCOTT: That is the intent, yes. That is the Commission's expectation.

MR. BARTON: That will now require that be done.

MR. SCOTT: Right. Essentially, what had been being done before under 50.59 in this area would move over under the responsibility --

MR. BARTON: 50.65(a)(4).

DR. BONACA: So you would have to perform it under your PRA evaluation or whatever, Maintenance Rule.

MR. BARTON: Under (a)(4).

DR. BONACA: And that temporary addition or whatever, alteration, will have to be considered.

MR. SCOTT: Yes.

DR. BONACA: For all the 90 days, on every change you may.

MR. SIEBER: That's okay.

DR. BONACA: Oh, yeah, in principle it is okay. I am trying to figure out all the thousand possible ways it can fail.

MR. SCOTT: Yes, me, too. This issue arose when somebody --

DR. BONACA: They always talk about, you know, everything is perfect out there. Why is an organization with other people -- and things always, this kind of stuff always falls into crack. Oh, we didn't consider -- oh, we didn't consider -- oh, we missed that, you know. I mean, have you heard that before?

DR. POWERS: Never, Mario.

MR. SIEBER: I haven't either.

DR. POWERS: At his utilities, nothing will ever fall in the crack.

MR. SIEBER: But things fall through the crack whether it is 50.59 or 50.65(a)(4), you know, same crack.

MR. SCOTT: The issue as raised to us, that we said, oh, gosh, let's think about that, was the issue of a licensee having, say, valves in the overhead that needed to be testing once a year. And so they put up -- they open a maintenance activity, they put up the scaffolding, they test the valves, and they leave the scaffolding up and they don't close the maintenance activity.

MR. SIEBER: Right.

MR. SCOTT: And any time anybody would point out at it, the issue, oh, well, we are still doing maintenance. So the scaffolding stays up forever because every year they walk up it and test the valves. So we said that is out of the question, we don't want that to happen. We want people -- our expectation is that they will do these things, perform the maintenance, and then put them back the way they were.

And if we find the licensees taking advantage of this issue, then we are going to revisit it.

DR. BONACA: I guess the concern is already we attempted to address within the Maintenance Rule the issue of multiple configurations and complex configurations, including multiple components. Now, we are addressing the issue of adding to that.

MR. SCOTT: Temporary alteration.

DR. BONACA: Temporary alterations that would be there in place overlapping for periods of time which would make the configurations even more complicated.

MR. SCOTT: That certainly is true. But the risk -- the assumption in all this issue is that the risk of this activity is so low, it is not covered by tech specs, it is not covered by any regulation beyond the 50.59 sort of thing.

MR. SIEBER: Let me ask a simple question. It was

our practice back when I worked in power plants to specify in a lot of maintenance procedures what temporary mods like jumpers and lifted leads or what-have-you, where they were to be installed and all that, and then when the procedure was approved, a 50.59 evaluation was done on that procedure.

MR. SCOTT: Right.

MR. SIEBER: Does that make you redo 50.65(a)(4) for all those changes that were already approved in the procedure, temporary mods?

MR. SCOTT: I have to say yes because (a)(4) is an integration of the status of the plant at any particular time.

MR. SIEBER: Right.

MR. SCOTT: And if a new activity, maintenance activity comes along, then that activity and its associated pieces have to be assessed.

MR. SIEBER: So the burden goes up then for the licensee, because he ends up doing it twice.

MR. GILLESPIE: Yeah, I think one of -- what brought this to the fore was (a)(4) and the requirements of (a)(4) exist no matter what.

MR. SIEBER: Right.

MR. GILLESPIE: So then the question was, do I have to do 50.59 in addition, or is what I did for (a)(4) good enough to fill both slots? So this doesn't change the

requirements under (a)(4), it is just that we hadn't thought that part of the risk to the plant is heavy loads, it is staging, it is putting those jumpers in. But, in fact, the way (a)(4) was worded, it did already encompass this. And when people visualize that, they said, okey, now we have to do it under (a)(4), and, oh, shoot, now we have to do it under 50.59. So now we are doing the same assessment twice for everything, and this was an attempt to say, no, one assessment is okay.

DR. POWERS: This is really not the same assessment because the standard --

MR. GILLESPIE: Different. Different. Okay. This is probably considered less onerous than the 50.59.

DR. POWERS: You have got more freedom under 65 than you do under 59.

MR. GILLESPIE: Yeah, you do. Yes.

DR. POWERS: Because one of them is a minimal increase and the other one is a change in risk.

MR. GILLESPIE: Yeah, absolutely.

DR. POWERS: It is really just a risk management.

MR. GILLESPIE: It says manage and assess, right.

DR. POWERS: That's right.

MR. GILLESPIE: So you need enough information to manage and assess. So it was kind of a double jeopardy. The utilities were going to be stuck with both requirements,

and then what was the proper interface? So, and that is how this really came about. But it doesn't really change (a)(4), it just caused us to focus on what (a)(4) encompassed.

MR. SIEBER: Thank you.

DR. BONACA: I guess just one last thing. My only concern I am thinking about how people operate, and if you are exercising a PRA, you are able to address multiple changes there. I am not sure that you are going to reflect the scaffolding in the PRA. You are simply going to perform an evaluation and say, does it impact this area?

Now, I am trying to think how the PRA analyst which doesn't live inside the plant with the maintenance people is going to evaluate this consideration of all these added components which are not in the PRA, to his PRA evaluation.

MR. GILLESPIE: Yeah, this is much easier guidance to say it looks good than it is to implement. This is going to be a challenge because it is a different animal.

DR. BONACA: Oh, sure.

MR. GILLESPIE: And we are going to be looking at things like the PRA analyst match of the maintenance guy, where the maintenance guy has to figure -- think about single failure-proof cranes, heavy loads over pumps. And so you have got this spatial distribution that the PRA guy is

normally not interested in, but now he has to be interested in it.

So it is a different kind of analysis. It is going to be interesting to see how the industry implements this, because their traditional organizations are really not set up right now to step right into this. They have all the right people, they are just not necessarily in the right work units to integrate this together. Yeah.

DR. BONACA: That is exactly why I was asking myself the question. I was trying to figure out from memory how they work out, and they don't converge oftentimes.

MR. GILLESPIE: Which I think may lead to the other side that they had, that 120 days may not actually be enough time to implement what has come out of all the discussions on this, if this represents kind of the end point. And many of the people who commented said, we didn't -- we are going to need more time now.

MR. WONG: Okay. The last slide is, where do we go from here? Our target date to provide the final guidance package to Commission for review and approval is March the 31st and the Commission can decide, given the comments that we received, whether they will extend the 120 days, that is their prerogative. That is all we have.

DR. APOSTOLAKIS: So the Committee action is a letter?

MR. WONG: Yes.

MR. SCOTT: Yes.

DR. POWERS: Could you just sketch out for me one more time about this business on a companion guide?

MR. SCOTT: It is a separate Regulatory Guide. It will endorse the revised Section 11 of NUMARC 93-01, and has words in it that states it works, essentially, in concert with 1.160. So it focuses completely on (a)(4) as does the Section 11.

DR. POWERS: Really, all I am interested in, is there anything that is going to come back to us on this?

MR. SINGH: No.

MR. BARTON: This is it.

DR. POWERS: This is it?

MR. WONG: This is it. Yes.

DR. POWERS: It was a scheduling concern.

MR. BARTON: No, it is not Rev. 3 to Reg. Guide 161. The title of this thing is going to be what?

MR. SCOTT: Companion Guide 1.XXX.

DR. SEALE: Well, right now it is Reg. Guide 1.XXX and Research won't assign a number to it until after the Commission approves it and it heads over there for --

MR. BARTON: Is it still Rev. 3? Is it still Rev. 3?

MR. SCOTT: No.

MR. BARTON: It is just Reg. Guide 1.XXX?

MR. SCOTT: It is an independent Reg. Guide, yes, sir.

MR. SIEBER: It doesn't have a Rev. yet.

MR. BARTON: And it is called Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants?

MR. SCOTT: Right.

MR. WONG: Yes.

MR. BARTON: Okay. Any other questions of the staff? Does the Committee feel comfortable when I write this letter that we endorse proceeding for industry use with what we heard?

DR. SEALE: I take it there is no one from industry here?

MR. SCOTT: Biff Bradley was going to be present. I talked to him this afternoon, he said that he feels comfortable not being here, that they are in complete agreement with what we are up to and so we end here.

DR. APOSTOLAKIS: I might add an additional comment, I don't think it is worth the Committee's time to argue about availability, but I think, for the record, it should be there.

DR. POWERS: George, we can include in the meeting minutes a protracted discussion with references, citations

and equations.

DR. APOSTOLAKIS: Oh, no, no, no. It is not worth it. It is not worth it.

DR. POWERS: Oh.

DR. APOSTOLAKIS: It is a simple definition.

DR. POWERS: Mr. Barton, are we through with this subject?

MR. BARTON: Yes, I think so. I'll turn it back to you.

DR. APOSTOLAKIS: Are you happy with this?

MR. BARTON: I am not sure.

DR. APOSTOLAKIS: Oh.

DR. POWERS: I think we need to talk just a little bit about this, but, on the other hand, what I see, my personal view on this is that you are carving out a little space to begin the construction of a 50.59 that is risk-based. Okay. And this is a good thing.

DR. APOSTOLAKIS: Then I support it.

[Laughter.]

MR. GILLESPIE: Okay. Take down what George says.

DR. POWERS: If -- if and when you can get your availability definition.

[Laughter.]

MR. GILLESPIE: I will say, you have really seen -- this is the -- I think when we look, as we are

approaching a risk-informed regime, of something more risk-informed, this is the first place where we have seen potentially actually an organizational impact on utilities in how they perform a function.

DR. POWERS: That's right.

MR. GILLESPIE: So I think what you are seeing is, in direct application of really what is the first kind of manage and assess your risk, that we are going to see an evolution that the traditional organizations are going to have to adapt to to get the technical talents together that need to do these things. So I think that is an interesting note that is coming out of this, a revelation that scaffolding and stuff is part of risk. Not quantifiable, but, you know. It is different, it is different.

DR. POWERS: The rule does not require them to quantify it, it only says manage --

MR. GILLESPIE: Manage and assess. So you have to cognizant of it and be able to recognize its potential impacts. Yes.

MR. BARTON: What I am struggling with, is it really going to be easier for them to add this to their assessment of maintenance, or is it going to be answer six questions on a pre-screening, on a preliminary evaluation to a safety evaluation? And I don't know why I wouldn't think the six questions and check them all off and be done with

it. But, anyhow.

DR. POWERS: Because you can't. Because you can't. Still, not matter you have done, you are blocked with 65(a)-4. It says you have got to manage and assess.

MR. SIEBER: You are blocked by the rule, and it will be an extra burden, and in some cases it will be a double burden. That's the way it is.

DR. BONACA: Well, organizationally, it is going to be a challenge, because 50.59 today is as incompatible with PRA as it was before.

DR. POWERS: That's right.

DR. BONACA: You are going to have a lot of, you know, by having been there and knowing what it is, you don't want to have PRA people doing 50.59s because you get in trouble with the NRC.

DR. POWERS: Well, and that is what they are trying to do, is avoid having a bunch of 50.59 folks intruding into the risk managing and assessing process.

Thank you, gentlemen very much.

MR. SCOTT: Thank you.

DR. SEALE: Thank you.

DR. POWERS: Let's see. Sherry, are we ready. I don't have the tools of my trade here. I need my black things. I think we can dispense with the recording at this point.

[Whereupon, at 5:13 p.m., the meeting was recessed, to reconvene at 8:30 a.m., Friday, March 3, 2000.]

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: 470TH ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

CASE NUMBER:

PLACE OF PROCEEDING: Rockville, MD

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

Mark Mahoney
Official Reporter
Ann Riley & Associates, Ltd.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D. C. 20555

February 11, 2000

SCHEDULE AND OUTLINE FOR DISCUSSION
470TH ACRS MEETING
MARCH 1-4, 2000

WEDNESDAY, MARCH 1, 2000, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

1) 1:00 - 1:15 P.M. Opening Remarks by the ACRS Chairman (Open)
- 1.1) Opening statement (DAP/JTL/SD)
- 1.2) Items of current interest (DAP/NFD/SD)
- 1.3) Priorities for preparation of ACRS reports (DAP/JTL/SD)

2) 1:15 - 3:15 P.M. Development of Risk-Informed Revisions to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities" (Open) (GA/MTM)
- 2.1) Remarks by the Subcommittee Chairman
- 2.2) Briefing by and discussions with representatives of the NRC staff regarding the status of developing risk-informed revisions to 10 CFR Part 50 and related matters.

Representatives of the nuclear industry will provide their views, as appropriate.

3:15 - 3:30 P.M. ***BREAK***

3) 3:30 - 6:00 P.M. Discussion of Proposed ACRS Reports (Open)
Discussion of proposed ACRS reports on:
- 3.1) Low-power and Shutdown Operations Risk Insights Report (GA/MTM)
- 3.2) Proposed Revision of the Commission's Safety Goal Policy Statement for Reactors (TSK/GA/PAB)

6:00 - 6:15 P.M. ***BREAK***

4) 6:15 - 7:15 P.M. Discussion of Topics for Meeting with the NRC Commissioners (Open)
Discussion of issues associated with risk-informed regulation, including:
- 4.1) Impediments to the increased use of risk-informed regulation (TSK/MTM)
- 4.2) Use of importance measures in regulatory applications, impact of the scope and quality of the PRA on importance measures, and threshold values for importance measures (GA/AS)
- 4.3) Technical Adequacy of Performance Indicators (JJB/NFD)

THURSDAY, MARCH 2, 2000, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

5) 8:30 - 8:35 A.M. Opening Remarks by the ACRS Chairman (Open) (DAP/SD)

6) 8:35 - 9:15 A.M. Discussion of Topics for Meeting with the NRC Commissioners (Open)
Discussion of topics listed under Item 4.

9:15 - 9:30 A.M. ***BREAK***

7) 9:30 - 11:30 A.M. Meeting with the NRC Commissioners (Open) (DAP, et al./JTL, et al.)
Meeting with the NRC Commissioners, Commissioners' Conference Room, One White Flint North, to discuss topics listed under Item 4 and other items of mutual interest.

11:30 - 1:00 P.M. ***LUNCH***

8) 1:00 - 2:30 P.M. Technical Components Associated with the Revised Reactor Oversight Process (Open) (JJB/MTM)
8.1) Remarks by the Subcommittee Chairman
8.2) Briefing by and discussions with representatives of the NRC staff regarding the technical components associated with the revised reactor oversight process, including the updated significant determination process, technical adequacy of the current and proposed plant performance indicators, and related matters.

2:30 - 2:45 P.M. ***BREAK***

9) 2:45 - 4:00 P.M. Oconee Nuclear Power Plant License Renewal Application (Open) (MVB/RLS/NFD)
9.1) Remarks by the Subcommittee Chairman
9.2) Briefing by and discussions with representatives of the NRC staff and Duke Energy Corporation regarding the license renewal application for the Oconee Nuclear Power Station and the associated NRC staff's Safety Evaluation Report.

4:00 - 4:15 P.M. ***BREAK***

10) 4:15 - 4:45 P.M. Proposed Final Amendment to 10 CFR 50.72 and 50.73 (Open) (MVB/NFD)
10.1) Remarks by the Subcommittee Chairman
10.2) Discussions with representatives of the NRC staff regarding issues raised by the ACRS members during the February ACRS meeting, including the intent of the 10 CFR 50.73 requirement for reporting degraded components.

Representatives of the nuclear industry will provide their views, as appropriate.

11) 4:45 - 5:15 P.M. Proposed Final Revision 3 to Regulatory Guide 1.160, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants" (Open) (JJB/JDS/AS)

11.1) Remarks by the Subcommittee Chairman

11.2) Discussions with representatives of the NRC staff, as needed, regarding the proposed final revision 3 to Regulatory Guide 1.160.

Representatives of the nuclear industry will provide their views, as appropriate.

12) 5:15 - 6:15 P.M. Break and Preparation of Draft ACRS Reports
Cognizant ACRS members will prepare draft reports for consideration by the full Committee.

13) 6:15 - 7:15 P.M. Discussion of Proposed ACRS Reports (Open)
Discussion of proposed ACRS reports on:

13.1) Technical Components Associated with the Revised Reactor Oversight Process/Technical Adequacy of the Current and Proposed Performance Indicators (JJB/MVB/MTM)

13.2) Proposed Final Amendment to 10 CFR 50.72 and 50.73 (MVB/NFD)

13.3) Proposed Final Revision 3 to Regulatory Guide 1.160 (JJB/JDS/AS)

13.4) Oconee License Renewal Application (MVB/RLS/NFD)

FRIDAY, MARCH 3, 2000, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

14) 8:30 - 8:35 A.M. Opening Remarks by the ACRS Chairman (Open) (DAP/SD)

15) 8:35 - 10:15 A.M. Phenomena Identification and Ranking Table (PIRT) for High Burnup Fuel (Open) (DAP/MME)

15.1) Remarks by the Subcommittee Chairman

15.2) Briefing by and discussions with representatives of the NRC staff regarding the use of PIRT process for high burnup fuel.

Representatives of the nuclear industry will provide their views, as appropriate.

10:15 - 10:30 A.M. ***BREAK***

16) 10:30 - 11:30 A.M. Proposed Resolution of Generic Safety Issue B-17, "Criteria for Safety Related Operator Actions" (Open) (RLS/PAB)

16.1) Remarks by the Subcommittee Chairman

16.2) Briefing by and discussions with representatives of the NRC staff regarding the proposed resolution of Generic Safety Issue B-17.

Representatives of the nuclear industry will provide their views, as appropriate.

17) 11:30 - 12:00 Noon Report of the Planning and Procedures Subcommittee (Open) (DAP/JTL)
Report of the Planning and Procedures Subcommittee on matters related to the conduct of ACRS business.

12:00 - 1:00 P.M. ***LUNCH***

18) 1:00 - 1:15 P.M. Future ACRS Activities (Open) (DAP/JTL/SD)
Discussion of the recommendations of the Planning and Procedures Subcommittee regarding items proposed for consideration by the full Committee.

19) 1:15 - 1:30 P.M. Reconciliation of ACRS Comments and Recommendations (Open) (DAP, et al./SD, et al.)
Discussion of the responses from the NRC Executive Director for Operations to comments and recommendations included in recent ACRS reports and letters.

20) 1:30 - 2:30 P.M. Break and Preparation of Draft ACRS Reports
Cognizant ACRS members will prepare draft reports for consideration by the full Committee.

21) 2:30 - 7:00 P.M. Discussion of Proposed ACRS Reports (Open)
Discussion of proposed ACRS reports on:

21.1) Oconee License Renewal Application (MVB/RLS/NFD)

21.2) Proposed Resolution of Generic Safety Issue B-17 (RLS/PAB)

21.3) Low-power and Shutdown Operations Risk Insights Report (GA/MTM)

21.4) Proposed Revision of the Commission's Safety Goal Policy Statement for Reactors (TSK/GA/PAB)

21.5) Technical Components Associated with the Revised Reactor Oversight Process/Technical Adequacy of the Current and Proposed Performance Indicators (JJB/MVB/MTM)

21.6) Proposed Final Amendment to 10 CFR 50.72 and 50.73 (MVB/NFD)

21.7) Proposed Final Revision 3 to Regulatory Guide 1.160 (JJB/JDS/AS)

SATURDAY, MARCH 4, 2000, CONFERENCE ROOM 2B3, TWO WHITE FLINT NORTH, ROCKVILLE, MARYLAND

22) 8:30 - 1:30 P.M. Discussion of Proposed ACRS Reports (Open)
(12:00-1:00 P.M. - LUNCH) Continue discussion of proposed ACRS reports listed under Item 21.

23) 1:30 - 2:00 P.M. Miscellaneous (Open) (DAP/JTL)
Discussion of matters related to the conduct of Committee activities and matters and specific issues that were not completed during previous meetings, as time and availability of information permit.

NOTE:

- **Presentation time should not exceed 50 percent of the total time allocated for a specific item. The remaining 50 percent of the time is reserved for discussion.**
- **Number of copies of the presentation materials to be provided to the ACRS - 35.**

ACRS BRIEFING

MAINTENANCE RULE GUIDANCE

March 2, 2000

Contacts:
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ACTIVITY SINCE THE NOVEMBER 4, 1999, ACRS BRIEFING

- November 10 -- Commission briefing
- November 30 -- Provide guidance package to the Commission for information
- January 10 ----- Completed 30-day public comment period on draft guidance

Public Comments:

- Comments received from 7 utilities, one state agency, Winston & Strawn, and NEI

- Specific Comments:

  - Extension of 120-day implementation period
  - (a)(4) interaction with 50.59
  - Minor technical/editorial clarifications

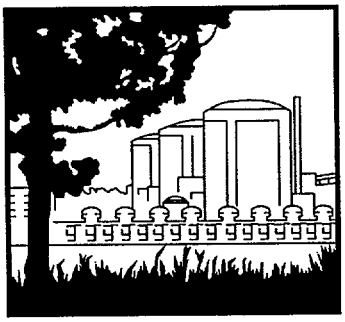
Schedule:

- **03/31 -- Provide final guidance package to Commission for review and approval.**

- **120 days after Commission approval of guidance -- revised 10 CFR 50.65 becomes effective.**

Duke Power
A Duke Energy Company

Oconee License Renewal Project



Meeting with the Advisory Committee on Reactor Safeguards

March 2, 2000

Duke Power
A Duke Energy Company

Topics

- Scoping Methodology
- Insulated Cables & Connections
- Reactor Vessel Internals
- One-time Inspections
- Buried Piping

Duke Power
A Duke Energy Company

Scoping Methodology
SER Open Item 2.1.3.1-1

- License renewal scoping methodology relied on the current licensing basis definition of design basis events for Oconee
- At issue was whether the set of events that are considered by the methodology are sufficient for scoping
- The methodology was validated by a case study of 10 additional events which did not identify any SSCs that were not included in the original scoping results

Duke Power
A Duke Energy Company

Insulated Cables & Connections
SER Open Item 3.9.3-1

- SER OI 3.9.3-1 was initiated following the on-site inspection review of Oconee operating experience
- An Insulated Cables Aging Management Program will be developed and implemented to manage aging effects during the period of extended operation
- The focus of the program is on cables and connectors in adverse, localized environments which include applicable aging effects from thermal, radiation and moisture environments

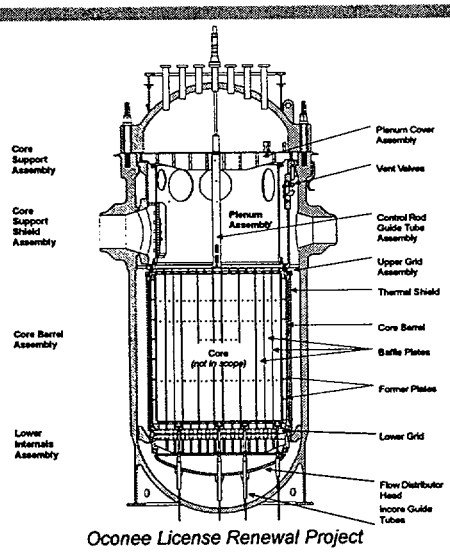
Duke Power SM
A Duke Energy Company

Reactor Vessel Internals Safety Evaluation Report Open Items Resolution

- SER Open Items
  - 3.4.3.2-2 Changes in Dimensions Due to Void Swelling
  - 3.4.3.3-3 Cracking in RV Internals in Non-CASS Internal Components
  - 3.4.3.3-4 Cracking of Baffle Former Bolts
  - 3.4.3.3-5 Embrittlement of CASS RVI Components
  - 3.4.3.3-6 Thermal Embrittlement of Vent Valve
  - 4.2.5.3-1 Reduction in Fracture Toughness (TLAA)

Duke Power SM
A Duke Energy Company

Reactor Vessel Internals Description



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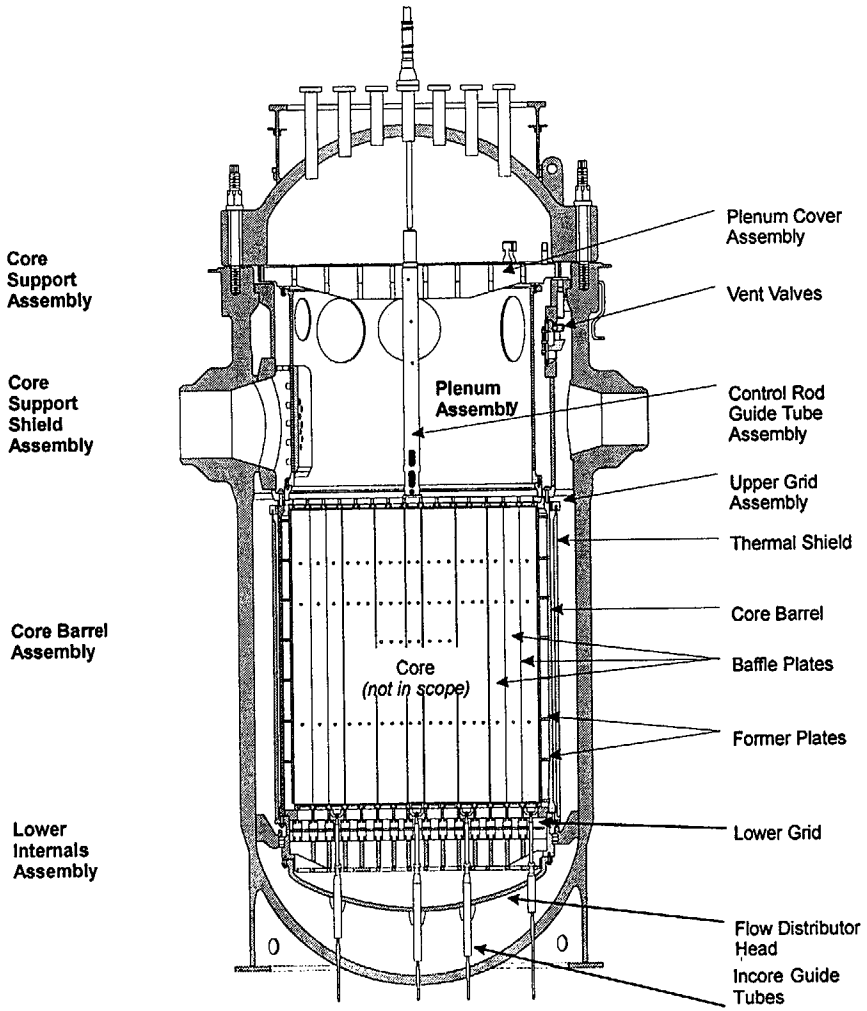
Reactor Vessel Internals Description



Duke Power
A Duke Energy Company

Approach (Process vs Inspections)

- Duke proposed licensing a Reactor Vessel Internals Aging Management Program (process)
  - Included characterization of aging effects, analysis, development of any needed inspections (method, acceptance criteria, frequency, etc. .)
- As a result of staff reviews, an Inspection Program was developed which included:
  - Specific Timing of Inspections
  - Incorporated process within inspection program
  - Industry Participation
  - Reports
- Modifications of the Program will occur over time:
  - As Industry data and analysis are evaluated
  - Plant specific justification would be submitted for review if any inspection was determined not necessary

Duke Power
A Duke Energy Company

Oconee Reactor Vessel Internals Inspection

- The Oconee *Reactor Vessel Internals Inspection* includes the following *three* interrelated inspections:
  - Baffle Bolts

    Aging Effects – The aging effects of concern are (1) cracking due to irradiation assisted stress corrosion cracking, (2) reduction of fracture toughness due irradiation embrittlement, and (3) dimensional changes due to void swelling.
  - CASS

    Aging Effects – The aging effects of concern for the reactor vessel internals items fabricated from CASS and martensitic steel are reduction of fracture toughness by thermal embrittlement and irradiation embrittlement.
  - Other Components

    Aging Effects – The aging effects of concern are (1) cracking due to irradiation assisted stress corrosion cracking, (2) reduction of fracture toughness due irradiation embrittlement, (3) dimensional changes due to void swelling, and (4) loss of bolted closure integrity due to stress relaxation.

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One Time Inspections

- One time inspections are aimed at verifying aging effects are not occurring. Any aging effects identified will require engineering evaluation and could result in further programmatic action.

1. Cast Iron Selective Leaching Inspection
2. Galvanic Susceptibility Inspection
3. Keowee Air and Gas Systems Inspection
4. Steam Generator Upper Lateral Support Inspection
5. Pressurizer Examinations
6. Reactor Building Spray System Inspection
7. Reactor Coolant Pump Motor Oil Collection Tank Inspection
8. Small Bore Piping Inspection
9. Treated Water Systems Stainless Steel Inspection

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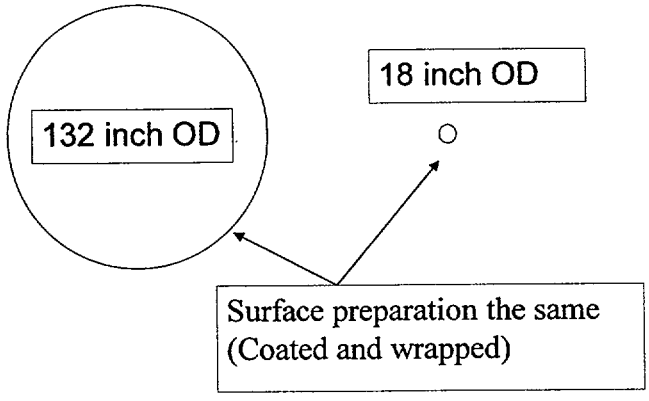
Buried Piping



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Buried Piping

- Aging management by internal surface inspections
- Approximately 460,000 square feet (surface area of 10 football fields) covered by inspections
- Operating experience review identified very limited number of through-wall leaks
- Behavior of Oconee and Keowee buried piping is managed by existing inspections

Oconee Nuclear Station License Renewal Application

Advisory Committee on Reactor Safeguards
March 2, 2000

Oconee License Renewal Application

Agenda

- Resolution of open and confirmatory items
- Reliance on current licensing basis and the regulatory process
- Perspective on one-time inspections
- Acceptability of inspections of buried pipe

Resolution of OIs and CIs

Open Item Number	Description
2.1.3.1-1	Scoping issue
2.2.3-1	Recirculated cooling water system should be within scope
Section 2.2.3.3.2.1	Updated discussion in this section regarding ECCS piping insulation based on Duke letter dated January 7, 2000
2.2.3.4.3.2.1-1	Chilled water system should be within scope
2.2.3.4.3.2.1-2	Sealant materials for the control room pressurization and filtration system
2.2.3.4.8.2.1-1	Portions of the SSF Diesel fuel oil system, starting air system, and jacket water heat exchangers
2.2.3.6.1.2.1-1	Structural sealants – water stops, caulking, expansion joints
2.2.3.6.4.2.1-1	Turbine building and Keowee building roofs
2.2.3.7-1	Fire detection cables
2.2.3.7-2	Active equipment in storage
3.0-1	Content of FSAR Supplement
3.1.1-1	Aging effect inconsistencies in the license renewal application
3.1.3.1.7.4-1	Buried piping
3.2.3.3-1	Appendix B commitment
3.2.12-1	SSF HVAC coolers
3.2.12-2	SSF heat exchangers

Resolution of OIs and CIs

Open Item Number	Description
3.2.13-1	Service water piping corrosion program loss of material
3.2.13-2	Carbon steel inspection "indicator" of the condition of non-carbon steel components
3.2.13-3	Service water piping corrosion program relationship to Keowee
3.2.13-4	UT inspections capability to detect localized degradation
3.3.3.1-1	Tendon anchorages
3.4.3.2-1	Spray head aging effect (CASS item)
3.4.3.2-2	Void swelling (Reactor Vessel Internals)
3.4.3.3-1	Pressurizer heater bundle
3.4.3.3-2	Heater-sleeve-to-heater-bundle diaphragm plate inspection
3.4.3.3-3	Identify limiting Reactor Vessel Internals component items and incorporate into the ISI program
3.4.3.3-4	Baffle former bolts inspection (Reactor Vessel Internals)
3.4.3.3-5	For loss of fracture toughness from synergistic thermal and neutron embrittlement, perform supplemental examinations/evaluations of CASS items (Reactor Vessel Internals)
3.4.3.3-6	Vent valve bodies and retaining rings (CASS items) (Reactor Vessel Internals)
3.4.3.3-7	Evaluate CASS components to criteria in EPRI TR-106092 (RCP Casing)
3.4.3.3-8	Letdown coolers thermal fatigue
3.4.3.3-9	Reactor Vessel monitoring pipes (not part of original SER added to track B&WOG issue)
3.6.1.3.1-1	Aging effects of HVAC sub-component parts of isolators
3.6.2.3.2-1	RCP oil tank inspection plan

Resolution of OIs and CIs

Open Item Number	Description
3.8.3.1-1	Spent fuel pool temperature
3.8.3.1-2	Experience database should consider results of Oconee baseline inspection and instances of reported unusual events
3.8.3.1.9-1	Aging effects for cable trays
3.8.3.2.5-1	Secondary shield wall prestressing tendons
3.9.3-1	Insulated cables and connections (not part of original SER added due to inspection findings)
4.2.1.3-1	Provide discussion of cumulative effects of all possible cycles in the containment fatigue analysis
4.2.2.3-1	Trend lines for containment tendons
4.2.3-1	Provide information regarding the Section XI flaw evaluations for identified locations
4.2.3-2	GSI-190
4.2.5.3-1	Plan to develop data to demonstrate that the Reactor Vessel Internals will meet the deformation limit
4.2.5.3-2	Applicability of flaw growth acceptance in accordance with the ASME B&PV code, Section XI ISI requirements (Reactor Vessel Internals)

SER Confirmatory Items

Confirmatory Item Number	Description
2.2.3.6.9-1	Pipe segments that provide structural support
3.5.3.2-1	Reactor Building spray system inspection
3.6.1.3.2-1	Auxiliary service water system operating experience
3.6.3.3.2-1	Basis for Keowee oil sampling program
4.2.1.3-1	Containment pressure tests
4.2.3-1	Fatigue Management Program analyses commitments

License Renewal Principles

Reliance on Regulatory Process

- The regulatory process is adequate to maintain safety, with the possible exception of the detrimental effects of aging
- The licensing basis must be maintained during the renewal term

Perspectives on one-time inspections

- Oconee LRA contains 9 one-time inspections
- Purpose of the one-time inspections is to verify that aging effects are not occurring such that an aging management program would be required
- Staff finds approach acceptable because, if present, the aging effects are expected to be slow acting and can be resolved by the established corrective action process

Buried Piping

- Aging managed by two preventative maintenance activities
  - Condenser circulating water system internal coating inspection
  - Standby shutdown facility diesel fuel oil tank inspection
- Condenser circulating water system 11-foot diameter pipe accounts for 80 percent of the buried pipe

ACRS PRESENTATION

Revised Reactor Oversight Process

Pilot Program Results and Lessons Learned

William Dean

Alan Madison

Doug Coe

Gareth Parry

March 2, 2000

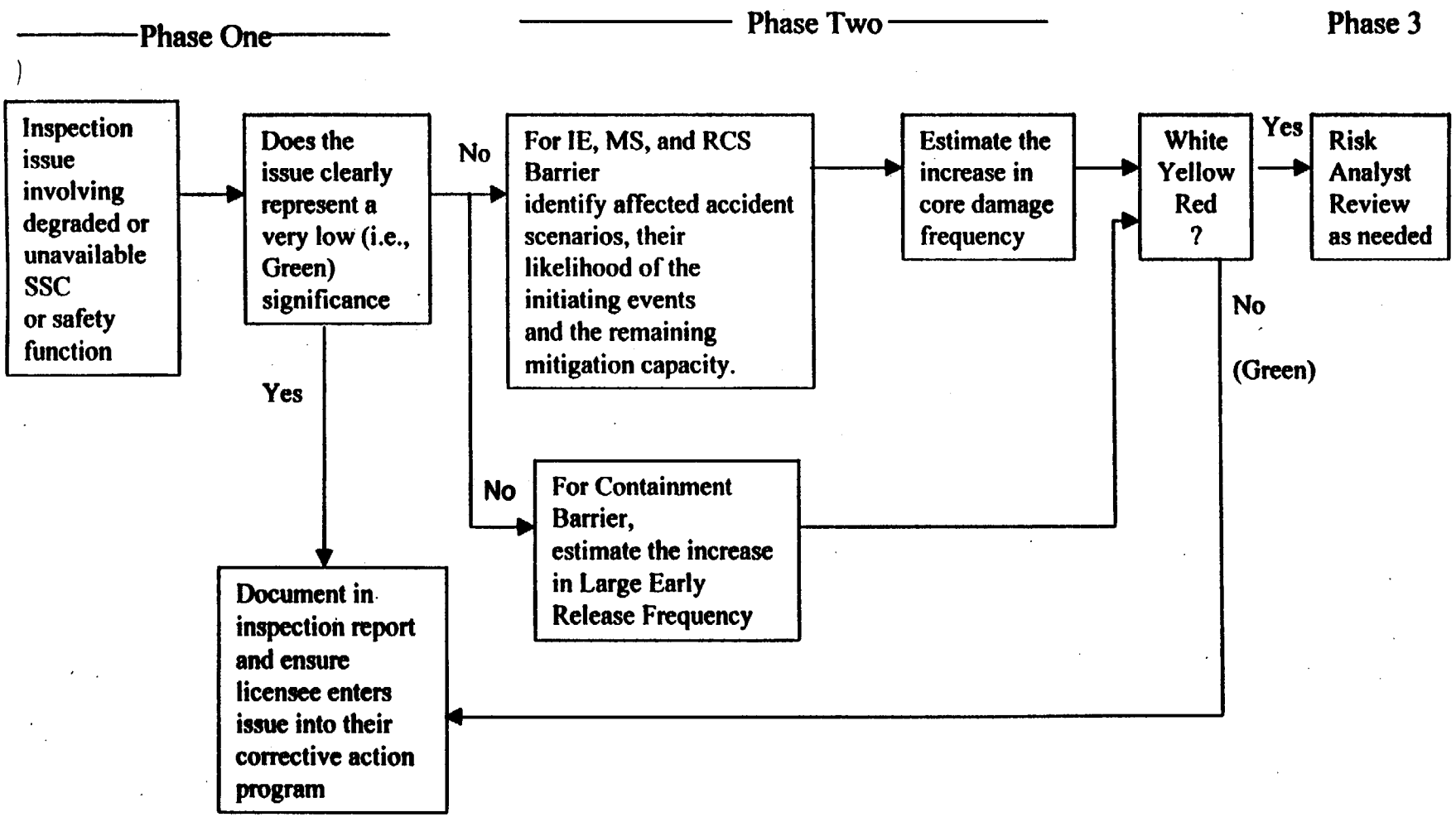
AGENDA

- Introduction
- Significance Determination Process
- Future Initiatives

SDP PRINCIPAL OBJECTIVES

- **Significance Characterization**
  - To characterize the significance of inspection findings arising from deficient licensee performance, where appropriate, using similar risk metrics as those used for PIs
- **Communication**
  - To clearly communicate the staff's bases for its characterization of the significance of deficient licensee performance

Reactor Safety Significance Determination Process (IE, MS, and Barrier)



SDP DEVELOPMENT/REFINEMENT
Plant Specific Reactor SDP

- Plant-specific worksheets are developed from information directly available to the staff (e.g., IPEs)
- Site visits to be conducted with each licensee to obtain comments and any recommended worksheet changes
- Each reactor safety SDP should be tested against the licensee's PRA for general consistency of results

SDP DEVELOPMENT/REFINEMENT
All SDPs

- A feasibility review using actual issues is performed on all SDPs prior to initial implementation

SDP ONGOING WORK

- Site-visits and consistency testing for reactor safety SDP are expected to continue through May 2000
- Containment SDP expected to be developed and ready in April 2000
- Shutdown issues screening tool expected to be developed and ready in April 2000
- External events screening tool development in progress with target date of April 2000

PROPOSED CHANGES TO PERFORMANCE INDICATOR GREEN-WHITE THRESHOLDS

	OLD	NEW
Scrams With Loss of Normal Heat Removal	>4	>2
Unplanned Power Changes	>8	>6
Safety System Unavailability:		
EAC	>3.8%	>2.5%
PWR HPSI	>2.0%	>1.5%
BWR RHR	>2.0%	>1.5%
PWR RHR	>2.0%	>1.5%
Safety System Functional Failures		
BWR	>5	>6
Occupational Exposure Control	>5 in 3yrs	>2 in 1yr
White-yellow threshold	>11 in 3yrs	>5 in 1yr
Security Equipment Performance Index (yellow threshold deleted)	>0.050	>0.080

FUTURE INITIATIVES

- Develop additional Performance Indicators (e.g., containment performance)
- Industry-wide assessment and trend evaluation
- Oversight process self-assessment
- Guidance for annual Agency Action Review Meeting and Commission briefing