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

1:53 p.m.

CHAIRMAN APOSTOLAKIS: Next item, "CRDM Penetration Cracking and Reactor Pressure Vessel Head Degradation." Dr. Ford, please lead us through this discussion.

MEMBER FORD: On April 9, presentations were made to the Materials and Metallurgy and the Plant Operations Subcommittees on the 2001-1 and 2002-1 bulletins relating to cracking of CRDM housings and the degradation of CRDM housings. Obviously there's a tremendous amount of work going on on those two issues by both the industry and the staff. And on April 9, we heard preliminary information especially on that from Davis-Besse related to the root cause and generic implications of the degradation.

Today, we're going to hear an update on these issues, and it's primarily for information. The staff have not requested a letter from us. Future meetings with the subcommittees and the full ACRS are scheduled somewhere in the near future for which there will be a letter, presumably, requested. Jack, you didn't have any comments?

MEMBER SIEBER: No.

MEMBER FORD: I'd like to move on then.

We're going to take it in order, from the industry perspective, given by Larry Mathews, and then we'll move on to the Davis-Besse, and then finishing off with the presentation by the staff. So Larry is the Chairman of the MRP Program and from Southern Nuclear.

MEMBER SIEBER: What's MRP?

MEMBER SHACK: The first test.

CHAIRMAN APOSTOLAKIS: What's MRP?

MEMBER FORD: Materials Reliability Program, sponsored by EPRI.

MR. MATHEWS: Like Dr. Ford said, I'm Chairman -- is this on? I'm Chairman of the Alloy 600 Issues Task Group of the Materials and Reliability Program. I work for Southern Nuclear, in case you care, or at least they pay me. I don't do much for them.

(Laughter.)

MEMBER POWERS: An extraordinarily honest man here.

MR. MATHEWS: Not to imply I don't work. I just don't --

(Laughter.)

These are kind of four topics I'd like to run through fairly quickly here today and provide a summary on: The Alloy 600 82/182 strategic plan that we have developed, an update on where we stand on crack growth rate issues, some brief words on the risk assessment and the probablistic fracture mechanics that we're doing for the reactor vessel head penetrations and then, basically, how we are responding to the Davis-Besse issue at this point.

This is basically an outline of the strategic plan that the MRP has put together to address the Alloy 600 and the 81/182 issues. The plan has a problem staying on the goal and mission of trying to manage the issue, how we're going to go about it, what the roles of our various stakeholders are. And then we have a strategy right now, which are the five areas you see here.

Basically, on the -- are you looking for this presentation?

PARTICIPANT: Huh?

MR. MATHEWS: Are you looking for the presentation?

PARTICIPANT: No, no, no.

MR. MATHEWS: Oh, okay, okay. On the butt welds, the basically strategy we've laid out is we're going to rely primarily on the ASME Section 11, the guidance for inspections and the frequency, but we're driving and we're trying to drive improvements into technology for doing those inspections. And, primarily, Appendix 8 has to be implemented by next fall, and at that point, all the inspections will be done by qualified inspectors.

One of the things we will have to be looking at potentially in more detail is the frequency, is it appropriate, et cetera? But that's where we are right now is we believe Section 11, coupled with Appendix 8, will be the appropriate way to do it. There is a potential issue with the pass rates and the qualifications of the inspectors, and we're trying to address that right now.

There's other areas up here, excuse me. The head penetrations in the near term, we put finalizing a safety assessment, but the real thing we're doing here is putting together mockups to drive the technology for doing volumetric inspections and to demonstrate those inspections. We're having mockups built that will be used in blind tests this summer for vendors that will be qualifying to do volumetric or under-the-head inspections next fall. There's also a mockup that was built that was available for people to use early and then another one for the spring outages.

In the area of the longer term, what we're doing to do is get out inspection guidelines on what people ought to be doing, as far as inspecting their head penetrations. And then we want to work with the NRC and ASME to make sure this is, you know, all in conjunction with what's the right thing to do as far as inspecting the heads.

All the other locations, we're working with the owners' groups to see what's already been done. We don't want to duplicate anything for all the other Alloy 600 locations. And where there are holes in what they've accomplished, we know they've done a lot of work, where there's holes in what they've accomplished, we'll work with those owners' groups and vendors to figure out where's the right place to develop those guidelines and get those programs underway.

And, ultimately, the goal is to get out a management guideline for all the locations that would either provide information on how to manage it for your plant or direct you to where it would be available.

One of the first things we want to work on is the inspection plant. We have draft inspection plant out now. This is something we need to get with the staff and make sure we're all in agreement on what's the right thing to do in the inspection. But it basically marches toward -- as the plant gets older and it has more time at temperature on the vessel head, the inspection should become more rigorous, if you will, going from a visual to ultimately, potentially all the way down to you must do a volumetric on some frequency. We haven't finalized that. That's in the final stages at this point.

In the area of crack growth rate for Alloy 600, what we're trying to do is figure out what's the right crack growth rate people ought to be using when they're trying to do evaluations of cracks in the Alloy 600, initially looking at the base metal. We've created an expert panel. That expert panel has met several times, and they've screened databases available in the world. They're trying to refine their approach. It's been consolidated, but apparently, recently, we were very close to publishing the report, but then one of the labs said, "Well, we want to take another look at our own data."

And then while that's going on, Davis-Besse occurs, and so especially with respect to what the annulus environment might be and the impact of the annulus environment, the experts said, "Well, we know what we said," and I'll tell you what that was in a second, "but before we publish we want to take another look at that and make sure we still believe it." And so they're meeting next week. It's a sid bar meeting to a meeting going on in France to look at that issue.

CHAIRMAN APOSTOLAKIS: So when you say "curve," what are the axes? I mean one must be the growth rate.

MR. MATHEWS: Growth rate and stress intensity factor.

CHAIRMAN APOSTOLAKIS: Stress intensity. Now, isn't there any uncertainty in those curves? I mean are you displaying --

MR. MATHEWS: Oh, yes, quite a bit.

CHAIRMAN APOSTOLAKIS: And you are displaying it?

MR. MATHEWS: Pardon?

CHAIRMAN APOSTOLAKIS: You are displaying it or are you just showing one curve?

MR. MATHEWS: What we're proposing is a couple of different approaches.

MEMBER FORD: Well, before you -- are you going to continue answering that specific question?

MR. MATHEWS: Yes. Go ahead. What were you going to say?

MEMBER FORD: Well, answer that question, because I want to come back to that.

MR. MATHEWS: Okay. What we've done is we've taken the whole database and we've come up with a curve that we feel can be used for the deterministic evaluation of the crack growth rate for real flaws. And, basically, any flaws that you're trying to evaluate to leave in surface, the main ones that have been evaluated are flaws that are either ID axial flaws or if they are on the OD, they're below the weld. Anything above the weld it has to be a leakage path, and we can't leave that in service, so we wouldn't be evaluating real flaws above the weld.

We do want to evaluate hypothetical flaws, for instance, all in the circ direction to determine if it flows into the safety, how long have we got and that sort of thing. And so above-the-weld flaws they've recommended a factor of two to account for the chemistry in the environment, but that's one of the things that the guys are going to take a look at next week in France, will make sure that Davis-Besse doesn't really throw a monkey wrench in.

CHAIRMAN APOSTOLAKIS: But are on the issue of uncertainty now? You said it can be used for deterministic evaluation.

MR. MATHEWS: Right. And the curve that we're proposing is for deterministic evaluation is like the one that would fit the 75th percentile of all the heats and material in the database.

CHAIRMAN APOSTOLAKIS: Oh. So you're -- oh.

MEMBER FORD: I think this is an ongoing argument within the industry for quite some time, and you've got a big scattered database, experimental. How much of that scatter is due to experimental control? Is much of it due to heat variations, for instance, in the materials in that database? And we have requested that at the next meeting that that database will be shown to the committees and how that has been analyzed. So that will directly answer your question.

CHAIRMAN APOSTOLAKIS: Because it would seem to me to be an ideal place for a family of curves, would it not?

MEMBER FORD: For a --

CHAIRMAN APOSTOLAKIS: A family of curves rather than one curve.

MEMBER SHACK: People recognize there is a distribution. Just for deterministic evaluation you'd like to have --

MR. MATHEWS: No, but if you knew exactly -- if you knew exactly.

CHAIRMAN APOSTOLAKIS: No. CGR data for base material feeds directly into the PRA.

MR. MATHEWS: Well, that's not how we feed it into the probablistic approach, though. Instead of feeding it into the probablistic approach as a single curve, we put the whole database and all the scatter of the database to be sampled in the probablistic approach. The whole scatter for the whole database is put into the probablistic analysis.

CHAIRMAN APOSTOLAKIS: I'd like to see that.

MEMBER FORD: That is one of the things we've been asking that we do all see the database so we can understand the reasoning behind these words.

MR. MATHEWS: Yes. And some of the staff is saying but we haven't shown them the ACRS. And part of the reason is it's in a state of flux right now.

CHAIRMAN APOSTOLAKIS: So you're going to do this in a subcommittee meeting?

MEMBER FORD: We'll do it in the subcommittee and present it at the full committee, yes.

MR. MATHEWS: And hopefully we can do that at the next meeting.

MEMBER FORD: Correct.

MR. MATHEWS: I think we'll be much closer and we can do that.

MEMBER FORD: Could you go back to your previous page?

MR. MATHEWS: Sure.

MEMBER FORD: The implications of the Davis-Besse, your last bullet, is that in terms of the question as to what the environment is in the circumferential annulus?

MR. MATHEWS: Yes. That's what -- I believe that's what the experts would want to take a look at. They had made some assumptions, some MULTEQ calculations and some other discussions amongst the experts about what are the possible environments that could be in there in the annulus region, and then what effect would that have on the crack growth rate? And they came up with what they felt was a conservative multiplier, a factor of two.

Given the situation at Davis-Besse, thought, they said, "Well, I don't know that it's going to change, but let's take a look at it and see if there's anything coming out of the Davis-Besse situation that would say that environment that we predicted is inappropriate to use for a circumferential crack growth.

MEMBER FORD: And, again, that information will be discussed, presumably, at the next meeting, this specific information.

MR. MATHEWS: We hope to have our report published well in advance of that meeting, and we can come talk about it.

CHAIRMAN APOSTOLAKIS: Next meeting.

MEMBER FORD: Well, in the near future, maybe one, two months time.

CHAIRMAN APOSTOLAKIS: Subcommittee meeting.

MEMBER FORD: Correct.

MR. MATHEWS: Also, the expert panel they met very recently to look at the weld metal Alloy 82/182 and what we know about the crack growth rates in the weld metal. And they will be coming back to the MRP with recommendations on where there's holes in that database, and there are likely to be some because it's a limited database and where testing may be needed.

There's also a research effort that's being undertaken right now by EPRI, and it's a DOE part of the NEPO Program to look at some crack growth rates in weld metal. And there may be some additional base metal crack growth rate in there, I'm not sure. And we will certainly be willing to continue to update you as we get more data, maybe provide you some.

In the area of the risk assessment work, the approach is to predict the probability of leakage based on the industry experience and where we've seen links and modeling that in a Weibull model, Weibull statistics model. Then compute, after a leak develops, the probability of a nozzle ejection, looking at or considering the initiation and growth of a circumferential flaw above the J-groove weld. We can factor into that inspection and the probability that a leak might be detected prior to growing to an ejection situation.

CHAIRMAN APOSTOLAKIS: How would you do that?

MR. MATHEWS: I left that slide out. What you do is as the model progresses through the time, it's a statistical model but it progresses through time, and at given points in there, depending on the inspection frequency that you put in, you can put in a probability of detection. And if you -- and you do a sample on that. And if you find the probability that it is detected on that particular sample, you take it out of the database for an ejection.

And if you don't, it goes on down to maybe the next level of inspection or the next whatever. You just the run the statistics, and if you put a probability of detection of 80 or 90 percent in there and you're doing inspection at a certain point in time, then 80 or 90 percent of any flaws that might be in existence there would be taken out of the database or if they're not --

CHAIRMAN APOSTOLAKIS: Would that be consistent with the Davis-Besse experience? An 80, 90 percent probability of detecting?

MR. MATHEWS: Today, I would say, yes, probably. I'm not sure what the POD, probability of detection, that we're going to put in there. That's just the way it's modeled, and we'll have to decide. We haven't settled down on exactly what kinds of inspections or when they would be into the model to figure out the risk. But, you know, before Oconee the world was different than it was after Oconee, so people look at things a whole lot different.

CHAIRMAN APOSTOLAKIS: See, what worries me is that I don't know how many times the world is going to change.

MR. MATHEWS: Oh, yes. I know what you mean.

CHAIRMAN APOSTOLAKIS: I mean it shouldn't. It should change any more for the current generation reactors. That's my problem.

MR. MATHEWS: Knowledge isn't perfect, I must admit.

CHAIRMAN APOSTOLAKIS: Boy, you can say that again.

MR. MATHEWS: Yes. Anything else? Finally, what we do is we grow the flaw to the critical flaw size on a statistical basis from Monte Carlo sampling, and some of them grow to critical flaw and some of them don't. And then they take the fractions that do and that's the probability there.

Couple that with the probability of a conditional -- I'm sorry -- yes, with the conditional core damage probability from a small break or medium break LOCA, and you have the core damage frequency. What we're going to do is assess the potential impact on the conditional core damage probability of the collateral damage. We think it's going to be minimal that might occur from an ejection.

CHAIRMAN APOSTOLAKIS: Is it clear to everyone why nozzle ejection is the issue here?

MEMBER SHACK: That's what causes your medium-break LOCA.

MR. MATHEWS: Yes.

CHAIRMAN APOSTOLAKIS: Oh, that's --

MR. MATHEWS: In almost all -- you know, if you look at all the times that plants run most of the time, almost all the time these plants are up at power and all the control rods are essentially all the way out.

CHAIRMAN APOSTOLAKIS: So what's the equivalent diameter?

MR. MATHEWS: The inside of a nozzle is about two and five-eighths inches, I believe.

MEMBER SHACK: But when the whole thing comes out, it's like four inches.

MR. MATHEWS: Yes.

CHAIRMAN APOSTOLAKIS: Oh, okay. So then it's --

MR. MATHEWS: Well, you've still got to get through the part that's left. If you have a circ flaw above the well, then you've got a segment that's left from the well down that's not ejected and the inside diameter of that is two and something inches, and if it's a control rod location, it will still have a shaft in it unless that gets pulled on out too.

CHAIRMAN APOSTOLAKIS: How will you go to the condition core damage probability? I mean you would just consider the new probability of a medium LOCA? The probability of nozzle ejection would be --

MR. MATHEWS: Well, the CCDP is the conditional core damage probability.

CHAIRMAN APOSTOLAKIS: Right.

MR. MATHEWS: Given that you have a medium-break LOCA, the plant risk assessments already have looked at what is the probability that you have core damage, given that you have a medium-break LOCA. And that goes through all the possible failures of your ECCS systems and all of that.

CHAIRMAN APOSTOLAKIS: Would you consider dependencies between the initiating event and some of the other events?

MR. MATHEWS: Yes.

CHAIRMAN APOSTOLAKIS: In particular SCRAM? Would SCRAM be affected?

MR. MATHEWS: Yes. And that's what we would look at as would there be collateral damage from the ejection of a control rod nozzle that could make that conditional core damage probability of a medium-break LOCA higher than if it was on a pipe somewhere. We'll look at that, and if it would make that conditional core damage probability, given the LOCA here as opposed to on a pipe higher, then that effect would be factored into the risk assessment. We think that effect's going to be minimal and we've gotten some preliminary work from the vendor, but we need to finalize that.

CHAIRMAN APOSTOLAKIS: So you are also looking at small-break LOCA, I see. All right.

MR. MATHEWS: From a risk standpoint, yes. We're not doing a deterministic blowdown of a small-break LOCA type thing, it's more of a risk analysis.

CHAIRMAN APOSTOLAKIS: Okay. You're going to have to have experts again telling you what's going to happen if you have a nozzle ejection.

MR. MATHEWS: Yes. And the vendors know --

CHAIRMAN APOSTOLAKIS: And how it will affect the SCRAM system.

MR. MATHEWS: -- what's up there, and we're asking them to provide us input on that, and they've given us some preliminary stuff, and we need to follow-up on that and figure out how to factor that input back into the risk assessment.

CHAIRMAN APOSTOLAKIS: So when will this be done?

MR. MATHEWS: We were hoping to be through this month, but everything's kind of taken a --

everybody's busy on Davis-Besse issues right now.

CHAIRMAN APOSTOLAKIS: Okay.

MR. MATHEWS: Some of the key elements of the probablistic fracture mechanics analysis, which is the major part of the risk assessment, is the simulation of the leakage as a function of time and a Monte Carlo model. That's based on our time and temperature model using the fracture for the stress intensity factors, for the various types of flaws that would be in there as the flaws grow. The entire database for the structure crack growth rate database and the statistics, all of those statistics would be fed into for the sampling and then the effects of the inspection and the inspection reliability.

We have some very preliminary results for a tight temperature plant, and I do stress preliminary. First cut thereafter after you've an inspection, the probability of nozzle ejection within the first or so is less than times ten to the minus three after you've done inspection. And then the conditional core damage probability, the worst one we could find on the high temperature plants was five times ten to the minute three. Multiplying those two together you get a core damage frequency in the range of five times ten to the minus six.

CHAIRMAN APOSTOLAKIS: What is the main reason why the probabilities are so low?

MR. MATHEWS: The main reason the probability of an ejection is so low after you've done an inspection is that you've found your leaks and repaired them. But in a few cases, when you do the statistical Monte Carlo approach, you can have some very high crack growth rates on some of this sampling. And those that grow very, very rapidly a few of them may grow all the way to the ejection in the sampling process, but it's a very, very few of them within one cycle or before you come back to do another inspection.

CHAIRMAN APOSTOLAKIS: So you're assuming that when the size reaches a certain level, then there's a very high probability that they will be caught by inspection and somebody will act on it.

MR. MATHEWS: Yes. Given today's environment and what everybody knows about what they need to be looking for, yes.

CHAIRMAN APOSTOLAKIS: Today's environment meaning?

MR. MATHEWS: After Oconee. I mean Oconee showed that you could have a leaking penetration that didn't have a lot of boric acid coming out down the side of your vessel. And so now people are keyed into you have to look for popcorn instead of big piles.

CHAIRMAN APOSTOLAKIS: And CCDP, why is it so low?

MR. MATHEWS: Because a small-break LOCA or --

CHAIRMAN APOSTOLAKIS: No, a medium LOCA.

MR. MATHEWS: Okay. I'm not sure of the exact square inches on the small and medium LOCA, but we have lots of safety systems that are designed to handle the LOCA and to keep the core from being damaged. And the way you get damaged typically on a risk assessment analysis on the LOCAs is something fails, and there's probability and statistics put in on a failure probabilities of your various safety systems, and as you do that sampling on all the systems and their probabilities, it comes out with a fairly low probability for that size break that you're going to have core damage.

CHAIRMAN APOSTOLAKIS: But how much credit are you taking for scrap?

MR. MATHEWS: I'd have to go look at the PRAs. I'm not sure if we -- I know in the design basis axis on LOCAs I'm not sure we take any credit for SCRAM.

CHAIRMAN APOSTOLAKIS: You're not sure of what?

MR. MATHEWS: I'm not sure they take any credit on the design basis analysis, but on the risk assessment I think we do take credit for SCRAM.

CHAIRMAN APOSTOLAKIS: The question is how much because I don't know that we really know what's going to happen if you have a medium-break LOCA at that location.

MR. MATHEWS: Well, that's what we're counting on the collateral damage assessment to tell us: Does it have an impact on the conditional core damage probability?

CHAIRMAN APOSTOLAKIS: Oh, so the collateral damage is not part of these numbers?

MR. MATHEWS: Right. But like I say, the conditional assessment we have from the vendors is that it will have very minimal impact, if any, on the conditional core damage probability. A break at the top of the vessel is better than one that's at the bottom, and the CCDP is for all breaks. But --

MEMBER ROSEN: A break at the top of the vessel is better than one at the bottom but not for an event when you want the control rods drives to operate.

CHAIRMAN APOSTOLAKIS: That's right.

MEMBER ROSEN: Because the control rod drives on a PWR are at the top.

CHAIRMAN APOSTOLAKIS: They're at the top.

MR. MATHEWS: That's right. And that's what we have to see and have to assess in this collateral damage is is there something that could happen that would prevent a SCRAM or a significant portion of the rods from not going in? Severing the cables is great.

MEMBER SIEBER: It's designed to have one rod stuck up.

MR. MATHEWS: At least one.

MEMBER SIEBER: And still get enough reactivity.

MEMBER ROSEN: From a reactivity standpoint.

MEMBER SIEBER: But if you damage the adjacent rods somehow so that they don't, then the probability of core damage goes up.

CHAIRMAN APOSTOLAKIS: That's exactly what we're exploring here.

MEMBER SIEBER: Wiping out 60 of them, I think, is pretty improbable.

MEMBER ROSEN: What we're worried about is the steam environment, the jet environment and all of that that will be up there in very aggressive to the operation of the drives and the rest of the equipment up there.

MR. MATHEWS: Well, most anything that's going to -- the real concern, if there is one, from a collateral damage, is if you could something that would prevent the rods from moving physically.

MEMBER ROSEN: That's right.

MR. MATHEWS: Severing the cables, no problem, they're going in. It's the --

CHAIRMAN APOSTOLAKIS: Physical, yes.

MR. MATHEWS: If you bend the tube or something like that, that's the condition --

MEMBER ROSEN: If you have a plate right above this, you know, above the point where you have the break, and you create a high pressure environment between the plate and the top of the head and what if that plate cocks or something like that? I mean you can imagine --

MR. MATHEWS: The insulation plate.

MEMBER ROSEN: Yes.

MR. MATHEWS: Yes. Those are pretty low.

MEMBER SIEBER: But what's the point if it does?

MR. MATHEWS: And that's what -- we have to look at the --

MEMBER SHACK: We're not done.

MR. MATHEWS: We're not done yet, but, you know, I think I heard yesterday and it's, at least to my way of thinking about it, the first thing that's going to happen is the voids are going to shut the reactor down.

CHAIRMAN APOSTOLAKIS: The point is that the five ten to the minus six number does not include considerations of this type.

MR. MATHEWS: Right.

CHAIRMAN APOSTOLAKIS: Okay.

MR. MATHEWS: It includes an initial estimate that it's going to be a very minimal impact on that number, but we still have to go back and tie all that together. We're not through yet.

MEMBER FORD: The first time that such an analysis was given, to the staff that is, was during the Duke presentations relating to Oconee, and my question now is have there been any subsequent discussions between you and the staff on this whole approach?

MR. MATHEWS: We've had some fairly detailed meetings with the staff on how we are modeling primarily the probablistic fractured mechanics part. We haven't really gone in in much detail on the rest of the risk assessment. I think we've laid this level of detail out and discussed it with the staff. But on the probablistic fracture mechanics and how we're modeling the crack and the crack growth rate, we've met with Ed Hackett and the research folks and their contractors and had a couple of rounds of questions about how we're doing it versus how they're doing it and trying to reach resolution on some of those issues.

MEMBER POWERS: Suppose that after all that they said, "Gee, you're just doing great. The crack growth rates are great, everything's great." How do you know the results are right?

MR. MATHEWS: Well, from the probability of leakage is -- well, it's based on the experience in the field, and we continue to get experience in the field, and that is adjustable to match the experience in the field. We're trying to be somewhat conservative in this, and although it is a statistical approach --

MEMBER POWERS: How do you know you're being conservative?

MR. MATHEWS: There are a number of

details of how we're modeling the probability fracture mechanics work that are -- like immediately upon a crack going to a leak, we assume that it's instantly like -- I think it's 20 or 30 degrees around branch of the flaw, and it's going to take some time to initiate a circumferential flaw, but we assume it happens instantly. That's one thing.

CHAIRMAN APOSTOLAKIS: Would assuming the presence of the degradation around this nozzle, similar to that of Davis-Besse, be a conservative thing to do and what numbers would you get?

MR. MATHEWS: It might be a conservative thing to do, and we could model it. And I guess the next slide is --

CHAIRMAN APOSTOLAKIS: You don't know what number you're going to get, though, do you? Because it's not just the normal rejection.

MR. MATHEWS: No, I don't know.

CHAIRMAN APOSTOLAKIS: You may have additional failures.

MR. MATHEWS: There is the potential there that if you got a nozzle that was in a situation like Davis-Besse where there is a wastage cavity next to it, if the cavity comes all the way around so that you lose a back wall on the opposite side from where the cert flaw is growing, it might have an impact on how fast the crack grows. And we can model that and do some studies on that, and we probably will do that, where we remove the nozzle, the constraint from the nozzle on the opposite side from the cert flaw.

CHAIRMAN APOSTOLAKIS: Well, that would be an interesting case to see, a sensitivity case.

MR. MATHEWS: Yes. And it's not that hard to do. There's gap elements on that side of the nozzle that we just set them to a gap instead of an interference and then see what happens to the nozzle leaning over as a function of the crack growing. Really, the way we've modeled it, it would only have impact after the flaw hits 180 degrees in through wall. If it's part through wall, we don't even model that restraint; that's ignored. So, basically, we're modeling it without that restraint already.

CHAIRMAN APOSTOLAKIS: So if you were doing this analysis before Oconee, what number would you get? You said earlier, "in today's environment." So in yesterday's environment, what number would you get, five ten to the minus nine or five ten to the minus --

MR. MATHEWS: Well, we probably would have, yes.

CHAIRMAN APOSTOLAKIS: Huh?

MR. MATHEWS: Yes. It probably would have been in that --

CHAIRMAN APOSTOLAKIS: So all Oconee did was raise the number from ten to the minus nine to ten to the minus six? No? What? That's what they said.

MR. MATHEWS: I didn't do it before Oconee, so I don't know what the number would have been if we hadn't -- where it comes in is the probability of the ejection.

CHAIRMAN APOSTOLAKIS: Yes.

MR. MATHEWS: Which starts from the probability of a leak. We would have thought that prior to Oconee in those flaws that have been recently discovered, we would have felt that the probability of developing a leaking penetration on a USPW head was lower than it really was.

MEMBER FORD: I think the answer to both your questions, to a certain extent, is, again, I don't think you can -- the proof of the pudding, of course, is observation versus theory, and we haven't had any raw dejections, thank goodness. But you can do it what's the probability of a number of through wall -- through circumferential wall cracks that have been observed. And that's essentially the approach that Oconee did, or Duke did for Oconee, to compare these predictions against the number of circumferential cracks that they saw. Now, admittedly, it's not going the whole way, you're absolutely correct, but it is going -- they're doing a check of observation versus theory.

MEMBER POWERS: What I guess -- I mean you've certainly interpreted my question correctly, and what I'm really struggling to find we apply this probablistic fracture mechanics in a lot of regimes now. This seems to be the first one where we don't get answers like ten to the minus 45, which I thought was a constant --

(Laughter.)

-- in probablistic fracture mechanics. But I never -- I mean I'm sufficiently unfamiliar with the technology that no one ever shows me that it actually gives you good answers for any circumstance that isn't fairly well-contrived laboratory circumstance. And so I'm wondering as the geometry has become more complicated, and here they're about as complicated as comes quickly to mind, do we really have data for any circumstances, I mean it doesn't have to be a reactor vessel, but how about an internally pressurized vessel of some sort where we can show that indeed the probablistic fracture mechanics has got all the physics in it so that if we do what the speaker has said, we parameterize the model conservatively, we should get a conservative answer?

MEMBER FORD: Do you want to answer that?

MR. MATHEWS: I'm not a probablistic fracture mechanics guy.

MEMBER POWERS: Well, that speaks well of you.

(Laughter.)

MEMBER FORD: I don't know -- quickly, off the top of my head, I don't know --

CHAIRMAN APOSTOLAKIS: Are there any cases where probablistic fracture mechanics gave probabilities on the order of 0.2, 0.3 value? Or is it an inherent thing of the methodology?

MEMBER POWERS: Ten to the minus 45 is a really common number, I know that.

MEMBER SHACK: Just to come back, George, you know, one of the things one observes is the way things depend on diameters, your famous Thomas correlation that you PRA guys love, you know, that comes out of the fracture mechanics. The low probabilities, of course, are for a large diameter pipe where, again, for the crack to grow all the way around the pipe, you have to grow a crack that's many, many inches long. So, obviously, that's going to take a lot longer than it does to, say, grow a crack around a four-inch pipe. I mean the physical -- you still have to grow 330 degrees, it's just the 330 degrees on a four-inch pipe is a whole lot less metal than 330 degrees on a 24-inch pipe.

Now, it's very difficult, of course, to get one-to-one comparisons, because we just don't have a whole lot of data, but when you go back to the database, you get probabilities of failure that aren't all that -- you know, they're in the ballpark of what you're computing for your probablistic fracture mechanics; it's not a one to one.

We have experimental confirmation of the ingredients; that is, you know, crack growth rate is measured independently. It's not in a probablistic fracture mechanics test. The biggest thing that you have are the loads on the pipe where we know the pressure loads very well. PR over T really work. The residual stresses you can measure independently. So you can measure those independent ingredients, and then --

MEMBER POWERS: But I never see anybody

put the whole thing together and say, "Okay. Here are a bunch of data on this thing, and this thing works."

MEMBER SHACK: When you come out with the probability of large diameter pipe failure of ten to the minus nine, you're not going to find data.

MEMBER POWERS: Well, give me a small diameter pipe.

MR. HACKETT: If I could add, this is Ed Hackett from the staff, we briefed the Committee, I guess, numerous times now on the pressurized thermal shock reevaluation program. I think that's where the staff and the industry have done the best job of applying this type of methodology. And in fact that has been benchmarked to international reference experiments, and in several cases has done quite well.

In think in the case of Professor Apostolakis' comment, I'm not aware of any that have come up that high. We see these failures for vessels, and, again, thankfully, as Dr. Ford was mentioning, are in the range of E minus six or less when we're looking at reactor pressure vessels, different application than what Larry's talking about here specifically.

MEMBER SHACK: But even there, Ed, when you benchmark that, you benchmark the fracture mechanics, "Yes, I failed a vessel with a crack so big."

MR. HACKETT: That's correct.

MEMBER SHACK: Just to say that the probability of the vessel failure is ten to the minus eight, you're not going to get a whole lot of statistics to --

MR. STROSNIDER: This is Jack Strosnider. I'd like to make a few comments on this too and maybe to defend the credibility of probablistic fracture mechanics somewhat. First of all, I think, you know, when you talk about benchmarking this, as Ed pointed out, thankfully we don't have an empirical database on pressure vessel failures or CD control rod drive mechanism failures, for that matter. So it is rather difficult to get that sort of benchmarking.

However, I think when you look at the probablistic fracture mechanics, you can get results that are reasonable depending upon the conditions that are being considered. And I think the ten to the minus 42nd number that was brought up a couple times, I think you're referring back to some of the PWR work on vessel inspection. And in fact that number, it turned out, was the number that was generated when you assumed design basis conditions were satisfied. In fact, when you go through the full risk assessment that was done and what we ultimately ended up with, we came up with more like ten to the minus six to the ten to the minus seven numbers when we took into account beyond design basis events. The conditional -- or the vessel failure probability, given those events, was somewhat higher. It certainly wasn't those low numbers.

But the other comment I'd make is that the analysis, methodology exists. We know how to put models together, we know how to identify random variables, we know how to model those, how to do Monte Carlo simulations. There's some challenges looking at dependence between the variables. But the biggest challenge, and frankly I would say this is true in all our PRA modeling, is coming up with the distributions that represent those random variables.

For example, in this case, where one of the first things you had to look at was the initiating frequency, when does a crack initiate one of these? There's very little data available until we started getting results from the inspections that were done and could try to construct a distribution. So the biggest challenge that we have when we go into this sort of analysis is being able to define those random variables, the distributions for them, with some level of confidence. And usually you have to go out and do some work, inspections or whatever to get the information to do that.

CHAIRMAN APOSTOLAKIS: But speaking of that, though --

MEMBER POWERS: Jack, you make huge amounts of -- when you do these probablistic fracture mechanics analysis, you're making huge simplifications in the way you describe the metal and the way you describe the crack, things like that. And I guess what I'm struggling with is how do you know you got them all. All the physics and all these approximations really are good ones to make. I mean some of your approximations are made because you know how to solve the mathematics.

MR. STROSNIDER: Well, again, I would come back to if you look at all these models have an underlying deterministic model associated with them. If you look at the ability to predict crack growth rates as a function of stress intensity values, if you look at the ability to predict failure using either limit load or linear elastic correction mechanics, they work pretty well if you have a really well-controlled situation. And it comes back again to defining the distributions that are associated with those in real life. And I agree, that's a challenge.

MEMBER POWERS: Well, every time I look for things that you predict well, you predict well those things that have been used to derive the physics, you know, nice, simple specimens, simple geometries. Now, you're applying them in really complicated geometries. There doesn't seem to be any database that I'm aware of, and I can't say that I've looked exhaustively, that says, okay, I've done my laboratory specimens, now I'm going to do this complicated thing that I don't understand very well and see if I can get it about right. Is there such a database?

MR. HACKETT: I guess the one -- this is Ed Hackett again -- I guess the one I could point out, Dr. Powers, is the one -- it's a complicated acronym. They called it fracture assessment of large-scale international reference experiments; it's the FALSIRE project. And then there have been follow-on series, and this is an international collaborative effort, where they have gone from the small specimen geometries where things are nice and fairly simple to predict, to trying to predict what actually happens in a vessel. The Germans have blown up scale model vessels, we have at Oak Ridge.

MEMBER POWERS: Yes. Now you're hitting exactly what I want to see.

MR. HACKETT: And we have in fact --

MEMBER SHACK: Plus an enormous number of pipes at Battelle.

MR. HACKETT: Absolutely. The most recent one, thinking of the follow-on activity, the NESC 1 spinning cylinder experiment in the United Kingdom. In fact, the folks at Oak Ridge, using their probablistic model, the FAVOR code, which is what we're using in the PTS Program right now, predicted the propagation of an embedded flaw in that vessel almost dead on in terms of initiation and arrest.

CHAIRMAN APOSTOLAKIS: Don't take the viewgraph down.

MEMBER POWERS: But if somebody can point that out -- point it out to me or come present it or something like that, it adds a lot more credibility to some of these categories.

MR. HACKETT: Probably in the context of the PTS project we'll do that.

MEMBER POWERS: That would be great. You know, if we could take a half an hour and just go through that, that would be great.

MEMBER FORD: Could I suggest, Larry, that -- this will be --

CHAIRMAN APOSTOLAKIS: What does it mean the probability is less than ten to the minus three? Have you done an uncertainty analysis? How uncertain is that? How high can the ten to the minus three be?

MR. MATHEWS: I don't have that right now.

CHAIRMAN APOSTOLAKIS: But you will?

MR. MATHEWS: I'm not sure we were going to do a full-blown uncertainty analysis.

CHAIRMAN APOSTOLAKIS: Well, then what are you doing? I mean there are so many questions about all this. To give one number, what does it mean? If the ten to the minus three can be ten to the minus one, I don't know what conclusion I can draw from this. I mean all kinds of doubts have been raised, and it seems to me doing an uncertainty analysis means exactly, precisely to address these doubts and comments. There's something about the five ten to the minus six that bothers me, okay? That it was five ten to the minus nine and now it's ten to the minus six, that's all we learned. I just don't believe that.

And the other thing I want to finish is that there is a certain pleasure in listening to Mr. Strosnider defend the probablistic method. Usually he's a skeptic. Today, he was on the other side.

MEMBER SHACK: It's probablistic fracture mechanics he's defending.

CHAIRMAN APOSTOLAKIS: I don't care what you put after probablistic.

(Laughter.)

It was nice to hear him talk that way.

MEMBER POWERS: But, George, there is a difference.

MEMBER SHACK: One's a science.

(Laughter.)

MEMBER FORD: If I could just --

CHAIRMAN APOSTOLAKIS: Go ahead, Dr. Ford.

MEMBER FORD: -- move along here. In defense of the MRP, a lot of this is dependent on having a reasonable database for crack growth rates upon which that is dependent. Now I'm told that we're close to it. The next meeting we will see that database, and then we will see the follow-on to your specific question.

CHAIRMAN APOSTOLAKIS: Great.

MEMBER FORD: -- on that particular kinetics-driven analysis.

Could I ask you to finish in five minutes, Larry? I realize that I've now cut you down to your knees.

MR. MATHEWS: I will. In response to the Davis-Besse issue, we've had lots of interaction with the staff, but even before the bulletin came out we conducted, as an MRP, a survey, and it was based on some -- basically assumptions about what the possible causes at Davis-Besse were before the root cause or even the preliminary root cause was out. And there were three possibilities that we tried to consider in our survey, and that was leakage from above, leakage from a crack in a nozzle or a combination of the two. And then we'll be -- the ongoing Davis-Besse work will be used.

We did that survey, we came up with four questions basically aimed at how confident are you that you don't have wastage on your head? And we received responses from all the PWRs in the country. We wound up categorizing the responses into four categories plus another group that didn't quite fit, and they range from -- you know, category one was they got the best knowledge, they're darn certain, they've gone and looked, they don't have any wastage. Category four, it was more like they were able to do from a historical view of leakage, et cetera, to feel confident. And then there was a category, other, that they had leakage and perhaps had not fully cleaned it up or there was some other reason they didn't fit into one of the other categories. And we categorized all these plants, gave the names of the plants to the staff, and I believe they've actually used our tables to help guide a little bit how they're contacting plants as far as what their intentions are.

This is our ranking of the units that we put together a while back. If you look at it, the red triangles are the leaks, and most of those leaks are to the left of the graph, which is kind of where -- if the model's worth anything, that's where they'll be. A couple outliers, we do have one plant that had some cracks that was a little bit further out. Those cracks were nowhere near as severe as the cracks at these plants that have had leaks, so maybe we're picking up the precursor here. That's something we have to look at.

All the blue diamonds have done inspections and haven't had leaks or the open blue diamonds are doing inspections this spring, yet to do a few plants in the fall and a few more next year. We'll have done inspections per bulletin 2001-01.

Here's the table we sent to the staff. Turns out most of the plants, as far as the wastage on the head, feel a good degree of confidence that they don't have any significance wastage on the head. Some of these plants have even done inspections since then. Cook 1 I know plans an inspection very soon. Wolf Creek, I believe, has done an inspection, and I think Palo Verde just finished their inspection. So most of these plants are moving into greater degrees of confidence that they really don't have an issue with wastage at this point in time.

MEMBER FORD: You should point out that, Larry, that that's on the basis of your survey, not on the basis to the replies of 2002-1.

MR. MATHEWS: Absolutely. This was all put together -- it was probably right at about the time the bulletin was coming out or maybe shortly thereafter, but it was based on the response to our questions, not the responses to the bulletin.

A couple of points about that. All the plants that are less than ten effective full-power years on our histogram will have been inspected by the end of this spring outage season. That includes the highest ranked 20 units in the country. And they should have a reasonable assurance that they don't have any significant corrosion on top of their head because of those inspections. And of the plants that were less than 30 EFPY, 34 out of 45 will have inspected by this spring. We're showing five in the fall and six in the spring of 2003. There's a little bit of confusion right now. We're not off more than one or two plants, I don't believe, but we've got to settle that out, straighten that out.

This is something that we wanted to say, that of the 34 leaking nozzles and penetrations that have been discovered to date, all of them displayed visible evidence of leakage or corrosion on top of the head, leakage primarily. A total of 203 nozzles have been inspected at those -- let's see, is it nine plants where leaks have been discovered? And NDE has confirmed through-wall leaks or cracks -- I mean through-wall defects in all 34 of the nozzles that showed leakage. NDE did not detect through-wall defects in any of the others, and there have been, this says, four plants without evidence of leakage, and I'm sure by now it's much more than four plants have inspected the nozzles without any defects found.

MEMBER SHACK: It would interesting on your chart, you know, where you've got the one with cracks that you found by NDE, to also see where the guys that inspected by NDE and found no cracks were on that chart.

MR. MATHEWS: Yes. Up until when I put that together there weren't a lot. There was Cook 2 and maybe a couple of others that had done volumetric, that didn't have a prior indication of a leak that they were going and confirming. But we're getting more and more of the plants now that are doing volumetric inspections. I think Palo Verde just completed a volumetric inspections, and I don't even have them marked as having done that. But we will update the chart and try and figure out how many colors we could put on it. But we'll do that.

Recent experience of the -- except for the Davis-Besse issue, in the other 31 leaking penetrations, there's no evidence of any significant corrosion or wastage. There has been a hint at a couple of other nozzles that there was a little bit here and there on top of the head or whatever but no significant evidence. And also on the plants that have repaired their nozzles that were leaking, most of those repairs have been performed using the Framatome repair technology where the nozzle is bored out and then rewelded up inside the head to the low alloy steel. And if there were significant wastage there, it would have been evident. They have to go PT that surface before they weld to it, and if there's a big gap, they can't even get it to weld. So out of all those other nozzles, there hasn't been any significant wastage like the one big cavity at Davis-Besse.

CHAIRMAN APOSTOLAKIS: So what do I learn from that? What's the conclusion from that?

MR. MATHEWS: Well, the conclusion is that something's different about Davis-Besse, the waste, the big cavity like they had compared to the rest of the industry. And they're going to talk about it --

CHAIRMAN APOSTOLAKIS: And the rest of the industry also had wastage there for the number of years that Davis-Besse had it?

MR. MATHEWS: Well, that may be the key, and in fact it may be the difference between this one nozzle and the rest of them is the amount of time that the nozzle leaked. And Davis-Besse will discuss that when they get up here. That may in fact be the key is how long was the leakage allowed to go on without being detected? But do I know that that's absolutely the reason? I don't know that, not right now. Okay.

I've only got two more. Ongoing activities, we're reviewing or have reviewed the Davis-Besse initial root cause, and we will review the final root cause for generic implications of that and use that information to get back into MRPs recommendations as far as inspection to the plants. And we're also taking a look back at the Owners' Group work that was done back in the early '90s. They did some work on head wastage, and we want to take a look at that and see does this really change any of that?

CHAIRMAN APOSTOLAKIS: Are you done?

MR. MATHEWS: Yes. I'll quit.

MEMBER FORD: Questions?

CHAIRMAN APOSTOLAKIS: Yes. I mean I'm amazed that you say you are not planning to do an uncertainty analysis. Uncertainty analysis is not an academic exercise. You keep telling me that there are all these experts that are looking at the huge scatter of data and so on, and then at the end we're not going to do an uncertainty analysis.

MR. MATHEWS: Well, we're definitely going to do all kinds of --

CHAIRMAN APOSTOLAKIS: I'm amazed.

MR. MATHEWS: We're going to do all kinds of sensitivity studies and look at the various parameters that go into the model and determine --

CHAIRMAN APOSTOLAKIS: Sensitivity studies, are you going to do them two at a time, three at a time, variables, playing all sorts of games to really gain insights? I mean to vary one variable at a time doesn't really do much for me.

MR. MATHEWS: Well, the nature of the Monte Carlo is you do them all at once.

CHAIRMAN APOSTOLAKIS: And that's a sensitivity study?

MR. MATHEWS: No. You do -- well, yes. You put all of the uncertainty of all of the databases and all of that, it goes in there at one time and you do a Monte Carlo sample --

CHAIRMAN APOSTOLAKIS: Well, that's not sensitivity, that's uncertainty analysis.

MR. MATHEWS: Right. But doing the sensitivity we'll go in and we'll change some of those parameters and distributions.

CHAIRMAN APOSTOLAKIS: But you said you were not planning to do that. That's why I'm amazed. If you were planning to do it, I wouldn't be amazed.

MR. MATHEWS: The term, "uncertainty analysis," caught me off -- we are going to do sensitivity studies to look at what the sensitivity of the analysis is to the various --

CHAIRMAN APOSTOLAKIS: Well, that's a way of doing it. That's a mechanics review.

MR. MATHEWS: Yes.

MEMBER FORD: Could I, just in terms of

time management, call this one to a close but recognizing that there are questions along these lines, and when you come back within the next two months be prepared to answer them.

MR. MATHEWS: Yes.

MEMBER FORD: Mr. Chairman, am I allowed to go five, ten minutes over?

CHAIRMAN APOSTOLAKIS: Well, if the Vice Chairman went over 45 minutes, I don't see why the members can't go over five minutes.

(Laughter.)

MEMBER FORD: Okay.

CHAIRMAN APOSTOLAKIS: There's no schedule today anyway, so keep going.

MEMBER ROSEN: Let's establish some sort of quantitative mechanism or a curve here, we can begin to --

MEMBER POWERS: Could I ask a question?

CHAIRMAN APOSTOLAKIS: Yes, sir.

MEMBER POWERS: Something perplexes me a little bit here. The speakers indicated the time that the nozzle was allowed to leak, I guess is the word, and Davis-Besse may have been key. And he said leak without being detected. Okay? And then we have inspections of the other things, which presumably have some probability of detection so that some of those declared not to have any cracks may in fact have cracks and may in fact be leaking but we just don't detect it. What are we doing about that?

MEMBER FORD: A related question to that is we are assuming that when you see a nozzle, the popcorn on the top of the nozzle, that is the sufficient evidence that you've got a crack underneath. That's something that we've questioned. Could you have a crack down below the J-weld and not see the popcorn at the top?

MEMBER POWERS: Well, I think the answer to that is yes.

MEMBER FORD: Well --

MEMBER SIEBER: It's not through-wall or plugged. Either way you won't get --

MEMBER FORD: Well, plugged over the surface. We've asked that question, and that's under consideration.

The other question is to whether from human error you don't see it.

MEMBER SIEBER: Right.

MEMBER FORD: That one has not been addressed apart from in the Duke presentation on Oconee the human error was addressed of not seeing it.

But recognize this is still a fairly recent phenomenon, if you like.

MEMBER POWERS: Well, I mean isn't it the conclusion that you come out of this as, "Gee, our methods of inspection are inadequate."

MEMBER FORD: This is something you may have from the staff, because this might be a policy decision.

CHAIRMAN APOSTOLAKIS: I'm not sure it's the methods. Ultimately goes to the safety culture.

MEMBER FORD: But that question about --

CHAIRMAN APOSTOLAKIS: It didn't say -- it doesn't say here that they didn't know because, it's just they didn't pay attention.

MEMBER FORD: This question of management of this whole situation by inspectors --

CHAIRMAN APOSTOLAKIS: This gentleman wants to say something; he's been trying for a while.

MR. MATHEWS: I was just going to say that the human error -- this is Larry Mathews, I was just up there. The human error part could be easily factored into the inspection on a probablistic fracture mechanics as a probability of detection.

CHAIRMAN APOSTOLAKIS: It could be easily placed there. Now what value you use is not going to be easy.

MR. MATHEWS: Oh, yes. We have to figure that out.

(Laughter.)

CHAIRMAN APOSTOLAKIS: That's the whole issue.

MEMBER SHACK: Sensitivity studies.

CHAIRMAN APOSTOLAKIS: Oh, you do sensitivity, excuse me.

MEMBER FORD: The answer to your question may well come up in the staff's presentation. Could I ask the representatives from Davis-Besse to come up. Normally half an hour but make sure you have enough time to present the stuff on the risk assessment aspect. John Wood and Ken Byrd from Davis-Besse.

MR. WOOD: Good afternoon. My name is John Wood. I'm the Vice President of Engineering Services for First Energy Nuclear Operating Company. In our agenda today, I'll be discussing the information that we presented to the subcommittees on Tuesday. And then at the end of that, we'll have, at the subcommittees' suggestion, a discussion of the safety significance assessment that was given to the staff early this week.

I'd like to just cover a couple points on background for Davis-Besse in that if you'll note in the middle there we have 15.8 effective full-power years at that Unit. Toward the bottom, hot leg temperature is a little bit hotter than other Babcock & Wilcox plants at 605 degrees up. That's about three or four degrees higher based on our core delta T. And we have 69 nozzles at our Unit. Sixty-one of those have control rod drive assemblies, seven are spare and one is used for a head vent that goes to our steam generator.

This is a depiction on the next page of our reactor pressure vessel head configuration. The insulation is shown across horizontally here. You'll note that the dose above the insulation in the area of the flanges is about one-half a rem per hour. And beneath the head the dose is approximately three rem per hour. And those are the fields that we have to engage as a head sits on the head stand.

In our next picture, or actually two pictures, what we have shown on this slide is the reactor vessel head sitting on the head stand in the left-hand picture with a couple gentlemen working up above. The picture on the right has been cut open this outage in order to access at the flange level. That area is 20-some feet below where those gentlemen on the left are standing, so typically people would be working in and around the flanges using 20-foot-long handled tools.

The next diagram depicts a typical B&W control rod drive nozzle. It is shown in its position. There's a shrink fit of about one-half to one and a half mils that enters into the low alloy carbon steel. You can see there the shell cladding and the J-groove weld. Now, when I talk in a little bit about cracks, the cracks that we have depicted actually are on the OD of the tube on the wetted side, or ID, of the main reactor vessel head. And then through-cracks would go up past the weld into this annular space here.

We went through details Tuesday with the subcommittees in regard to the UT examinations that we performed at Davis-Besse. This picture depicts the below or underhead UT examination tool. It has been demonstrated, using EPRI capability, to detect actual and circumferential flaws. It is delivered with a robotics system and an automated data acquisition system. This was used on all 69 nozzles at Davis-Besse, and then those nozzles produced indications of flaws were also inspected the top-down UT examination tool, and that has ten transducers in order to characterize the flaws.

MEMBER POWERS: Would you give me an idea how long it took to inspect 69 --

MR. WOOD: That inspection period for Davis-Besse was approximately 96 hours. And that is around-the-clock time.

Our UT examination results, and these, again, were detected with the underhead and then confirmed top-down, are shown on the next page. You'll see that there's six nozzles listed here. The first five had cracks indicated, the first three were the through-wall cracks. You can see Nozzle 1 had nine actual tracks, two went through-wall, and nozzle Number 2 had eight actual cracks, one circumferential flaw. And that circumferential flaw was approximately 30 degrees, a little bit more than an inch in length, 1.2 inches in length, and was about 50 percent through-wall for the nozzle. I should mention also the nozzle is approximately 0.63 inches thick.

Number 3, of course, the one that has the cavity associated with it, had two through-wall leaks and there were cracks on Nozzle 5 and 47. Number 46 did not have a crack indicated; however, there's an investigation with a backwall signal on 46.

CHAIRMAN APOSTOLAKIS: These examinations were done when?

MR. WOOD: These were done approximately in early March, the first week in March. Actually, the last part of February, early March.

CHAIRMAN APOSTOLAKIS: After the problem was found.

MR. WOOD: That's -- no. This led to the finding of the problem.

CHAIRMAN APOSTOLAKIS: Oh, this led to the problem.

MR. WOOD: That's correct. This was the 100 percent UT examination of the nozzles at Davis-Besse was done in conjunction with our answering of 2001-01 in our extension from the end of the year to February 16.

CHAIRMAN APOSTOLAKIS: But were examinations like this done routinely and on a periodic basis?

MR. WOOD: No. At the time, we had the most extensive examination of the head using ultrasonic examinations.

CHAIRMAN APOSTOLAKIS: So that was the first time you did this?

MR. WOOD: That's correct.

MEMBER POWERS: These were surprises to

you?

MR. WOOD: It was not entirely surprising that we had axial cracking. Based upon the information of 2001 and the information that we were getting from the industry, we expected to find some cracking. We did not expect to find through-wall necessarily and certainly didn't expect to find the cavity that we found on Nozzle 3.

MEMBER POWERS: I'm sure that was a -- but I'm just asking about the --

MR. WOOD: Right. In fact, our plans included fixing up to four nozzles in our base plan for this refueling outage.

This diagram lays out the nozzles that were found with cracks. Those are indicated in both the red and the green. I will note that the five nozzles in the center of the head are all from the same heat, and I'll talk about that later. Those are the only five nozzles from that heat at our Plant. You can see Nozzle 2, which had the circumferential crack, was located in this quadrant, and there was a very small amount of wastage in this area of Nozzle 2 that I'll talk about in a little bit as well.

I guess that's the next slide. As we were going through the repair process for the nozzles, we did note, as it's shown here, as we machined up, as Larry discussed the repair process used by Framatome, you machine up and then the intent is then to weld onto the carbon steel. We did find a small cavity in that area. Its dimensions are approximated on this sketch. We have since removed that nozzle for further clarification. It is essentially as depicted here. It goes about a quarter to three-eighths maximum depth, as indicated in the reactor vessel head.

MEMBER POWERS: You mentioned that the afflicted nozzles came from a particular heat, and the reason you know that is because of your Appendix B requirements?

MR. WOOD: That is part of the MRP process that we have been working on and also the response of 2001 and the Babcock & Wilcox Owner Group efforts, knowing what the heat numbers are for the various nozzles in all the plants.

The primary reason we're here today is the Nozzle 3 cavity. This is depicted in this drawing, or this picture. I will remind you that this circular hole where the nozzle was located is approximately four inches across. You can see there is some wastage on the right-hand side at the surface level, and this is the stainless steel cladding evident at this location. This is our number one nozzle, so this would be the dead center of the head, and flow downhill in that direction.

The next page is more of a display of some of the numbers that we have determined using various tooling. It does not show the surface wastage that is off to the right. You can see there's a difference in color here. This is to represent a nose or an overhang, and there is additional erosion at -- or corrosion that goes on underneath that zone.

You'll also notice that there is a proposed 13-inch circular cut line indicated here. In order to better capture this area, we're going to cut that out in one piece using an abrasive water jet, and that will then be retained for further evaluation as we go forward. That abrasive water jet will also leave us a very smooth finish that we can then prepare a final fit up of the forged disc that we discussed in concept yesterday with the NRC staff. The exact location of that cutout will be determined to optimize all things involved.

After we found the cavity area around Nozzle 3, we chartered a root cause initial investigation team using First Energy personnel to lead the effort. Those individuals were not from the

Davis-Besse staff. We did include members from the Davis-Besse staff on the team, as well as augmented it with industry experts from Framatome, Dominion Engineering and EPRI, as listed here.

The team came up with a probable timeline using best engineering judgment in looking at the evidence that we had from the period of time in question. What you see here is a summary of that probable timeline. It shows that the crack potentially propagated through-wall in the '94 to '96 time frame, and thus went basically unaddressed for a period of two to three operating cycles.

CHAIRMAN APOSTOLAKIS: Now, that's where I have a question. What does that mean? Were you aware that there were cracks?

MR. WOOD: No, we were not aware that Davis-Besse had cracks at that time.

CHAIRMAN APOSTOLAKIS: So when you say unaddressed, what do you mean by unaddressed?

MR. WOOD: Unaddressed means that the leak was allowed to be active without awareness for that period of time.

CHAIRMAN APOSTOLAKIS: Did you have any indications there was a leak?

MR. WOOD: In a retrogressive look,

certainly there were missed opportunities, and I believe the staff will relate those as well. And as I go through some of the contributing causes, there were reasons that the staff used to perhaps not center on those clues that a leak was occurring on the nozzle region.

Now, I'll talk --

CHAIRMAN APOSTOLAKIS: All the rules and regulations were followed. You were not in violation of anything.

MR. WOOD: I don't think I'm in a position at this point to say that there was nothing that was violated. Certainly, there were people with very good intentions that were doing the things they thought were right. As we look back, things did not go according to the desires and the expectations that should have been in place.

CHAIRMAN APOSTOLAKIS: And that was, in your opinion, more a matter of judgment, which perhaps was poor in this case?

MR. WOOD: Certainly, poor judgment.

CHAIRMAN APOSTOLAKIS: Okay.

MEMBER LEITCH: What gives rise to the probability that the crack initiated about three years before it went through-wall? Is that based on some crack growth rate?

MR. WOOD: That's based on the same crack growth rate that you would have heard from the MRP individual -- Larry.

MEMBER LEITCH: Then I guess one could assume that since we see no crack in Nozzle, what is it, four?

MR. WOOD: Number four.

MEMBER LEITCH: That we have a certain degree of confidence that it would not go through-wall within one cycle of operation.

MR. WOOD: That's correct. But that's based on probabilities and not certainty.

MEMBER LEITCH: Yes. Because Nozzle 4 seems like it's crying out to crack, right? I mean it's

MR. WOOD: Well, and there have been numerous people, including myself, who have asked over and over and been told again and again that Number 4 does not have cracks.

MEMBER SIEBER: Yet.

MR. WOOD: Yet. And that's an important yet, and that's true with all the nozzles that are in that head.

MEMBER LEITCH: Okay. Thank you.

MR. WOOD: Now, the probable cause here is really of the failure mechanism, that being the cracking. And since we were in the repair process prior to finding the cavity -- as I have mentioned earlier, the repair effort requires us to grind up the nozzle from below to above the J-groove weld, and so the cracks themselves were taken out as a result of doing that. So that's why it's listed as probable cause because we don't have material to identify it as a factual root cause. But every indication --

MEMBER SHACK: Nobody tried to map the cracks as they were grinding them either.

MR. WOOD: That's correct. We did have UT data that we showed the subcommittees Tuesday that mapped them out in the general sense but not to progress and grind in PT, as an example.

With what we know that is happening in the industry on Alloy 600 and the control rod drive nozzle issue, we feel confident that it is primary water stress corrosion cracking that resulted in the crack initiating propagation and then allowed leakage to the reactor vessel low-alloy steel head.

MEMBER FORD: If I could ask a question. It's fairly obvious that the initiating event was primary water stress corrosion cracking rising to a liquid of some sort in the annulus. But the key question is why did that environment give erosion or corrosion of the low-alloy steel in your condition but did not in many of the others, like Oconee? And that's the root cause question that needs to be answered.

MR. WOOD: Correct. And the root cause of the cavity being there is this next page.

MEMBER FORD: Okay.

MR. WOOD: And that is our Boric Acid Corrosion Control and In-Service Inspection programs did not allow us to see that leakage at an earlier time. Now, this is, again, looking backwards at the data that we had at hand, but we feel that the leak had existed through-wall for two to perhaps three operating cycles and thus did not allow us to identify that --

CHAIRMAN APOSTOLAKIS: I'm confused by the words on this slide.

MR. WOOD: Okay.

CHAIRMAN APOSTOLAKIS: "The Boric Acid Corrosion Control and In-Service Inspection programs and the program implementation resulted in the Plant not identifying the through-wall crack." What does that mean? That the program resulted in you not identifying it?

MEMBER SHACK: The failure to implement the Boric Acid Control Program.

MR. WOOD: Right.

CHAIRMAN APOSTOLAKIS: Oh.

MR. WOOD: The Program neither robust enough nor was it implemented sufficiently in its form to detect the crack. So had it been, let's say, more robust and more rigorous applications, that would have been one approach. Even apart from that, had it just been implemented appropriately or properly, it would have been the other case.

CHAIRMAN APOSTOLAKIS: So you are blaming both the Program and the implementation, at this point anyway.

MR. WOOD: That's correct.

MEMBER SIEBER: Now, I have a question. You, actually, when you asked for your extension from the bulletin schedule for inspections, you relied on videotapes, as I understood it, to say that leakage was·not there?

MR. WOOD: Yes. And what I think is being asked, as we went through the effort on 2001-01 to extend our outage from the end of the year, as was requested from the staff, until the time of February

16, we did an evaluation of the information we had in hand and knowing that there was some boric acid in the vicinity, the thought of the staff was that that boric acid had come down from the flanges from above and the mindset, for whatever reason, was focused on circ cracking and not on the potential wastage issue that we eventually found.

MEMBER SIEBER: Did anybody from the NRC staff see those videotapes before the extension was granted?

MR. WOOD: I cannot answer that question directly.

MR. BATEMAN: Yes, I can answer that question. We spent about three hours looking at videotapes from the 1996 inspection, the 1998 inspection and the 2000 inspection. And there were substantial amounts of boric acid on the head at that time.

MEMBER SIEBER: Did you, like the Licensee, assume that it came from the joint in the housing up above?

MR. BATEMAN: We did not have that discussion at that point in time.

MEMBER SIEBER: Okay. Thank you.

MR. BATEMAN: By the way, Bill Bateman

from the staff.

CHAIRMAN APOSTOLAKIS: So let me understand the second bullet here, "Plant returning to power with boron on the RPD head after outages." So Plant personnel knew that there was boron on the RPD head after outage?

MR. WOOD: There were individuals at the Plant that knew there was boron on that head, that's correct.

MEMBER SIEBER: And, apparently, the staff did too prior to granting the extension.

CHAIRMAN APOSTOLAKIS: They thought it was coming from the flanges.

MR. BATEMAN: This is Bill Bateman from the staff again. I want to make it clear that the videos that we looked at were videos inside the shroud area around the mechanisms, not outside where the weep holes -- I think you saw the picture yesterday -- where the weep holes actually -- it dripped down from the holes onto the -- near the bolt circle on the head. We did not look at -- we did not see those particular pictures. We were inside that shrouded area of the videos that we looked at.

MEMBER SIEBER: This was through those mouse holes.

MR. BATEMAN: Right.

MEMBER SIEBER: Camera on a stick?

MR. BATEMAN: Right. Yes. Those are the videos we looked at.

MEMBER SIEBER: Okay.

CHAIRMAN APOSTOLAKIS: Okay. You said, Jack, that they knew there was boron there and they assumed it came from the flanges. So what, didn't they still need to clean it up? I mean whether you clean it up depends on where it's coming from?

MEMBER SIEBER: I would have thought so at the time, but I'm not sure that everybody makes their -- up until today, makes their reactor vessel head squeaky clean each time they do an inspection.

CHAIRMAN APOSTOLAKIS: But there's a difference between each time and not doing three or four times.

MEMBER SIEBER: That's true.

MEMBER POWERS: By the way, George, I just remind you of a point that was made at the beginning of the presentation. This is -- doing things on the vessel head that aren't absolutely required is a highly costly thing, not only in time but because of the radiation dose that you incur to your workers. So if you don't think you have to do it, you're probably not going to do it.

CHAIRMAN APOSTOLAKIS: So the question is when do you decide that you have to do it?

MEMBER POWERS: That's right.

CHAIRMAN APOSTOLAKIS: Now, maybe you have already explained it, what is 12RFO?

MR. WOOD: Twelfth refueling outage. We're currently in our 13th refueling outage.

CHAIRMAN APOSTOLAKIS: Okay. Thank you.

MR. WOOD: Okay. And as we have just been discussing, the environmental conditions which contribute to this is the cramped conditions of the design. And by that I mean there's about two inches of clearance between the top of the head and the insulation. As was mentioned, we have 18 weep holes near the bottom that provide us some access. And we, therefore, did not take appropriate compensatory measures as a result of these cramped conditions to allow ourselves to find that leakage.

Another contributing cause was the fact that in the late '80s, early '90s, there was much leakage of the CRDM and flanges above the insulation, which allowed some boron to pass through to the head and participated in the mindset of the staff at the time.

Now, I did mention the fact that we had a material heat that was unique for five nozzles, four of which had cracking, three of which had through-wall cracking. And all three of those nozzles that had through-wall were from this heat listed. We're aware that that heat is used at two other B&W plants. One plant has all but one of their nozzles from that heat; another B&W plant has one nozzle from that heat. The one that has the majority has been well-inspected and has thus contributed to a database that suggests that 20 percent of this particular heat of nozzles has cracked or has had evidence of cracking thus far.

We spent some time Tuesday talking about crack length versus leakage. I don't intend to go into a long conversation on that, but I did want to mention that our unidentified leak rate at the Plant during the period of time in question was approximately 0.1 to 0.2 gallons per minute. So that is well below the tech spec limit of one gallon per minute. And you can see the fact that the longer crack lengths have more damaging corrosion resulting from them. Whether that's just evidence that it is interesting at this point or it is matter of fact, we don't know for certain.

MEMBER POWERS: Could you give me some

idea of what the width of the cracks is?

MR. WOOD: The width of the crack, I don't have that information. I don't know if anyone from the staff does in the back there.

MEMBER POWERS: Real tiny, as big as my finger?

MR. WOOD: Very tiny, and we're talking in the orders of a thousandths of a gallon per minute up to the 0.2, 0.8 region. And so --

MEMBER POWERS: That's what I was looking for.

MR. WOOD: Okay. As a result of our meeting Tuesday and getting together with --

CHAIRMAN APOSTOLAKIS: Before we go on, if I were to take with me the top two causes why this situation developed, what are they? Something must have gone wrong someplace, so what are the top two causes, so I remember? I read a lot of stuff and they say a lot of things, the timelines and this and that, but if you ask me what was the number one and number two contributing causes, I have difficulty figuring those out. So can you summarize them for us?

MR. WOOD: Well, I think number one was the Boric Acid Control Program and the application of that.

CHAIRMAN APOSTOLAKIS: Okay.

MR. WOOD: I guess almost everything else pales by comparison.

CHAIRMAN APOSTOLAKIS: Okay.

MEMBER KRESS: I would have listed the potential for having a bad heat. There are cracks already there.

MR. WOOD: Granted however in this business we're accustomed to dealing with things that may be first of a kind or second of a kind or whatever. So we wouldn't want to use the fact that we had a bad heat as the indicator of the cavities, the indicator of the crack.

MEMBER KRESS: You still have to deal with those.

MR. WOOD: Correct.

MEMBER SIEBER: There may be an issue of standards involved too on the part of the inspection personnel and decision makers.

MR. WOOD: Yes. Those standards of course will go to the very top. That's where standards come from.

CHAIRMAN APOSTOLAKIS: I'm sorry. What standards are these? I missed it.

MEMBER SIEBER: The kind of standards one would expect from a professional organization that operates a nuclear power plant.

CHAIRMAN APOSTOLAKIS: Isn't that what some other people call safety culture?

MEMBER SIEBER: That's a piece of safety culture.

CHAIRMAN APOSTOLAKIS: Yes. It can be all of it.

MEMBER SIEBER: Questioning added to high standards.

CHAIRMAN APOSTOLAKIS: Yes. Okay.

MEMBER SIEBER: Vigilance.

MEMBER ROSEN: The application of the corrective action systems.

CHAIRMAN APOSTOLAKIS: Okay. Thank you.

MR. WOOD: Okay. Then as a result of our meeting on Tuesday, Peter Ford asked that we would include safety significant assessment. So we have Ken Byrd who will present that.

MR. BYRD: Okay. My presentation will be a very brief summary of the results of a safety significance assessment that was provided to the staff earlier this week. For this assessment, we considered a range of breaks from very small to the size described on the top of this page 23.

So that for the maximum size, we assumed the failure of the exposed cladding area which is approximately 25 square inches. In addition, we assumed that the whole was 50 percent larger than the exposed cladding area for about 38 square inches.

We also assumed that CRDM Number 3 would eject. So our total area was approximately 50 square inches or 0.35 square feet. We're looking at a range from very small up to 0.35 square feet. For our analysis, we evaluated three critical functions.

MEMBER ROSEN: Now before you get off that in terms of assumptions. You've obviously made the assumption although it's not shown here that nothing else was damaged. There was no additional damage.

MR. BYRD: No, sir. I'm going to talk about that next when I look at these next three functions.

MEMBER ROSEN: Okay.

MR. BYRD: I'll get to that. We looked at three critical functions when we did this analysis. We looked at the ability to have core cooling, to maintain shut down margin, and finally containment integrity.

We do not have a Davis-Besse ACE, an analysis for a LOCA at this specific location.

However our LOCA analysis covers a spectrum of LOCAs from 0.01 square feet up to 14.2 square feet.

Setting aside at the moment collateral damage, this particular LOCA is equivalent to a hot leg LOCA with respect to core cooling. In that respect we would get injection flow going through the core for both core cooling and for boron precipitation control. Therefore with respect to core cooling, we were bounded by our existing LOCA analysis.

Let's go on to my second bullet here which relates to shut down margin. I think this is where we get into the concern about the issue of collateral damage that might occur to adjacent control rod drive mechanisms. Consequently we had Framatome ANP do an evaluation of the potential for damage to adjacent control rod drive mechanisms.

The Framatome Analysis looked at several different mechanisms. They looked at jet loadings. They looked at pressure loadings. They looked at loose debris which might mechanically jam an adjacent control rod drive mechanism.

The results of their analysis was that it was unlikely that an adjacent control rod drive mechanism would be affected. Not withstanding that result, we went ahead and had them do a further analysis to look at the impact of all of the control rod drive mechanisms. We actually looked at five control rod drive mechanisms surrounding the affected area.

Failing to insert is a result of collateral damage. In addition to that, we added one additional control rod which would be a random control rod failing to insert with the highest shut down margin for that control rod. With those six control rods failing to insert as a result of this accident, we were able to have both immediate and long term shut down margin.

MEMBER ROSEN: Is that for the conditions that the Davis-Besse found themselves in at the end of the day on February 16 or whenever it was that you shut down? Was that a more general conclusion for any time during the cycle?

MEMBER FORD: Before you answer, Ken, could you just let the Committee know if the staff have not reviewed this analysis yet?

MR. BYRD: No.

MEMBER ROSEN: So let me repeat my question. Is that result that you had plenty of shut down margin even with those six rods not reinserting? Was that a general result for if this had happened at any time during the cycle or a specific result that applies only to that day, the day you shut down?

MR. BYRD: It was really intended to apply only to that day. But the analysis was done using the beginning of life for cycle 14 which was actually a more conservative time period.

MEMBER ROSEN: Okay.

MEMBER SIEBER: But is the break size you had, the larger the break the better able you would be to get reactivity reduction because of the insertion of highly borated water?

MR. BYRD: Yes, sir. That would be true.

CHAIRMAN APOSTOLAKIS: The rod ejection effect is instantaneous, but you're at full power. So you have some full power conditions.

MEMBER SIEBER: Right.

MR. BYRD: Right.

CHAIRMAN APOSTOLAKIS: So that reduces the concern with the rod ejection.

MR. BYRD: Okay. If I could go on to the third condition that we considered. We also considered containment integrity. The issues we were concerned with here were two issues.

One was the control rod ejection, actually impacting on our containment. The other issue would be the mass and energy release from the particular LOCA.

With respect to the first of these issues at Davis-Besse, we have missile shields above the control rod drive mechanisms which would prevent an ejected control rod from impacting a containment. With respect to the second issue, mass and energy release, this particular LOCA is bounded by much larger LOCAs which have been analyzed. So we did not see any significant issues with respect to containment integrity.

MEMBER POWERS: Let me ask a question that you may not have the answer to. If you have blow out in that particular location, do you put an unusually large amount of mass into your sumps that could clog some pumps and things like that?

MR. WOOD: No. That area would not be directly driven towards the sumps. That would be within the refueling canal. Then you saw the service structure arrangement around it. So there's not a lot of direct accessibility out of that into the sump area which is quite a ways away from that.

MEMBER SIEBER: The refueling canal is empty during operation.

MR. WOOD: That's correct.

MEMBER SIEBER: You use a diaphragm between the vessel flange and the edge of the canal.

MR. WOOD: No. There would be an opening in that area.

MEMBER SIEBER: During operation.

MR. WOOD: During operation.

MEMBER SIEBER: That's the flow path to the sump.

MR. WOOD: Right.

MEMBER SIEBER: Okay. So there is a connection.

MR. WOOD: The sump itself is up on a different level beneath the head. But would initially accumulate.

MEMBER SIEBER: Okay.

MEMBER POWERS: So it's a fairly contorted path that something would have to follow to get to your sump.

MR. WOOD: That's correct.

MEMBER SIEBER: It would have to go uphill.

MEMBER POWERS: It wouldn't be so uphill.

MEMBER ROSEN: The insulation that's above the head in that region is reflective insulation. There's no silicacious insulation.

MR. WOOD: That's correct.

MEMBER ROSEN: That's all metal in pipe insulation.

MR. WOOD: Right.

MEMBER POWERS: That didn't help you much.

MEMBER KRESS: It's gets really pushed around a lot.

MEMBER ROSEN: Well it does actually.

MR. WOOD: However all that insulation would have been inside of the service structure.

MEMBER ROSEN: The three GSI-199 is the most damaging kind of material. It is the kind of material that can plug the screens. Typically it's the silicacious sand-like material that --

MEMBER POWERS: No.

MEMBER ROSEN: Plans toxin fibrous material and end up building the building up across the sumps.

MEMBER POWERS: Fibrous material is of course very bad. But we've seen experiments showing that you can shred this stuff up. That shredded material is not too good either.

MEMBER ROSEN: It may be. But I think if you read GSI-199, the most recent staff stuff that came out of, which lab? I'm trying to remember which lab. I think that report indicates that the worst material comes out of Los Alamos and the University of New Mexico. So I'm reasonably familiar with it.

MEMBER FORD: If I could interrupt, could we just get this one through? Again I'm looking at the time.

MR. BYRD: Okay. Going on to the next page. As a further effort to address the safety significance of this condition, we had a stress analysis of the as-found head condition performed. This stress analysis is a three-dimensional finite element, stress analysis of the wasted -- and the reactor pressure vessel head.

We had a failure criterion set at the maximum strain of 11 percent through the thickness of the clad. We had the results verified by an independent analysis. We had this both performed by Framatome ANP and Structural Integrity Associates.

The results were that the degraded cavity would maintain its integrity in excess of twice the transient loads. The results for the two analyses were fairly consistent.

MEMBER SHACK: What's the rational for the 11 percent?

MR. BYRD: This particular analysis is an input to my safety assessment. I think I have an expert here from Framatome who could probably address that better than I can.

CHAIRMAN APOSTOLAKIS: Please identify yourself.

MR. FYFITCH: I'm Steve Fyfitch from Framatome. The rational here is that's actually a conservative value that they used for the analysis. The 11 percent comes from an Oak Ridge report that we have access to that looks at 308 in stainless steel weld metal.

The 11 percent is where necking starts to occur in the tensile test. We assumed that 11 percent was the failure strain. So it's in fact a very conservative because once the uniform elongation starts to disappear, it actually goes out and total elongation about 30 percent.

MR. HACKETT: Bill, this is Ed Hackett from the staff. A follow up to that would be we're doing confirmatory analyses too as you know for the criterion failure strain. That number probably needs to be adjusted, Vom Mises or Treca for the multi-axial state of stress that would exist in the head.

So probably the real number should be less than 11 percent. I don't know what the number should be. As Steve pointed out, that number is from uni-axial tension test. So what you have is at least a bi-axial state of stress in the head. That will come down somewhat. We're looking into that right now.

MR. HERMANN: Ed, I think in the models the tensile stresses that were taken were compared to Vom Mises output in the models.

MR. HACKETT: The 11 percent already reflects a Vom Mises or Treca adjustment.

MR. HERMANN: Yes. It's just a comparison of what came out of the tensile stress versus that's not what was in the model. It was just a comparison of that. A unilateral strains.

MR. HACKETT: Okay. Thanks.

MEMBER FORD: For the Recorder, that was Bob Hermann.

MR. HERMANN: Bob Herman from Structural Integrity.

MR. BYRD: Now going to my last page. The results of this analysis on the previous page indicated that the expected failure pressure was well in excess of the pressure for any postulated transients. It's also well in excess of the pressure for any transients that have actually been experienced at Davis-Besse.

However to estimate a risk of the as-found condition, we looked at the probability of a failure occurring at less than this estimated pressure based on our stress analysis. The results of this indicated that there are core damage frequency we estimated to be in the range of 1 times 10 to the minus 5th per year. The larger the release frequency was approximately of 1 times 10 to the minus 8th per year. Our public health risk was approximately 0.56 person rem per year.

CHAIRMAN APOSTOLAKIS: Are these Deltas given these conditions?

MR. BYRD: Yes, sir. These are Deltas.

CHAIRMAN APOSTOLAKIS: So what is your baseline CDF?

MR. BYRD: My baseline currently for internal events is 1.2 times 10 to the minus 5th per year.

MEMBER ROSEN: Ten to the minus what?

MR. BYRD: Fifth per year.

CHAIRMAN APOSTOLAKIS: So your doubling.

MR. BYRD: Approximately doubling our internal event baseline.

MEMBER SHACK: Now as I'm corroding away at two inches a year, how many weeks do I have to wait until this thing goes?

MR. BYRD: We have that analysis currently in progress. We're expecting an answer to that relatively soon. We have an analysis that will give us the size at which point we would have a failure at a normal pressure. As far as how long it would take to get to it, I think that's a little bit more speculative.

CHAIRMAN APOSTOLAKIS: So this is given that I have the amount of degradation that was observed, the core damage frequency would be 10 to the minus 5.

MEMBER KRESS: The maximum it could be is conditional. What's the conditional core damage frequency?

CHAIRMAN APOSTOLAKIS: Well it is conditional.

MEMBER KRESS: Given that you have the hole there.

CHAIRMAN APOSTOLAKIS: Oh, the hole.

MR. BYRD: If we had a LOCA?

MEMBER KRESS: Yes.

MR. BYRD: That would be a conditional core damage probability. In the calculation of this core damage frequency, we evaluated the conditional core damage probability from a range all the way to very small up to the 0.36. The largest was at about 0.1 square feet. That was 2.9 times 10 to the minus 3rd.

CHAIRMAN APOSTOLAKIS: You said 0.36?

MR. BYRD: The hole size with the maximum core damage probability.

CHAIRMAN APOSTOLAKIS: So you estimated the probability of this LOCA to be the order of 7 10 to the minus 3.

MR. BYRD: I'm sorry.

CHAIRMAN APOSTOLAKIS: What's the frequency of this LOCA?

MR. BYRD: I guess it might be easiest if I could just take a minute here and walk through the process because I think I have a few questions. Essentially what we did was we understood that at the pressure we calculated we weren't supposed to get a failure. So we looked at ways that this would fail at less pressure.

There's a couple of things that came to our mind. One was a sizemic event. The other being overpressure transients that didn't actually get to this pressure.

With respect to the sizemic event, we have recently completed a sizemic PRA. We looked at that. Based on the results of that a sizemic event of sufficient magnitude to cause this damage in Northwest Ohio the frequency is very small. So that was a very small contributor.

The other thing that we looked at though was overpressure transients. We recognized that this number that we had from the stress analyses is a calculated number. It's dependent on a number of things such as the analysis, the actual condition of the clad, and the material strength.

So we employed a process that is outlined in NUREG 2300, the PRA Procedures Guide and NUREG 5603 and 5604. This is a process we've used for doing our interfacing system LOCA type of evaluations in our PRA. It's also similar to what we use in our sizemic analysis and in our external event tornado analysis.

To do that you actually assume a median failure capacity which we took to be the number we got from the stress analysis. Then we had to develop a logarithmic standard deviation. To do that we went to the new rigs and looked at the various different tabulated standard deviations for materials, for temperatures and different kinds of configurations.

We took one that basically bounded the

results we've seen in there. This is a way of approximating the probability that the failure might occur earlier. Based on that we were able to calculate the probabilities of failures at pressures of about 5600. We were able to come up with probabilities of 3 times 10 to the minus 3rd to 7 times 10 to the minus 3rd depending on the pressure.

So that gave us a probability of failure at a given pressure. Then we had to determine since we weren't trying to calculate a frequency, we had to calculate a frequency which over pressure transients would occur at the plant. To do that we went back through our plant history all the way back to 1979 and looked at all of our overpressure transients.

We actually calculated frequencies for various different categories in terms of the extent to which they overpressurized the plant. Then we were able to calculate a frequency of that we would get a transient that would actually cause a LOCA. That number was in the order of 4 times 10 to the minus 3rd which is about to give you a feeling two orders of magnitude higher than our normal medium LOCA number.

CHAIRMAN APOSTOLAKIS: Does the number of 10 to the minus 5 include as part of the conditions the possibility of the six rods not going in?

MR. BYRD: Based on our deterministic analysis, we had evaluated that even if the six rods did not go in, we would have sufficient shut down margins. So we did not specifically include that.

CHAIRMAN APOSTOLAKIS: All right.

MEMBER FORD: Okay. If I could jump in here. I'm watching the time here, George, unless you want to extend into your other time.

CHAIRMAN APOSTOLAKIS: No. That's unfair. I shouldn't extend it if I want to ask questions myself.

MEMBER FORD: That's right.

CHAIRMAN APOSTOLAKIS: Let's move on.

MEMBER FORD: Thank you very much indeed. I appreciate your comments. Let's call on Jack Grobe. You're now going to hear two presentations by the staff.

CHAIRMAN APOSTOLAKIS: Should we take a break? We've been going forever. Do the members want to take a short break?

MEMBER KRESS: Yes.

MEMBER SIEBER: That would be good.

CHAIRMAN APOSTOLAKIS: Okay. We're recessing until 3:50 p.m. Off the record.

(Whereupon, the foregoing matter went off the record at 3:40 p.m. and went back on the record at 3:50 p.m.)

CHAIRMAN APOSTOLAKIS: On the record. Back in session.

MR. GROBE: My name is Jack Grobe. As was mentioned, there's three presentations this afternoon from the staff. I'm going to present the results of a recent inspection that was completed about a week ago. We exited on that inspection last Friday. Allen Hiser will then present the status of Bulletin 2001-01. Ken Karwoski will present the current status of the bulletin responses for Bulletin 2002-01.

Being from Region III, I'm the Director of Reactive Safety. I don't get to see you folks very often. I appreciate the opportunity to be here. Quite frankly I'm quite embarrassed to be here. As I go through this you'll see why.

This wastage occurred over a period of years. Our staff did not identify it. Certainly the Davis-Besse caused it and had many opportunities to identify it. We'll get into that a little bit.

I was going to cover three topics. The first and third I think we've addressed pretty extensively with the staff's presentation from Davis-Besse. There are just a couple of issues that I'll touch on in that area.

As was mentioned there were five cracked nozzles, three were through wall. I'm going to get into a little bit of the description of the cavity, just some of the information that I think was important but not presented yet. You've already understood what happened at nozzle 2.

This is just a little bit different rendering. This is an artist's rendering of the cavity. They spoke of the nose. There was substantial undercut in the cavity.

In addition to that, there were some UT measurements were taken from beneath the cladding. There was an unusual result. They were taken on one inch centers. There were indications that for an extended distance outside of the visible cavity on the order of maybe two and sometimes more inches, there appeared to be a gap on the other side of the cladding.

It's not clear what that is. When the licensee cuts out the cavity, they'll be able to investigate that more clearly. It's not clear whether that's a reflection. Whether it's actually a separation, it's just not clear.

If you look at the physical character of the cavity, there's an uneven area quite a bit bigger than the cavity that appears to be as a minimum de-bonded between the stainless steel and the --

VICE CHAIR BONACA: Could you show us the location there? Is it possible to see the location?

MR. GROBE: I don't have a slide that shows the layout of that. A plan view as it were. I don't have that. I apologize.

MR. HISER: Yes. I guess just to try to provide a little bit of an answer this is Allen Hiser from NRR. It's around nozzle 11. It's just not clear at this point how far --

VICE CHAIR BONACA: Okay. Down there on the picture.

MR. GROBE: Well, it actually goes laterally across the cavity as well as downhill. It appears to go the whole way to nozzle 11 and maybe somewhat around nozzle 11. Like I said it's at least in some cases two or more inches beyond the visible aspect of the cavity.

VICE CHAIR BONACA: The reason I'm asking the question is that in the repair, they've already defined the size of the plug.

MR. GROBE: Right.

VICE CHAIR BONACA: Does that mean the

plug may have to be larger than what they are planning right now?

MR. GROBE: Or there may be repairs necessary. One of the first things that they are going to do after they cut out the 13 inch diameter, their current plan, is they're going to do diapenetrate testing of the surface to try to identify whether or not there's additional damage to that surface.

VICE CHAIR BONACA: Okay. I understand.

MR. GROBE: This is a view of the cavity. I think you can see in the lower section of the cavity there's a shiny area. That's where it was machined prior to the penetration to pitching as it were. The tube has been removed. You can see the walls of the cavity are fairly smooth. They slope in.

You saw this drawing in the last presentation. There's nothing more to report on this except a characterization of the wastage area is a little bit incorrect. It comes out a little bit more now that we have impressions in the lower area. Then it tails off to be a little bit thinner.

So it appears that there may be more than one mechanism. It may not just be corrosion. There may be some other things as well.

I want to get into missed opportunities. I'm going to cover three areas. They are the containment air coolers, the containment radiation monitor filters and also the Boric Acid Corrosion Program implementation.

Dr. Apostolakis, you asked what are the two main causes. The easy cause is to blame the Boric Acid Corrosion Program implementation. The entire operation of these facilities depends on human beings whether it's people doing designs, operators of the control panels, human beings make mistakes.

Implementation of this program was not well implemented. That's by engineers. But the results of the program implementation were known to a number of people as well as a number of other precursors.

I believe that the most important cause here is a complete failure of the Corrective Action Program. You'll see that as I go through my presentation.

Just a little bit of system knowledge that you may not have that's important to this. There's a ventilation that the system intakes as suction on this volume here. Discharge is near the top of containment above the D-rings.

The area below the insulation is connected to the area above the insulation through small gaps around the nozzles and things of that nature. So there is a communication of the ventilation system between these two areas.

There are a series of almost 20 five by seven inch what are called "mouse holes" or "weep holes" that are right down here at the edge of the vessel. (Indicating.) So they are for air coming in through that direction. It's critical to understand that the discharge from these areas at the top of containment just to see what happened in the containment air coolers and radiation monitors.

MEMBER SIEBER: The way out of that bottom plate and the mirror insulation is such that since the air flow is up, they don't have conoseals, but in those joints the leakage is probably not going to go down. Some of it does.

MR. GROBE: The leakage will likely be horizontal.

MEMBER SIEBER: That's right.

MR. GROBE: It will be steaming horizontally. It will spray against other surfaced and evaporate. Then the vapor will be taken up through the ventilation system.

There's been sufficient leakage at times during the past ten years that has actually leaked down along the penetrations, through the floor of this service structure and through the insulation and gotten onto the top of the head.

MEMBER SIEBER: My recollection is that it's pretty windy in that area.

MR. GROBE: I haven't been there.

MEMBER SHACK: That is a plate though there.

MR. GROBE: Yes.

MEMBER SHACK: There was some picture there yesterday that gave me the impression of a gridwork that you attached the insulation to rather than a plate.

MR. GROBE: I think it's a framework. Is it gridwork?

MR. MCLAUGHLIN: It's angle iron.

CHAIRMAN APOSTOLAKIS: Identify yourself please.

MR. MCLAUGHLIN: This is Mark McLaughin from Davis-Besse. There is actual angle iron that goes across the service structure. That's what the insulation is laid on top of.

MEMBER ROSEN: So you would not expect

there be a large Delta P that would arise across that structure if there was a substantial steam leak below at the top of the head. Is that correct?

MR. MCLAUGHLIN: That would be correct. The other thing that's not shown on there is there's insulation. See on the outside of the flange, that's were the reactor vessel hold-down bolts are. There's another layer of insulation that's L-shaped that's outside of that which covers up the bolt holes. So that would even further restrict air flow in that area underneath insulation.

MEMBER ROSEN: What I was getting as was I was postulating that if you had a big leak right at that point of steam at the top of the head that somehow that insulation in that structure would somehow cock and cause some stresses. I'm trying to get the sense of whether you think that's possible. I think you're saying is this the gridwork that came with the Delta P that could create some kind of cocking of that structure.

MR. GROBE: No. I think there's a fairly tight clearance around each penetration hole. This is a sheet material. Clearly the floor of the service structure is sheet material.

I would expect if you're discharging 2,200 pounds into this area that you're going to get a very substantial differential pressure between these two areas. You would see some deflection in these plates which may result in some movement of the penetration tubes.

I don't remember who asked the question. But they were very interesting and complex questions. These are also restrained near the top for sizemic purposes. I think you'd really have to get into how much would those bowl and what are the clearances inside before you could say how many rods would be affected.

MEMBER ROSEN: Now you made me worry again. I was almost to the point where I was done worrying. I was the one who postulated this originally. Now I'm back to work. That's exactly what I was worried about. Because of the yards Delta P across some of this, there would be enough distortion caused by flexing of something that you could have some sort of common cause failure.

CHAIRMAN APOSTOLAKIS: More about six rods.

MEMBER ROSEN: Yes.

MEMBER SIEBER: Well, the mirror insulation is in blocks. Right?

MR. MCLAUGHLIN: I'm sorry. I didn't hear the question.

MEMBER SIEBER: The mirror insulation is in blocks. Right? It's a puzzle that you put together.

MR. MCLAUGHLIN: The way the mirror insulation was manufactured is if you look at it there's a flange right up above the insulation.

MEMBER SIEBER: Right.

MR. MCLAUGHLIN: The mirror insulation is really in long strips, I'll say. Each strip has a cut-out area for half of a nozzle along an entire row though. So what they did is they slid it in on its side. Then they laid it on top of the angle. So the insulation is installed with long strips.

MEMBER SHACK: It's like around recessed lighting in your basement.

MR. MCLAUGHLIN: Exactly. If you cut it around if you have recessed lighting in your basement and you cut half of one of your ceiling tiles, that's how it would look. So that's how it's installed. I would think that if you had enough of a force you might move one strip. However there is sufficient room between the insulation and the nozzles that it should move up. I would think it would tend to flip out of the way.

MEMBER SIEBER: Now is there or is there not a plate involved here someplace?

MR. MCLAUGHLIN: There is no plate.

MR. GROBE: What's the construction of this, Mark, the floor of the service structure?

MR. MCLAUGHLIN: That's just showing the circle. There's no plate inside there. The only thing that you have is the angle iron that supports the insulation.

MEMBER SIEBER: The insulation is sitting in there loose.

MR. MCLAUGHLIN: That's correct.

MEMBER SIEBER: Does that help you?

MEMBER ROSEN: A little bit. I'd actually like a more detailed drawing so I could conclude.

MR. GROBE: Okay. Thank you. The tubes and fins of the containment air coolers obviously are cooler than atmosphere. Anything that's in the atmosphere they'll condense water out of the air as they're cooling the air. Contaminants in the air and moisture in the air will plate out on the fins and tubes.

The containment air coolers need to be cleaned occasionally depending on leakage inside containment. They were cleaned in 1992. Prior to some substantial leakage, there was equipment that needed corrective maintenance in the 1998 time frame, late '98/early '99 which resulted in unidentified leakage in containment going from about one-tenth of a gallon per minute to about 0.8 gallons per minute. During that time frame it was necessary to clean the containment air coolers 17 times.

A mid-cycle outage was taken in April 1999 to repair that equipment. Unidentified leakage only went down to about 0.3 gallons per minute after that outage. It remained higher than it had been prior to '99.

Also during this time frame after the mid-cycle outage, the containment air coolers had to be cleaned twice in late '99 and seven times throughout 2000 and 2001. During that time frame, the engineers reported that the character of the material on the containment air coolers had changed.

Previously it might appear as a spray painting, a very white dusty material on the fins and the tubes. During this time frame it took on a different color. It was dark brown. The Davis-Besse staff assumed that the change in color was due to corrosion of low alloy steel components in the air coolers themselves.

MEMBER ROSEN: Did anybody do any measurement of the activity of that deposit?

MR. GROBE: No. I don't believe so. When you say "activity" you mean specific activity, radio activity?

MEMBER ROSEN: Yes.

MR. GROBE: I'm not aware of that. I'm not sure if the Davis-Besse folks here are aware of that either. I did not ask that question.

Okay. The radiation monitor filters. There were routine preventive maintenance to change the filters on the airborne radio activity monitors inside containment every 31 days. Prior to the '99 time frame, that was sufficient to maintain that equipment.

Beginning in May '99, this is after the mid-cycle outage, the frequency of filter changes increased. Between May and August of '99, it went from about once a month as a preventive activity to every other day. In July '99, the engineer responsible for this equipment requested to have the material analyzed on the filter.

The filter itself had previously never appeared reddish-brown in color. That was the character of the filter in this time frame. It was analyzed in July '99. The analysis came back that the filter was clogged with boric acid and iron oxide that was produced in a steam environment, not surface corrosion.

The facility staff looked for a leak that might cause this. They were unable to find one. They assumed that the leak was from flange leakage. You can't observe the flanges during operation.

In August '99, they installed banks of HEPA filters with high volume fans to try to reduce the frequency change for the radiation monitor filters. That was successful. It reduced it to about every other week.

In July '01, the frequency gradually began to increase again. This is after refuel outage in 2000. It continued to increase to every other day. In October '01, the staff reported that the filters were abnormally dark brown.

MEMBER KRESS: Are these little filters?

MR. GROBE: I haven't seen them. What's the physical size of these filters? I don't think we have anybody here that's seen them. They're in-line filters in the air sampling system so I don't expect them to be very big.

MEMBER KRESS: They're small I would guess.

MR. GROBE: Yes. I've talked about the containment air coolers and the rad monitor filters. Nothing associated with the air coolers was reported in the Corrective Action System.

The rad monitor filters was captured in the Corrective Action System. But the Corrective Action was inadequate to identify the source of the material. In fact some of the actions taken potentially insulation of the HEPA filters masked any ability to detect whether it was increasing on the short term.

I want to talk next about the Boric Acid Corrosion Control Program. I think you're aware that this is an NRC required program. Through our Quality Assurance Regulations, it's clearly a procedure affecting the safety of the plant. So it's required to be implemented.

In 1998, we issued a bulleting that required licensees to describe their program for monitoring boric acid. It's an extremely sensitive but not on-line of course way of detecting leakage. Just a little analogy here. One drop per second will leave about 15 pounds of boric acid in a year. So it's an extremely sensitive indicator of leakage.

Ongoing nozzle flange leakage. The engineer responsible for maintaining the quality of the flanges was provided a period of time each outage to repair nozzle leakage, flange leakage. During some outages there was a little flange leakage. All of them were repaired.

During some outages there was more extensive nozzle leakage. The engineer would prioritize those nozzles as far as how badly they were leaking and get as many of them repaired as he could before it was time to restart the unit. Nozzles were left in service leaking.

In 1990, the Davis-Besse staff identified that it was necessary to have a modification to the skirt beneath the service structure. The mouse holes or the weep holes at the bottom of that skirt were not sufficient to do adequate inspections and cleaning of the vessel head. That modification would involve a number of large diameter openings around the parameter of the skirt, much higher in that skirt structure.

That modification was approved for implementation in the early '90s. I think it was '94 or '95. It was scheduled in successive outages and deferred out of each of the successive outages. So the fact that the licensee was unable to do thorough inspections and cleanings of the head was of their own doing.

Reactor vessel head boric acid deposits were not removed at the end of each outage. It was believed throughout that period of time that boric acid deposits on the head were not significantly hazardous. Moisture would be driven out of the boric acid and the remaining crystals would not be significantly corrosive.

In the '96 outage, the boric acid that was left on the head was characterized as "patches of white loose consistency material." What could be gotten was cleaned up with mechanical means vacuuming.

In '98, the boric acid was characterized as "fist-size clumps and a thin layer of generally brown boric acid around the center penetrations." Again, most of the boric acid was removed by just vacuuming.

In the year 2000, the boric acid was characterized as "accumulating over the head." There was a thick layer of boric acid in the center of the head. I'm going to put a slide up now. This is from the 2000 Bulletin and as Bill Bateman mentioned a few minutes ago, the staff did not have the opportunity to see the condition of this part of the vessel head.

The Boric Acid Control Program clearly indicates that if there are indications of red or brown coloring, that's an indication of corrosion. It should be pursued.

In 2000, this material was approximately one to two inches deep. It had flowed out the weep holes. In fact, the material inside the weep holes was high enough to cover the weep holes. The material had to be removed with crowbars. Eventually a water wash was used to dissolve some of the material. But a substantial amount of material was left on the head.

This was documented in the Corrective Action Program as was the boric acid on the head throughout this period of time. The close-out of the Corrective Action Program document, the Condition Report, actually they call them "peacocks" at Davis-Besse at this time, was listed as "head was cleaned and inspected."

MEMBER ROSEN: I'm sure that you're going to take a close look at the corrosion effects of all this leakage on those bolt circles.

MR. GROBE: Yes. We issued a confirmatory action letter that requires a review of the entire primary reactor coolant system. Not only the head and the bolts on top of the head, but throughout the entire system including the bottom head and other areas.

Clearly there were indications of reactor head corrosion. They were not recognized as indications of corrosion and not evaluated.

The licensee described the preliminary root cause, outside diameter, primary water stress corrosion, cracking cavity caused by boric acid corrosion. Significant corrosion began at least four years ago. It's pretty difficult to argue with any of that.

There's a lot of issues that are clearly not addressed yet at least in documents that we've seen. They haven't submitted their corrective action document to us yet.

There's very interesting chemistry I'm learning from this opportunity. Boric acid crystals begin to react with air at a temperature far below the temperature of the head and begin to form boric oxide. In addition to that the melting temperature is only slightly higher then the temperature at which that reaction starts.

So you could have had a very interesting combination of boric acid, boric oxide, and liquid boric acid flowing down the head. It's not clear what role that chemistry played in that cap over the top of the head and corrosion that might have initiated from the head down.

The role of head temperature throughout the operating cycle, outage times, start up times, it appears that there were times that boric acid was pooled in the bottom of this cavity. That's certainly an opportunity during shut down times when the head is at ambient temperatures. It's not clear what role that may have played in the corrosion process.

The rate at which the cracks progressed and the corrosion progressed is not clear. I don't see a reason to believe that the corrosion progressed at a uniform rate through the years. So those issues are not answered. Clearly the correlation between Davis-Besse and the rest of the industry hasn't been explained.

So there's a lot of outstanding questions that I'm hoping are answered to a large extent in the licensees root cause assessment. That completes the information. I apologize for being quick.

MEMBER FORD: Jack, who has the action to provide that data.

MR. GROBE: I'm sorry.

MEMBER FORD: Who has the action to provide that data.

MR. GROBE: The licensee is required to provide us the root cause. It's not clear to me that those questions can be answered without research. The grinding operation on the nozzle in penetration 3 started. The nozzle twisted a little bit and tilted a little bit.

At that point the licensee did extensive cleaning operations on the top of the head to discover the cavity. All of that material is gone. Had we been able to take samples of that material, it would help. The licensee at that point had no reason preserve that material because they didn't understand what was going on. Maybe that's reason enough to preserve it.

In addition, of course all the cracks were machined out. So we have no information on the cracks. It's not clear to me that we're going to have sufficient data from the licensee's analysis to answer all·these questions. Likewise it's not clear to me that we need all those answers necessarily to approve an appropriate repair to the head.

Those answers are important for going forward as far as Davis-Besse and the rest of the industry. So there's a lot of things that play here. I anticipate there may be some research, Hackett's ears are perking up, that will come out of this.

MEMBER FORD: That comes down to the question of the timing of which this research goes to get to an identifiable goal. Bearing in mind that it's assumed that there are no other observations of such magnitude in the existing fleet. Until we have that data we don't know. Tomorrow it may start, unless we know the chemistry, physical dimension interactions.

MR. GROBE: It may be that the right answer is to do volumetric examinations of these areas every outage. I don't know what the right answer to this is.

MEMBER FORD: Okay.

MR. GROBE: Then you never get into this situation. At least not from these cracks.

MEMBER POWERS: This is the part that I don't quite understand, Peter. In the inspections of heads that we're doing elsewhere, are we looking for boric acid corrosion of the mild steel pressure vessel?

MEMBER FORD: Inside the annulus?

MEMBER POWERS: Yes.

MEMBER FORD: Not as far as I know. Not unless they're doing 100 percent UT. They're not.

MR. STROSNIDER: This is Jack Strosnider. I just wanted to make two comments on the discussion. First of all with regard to the research, NRR has requested the Office of Research to start doing some work in this area including looking at what information is already available. Also looking at the feasibility of mock-ups. We've also had some additional discussions with the industry I believe with regard to doing that kind of work.

With regard to what the inspections are expected to look at, I think that's a subject of the next presentations. In particular Bulletin 2002-01. When you hear the presentation, you'll see that's exactly the issue that we're trying to get to in that bulletin.

CHAIRMAN APOSTOLAKIS: If I look at this incident from the New Reactor Oversite Process. Is this white?

MR. GROBE: The licensee's analysis puts it at the white, yellow order. We haven't even begun to review that. That's the next inspection that will begin in the next week or so, both to look at the regulatory implications of the findings of the AIT as well as the risk analysis.

CHAIRMAN APOSTOLAKIS: But are you using the action matrix right now? No.

MR. GROBE: The AIT, the Augmented Inspection is an event response. Now we'll go into the follow up inspections and apply the Significance Determination Process.

CHAIRMAN APOSTOLAKIS: Okay.

MR. GROBE: It's an interesting opportunity.

CHAIRMAN APOSTOLAKIS: Yes. We've been hearing a lot about the utility personnel there and so on. How about the resident inspectors?

MR. GROBE: That's an excellent question. As part of the follow up activities, I'm required to recommend to appropriate offices actions to take.

CHAIRMAN APOSTOLAKIS: Were they aware of any of this?

MR. GROBE: No. The residents were not aware. Our inspection program does not require inspections in these areas. The in-service inspection program primarily focuses on piping and welds in the BWRs, BWR internals, as well as steam generators. Reactor vessel heads was not included as part of our inspection program.

CHAIRMAN APOSTOLAKIS: They were aware of the fact that the 1990 modifications to improve the reactor vessel heads had not been installed.

MR. GROBE: No.

CHAIRMAN APOSTOLAKIS: They were not aware of that.

MR. GROBE: No. I don't know how many modifications every year that Davis-Besse has. But I would expect that it's certainly in the dozens and maybe many more than that. Corrective maintenance activities would be in the thousands. So the chance that a resident inspector may choose to pick one of these activities to look at is fairly small.

CHAIRMAN APOSTOLAKIS: Now the Corrective Action Program is one of the cross-cutting issues. Is it not?

MR. GROBE: That's absolutely true.

CHAIRMAN APOSTOLAKIS: So what? We're not doing anything about it. It's an old issue between us and the staff. The staff claims that even if you have a defective Correction Action Program, then you will see the consequences of that. That's what happened here.

MR. GROBE: I think that's what we have here.

MEMBER ROSEN: I think that's what you said, Jack, is that you're doing a Significance Determination Process.

MR. GROBE: Right.

MEMBER ROSEN: What comes out of that is what's off the action matrix.

MR. GROBE: Exactly. Also to answer your question, we're going to have to look at our inspection program and how we implement it to make sure that we're addressing appropriate inspection activities.

CHAIRMAN APOSTOLAKIS: The question is whether you should stick to this point of view that if there are problems with the Corrective Action Program let them be until something happens or you should try to devise some ways of evaluating the quality of the Corrective Action Program before things happen.

MEMBER ROSEN: I don't think your premise is correct. I don't think that they do. I'm not talking about Davis-Besse, any place without a serious event. If the inspection, resident inspectors and the NRC find that the Corrective Action System is somehow not working as it should, then that becomes an issue.

CHAIRMAN APOSTOLAKIS: They're not looking, Steve. They're not looking.

MEMBER ROSEN: I think they are.

CHAIRMAN APOSTOLAKIS: No. It becomes a major contention.

MEMBER SIEBER: There's a module for that.

CHAIRMAN APOSTOLAKIS: There's a what?

MEMBER LEITCH: It's 4500. Isn't it?

MEMBER ROSEN: I think it's a major focus of the inspection program now.

MR. GROBE: There's three areas where we look at the Corrective Action System. There's an inspection that's now conducted every other year which is a team inspection. It's a large inspection. It covers several weeks.

CHAIRMAN APOSTOLAKIS: Of what?

MR. GROBE: It's of the Corrective Action System itself. A wide variety of condition reports are chosen on a risk informed basis to examine the effectiveness of the Corrective Action System. There's also a series of interviews of staff across the facility to get a sense for their safety focus as it were.

In addition to that a certain percentage, I believe it's 10 percent of the hours of every inspection whether it's a radiation safety inspection, security and safeguards, maintenance, surveillance testing, or whatever it may be, is intended to spend in the Corrective Action area looking at Corrective Actions for deficiencies identified in that specific area. In addition to that now we're implementing sampling of about ten more minor events.

Events that wouldn't get to the level of a special inspection where you send a team out to the region. More minor daily events that by following our nose, catch our fancy. We spend a little bit drilling more on that specific event into how it happened. So there are three ways we look at the Corrective Action Program.

It's very difficult to apply the Significance Determination Process to Corrective Action violations. The Corrective Action Program if it's a violation of not fixing things correctly, it will most likely found the issue before it became significant from a risk perspective. But didn't fix it properly. So by definition that would be a low-risk violation.

There's still quite a bit of dialogue among myself and my peers about whether or not it's appropriate to apply a risk-based, risk-driven Significance Determination Process to a Corrective Action Programmatic deficiency. Or whether there should be some programmatic Significance Determination Process developed that's more deterministic.

MEMBER ROSEN: So given all that, what was the staff's conclusion about the Corrective Action Program at Davis-Besse prior to this event?

MR. GROBE: The staff's view is that the Corrective Action Program is well implemented at Davis-Besse. That's what's very troubling. It's something that I'm going to be getting to the bottom of over the next several weeks, maybe months.

The extent of the behavior that created this problem is multiple people weren't following the Corrective Action Program. For example, engineers were not speaking laterally. The rad monitor engineer wasn't talking to the containment air cooler engineer, who wasn't talking to the head engineer.

There were several decisions that were made which included supervision and management that don't appear to have been good decisions. Some examples are the delay of the modification, installation of HEPA filters in containment, the decision to not continue to pursue the source of iron oxide in the '99 time frame, quite frankly the decision to restart after the 2000 refueling outage.

So there's just a plethora of issues that we need to continue to follow up on. Why those decision making processes, communication processes, supervision deficiencies didn't manifest themselves in other areas, that's another question we have to ask ourselves and try to find the answer to. But they didn't. I'm fairly comfortable with our inspection program.

CHAIRMAN APOSTOLAKIS: Okay. They didn't. But we, the NRC, have no way of finding out that they did not because we were not looking for that. Is that correct? We were not looking for the existence of communication channels between this group of engineers and that group of engineers because that's a safety issue. We're not supposed to look at that. Is that correct?

MR. GROBE: Whenever you identify, it's what I refer to hardware and software. Most problems have fixes in two sides. They have a hardware fix. For example in this case potentially drilling out a hole in the head, installing a plug, welding it in. They also have a software fix. It's a human performance problem or a communications problem or a procedural deficiency.

CHAIRMAN APOSTOLAKIS: Right.

MR. GROBE: We look at all of those issues when we look at fixing a deficiency in the facility. If it's our violation, we follow up on it. The 10 percent of each inspection procedure is spent doing that. We pick about a half a dozen less significant events per year. We drill down in each one of those to make sure that the root cause is identified and fixed. Every two years we spend a significant period of time.

CHAIRMAN APOSTOLAKIS: I think I'm getting a different picture from you of what our inspections do. Then you guys would develop the ROP.

MR. GROBE: Well, I can tell you that you get a picture of what we're doing in Region III. I believe it's the same as the other regions.

CHAIRMAN APOSTOLAKIS: Yes.

MR. GROBE: I apologize.

MEMBER POWERS: In fairness, you explained this when we visited you. All of the regions have explained this. They do this baring down on the less significant issues and things like that. It's one of the values of our visit to the regions.

CHAIRMAN APOSTOLAKIS: I know. Sure. Another thing that you said that I find very interesting is you said that you are not sure of the Significance Determination Process as it is structured now. That makes sense for things like the Corrective Action Program. Put another way, should we evaluate everything on the basis of CDF and LERF? That's really what you are saying.

MR. GROBE: Exactly.

CHAIRMAN APOSTOLAKIS: I don't think we should.

MR. GROBE: I agree.

CHAIRMAN APOSTOLAKIS: You agree with me. Okay.

MR. GROBE: When you look at the Design Control Program for example if our inspectors go in and we spend a week and we find 20 calculational areas which are not minor oversights like a transposition of numbers or something like that --

MEMBER ROSEN: This is at Davis-Besse.

MR. GROBE: No. This isn't Davis-Besse. This is philosophical.

MEMBER ROSEN: I apologize. I won't digress.

CHAIRMAN APOSTOLAKIS: That's fine. Philosophy is good. Keep going.

MR. GROBE: If you find 20 calculational areas where the calculational area had a precursor of not understanding the engineering a mis-application or a mis-assumption or something of that nature but each one of them came out as to not render the equipment inoperable, currently the Significance Determination Process would classify those as either minor or green. They would be non-cited violations.

When in fact that's a clear precursor that there's a problem with the competency of the engineers as well as the competency of the engineering supervisors. So there are areas and these are the things that we're still working out in implementation of the ROP.

I think the Corrective Action Program is likewise. It needs something less than less rigorous analytically than a risk analysis to evaluate the significance. I certainly appreciate this podium to express these views. I don't get it very often.

CHAIRMAN APOSTOLAKIS: It can be a risk-like analysis but not using core damage frequency is the end stake. Something before that.

MEMBER ROSEN: It sounds to me like what you're suggesting is the Reactor Oversite Process ought to be risk-informed not risk-based.

MR. GROBE: That's exactly right. In some areas it can be risk-based, but overall it should be risk-informed.

CHAIRMAN APOSTOLAKIS: Nothing we do is risk-based.

MEMBER ROSEN: Well, if you're writing something that's agreeing because it's number that you've calculated is way down there, that's risk-based not risk-informed.

CHAIRMAN APOSTOLAKIS: No, but that's a rule.

MEMBER ROSEN: What Jack is arguing for is a true risk-informed regiment which is in my view the right answer. It's always I think the wrong answer to use a risk-based regiment.

CHAIRMAN APOSTOLAKIS: No, but the point is should you be using core damage frequency to make all these determinations. I think that's a fundamental problem.

VICE CHAIR BONACA: For example one concern that you have raised and I brought out at least personally was the fact that the Significant Determination Process doesn't take into consideration repeat events.

CHAIRMAN APOSTOLAKIS: That's true.

VICE CHAIR BONACA: And yet it is something that traditionally we have looked very hard at the plans as indicators of problems with the

Corrective Action Program. You fix something, you say you fixed it and it's not fixed again and again. That's a major indicator. Yet the Significance Determination Program doesn't deal with that.

CHAIRMAN APOSTOLAKIS: Also the example with the calculations is a very good point.

VICE CHAIR BONACA: Yes.

CHAIRMAN APOSTOLAKIS: Because you have 10 wrong calculations spread over time. Each one would probably become a "green." But if you find a common cause behind them then I don't know what you are going to get.

MR. GROBE: I think we still have growth in the area of how to apply our risk tools. A good example of that in the maintenance area was at Quad City several years ago. They were incorrectly maintaining their motor operated valves. They were repetitively failing. But at each failure they didn't have redundant equipment in a failed state or out of service.

Consequently there was essentially no risk significance to each individual failure but there were 17 valves that failed over a period of two years. It was because the maintenance activity was inadequate and the Corrective Action Program wasn't identifying it. So that's a situation I think that goes to right to both these issues.

CHAIRMAN APOSTOLAKIS: Exactly.

MR. GROBE: We need to continue to mature in how we are using our risk tools.

CHAIRMAN APOSTOLAKIS: Very good. It has been really very useful.

MR. JOHNSON: George, this is my chance. Over here at the table. George.

CHAIRMAN APOSTOLAKIS: Oh, you again. I thought you weren't in the room, Mike.

MR. JOHNSON: I was hoping not to say anything here. But I couldn't not say anything. I do want to point out that we have had continuing dialogue with ACRS on cross-cutting issues. I couldn't sit there and remind us that the goal of the ROP was never to make sure that we didn't have issues. There is never a guarantee in the ROP that would say that we would not have issues and then you would find and look back and say hey you know what. There were some cross-cutting issues that if the licensee had taken care of we wouldn't have gotten here.

In fact what the philosophy of the ROP is is that if in fact there are problems in cross-cutting areas that those will be reflected in performance issues like perhaps this performance issue that we're talking about in time for us to take action before the performance is unacceptable. So that's the premise of the ROA. I wanted to be very clear about that.

The other thing is that I wanted to be sure that we remember that the commission has given us some specific direction with respect to treatment of cross-cutting issues. The direction from the commission was before the agency takes action on a cross-cutting issue we need to make sure that it is an issue that has reflected itself in terms of performance that it has crossed some threshold.

So the commission has been very clear with us with respect to our previous process of looking at issues that have continued to aggregate if you will. Aggregation was a feature of the previous process and has steered us away from aggregation towards where we are in the ROP.

I'm sorry, George. I just couldn't sit there and not say that.

CHAIRMAN APOSTOLAKIS: Are you still the head of that?

MR. JOHNSON: No, I am not.

MEMBER FORD: George, I have one question from the public. Then I'd like to get back on to the agenda.

CHAIRMAN APOSTOLAKIS: Sure. We can never go back.

MEMBER FORD: That's true.

MR. GUNTER: Paul Gunter, Nuclear Information Resource Service. Just a quick question. Jack, could you inform me if the 1990 modification that Davis-Besse didn't undertake was that part of compliance with generic letter 8805? I mean 8805 had a specific piece about increasing accessibility for inspection. I'm wondering in what context did the 1990 modification come about. Did Davis-Besse just volunteer it or was this part of 8805?

MR. GROBE: That's Paul Gunter by the way for the records. Paul, 8805 didn't require any sort of modifications. It simply required the licensee to have a program in place that addressed certain attributes of boric acid corrosion management and to describe that program to us. The modification that was identified in 1990 was proactive in a sense that the Davis-Besse staff identified for themselves that this would be a benefit to them. There wasn't any requirement to implement a modification of any sort.

As a matter of fact of the B&W pressurized water reactors most of them have implemented such a modification. Some have not. So it's simply a matter of what a licensee views is necessary for their own organization.

The disturbing issue at Davis-Besse is that over the years their staff had identified that one of their inabilities to effectively inspect and clean the head what influenced that inability was the fact that they had limited access through these mouse holes or weep holes. That reemphasized the need for implementation of the modification. I think I've answered your question.

MEMBER FORD: I'd like to move on if I may. Ken, do you want to swap your presentations? You deal with 2002-01 and finish off with 2001-01. It's a suggestion.

MR. KARWOSKI: That's fine. For continuity purposes, I'll be discussing Bulletin 2002-01 which was issued in response to the findings of Davis-Besse. Just to recap, the NRC is taking a number of generic actions as a result of the findings at Davis-Besse. I'll be discussing some of those. I'll also be discussing some of the results that we have to date as a result of reviewing responses to the bulletin and talking to licensees.

Just to go through it quickly because I

know we are behind schedule. The first slide just recaps what we knew about the findings at Davis-Besse at the time. We knew that they had boric acid on the top of their head and we knew that they had leaking nozzles.

With that information and the knowledge that there was a cavity, we contacted the industry and asked them three questions. Those three questions are listed on this slide. Basically we asked them for plants that had just recently completed their inspections in response to Bulletin 01-01 which had to do with circumferential cracking of the nozzles. Were the techniques used during that inspection capable of detecting the type of wastage that was observed at Davis-Besse?

The other thing we asked them is to provide a justification for continued operation for the plants that had not performed those inspections at that point. We also asked them for a risk assessment.

The industry conducted a survey and Larry Matthews of MRP described that survey. They categorized their results. While the industry was performing that survey and about the time we received those results, the NRC issued Bulletin 2002-01 on March 18. We had several reporting requirements in that bulletin and I've listed those on this slide.

Within 15 days of the date of the bulletin, we asked licensees to provide a summary of the reactor vessel head inspection and maintenance programs. We asked them to evaluate those programs for the ability to detect degradation such as what was observed at Davis-Besse. We asked them to identify conditions that may lead to degradation such that was observed at Davis-Besse. We also asked for their plans for their next inspection outage and then the justification for continued operation.

We also asked that within 60 days that they provide a more comprehensive evaluation of their Boric Acid Corrosion Prevention Program. We also asked the results of their next inspection to be provided within 30 days of the completion of that outage.

With respect with where we stand today, the staff as a result of the MRP survey, we took the plants that were listed in the other category that were on the slides of Larry Matthews that presented including Beaver Valley, Calaverdi, Wolf Creek, Watts Park. We've contacted all those licensees because of possible concerns because the other category is a category where the results of the inspection were questionable and we felt we needed to understand a little better why they were categorized that. Some of those plants have subsequently performed inspections. We are still pursuing additional information from one of those plants.

We are also contacting licensees that are currently in outages to obtain the results of their results of their inspections and also to discuss their plans for the inspection recognizing that the bulletin went on the 18th and the responses weren't due back until the first week of April. We wanted to make sure that we understood the licensees inspection scopes and we wanted to make sure that the results of inspection whether or not we wanted to evaluate those results to determine whether or not we needed to take additional regulatory actions. Those phone calls are still on-going.

As a result of those phone calls, we have not identified any other plant with similar conditions. In most cases, I have characterized the results as there is small debris on the top of the vessel head. That debris could be a result of maintenance activities and be metal shavings or pieces of metal or small pieces of boric acid crystals as a result of previous leaks but nothing to the extent as what was observed at Davis-Besse.

We are reviewing the responses to the bulletin. We have completed initial categorization. We are proceeding on those reviews now. That's basically where we stand with respect to the activities of this bulletin.

MEMBER FORD: Thank you, Ken. Questions?

MR. HISER: I'd like to describe that the status of review of Bulletin 2001-01 looking back that was on circumferential cracking of vessel head penetration nozzles.

VICE CHAIR BONACA: Could I ask a question? I'm puzzled. It will be a quick question. When they looked at the Davis-Besse, they looked from the bottom. Then they did the inspection and identified cracking I guess through UT inspection in the sense. So that means they never looked from the top because of the super structure (PH) I guess it was. Right?

MR. HISER: As a part of the 2001-01 inspections for the prior bulletin, they looked using ultrasonics to determine whether or not they had any circumferential cracks. As a part of their overall activities, they intended to do a visual inspection of the head as well. The sequence of events was such that they completed their ultrasonic inspections and then begun repairs before they did their visual inspection.

VICE CHAIR BONACA: I just wanted to make sure for the other plants in genera that there is always a plan to inspect visually from the top.

MR. HISER: For many plants that's true. For some plants the insulation configuration is such that the insulation is directly on the head. Then there are cases that it really isn't feasible to do a visual exam of the head's surface.

VICE CHAIR BONACA: So would you find the same problem if you -- Do you see where I'm going?

MR. KARWOSKI: There are a number of plants whose insulation is either glued or cannot be removed for the head easily. One of the recent plants that shut like that is Genet. They had a well documented history of prior leaks. They also did a visible inspection of the surface of the insulation.

In areas where it was stained they cut up pieces and looked down to the bare metal. They also did additional examinations in areas where there was a known prior history of leaks. In the case of Genet specifically they did UT thickness measurements from the bottom of the head near the center nozzle. They also did some UT in the periphery around the shroud ring as result of a prior leak in that area.

So there are other actions that plants who have nonremovable insulation can take. Certainly if they have never had a leak there is a possibility that leakage would come down from the top.

VICE CHAIR BONACA: But you would expect provisions however that they would take so if there is a faradic erosion over time taking place in the ferritic steel would be identified.

MR. KARWOSKI: Yes. I was just addressing the corrosion from the top of the head.

VICE CHAIR BONACA: I understand. I have just been wondering though since in some cases you cannot have a visual from the top, how do you assure that if you have an event of this type it's going to be identified in all cases? That still puzzles me.

MR. BATEMAN: Just a point of clarification. Bill Bateman from the staff. When Ken says leaks, he's referring to flakes from above from the phalanges at the conoseals that would run down and land on the header and the insulation.

MR. HISER: One of the things that the industry talked about on Tuesday was interpretation of the ultrasonic data above the weld and the inference fit zone and the ability of that to characterize whether they have metal behind the nozzle or not. That's one approach that the industry is taking.

VICE CHAIR BONACA: But they're addressing this issue.

MR. HISER: Right. Here's what I would like to do today is to just provide a brief summary of the inspection results and how that fits within the context of the susceptibility ranking approach and then provide some observations and forward looking on where we are headed with this.

The table illustrated here provides the inspection results for all the high susceptibility plants along with two moderate susceptibility plants, Crystal River 3 and Millstone 2 that did identify cracked nozzles. In general, plants have tried to use a qualified visual exam if they are able to do that. Again the qualified visual means that you are able to inspect the inner section of the nozzle with the head so that you can split to that bare metal to see if there are any boric acid deposits. Also you have done a plant specific analysis to demonstrate that any leaks in the annulus between the nozzle and the base metal would provide a deposit on the head that would be available for detection. In some cases in

Millstone 2 and Davis-Besse, they also did a 100 percent ultrasonic inspection because they were not capable of doing a visual exam with the as-found condition.

Now for the plants that have identified leaking or cracked nozzles, any positive findings from the qualified visual exam were followed up with ultrasonic techiques in order to characterize the type of degradation or is it actual flaws or a circumferential flaw whether it was through wall or not. A number of nozzles have been repaired. I guess two things to point out is from the susceptibility rankings, we do have two plants in the moderate susceptibility bin that have found cracked or leaking nozzles. One of those Crystal River 3 is actually the first plant in the moderate susceptibility range. They did identify a circumferential crack in the one nozzle. Millstone 2 identified three nozzles with crack from the ultrasonic test. None of those were thrown wall and none of them appeared to provide any leakage.

Some discussion of Oconee 3. That was the first plant that identified circumferential cracking. That was identified in February of last year during a midcycle maintenance outage. A refueling outage in past November did identify additional degradation with the seven nozzles having cracks or leakage. One of those nozzles did have a circumferential crack.

So I guess some of the points to be made here is at this point all of the high susceptibility plants with the inspection of Davis-Besse have been inspected. We have continued to find cracked nozzles and also some circumferential cracking. Looking at this within the context of the susceptibility ranking, plants are within zero to five EFPY of Oconee 3 were classified as high susceptibility. As you can see many of these have identified cracked nozzles. In two cases they have not from recent inspections this is the Crystal River --

MEMBER SHACK: Those are really leaking nozzles. Right? They did visuals.

VICE CHAIR BONACA: That's right.

MR. HISER: In some cases. In at least one plant all of the nozzles that were found to be cracked did not have definitive indications of leakage on the head, did not have definitive conclusions of through-wall.

MEMBER SHACK: No, the two that we have down there in the high zone that say no cracking. Those had some visuals on them.

MR. HISER: That's correct. Yes.

MEMBER SHACK: So the no leaks is the true --

MR. HISER: No leaks. Yes. That is correct. The highest ranked plant that has leakage is Crystal River at this point. Again Millstone 2 identified cracking because they did an ultrasonic exam. Probably if they had done a visual exam they probably would have been a blue square. We would have said they have no cracking. As you can see there clearly are a lot of plants that still will be doing inspections either later this spring, next fall or even next spring because of the cycle of outages.

MEMBER FORD: Allen, did I hear that correctly that particular plant a visual inspection is not sufficient to determine that you have no cracking? Is that what you said?

MR. HISER: In this case the cracking that was identified as the maximum extent was about 40 percent through-wall.

MEMBER FORD: Oh. So there it wasn't a through-wall crack.

MR. HISER: Right. It was not a through-wall crack.

VICE CHAIR BONACA: Some of the confusion is that you are using the expression "cracking." You should use the expression "leaking" because that really is what you are monitoring with the exception of that plant there, Millstone 2. I would suspect that all of them are somewhat cracked.

MR. HISER: They may be. That's correct. We'll improve the indications on this chart.

MEMBER SHACK: No. Matthews' chart says it has four plants with volumetric inspection that had no cracking.

VICE CHAIR BONACA: I thought there were two. There were two on that table. Only two plants with UT. Millstone 2 and Davis-Besse.

MEMBER SIEBER: But there were others who found cracks.

MR. HISER: Yes. The plants that are shown in the table are predominantly those that are less than five EFPY. Some of these other plants probably also did ultrasonic inspections. They should be indicated a little bit differently. That's correct.

I guess the one point we wanted to make is that although all of the leakage is down in the low EFPY area we have seen cracking here. Ultimately it is going to get to the point that cracking extends throughout the histogram. At this point in time the history does justify I think the susceptibility ranking model that we have.

MEMBER POWERS: I guess that's not apparent to me. You have appointed 15 EFPY. It seems to say that this ranking is not correct.

MR. HISER: From the standpoint of circumferential cracking in nozzles, the plant had no circumferential cracks. It had three nozzles with about 40 percent through-wall.

VICE CHAIR BONACA: And no leakage.

MEMBER POWERS: If I wait until 12 EFPY it has two wall cracks.

MEMBER FORD: I think an explanation, Dana, is that this model is based purely on time and temperature. It misses out the fact there is differences in stress and especially differences in heat. Therefore you are going to expect a scatter around those values. So it doesn't surprise me at all that you have at least one plant who when you look at the distribution of those plants that have seen cracking --

VICE CHAIR BONACA: If that plant had performed a visual --

MEMBER POWERS: Well, I think what this is telling you is that this ranking is just not adequate.

MEMBER FORD: You're always going to scatter around those points. You are absolutely correct.

VICE CHAIR BONACA: If that plant had performed visuals like the other reds it would not have been red but it would have been green.

MEMBER POWERS: That also says that visual inspection is not adequate.

MR. STROSNIDER: This is Jack Strosnider. I'd just like to make a comment on this discussion. As was pointed out with these susceptibility models there are parameters that aren't taken into account here such as residual stresses, materials, *et cetera*. We wouldn't expect this to be exact.

I think the one thing I want to caution is when we say it's not exact. When we ask the question is it adequate from a regulatory perspective, I want to point out that even the largest circumferential crack found in these plants had substantial margin to failure.

Is it adequate in terms of protecting against the circumferential crack that's going to lead to failure? That's what we're concluding that yes the inspections are happening soon enough to give us that information.

It's not going to predict this plant is going to be at exactly this time or this plant will be exactly before that plant. But when you look at the results of the inspections, we believe it's adequate to provide confidence that the cracks will be caught in time to preclude any failures.

I guess the one other thing that I'd point out is then you ask the next question. What about the Davis-Besse experience and the fact that a leak lead to the sort of thing that we saw at Davis-Besse? That's the point of the bulletin that Ken talked about.

For people who have already done these inspections, one of the things that they have to respond to is tell us why that inspection was good enough to tell you that you didn't have any degradation occurring in the head. So I think you need to look at both the bulletins and what they're accomplishing there.

MEMBER KRESS: Yes. But there's going to be an unfinished part of that. They're going to come back and say we're sorry we couldn't have found the Davis-Besse thing without inspection. Then you'll have to come back with now what.

MR. STROSNIDER: Yes. If we see a responsible Bulletin 02-01 which says that we can't tell you a licensee that can't provide the argument as to why they don't have degradation occurring in the head, we need to have more discussions with them.

MEMBER KRESS: They'll have some arguments. But you'll have to use judgement as to whether they're good enough. I think what you'll find out is they really can't tell you. Then you have the decision to make. What are you going to do? I think you ought to be thinking about that.

MR. STROSNIDER: We are.

MEMBER KRESS: Okay.

MR. STROSNIDER: If we get a response to Bulletin 02-01 which doesn't provide confidence that the type of degradation saw at Davis-Besse is not occurring, then we will have to follow up on that. That's the point of our argument.

MEMBER POWERS: Jack, let's come back on this regulatory adequacy. You have this, I think it's Crystal River up there at 15. Is that right?

MR. HISER: That's Millstone 2.

MEMBER POWERS: That's Millstone 2. I'm sorry. You say it's okay because this things going through a wall. Isn't that an accident? If I look at the next plant down, couldn't it be that it has through-wall cracks?

MR. STROSNIDER: Which one?

MEMBER POWERS: One of them.

MR. BATEMAN: Right now we're managing this issue through leakage. If we look at that plant, do a visual inspection and we see popcorn there then we know there's leakage. The licensee fixes it. They don't restart until they've fixed all their leaks. Right now the way we're managing this issue is through leakage.

MEMBER POWERS: Right now this curve is used to tell you the urgency with which they're doing an inspection.

MR. HISER: Actually I should have set the stage on this. The bulletin had two main purposes. First of all is to identify any plants that had a safety issue such as the cracks that were identified at Oconee. So far we've found no plants that have a safety issue with large circumferential cracks.

The other is to provide us with data in a graded approach that would help us to determine what the long term management, *i.e.* inspection methods need to be to assure that we don't get any large circumferential cracks. Within that context, the susceptibility ranking is supported by the data that we have at hand.

MEMBER KRESS: I don't think you should overlook the blue squares, Dana. They tell you a lot of information.

MEMBER POWERS: You have blue squares down here at three.

MEMBER KRESS: I know. You would expect --

MEMBER POWERS: They don't tell me anything except that the curve is not adequate.

MEMBER KRESS: You expect some overlap at that level down there.

MEMBER POWERS: It looks to me like the density is about the same. I would argue that the blue squares are about uniform across that grid.

MEMBER FORD: You don't think that the ratio of cracking to no cracking changes as you go from the left hand side to the right hand side.

MEMBER POWERS: It doesn't look to me like it does.

MEMBER FORD: There's no red squares up in the right side.

MEMBER POWERS: But you haven't looked.

MEMBER KRESS: I'm presuming that you've looked at the blue squares.

MEMBER POWERS: First of all I have two blue squares in the first block. I have four in the next block. I have three in the next block. I have three in the block. Two in the next block.

MEMBER KRESS: That's just an indication of which ones you looked at.

VICE CHAIR BONACA: But let's change the name to leaking because really the cracking is just misleading. Those two boxes on the left between zero and five may be --

MEMBER POWERS: That's what I disagree with, Mario.

VICE CHAIR BONACA: May be 90 percent through right now. They show however no cracking. No that's not true. No leaking. They haven't seen any leakage. But they may be so close to all extent they're in the same bunch.

MEMBER POWERS: I think I agree with you.

VICE CHAIR BONACA: What will you shift the criteria? Do you call the other one up there no cracking? That means no leaking actually. You have seen no leaking in less than two. But you know that there is cracking.

I can make the same statement about any of those. I probably could go at 20 years and find some at 20 years that have cracking but no leaking.

MEMBER KRESS: But I would be awfully surprised to see that many blue squares if indeed you're supposition is right. Some of them are that close to being --

VICE CHAIR BONACA: I was talking about the one between zero and five, those two.

MEMBER KRESS: Well, those two might very well be.

VICE CHAIR BONACA: They may be very close.

MEMBER KRESS: But that just validates the curve if that's the case.

MEMBER POWERS: It may also be true that the two up around 15 are within 95 percent of through wall.

MEMBER KRESS: But I would be very surprised.

MEMBER POWERS: You see if I didn't have the red dot, I might be surprised. But now I have the red dot. Why am I going to be surprised? You know already.

MEMBER KRESS: The red dot is the one thing that raises a flag.

VICE CHAIR BONACA: That's apples and

oranges.

MEMBER KRESS: If I had two red dots, I'd be more concerned.

VICE CHAIR BONACA: But you don't have that.

CHAIRMAN APOSTOLAKIS: So this is the one minute presentation?

MEMBER LEITCH: Another important variable and it becomes a limitation I imagine of how much you can plot, is the inspection method.

CHAIRMAN APOSTOLAKIS: Good.

MEMBER POWERS: The one uncontested conclusion I get out of this is visual inspection looking for evidence of leakage is --

MEMBER FORD: This is going to come up in further discussions because this is relating to the policy of how you manage these.

MR. HISER: Okay. I believe initially this whole two hour meeting was going to be on Bulletin 2001-01. That overtook us. So we're trying to squeeze two hours into about five minutes.

MEMBER FORD: If I could just interrupt because this is a serious point. Dana, this will come up for discussion in the near future to discuss that policy with regards to how we're going to manage this.

MEMBER POWERS: Good.

MR. HISER: This says conclusions. But really these should probably be observations and status. I guess what I really want to focus on is the implications of Davis-Besse to the future inspection needs for CRDM nozzles is yet to be determined. Once the Bulletin 2002-01 review activities are completed and the root causes end then we will have a better understanding of that.

In addition the bulletin addressed the next refueling outage for plants after August 2001. In some cases plants a year from now will be up to their second inspection. In all honesty, the bulleting really doesn't apply in that case. What we hope to do is have some inspection guidance in hand by that time so that plants will be able to implement that next spring.

I believe that the Committee was provided with a copy of our draft action plan that will be used to resolve the VHP nozzle cracking issue. Again that was drafted before the Davis-Besse findings. We have chosen at this point not to modify it because things are in such a state of flux. Clearly that will be revised as the implications of Davis-Besse become understood.

MEMBER FORD: That's both underlining I think, Allen, that parts of the actual experiments and analyses in that action plan are already being done by the MRP. So you say it's a draft. It is in fact. The actions are already going on.

MR. HISER: Yes. That's correct. That's what we had planned to talk about today.

MR. STROSNIDER: This is Jack Strosnider. I'd like to just add one comment here if I could to emphasize something that Allen touched on. I don't know if this will go fully to addressing Dana's concern. Hopefully it might help.

Again the bulletin was just a one time at their next outage, that's all it addressed. We recognize that we need a longer term program to manage this. I think that's where the work is ongoing.

The Sub-Committee heard on Tuesday and the Committee today heard something very important from the MRP that I just wanted to go back and highlight. That was that the MRP has reached a conclusion that just visual inspections to look for leakage is not an appropriate long term method for managing this type of degradation which has very important implications with regard to the type of inspections that would be done.

Basically it draws you to doing volumetric examinations and finding cracks before they ever develop into any kind of leak at all. Hearing that from the MRP and that's an issue that we were looking to have some resolution on I think we'll be working with them to look at a longer term program that follows that philosophy. We're waiting to see their proposal on that subject.

Recognize that, yes, there is a longer term follow up that has to happen here with regard to managing this problem because it will show up at other plants. This distribution is marching forward in time. It will have to be managed.

MEMBER FORD: I'll pass it back to you.

CHAIRMAN APOSTOLAKIS: Well, thank you very much. I guess we'll take another break now. Then we'll go with the last item on the agenda. We'll take 15 minutes, until 5:20 p.m. Off the record.

(Whereupon, the foregoing matter went off the record at 5:07 p.m. and went back on the record at 5:21 p.m.)

CHAIRMAN APOSTOLAKIS: On the record. We're back in session. Risk-informed inservice inspection, break exclusion, region piping, that's what it says here.

MEMBER SHACK: Just to remind everybody

that we've been through this notion of risk-informed inspection for piping which seemed like a good idea at the time. Again it was a notion. Now we've learned about where pipes fail and about the consequences of failing. In fact we could do better inspections by looking mostly at regions where we expected to find degradation of piping and looked hardest at the piping who's failure had the most severe consequence.

When we approved that it was basically for piping that was covered by the ordinary Section 11 plants. The augmented inspection regions were not covered under that one. Now the industry is proposing to extend that to regions who are augmented and inspections were required.

One of those is the break exclusion region where in fact you're supposed to do 100 percent inspection of the welds. There's a proposal then to risk-inform that. The staff is going to tell us about their assessment of that proposal.

MS. KEIM: Okay. I'm Andrea Keim. I'm going to be handing off this presentation later to Steve Dinsmore. We have a few other support staff here to help us answer any questions. Again we're here to talk about the risk-informed inservice inspection of an augmented inspection program covering break exclusion region piping.

A little bit of the background of the PRA implementation plan included the following guidance that was developed for devising risk-informed decision making. There were some general guidance developed and four application specific guidance in four areas. They covered technical specifications, inservice testing, graded quality assurance and inservice inspection. So far mostly the inservice inspection has been the most useful for industry.

MEMBER ROSEN: A point of order. I think our hand out is every other page. At least mine is. No, there's two on each page. I'm sorry. Human error.

MS. KEIM: A little bit more on the regulatory project covering risk-informed inservice inspection. Again we've developed a regulatory guide that was issued in September 1998 and a standard review plan. We've also reviewed topical reports from Westinghouse Owners Group and an EPRI topical report covering inservice inspection. Again that covered ASME code piping from code class 1 and 2.

These were issued back in '98 and '99. Now what we're looking to do is extend that to a different augmented inspection.

First I wanted to go also and show the status of risk-informed ISI reviews. We're proposed to receive 99 plants wishing to implement a risk-informed ISI inspection program. We've received 46 through December 2001. We anticipate getting another 42 in 2002. We anticipate an additional 11 post-2002.

The 37 of these submittals that we've already received used the EPRI methodology. The 13 have used the WOG methodology.

CHAIRMAN APOSTOLAKIS: What's the difference between the second bullet and the third bullet?

MS. KEIM: Not much.

MEMBER KRESS: A few months.

CHAIRMAN APOSTOLAKIS: Major bullet.

MS. KEIM: Yes.

CHAIRMAN APOSTOLAKIS: Number of plants expected to implement RI-ISI is 99. Number of plants that have submitted, what is that?

MS. KEIM: That's what we have received so far to date. So we have 50 applications so far.

CHAIRMAN APOSTOLAKIS: So it's the 46 through 2001 plus a few --

MS. KEIM: A few that we have gotten this year.

CHAIRMAN APOSTOLAKIS: Okay.

MS. KEIM: We've approved 46 of these plants. All the ones through 2001.

CHAIRMAN APOSTOLAKIS: I don't understand. Why do you have to approve them since they are following methodologies that you have approved?

MS. KEIM: Because these cover ASME code piping class 1 and 2 which require a submittal for a relief request.

CHAIRMAN APOSTOLAKIS: Okay. Even though they follow an accepted methodology.

MS. KEIM: Yes.

MR. BATEMAN: It's never quite so simple that they follow an accepted methodology. Each licensee always has their own little differences they want to take from the accepted methodology.

CHAIRMAN APOSTOLAKIS: So you have number of plants that have submitted is 50 or approved. Sorry.

MS. KEIM: So we have 50 that are submitted. Our current activities are covering the Westinghouse Owners Group and EPRI submittals that are extending this risk-informed ISI methodology to the augmented inspection of break exclusion region piping.

MEMBER KRESS: Could you give me a little idea of what break exclusion is about?

MS. KEIM: We're going to get to that.

MEMBER KRESS: Okay.

MS. KEIM: That is coming. Where that's defined and where those requirements came about. Primarily our today's presentation will focus on the EPRI methodology and the EPRI submittal because that one is farther along in the review process.

A little bit more background on the objective of ISI, inservice inspection. That's to identify degraded conditions that are precursors to pipe failures. I think we're all familiar with that. For normal ISI, it's referenced in 10 CFR 50.55(a)(g). That's the requirement that still requires them to still submit a relief request for the code class piping. That again references ASME code for the requirements.

Now to what everybody's interested in. The break exclusion region came around from reviews of general design criteria, number 4 which requires that structures, systems and components important to safety be designed to accommodate the effects of a postulated accidents and include appropriate protection against the dynamic and environmental effects of postulated pipe ruptures. The staff has issued a number of documents that provide criteria for implementing the above requirements. That covers the Standard Review Plan chapter 3.6.2 which also includes a staff technical position MEB 3-1.

The Standard Review Chapter states that breaks and cracks need not be postulated in break exclusion region piping provided they meet certain design and inspection criteria. So from this they designed these pipes with the different criteria. They also are required to inspect 100 percent of the piping welds in these regions.

CHAIRMAN APOSTOLAKIS: I must say it's not clear to me what a break exclusion region is. What is it?

MS. KEIM: Well actually it's piping that is in the vicinity of the containment which is from the inside isolation valve to the external isolation valve.

CHAIRMAN APOSTOLAKIS: Okay.

MEMBER KRESS: That's piping that you guys want them to design and inspect so that you can exclude the possibility that it won't break.

MS. KEIM: Right.

MEMBER ROSEN: That's what exclusion really means. It doesn't have anything to do with excluding from the welds or from the inspection.

MEMBER KRESS: Yes. Okay.

MEMBER ROSEN: It has to do with excluding breaks from the process.

MEMBER KRESS: There are important regions of piping that you just don't want to break. You want to be sure.

MS. KEIM: Right.

MEMBER SIEBER: So you have to do 100 percent of every weld.

CHAIRMAN APOSTOLAKIS: This is the only place where 100 percent inspection takes place.

MEMBER SIEBER: I think that sampling in other places.

CHAIRMAN APOSTOLAKIS: Everywhere else it's sampling.

MS. KEIM: Yes.

MEMBER ROSEN: The code typically requires I think 25 percent.

MS. KEIM: Yes. For class 1.

CHAIRMAN APOSTOLAKIS: What is MEB?

MS. KEIM: MEB is another acronym that we use to identify different branches. MEB is the Mechanical Engineering Branch.

CHAIRMAN APOSTOLAKIS: Oh, okay.

MS. KEIM: That's included in the Standard Review Plan which is attached into the Chapter 3.6.2.

MEMBER SIEBER: I think the nickname for the break exclusion region piping is superpipe because it gets inspected so much.

MS. KEIM: Also because it has additional design criteria.

MEMBER SIEBER: Right.

CHAIRMAN APOSTOLAKIS: Okay. So now I understand what a BER is. What is the first sub-bullet? "Pipe breaks not postulated in BER if criteria is satisfied including augmented IDI of piping welds." What does that mean?

MS. KEIM: I think some of that we're going to cover a little bit later.

CHAIRMAN APOSTOLAKIS: What do you mean "not postulate"?

MR. DINSMORE: This is Steve Dinsmore from the staff.

MEMBER SIEBER: You don't have to consider it.

CHAIRMAN APOSTOLAKIS: Oh, if the criteria is satisfied --

MEMBER SIEBER: You don't have to postulate a pipe break.

CHAIRMAN APOSTOLAKIS: You do the safety analysis.

MEMBER SIEBER: Right.

MR. ALI: This is Syed Ali from the staff. Maybe I can clarify just a little bit. I think one of the big differences between the BER and the non-BER is in the regions breaks had to be postulated and hardware had to be installed for the effects of those breaks such as pipe replacing, check shields.

This region which is generally between the inside and the outside containment isolation valve is so congested that the staff came up with the criteria that you don't have to postulate breaks. Therefore you don't have to install all that hardware provided a number of conditions can be met.

One of those conditions was 100 percent inspection. Other conditions were stress below a certain level, you critique below a certain level.

CHAIRMAN APOSTOLAKIS: Okay. So I guess if you had written "pipe breaks need not be postulated" then it would be clearer.

MR. ALI: Right.

CHAIRMAN APOSTOLAKIS: Okay. This is an interesting situation that you just described because it goes against the defense in depth philosophy. Does it not? It says you are shifting everything to prevention. They say no longer areas. You also do something to mitigate, to contain the possibility. But here you just convince yourself that the break will not happen.

MR. ALI: There are a number of conditions that have to be satisfied.

MEMBER POWERS: George, you're promptly committing the cardinal sin of defense in depth. That is applying it to every damn sub-system in the whole reactor.

CHAIRMAN APOSTOLAKIS: That's a cardinal sin?

MEMBER POWERS: Yes.

CHAIRMAN APOSTOLAKIS: So big.

MEMBER POWERS: Yes.

CHAIRMAN APOSTOLAKIS: Jesus. I'm beginning to become a rationalist again. All right. That's clear now.

MS. KEIM: So now what the proposal is --

CHAIRMAN APOSTOLAKIS: Well excuse me. But it doesn't tell me anywhere that the defense in depth stops at some point. If I read all the documents, that's a philosophy.

MEMBER POWERS: If you read the exemplary paper by Sorenson, Powers and Apostolakis, it would outline this for you.

CHAIRMAN APOSTOLAKIS: That was probably the part that Apostolakis did right. Okay. Sorry, Andrea, it's late.

MS. KEIM: That's okay. So what the proposal is --

CHAIRMAN APOSTOLAKIS: You're doing fine actually.

MS. KEIM: Risk-informed methodology to select piping elements and welds to be inspected in lieu of the 100 percent examination. With that I'm going to hand it over now to Steve Dinsmore.

MR. DINSMORE: Hi. I'm Steve Dinsmore from the PRA branch. I've been involved in this risk-informed ISI since pretty much day one or since the beginning of time, whichever is longer.

CHAIRMAN APOSTOLAKIS: That's where time started.

MR. DINSMORE: Just to give you a brief overview that can avoid some confusion later. What we have is this temporary ISI TR, the original TR. It's about 200 pages. It has a whole description of a methodology. It's been approved to use. Except it was explicitly excluded for use in the break exclusion region.

Now we have this second topic. This is what we call the EPRI BER TR. Not topical essentially identifies tweaks to the original methodology. If they used them, they can take the original methodology, tweak it and apply it to the break exclusion region.

This slide is a quick overview of the different steps in the original methodology and how they're changed to let the BER program be included. The first one is scope definition. It's easy. It used to be excluded. Now we include it.

The consequence evaluation. The BER TR includes a fairly well defined criteria which should be used to determine the consequences of ruptures in these regions. So that's probably the major difference.

Degradation mechanism evaluation. There's no change. Piping segment definition. There's no change. Risk categorization. There's no change. Selection of welds. There's no change.

Risk impact assessment. Essentially what we --

CHAIRMAN APOSTOLAKIS: Let me understand that. When you say "no change" to what?

MR. DINSMORE: To the original methodology.

CHAIRMAN APOSTOLAKIS: Okay. Not to what you used to do to the break exclusion area.

MR. DINSMORE: Right. This is to the original methodology.

CHAIRMAN APOSTOLAKIS: This is to the report.

MR. DINSMORE: This is to the methodology.

CHAIRMAN APOSTOLAKIS: The methodology.

MEMBER ROSEN: The existing approved methodology to the 46 plants.

CHAIRMAN APOSTOLAKIS: Now it makes sense. But did you explain to us what they propose to do to the exclusion region?

MR. DINSMORE: The tweaks are described here. This is a quick overview.

CHAIRMAN APOSTOLAKIS: Okay.

MR. DINSMORE: The risk impact assessment. We had to figure out how to apply the risk criteria that we'd been using to this region and to the plant in total. There's also a slide on that.

Monitoring feedback. There's no change to that. The implementation is another one of the bigger changes. A lot of these BER programs are only referenced in the FSAR. You could use 50.59 to make changes that are referenced in the FSAR.

CHAIRMAN APOSTOLAKIS: What does that mean implementation if you use 50.59?

MR. DINSMORE: If you do a 50.59 evaluation, you can determine whether you need to make a submittal for prior review or not. Sometimes they are in other places, but those plants have their own problems.

If it's only referenced in the FSAR, you should be able to apply your 50.59 evaluation, use this methodology and then apply the evaluation. Then you won't have to come in with a submittal. You can just make a change.

CHAIRMAN APOSTOLAKIS: How would you apply 50.59 to piping in the exclusion region? Have you thought of the questions that you're effecting initiating vents?

MR. DINSMORE: Actually the seventh question is are you --

CHAIRMAN APOSTOLAKIS: I thought the first question of 50.59 was what you are about to do could effect initiating events.

MR. DINSMORE: We have our 50.59 person here specifically for that.

CHAIRMAN APOSTOLAKIS: Okay.

MS. MCKENNA: This is Eileen McKenna from the NRC Staff. I think you're going to get to it a little later in the presentation. I think part of the point that was trying to be made here is that this part of the program, the BER, is not in 50.55(a). So you don't have to follow a 50.55(a) review and approval process.

Then you look at what is the approval process if there is one that might apply to this. To the extent that it's in the FSAR, then it would be 50.59 that would apply to it.

What we're talking about as you'll see a little bit later is we're really looking at the methodology by which you select your inspection locations as changing from the 100 percent inspection to the risk-informed approach. Then using a methodology that has been approved through the topical process. Then you would go through Criteria A which is the method of evaluation criteria in 50.59.

CHAIRMAN APOSTOLAKIS: But I suspect that all of this will fail to pass the Criteria 50.59. Would it not? So you would actually have to come to the staff.

MS. MCKENNA: We're approaching it from

looking at it as being the method for determining the inspection locations.

CHAIRMAN APOSTOLAKIS: Right.

MS. MCKENNA: We're looking at it as being Criteria A method of evaluation. The criteria that's established is that if you're changing from the method that you had in your FSAR to another method that has been approved by the NRC for the intended application, that is a change that can be done under 50.59.

MR. DINSMORE: You don't have to answer the other seven questions.

MS. MCKENNA: Right. If it's methodology.

CHAIRMAN APOSTOLAKIS: It's only methodology here? You say you are reducing the number of locations.

MEMBER SHACK: You're changing the method that you're selecting the inspection.

MR. DINSMORE: Right.

MS. MCKENNA: It has that effect, yes.

MEMBER SIEBER: But that's already been approved by the staff as a generic methodology. So it doesn't result in an unreviewed safety question.

CHAIRMAN APOSTOLAKIS: No. But it has been approved for regional solid of the exclusion rate.

MR. DINSMORE: We're in the process. If we issue this SE, it will approve it for use specifically in this region. The SE even says that.

CHAIRMAN APOSTOLAKIS: Let me understand this. Before this, we were inspecting at how many locations?

MR. DINSMORE: At 100 percent.

CHAIRMAN APOSTOLAKIS: At 100 percent. Now it's going to be in a smaller number.

MR. DINSMORE: Yes.

CHAIRMAN APOSTOLAKIS: You consider that a change in method. Is that an unresolved question?

MR. DINSMORE: No. We're reviewing it as a change in methodology.

CHAIRMAN APOSTOLAKIS: That's what I'm saying. Why is that so? It doesn't sound to me like it's a change in method. It's a change in results. You are inspecting less.

MEMBER ROSEN: I think it's a change in method that results in a change in results. It's a change in the methodology.

CHAIRMAN APOSTOLAKIS: Which results though in a real change which may effect initiating events.

MR. DINSMORE: But all methodology changes could result in a real change.

CHAIRMAN APOSTOLAKIS: All?

MR. DINSMORE: I think so.

MEMBER SHACK: The assessment will find that it doesn't significantly increase your risk.

MEMBER SIEBER: The generic assessment. The SER.

MEMBER SHACK: If you follow the methodology.

MR. DINSMORE: Yes.

MEMBER ROSEN: George, you're having a bad day.

MR. ALI: This is Syed Ali from the staff again. The original EPRI methodology is specifically excluded from its scope the application to this region. So what they are doing now is coming with an addendum to that methodology that says their methodology can be applied to this region also.

We are reviewing that addendum. If we approve the addendum then we would have approved the original methodology but now being applied to this region also. There are some slight tweaks to the methodology changes. But it's basically the same methodology.

MR. DINSMORE: I think the idea is first

put out this NEI 97.06 that if you use this approved methodology or an approved methodology for the purpose it was approved for, you don't have to address those other questions. The NRC has accepted that as guidance for using 50.59.

MEMBER KRESS: These pipes penetrate the containment generally. There's isolation valves on either side of the containment. If the pipe breaks on the other side of containment, you've automatically violated your containment.

MEMBER SIEBER: Not if the valves work.

MEMBER KRESS: Well, the valves are generally open. You have to close them. Right?

MEMBER SIEBER: Well, they close generally automatically.

MEMBER KRESS: What I'm trying to reconcile is that 1.174 and by extension to the inservice inspection part of 1.174 there's a stipulation that you don't violate the defense in depth principle. It seems to me like this is a defense in depth consideration. I don't know whether it violates it or not. It appears to violate it to me, but I'm not sure.

CHAIRMAN APOSTOLAKIS: No. The 1.174 says the defense in depth philosophy.

MEMBER KRESS: Well, that's a philosophy.

CHAIRMAN APOSTOLAKIS: So that's a way out of that.

MR. DINSMORE: Well, we include the spatial effects of the failure of this piping in the evaluation. Exactly what you gentlemen are talking about is why we have a much more well defined spatial effects evaluation process in the TR instead of leaving it somewhat up to the licensees to develop and document how they want to address spatial effects.

In this case, we've taken the extra step. We've put in a good bit more description and criteria about how they're supposed to do that analysis. But if the results of the analysis are acceptable according to all the other criteria that we have, then it's okay.

MEMBER LEITCH: It seems to me that if you get past this first issue of the questionable definition of methodology and you applied the other seven questions, it would fail. Would it not? Clearly it would fail.

CHAIRMAN APOSTOLAKIS: Yes. Clearly fail.

MEMBER LEITCH: So if the whole arguement is hinged on the definition of methodology then you're not going to get to the others.

CHAIRMAN APOSTOLAKIS: Exactly.

MR. DINSMORE: It might not fail so bad though because we did look at the questions a bit.

MEMBER SIEBER: My way of looking at it, and you can correct me because it's a simple way of looking at it is that if it fails, that means it is an unreviewed safety question. Then you have to go to the staff to get approval.

MR. DINSMORE: Right.

MEMBER SIEBER: But they've already approved when they write this SER the methodology. So it's no longer an unreviewed safety question. I think that's what that means. So you don't end up having to go down that chain of questions to legitimately apply the methodology because the staff has already approved the methodology. Is that a way to look at it?

CHAIRMAN APOSTOLAKIS: How does that compare with the earlier information that Andrea gave us about the number of plants submitting risk-informed ISIs and being reviewed by the staff?

MR. DINSMORE: But that's a totally different process.

CHAIRMAN APOSTOLAKIS: You are reviewing the process that you have.

MR. DINSMORE: If you want to get a relief from applying, that's going to be Section 11 inspections, you have to come in to the staff and request relief.

MEMBER SIEBER: An exemption. Right?

MR. DINSMORE: It's a relief request.

CHAIRMAN APOSTOLAKIS: So that doesn't apply here.

MEMBER SIEBER: From 50.55(a).

MR. DINSMORE: Yes.

MEMBER SIEBER: Right.

MR. ALI: Again, it's Syed Ali. I just want to add something on that also. In the original program, they were specifically going below the inspections that are required by ASME 11. So they had to come in for a relief. Here in this region there's ASME piping and there's non-ASME piping.

For ASME piping that is in this region, they would have to maintain at least the ASME 11 inspections in order to apply 50.59 and not come for a relief. If they go below the ASME 11 then it will go into the same kind of a treatment as the rest of the plant. They will have to come in with a relief request. So the floor is still the ASME 11 in this region for the 50.59 process to be applicable.

MEMBER LEITCH: The actual floor is about a 10 percent inspection.

MR. ALI: Well, it's 25 percent for ASME class 1 and about 7 and a half for ASME class 2. That's the ASME level in the floor.

CHAIRMAN APOSTOLAKIS: Well, I guess if it's clear to all the members, we can go ahead.

MEMBER LEITCH: Just one more question. Is that 25 percent per 10 year interval?

MR. ALI: The 25 percent per each 10 year interval, yes.

MEMBER LEITCH: Thank you.

MR. DINSMORE: Okay. Now we move to the consequences. We'll explain a little bit again the difference between BER piping and non-BER piping. The non-BER piping had pipe failure postulated during the design and evaluated using these SRP guidelines. The mitigative hardware was added as needed. I guess we already talked about this a lot.

In the BER piping, the pipe failures were not postulated and the mitigative devices were not constructed. So essentially when we did the original risk-informed ISI we were looking at the non-BER piping because that's the only place they were changing inspections. We were more or less crediting this SRP analysis out there. They had done this SRP analysis one time already. So these guys can do their PRA realistic analysis on top of that.

Now inside the BER piping, we don't have that fall back. It's just whatever is there. That's the reason in the EPRI BER TR, we essentially said you can use the SRP guidelines or criteria or somewhat more conservative. They can use somewhat more conservative because it's not as sensitive. What the result is, is that the segment goes into higher medium. The result of that is they do 10 percent or 25 percent of inspection.

It's not that they have to build in all this equipment. So I think the two pilots were somewhat conservative because it didn't hurt them that much to be conservative.

MEMBER LEITCH: Once again I just want to make sure I understand this. Under the BER piping, the reason that pipe failures were not postulated is because this particular piping was very conservatively designed and because we were going to do 100 percent inspection.

MR. DINSMORE: Right.

MEMBER LEITCH: Not because it's not important. In fact it's to the contrary. It's very important.

CHAIRMAN APOSTOLAKIS: Yes. I think that was the reason.

MEMBER LEITCH: These are high energy pipe lines.

MEMBER SIEBER: Some are, some aren't.

MR. DINSMORE: We're working on it.

MEMBER LEITCH: It's main stage. It's feedwater. Isn't it?

MEMBER SIEBER: Sure.

MR. SULLIVAN: This is Ted Sullivan. I'd like to add a little perspective. I think Dr. Kress really hit upon it earlier. You couldn't postulate a break in these areas. If you postulated a break for example in a boiler and coupled with it the single failure of the isolation valve --

MEMBER KRESS: Or leaking at that.

MR. SULLIVAN: You violate containment. So it's really an outgrowth of that.

MEMBER LEITCH: All the more reason for inspection though as I say. I agreed you couldn't postulate a break. But I just don't understand the logic of this. If you couldn't postulate a break, it's not because it's not a problem. It's a big problem. So all the more reason to inspect.

MR. SULLIVAN: I don't disagree with you.

There are some representatives of industry here if they want to add to what I'm saying, industry's view was that these are fairly high radiation areas. They really have not been finding anything to speak of or much to speak of from doing these inspections.

They've done thousands and thousands of weld inspections. The performance of this piping is very good. So what they proposed and we've been reviewing is a concept of focusing inspections basically for cause. Where is the degradation expected to have some potential to occur? Let's inspect in those regions and couple that with regions where the consequences would be high rather than forcing the licensees to continue to do 100 percent in a lot of area where they really can't even identify a potential degradation mechanism.

CHAIRMAN APOSTOLAKIS: It's a performance based initiative. Because they haven't found anything in many inspections, they say why should we keep doing this.

MR. DINSMORE: Why should we keep doing 100 percent?

CHAIRMAN APOSTOLAKIS: Yes.

MR. DINSMORE: I think that's right.

MEMBER KRESS: That's a different

arguement than we've been hearing.

CHAIRMAN APOSTOLAKIS: It's a very different arguement.

MEMBER KRESS: It's a more persuasive arguement.

CHAIRMAN APOSTOLAKIS: In fact, it's much more persuasive, yes. This is not risk-informed stuff. This is performance based.

MEMBER POWERS: In fact, it has to be a risk-uninformed thing. I mean, WASH 1400, NUREG 1150 all tell us if you want to get yourself in real trouble you have a bypass accident.

MEMBER KRESS: That's exactly right.

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER POWERS: So if you bust these pipes, you have a bypass accident. Anything that degrades your confidence in these, would have to be a risk-uninformed activity, inverse of risk-informed.

CHAIRMAN APOSTOLAKIS: You would never pass 50.59. You just don't.

MS. KEIM: We have someone from industry that would like to speak.

MEMBER KRESS: You might if you postulate that the inspections aren't doing you any good because they never found anything.

CHAIRMAN APOSTOLAKIS: No. The inspections are always doing something good. They never found anything. That's strong evidence that the uncertainty has been reviewed significantly. Right?

MR. DINSMORE: Yes, sir.

MR. BALKEY: This is Ken Balkey from Westinghouse. I'm working with our team on the Westinghouse Owners Group methodology. They fall as the same procedure in the EPRI method as well.

To add to Ted Sullivan's comments, when we did the risk-informed ISI work from the original topicals a few years ago, we learned a lot. That ASME code had 25 percent and 10 percent. There was a history of how they came up with that. It just says there's a history is why there's 100 percent here.

To do these exams, it's not simply just go out. They are in congested areas and high radiation areas. There are only so many examiners to go around as well too.

When we did the risk-informed ISI process with either method to do the Section 11 exams, we feel that we've done a real service. Even though we're doing a smaller population, we are in the process of moving the exams to the areas of active degradation. Therefore making very good use of the utility's resources in doing those examinations.

We knew about this area when we did the original program. We even had a lot of discussion with the NRC of could we include this, even in the original topical three or four years ago.

The staff felt and industry agreed that we have to take one step at a time here. It was enough of an issue to get through the ASME Section 11 exams and working through a regulatory process with the relief as Andrea said in terms of utilities making submittals and getting approval for a relief request.

The industry now said we should be able to take the same knowledge we just gained from that program, and apply it to the high energy line break exclusion region. We're not taking exams down to zero. I think we're trying to support what Dr. Kress said. Do you really 100 percent to give you assurance that the integrity is good within this piping?

If it was easy to do, we wouldn't be here. They are difficult exams to do. So we're saying can we do a smaller population and still get the same level of assurance in this region like was done in the same piping for the Section 11 program. All the questions in terms of if it breaks, would it take out other areas or what it's effect is from a PRA, we still have to look at that. There are areas where we will not remove examinations because the PRA indicates them a consequence. You really still need to do a number of exams in that area.

In summary, what we are trying to do is really take what we learned on the original application and now extending it to this for the 100 percent. It does free up the resources to really get at some other degradation issues we're dealing with in our plants.

MEMBER KRESS: Let me ask you a question.

MR. BALKEY: Sure.

MEMBER KRESS: When you say 25 percent of piping instead of 100 percent, let's just pick a number.

MR. BALKEY: Okay.

MEMBER KRESS: Does that mean you eventually inspect all the piping? You would only spread it out in time a little more.

MR. BALKEY: That's a good question. The original concept for the 25 percent came from 30 years ago. You do 25 percent in the first 10 years, 25 percent in the second and so forth. So over the life of the plant, you do 100 percent.

But guess what? As plants operated, folks said we did the first 25 percent and we really should go back and take a look to see if anything changed. If you go another 25, going back to a location you just did 10 years ago and you get a different signal from your ultrasonic, you know degradation is under way. So you're better off getting to a smaller population and really monitoring the degradation closer than trying to do it all one at a time.

MEMBER KRESS: You could do a combination of those two.

MR. BALKEY: Right. In this application, the intent would be you'd have a smaller population. But they are the areas that you would expect degradation and of course areas of high consequence. You would go back to those areas each ten year interval.

CHAIRMAN APOSTOLAKIS: So you are always inspecting the same 25 percent?

MR. BALKEY: Yes. Or whatever the percent ends up being in this region. Yes. You would go back to the same. But the program also as part of its update if you find something whether it's in the Section 11 program or if it's in a break exclusion region, you may have to expand your sample. Not may, it is.

There's a sampling scheme that if you find something in that outage, you have another population that sees it now somewhere else you weren't inspecting. If you find something there, then you're doing 100 percent of your area. So the process allows you to get to 100 percent if you start finding degradation in the sample that you're doing.

MEMBER LEITCH: How big an issue is ease of inspection in determining which 25 percent?

MR. BALKEY: I would actually ask one of my colleagues here who is an examiner at his plant. Dave, do you want to speak to the difficulty in getting to some of the locations.

MEMBER LEITCH: I know some of the locations are very difficult. My question was really how do pick your 25 percent.

CHAIRMAN APOSTOLAKIS: Do you pick them randomly?

MR. BALKEY: Right now Dave has to do 100 percent of the exams at his plant.

MEMBER LEITCH: I know some of them are really hard. What I'm saying is when you determine your 25 percent sample view, do you eliminate the real hard ones?

MR. BALKEY: No. I can give you an

example. Turkey Point is one of the plants that's been submitted not for break exclusion but in the original Section 11. We looked at their risk-informed ISI. We indicated in their surge line for their operational experience. They had to do 100 percent of the surge line.

That was a very difficult finding because they had to go back and spec underneath the pressurizer. It's a very high radiation. But we said you have to examine it because of the information you had. We would use the same philosophy. The same philosophy would apply here.

Just because it's hard to get to is not the reason you would drop it out. If you find it's an area of degradation and your PRAs telling you that it's really important if it fails, unfortunately you're going to have to go in and make the effort to do the examination.

MEMBER KRESS: What is the risk criterion? How do you establish whether the one pipe section is more risky than another one? Is it because of equipment that may be around it?

MR. BALKEY: Yes.

MEMBER KRESS: Is it the size of the pipe or the flow rates or a combination?

MR. BALKEY: It's a combination of the temperatures and pressures. That's part of what Stephen was talking about and the consequence evaluation on this slide here. One has to go in and look a lot more carefully. You look at your pipe whip for jet impingement effects and also flooding effects on the electrical equipment if there's anything that happens to be nearby.

MEMBER KRESS: That's how you decide the risk.

MR. BALKEY: Yes. That's part of the process.

MEMBER ROSEN: The functions of the piping as well.

MR. BALKEY: As well as the functions of the piping. We usually break it in to a direct consequence to address the functions. Then the indirect effects are the pipe whip and jet impingement of pipes whipping and taking out other equipment nearby. That has to be done as part of the process.

MEMBER KRESS: Thank you.

MR. DINSMORE: Okay. I'm not quite sure this is resounded. We do use some risk information in the process. So that they don't have to come in with a submittal, you have to keep that in the back of your mind, the quality of the PRA needs to be the same acceptable quality as for risk informed ISIs since it's pretty much the same process.

MEMBER SHACK: Can he do this without having a risk-informed ISI program for his Section 11 piping?

MR. DINSMORE: They can apply this to the BER region without doing a risk-informed ISI.

MEMBER SIEBER: Right.

MR. DINSMORE: Within the BER region then as Syed was saying earlier --

MEMBER SHACK: Could you do it with 50.59?

MR. DINSMORE: Yes. But you couldn't change the ASME Section 11 inspections if there are any in this BER region. You could only change the BER specific ones.

MEMBER ROSEN: Do you expect anybody to actually do that, someone who hasn't done the basic risk-informed ISI?

MR. DINSMORE: I have Pat O'Regon back there nodding. He's from industry. So I have a feeling he knows.

MR. O'REGON: I'm Pat O'Regon from EPRI. The answer is yes. There are several plants that would like to implement BER only. In particular a couple of BWRs will be implementing BWR VHP 75 on the stainless steel piping and risk-informed BER on the carbon steel piping.

MEMBER POWERS: How would the quality of your PRA affect the conclusion that seems to be robust trough all PRAs that containment bypass accidents are very hazardous accidents?

MR. DINSMORE: Well, they would assign a pretty high conditional core damage probability or a conditional large early release probability to those segments which would contribute to those sequences. Then it would be up to whatever degradation mechanisms are in those segments.

If there's no degradation mechanism and a very low failure probability then those segments would be lower risk. If there's some degradation mechanism and a high probability, there would be a higher risk.

MEMBER LEITCH: Do we have any idea how much man-rem per plant per year is attributed to the execution of this program as it now stands? In other words, what's the man-rem saving per plant per year estimated to be?

MR. DINSMORE: Maybe industry would know. I don't. I guess not. No.

MEMBER ROSEN: Another way to look at that same question is what's the percentage reduction in the program that would come out of this. How big an effect is it on the remaining overall program? Can you give us any feel for that?

MR. DINSMORE: The EPRI TR says that if you get below 10 percent, you need to provide a good explanation of the design features in your plant which supports finding that you have to inspect less than 10 percent of the welds in this region.

MEMBER ROSEN: That's not exactly the question. That's not the answer to the question that I thought I asked.

The question is let's say before you have a start at this you were inspecting 1,000 welds in the 10 year period. Then you go to risk-informed ISI. Now you're only inspecting 350 welds. You knocked out two-thirds of them which I think is the number I remember.

So you're down to 350 welds in the 10 year period. Now can go to break exclusion piping and knock that out. Now you're inspecting not 350 but only 175 or 300? I'm trying to get a feel for the additional reduction.

MR. DINSMORE: This is one of the pilots that we didn't review by the way we just looked at it.

If you had 135 welds, one of them went down to 20 for example. So that's about 11 percent. The other one went down to 3 percent.

MEMBER ROSEN: Wait a minute. You said 135 and you went to 20.

MR. DINSMORE: Yes.

MEMBER ROSEN: That's a reduction of almost 90 percent. Right?

MR. DINSMORE: That's because we're starting with 100 percent. You see if you start with ASME --

MEMBER ROSEN: Out of 135 welds you're total example was the BER scope.

MS. KEIM: Yes.

MR. DINSMORE: Right. You inspect them all to start with. In the ASME class 1, you were going from 25 percent down. Here you're going from 100 percent down.

MEMBER ROSEN: So basically it's a very large reduction in the BER scope.

MR. DINSMORE: It can be.

MEMBER KRESS: When you do the risk assessment to calculate the change in LERF for example, can you check it along with the absolute LERF? If you have more than one unit on the side, are you going to add the LERFs together?

MR. DINSMORE: We don't have process to deal with that. If you had more than one unit on the site I think what happens is if you add the two together, the relative increase would be the same. We don't really apply these criteria.

MEMBER KRESS: No. You have an absolute LERF then you have a Delta LERF. The Delta LERF stays the same. If you do it to one unit only, the Delta LERF is for the unit. But the LERF is a LERF for the site. It ought to be the sum of all the plants that are on the site. That's a glitch or a short coming of 1.174 that I've been trying to get fixed. That's why I ask the question every time.

MR. DINSMORE: We haven't fixed it in this SE.

CHAIRMAN APOSTOLAKIS: A straightforward answer. You'll wait until 1.174 is fixed first I imagine.

MR. DINSMORE: Right.

CHAIRMAN APOSTOLAKIS: Okay. Let's move on. Go to 11.

MR. DINSMORE: This is 11.

CHAIRMAN APOSTOLAKIS: This is 11?

MR. DINSMORE: I have a different

numbering system.

CHAIRMAN APOSTOLAKIS: So what number do you have for this one?

MR. DINSMORE: I have 11 for the other one. We took one out. We put one together.

CHAIRMAN APOSTOLAKIS: We discussed this. Didn't we?

MR. DINSMORE: Yes. We discussed this in the beginning. We can just maybe even skip it.

CHAIRMAN APOSTOLAKIS: Yes.

MEMBER KRESS: This is the final conclusion you have.

MR. DINSMORE: Right.

CHAIRMAN APOSTOLAKIS: Now let me understand the first bullet. As I recall Regulatory Guide 1.174 as we said earlier today has a beautiful discussion of uncertainties incompleteness, models. Are you guys doing any of that?

MR. DINSMORE: Those are included mostly in the system level guidelines. We don't allow them to for example take a bad weld in a dangerous system and start inspecting that. They get a big plus risk from that and use that to stop inspection many welds in other systems. We don't believe that the numbers support those type of large shuffling of risk.

CHAIRMAN APOSTOLAKIS: When you say the basic acceptable quality of the PRA is the same as the risk-informed ISI, so you have already approved 46. Right?

MR. DINSMORE: Right.

CHAIRMAN APOSTOLAKIS: These are 46 submittals. You are now reviewing four.

MR. DINSMORE: There are five. We got one yesterday.

CHAIRMAN APOSTOLAKIS: Five. Okay. So you are really busy then. When you reviewed the 46, did you look at issues like model uncertainty and incompleteness? My impression is that nobody's doing uncertainty analysis anymore.

MR. DINSMORE: What we required for the risk-informed ISI is that the licensee go back and look at all the negative comments made by the research review and the peer review process, the BWRG. They evaluate all these comments and make sure that either they don't affect the results of the ISI analysis or that they incorporate somehow the comment into the evaluation.

CHAIRMAN APOSTOLAKIS: But what if the PRA has not done an uncertainty analysis at all? We were told last month that asking for uncertainty analysis means killing the program because nobody does it. So I don't know how you conform with Regulatory Guide 1.174 if you don't do that.

MR. DINSMORE: Well, I think 1.174 says that if you do a reasonably conservative analysis or if you do something that you think is a bounding analysis, you can address uncertainty in that way.

CHAIRMAN APOSTOLAKIS: I thought 1.174 really looked at all these uncertainties. How do you know something is conservative if you don't understand the uncertainties? Don't you have to understand what is uncertain first before you say now what I'm doing is conservative?

MR. DINSMORE: It's also that the uncertainties in the pipe failure probabilities are probably much larger than in the PRA.

CHAIRMAN APOSTOLAKIS: That's also true. So how are these uncertainties handled?

MR. DINSMORE: We handle them by having different criteria. Again this risk level criteria, we don't allow them to move risk around between systems very much. The risk level criteria is you can't get more than a 10 to the minus 7th increase in LERF.

So it's a factor of 10 below the plant

level criteria. It's regardless if you only have three systems. Then the plant level is going to be 3 times 10 to the minus 7th and not 1 times 10 to the minus 6th.

We've tried to deal with uncertainty by putting in this backstop of what you can move and what you can't move. We've actually done it in the BER program as well. We've taken the BER program by itself. They have to apply the same criteria to the BER program.

In other words, every system within the BER program they cannot increase the CDF by more than 10 to the minus 7th per year. For the total BER program although it's not really useful, they couldn't increase the CDF by 10 to the minus 6th. Then if they put it together with the risk-informed ISI, they have to apply those criteria to the total change as well.

So there's a couple of steps in the criteria. That's the main --

CHAIRMAN APOSTOLAKIS: What you're saying is that they don't need to do the uncertainty analysis because the criteria we have established have allowed for the uncertainties that you may have which is a new interpretation of 1.174.

MR. DINSMORE: We used it in the basic

programs.

CHAIRMAN APOSTOLAKIS: I understand that you have used it. Okay. Let's go on.

MEMBER ROSEN: I have a question about those few licensees that might come in and just want the BER program. Would they have to come and get approval or could they completely avoid any review, just do 50.59 and off they go?

MR. DINSMORE: If they don't change the ASME Section 11 or any other licensing basis, they could. Yes. They would not have to come in. They could just do it. They have to put it in their yearly report that they've done it.

MEMBER ROSEN: So the staff would never get a chance to talk to them about their PRA and how good it is or any of those things.

MR. DINSMORE: No. But they're required to do the same analysis which we've been requiring them to do for risk-informed ISI which is to take all the comments and everything and document it. The documentation requirements to be maintained onsite are the same if they just do the BER as they are if they do a risk-informed ISI. It's just that they don't send us anything.

MEMBER ROSEN: That part troubles me quite a bit. At least in the basic risk-informed ISI program licensees came in with the EPRI method. The staff reviewed what they wanted to do, looked at their PRA and their peer review and had some handle on it. With the small number of licensees I'm told who would never have to go through that process, could use 50.59 and change the break exclusion region piping sample size without any staff at all of anything except after the fact.

MR. DINSMORE: We do very limited reviews of the PRA. Really all we ask for is who said what bad things about your PRA and what did you do about them. We look at what they do. They usually give a reason. If somebody said you had a bad human error, they say we applied these new methodologies and so on.

We've occasionally gone back and said that's not enough, please give us more. But that's not often. These guys if they just do the BER, they're still going to have to do the same process. If we go out and eventually audit one of these guys and they didn't do it or they didn't document it, then I'm not sure what we'll do. But we'll do something.

MEMBER LEITCH: I'm still a little bit confused with the approval of this proposal. What determines whether it's 25 percent or 10 percent?

MR. DINSMORE: Well, 25 percent of the welds in high safety significant segments have to be inspected. The 10 percent of the welds in medium safety significant segments have to be inspected. That's a hold over from the old methodology.

MEMBER LEITCH: So the determination is based on whether it's high or medium safety.

MR. DINSMORE: Right.

MEMBER LEITCH: There are no low safety significant systems in this set, I guess.

MR. DINSMORE: There are. You do not have to inspect those.

MEMBER LEITCH: Are they inspected now?

MR. DINSMORE: On the BER everything is inspected, yes.

MEMBER LEITCH: So there are some where there are low safety significant that you would go from 100 percent inspection to zero inspection. Is that what I understood you to say?

MR. DINSMORE: That's correct.

CHAIRMAN APOSTOLAKIS: I'm missing something here. Has anybody objected to that? Why are they reluctant to do that when we talk about option 2? The low risk significant SSC still impose some requirements. They are unwilling to lump them with non-risk significant. Yet for pipes it seems that they're willing to go to zero.

MR. DINSMORE: Well we did a bounding calculation.

MR. O'REGON: Pat O'Regon from EPRI again. We looked at three plants, two sites out of the BER application. We did find some low safety significant locations. But they were as a result of the utility conservatively applying the BER rules. They extended piping beyond where they would have had to if they held strictly to the SRP requirements.

So that's why they fell as low safety significant. They weren't big pipes that created big holes in containments. As Steve mentioned, the high, medium or low are from the EPRI TR ISI, the base case methodology where we rank things as high, medium or low. We just kept that consistent when we extended it to the BER programs.

CHAIRMAN APOSTOLAKIS: All right.

MR. DINSMORE: The methodology is consistent with the EPRI Topical Report. The inconsistencies are the things we've explained to you. The changes to BER program as described in the FSAR may be made under 10 CFR 50.59. Inspections within the BER program to change that come from other regulatory requirements need to be changed according to how you change the other regulatory requirements.

MEMBER SHACK: Anything else?

CHAIRMAN APOSTOLAKIS: No letter. Right? No request for a letter.

MEMBER SHACK: There's no request for a letter.

CHAIRMAN APOSTOLAKIS: So there will never be a letter.

MEMBER SHACK: Not unless we decide one. They're not requesting one. We can discuss whether we want to send one.

CHAIRMAN APOSTOLAKIS: Okay. Anymore questions to the lady and the gentleman?

MEMBER POWERS: Well, there's another point to be made. That is it is true enough that bypass accidents are risk dominant. But bypass accidents initiated by failure of this particular piping don't show up in the PRA at all. They never occur.

MEMBER SHACK: There is one difference though. When we did the original in service risk-informed, you could make the argument that you were in fact approving safety. Obviously you might have been looking at fewer welds. But you were looking at the more important welds. So you could make an argument that your Delta CDF could have gone down. In this case, it might be a small change but it has to go.

MR. DINSMORE: That's part of the reasons that we applied the criteria specifically to the BER as well. That was the best way we could think of to deal with that.

MEMBER POWERS: But you still have this performance observation.

MEMBER SHACK: Right.

CHAIRMAN APOSTOLAKIS: That's really a powerful argument.

MEMBER SHACK: That's incorporated in the argument that you're going to apply all that good performance to assign most of this stuff to a low probability of failure. You don't want to give them double credit for that. They're going to take that credit already. Again, it's a very small change in LERF for perhaps ALARA reasons.

CHAIRMAN APOSTOLAKIS: Isn't there a table that the regional methodology has when they have the risk significant of a piece of piping? Then they have a susceptibility. That's where the performance comes.

MEMBER SHACK: That table still applies.

CHAIRMAN APOSTOLAKIS: The performance

comes there.

MEMBER SHACK: Yes.

CHAIRMAN APOSTOLAKIS: Is this for everything or at Westinghouse?

MEMBER SHACK: Yes. It's everything.

MR. DINSMORE: I wouldn't bring Westinghouse to EPRI SE.

CHAIRMAN APOSTOLAKIS: No. I mean, they have something similar I think.

MR. DINSMORE: They have something similar, yes. But you can see here if it's a really high consequence in this methodology, it would end up in a medium box even with no degradation mechanisms.

CHAIRMAN APOSTOLAKIS: Medium means?

MR. DINSMORE: The 10 percent.

CHAIRMAN APOSTOLAKIS: My concern is bigger than what you're doing. I think that the implementation of Regulatory Guide 1.174 has drifted away from what the guideline is saying. It has a lot to do with you. Are there anymore questions for Steve and Andrea? Well, thank you very much.

MR. DINSMORE: Thank you.

CHAIRMAN APOSTOLAKIS: I would ask the members to stay here for a few more minutes. Maybe we can discuss things among ourselves.

Shall we take a five minute break? Eight minutes. We don't need transcription anymore. Thank you. Off the record.

(Whereupon, the above-entitled matter concluded at 6:21 p.m.)