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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

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JOINT SUBCOMMITTEES ON MATERIALS & METALLURGY

AND PLANT OPERATIONS

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Tuesday, April 9, 2002

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Room T2B3

11545 White Flint North

Rockville, Maryland

The discussion on vessel head penetration cracking and vessel head degradation commenced at 1:00 p.m.

PRESENT:

F. PETER FORD, Chairman

Materials & Metallurgy Subcommittee

JOHN D. SIEBER, Chairman

Plant Operations Subcommittee

MARIO V. BONACA, ACRS   THOMAS S. KRESS, ACRS

GRAHAM M. LEITCH, ACRS   STEPHEN L. ROSEN, ACRS

WILLIAM J. SHACK, ACRS

MAGGALEAN W. WESTON, Senior Staff Engineer

A-G-E-N-D-A

A-G-E-N-D-A

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

(1:00 p.m.)

MR. FORD: This meeting will now come to order. This is a meeting of the ACRS joint Subcommittees on Materials and Metallurgy and Plant Operations. I am Peter Ford, Chairman of the Materials and Metallurgy Subcommittee. My Co-Chair is Jack Sieber, Chairman of the Plant Operations Subcommittee.

ACRS members in attendance are Mario Bonaca, Thomas Kress, Graham Leitch, Steve Rosen, and Bill Shack. We also have Region III on videoconferencing. Can you hear us in Region III?

VOICE: This is Region III. We can hear you.

MR. FORD: Great. The purpose of this meeting is to discuss the vessel head penetration cracking and vessel head degradation issues. We have had a number of subcommittee meetings on the former issue, and this meeting will also include the head degradation issue observed at Davis-Besse.

Ms. Maggalean W. Weston is our cognizant ACRS Staff Engineer for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting published in the Federal Register on March 22, 2002.

A transcript of the meeting is being kept and will be made available as stated in the Federal Register Notice.

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

We have no written comments from members of the public regarding today's meeting.

For the first hour we will be talking primarily about the cracking issues and Bulletin 2001-01. For the rest of the afternoon we will be talking about Davis-Besse degradation issues and Bulletin 2002-01. We have a very full agenda and ask everybody to keep to the agenda, as written.

Jack, do you have any comments to add?

MR. SIEBER: Not at this time. Thank you.

MR. FORD: We will now proceed with the meeting, and I will begin with Ms. Wetzel to start for us.

MS. WETZEL: I'd just like to follow up on what you said about the two bulletins, and I'd like to try to set the tone of the meeting that way.

There are two bulletins, Bulletin 2001-01 which deals with the circ issue, and that's what I will be summarizing, and Allen Hiser will be discussing some of the technical issues, the status of the technical issues, now there is the Davis-Besse issue, and the bulletin that was issued in response to Davis-Besse, Bulletin 2002-01, which pertains to both the head condition and axial cracking. And for the purpose of this meeting, we would like to try to keep the technical discussions and the questions separated because if we mix them, it can get confusing.

Now, Jack Strosnider -- eventually these converge, and Jack Strosnider said he would give a summary at the end of the meeting where we think they overlap and converge.

We do have a full agenda, and I would like to just keep my remarks as brief as possible. I am the lead Project Manager for Bulletin 2001-01, and I'm just going to give a brief status of where we are on that bulletin and the action plan for that bulletin, and we will have many technical presentations to follow, and you can -- there can be interrogations -- I mean, questions for the --

MR. FORD: It might be interrogation.

MR. SIEBER: It's her words.

(Laughter.)

MS. WETZEL: I wrestled with how to deliver that.

(Slide.)

Just to discuss our handouts, the NRR folks are going to give three presentations and they will be at separate times throughout the agenda. So, I did try to separate the presentations there for you.

Bulletin 2001-01 is divided into short-term management and long-term management, and right now we're in the short-term management trying to get to the long-term management of this issue, and the short-term management is through dealing with each plant on a specific basis, receiving the responses which we've all received, inspections, and we plan to issue three NUREGs summarizing the bulletin -- one summarizing the bulletin responses, one summarizing the inspection results, and a third one summarizing our technical assessment of the bulletin.

And we also have some policy issues, and the policy issues, the main one is managing this through leakage or managing this through nonleakage, and that is a major policy issues to resolve.

MR. FORD: You're going to manage it by just regular inspection looking for leaks rather than looking for cracks per se? Is that what that means?

MR. HISER: Yeah, there are tech spec requirements of no leakage, and the concern relates to do we allow a leak detection to be the main management tool, or should ultrasonic, some sort of volumetric, any current -- some sort of examination like that that is capable of detecting part-through-wall cracks, the head of the leakage, is that necessary.

MR. BATEMAN: This is Bill Bateman, from the staff. I juts want to clarify that as it stands right now, we are managing this issue through leakage detection. That is how we are currently managing the issue, through leakage detection.

MS. WETZEL: Which may be not looking under the vessel at all, just doing qualified visuals on the top of the heads.

MR. FORD: Could you just put a time scale on the short-term management versus the long-term? Short-term will be completed when?

MS. WETZEL: Well, we would like to get out of the short-term because it is very resource-intensive for both the staff and the industry because we are basically dealing with this plant-by-plant, on a plant-specific issue.

Now, the Bulletin 2001-01 only covers the first round of inspections, and those should be completed by the end of calendar year 2002. In fact, I guess some second rounds start in 2002, but we would like to have some long-term guidance in place by January 2003, and that's -- you jumped ahead to my last slide, but I'll discuss that a little bit more.

(Slide.)

Long-term management, there's three parts for developing our long-term management, which the goal would be to have ultimately some type of guidance, regulatory guidance or requirements in place for inspections and inspection frequency, and in order to do that we need to determine criteria, we need to determine the appropriate regulatory tool --a nd i've got some listed up there -- and then we would implement that regulatory tool.

(Slide.)

Technical issues -- these are the explicit items that both the industry, the MPR and the NRC have agreed on that are the technical issues that need to be resolved in order to reach our long-term goal. And I've just got a listing of them here, and Allen is going to give a brief status on where we are on each of those technical issues.

(Slide.)

Industry/stakeholder interactions. That is a very large part of our action plan. We are not trying to solve this alone, we are dealing with the MRP and the industry. We plan to come to you much more, I'm sure. We've got other oversight groups, public meeting, many public meetings, and we have a Web site -- we actually have two Web sites, one for each of the bulletins now -- and we try to put all of our material up on that Web site for the public to see.

(Slide.)

Conclusions. Our main goal is to get out of this plant-specific -- where we are right now, dealing plant-by-plant, and have generic guidance in place, and we do have these goals of the selection of the appropriate regulatory tool, completion of our technical basis supporting that regulatory approach. We do have some dates in our action plan for these, and they are very -- it's a very aggressive schedule, and we're not sure where we stand with that because Davis-Besse and other plant-specific issues that we've been dealing with, we have been working closely with the MRP and NEI, and we do feel we're trying to work to the same aggressive schedule to have some guidance in place, some requirements in place for the next round of inspections, which would be Spring of 2003.

MR. FORD: The time scale for both the short-term and the long-term, an integration of the two, one into the other, is it appropriate given the risk of this particular degradation mode, presented by this degradation mode? I mean, you talked about the short-term ending end of 2002-2003. I'm assuming that the long-term is five years? I don't know. For some of these technical issues, you are talking five years in a normal course.

MS. WETZEL: You mean to resolve the technical issues?

MR. FORD: Correct.

MS. WETZEL: We're looking at resolution of the technical issues to input into our regulatory tool that we would start to initiate implementation of in January 2003.

MR. FORD: Oh, so the short-term and the long-term meld into each other?

MS. WETZEL: Yes. Yes.

MR. FORD: On a very short time scale.

MS. WETZEL: It's a very short, very aggressive time scale, but right now the Bulletin 2001 only has guidance out to the industry for this first round of inspections, and we would like some more generic guidance, and they need it for planning purposes. They are ordering new heads.

MR. FORD: Jack?

VOICE: I think the hope is that we will have enough experience from the inspections that have been performed and with the technical analyses that we would be able to perform, that we could go ahead and put in some in-place requirements for inspections that would serve the long-term interest.

MR. FORD: Okay.

MS. WETZEL: We might not have -- by January 2003, for instance, if rulemaking is required, we're not going to have rulemaking completed, but we would hope that guidance would be in place for inspection, what type of inspections would be necessary, and frequency of inspections.

(Slide.)

MR. HISER: To follow up on Beth's overview of Bulletin 2001-01, I want to go over some of the technical status. What I want to do here is provide an overview of the types of inspections that have been performed in response to the bulletin, summarize the results from those inspections, and then discuss the status of the technical issues that Beth listed on one of her slides.

(Slide.)

If you remember in the bulletin, we had the PWR plants in four categories. The first category were those plants that had experienced cracking or leakage from CRDM nozzles. The second group of plants was termed high-susceptibility based on a susceptibility ranking model that the industry proposed. The next two groups we term moderate and low susceptibility. Within the context of the inspections that have been performed since issuance of the bulletin, the plants with a cracking or leakage history and those plants that are in the high susceptibility bin have generally performed qualified visual examinations of the head, looking for boric acid deposits.

In some cases, the licensee did opt to do either ultrasonic examination or an AD-current examination of all of the nozzles to provide additional assurance. In the case of the visual examinations, if licensees were not able to determine that a specific nozzle was free of any deposits, they would then follow up using ultrasonic testing to determine whether there were flaws in the nozzle. And in addition, ultrasonic testing was also used for sizing of flaws in nozzles that had clear deposits on the head.

MR. FORD: The presumption there, Allen, is if you do not see boric acid by visual inspection, that there is not therefor a crack. That is the presumption. Is it possible that you could have plugging of the annulus below the surface for which you would not see it but there is still a crack?

MR. BATEMAN: I just want to clarify, when you say "crack", you mean through-wall crack?

MR. FORD: Correct. Yes.

MR. HISER: The experience thus far with inspections of nozzles that have not shown any deposits on the head, no through-wall cracks have been identified in those nozzles. So, at least with the experience we have so far --

MR. FORD: And roughly 22 plants have been inspected, is that right, approximately?

MR. HISER: Well, about 16 inspections have been performed with ultrasonics and under-the-head sorts of methods that can really find cracks themselves, not just the deposits. I think that's one of the concerns that we have in formulating the long-term plans, is issues such as that --

MR. FORD: I guess my susceptibility in this case is to best comment that you're trying to move towards having a visual as the precursor to looking more deeply. So, if you don't see any visual, no problem.

MR. HISER: Again, within the context --

MR. FORD: I'm questioning --

MR. HISER: Within the context of the bulletin, and I think the thing we need to remember is the bulletin is a short-term one-time action that we're trying to use information from that to guide us in the longer-term direction that we need to go, in particular, given the recent results from Davis-Besse, I think that has put a different color on where things will end up going long-term. But within the context of the bulletin -- and I think the results that we have to date -- demonstrate that for the short-term I think we have reasonable assurance that we will not have any safety concerns relative to circumferential cracking of nozzles. For the longer-term, I'm not going to speculate right now as to what we'll do.

Beth mentioned one policy issue, and I'm sure there will be other issues like that, that will have to be dealt with before we can determine the long-term management scheme.

MR. SHACK: When Oconee did a second round of inspections, they came up with more cracks. Had those nozzles been looked at with the UT or AD-current? I mean, they presumably had passed a visual inspection of the first -- had they been looked at with any other tools?

MR. HISER: At that inspection, no. None of the nozzles had been inspected with UT or anything under the head.

MR. SHACK: So it's only a purely visual inspection.

MR. HISER: Right. Well, the nozzles that did not have UT were cleared last spring using visual. Let me finish this off.

With the moderate susceptibility plants again within the context of the bulletin, the bulletin described an appropriate inspection as being a visual examine of the head or some sort of an ultrasonic or AD-current examine if one could not do a visual examine of the head. Plants have either performed effective visual exams or, in some cases, ultrasonic exams of the nozzle ID. In other cases, AD-current examines of the nozzle ID and the J-groove weld have been performed.

And the low susceptibility plants were not advised in the bulletin to perform any additional examinations, and the responses indicate that they would perform inspections in accordance with Generic Letter 88-05 and in some cases they propose bare metal visual examinations of the head.

MR. SHACK: What's the difference between a qualified and an effective visual examination?

MR. HISER: An effective visual exam means that you're able to view the interface of the nozzle and the head for all of the nozzles 360 degrees around the nozzle without impediment such as insulation or other impediments to viewing that area, and also that there are boric acid deposits that could obscure the vision of that area. In contrast, a qualified visual has the same operational aspects as the effective visual, that you can see intersection of the head and the nozzle, but it also has an analysis to determine that there's a leak path from the J-groove weld to the top of the head such that if you do get leakage through the nozzle, that ultimately you should get deposits on top of the head. So it's a little higher threshold that we thought was appropriate for those plants.

MR. LEITCH: Allen, does the inspection to date call into question at all, or does it validate the criteria that was used for the binning of the plants. In other words, recall that we used effective full-power years as compared with Oconee bias by temperature to bin the plants, and I guess basically what I'm asking is based on the data to date, does it appear as though that binning is reasonable?

MR. HISER: If I can hold that just for two slides.

MR. LEITCH: Absolutely, sure.

MR. HISER: The first thing I want to do is just provide a table that has all of the inspection results for the plants that are in the first bin and the second bin, so it would include all the high susceptibility plants.

(Slide.)

In addition -- and these results include also inspections that demonstrated no degradation, I guess in the case of Robinson and Surry 2 and D.C. Cook Unit 2. In addition, results are shown for two moderate susceptibility plants for which cracked or leaky nozzles were identified.

To date, with the inspections that have been performed, seven nozzles have been identified with circumferential cracks at or above the J-groove weld. There are numerous cases of circumferential cracks below the J-groove weld, but that does not have a safety implication. In addition, at this point there have been about 48 nozzles that have been repaired.

MR. ROSEN: Allen, I derive from this table the conclusion that no cracks have been observed in low susceptibility plants, or is that a wrong conclusion?

MR. HISER: That's correct. At this point, the only plants that we found any cracks are in two moderate susceptibility plants. And I guess the one point I'd like to make about -- well, Crystal River Unit 3 was -- the nozzle was identified through the visual exam where a deposit was identified. Millstone 2, because of the head insulation package, they were not able to do a visual exam, so they actually performed an ultrasonic exam of all the nozzles. They did identify three nozzles with part-through-wall cracks, part-wall cracks. They were not through-wall. There were no indications of leakage. If Millstone had been able to do a visual exam on top of the head, they would have identified no cracked nozzles. So there is some difference, again, depending on the type of inspection that was performed. The depth of knowledge that we have from some of these inspections clearly is dependent on the type of exam.

MR. ROSEN: Because of the importance of this question, I want to be sure I understood your response. For low susceptibility plants, have they done inspections?

MR. HISER: Yes.

MR. ROSEN: And no low susceptibility plant has found any cracking, is that correct?

MR. HISER: That's correct.

MR. BATEMAN: Bill Bateman, from the staff. I'd just like to clarify that. The low susceptibility plants have not done any type of volumetric inspection. So the types of inspections that the low susceptibility plants have done have been visuals, and I'm not sure in each and every case they've been bare metal visuals, they may have been visuals with insulation in place. So, not as aggressive as the inspections that have been done by the other plants.

MR. HISER: That's correct, and depending on the insulation package, if a plant has insulation directly in contact with the head, the ASME Code required inspection would be to look at the top of the insulation. That's not real effective in finding deposits from a nozzle crack. The bulletin did not ask licensees to do any additional exam beyond what they are currently required to do, so I think that would not have been effective in determining nozzle leakage in those cases.

MR. ROSEN: So I should take only cold comfort from the idea that there's no low susceptibility plants on this table?

MR. HISER: I'd take warm comfort. There are some plants that have looked at the bare metal -- I don't have a list right now of how many have done which type of exam, but we can provide that information.

MR. FORD: On that very issue, Allen, I seem to remember seeing a slide in the packages that were received, there's many, many more UT exams done than are shown on that table.

MR. HISER: Well, all of the nozzles that have cracked or been identified as leakers have been inspected using UT. There may be some plants that have done ultrasonics that do not show up on this table.

MR. FORD: But it's important for you to have stated that because it relates to Steve's question, that when you've got down, for instance, qualified visual for Oconee plants, they have all had a UT also, to confirm that there was, in fact, cracks.

MR. HISER: Not every nozzle, for example, at Oconee 1 has had a UT exam because it has not been thought by the licensee nor, I think, the staff to be really necessary at this point. The one exception to that, it is Oconee Unit 3, which identified the first circumferential cracks last February. If you scan down the table to November, they had their scheduled refueling outage, identified seven more nozzles with cracks or leakage. Between the two inspections, they have inspected every nozzle with UT, but I believe that may be the only of the three Oconee plants that's in that condition.

MS. WETZEL: This might clarify your question. Some plants are -- they are clearing their nozzles, first of all, by doing visuals on the top. And if they can't get a visual on the head, then they will go underneath and do a UT. So, some plants will have a mix of visually cleared nozzles and UT nozzles.

MR. BATEMAN: You need to clarify that's only for the moderate susceptibility, that doesn't hold for the --

MR. FORD: I think maybe we're just going round and round on this. I think in some of the future presentations, just to reassure us, when you see a visual or not see a visual, that has a direct factual relationship to whether or not you see cracks.

MR. HISER: I would expect the next time we will provide a more thorough review of the inspection results, given the circumstances with Davis-Besse, we wanted to put this at a relatively high level.

MR. SHACK: Before you remove that, when I have a crack and I have no repairs, does that mean it's below the J-groove weld or we're operating on sort of a crack growth analysis?

MR. HISER: I think in all cases the crack is below the weld. And crack growth through the next cycle did not indicate that it would go up to the weld level.

MR. SIEBER: Is it fair to assume that the volumetric examination is better than a visual examination?

MR. HISER: I think it's more thorough because the ultrasonic exams are able to interrogate the entire volume of the nozzle. The situation as it exists right now is that the only -- you have the two components in the area are the nozzle base metal and the J-groove weld. The ultrasonic exams are not able to interrogate the J-groove weld. So, as an example, you could have a crack that is not detected that's in the J-groove weld. You may think that your nozzle is clear when, in reality, you could have a through-wall crack in the weld. So, in the context of this bulletin looking at circumferential flaws, though, ultrasonics is the preferred approach to rule out the existence of circumferential cracks.

MR. SIEBER: Based on that reasoning, it would seem to me that you need a combination of both volumetric and visual in order to provide substantial assurance that you aren't going to end up with a separation problem.

MR. HISER: Within the context of this bulletin and in segregating any Davis-Besse related issues, the ultrasonic exams can detect the presence of circumferential cracks, and we know that there's a certain time period from initiation of a circumferential crack to the growth of it to a critical size, and I think we have some comfort level in that that if we do not detect a circumferential crack today, that it will not develop to a critical size within a certain time period.

MR. SIEBER: Perhaps sometimes during your presentation you could tell us why you would not require licensees to perform both visual and volumetric.

MR. HISER: In some cases, visuals cannot be performed because of insulation package.

MR. SIEBER: Why would you not have every licensee who is in the high susceptibility category to do both types?

MR. HISER: Every plant that's in the high susceptibility bin can do a visual exam of the head.

MR. SIEBER: But why would you not have them do both visual and volumetric since each seem to address slightly different problems?

MR. HISER: As we develop our long-term management strategy, that probably will be something we'll consider.

MR. BONACA: Bill Bateman again. As I mentioned earlier, we are managing this issue right now as discussed in the bulletin, through leakage. In other words, if a plant detects a leak, then they've got to go make a repair. And when they restart, they will have fixed all the leaks. So that's how we're managing the issue.

Now, if we wanted to manage this thing such that we were 100 percent convinced there wouldn't be any leaks during the upcoming cycle, then of course it would involve doing a volumetric examination, but that's not the decision that was made in terms of how we managed the issue when we initiated this bulletin.

MR. STROSNIDER: This is Jack Strosnider. I'd like to follow up on that because it's very important to understand the context of the information we're presenting.

Bulletin 2001-01 that went out, as Bill just indicated, it provided the option basically for people to manage this problem in this first round of inspections by doing visual exams, looking for leakage. In some cases, they did under-the-head ultrasonic exams because that was actually to their benefit, depending upon the insulation type. But the information we're presenting is the responses and the results of the examinations performed to Bulletin 2001-01. And, in fact, not all those inspections are complete yet. I mean, they will go out through the end of this year. So we're collecting information on that and Allen is going to show the histogram in a minute to show where all this falls in place, which we are going to use to inform what needs to be done in terms of the longer-term program.

We're also looking at, as we get the results, to see if there's anything here that tells us we need to take some more aggressive action right now, and we haven't seen that so far. It appears that the program is finding cracks as it should, and Davis-Besse is another issue that we'll talk later in the presentation as to what the implications of that might be. But, right now, we're still collecting information in response to the first bulletin that went out. That bulletin had a graded approach for inspections where people could use visual examinations and, depending on whether they were high to low susceptibility, different levels of qualification. So we're collecting that information and Allen is basically just summarizing where that is.

There are clearly some issues that come up with regard to why doesn't everybody need to do ultrasonic as opposed to just doing visuals, and the policy that that was referring to earlier, that's one example of an issue we have to answer in order to establish a longer-term program for managing the issue. And it's very important that we ultimately get to that longer-term program because in the meantime we're managing this problem with bulletins and inspections and plant-specific activities which are very resource-intensive, but when we get back to summarizing at the end, maybe I'll say a little more about that, but I just wanted to make sure we understand what we are presenting here is in the context of the first bulletin that went out.

MR. SIEBER: Well, my questions did not refer to the data that's already been collected and ready for analysis, but what the future holds and what is the best long-term strategy that you might have. And I take it from your answer you would consider at sometime in the future make a decision related to whether both visual and volumetric examinations will be required to provide the level of assurance that is expected. Is that correct?

MR. BATEMAN: That's correct. And like I mentioned earlier, that was one of the policy issues that Beth mentioned. Do we want them to continue to manage this through leakage, or not, but that's a key policy decision that will need to be made.

MR. SIEBER: Thank you.

MR. HISER: And I guess just one short follow up, my guess is that the implications at Davis-Besse may weigh very heavily in terms of what those requirements are. And until we fully digest that information, it's hard to speculate where we'll end up.

(Slide.)

Now, this is a visual depiction of the susceptibility ranking and the results from inspections to date. The red circles indicate those plants that have identified either leaking nozzles or cracked nozzles. Within the context of the bulletin, plants that were within up to 5 EFPY were binned as high susceptibility plants. As you can see from -- there are two plants that are outside of that region that did have cracking. This is the Millstone plant which, again, did an ultrasonic exam, had no through-wall cracks in the nozzles. It may be that if some of these other plants did similarly intensive inspections, they also may have identified some cracked nozzles, but clearly their visual exams did not find any leaking nozzles.

The green symbol plants are those that still have to inspect. I think there are about six plants within this regime here up to 30 EFPY that still have inspections this spring. There are another 12 plants we'll inspect either next fall or even Spring 2003. There are some of the plants that have 24-month cycles.

At this point, I think we think this provides some validation of the susceptibility ranking. The highest ranked plant with any leakage is here at about 6 EFPY. It is the first plant out of the high susceptibility bin. The fact that we have not identified any circumferential cracks at higher EFPY levels and have identified no leakers, I think, gives us some level of comfort that for the short-term we have an appropriate management scheme for this, and this will enable us to develop our long-term inspection criteria.

MR. FORD: Okay. But it's a management scheme, it's not a resolution scheme. It will occur. In other words, you're just going to walk up that curve.

MR. HISER: Right, absolutely. It's just a matter of time.

MR. ROSEN: On that same chart that we're looking at now, the susceptibility ranking histogram, there are many plants that have found no cracking throughout the chart. Have you thought about what the lessons are from having plants in the high susceptibility region with no cracking?

MR. HISER: I think there may be many lessons. It may point us to some additional parameters that we need to consider, such as heat of material and things like that. There will be additional consideration of this data as we continue to accumulate it.

MR. ROSEN: Please consider both sides of it.

MR. HISER: Absolutely.

MR. FORD: Is that part of your strategy, this question of a quantitative root cause analysis of this cracking? You mentioned heat variations, there's also residual stress variations. Is it the plan in the long-term as you go through all your technical lists, to come up with a quantitative tool to predict what's going to happen in the near- and long-term? And, in fact, to improve as you go from one repair strategy to the other? Is that one of your goals?

MR. HISER: I think to the extent that we're able to do that and that we're able to implement something in a reasonable manner. What we do not want is 69 solutions to 69 problems. We'd like to have --

MR. FORD: But, surely, until you get to that capability, you cannot regulate a plant when it comes along and says, "Hey, I haven't seen cracking and therefore I can go for another year", but within that next year you should be able to tell them, "You are a high susceptibility, a high probability that you will crack in the next year if you continue operating the way you are".

MR. HISER: I don't think we would err to the wrong side of that. My guess is the inspections will be sufficient to cover those kinds of situations that could occur.

MR. STROSNIDER: This is Jack Strosnider. I'd just make the comment in response to that question that our intent would be to develop quantitative models that can help inform the development of the regulatory framework in the long-term inspection program, but we have some experience with the susceptibility models both on this type of cracking from the susceptibility ranking that was developed back in the '90s, and on other components like steam-generator tube plugs and steam generator tubes, and we know that we're not -- I mean, we're not going to be able to come up with a quantitative solution that says this plant is going to crack on this day, all right? And the best we're going to be able to do is get some relative susceptibilities, use inspection results to inform as we go down the road, and use those quantitative models to help inform decision, but we're going to have to apply some judgment here, recognizing the uncertainties in these models. And I think what Allen was saying is we will apply that judgment to make sure that we have sufficient conservatism in there to account for uncertainties in these parameters that either are not accounted for in the models, or that, frankly, you may not be able to account for because you just don't have the information. So we are dealing with uncertainties here, and there's going to have to be some level of judgment applied.

(Slide.)

MR. HISER: As I listed earlier, technical issues that we have covered in our action plan. They are reflected on this slide as well. I guess the two points I want to make on this regarding the technical issues is that we expect the industry to do the bulk of the work in this area, and they have taken the lead on many of these issues, and we are awaiting in some cases reports from them. We also have through our Office of Research several contractors that are doing the bulk of the work for the NRC and, as indicated, for example, on probabilistic fracture mechanics and residual stress activities, we do have strong interactions between the staff, our contractors and the industry in those areas.

MR. FORD: On that issue, does the industry have any warning of your expectations in these relationships? For instance, crack growth rates, as you know very well, they are all over the map. Are you going to go to an average crack propagation rate, or are you going to accept an upper bound crack propagation rate? I mean, they presumably know what your intentions are at this time.

MR. HISER: There have been some discussions on that. We've had, I think, several meetings where they've presented status reports on their review of the available data, and I believe the industry has generally proposed a 75 percentile curve as an upper bound. Several of the licensees have proposed for their plant-specific application 95 percent, and that seems to be an acceptable kind of value.

MR. FORD: And you could relate that to the probability of the first crack occurring, through-wall crack, et cetera? I mean, you can relate that to that physical occurrence?

MR. HISER: That's correct.

MR. FORD: Why isn't there repair on this list, repair strategies? Well, for instance, if you are going to go to 690 or the relevant weld material, how do you know what the factor of improvement is going to be? I don't see that on this list.

MR. HISER: To resolve the current issues that we have with the existing Alloy 600 nozzles, this is the list. We also have user-need in with the Office of Research to look at the characteristics of

Alloy 690, the replacement materials.

MR. FORD: Everybody takes as gospel that 690 is better than 600, and it probably is -- well, it is in the lot -- and to very limited experience in the field, but we cannot put what the factor of improvement is going to be, can we?

MR. HISER: I don't know at this point that we can put a specific number to it. The comment you made earlier about the susceptibility ranking, eventually that will get cracks at higher and higher susceptibility levels, my guess is for 690 it's only a matter of time.

MR. FORD: I guess I'm just trying to assess as to where we're going on all this to make sure that in ten years' time you're not going to have another "oh, hell, we didn't think of this" or "we didn't think of that". I'm trying to be constructive as much as possible here.

MR. HISER: I guess the one point that we haven't mentioned in any detail is the number of plants that have planned to replace their heads, and I think many of the plants that are on the table that have identified cracked nozzles or leaky nozzles do plan to do that.

MR. FORD: Well, presumably replacing with

690, but is -- you're just saying, "okay, then, that's as best as we can do", or quantifying improvement.

MR. HISER: Well, I think at this point in time our focus is really on the Alloy 600 nozzles in place. We do plan to address the 690 nozzle.

MR. FORD: So when you do crack growth rate data, there will be crack growth rate data for 690?

MR. HISER: Not -- let me point out one other -- this technical issue list is really to address the short-term management items that Beth mentioned, to put us in a position to develop the long-term management criteria. So this is -- I would say over the next 12 months we would have completed these issues for the present situation, but we do have Alloy 690 growth and initiation characteristics as a part of our longer-term research activities that we've asked the Office of Research to look into.

MR. FORD: And all the subcontractors -- Argonne, et cetera, et cetera -- who are working on some of these issues, they are all working to that time scale?

MR. HISER: On these issues, yes.

MR. BATEMAN: Working to what time scale?

MR. FORD: Well, the mention of all these issues, Bill, relate to the short-term, which we said --

MR. BATEMAN: No, no, no no. They are not working to establish, for example, crack growth rates for Alloy 690 in the short-term, to meet our short-term schedules, no.

MR. HISER: Let me just re-emphasize that the technical issues that are listed here are short-term issues relative to Alloy 600 nozzles and the existing heads. For replacement heads, repaired nozzles with Alloy 690, they are not on these technical issues list.

MR. BATEMAN: We have some folks from Research here who might be able to answer your question. Ed, do you have any ideas on when we might have that Alloy 690 crack data?

MR. HACKETT: This is Ed Hackett from staff. I guess the issue -- and Peter knows, I guess -- also goes beyond just 690 versus 600. There's weld, residual stresses, and other issues. Those are going to be longer-term. We're hoping to have PFM analyses completed this year for the issues that Allen's been talking about. The other ones are obviously be longer-term. There is crack growth rate data on 690. I guess we could back up and maybe make a couple of comments.

First off, I guess, there's going to be the idea going in that 690 is less susceptible to the phenomenon. I think, however, this issue goes not just to the base material, it goes to the welding and the residual stresses. So when Allen is making the commentary on, for instance, replacing the heads, the heads -- we can go into a lot of detail on this, but we have limited time here. The heads, as part of the improvement for the new heads, will include 690, but they are also including new types of machining for the penetrations. They are assuming new treatments for the penetrations, new types of welding that will induce less residual stress. These things will, in summary, hopefully cause significant improvements. You've asked for a number. I agree with Allen, I don't think we have a number. And I think only part of that would go to crack growth rates or susceptibility of Incanel 690 versus Incanel 600, but there are obviously data already available on 690. There's nowhere near the amount of data that's available on 600, and we are going to be generating that type of information for the future.

MR. FORD: Okay.

MS. WETZEL: We have told the industry

that replacing their heads is not the end of this issue, and there will be expectations in the future for some sort of inspection guidance on new heads.

MR. FORD: Could you expand very briefly because it always comes down to this question -- maybe someone from MRP can answer this one. What is being done specifically on risk assessment? We've heard the Duke Oconee presentation. I haven't heard any others. Maybe there have been others to you -- maybe Davis-Besse has done one, I don't know. But what specifically is being done in the risk assessment and its qualification?

MR. MATHEWS: I'm going to provide a little bit of discussion of the work that we're doing in the risk assessment area.

MR. FORD: Okay.

MR. HISER: Since I have grossly overstepped my time and hopefully did not set a precedent for today --

MR. FORD: We're just asking questions.

MR. SHACK: Before you take that slide away, have we looked at enough plants now to know that we can do UT on all the configurations that we have, or are we still doing development work on that?

MR. HISER: There have been isolated

problems with maintaining contact of transducer-to-nozzle, some access problems. I think the area of the inspections, in particular UT, has probably been the biggest growth area so far, and hopefully will continue to progress, if nothing else, to provide more timely inspections. That's one of the issues right now, is the amount of time it takes to inspect a whole head, but there has been a lot of improvements in that area. And I would venture at this point -- maybe Larry can address it -- that there probably is no situation where UT exam could not be performed on the nozzle from the ID. For the J-groove welds, that's a different situation at the present time.

MR. MATHEWS: There are perhaps a few isolated nozzles on a few heads that have caps on the bottom end of them, that the cap would either have to be cut off or something like that to get inside, but those are rare.

MR. SHACK: There's always exceptions.

MR. HISER: Yes, always.

(Slide.)

I guess the main things I'd like to point out in the conclusions is that the inspection findings to date are generally consistent with the susceptibility ranking approach. Implications from the Davis-Besse findings both in 2001-01 clearly are yet to be determined.

In addition, as Beth has mentioned, for some plants the second round of inspections after issuance of the bulletin will begin next spring, so we need to be in position to have some guidance or requirements in place for those inspections. If there are any questions, I'll address those.

MR. FORD: I think we are about to move now on to the next topic. I'm sorry, is there an MRP on specifically 2001-01?

(Slide.)

MR. MATHEWS: This is an outline of what we're going to talk about. We're going to save the Davis-Besse part until the end.

(Slide.)

The first thing is the MRP has put together and gotten approved all the way up through the MRP management structure a strategic plan for managing Alloy 600, 82-182 issue. This is kind of an outline of that strategic plan. We state the problem. We have a goal and a mission. It's laid out an approach of how we're going to solve the stated problem, and then we define the roles of the various organizations in the strategic plan, and then laid out a specific strategy in each of the five areas here.

MR. FORD: Forgive me if we've seen this -- I haven't seen this. I'm assuming that this has got timelines with expected resolutions at various times, and it fits into the regulator's requirements?

MR. MATHEWS: The goal is to definitely work within the regulator's time frame so that we have a meaningful interaction and we don't come in --

MR. FORD: Five years too late.

MR. MATHEWS: -- five years too late. We have a window of opportunity to influence and be a part of what's the long-term --

MR. FORD: And the regulators have seen this?

MR. MATHEWS: Yes, we've discussed this with the NRC. I don't know that they've seen the specific details of the plan, but we gave them a more detailed presentation on this.

In the area of the primary butt welds, Area 1, our approach is to use --

MR. FORD: I'm sorry, could you go back to the other one, please?

(Slide.)

You don't mention repair there.

MR. MATHEWS: Repair. It's probably

included as a mitigation -- most of the repairs have been handled by the vendors that are doing those repairs in the relief requests. But we have a Repair Committee that is working with, in each of these areas, like on the butt welds and head penetrations, documenting the repair techniques that are available.

MR. FORD: What other committees are there that -- interacting with this?

MR. MATHEWS: Basically, I have an Assessment Committee, an Inspection Committee, and a Repair Mitigation Committee within the Alloy 600 Issues Task Force.

MR. FORD: The reason for my questions is in these multi-organizational deals, information just goes down a plug hole sometimes because of lack of communication. That's why I'm asking the question. Repair is obviously a big thing on everybody's mind, I just didn't see it on your list, but somebody is looking out for it.

MR. MATHEWS: It's imbedded within each of these areas.

On the primary butt weld, our strategy primarily is to use the ASME Section 11 guidance for inspections and frequency. We think that's appropriate at this point, but in conjunction with the vendor demonstrations and PDI, we're driving improvements in inspection technology. Basically Appendix 8 has to be implemented by next fall, or the fall of this year, and that will require qualifying inspections for all of dissimilar metal welds that go on in the plant. So that's our basic strategy. We have a meeting set up to discuss the status of PDI this month, with NDE Center and PDI and where they stand on qualification of inspectors for the dissimilar metal welds.

In the near-term on the head penetrations, we're working with the NRC. We want to demonstrate that all the plants are safe, and there's an acceptable risk on an industry-wide basis. We're documenting all the inspection plans that people have turned in for 2001, and that's going to be history within a year, and other specific utility commitments and plans that they are doing beyond the requirements.

We're working with the inspection vendors to demonstrate the inspection technologies to a standard measure. And by that we mean we have initiated development of mock-ups, and one that will be available this summer is a blind mock-up so that the vendors can come in and demonstrate their NDE technology, their UT or whatever, on a blind mock-up, and demonstrate their capability to find flaws on those mock-ups.

We're also working to define reinspection requirements based on risk as we get to our probabilistic risk assessment, and to identify long-term mitigation techniques for RPV heads. These are the ones that have no leakage or the ones that haven't detected degradation at all.

In the longer-term, we want to develop inspection guidelines for the industry, moving toward early detection to minimize the leaks in the plants, and we want to use our risk assessment that we're putting together to work on that. Provide an assessment management plan that supports the appropriate examinations and work with the staff in implementing a long-term strategy, and also if mitigation techniques require qualification, we want to be working in that area to qualify the mitigation technique.

For all the other Alloy 600 82-182 locations, a lot of work had already been done by the various owners groups and other entities on a lot of the other locations of Alloy 600 or in the metal in the plants. Our approach was to determine what's already been done. We don't want to duplicate it and waste everybody's resources. To that end, we sent letters to all the owners groups and we have gotten responses back. Our next step is to work and get specific information on the programs that have already been completed by the vendors, and then to identify and evaluate all the locations not addressed in the existing programs, and then figure out with the owners groups and the vendors where is the right place to do that. Is the MRP the right place where it would be more appropriate than the owners group. And then provide guidelines for management, and ultimately put out an Alloy 600 management guideline which would either provide information to a utility on how to manage all the locations in their plant, or reference them to an appropriate location if it's something that's been performed by owners groups or something like that.

MR. FORD: You know, Larry, this is a great bulletized management thing that everybody puts out, especially EPRI, on what they are going to do. When did this start?

MR. MATHEWS: When did it start?

MR. FORD: Yes.

MR. MATHEWS: We've been working on it since over a year, but just pieces of it, and lots of it has already been completed, it's just a matter of when we --

MR. FORD: Are we going to see some data on that? You say some of the things are being completed and conclusions made, presumably. Are we going to see data to support those?

MR. MATHEWS: I'm not sure what you mean by data, but, yes, I have more information in here.

MR. FORD: Have you got some backup slides on crack growth and things of this nature?

MR. MATHEWS: I didn't bring them. This meeting was scheduled after a meeting in France where all the experts on crack growth are right now, and that's been scheduled for a year, and I couldn't bring my experts with me on crack growth rate, but I have some summary information on that.

MR. FORD: Okay.

MR. MATHEWS: We're also putting together an inspection plan on what plants ought to do to inspect their plants. It's based on gathering -- yeah, this is for head penetrations -- for gathering visual and nonvisual NDE data, and basically try to see if we can't verify that the MRP time and temperature model continues to be an effective management tool. And, basically, like Al said, the inspections to date tend to support that. The plants that have shown cracking further out were not through-wall yet, so maybe we're picking up some of the initiation of the cracking.

It will be coupled with our risk assessment to demonstrate that the increase in the core damage frequency is acceptable and, additionally, there will be other nonvisual NDE, UT, et cetera, gathered. Hopefully we might be able to do what you were talking about about separating segments of the fleet and say, well, this is a different kind of material than that, if it makes a difference.

One thing that we always keep in the back of our minds, though, is that, well, they're all welded in with 182 and, you know -- so, if that's a leak path, it's a leak path, and so even though Huntington may be a better material or whatever, somebody may have a better material, it's still welded in with the same weld mark.

Generally, what we've done is we were breaking the plants into various bins, sort of like the bulletin, only I think finer bins and we're coming up with inspection recommendations, and those recommendations move toward more and more aggressive inspections as the plant gets closer and closer to

Oconee 3 in the effective time and temperature.

Like we said at one point, we have to decide here and work with the staff on what is the appropriate point to say it's no longer appropriate to think that a visual is all you need to do, and you need to move on in, and we're working to work what is the right point for that.

MR. SIEBER: Could you elaborate a little bit on what you mean by more aggressive inspections as --

MR. MATHEWS: Well, like an effective visual is looking at the top of the surface, and then a qualified visual, as defined in the bulletin, was not only do you have to be able to look, but you have to be able to show that you have a gap at operating conditions so that the boric acid could leak out, and then on into under-the-head volumetric or NDE or AD-current or UT examinations.

MR. SIEBER: So volumetric could eventually be a part of this?

MR. MATHEWS: Yes. Yes.

MR. SIEBER: Thank you.

MR. MATHEWS: Next topic is crack growth rate for the Alloy 600 nozzle material.

(Slide.)

We established an expert panel -- and I've made this presentation so many times I'm not sure how much of it the ACRS has heard -- but there was an expert panel set up. They reviewed a lot of data. I guess Mr. Shack was on the initial part of that panel, he's still involved. They are refining their approach. We were very near, we thought, to publishing a curve and saying this is what we believe is the right approach, and then we found one lab voluntarily saying, well, we might need to take a look at our data and adjust it. And then Davis-Besse came up, and so that's kind of created another look at what, well, what's going on in the annulus.

So, some of these things are being reassessed by the expert panel, or those that are in France are going to get together in a sidebar meeting and take a look at it, and try and reassess some of this issue right now, as we speak. You want data points, I don't have data points here today.

MR. FORD: Well, it's really the same question I asked Allen. There's a load of data out there, and it's generally rather poor data, bad quality data because it hasn't been controlled or in the relevant environment.

Last time you gave us a presentation on

this topic, you made the statement that the crack growth rate appropriate for circumferential cracks was the environment that is in the primary site, primary water site, and we questioned that.

Is that still the approach that's being used for the development of your master curve?

MR. MATHEWS: We're developing a curve in primary water, and that curve, I believe, is supposed to be the 75th percentile of all the material that's in there, but --

MR. FORD: Yes, I know, but my question --

MR. MATHEWS: -- in the annulus region for circumferential cracking, we're proposing that we at least multiply -- or that we do multiply that crack growth rate by a factor of 2.

MR. FORD: And the rationale for a factor of 2 and not a factor of 10? 20?

MR. MATHEWS: Well, the experts kind of looked at that -- and I'm not one so I can't give you that -- but they had looked at all kinds of things about what could the possible pH range be, and do we have testing in that range, and what's the effect of it, and they used that to come up with the feeling that -- and I think this is where they were -- that a factor of 2 would bound the kind of environment that could possibly seen in the annulus. Now, they stopped as a result of Davis-Besse, and they want to say, "Well, let me look again", but prior to Davis-Besse that was the feeling that based on the buffering and the things that go on in that region -- and they actually ran "multi-Q" (phonetic) to try and figure out what the pH and all might be in there, and then look at the data to try and determine what effect it could have on the crack growth rate. And they felt that a factor of 2 was an appropriate multiplier there.

MR. KRESS: Does Davis-Besse imply that crack growth rate is not the right parameter to use now?

MR. MATHEWS: Well, it depends on what you're trying to model and what you're trying to assess. If you're trying to assess wastage on the head, then, yes, crack growth rate is irrelevant. If you're trying to assess whether or not a circ flaw will go around the penetration and result in ejection and a LOCA from the ejection of the penetration, then crack growth rate is very relevant.

MR. KRESS: Well, I was thinking in terms of priorities for inspection, which is based on crack growth rates also, implicitly based on that.

MR. MATHEWS: Yeah, you know, where we ought to go in future inspections, you know, we believe that a visual would find this kind of information that was existing at Davis-Besse.

MR. KRESS: Well, I was thinking of your susceptibility curve.

MR. MATHEWS: Oh, the susceptibility ranking. I guess the one thing -- you know, we've always talked about that ranking as so many EFPY to be an equivalent to Oconee 3 and just kind of said, well, okay, that says you are normalizing to a plant that's got a 165 degree circ flaw, but it's really just a ranking.

MR. KRESS: I understand.

MR. MATHEWS: And so, you know, if a leaky flaw is now the important criteria, that might move you further out onto the curve as your area of concern.

MR. KRESS: That's exactly what I'm saying.

MR. MATHEWS: But the same curve probably would still apply. Okay.

(Slide.)

The crack growth curve that we're going to come up with eventually, and we hope sooner rather than later, is intended for disposition if you find a flaw in the Alloy 600 thick-wall component exposed to normal PWR primary water. It's directly applicable, and if you find a shallow axial ID flaw, for instance, on the inside of a penetration to determine what kind of -- and, really, we feel somewhat of a bounding crack growth rate to apply to figure out can I make it to the next outage before I violate 75 percent through-wall or whatever.

We feel it is appropriate for the nozzles that are in use in the plants, and if you were going to evaluate a circumferential flaw above the weld, like I said earlier, we're recommending a factor of 2 be applied in that situation, but that's typically -- or that's going to be a hypothetical evaluation because we're not going to leave -- I don't think anybody is going to leave one of those in service. If you have a circ flaw, it's going to be repaired above the weld.

(Slide.)

MR. FORD: Could you explain why ID is beside "real" and why "hypothetical" beside OD?

MR. MATHEWS: For instance, a plant has found a shallow ID axial flaw. That could be a real flaw and they could evaluate it. It's been done at Cook, it was done at a couple other plants. They evaluate then the growth of that flaw and determine can we make it to the next cycle, or whatever.

For an OD flaw above the weld, you're not going to be doing an evaluation to leave that flaw in service.

MR. FORD: Okay. I was just following up on what you just said.

MR. MATHEWS: Yes. So it would be a hypothetical flaw you might want to evaluate for some other reason, like how long would it take to grow to ejection or something like that, if there were a flaw. But if you found one in your plant, you're not going to leave it there whereas you might do so for --

MR. FORD: Is this a new approach that you've taken, that all circumferential cracks will be repaired or removed?

MR. MATHEWS: Well, basically -- well, I'm talking about a circ flaw above the weld, okay, which means you've already got a leak that went on. And if you've got a leak, that nozzle will be repaired. Every one that has been found leaking has been repaired, and I don't think anybody would intend -- we couldn't by tech specs and the staff would not let us run with a leaky nozzle.

MR. FORD: Okay.

MR. MATHEWS: Another thing is that the crack growth rate that we come up with and feeds directly into our probabilistic risk assessment and our probabilistic fracture mechanics analysis, but we're not treating it as a curve, we're feeding the whole database and all the uncertainty in that database into the PFM.

Expert panel is working now to screen some more data. Some of the data that was originally in the database has been relooked at and screened out because we didn't feel it was appropriate data. I'm sorry -- this is also saying the expert panel is looking at weld metal, what data is out there -- we haven't come up with a curve for weld metal yet, but they are in the process of gathering the data on the weld metal, they are going to screen it, and they are going to recommend an approach for the weld metal itself. I think we all feel like it's going to be a little bit faster than the base metal, and so we -- may not be as relevant, but they are going to come up with some recommendations, as far as head penetrations. For something like a large nozzle where you've got a 2.5 inch thick weld, it could make a difference as to how fast it grows through the weld.

Research is being initiated by EPRI in a DOE/NEPO co-funded program on crack growth rates in these metals, and we will continue to keep the NRC up to date on where we stand on that. And we'll try and bring the data and the experts next time.

(Slide.)

In the risk assessment methodology, what we're proposing is an approach where we predict the probability of developing a leak using the industry leakage experience that we have to date and feeding that into a Weibull model, using that then to compute the probability of nozzle ejection considering initiation in growth rate for a circ flaw above the J-groove weld once you get leakage into the annulus, factor in the probability of leak detection in that interim between the time that a lead developed and ejection might occur, and then the growth to critical flaw size, follow that with a computation of the probability of core damage, considering the probability of the nozzle ejection and the conditional core damage probability for a small break or a medium break LOCA, and then assess the potential effects that might occur from collateral damage, although we think those are minimal.

MR. KRESS: What do you mean by Weibull model, is that just the distribution of the flaw sizes?

MR. MATHEWS: Well, it's the distribution in time of leaks developing --

MR. KRESS: It's the time distribution of the leakage rates?

MR. MATHEWS: Right. It's the distribution to predict when a particular plant might experience -- be expected to experience a leak. And it's based on our time and temperature model.

MR. KRESS: Why do you call it a Weibull model?

MR. MATHEWS: I'm not a statistician, but that's --

MR. SHACK: They use a Weibull to describe the statistics of the process.

MR. KRESS: To describe the flaw sizes?

MR. SHACK: No, describe the probability of a leak.

MR. ROSEN: On your last point on the slide, assessing the potential effect of collateral damage, as I understand what you said, you said that would be done after the calculation of a conditional core damage probability.

It seems to me that if you have a probability, however small, of collateral damage, it ought to be part of the calculation of core damage. In other words, that's not a quality for consideration after-the-fact, it's part of the analysis.

MR. HISER: It would be factored into what is the effect on the conditional core damage probability given an ejection versus a small break LOCA in a pipe.

MR. ROSEN: Given an ejection that results in damage to other rod drives, perhaps?

MR. MATHEWS: That goes into the assessment, what other rod drives might be damaged, how badly might they be damaged, what would that do then to the core damage probability.

MR. ROSEN: Okay. I think that's the right way to do it. It should not be considered as a qualitative consideration after the conditional core damage probability is calculated, it is part of the quantitative assessment, I think -- should be part of the quantitative assessment.

MR. MATHEWS: It depends on how we get into it, but I think to do it absolutely rigorously correct, I think you're right. I'm not sure that our proposal right now is --

MR. ROSEN: It's just another set of sequences in the analysis. They may have very low probabilities, but they should be part of the total core damage probability.

MR. MATHEWS: I see what you're saying. I'm not sure we were headed in that direction. We'll go back and look at it.

(Slide.)

The probabilistic fracture mechanics model that has been developed, the key elements of that is, like I said, the probability of leakage, using the Weibull model, simulated in a Monte Carlo model, the fracture mechanics modeling for stress intensity factors, for through-wall cracks, part-through-wall cracks, and multiple flaw initiation, stress corrosion crack growth statistics, the whole database and all the statistics with the crack growth rates being fed in. We can factor in the effects of inspections in the model, and what that -- turn them on and turn them off in different probabilities of detection, and that can be used to determine what is an appropriate inspection interval. And then inspection reliability. That's the POD.

MR. FORD: So this is just --

MR. MATHEWS: I suspect it is except that we're looking at the whole fleet.

MR. FORD: You're looking at the whole fleet?

MR. MATHEWS: All the PWRs. The model is intended to be applicable to all the plants.

MR. FORD: How can it be applicable to all the fleet. Each plant has got very specific conditions.

MS. KING: We're building a B&W model. We're putting together some Westinghouse and generic models because obviously they have many designs, and a CE model, so there will be several versions of the PFM.

MR. MATHEWS: They are all structurally very similar, but the dimensions would be different, and tolerances, et cetera, would be different.

(Slide.)

I guess all this shows is how the inspections would be taken credit for. You assume a sample, initiate a crack, grow it to leakage, and then at that point in time if you're doing an inspection, there's some probability that the leak would be detected and, if so, you take it out of the statistics at that point in time. If it's not detected, it goes on and continues to grow, and maybe you do a different inspection or a volumetric inspection at a later point in time, and depending on the inspection scheme that's fed into the probabilistic fracture mechanics, once something is detected it is taken out of the future probabilities.

(Slide.)

Some preliminary results -- and I must stress very preliminary -- the increase in core damage frequency for a high temperature plant is a product of these factors. The probability of a nozzle ejection after a first inspection is calculated to be less than 10^{-3}. Conditional core damage probability for a small and medium break LOCA, the largest number we could find for these high temperature plants was 5×10^{-3}. That product is 5×10^{-6}.

MR. FORD: Are those values -- for instance, the condition of core damage frequency for small break and medium break, those are for specific geometries where you might have multiple raw ejections, or collateral damage, if that's the right word?

MR. MATHEWS: The condition of core damage frequency was taken from the IPEs or the plant's probabilistic risk assessments for medium break LOCA, and it was not for a top-of-the-head LOCA.

MR. FORD: So the presumption here is --

MR. MATHEWS: So, top-of-the-head, in many ways, is better than out on a -- but collateral damage has been qualitatively assessed at this point, and the vendors do not expect that to have any significant impact on the core damage probability. There's just not much up there. There's other rods, but there's not going to impact your ECCS systems that you need to mitigate the accident, et cetera. So the effect of the collateral damage is expected to be minimal. We're not through with that yet. But we do expect most plants to come out to be less than 10^{-6}, or 5 x 10^{-6}.

I've only got one more slide.

MR. ROSEN: I want to make sure I understand what you have on this slide. The assumption here is that you have -- correct me if I'm wrong -- you have a nozzle ejection as a result of the propagation of the kind of damage we're seeing.

MR. MATHEWS: Yes.

MR. ROSEN: And that causes small break LOCA, or it is the small break LOCA?

MR. MATHEWS: It is the small break LOCA.

MR. ROSEN: It is the small break LOCA. Well, of course, I understand that it is a small break

LOCA, but why would you -- are you multiplying those terms together? What is the meaning of the multiplication?

MR. MATHEWS: Well, the probability that you have the nozzle ejection for a year --

MR. ROSEN: 20^{-3}, right.

MR. MATHEWS: -- times the conditional core damage probability, the probability that you damage the core if you do have the small break LOCA --

MR. ROSEN: I see. What you are saying is you have the ejection, that is the small break LOCA, and the probability that the safety systems in the plant do not act to prevent core damage is --

MR. MATHEWS: The biggest one we could find was 5×10^{-3}.

MR. ROSEN: Because, otherwise, if they do, you just have a small break LOCA.

MR. MATHEWS: Yes. If the systems all work, you don't really have a problem -- well --

MR. ROSEN: It's spraying boric acid all over the place, but -- you have a problem. You've got a big --

MR. FORD: The biggest uncertainty there is the probability of the nozzle ejection because that relates to the whole question of uncertainties about crack initiation and crack propagation, et cetera. Have you discussed this with the staff?

MR. MATHEWS: Yes, and we've had some technical meetings with both Research and with the NRR, and went into more detail than we've got here on exactly how we're modeling it.

MR. FORD: And there's no disagreement, in general?

MS. KING: We've worked to take the comments that we've received from NRC Research, especially on the PFM model, and incorporated those suggestions back into the model as we've had these meetings. We've had one conference call and one meeting, and we're planning meetings and trying to set up some meetings in May to come back to these issues as we start to run base cases.

MR. FORD: I can see how when you don't have a crack to start with, I can see you can go through a fleet sort of argument for that. But when you've already got a crack, or rather you predict you're about to get a leak at a specific plant, can you use that fleet data of 1×10^{-3}, that generic probability of nozzle ejection? You can't, can you?

MR. MATHEWS: No. Probability of ejection is not 1 just because you've got a leak.

MR. SIEBER: No, but in light of the Davis-Besse event, where you're also imbedding in that probability of detection, then 1 x 10^{-3} is, to me, not a good number.

(Simultaneous discussion.)

MR. MATHEWS: This is after a first inspection. I've done an inspection, didn't see a leak --

MR. FORD: And you say that 10^{-3} that within the next inspection you are going to have a leak, initiate a circumferential crack and it will whip through and --

MR. MATHEWS: In order for that to happen, you know, within that sort of time period, you're going to have to have very high growth rates, and that's why the number is so low.

MR. FORD: Okay. I understand.

MR. MATHEWS: I only have one more slide, and that's the impact of Davis-Besse on this.

(Slide.)

MR. FORD: This is the impact of Davis-Besse on 2001-01?

MR. MATHEWS: Yes, on the PFM model that we're using.

MR. FORD: Okay. Then I think we'll stop

before we get into the Davis-Besse specific degradation.

MR. MATHEWS: We're going to update the PFM model as we need to, as a result of that. We still have to figure it out, but a preliminary assessment is that the model and results wouldn't be significantly affected for growing a circ flaw and ejecting the rod. It's not talking about the wastage issue, just growing a circ flaw and a nozzle and ejecting the nozzle.

There are gap elements on the opposite side of the crack in the PFM that provide restraint. One way that you might do is remove that restraint or increase that gap to inches instead or mils, and that's something that could be done, although it's not totally obvious to me this is the way to address the wastage issue, and we have to wade through all of this.

There is no back-wall constraint on the part-through-wall crack in our model, so it really wouldn't have an impact on that. It's only once you get a through-wall crack the nozzle has a tendency then to try and lean and the back wall on the other side has elements in the model that could be adjusted to account for lack of a back wall there. But like I said, it's not totally clear yet to me that's where we need to go.

MR. FORD: As an educated member of the public, my gut would tell me that can't be right.

MR. MATHEWS: What's that?

MR. FORD: That whole reasoning, that the vessel wastage have no impact at all on the likelihood of having an injection.

MS. KING: That statement is meant only for our part-through-wall model.

MR. MATHEWS: Well, no, it applies to this.

MS. KING: Therefore, vessel wastage is not a factor, and this only applies to the part-through-wall model of our PFM.

MR. MATHEWS: The way we grow the model in the probabilistic fracture mechanics is as soon as you get a leak, we assume you have a significant part-through-wall model. Our part-through-wall crack -- I think it's 20 degrees around --

MS. KING: Thirty degrees.

MR. MATHEWS: -- 30 degrees around 50 percent through-wall, in that part of the model, as that crack then propagates around the nozzle in the model, until it's 180 degrees -- I think it's 180 degrees -- it stays a part-through-wall model, and in that part of the model as that part-through-wall crack propagates, there is no back-wall element that's part of it, so wastage is not a part, not a factor in --

MR. SIEBER: Of that.

MR. MATHEWS: -- of that part of the growth. Once you reach 180, it goes through-wall in the model and then it does become a factor in the calculation, if we model it, if that's the way we want to do it.

MR. SIEBER: Did you consider, though, that once you waste the material in the head, you're down to essentially a cladding member, which in the case of Davis-Besse deflected, and whether the nozzle separates or not, the cladding may burst open and you've still got your small or medium break LOCA. Is that factored into these risk numbers?

MR. MATHEWS: No.

MS. KING: At this point, no.

MR. MATHEWS: No. These risk numbers were put together for the Bulletin 2001-01 assessment. 2002-01 and where we go with that, basically, I don't think the industry doesn't ever want to let that happen again.

MR. SIEBER: I would hope so. On the

other hand, it's good for us to know what happened the last time.

MR. MATHEWS: Yes. And I think Davis-Besse is going to --

MR. ROSEN: Jack, in a way, you're following up on what I think is the weak point here. On your slide 13, you talk about collateral damage not being expected to be a significant contributor to core damage frequency, that's an unsupported assertion, almost unsupported, and I think you need to back that up with some analysis that you make available to us.

MR. MATHEWS: And that is the intent. We have some preliminary stuff from each of the vendors, and that's their conclusion at that point, but it's not a rigorous analysis at this point, but we intend to follow up and make sure that it's an appropriate conclusion to make, not just --

MR. FORD: We'll stop here. If I could make a request, the next time you see us, which hopefully will be within a couple of months, that you bring us some back-up data so that the committee can get an idea of, for instance, the scatter of the crack growth rates happens to be just one thing, your assumptions in the risk assessment, and things of this nature because although these are great conclusions, we have no way of assessing what goes behind them.

MR. MATHEWS: Understand. I understand. And I would have brought more on the crack growth rate today --

MR. FORD: And I recognize you have a restriction of time. Thank you very much, indeed, I appreciate it.

We will go into recess for ten minutes only, and then we'll start talking about Davis-Besse.

(Whereupon, a short recess was taken.)

MR. FORD: The meeting will be in session. I'd like to start the discussions on the Davis-Besse situation. Jack Grobe is going to give the kickoff.

MR. GROBE: Thank you very much. Good afternoon. My name is Jack Grobe. I'm Director of the Division of Reactor Safety for the NRC Office in Region III in Chicago, Illinois.

(Slide.)

I've compared the materials that we're going to present with what First Energy is going to present. There is a bit of overlap, but there's also some additional information.

Thirty-four days ago, Davis-Besse management informed the NRC that during a repair of a crack on one of the control rod head penetration nozzles they discovered an unexpected several-inch-deep cavity in the reactor vessel head. NRC Region III and Headquarters management chartered an Augmented Inspection Team to identify the facts and circumstances surrounding the formation and discovery of that cavity. Our purpose for the presentation here today is to give you a summary of the results of the Augmented Inspection Team's findings.

With me here today are two members of the team. On my immediate right is Mr. Mel Holmberg. Mel is a senior metallurgist on my staff in Region III, and on the other side of the projector is Dr. Jim Davis. Dr. Davis is a member of the research staff here at NRC Headquarters.

Put up the next slide, please.

(Slide.)

We're going to cover three topics today. We'll provide a characterization of the control rod drive penetration and reactor head inspection results. We'll discuss several methods and results of those methods for identifying reactor head corrosion earlier than was identified at Davis-Besse. And then, finally, we'll discuss the preliminary causes for the head corrosion. We look forward to addressing any questions you have. Please don't hesitate to interrupt us at anytime.

I'd now like to turn it over to Mel and get started. Thanks, Mel.

MR. HOLMBERG: Good afternoon. My name is Mel Holmberg. I'm an inspector with our Region III office in Illinois, and I'm also a team member of the Augmented Inspection Team that conducted inspections of the Davis-Besse site beginning on March 12.

Today I will be discussing the reactor vessel head inspection results in this portion of my presentation. As has been discussed earlier, this included identification of cracked nozzles, 5; 3 that had through-wall cracks; and the cavity near nozzle 3. In addition, there was an area of metal loss at nozzle 2 that was identified..

(Slide.)

This slide is depicting a cutaway view of a nozzle -- not necessarily specific to any plant. Just to give some idea of scale, it is typically a 4-inch outside diameter pipe, if you will, approximately 3 feet long from the center nozzles, and it has a stainless steel flange welded to the top.

Where the nozzle penetrates the head is typically an interference step.

Now, for Davis-Besse, in response to the Bulletin 2001-01, conducted an inspection of all 69 nozzles in the reactor vessel head. This included both an ultrasonic inspection and visual inspection. The ultrasonic inspection performed was conducted initially from below the reactor vessel head, using what they call the circ related probe. This is an ultrasonic probe set up for time-of-flight or tip-to-fraction type of UT method, and it was specifically oriented to give maximum response or sensitivity to circ-oriented cracks.

After conducting the inspection, they had five nozzles -- or, actually, 6 initially -- that had potential cracks. They followed that up with a top-down UT on all these 6 nozzle locations. And this top-down is a rotating head probe UT with roughly ten different transducers, and oriented at various angles so that they could, in fact, characterize in detail both axial and circumferential oriented cracks. Based on that exam, 5 of these nozzles were confirmed to have cracks.

The 5 nozzles with cracks, I want to briefly discuss the cracks that were found. In nozzle 1, there were 9 axial cracks detected. Two of those were through-wall. The length of those flaws was 1.8

inches and 3.5 inches. In nozzle 2 --

MR. SHACK: That was the through-wall extent?

MR. HOLMBERG: That was the length of those flaws. There were 2 flaws in nozzle one that were through-wall. The length of those flaws, one of them was 1.8 inches long and the other one was about 3.5 inches long. These flaws typically traverse the J-weld.

MR. SHACK: How much of that was above the J-weld.

MR. HOLMBERG: Okay, I'll get to that. One of the flaws actually did not really extend to any significant extent above the J-weld, it basically just barely crossed it. The second one crossed it by about half an inch above the J-weld.

For nozzle 2, this had 8 axial indications. Five of those were through-wall and the length of those through-wall flaws ranged from 2.7 inches up to about 3.9 inches in length. And anticipating your next question, the greatest extent above the J-weld was approximately 1 inch for the longest flaw in that nozzle.

MR. ROSEN: How thick is the vessel head?

MR. HOLMBERG: 6.6 inches.

MR. ROSEN: That's 6.6 inches of the low alloy steel, and then the stainless steel cladding on the interior surface.

MR. HOLMBERG: In addition to the axial flaws on nozzle 2, there was also one circumferential flaw identified above the J-weld, and that was 1.2 inches in length, and it was not through-wall.

MR. FORD: This is on nozzle #2.

MR. HOLMBERG: Nozzle #2, correct. For nozzle #3, there were 4 axial flaws identified, 2 of those went through-wall, and the length of those were 4.1 inches long and 3.8 inches long. The extent above the J-weld for the longer flaw was 1.3 inches, and that's basically the characterization of the ones that had through-wall flaws. I can give you the other two if you'd like, but they weren't through-wall and they didn't really traverse the J-weld.

Okay. The path obviously for leakage --

MR. SHACK: Some of these are Oconee 3 heats, right, or are these particular nozzles the Oconee 3 heats?

MR. HOLMBERG: All three of these were through-wall flaws, are also heat that was used at Oconee, 4 of the 5 nozzles from that heat.

A through-wall flaw in this region

obviously --

DR. DAVIS: Excuse me, Mel. Four of the five penetrations that had cracks were from that heat. Just wanted to make sure that was clear.

MR. HOLMBERG: Okay. Starting to talk about the primary coolant, obviously if it moves through the cracks, it will flow up along outside of the penetration tube and end up deposited typically as a popcorn kernel-type deposit of boric acid.

To fix the five cracked nozzles, the Davis-Besse staff machined the lower part of the nozzle such that it machined up through the attachment weld. In fact, it was during this machining process that the nozzle 3 rotated slightly and shifted. Again, this was an unexpected phenomenon because the nozzle at this location, in fact, is supposed to have an interference fit.

(Slide.)

During a subsequent investigation into this shifted nozzle, the Davis-Besse staff identified a large cavity adjacent to the nozzle. The picture now on the screen is trying to depict a profile view of this cavity. The cavity dimensions such that it's roughly 6 inches long. And by length, I'm talking moving this direction toward an adjacent nozzle, that's penetration 11, and it's 4 to 5 inches wide at its widest point, and for this entire area, the 6.6 inch thick steel head has been corroded away, which left the stainless steel liner as the floor of the cavity. The stainless steel liner was, in fact, measured and found to be pushed up into the cavity approximately 1/8th of an inch. This condition was likely caused by the normal operating pressure of the reactor coolant system.

MR. SIEBER: I presume that the cladding is not designed to be the pressure boundary.

MR. HOLMBERG: The cladding is not considered pressure boundary, it is there for corrosion resistance.

MR. SIEBER: Thank you.

MR. FORD: Are we going to comment later on, Jim, to describe your analysis of the -- or your opinion about the nature of the corrosion?

DR. DAVIS: We'll do that at the end.

MR. FORD: Good. Thank you.

MR. SHACK: As to the stainless steel yielding that you described, was it something that was going to continue to yield, or had it yielded as far as it was going to go, or do you know?

MR. HOLMBERG: We don't know that. They

are trying to, as part of their safety evaluation, determine in fact the failure point. I think they're using 11 percent strain, to answer your question, in terms of what they consider the failure point. The amount of yielding represented only a few percent strain. Probably they can give you a better number, the utility has been working on that aspect. We did not investigate that end of it in terms of the safety evaluation. That was not part of our charter to try to determine the safety significance at this point.

(Slide.)

The picture now on the screen is an actual picture of the cavity as viewed from the top of the head. Note that the sides of the cavity generally sloped down toward the bottom such that it's a larger cavity at the head surface. The cavity is generally smooth in texture. The picture that you're viewing is a picture from, if you will, the penetration 11, the downhill side, looking back to where the nozzle 3 position would have been. The nozzle has been removed and the kind of shiny machined area is where they've actually machined up through the attachment weld.

In addition to the visual inspections and measurements that were done on the cavity, the cavity was inspected with ultrasound from below or underneath the head, and based upon that ultrasound result the cavity appears to be or may be larger than what is visually observable from the top of the head.

MR. SHACK: Where would the axial crack be on that picture?

MR. HOLMBERG: The large axial crack, the largest axial crack, the one with the 1.3 inch extent above the J-weld, is aligned basically in the center of the cavity on the downhill side, the zero-degree side is the reference that they usually talk about. The other flaw in there was located directly adjacent to it on the uphill side, and it extended for about .8 inches above the top of the J-weld.

MR. ROSEN: Your comment that the cavity may actually be larger than what we see here, I'm having visualizing what you mean.

MR. HOLMBERG: I do have some additional data on that.

MR. GROBE: This is kind of a busy slide, but we anticipated you might want some more information on this.

(Slide.)

MR. HOLMBERG: Okay. What I've drawn here is taken from one of their NDE reports, and what it is trying to do is give you a grid map, if you overlay it, looking down from above the head so you've got the correct reference frame, what the thickness of the cavity is as measured -- now this is taken from below, but it's from ultrasonic thickness measurements. And you'll notice -- all I did was nothing more than connect the dots at data points where they've got readings that are roughly in the .3 inch category, indicating that you have only a stainless steel cladding layer at that point.

Visually from above, you don't see that shape. What you see is a shape that tapers in roughly a "V" shape toward nozzle 11. Here you will notice that the cavity goes outward and, in fact, begins to expand as you approach nozzle 11. That is not what you see when you look at the cavity from above.

MR. GROBE: In addition to that, the cavity, when viewed from above, does not extend the whole way to nozzle 11 whereas this data might tell you something different.

VOICE: I believe in our presentation we'll provide more detail on that.

MR. ROSEN: That implies there's sort of a cavern under some of --

MR. HOLMBERG: Could be. I think the term that they're using that I've heard kicked around is possibly "debonding". They feel there is likely metal behind there, but the UT is showing us that there is some sort of separation there --

MR. ROSEN: Between the cladding and the remaining metal?

MR. HOLMBERG: That's what I've heard characterized so far, yes.

MR. KRESS: Are all those numbers supposed to be 6.6?

MR. HOLMBERG: No. There's another interesting phenomenon. They have -- you'll see some numbers in there that are roughly at the midpoint, 3.something inches, and those are believed to be laminations, part of the fabrication process that the UT is picking up.

(Slide.)

Now, in addition to the cavity at nozzle 3 during the machine repair on nozzle 2, a second area of metal loss was detected, again, in a similar way, during the machining. In this case, the penetration didn't move, but they identified a cavity that was behind the penetration of roughly 1.6 inches, as you see, extends below the bottom, so that the cavity that was initially exposed was this area here that's been machined out by the repair process. It extends, at the point that we left the site, about 4.2 inches. It was believed to go all the way to the surface. Subsequent to our departure, they have removed the nozzle and I believe they can confirm the dimensions on the height of the cavity, if you will. The width is 1 3/4 inches, and then trying to anticipate your questions, yes, there was -- the crack with the largest extent above the J-weld was in the same quadrant as this cavity.

MR. SHACK: Now, on the top surface here, they see only the sort of popcorn-style boric acid, or --

MR. HOLMBERG: This whole area was covered with several inches of -- and I'll get to this later on -- but lava-like boric acid by the time we roll around to this average.

The cavities both here and the larger cavity at this point are believed to be caused by boric acid corrosion, and through the larger cavity at nozzle 3, an estimated 35 pounds of steel have been corroded away. And we'll be providing a little more detail in the root cause section, but that ends basically this section of my presentation.

MR. GROBE: That's the extent of what we were going to present on characterizing the inspection results as far as the physical characteristics of the head and the penetrations.

MR. FORD: Could I ask a question, which I don't think you've got the answer to. How sure are we that a circumferential crack was not through-wall? I understand that the head is being removed --

MR. HOLMBERG: Let me explain a little bit. The way that the UT process works is if the crack was to propagate through-wall, they'll lose what is called the "lateral wave", the wave that goes between typically a time of light transducer sets up a surface wave they call a "lateral wave", and they'll see a signal response, and that -- if it actually breaks that surface, that lateral wave will then disappear and they'll know it's a surface-breaking flaw, i.e., that it's coming through the surface we're scanning on, which is the inside surface. So, because of the technique that's used, I think there is a fair amount of confidence that that did not go all the way through the wall.

MR. FORD: But there will be a destructive examination, presumably.

MR. HOLMBERG: It's already been done. We destroyed all these cracks during the repair process. Let me back up. There may be a cracked tip or end in penetration 3 that was removed, but I know of no cracks currently that we're aware of that exist.

MR. FORD: That's a pity because that's a crucial part of the root cause examination.

MR. HOLMBERG: Yes, it is.

MR. ROSEN: In response to the question on the nozzle 2 diagram about whether or not you had a confirmation on the surface of the popcorn kind of leakage that's been expected, your comment was, no, the lava-like deposit obscured it?

MR. HOLMBERG: Yes. There was a very --

MR. ROSEN: Could you tell me more about that deposit?

MR. HOLMBERG: Yeah, we're going to be getting into that in more detail later on, if we can just hold that for a few minutes, but basically the brief answer is there was a thick layer of boric acid and corrosion products that prevented or obscured this region from any inspection, so they really couldn't see the classical popcorn type --

MR. ROSEN: And you'll tell me about the extent and nature of that deposit?

MR. HOLMBERG: Yes.

MR. ROSEN: Okay.

MR. FORD: Well, that whole question, the root cause, what we understand to be why you got so much corrosion in that annulus? Will we be coming to that?

MR. HOLMBERG: Yes.

DR. DAVIS: But we're not going to give you a very good answer.

(Laughter.)

MR. GROBE: At the time of the inspection -- the inspection ended about ten days ago -- the licensee had not yet completed their analysis of what they believed was the root cause. We provided them a series of questions, about 30 questions, that when we left the site were of still concern to us, and we expect to get their root cause analysis shortly, and anticipate that it will answer all of our questions. And I believe, from looking at their slides, they have quite a bit of discussion of the root cause in their slides.

MR. SHACK: Where did you get the sequence of -- you have a lava-like flow of several inches of boric acid covering the whole head, and then somebody is shocked to find that there's boric acid corrosion? Is that roughly the sequence?

MR. HOLMBERG: Yes.

MR. SIEBER: Another question. There was

a confirmatory action order issued by Region III, and one of -- I think there were five conditions in it -- and one of those was to preserve the site of the incident. And given that, if the repair process then destroyed the actual flaws, is that consistent with the condition in the Confirmatory Action Letter, or if it is, why would we give up that important piece of evidence?

MR. GROBE: It wasn't a matter of giving it up. The discovery of the cavity occurred after the machining was completed on penetration 3. It actually was during that process -- during the process of machining out the weld and the penetration in preparation for finalizing the repair, the machining equipment moved and the penetration cocked just a little bit, and that was the discovery. So all of the information was lost simply because of the repair technique. The CAL was issued after that.

MR. SIEBER: Oh, okay. Thank you.

MR. GROBE: If there's no other questions on the material we've presented so far, I'd like to move on to talk --

MR. SHACK: Did you find out what the leak rate was, what their sump leak rate was?

MR. GROBE: Yes.

MR. HOLMBERG: We won't spend a lot of time on their what they call "unidentified leakage trend", but that is the balloon portion of the graph up there, the problem being that there's a fair amount of scatter down in the .1 to .2 gpm range, which is kind of where we believe that the leak rate for these cracks -- total leak rate for all the cracks -- was in that band. So, trying to track or trend that specifically with the other masking type of things that were happening on leakage rate alone, it was something that did not provide a definitive "ah-ha, here's where you see it", not that you couldn't see something in the data, it's just there was so much other activity that was potentially masking that happening in the same time that that is something we didn't --

MR. SHACK: Their total leakage then is on the order of .1-.2 gpm?

MR. HOLMBERG: Yeah. You'll see before the big spike there that that's roughly down in the .1 range. The big spike actually -- I don't want to digress too far -- is associated with a model variation that they made to a rupture disk downstream of a pressurized relief valve where they had actually punctured the rupture disk purposely to allow it to leak because they were afraid that the rupture disk, if it was allowed to function as originally design, would then torque itself off the pipe. It was a design error they were trying to correct. But that introduced leakage into the containment atmosphere because there was a minor seed leakage past the relief valve. So that was a source of leakage for much of the unidentified leakage peak that's there.

In addition, you also have -- and we'll get into this more -- the flanges themselves above the CRDM penetration nozzles that provided leakage at various times and various outages.

MR. GROBE: Just to give you some perspective, the peak there is a little over 3/4 of a gallon per minute, so below the tech spec limit for operation.

MR. SIEBER: Do you believe or surmise that the indication that the plant operator had that containment particulate radiation had increased significantly based on filter change requirements and measured levels, that that was reasonably -- could be reasonably assumed to come from rupture disk leakage, or would that have been an indication of some other leak in the pressure boundary?

MR. GROBE: All of these questions are

going to what we refer to as "missed opportunities", and Mel has a presentation that if he went through it might answer most of your questions.

MR. HOLMBERG: We're just about ready to jump on that, that's the next area.

MR. SIEBER: Well, let's let him go through it.

MR. HOLMBERG: What I intend to discuss now are some opportunities to identify which were available to the Davis-Besse staff to identify corrosion of the head at an earlier point in time.

(Slide.)

Specifically, I will be discussing the containment air cooler and radiation monitor clogging, and the deposits of boric acid which remained on the vessel head.

(Slide.)

To do that, I want to make sure we have a common understanding of the reactor vessel head configuration because one of the principal sources of leakage was, in fact, the flanges, and by flanges, I'm referring to where the control rod drive mechanisms bolt up to the top of the nozzle flange.

Historically at Davis-Besse -- and, in fact, at other B&W designed plants -- these have leaked in the past. The leakage which occurs at these flanges travels and deposits itself down on this insulation layer and, in addition, it runs down the side of the nozzles and ends up as deposits on the reactor vessel head.

The area here is referred to as a service structure which surrounds the head and supports this insulation layer, and also surrounds the outside of the control rod drive mechanisms. So it forms a very more or less tight enclosure, if you will, surrounding the top of the head preventing a direct readily viewable surface.

The leakage from these flanges not only deposits on the head, but it can also result in some airborne amounts of boric acid which become captured by the ventilation system, which takes a section inside the service structure and then moves it out and basically exhausts it high in the containment top of the D-ring.

Now, similar to flange leakage, leakage from the cracked nozzles would deposit boric acid on the head, but it would also expel some amount of boric acid into this cavity area which also would then be captured by the ventilation system and then dispersed into containment. And this would include not just the boric acid, but any corrosion products that may be forming.

(Slide.)

From the previous discussion, one of the places that boric acid deposits have been historically found, where they've collected in containment is in the containment air coolers. The containment air cooler is designed to cool the containment, as the name would imply. By doing so, though, it condenses moisture in the air and ends up in collecting the boric acid and, in this case, corrosion products that were present in the containment atmosphere.

The plant has cleaned the containment air coolers periodically and identified boron deposits, and they are normally white in color. However, in 1999, a more frequent cleaning of the containment air coolers was required, which indicated an increase in volume of the boric acid present in containment. Also, the color markedly changed in that it was a brown or rust color.

At this point, the Davis-Besse staff had assumed that the increase in boric acid deposit in the containment air coolers was from known sources such as the flange leakage, and that the color change was due to the age of the deposits or rusting of the containment air coolers. The NRC team believes that the change in color of the deposits represents an indicator that corrosion was occurring in containment and, as such, represented a missed opportunity to identify the vessel head cavity penetration --

MR. ROSEN: Hold it right there.

MR. HOLMBERG: Yes, sir.

MR. ROSEN: When you say the Davis-Besse staff assumed changes, et cetera. Was that an ad hoc kind of thing, or was this a conclusion of a root cause analysis that was the result of operation or there corrective action system?

MR. HOLMBERG: I don't believe there was a formal root cause investigation, if you will. There was -- what this was was a conclusion based on interviews with the people involved with identification of the brown deposits at the time, what their conclusions were, what actions they took to follow up on those conclusions, and so forth.

MR. ROSEN: So I take from your response that you found no documents in their corrective action system of formally analyzing these findings and dispositioning them in one way or another?

MR. HOLMBERG: Correct, on the containment air coolers.

MR. ROSEN: And on the color change?

MR. HOLMBERG: Correct, specifically on the color change I don't believe we had anything formal that discussed exactly their conclusions. It was more based upon the interviews with personnel involved.

MR. ROSEN: Anecdotal kind of analyses?

MR. HOLMBERG: Right. What were you thinking at the time, what did you think it was, that type of question.

MR. ROSEN: But no formalized analysis.

MR. HOLMBERG: Right. But when we move on to the next indicator, there is more that was done with the next indicator.

MR. GROBE: I was just going to say, if you get a chance after the meeting to examine that chart in more detail. The time that the containment air coolers was cleaned prior to 1998 was in 1992, and there was no cleaning necessary between '92 and '98.

That large spike which was caused by leakage unrelated to -- largely unrelated to head leakage, resulted in numerous cleanings during the '98 time frame. And then in the middle of '99, there was a mid-cycle outage to repair or put in a modification to fix that problem. And you can see leakage went down dramatically. But cleanings continued to be necessary through the end of '99, 2000, and 2001, and the details of numbers of cleanings and time frames are up on that chart.

MR. HOLMBERG: And the more significant thing is probably the color change, in our mind, at this point.

MR. ROSEN: And you'll tell me when they finally entered this in the corrective system and did some sort of root cause analysis?

MR. HOLMBERG: Well, I'm going to get to the next indicator which was treated more rigorously than this one.

MR. GROBE: The answer to your question is this specific issue was not entered into the corrective system, although it has been thoroughly investigated since the cavity identification.

(Slide.)

MR. HOLMBERG: In addition to the containment air coolers, another area which would collect boric acid and corrosion products is the radiation monitor system filters. The filter is an element that has a normal frequency for changing basically set up on a monthly basis. However, beginning in May of 1999, the filters had to be changed more frequently such that by November of 1999 the filter had to be changed every other day, and this was because of recurring clogging and the deposits that were clogging these filters generally had a yellow or yellow-brown color. And this, again, was new, something new to them. And in this instance, Davis-Besse staff did act on this new indicator and did send the deposits out for analysis by an outside laboratory, and this lab concluded the deposits were, in fact, iron oxide corrosion products produced from a steam leak.

The Davis-Besse staff did make attempts to try to determine the source of these corrosion products, but they were not successful. The team believes that these deposits were likely corrosion products from the corrosion of the head cavity and, as such, represent a missed opportunity to identify the cavity at nozzle 3.

MR. GROBE: Let me just add a little bit more to that, Mel. Again, the details of the data are displayed on that chart. The frequency of filter changeouts increased to every other day, and the licensee proceeded to install a bank of HEPA filters with high-volume fans in containment for a period of time, which resulted in the frequency of filter changeouts decreasing.

The frequency increased again in the 2000-2001 time frame, and we're again back at the every-other-day time frame in the fourth quarter of 2001.

(Slide.)

MR. HOLMBERG: The next indicator that I want to discuss has to do with the boric acid control program itself. This is a program that was implemented shortly after the NRC Generic Letter 8805 was issued. The program essentially requires inspections of areas which are likely to experience leakage by looking for boric acid deposits. Further, the program requires removal of boric acid from components and evaluation of the component affected by boric acid. And, again, the visual inspection for looking for the presence of boric acid can be an effective way for detecting small leaks in the reactor coolant system. The example that's on the slide there is that one drop per second leak can result in accumulation of approximately 15 pounds of boric acid over a one-year period.

(Slide.)

I want to return your attention to the head configuration because what we're talking about now is how these inspections of the head itself were conducted. Historically, as we already discussed, the head had deposits of boric acid that accumulated, and the accumulation was on the head itself, underneath the insulation, and the volume of deposits we're talking about here, the number that was estimated before we left the site was roughly 900 pounds is what was on there by this outage.

MR. SHACK: That's not the historic experience at the end of the cycle, is it?

MR. HOLMBERG: No, it progressively got worse, and we'll step through some of these head inspections. I may not give you the numbers you want, how many pounds were left on there because I didn't have that information, but the 900 pound estimate was the basically as-found condition in this outage.

(Slide.)

Again, what I want to emphasize here is the challenge to the Davis-Besse staff for performing head inspections. Specifically, this service structure that supports the insulation here has 5 x 7 inch openings, about 18 of them around the circumference of the head, and through that opening they tape a video camera, if you will, to a pole, and push it up through that opening. And it probably doesn't do justice here to the challenges this represents. The curvature of the head on a B&W design is, I believe, the most curved, if you will, of any of the head designs, and it makes a challenge in terms of trying to get anything attached to a straight pole up on top of the head.

MR. GROBE: Mel, just for dimensional purposes, right at the top of the head, what is the distance between the insulation and the top of the head?

MR. HOLMBERG: This is a 2-inch gap where it approaches the insulation here at the very top. Again, particularly near the areas of the center of the head, this represented a challenge.

MR. ROSEN: Where was the rod that was corroded most severely in relation to this diagram, was it right in the center, or was it off to the edge?

MR. HOLMBERG: Dead center is rod #1, penetration #1 essentially, and if you count in a square pattern around the outside, you'd have like 3, 4, 5 around it. So it's the next ring around it.

MR. ROSEN: So it's very close to #3, which was the one that was corroded most, it's very close to the top dead center, a foot off top dead center.

MR. HOLMBERG: Very close.

MR. KRESS: Is that insulation to protect the control rod drive mechanisms to keep them cool?

MR. HOLMBERG: That's correct.

(Slide.)

As discussed earlier, this accumulation of boric acid on the head and the inspection challenges due to the configuration did not go unrecognized by the Davis-Besse staff. a modification to the service structure surrounding the head was proposed as early as 1990 to allow better access for inspections and cleanings, however, this modification was never implemented.

Beginning in 1996, when a head inspection identified that boric acid deposits were not being removed and that was contrary to the boric acid control program requirements. Further, they recognized that the boric acid deposits could be indicative of cracks in the nozzles, but the Davis-Besse staff did not consider that this was a likely source of the deposits for a number of reasons.

And the Davis-Besse staff was not successful in removing deposits near the center of the head because of the limited access and the cleaning methods that were employed. Therefore, the decision by the Davis-Besse staff to delay the implementation of the modification to the service structure that was first proposed in 1990 played a key role in preventing an opportunity for effective head cleaning and inspection. Further, the boric acid deposits left on the head following the 1996 inspection may have prevented viewing the corrosion cavity at nozzle 3 at an early stage.

MR. SIEBER: What head-cleaning method was the licensee using at this time frame?

MR. HOLMBERG: At this time frame it was a manual method. It was basically a --

MR. SIEBER: Squirt water?

MR. HOLMBERG: -- like a paint scraper taped to the end of a vacuum hose pushed up underneath the -- in through those 5 x 7 openings and up onto the head.

MR. SIEBER: So that would have the same difficulties as the camera in that it can't make the bend.

MR. HOLMBERG: Right. The hose was flexible, so it may have had a little more reach, but the deposits were at least by 1990 becoming more adherent. They were no longer loose and white in form, and that was the next point I was going to make here.

MR. SIEBER: And they were going underground probably.

MR. HOLMBERG: Yes.

(Slide.)

By 1998, this is the next refueling outage, the deposits had formed a semi-continuous layer over the nozzles in the center of the head. The deposits were more adherent and brown in color. This was a change from a previous inspection which had identified a white, loose or powdery form of boric acid. The change in color or form was not evaluated by the Davis-Besse staff.

(Slide.)

Now, by 2000, the Davis-Besse staff again inspected the head, and this is a picture of the head as it was found in early 2000. In fact, this picture is from the outside of the service structure, and what you are looking are areas where boric acid and corrosion products have spilled out of what they call the "weep holes" -- these are the inspection ports I've been discussing where they have to put a camera up through there to do the inspection, and they are essentially blocked through the wall of the head. So there is a thick layer of boric acid that covers at this point approximately 24 penetrations.

MR. ROSEN: What is that material down adjacent to the circle?

MR. HOLMBERG: This is where the corrosion products and boric acid have flowed down and pooled, if you will, along the --

MR. ROSEN: That's the iron oxide and boric acid mixed together --

MR. HOLMBERG: Yes. One other thing I want to mention here is the characteristics of this boric acid a little bit. The boric acid and corrosion products, as you can see, are red rust color, but they are also very hard. And the term used in their corrective action system to describe it is "lava-like". In fact, they had to use crowbars to remove the boric acid from the head. In addition, at this point they weren't making headway with the crowbars and they implemented a washing of the head with 175-degree water. Both of these techniques, though, ultimately were not successful in 2000, such that a thick layer of boric acid was left on the head at the center penetrations, so that the cavity at nozzle 3, for instance, would not have been something that would have been uncovered by their attempts to clean the head.

MR. SIEBER: Is it fair to assume that

when boric acid is corroding iron, it changes into another chemical compound which has different characteristics, and so that boric acid is probably not as reactive as pure boric acid would have been, but is probably harder and more tenacious in its nature?

MR. GROBE: You're getting into several issues involving the chemistry, and they get right to the issue of how much of this corrosion was top-down and how much was bottom-up, so to speak.

Jim, why don't you go into a little bit of boric acid/boric oxide chemistry and talk a little bit about this.

DR. DAVIS: Basically, what happens is around 300 degrees you start converting the boric acid to boric oxide and releasing steam, and it's not clear how quickly this reaction occurs. And then once you get up about 378 or 380, the boric acid that's left actually starts to melt. We think it's a mixture somehow of this, and plus you are adding additional boric acid as time goes on, to the bottom. So, it becomes very complex exactly what you have there, but from our interviews we know that the nature of the boric acid definitely changed dramatically with time.

It looks like when you get boric acid

deposits from one cycle, you can go in there and -- if you have access -- you can vacuum them up without a whole lot of difficulty, or you can power-wash them out. But there are some concerns there about power-washing because in the peripheral penetrations you have a gap there due to the J-groove welding process. You could actually fill those gaps with a boric acid solution, and that was their fear, that they were going to do that, and that was one of their justifications early on for not removing the boric acid from the head.

MR. SIEBER: Thank you.

MR. ROSEN: Has there been a look at what the effect of that corrosion product that's dripped down to the bolt circle is on the bolting?

MR. HOLMBERG: There's been documents in the past where they've had not necessarily red-colored boric acid, but incidents where the flanges have leaked and, in fact, have come out the weep holes and ended up on the same area back in 1991 time frame, where they removed them and then they document that there's no evidence of corrosion.

So, the answer to your question is they've documented they haven't seen corrosion due to --

MR. ROSEN: Is that because the material

of those bolts is different than --

DR. DAVIS: No, it's not.

MR. ROSEN: It's carbon steel, too?

DR. DAVIS: Those are carbon steel. In fact, the reason this area was cleaned up was because they couldn't get the head studs off to remove the head. But I didn't find the Commission report on the condition of the studs, which Brian Sheron asked me if I found anything, and I didn't. I don't know if the Root Cause Team did or not.

MR. GROBE: One of the items required in our Confirmatory Action Letter was what we refer to as "extent of condition", a thorough evaluation of the reactor coolant system for any other corrosion, and that will be captured in continuing inspections, and the licensee is in the process of doing that evaluation now.

MR. LEITCH: Can you describe how the joint between the service structure and the head -- is that just sitting on there, or is that intended to be --

DR. DAVIS: Those are weep holes.

MR. GROBE: His question is the attachment of the service tray, is it welded onto the head?

MR. HOLMBERG: This part appears to be

welded. This is the bolting connection to the rest of the service structure.

MR. LEITCH: I see that, but I was just wondering, the lower part of it there, below that bolt circle, is that welded to that?

MR. HOLMBERG: It appears to be.

MR. GROBE: I see some other folks that have spent some time looking at this nodding "yes".

VOICE: It's welded with bolts periodically.

MR. HOLMBERG: In summary, the team concluded that the Davis-Besse staff had several opportunities to review the containment air cooler, primarily the change in the color of the boric acid, the RE filters, again, where you get confirmed iron oxides and, finally, the head inspections themselves where there was a change in the color and nature of the boric acid.

So the Davis-Besse staff had several opportunities to identify and prevent the corrosion cavity, and failed to do so. And that concludes this portion of the presentation.

MR. GROBE: Any other questions before we go on to root cause?

MR. KRESS: Do they have temperature

measurements in the control rod drive area up above there?

MR. GROBE: I'm sorry, could you repeat the question?

MR. KRESS: Do they have temperature measurements in their control rod drive area above the insulation?

MR. HOLMBERG: Yes, there are temperature elements in the service structure area.

MR. KRESS: Did those change over time?

MR. HOLMBERG: I don't know the answer to that. On the face of it, I'm not sure -- they are far enough removed from, say, the source of this leakage and underneath the insulation is where the head is. I'm not sure that there would have been a definable trend, particularly since the flange leakage would have been closer to those temperature elements.

MR. GROBE: The answer is we don't know.

Other questions?

(No response.)

Okay. Jim Davis now is going to talk a little bit about the probable cause that we received prior to the completion of the inspection, and then go into some of the questions that we had with respect to that probable cause. The licensee has an extensive presentation of this material in their slides.

(Slide.)

DR. DAVIS: The Root Cause Team concluded that this damage was caused by boric acid corrosion, and it probably started four to six years ago, and we think that's reasonable. But the details of the boric acid corrosion and the effect of the cap above this nozzle is not known, or was not known at that time. Perhaps they have some more information now.

MR. FORD: But you are looking at an inch-a-year sort of corrosion rates?

DR. DAVIS: Or more.

MR. FORD: Or more. Are there any confirmatory experiments existing in the literature to explain how you could get an inch a year corrosion rates?

DR. DAVIS: There are quite a few.

MR. FORD: And will that be presented today?

DR. DAVIS: I'm not sure if they're going to present that information because I think they concluded that it was a couple inches a year was the corrosion rate, and you see rates up to seven inches per year.

MR. FORD: Quoted in the literature?

DR. DAVIS: Yes.

MR. FORD: That's what I thought. But those are primarily from impingement rather than general corrosion, which -- I'm just trying to tie you down on your definition of corrosion. You're not talking general corrosion?

DR. DAVIS: Yes.

MR. FORD: You are?

DR. DAVIS: Wastage.

MR. FORD: As opposed to impingement attack?

DR. DAVIS: Yes. What you get is concentration of the boric acid with time by evaporation of this solution, and when it gets very concentrated, that's when you get the very high corrosion rate.

MR. FORD: But the pH would be limited to about 4, would it not?

DR. DAVIS: Experiments have done with a range of pHs, and you still see the high rates when they get very concentrated, and with a crack an inch long, the leak rate goes up exponentially with length, and you're adding a lot of boric acid under that cap, and it also probably occurs at a lower temperature, but it's not exactly sure what temperature the really high rates are occurring at.

MR. FORD: I guess what I'm trying to drive at -- and maybe it will come out in the next presentation -- in order to explain 1-to-10 inches per year, in these prototypical geometries for annulus, et cetera, you are talking about steam escaping through a crack onto that surface, and there are data available that would explain that, in the open literature as well as closed literature.

DR. DAVIS: It's probably more in the closed literature or EPRI guidelines.

MR. FORD: Well, there's at least two references in environmental degradation conferences which would explain those sorts of rates under those prototypical conditions, is that correct?

DR. DAVIS: Yes.

MR. FORD: So, from what we know right now in the literature, open and closed, you could explain these corrosion rates of the pressurized steel.

DR. DAVIS: It appears that way.

MR. HOLMBERG: Yes, however, the B&W owners group did experiments, and based on their experiments came up with a number for corrosion which was 1.07 cubic inches per year. So that was what was used to state that the reactor would remain within structural requirements for six years, and that figure is certainly not --

MR. FORD: Probably wrong.

MR. HOLMBERG: Correct.

MR. BONACA: I have a question which I guess -- other plants like Oconee, they had leakage through cracks, but they did not experience this kind of wastage. Why was it, location, or what?

DR. DAVIS: I think it was more a matter of detectibility, what they call the "popcorn" indication. So they went in and did a UT and I think they caught this before it started occurring --

MR. BONACA: What you are really saying to me is that this is a process that could occur for any other plants where you have cracking, and as long as you don't identify it early enough.

MR. GROBE: The length of the cracks at Davis-Besse were longer than observed at any other plant that's been repaired.

MR. HOLMBERG: I want to stress the key length that the analysts that I talked to, who has done two of the Oconee units and several other plants, was the distance above the J-weld. And the other key thing -- and I don't think I brought it out earlier -- is the cracks that were OD-initiated at Davis-Besse, which was also consistent with Oconee, but that is different than other sites of experience. I want to make sure I'm clear on that.

(Simultaneous discussion.)

MR. ROSEN: Does the presence of the lava-like deposits distinguish Davis-Besse from the other plants?

MR. HOLMBERG: That's our understanding. I've got Region III plants that I'm experienced with --

MR. STROSNIDER: This is Jack Strosnider. With regard to the last two questions, the first comment I'd make is, understanding that the definitive root cause of this gets to the question of why here and not at the other plants -- and there's a lot of thoughts right now, but we really don't have that answer nailed down, and we're waiting for the licensee to provide -- and the industry to provide -- some additional information in that regard, and we're scratching our heads also.

With regard to the lava-like flow indications, the subject of the Bulletin 2002-02 (sic) which we'll talk about, we're asking people to go out and look and see if they have some more conditions. So, we have responses. We haven't seen anything --

based on our review so far, we haven't seen anything similar, but that review is still in progress, and we'll summarize that when we finish this part of the presentation.

MR. FORD: Jack -- I think I know what you're going to ask, you go first.

MR. BONACA: Just to say we have a number of lessons learned regarding played out on cold surfaces in containment, and to what extent are these observations going to be made part of programs for the other units. I mean, clearly, the timing here of identification of leakage through a crack is critical because you are saying that it is possible that this could be repeated as an event at some other unit, and also that we have learned that -- so is there anything being done to try to develop programs by which you have inspections in containment and -- you know, just HEPA filters and -- you know?

MR. BATEMAN: Jack, if I could interject here, we did issue an information notice, I guess, last week when we talked about this phenomena of the containment air filters and the radiation elements and changes in unidentified leak rate, to alert other utilities of those potential signs of problems.

MR. GROBE: And what Jack and Bill are

indicating is just the earliest part of getting information out and getting information back so that we can consider what are the appropriate inspections both from the utilities perspective and also from our perspective. This had been going on for a number of years, and we hadn't identified it either.

MR. BONACA: Because, I mean, up to now, in my mind, I've been focusing purely on the visual inspections of the head, whether there is something more we have learned from this were precursors of deposits elsewhere and in the atmosphere of the containment that may give some significant element to a problem that --

MR. GROBE: That's correct.

MR. FORD: I'd like to follow up on the discussion about how close are we to a cliff edge, if you like, that all reactors that found axial cracks could potentially have within some unknown time period this same sort of problem, which comes down to the importance of the root cause analysis. In order to get one inch per year, it's my understanding from the open literature data, that it is an impingement sort of problem, i.e., it's very important on the angle of attack of the impingement. Axial cracks should not, therefore, give the problem that we are seeing here, but circumferential cracks would. And that's why I asked the initial question, how sure are you that Davis-Besse did not have the circumferential through-wall crack? That was the reasoning behind my question and, of course, we don't have the answer to it.

MR. HOLMBERG: Yes. And on top of that, the circumferential crack -- again, if you look at the wastage area, the one that's aligned is basically the longer axial crack.

DR. DAVIS: And there are no circ cracks in nozzle 3.

MR. FORD: Okay. So you are still going -- if you were a betting man, Jim, you're still going towards corrosion as opposed to impingement attack, which has got a huge impact, therefore, on what the environment is really in the annulus and is, in fact, not only on the wastage, but also on circumferential crack growth rates.

DR. DAVIS: I'm not sure that I would say that 2200 psi steam hitting a steel surface is not going to do any damage.

MR. FORD: Well, it's just coincidental that it happens to do damage at around about 1 to 10 inches per year.

DR. DAVIS: It may be a combination of

both steam-cutting and boric acid corrosion, and we're hoping that the Root Cause Team gets some evidence because they're going to cut that hole out and they're going to examine it and they should be able to tell if there's steam cutting from --

MR. FORD: I realize we've got a bulletin out on this to try and define the problem, and in that Bulletin 2002-01 there is, I believe, a statement on coming up with a root cause analysis within a certain period of time, am I correct?

MR. BATEMAN: All the bulletin does is ask licensees to go out and inspect to determine what they have on the top of their head.

MR. FORD: Did I not see some document --

MR. STROSNIDER: Ken Karwoski might want to correct me if I get it wrong -- there's some discussion in the bulletin about, I think, the fact that we don't understand the root cause at this point, but these are the conditions that existed where this occurred, and we're directing plants to go out and look and see if they have similar conditions. Not knowing the precise root cause, we had to cast a net broader than you would if you knew that root cause precisely. So there is some discussion in there, and there is an expectation that -- and I don't remember the exact language -- at some point we will get a root cause, but we didn't have it at the time we wrote the bulletin.

MR. FORD: But will you be discussing this, Jack?

MR. STROSNIDER: Ken Karwoski is going to talk about the bulletin when we finish this part.

MR. GROBE: Through the discussion -- John Wood, when is the root cause analysis -- do you anticipate that will be submitted soon? We did a lot of speculating up here.

MR. WOOD: Yes.

MR. GROBE: Weeks, months, next week? Okay. Excellent.

Unless there are any other questions for the team, that completes our presentation.

MR. FORD: Thank you very much, indeed, appreciate it.

I understand now we'll go into about an hour and a half of discussions from First Energy.

I've had a request here that after this presentation, so we all know how to manage our lives, after this presentation we'll have a break for ten minutes.

MR. WOOD: Good afternoon. My name is

John Wood, and I'm Vice President of Engineering Services for the First Energy Nuclear Operating Company. Next slide, please.

(Slide.)

As far as our presentation this afternoon, I'll be giving some background information, then turn it over to Mark McLaughlin who will be discussing discovery and characteristics of our reactor vessel head degradation, and then over to Steve Loehlein to discuss the evaluation of the degradation. Next slide.

(Slide.)

Our objective of this presentation is to provide the results of our recent inspections and subsequent investigation of the degradation found at the Davis-Besse Nuclear Power Station.

(Slide.)

For background, Davis-Besse is located in northwest Ohio, near Oak Harbor. It began operation in August of '77. It is a raised loop, 177 fuel assembly Babcock & Wilcox pressurized water reactor, operating at 2772 megawatts thermal, about 930 megawatts electric. It has approximately 15.8 effective full power years at the conclusion of its last operating cycle, and what you see next are the nominal operating conditions, that being 2155 pounds per square inch for pressure, and a T_{ave} of a normal 582 degrees F., with a hot leg temperature of 605 degrees F. We have 69 nozzles located in the top of our reactor pressure vessel head, 61 of those nozzles are used for control rod drives, that gives us 8 additional. Of those 8 additional, 7 are spare and 1 is used for reactor vessel head, vent from the top of the reactor vessel head to the steam generator. Next slide, please.

(Slide.)

We've covered this diagram in some detail already, but I would like to point out that the head insulation is permanently installed, not meant to be removed. The dose rate at the flange level is about 1/2 of a manrem per hour, and the dose underneath is about 3 rem per hour.

MR. BONACA: Do you mean millirem?

MR. WOOD: I mean rem, 1/2 rem per hour -- excuse me.

MR. BONACA: What kind of insulation is it?

MR. WOOD: It is a mirror type insulation, stacked stainless steel. It is located on support steel that is carbon steel, however, and much of the service structure, as outlined there, is carbon steel in nature.

We show there the 18 access openings, or "mouse-holes", the 5 x 7 holes that we referred to earlier, and those provide the access into that area between the insulation and the top of the head.

I will mention that the service structure also has ductwork that allows cooling air to be pulled through. There is no forced air underneath the insulation other than what might come up through the mouse-holes and out through the openings that the nozzles penetrate through the insulation.

MR. SIEBER: It would appear, if I look at the support steel that's underneath the insulation, that it actually adjoins the head next to the center nozzles, is that true?

MR. WOOD: I don't believe it actually rests on the vessel itself. It's due to the orientation, I believe it's off to the side in that profile.

MR. SIEBER: Looks like it would be almost impossible to see the center nozzle.

MR. WOOD: I believe if you come from a particular access opening, or one of the mouse-holes, you can go directly to the center.

MR. ROSEN: Let's clear up the radiation levels. This is shut-down radiation levels --

MR. WOOD: That's correct.

MR. ROSEN: -- at ten days after shutdown, let's say, those are approximately 500 millirem per hour at that support steel plate?

MR. McLAUGHLIN: What that is -- you know, we've done a significant amount of work inside the service structure, and what we're giving you is the effective dose rate that our workers are seeing inside the service structure. So that's in -- if you look in the service structure, we've had workers inside this area doing insulation removal and several other activities. The effective dose rate that they have received to date in that area is approximately 450-500 millirem per hour.

MR. ROSEN: Thank you.

MR. SHACK: Where does it go to 3-r?

MR. McLAUGHLIN: Underneath the vessel. The contact radiation reading in this area here, after we did the under-head decom is 3-r per hour. If you want an effective dose rate for the workers down in this area here, it's about 700 millirem per hour is the effective dose rate that our workers have been receiving when they go under.

(Slide.)

MR. WOOD: If we go to the next slide, we have here a couple of pictures of the reactor vessel head as it sits on the reactor head stand. This is during one of our refuel outage. You can see this portion being the service structure, if you were to open it up, you would see then the control rod drive mechanisms. Some of those mechanisms have been removed in order to do work inside that structure. And, typically, you can see the individuals on top on the left-hand side of the screen there, they would be working with about 22-foot poles in order to service the flanges that are located at this location. Next.

(Slide.)

We've already talked some about typical control rod drive nozzle. It shows the Alloy 600 --

MR. ROSEN: Could you go back to that other picture again?

(Slide.)

The men on top of that structure are in full anti-Cs. Do they have controlled breathing apparatus, too?

MR. WOOD: No, not contained breathing apparatus. Next.

(Slide.)

I wanted to point out the Alloy 600 Incanel. The reactor vessel closure is about 6 5/8 inch thick, with the nominal clad thickness of 3/16 to 3/8 of an inch.

(Slide.)

If we go on to the next page, there are some unique features at the Davis-Besse site. Our hot leg temperature runs about 4 degrees F. higher than other Babcock & Wilcox plants. That's slightly higher because of our core delta-T being slightly higher due to being 2772 megawatt thermal. We also have the head vent which goes to the top of our steam generators. There is no counterbore present at the nozzle penetration. We should back up one slide, if we could.

(Slide.)

This actually depicts a counterbore situation here, and at this location at Davis-Besse, we were one of the last 177 fuel assembly B&W plants produced. They ended up just drilling holes and doing a shrink-fit using liquid nitrogen without a counterbore in the regions that are shown here. That is a unique feature. Don't know that it's a significant feature in what we have found.

If we could go on to page 10.

(Slide.)

We've heard today about Bulletin 2001-01, which was issued August of 2001. As a result of that issuance, Davis-Besse worked with the NRC staff to extend their outage from the requested December 31, '01 inspection date, and through those discussions they were successful in extending the date to February 16th. In that deliberation they committed to doing 100 percent visual examinations of the reactor pressure vessel head penetrations, and committed to doing 100 percent ultrasonic examinations of the nozzles. Next page.

(Slide.)

There were some compensatory actions that were taken in order to be granted that extension. That included a temporary lowering to T_{hot} to reduce susceptibility to primary water stress corrosion cracking during the remainder of the operating cycle. That was reduced about 7 degrees from the 605 that I mentioned earlier, which is normal, to about 598.

We also minimized unavailability of safety-related equipment during the remainder of the operating cycle. Dedicated an operator for emergency core cooling system transfer from borated water storage tank to the reactor building sump, and also conducted additional operator training. Each of the first three represented about 16 percent to 17 percent improvement in the core damage frequency as a result of doing those steps. Next page, please.

(Slide.)

Davis-Besse, of course, was aware of what was happening in the industry in regard to primary water stress corrosion cracking, had anticipated seeing some cracking in their nozzles. In fact, the planning for RFO 13 was to plan for four nozzles needing to be repaired, and that was based upon the susceptibility rankings that we talked about earlier, which are based primarily on operating time which we were a little behind Oconee, and head temperature which we were a little bit higher than Oconee.

(Slide.)

I'll now just cover a few of the sequence of events that have brought us here today. We commenced the outage on February 16, and moved the head to its head stand about a week later, started the UT examinations which revealed cracks through-wall on nozzle 3. We made our event notification announcement to the NRC at that time.

We then the next day completed the rest of the UT examinations and indicated that of all 69 nozzles, we had five denoted with cracking. Those are listed there, and Mark will be giving you much more detail on each one of those. And we confirmed those then using the top-down inspection tool that Mark will also be discussing.

I would like to point out on the bottom of that page 13 that we did understand from the UT data that we had suspect areas behind nozzles 2 and 3, and also you'll hear more about a nozzle 46 that Mark will talk about, that did not have a crack but had the indication in the back plane that needed to be investigated. Next page, please.

(Slide.)

On March 5, as Mark was watching the inspection screen, noted that there was unexpected movement of machining tool during the nozzle 3 repair effort, and we proceeded to go down path and removed nozzle 3 on March 6. We found degradation on March 8, which you saw the picture of in staff's presentation, and shortly thereafter there was an Information Notice on the event that was issued to the industry March 12, and Davis-Besse received a Confirmatory Action Letter on March 13, which included six items for consideration, the six being the quarantine for root cause analysis, determine what the root cause was, evaluate the extent of condition with respect to the degradation mechanism, NRC review and approval of repairs, NRC restart approval, and assessment of safety significance.

At this time I should mention that there was a question earlier about that safety significance, and what we have recently signed out as of yesterday to the NRC was that we believe that the clad, as it existed, would have held to 5600 pounds per square inch, and that assessment, the PSA portion of that, is included in the letter that was sent out yesterday. Next.

(Slide.)

Just to complete the sequence of events, on March 18 NRC notified the industry of the issue under Bulletin 2002-01. We completed repairs to three nozzles -- 1, 5, and 47 -- on March 27. We just recently removed nozzle 2 that would discuss some of the findings there, and then on April 4, we just talked about in here that NRC issued Information Notice to the industry in regard to the containment air coolers and radiation detector potential indications for the industry to be aware of.

And then that brings us to now a discussion that Mark McLaughlin will cover in regard to the discovery and characterization of degradations that we found.

MR. McLAUGHLIN: Good afternoon. My name is Mark McLaughlin. I am currently the Field Activities Team Leader. Since August, I have been the Davis-Besse Project Manager for the Bulletin 2001-01 inspections.

(Slide.)

I'd just like to point out a couple of things on this slide. This gasketed joint here at B&W plants is not seal-welded as in Westinghouse plants. A couple of dimensions for the nozzles to orient you, the outside diameter of the nozzles is 4 inches, and the nozzle wall is .63 inches. The head thickness is 6 5/8 inch thick, and the cladding is 3/16 nominal thickness.

(Slide.)

I'll go over our examination plan coming into this outage. The basis for our examination plan was to verify the condition of the head, to assess and fix any cracks that were found, and then there's one other important thing that we were going to do before the head was placed on the reactor vessel, and that is clean the head. To do that, I contracted with Master Lead Decontamination Services because they had the equipment and expertise to clean the head through the mouse-holes.

Our examination plan had three steps. The first step was to perform a visual examination so that we could categorize any of the nozzles that would have been put into one of the three categories, either no leaks, obscured, or suspect.

The second step of the process then was to perform ultrasonic examination of all 69 nozzles which at the time was the most extensive examination in the industry. To do that ultrasonic examination, we employed two different tools. One was the under head blade probe UT, and the other one was a top-down rotating UT tool.

If any flaws were found, then our plan was to evaluate the flaws using the NRC guidance. That guidance has different criteria for pressure boundary or non-pressure boundary flaws, and our definition of pressure boundary was from the bottom of the weld, up.

(Slide.)

This slide shows a picture of one of the tools that we used. This is the blade probe. This tool is inserted in the gap between the guide tube and the nozzle, so it inspects from the inside diameter of the nozzle, looking through the nozzle material, out.

The advantage of this tool is that it saves some time because the control rod drive mechanisms do not have to be removed to do the inspection.

The actual transducer set that we used was optimized for circumferential flaw detection. Before the outage start, during the preparation process for these inspections, we brought in the EPRI test block so that we could test out or demonstrate the actual equipment that was going to be used at Davis-Besse. To help us with that, we had an EPRI individual who was onsite, providing oversight of that demonstration. The particular test block that we used had an actual crack from another plant that they had retrieved, so we felt that that was an excellent demonstration of the equipment prior to using it at Davis-Besse.

MR. FORD: So the operators who are using this have never done this before?

MR. McLAUGHLIN: The operators, the ones that we are using? Yes, they were experienced. They had done it at another plant.

MR. FORD: One other plant? What I'm trying to get at --

MR. McLAUGHLIN: One other plant that I know of, yes, using the actual configuration of equipment that we used here.

MR. FORD: The reason for my questioning, so we are not dancing around, is how sure are we that that circumferential crack wasn't all the way through, and the only evidence that we've got is based on the output from this. And I'm just trying to get a feeling as to how reliable is that conclusion that the crack was not all the way through?

MR. McLAUGHLIN: I'm 100 percent positive that that circumferential was not through-wall. The reason I can say that is because the second part of our inspection was if a flaw was found with the circ blade, then we followed it up with the top-down tool, so we actually removed the control rod drive mechanisms. And the top-down tool with the ten transducers, that's going to characterize any cracks found in these nozzles.

MR. FORD: Because the upshot is that I suspect -- if what you are saying is correct -- then we must regard incidences of axial cracks as potentially giving rise to a lot of steel corrosion at these sort of rates.

MR. McLAUGHLIN: I would agree that for me the biggest thing that opened my eyes when we did find cavity 3, is the fact that axial flaws, or axial cracks, are significant.

MR. FORD: Okay.

MR. McLAUGHLIN: Another unique feature of the ultrasonic testing method that we used here is that it can identify a leak path, and I'll show you a UT scan showing leak path in a little bit. The circ blade probe is deployed using the ARAMIS robotic system that was developed in France, and we also had an automated data acquisition system to retrieve the data.

(Slide.)

As I just said, if any flaws were found using the circ blade, our plan was to pull the control rod drive mechanism and then use the top-down UT tool to characterize any axial and circumferential flaws.

The top-down tool, because it does have the ten transducers, it's optimized for characterization of axial and circumferential flaws as well as it has shown good capability of finding a leak path.

MR. SIEBER: That's a rotating probe, right?

MR. McLAUGHLIN: That's correct.

(Slide.)

The third step in the evolution then would be to evaluate any flaws that we had found. The guidance that was promulgated in the letter from the NRC to NEI was the basis for our flaw evaluation criteria. This guidance, I will say, is for crack-like flaws in the nozzle. The guidance offers different criteria for pressure boundary and non-pressure boundary flaws, and essentially our plan was to repair any outside diameter initiated flaws in the pressure boundary region. We would evaluate -- our plan was to evaluate any inside diameter initiated flaws. We would have done a crack growth rate and made sure that they wouldn't grow greater than 75 percent through-wall within the next cycle.

For non-pressure boundary flaws, the two evaluations that stand out to me are you need to do a loose parts evaluation, and essentially what that is is if you had a circumferential flaw below the weld and an axial flaw that could meet up with that circumferential flaw, there is a chance that a piece of the lower non-pressure boundary nozzle could fall off and become a loose part in the reactor coolant system.

The other evaluation that would need to be done if you had an axial flaw, you need to do a crack growth calculation to ensure that that flaw would not grow up into the pressure boundary within the next cycle.

MR. FORD: I'm assuming your crack growth evaluation would be along the lines of the MRP and whatever is approved by the NRC, is that correct?

MR. McLAUGHLIN: Yeah. What we had committed to do was use the MRP guidance. Luckily, we didn't have to get into that, as I'll show here in a little bit, because originally when we were looking at that, the MRP was supposed to have guidance out prior to our outage, but that has been delayed.

MR. FORD: Are you going to talk now or later about the repair criteria, or the approach, the qualification, et cetera -- your first sub-bullet, repair all OD initiated flaws.

MR. McLAUGHLIN: As far as the criteria of what we would repair, this is the criteria. Any outside diameter initiated flaws in the pressure boundary region would be repaired.

MR. FORD: But the question is, how would you repair it?

MR. McLAUGHLIN: The repair method that we chose, and that was based on industry experience with this repair method was the Framatome repair method, which goes in and machines out the bottom of the nozzle, and then puts a new pressure boundary weld essentially up inside the head material itself, and that's what we chose based on -- that equipment has worked very well, and it seemed to us that that was a very good repair approach overall.

MR. FORD: Now, when you say "seemed to us", this has been approved by the staff?

MR. McLAUGHLIN: Yes, it has.

MR. FORD: And this is what will be presented tomorrow?

MR. McLAUGHLIN: No. The repair for the cavity is considerably different than the repairs for -- because the repairs that you're looking at here leave the nozzle installed.

MR. FORD: And the repairs for the cavity will be discussed tomorrow?

MR. McLAUGHLIN: That's correct.

MR. FORD: And just to put it out of our misery, the repair for the cavity, that has been approved by the staff?

MR. McLAUGHLIN: No, it hasn't. As a matter of fact, a repair for the cavity hasn't been presented to the staff as of yet. That's why we're going to have our meeting tomorrow, to present our overall concept for repair.

MR. FORD: Outside of the bounds of this

conversation, okay.

MR. McLAUGHLIN: Next slide, please.

(Slide.)

Okay. So that was our plan. Now I'm going to give you the results. The results of our inspections are we found 5 nozzles with axial flaws, 3 of these nozzles the axial flaws were through the pressure boundary, 1 nozzle had a circumferential crack. The extent of that circumferential crack was 29 degrees in circumference, which equates to approximately 1.2 inches long, and it was approximately 50 percent through-wall.

All of our cracks that were found were outside diameter initiated, and they were -- at least a portion of them was into the pressure boundary so, therefore, all the nozzles with cracks found were going to be repaired.

The other thing I want to mention is that nozzle 46 showed a shadow that was found on the UT. However, it did not have any cracks going up to that shadow, or there were no cracks found in the nozzle itself.

MR. SIEBER: Do you have an explanation as to why there was a shadow?

MR. McLAUGHLIN: I'm going to get -- we'll talk about what we're doing with nozzle 46 right here.

MR. SIEBER: All right.

MR. McLAUGHLIN: I just want to give you a rundown on the review process that we used for reviewing the ultrasonic testing data.

(Slide.)

The first review was performed by Level II analysts. The second review then was -- and it was a 100 percent review -- was performed by the vendor Level III. We also had our Davis-Besse Level III review the data, and to present -- to have 100 percent oversight, we brought in an EPRI person to oversee the entire data collection process and review process.

Now, what I want to say is, after the first four reviews here -- I'm going to call those the initial review. All the cracks were found in all the nozzles. There were 63 nozzles that were found without cracks -- I'm sorry -- actually 64 nozzles that were found without cracks -- got to get my math right -- and then one nozzle was found with an anomaly.

Nozzles 2 and 3, though, had anomalies that we couldn't explain at the time. We did note that further investigation was going to be required. And then, like I said, there was a shadow that was noted on nozzle 46, but there were no cracks leading up to the shadow. So, in accordance with our repair plan at the time, nozzle 46 was not considered a repair candidate. The reviews, those first four reviews, focused on finding cracks.

Now, based on the nozzle 2 and 3 corrosion findings, we performed a follow-up review, and that's what the last bullet there is. We wanted to have another review done by Framatome and a new EPRI individual of all the data looking for anomalies we had seen in nozzles 2 and 3. So we went back and did an experience history of the UT data.

Nozzle 46 was again identified as requiring additional investigation. This review also confirmed that we had found all the cracks the first time through.

What we've done with nozzle 46 so far is we've removed the control rod drive mechanism associated with that nozzle. We inserted the top-down rotating UT tool to confirm the findings. The findings were confirmed. We performed visual inspections of the top and did not find any corroded areas like we had seen with nozzles 2 and 3. So what that led us to was, okay, we don't have anything in the nozzle material itself, or there was no cracks in the nozzle material. We can't for sure explain why there is a shadow there.

So the next thing we wanted to look at was, okay, let's do a dye penetrant test on the wedded surface of the J-groove weld, and that's what we did. The dye penetrant test, we found four rounded indications. We ground those indications to an eighth of an inch depth. We cleared one indication, and we found two others still rounded.

So what we've done to this point I would say is not destructive, however, we conservatively have placed nozzle 46 in the quarantine associated with our Confirmatory Action Letter, and we're evaluating further actions. So that's where we're at with nozzle 46. Next slide.

(Slide.)

This slide shows the relative positions on the head of the nozzles that were found. One thing I want to point out is that nozzles 1 through 5 are manufactured from the same heat. And then I also wanted to show you the location of the cavity on nozzle number 3.

MR. ROSEN: Have you gone back to other places where other people have done the UT examination and seen whether are any anomalies in their data, anything that looks similar to what you're seeing?

MR. McLAUGHLIN: We have not. I can't speak for with Framatome to say with they have or not.

MR. ROSEN: Have you asked yourself what's different about 4?

MR. McLAUGHLIN: We have, and we just can't -- we don't have any explanation why 4 is -- I mean, if you look at the other plant that has this heat, they did ultrasonic testing and the majority of theirs are not cracked. Now, why did four out of five of ours crack? I couldn't tell you. Maybe I'll pass that question off to the root cause, but as far as I know, I don't think we have an answer as far as from an industry standpoint now of why -- obviously, this heat, though, there's something with it.

MR. FORD: There's something really about this propensity towards cracking, and that's understandable. It's extreme sensitivity to heat-to-heat variations, and we don't know why, unfortunately.

MR. McLAUGHLIN: Correct.

MR. FORD: But in terms of the quarantine and the root cause analysis, we're not going to get much more, are we? Everything is destroyed.

MR. McLAUGHLIN: That's correct. The machining process, unfortunately, removes all the cracks. I mean, that's what it's designed to do, and it did that. So, yeah, there's no cracks that we can pull out of these nozzles and say, you know, send it off to a laboratory and do any testing.

MR. FORD: Okay. Well, we'll get into those discussions when we come to the root cause --

MR. BIFITCH: This is Steve Bifitch (phonetic) from Framatome. We have nozzles 3 and 2 in quarantine right now, and the plans that are in place are to take those nozzles and do destructive failure analysis of the nozzles. Obviously, the cracks are now gone, but we can do things with the nozzles such as look at the micro-structure, look for areas that are possibly cold-worked that could cause higher propensity for stress corrosion cracking and things like that. So we have plans in place to do that, but we have not continued with that at this point. They are still in quarantine.

MR. McLAUGHLIN: So, hopefully the laboratory testing on nozzles 2 and 3 that have been removed -- because it is the heat material, the actual heat material, maybe that will tell us something -- and help further the root cause for the industry.

MR. FORD: Just for my information, what does "in quarantine" mean, they can't do anything to it? They can't touch it? They can't --

MR. McLAUGHLIN: No, no. What in quarantine means -- and this was something we worked out with the staff. What we do is before we go in and do anything that could affect root cause related data, we submit a written plan to the staff. The staff reviews it and then we discuss it, and so far we've discussed it over the telephone, and if there's any comments, then we incorporate those into the plan. And we've broken it down into small enough sections that it makes it, I think, relatively easy to review, and then it also helps us to follow that plan. And that's the way we've proceeded so far with the quarantined items.

MR. SIEBER: Has anybody attempted to identify every nozzle and every point up from that heat?

MR. McLAUGHLIN: We know every nozzle in every plant that has that heat in it.

MR. SIEBER: And how many plants does that affect, do you know, or can you tell us?

MR. WOOD: I believe it affects three plants, ourselves and two others.

MR. ROBBIN: This is Mike Robbins, from Duke Energy. At our Oconee 3 plant, of the 69 nozzles that are in Oconee 3, 68 of them have this heat material, and most of the cracks we found at Oconee 3 are of the same heat material.

We've also taken samples of the Oconee 3 nozzle material and have done fairly extensive metallurgical work looking at those nozzles to see if there's anything unique or different about the material, and there's nothing in the characterization that we've seen so far that would suggest there's anything obvious as to why these nozzles cracked. If you look at the micro-structure, the grain sizes, those type things, you see pretty much what you would expect to see of Alloy 600 material.

MR. WOOD: So the answer is two plants, Oconee and Davis-Besse.

MR. McLAUGHLIN: I believe that that's true, there are two.

DR. DAVIS: ANO has one nozzle in this material.

MR. McLAUGHLIN: Okay. I'm sorry. Next slide, please.

(Slide.)

What I'm showing here is -- essentially, this is ultrasonic test data rollout of the nozzle, so if you could envision that you would roll the nozzle out flat, a couple of things I want to point out on this. If you look across the top, the degrees, zero degrees, just for orientation purposes is downhill. The left side shows inches, and the way that the measurement is done is from the top of the flange of the nozzle down to the bottom of the nozzle, so that's why the numbers decrease as you go from the top to the bottom -- I'm sorry -- increase as you go from the top to the bottom.

The solid black line in this area here, that depicts the J-groove weld, so that the pressure boundary area is defined. The bottom -- along the bottom there where the numbers and the colors are, those are just crack numbers. And I just wanted to show you that on this nozzle, this was the crack that was found with the top-down ultrasonic testing equipment and, as you can see, it does not proceed all the way through the pressure boundary. This nozzle, however, because the crack did go up into the pressure boundary, this nozzle has been repaired.

(Slide.)

This is nozzle #5. It had a crack similar to the one in #47, small crack that went up into the pressure boundary, did not go through the pressure boundary. This nozzle has been repaired also in accordance with our plan. Next slide, please.

(Slide.)

This is a rollout of nozzle #1. A couple of things, as you can see there are a significant number of cracks in nozzle #1. Two of them go through the pressure boundary. The crack that I want to point out is this crack right here, and in a couple of slides I will show you there is a leak path that was associated with that. Remember, I said earlier that the UT data can actually detect a leak path. This will be the crack when we looked at the printout for #1 that caused that leak path. Again, this nozzle has been repaired in accordance with our plan.

MR. SIEBER: Is there any significance to the angle of the stripe on these?

MR. McLAUGHLIN: That shows the relative --

MR. SIEBER: That's not the crack?

MR. McLAUGHLIN: -- the crack, no. That's where the crack actually grew up at that angle. So it could be an axial crack, but it didn't grow straight up and down the nozzle, and that's what that's showing.

MR. SHACK: Suppose I had a J-groove leak and I got some OD attack, how sensitive is the blade

UT to the OD initiated cracks? How deep would it have to be before I'd see it?

MR. McLAUGHLIN: From a UT standpoint, what it's looking for is a gap between the outside diameter of the nozzle and the nozzle bore itself. From a UT standpoint, it doesn't really matter if it's a couple of thousandths or several inches. So it does not have to be a very large gap. And if you want a real good explanation of the UT and the process that we use to find a leak path, I have Kevin Hacker here from Framatome and he can explain that.

MR. SHACK: All my question is, if I initiate an OD crack, can I see a 10 percent through-wall OD crack with the blade UT?

MR. McLAUGHLIN: Yes, you'd be able to.

MR. SIEBER: One other question before you leave this. These are all axial cracks?

MR. McLAUGHLIN: That's correct, yes.

MR. SIEBER: If you had a circumferential crack, what would it look like on that drawing?

MR. McLAUGHLIN: The next slide I'll show you.

MR. SIEBER: Okay. I'm a good straight man.

MR. McLAUGHLIN: Excellent lead-in, thank you.

(Slide.)

Okay. This is the results of nozzle 2 inspections. A couple of things I want to point out on this nozzle 2 -- well, actually three things. One is, as you can see, there is the circumferential flaw that was found. I want to point out this crack here. This is the second longest one above the weld that's been found to date. And the other thing I want to point out is we'll see in a few slides, the corroded area for this nozzle came down approximately like this, came up -- so these are the three cracks here that caused that corroded area. Next slide, please.

MR. SHACK: Your laser pointer was approximately correct on the height above the J-groove for that.

MR. McLAUGHLIN: I'm sorry, what was it?

MR. SHACK: Just draw it for me again on this picture where the corroded area is on nozzle 2.

(Slide.)

MR. McLAUGHLIN: It would be right around -- just over past the 270, come down about like this, in that area was the corroded area that we found.

MR. ROSEN: I'm sure everybody else in this room knows except me, the lines that go this way across, that's the weld area?

MR. McLAUGHLIN: These lines, these black lines here?

MR. ROSEN: Yes.

MR. McLAUGHLIN: That depicts the weld, yes.

MR. FORD: I'm jumping the gun to the root cause. Why didn't you see -- why would you not expect to have seen excessive corrosion on the other side? That third crack along there looks about the same extended -- in your comments, you said that you're correlating excessive corrosion at one inch per year, or thereabouts, to the length of the crack, the axial crack. So why there and not at the other --

MR. LOEHLEIN: We will be talking about that, but clearly you'll see here on this slide and on the next one, it's the length above the weld. It really is the crack length above the weld that's different. This crack over here is only about a half-inch above the weld, and the crack through a weld that size is pretty minor.

MR. FORD: And that difference is enough to make a difference between microns a year and inches per year? I don't believe it. I find it hard to believe.

MR. LOEHLEIN: We'll go into that in more depth.

MR. FORD: Okay.

MR. McLAUGHLIN: Next slide, please.

(Slide.)

This is the same rollout of nozzle #3. I want to show you the middle again, just like Steve is talking about, this was less than an inch above the weld. This crack over here is kind of hard to see due to the color, but this is the crack that caused the corrosion or the cavity around nozzle 3. And if you note, it does extend approximately 1.2 inches above the weld. So it's the longest crack above the weld found to date. Next slide.

(Slide.)

What I wanted to show you here is I wanted to show you the leak path that can be detected with the ultrasonics. What this is is a plot of the reflected sound from the nozzle-to-head interface. The red indicates areas of lack of contact, however, UT cannot determine the depth of that lack of contact. So it could be a couple of thousandths or inches, and the UT can't really discern the difference. The dark areas are areas of good contact.

One thing I want to point out, at the top of the head here, you can see that from the UT trace. That's the top of the head. This black is the J-groove weld. And then, again, I wanted to show you the leak path, and you can see the crack coming up through the weld area, and this red area going all the way out through the top of the head, that's the leak path.

MR. SHACK: So that's my zero azimuth of the other plot.

MR. McLAUGHLIN: Yes. What this is, this plot is from the top-down tool. The top-down tool -- the reason -- anyway, the degrees don't line up because the top-down tool is indexed to an index mark on the top of the flange, and all those index marks point to one axis on the head. So the rollout won't be the same orientation as what you see in there.

MR. SIEBER: Do I interpret all the red areas between the weld and the interface as cavities or leakage? How do you interpret that? I can see the leak path.

MR. McLAUGHLIN: You mean these areas here?

MR. SIEBER: Right.

MR. McLAUGHLIN: If you look at it, there are a couple of cracks there, and they probably did start having some minor amount of corrosion. So there's a good chance that there was a small --

MR. SIEBER: So that's like a labyrinth.

MR. McLAUGHLIN: -- of boron in between the outside diameter of the nozzle and the bore.

MR. SIEBER: Sort of like a labyrinth in this.

MR. McLAUGHLIN: Correct. If you look at it, the leak path doesn't go straight up. The actual contact area is -- I'm sure there is gaps microscopically, and the water is going to follow the easiest path up, and that's what it's doing.

MR. SIEBER: If you would slice that up, you would see the micro-structure with these various cavities and cracks in it, if you were to do a destructive examination of that?

MR. McLAUGHLIN: If you could remove a nozzle intact by removing the J-groove somehow?

MR. SIEBER: Yes.

MR. McLAUGHLIN: If you had a slice there, you could see those cracks. And if you sliced it up here --

MR. SIEBER: You would see these cavities.

MR. McLAUGHLIN: You may be able to. There is a gap always -- you know, it's shrink-fit, but it's not going to be a perfect fit. And the reason I say that is because when we did the repair of this nozzle here, the cut line was right here. So you're going to see some of this. We performed dye penetrant testing on this area down here of the bore, and there was nothing found.

Now, the repair process does remove a small amount of bore inside diameter, so that may have cleaned that up, so it's not very deep.

MR. SIEBER: So one could conclude that when that became a through-wall crack and borated water began to go through it, it was not a jet impingement situation, it had to start as a corrosion situation to develop enough space in order to get the steam cutting velocity high enough to do steam erosion damage to the head.

MR. WOOD: If you look at that, I think you can see where the popcorn boron gives rise to the places where it comes out at the top of the head.

MR. SIEBER: I presume it's coming out at that point at a pretty -- pretty fresh and pretty low flow and not a lot of iron in it.

MR. McLAUGHLIN: I would imagine as far as this nozzle, consider what we found with the dye penetrant testing, I would believe that there was no iron removal in this area. There was probably a small amount of corrosion, like I said, that could have been removed during the machining process.

MR. SIEBER: Thank you very much.

MR. McLAUGHLIN: Next slide, please.

(Slide.)

This is the same type of printout or plot for nozzle #2. There are a couple of things I want to point out on this. Here's the three cracks that we showed you earlier. You can see this red area, and then, of course, it wraps around to here. Another thing that I want to point out is this area right here follows the contour of this weld. This is the top of the head. However, you can't see it right here in this area, and you can't see the head here. And that was bored out -- this is the area that we found that there was corrosion. There's about an eighth of an inch of steel lost at the top of the head.

So the UT did show that there was something going on up there.

MR. SIEBER: What is the significance of the plot to the right of the --

MR. McLAUGHLIN: I'll have to refer that to Mr. Hacker because I'm not sure. What is the plot to the right, Kevin?

MR. HACKER: That's the outside surface of the nozzle. That's representative of the depth, and the left side of that view being near the ID surface. Kevin Hacker, Framatome.

MR. McLAUGHLIN: Next slide, please.

(Slide.)

This is the picture that you saw earlier. We stole it from AIT. We felt this was an excellent representation of this nozzle. Again, at the top, it's about an inch -- or essentially all the way through the nozzle, it's 1 3/4 inch wide. It starts approximately 2 inches above the top of the weld, and it does extend all the way through the top of the head, and it ranges from 1/4 to 3/8 inch deep. It's about 1/8 inch at the top of the head.

I guess the one thing that I did want to point out is we removed nozzle 2 to help in characterization of the root cause. When we did that, the metallurgist who reviewed that cavity, we did some extensive video tapes, we also did an impression of the area. They looked at it and determined that this was corrosion, not erosion. So I think that that's kind of significant. It feeds into what we're seeing here.

MR. FORD: How did he come to that

conclusion?

MR. McLAUGHLIN: I'll refer that to Steve --

MR. FORD: Are you going to cover it later on?

MR. McLAUGHLIN: Are you going to cover that?

MR. LOEHLEIN: We can talk about that. The metallurgist is right here. Steve Bifitch is here. He's one of the members of the team, he and Dr. Mark Burdofski (phonetic) from our Failure Analysis area of Beta Labs reviewed that extensively this past Friday, and did conclude it's corrosion. If you want to talk about it, Steve, go ahead.

MR. BIFITCH: Yes, it's a little detailed. When we reviewed the videotape, you could see -- I mean, obviously, the video camera that you're looking at gives you a very good close-up picture. You could see typical remnants of corrosion, generalized corrosion that you would expect to see. You see things basically eaten away, and you're not seeing a flow type pattern that I would expect from steam erosion. Now, obviously, when we get a better look at it, I asked the Framatome folks to go back in there and look at it again and take some measurements with rollers and stuff, so that we can get a better characterization of what it actually looks like because this is just a schematic based on what we knew about a week ago.

MR. LOEHLEIN: But, Steve, isn't it also true that from the impressions and everything, we know that the areas of deepest penetration are somewhat higher up in the annular region than the actual crack location?

MR. BIFITCH: Yes, looking at the --

MR. LOEHLEIN: Corrosion as opposed to erosion because it's not actually right lined up at the exact leak points, but higher up.

MR. FORD: You've got independent data -- I mean, you've come out with a hypothesis right now. Do you have independent data, in either the open or closed literature, which will confirm that hypothesis with relevant corrosion rates?

MR. BIFITCH: We'll talk about that during the root cause portion of this presentation, but to answer the question, yes, there is an adequate amount of data in the literature and in the closed literature from the EPRI guide book that verifies what we're looking at.

MR. FORD: General corrosion rates of 1/4 inch per year for this one, without any flow assistant effects at all?

MR. BIFITCH: Yes.

MR. SIEBER: This doesn't surprise me because fluoritic material out in the air exposed to high concentrations of boric acid corrode pretty fast. I've seen bolting --

MR. ROSEN: We've seen reactor coolant pump bolts made of this kind of material extensively corroded back in the mid-'80s. So general wastage like this is possible with those kinds of rates without any flow phenomenon.

MR. SIEBER: And all of that can occur in one cycle.

MR. ROSEN: Well, it can occur very quickly. I don't know --

MR. SIEBER: Well, if at the end of the refueling, the next refueling, it's there.

MR. FORD: And this hypothesis would also explain why you see it specifically on this geometry and not on Oconee? It does not explain it, or it -- the question was, you've got a hypothesis which you've backed up by independent data, to explain why you've got corrosion rates of this magnitude on that particular geometry, annulus geometry, et cetera, and does that same hypothesis explain why you do not see it at Oconee?

MR. LOEHLEIN: There's a metallurgical answer and then there's a root cause answer that we'll go to. Do you want to talk about the metallurgy, Steve?

MR. BIFITCH: Well, you say of the extent that we're seeing nozzle 2, there's very little corrosion, in reality. I mean, that's not a lot of corrosion.

MR. FORD: Okay. But it's the same -- that same hypothesis presumably explains why you've got 1-to-10 inches per year on nozzle 3?

MR. BIFITCH: Yes, from a root cause standpoint -- and, again, Steve will get into this -- but we feel that nozzle 3 had been cracked and leaking much longer than nozzle 2, and the same for nozzle 1. So the age of the leakage is significantly different between 3, 2 and 1.

MR. FORD: So it would be about a factor of 10 difference in time?

MR. LOEHLEIN: We'll get into that.

MR. McLAUGHLIN: Next slide, please.

(Slide.)

This is the same data that we had earlier for nozzle 3. A couple of things that I want to point out. No. 1, if you look up here, we should see the head, the top of the head should have been up here. If you see these two lines here and here, those are the outlines of the cavity. Obviously, we didn't know it at the time that we took the UT data, but -- so this entire area here is the cavity and this is the crack that caused that cavity. Next slide, please.

(Slide.)

I just wanted to use this picture to introduce the cavity to you. A couple of things I want to point out. This distance here is the 4 inches where nozzle 3 was removed. This is the remnant of the J-groove weld that's left. And then this area here is the exposed cladding. There's also an under-hang in this area here that actually extends down to about right in this. It's enough so that you can actually stick your fingers underneath there.

MR. FORD: That's what you call a "nose"?

MR. McLAUGHLIN: Nose?

(Simultaneous discussion.)

MR. McLAUGHLIN: Next slide, please.

(Slide.)

I'll just go over what was going on at the time when we discovered the cavity. We were performing the machining operation on nozzle #3. The machine that we use is hydraulically locked into the nozzle. There was an unexpected movement of the machining tool, it actually rotated 15 degrees and then stopped. We stopped at that time, stopped the machining operation because we knew then that the nozzle had rotated.

When the machine was removed, there was some mechanical agitation with that process. That helped loosen up the nozzle further, and the nozzle then was -- a lot of people have seen pictures of the nozzle leaning against the flange that was next to it. There is approximately 1/2 inch in between from one flange to another, so it's not a real big area, or big distance there.

We did remove the nozzle and cleaned the cavity, and that's when we discovered that we had some significant degradation of the reactor vessel head. Next slide, please.

(Slide.)

Again, this is another picture of the nozzle area itself. What I wanted to do is kind of go over some of the actions that we've taken to gather data and characterize the cavity itself. I want to point out, like I said earlier, all these actions were reviewed and did have concurrence from the staff prior to being implemented. We had a written plan and then we had a work order so that we could follow our administrative process through to ensure that there wasn't anything missed in the data gathering.

The first thing we had to do was remove insulation to gain access into the cavity. We performed several video inspections of the cavity area, as well as nozzles 2 and 1. We've collected boron and corrosion samples from both the cavity and from the corroded area in nozzle 2. We had a collection device underneath nozzle 2 when we pulled that nozzle out.

We've taken ultrasonic readings and mechanical measurements so that we can get a good idea of the extent of the cavity, and we've done some liquid penetrant examinations of the cavity as well as taken impressions of the cladding area. Next slide, please.

(Slide.)

This is a tool that we had built to aid in taking mechanical measurements of the cavity. As you can see, the distance is about 4 inches. This fixture here was installed in the bore of the nozzle where nozzle 3 was removed so that way we could index from the nozzle in all our measurements that were taken.

We also used this little jig here so that we could take measurements off and we would know what the angle that we were taking those measurements.

MR. ROSEN: Did you clean the hole up at all, or is that the way --

MR. McLAUGHLIN: It was cleaned at this point when we did these measurements.

MR. ROSEN: You just scraped it with sandpaper or something like that?

MR. McLAUGHLIN: Brushes.

MR. ROSEN: Wire brushes?

MR. McLAUGHLIN: Not wire brushes, but nylon brushes.

We also probed the underhang area with a mirror, and used a wire so that we could determine where the farthest point was. The farthest point is approximately right in here, and the last slide that I have shows the actual dimensions of that.

MR. SIEBER: What was the surface like after you used the brushes on it? Was it solid material, or was it spongy?

MR. McLAUGHLIN: No, it's very solid material. It's actually pretty smooth. It's kind of got contours to it. I don't know, I guess these guys could probably characterize it a little bit better. I mean, I have gone out and felt it and touched it a few times, but --

MR. SIEBER: At those radiation levels?

MR. McLAUGHLIN: I took some of these measurements myself. I guess my feeling is that if I'm going to be the project manager and the team lead, I need to see what it is that I'm up against, and I needed to experience it first-hand.

MR. SIEBER: I just want you to be aware.

MR. McLAUGHLIN: I agree. We do practice ALARA.

(Slide.)

From a dimensional standpoint, I'll point out a couple of things. From here to here is approximately 6 inches. From here to the edge of the cladding here is approximately 5 inches. The farthest point that we saw and measured from the edge of the bore to here is just a little over 7 inches. One thing I want you to notice is the 13-inch cutout line that we have. That dimension is approximate at this point. What that's showing is our plan going forward is to use an abrasive water jet process to remove this entire cavity. We chose the abrasive water jet process for two reasons: One, that we could remove the entire cavity with it, and the second is that there won't be any heat input from the removal process that could destroy or alter any information that can be gathered from the cavity.

The other thing I wanted to point out is that we took ultrasonic UT ratings of the cladding for thickness. The readings we got had an average of .297 inches, and the one single point, the lowest point, was .24 inches.

For my part, I've described our plan. I've described our findings. I've talked to you about the cavity discovery and the characterization of that cavity. Are there any further questions?

(No response.)

Okay. With that, I'll turn it over to the person who I'm sure you all want to talk to, Mr. Steve Loehlein, to discuss the root cause.

MR. FORD: Can I just ask a timing question, Steve? How long do you think -- assuming we don't ask too many questions, roughly how long are you going to take?

MR. LOEHLEIN: Well, when we've done this presentation just sort of in a dry run fashion, it's been 20 minutes to half an hour, but it really is determined a great deal on how many questions we get.

So if you're asking should we take a break --

MR. FORD: I think what we'll do is take a ten-minute break. I'd like to finish at 6:00 o'clock, however, so let's make it no longer than ten minutes.

(Whereupon, a short recess was taken.)

MR. FORD: We are now back.

MR. LOEHLEIN: Once again, good afternoon. I am Steve Loehlein. I am the Root Cause Team Leader. Before I get started, I just want to make one comment based on a question that had been asked earlier of Mel Holmberg, and that had to do with our condition report records for things like steam relation of boric acid on the vessel flange and the containment air coolers, and the root cause report that we have prepared does have condition report references historically that were written on those subjects. So there is some information on that for Mel and for whoever, and when they see the report they'll see them in there.

(Slide.)

I'll start off by saying that soon after this damage was recognized at nozzle 3 and then soon after that in nozzle 2, Davis-Besse's management team realized quickly they needed an investigative team with members who would have a variety of expertise and a variety of experience. They wanted to have a team that was going to have objectivity. That's why persons like myself who are from Beaver Valley Power Station, and another member of the team that I've brought in from Beaver Valley who is our Latent Issues Program Manager, and we also wanted to have, of course, ownership by Davis-Besse staff for the results of the root cause, so we have members on the team directly from Davis-Besse staff, and we wanted to have the finest technical expertise on the team that we could get, so we augmented our folks with the technical expertise from Dominion Engineering, from EPRI MRP, from Framatome, and we had a failure analysis expert from our Beta Labs also come in and assist.

(Slide.)

Before I get into the root cause discussion, I want to familiarize people with the terms we're going to use here because we have under the root cause determination process that we have in our company, we have definitions for specific terms, and they are up here on the screen. Probable cause is for us, by definition, a root cause that cannot be validated after-the-fact. We also have root causes that are the more what I could call common definition, and that is that root cause is something that, if eliminated, would have prevented the incident or event. Similarly, I think our definition of contributing cause is pretty familiar in that it is a cause that either increases the likelihood or the severity of the incident or event.

The other thing I'll point out before we get started is that there's going to be a lot of discussion that talks about probable cause for the cracks, and then root causes for the damage that occurred at Davis-Besse, and I think by now we've heard a lot about the differences. We have discussions about PWSCC and then we have discussions about wastage.

So by this time, probably to no one's surprise, the damage to the RPV was not identified until we had machined on nozzles 2 and 3. That was just by happenstance because at the time the damage wasn't known, so we're not likely to be able to find the data that will prove that PWSCC caused the cracking in these nozzles, but we believe that this is highly supported by the evidence that's available. Since PWSCC is a known mechanism in the industry, it really doesn't explain the damage that occurred to the RPV head.

(Slide.)

So, from root cause base, we identified a root cause which was something that permitted the conditions to develop on the head that allowed the corrosion to occur, and what we determined was that Boric Acid Corrosion Control and Inservice Inspection programs were such that they allowed for the accumulation of boric acid to remain on the head. What this did or what this resulted in is the plant did not identify through-wall cracks and leaks during prior outages when they existed, that the plant returned to power with boron remaining on the head after outages, and that we were unable to identify the damage that was occurring on the RPV head by 12RFO, which is the outage prior to this one that we're in right now.

(Slide.)

A number of contributing causes are identified in our report. The major ones I'll go over here. The first one we've heard some about before are environmental conditions, cramped conditions and so forth caused by the design, the very tight fit between the insulation layer and the top of the head, the small drainage openings that are used for access, the high radiation area, the temperatures, all these contributed to making this access for cleaning and inspection difficult. So the same three bullets appear under there: It made the identification of cracks that did not occur in prior outages, cracks and leaks, we returned to power with boron on the head in the center head region, and we did not identify the damage when it began.

(Slide.)

Another important contributing case were equipment conditions that we had due to uncorrected CRDM flange leakage. We talked about -- a little bit earlier, I think John Wood showed the first slide, and it appeared later, that showed where the flanges are and how there's the insulation layer between, and so forth, and the historical problems with flange leakage on the B&W plants -- Davis-Besse was no exception -- had a number of flange leakage issues in earlier years, which now appear to be corrected, but some of those were bad enough to allow boric acid to leak down onto the head in regions where it was pretty inaccessible, and so accumulations from boric acid leaking from above were something that was internalized by the organization as common.

MR. SIEBER: Steve, how long do you think this corrosive environment was present, how many years?

MR. LOEHLEIN: We have a timeline later in the presentation that I can go -- it's probably best if I go over it then.

MR. SIEBER: Okay.

MR. FORD: I just want to be sure because it's been intimated in some of the documents that's been going around that a potential source of the boric acid or whatever the environment is, the boric acid rich, in the annulus originated from the flange region and dripped down. That's been intimated. And what you are saying is, no, that may have confused the issue, but it was not the prime source, that the PWSCC was the prime source of the annulus environment, is that correct?

MR. LOEHLEIN: PWSCC is what we've concluded is the initiator of the cracking, not the initiator of the wastage. I don't know if I've misinterpreted your question, and whether you're asking how does that relate to the leakage from above?

MR. FORD: As I understand --

MR. WOOD: I think you are correct in the way you stated that, that because there had been flange leakage over a number of years, that that was then attributed to the boron that was seen on the head versus the leakage coming out of nozzles as being the source.

MR. FORD: That's in no way intimating that the leakage occurred in the flange above dripped down and went into the annulus and caused this problem, that's not the issue.

MR. LOEHLEIN: No, we did not. In other words, just to be clear, the flange leakage that occurred over the years did not have anything to do with this wastage incident, or anything we've been able to find.

(Slide.)

As part of the probable cause for the nozzle leakage, we did assemble information on PWSCC and other possible reasons for cracking. I think by now we talked about the main factors associated with primary water stress corrosion cracking, susceptible material, high tensile stress, and aggressive environment. Of course, all of these were present at DB as they are at other PWR plants.

MR. BONACA: I have a question. Your root cause, you go -- I mean, somebody could ask a question of how far did you go back into asking why this happened, and you're saying the plant did not identify through-wall cracks during prior outages, plant returning to power with boron on the RPV head after outages -- we know these things happened, of course. But there were questions that were raised by the NRC on the missed opportunities, for example. I would like to understand, given that your filters needed to be replaced every other day, what do you attribute that to and did not connect at all. I would like to understand that.

MR. LOEHLEIN: Well, the condition report records and the interviews we conducted, the plant staff did not make the connection is all we can say about it. We investigated this from root cause standpoint, and we can say that that connection was not made, that it was -- that the source could be nozzles. It was felt to either be corrosion from some other source.

MR. BONACA: I'm not saying that we want to evaluate this here, all I'm only saying that to do it through root cause analysis that would prevent a recurrence of this nature, you would want to go farther back to understand really how come we misinterpreted these issues.

MR. WOOD: hat's correct.

MR. BONACA: What do we need to do to prevent recurrence of such event.

MR. LOEHLEIN: That's correct. We are looking at the management issues that allowed us to have that blind spot in our thinking.

MR. BONACA: The reason why I'm bringing it up is because I think it is important generically, as I said before, to other units to try to read from apparently maybe indirect readings, you know -- they are not doing direct -- but, really, they are maybe not specific in indicating the crack or the issue, but boron deposits somewhere --

MR. WOOD: And I believe that the AIT agreed with that, and that's why Information Notice 2002-13 was issued in order to draw the analogy to the containment air coolers and the radiation elements.

(Slide.)

MR. LOEHLEIN: It's also been mentioned earlier that in comparing Davis-Besse to others, we have observed that all the through-wall leaks at Davis-Besse are from a material heat. The displayed leakage in another plant, it's the heat identified there. We also noted that all these locations are at the top of the head, which is a region expected to be of lower stress than other regions in the head, but it's also true that nozzle 4 is exactly the same in terms of location and all that, yet it had no cracks identified at all, and it is the same heat.

(Slide.)

We also considered other possible causes of the cracks, like thermal fatigue, inner granule distress corrosion cracking, RCS chemistry, and some others, and we were able to dispel all those and we are pretty well convinced that primary water stress corrosion cracking was the initiator as far as cracks go..

(Slide.)

So that led us to, again, what was different about Davis-Besse's cracks, and it's been mentioned earlier. It's an important difference in that the through-wall cracks above the weld are the largest that have been reported to date.

MR. SHACK: Is that true even for the circ crack at Oconee?

MR. SIEBER: Probably not.

MR. LOEHLEIN: I don't know that about the circ crack at Oconee.

MS. KING: Christine King, EPRI MRP. I think what you're referencing is the axial length. This is a discussion -- a comparison of the axial flaws found in the industry today. Oconee still remains our largest circumferential flaw identified.

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MS. KING: Christine King, EPRI MRP. I think what you're referencing is the axial length. This is a discussion -- a comparison of the axial flaws found in the industry today. Oconee still remains our largest circumferential flaw identified.

MR. SHACK: My real question is, do you believe the leaks through these cracks are larger than the leak through the Oconee circ crack? That seems to be where we're headed here. Did anybody check that?

MR. LOEHLEIN: As part of this root cause, we would not have studied that. There's going to be plenty of ongoing work that will compare this to other things that are known and other events that are reported in the Boric Acid Corrosion Guidebook and elsewhere.

MR. FORD: But, surely, for the probable cause, root cause analysis to be valid, you've not only got to explain quantitatively why you've got cracks and other people don't. You've got to go through that process and, therefore, you'd need much more of a database than just that to prove your case. For instance, the other nozzles which cracked at your plant, which did not show the excessive corrosion, were they .9 of an inch, .8 of an inch, and they should therefore have a plot of amount of corrosion versus crack length, axial crack length, and would be uniform for all plants with that heat.

MR. LOEHLEIN: I don't think you'd ever be able to do that because every nozzle is loaded differently, has different residual stresses, responds differently during plant heatup and --

MR. FORD: Well, that then gives rise to the occurrence of the PWSCC, the stresses aspect.

MR. SIEBER: Then there is the time. They've been able to analyze to some extent how long this condition persisted.

MR. LOEHLEIN: I guess what I'm saying, if it were that predictable and you could reduce it to those kinds of numbers, we would have had leaks at nozzle 4, and we don't. We don't even have cracks.

MR. SHACK: But you are arguing that the difference -- the reason why your behavior with leakage is different from the other plants with leakage is simply that you're older. I mean, your argument leads to the conclusion that this will happen at all plants that leak. Is that --

MR. LOEHLEIN: What we would say is that if a leak is not attended to and it is allowed to continue where it can create boric acid pools above it, and then that leak continues to get worse and can allow the boric acid to remain wetted near that annular region, that significant corrosion rates can begin. And we'll get into the timeline and all that a little bit further here, but time is the issue. How long do the leaks exist? How much boric acid do you apply to the region? And we'll get into that. But the leakage rates, the important thing to understand about the leakage rates is that they are not at all linear with the axial crack length, they are quite a bit nonlinear. And so the crack lengths, as they enlarge, produce rates and can produce leak rates significantly higher.

MR. SIEBER: Is there a reason for this, the physical reason for this, the chemical reason for this?

MR. LOEHLEIN: There are a number of them, and there's models that have been run for it, and we'll talk about them on succeeding slides. So why don't we go on and move forward.

MR. SIEBER: I think it's interesting to point out that every crack starts as a small crack, and there is crack growth going on in every plant that there's a crack initiator. So, sooner or later you're going to get to a critical crack size that causes leakage that meets these conditions unless its repaired, but all of these are covered under the Code. You have to repair them once you find them, under the Boron Pressure Vessel Code.

(Slide.)

So looking at nozzle leak rates, what we believe they were at Davis-Besse, we examined the subject area from two perspectives, one was the analytical one and one was from available plant data. Different analytical models were looked at. There's a model out there that looks at this crack in a pipe, there are others that are finite element type analyses and which we're able to model whether the region is supported by a surrounding material like the head, or whether it's relaxed like you would see after enough corrosion takes place that there is no supporting mechanism, and the overall range on these predictions is fairly large -- 0.025 to 0.87 gpm is what we came up with on those approaches.

Looking at plant data, though, which is using things like the unidentified leak rate and the amount of boric acid on the head, and so forth -- and our Root Cause Report goes into some detail as to how we arrived at this -- the most probably leak rate range at the end of the cycle for nozzles 2 and 3 combined is .1 to .2 gallons per minute.

MR. SHACK: That first bullet, is that for a given crack size?

MR. LOEHLEIN: I think we did that for a range of -- we did that for a range --

(Simultaneous discussion.)

MR. LOEHLEIN: Right, 1.2 inch crack above the weld. And I think the .87 comes from the finite element model that tries to model this as an unsupported opening gap. And in answer to your question earlier, if you have an unsupported crack like that and you have pressure forces and other things on it, you can open up that crack so that linear measurement alone is not going to be a good predictor of the flow rate you get out of it because it's opening in width as well.

MR. SHACK: But the crack size doesn't seem to be a very good predictor either. I mean, the estimate for Oconee 3 is 1 gallon total leakage, and a fracture mechanics analysis of that crack would give you a much larger leak rate, which says it isn't the crack size that's controlling the leak rate.

MR. LOEHLEIN: Right. There's a couple of things that go on here. And if you really study the Boric Acid Corrosion Guidebook -- which Mr. Hunt has encouraged me to do a couple of times now, so I have read it a couple of times -- there's a lot of information out there that talks about how in the early stages, as tight as these fits are, and so forth, that you don't get a lot of leakage. So time really is on your side at the front end of this thing.

As long as the gap is tight, and you'll see a little bit of boric acid and so forth, but at some point, as demonstrated, I think, in one of the tests that EPRI did where we're injecting the annular region, once there's an opening up of that gap through some -- even if it's galvanic corrosion, if it goes on for several years, even though it's a minor rate, it opens up the gap eventually enough to where now oxygen can mix, and now the crack length that prior to that didn't provide much flow, now provides enough flow now, if that boric acid is allowed to accumulate, stay in that region, which it's going to tend to do much easier at the top of a head than at the steep slope end of a head, now you've got a number of factors working against you as far as creating an environment that's going to allow the boric acid to remain wetted. When it remains wetted, it drops to the temperature of the steel in that region, and now all of a sudden you have an environment that allows, by all the math, quite a higher corrosion rate. And, again, if that's allowed to continue even further and further along in time, this is the -- time is the enemy on this.

The overall band for leak rate, we say the absolute minimum from all sources of information would be 0.04 gpm and the max would be 0.2 but once again

0.1 to 0.2 is what we expect.

(Slide.)

Obviously, the damage to Davis-Besse's head occurred over some period of time. We have evidence from videos of the head conditions in past outages. We've had changes in containment conditions, other evidence available to us, we were able to build this probable timeline.

Now the way we've built this, it's really built from the baseline of a couple of key facts. One is in 1998 we saw the first signs of red-colored boric acid coming form the drain holes on the vessel. Then in 1999, which is a little bit after that, is when we started to have the problems with iron oxide appearing and clogging the filters to the rad monitors. We believe that those two facts are strong supporting evidence that that's when corrosion rates were of enough of a rate that we would say that significant rates were underway.

If you put that stake in the ground then in that time frame, you could look back using what I would just say typical estimates for crack growth lengths which we know are rough estimates only, but that's how we picked the time frame of '94 to '96 for propagating the through-wall and some several years prior to that for the actual initiation of the crack.

MR. SHACK: You would argue your crack is much then is much older than Oconee 3, despite its much longer extent?

MR. LOEHLEIN: Well, these are quite long cracks, too, in total length. I think that the one at nozzle 3 is almost 4 inches long, isn't it?

MR. McLAUGHLIN: It's over 4 inches long.

MR. LOEHLEIN: It's over 4 inches long. Whether they are the oldest or not, you know, I'm not smart enough to tell you whether that's true. I can tell you that our post-evidence type of review of this, the 20-20 hindsight says that signs are out there that this leak has been there for sometime, and that it, because of being obscured, went uncorrected for sometime. So, we believe we had four years of significant corrosion rates.

MR. BONACA: Since this could happen to other units and to other nozzles, it seems strange that we've been so lucky in all the other cracked nozzles that we caught them all as soon as they happened. So, I'm trying to understand if, in fact, there isn't some kind of other mechanism that worked here somehow -- and, of course, I don't expect an answer now.

MR. LOEHLEIN: I have looked at the top of the head myself, and I know what -- the boric acid, if it comes from the top, if it runs off and it creates a path for corrosion, what that will look like. You'll get these edge effects that are deep and so forth. You don't see anything like that on this head in this region. What you see is something that looks very much like a pool that then worked itself down along the side of the nozzle and progressed out from there.

Now, we put together in our Root Cause Report what we think is a plausible explanation of how it progressed, but we know there will be more work done on it as time goes on. But, clearly, if you look at all the facts available -- crack length, the evidence of boric acid accumulations and how it increased over the years, and these factors -- it seems pretty undeniable that the leak has -- it's an old leak.

MR. BONACA: I'm not denying that, I'm only saying that I'm thinking about the other units and the many indications we found of cracking through-wall, and I'm just saying it's surprising to me that in all those cases we always caught them as soon as they started and so there was no time for it to develop the erosion and corrosion we have seen here in this particular one. I wonder simply if there was some other phenomenon that took place, I don't know what it would be.

MR. LOEHLEIN: I think if we look at what we have here from Davis-Besse, we have a lot -- and you compare it to what's out here in the industry data -- we have a lot to suggest that we have three examples right there on the top of our head. We have nozzle 1 which is like a brand new -- we have a very small -- I think, above the weld we've got a half-inch or something crack length. The damage, if you want to call it, there is so minor we didn't even characterize it as damage, it's just a little bit of -- you know, we could take a feeler gauge at nozzle 1 and just sort of tell that we didn't have a tight fit anymore. That's kind of minor corrosion that existed at nozzle 1.

Nozzle 2 had a small cavity which structurally is really nothing. That was obviously older, the crack length is longer. And we have nozzle 3. Now, by our estimation, nozzle 3 has been leaking a fair amount for, we think, about four years. You know, I think if I was going to give a message to the industry, the advice that's out there is correct, once you find evidence of a leak you need to fix it right away because the clock starts to tick then, and four to six years later you have a significant problem perhaps.

MR. BONACA: One point that became very clear from the presentation is that the CRDM superstructure there really was a major contributor because it made it very hard to look in. It really helped accumulation of crystals up there, and I know you already had a plan to modify that. Is there something that can be done in this facility to make, in fact, a modification that makes that area much more accessible and visible, as a minimum, particularly to the mover?

MR. WOOD: We can speak to the B&W design plants, and you can put additional inspection up there that allow you to open up that area more, and we unfortunately had not done that prior to this. And there are other type units out there where, as you may know, the insulation is basically sitting on top of the head, and they'll have to evaluate what, if anything, they need to do to rectify that. But I think the Westinghouse plants, which we have a couple at the Beaver Valley unit, they are much more accessible. So, fortunately or unfortunately, the B&W plants are small in numbers, and we were one of the only ones not to make that modification.

MR. LOEHLEIN: And I do think, following up on what you said, it's important to -- this is something we couldn't evaluate because at Davis-Besse all the nozzles that did have leaks were at the top of the head. But it would be nice to know whether farther down on the head, if a leak had gone unattended there, what type of boric acid accumulation could have developed -- you know, because it's going to tend to fall off. We're not able to evaluate that, but it is true, in this region where we were, the boric acid that would accumulate there would tend to stay there and provide a ready source for continued -- I mean, the leak itself provides boric acid once it gets going, but even early on the accumulations of boric acid from whatever source, whether they come down from flanges up above or build up from the popcorn boric acid that isn't removed, regardless, it stays there because it's relatively there and it's available when the moisture supply becomes -- you know, comes from beneath. But all the evidence that we have here points to corrosion supplied by a moisture source from below.

MR. FORD: If I could just ask in terms of time management, if you could conclude in the next couple of minutes, if that's possible, because I want to give the staff 20 minutes to do their concluding statements, then I'd like to spend quarter of an hour just for us to go around the table and give our concluding remarks.

MR. LOEHLEIN: We are very close to the end here. This was the -- we were just going to mention some of the ongoing activities we have for ourselves, which we're still -- a lot of what we're doing is confirmatory in nature, has to do with us sending things like boric acid samples out, confirming that they do indeed contain iron oxide, and the big thing we have coming, of course, is when we do remove the area around cavity 3, which Mark talked about, and we'll study that for evidence, if there is any, of heavy erosion, and other elements besides corrosion as a contributor. And, of course, we'll complete the investigation of nozzle 46, and we plan to stay involved with the EPRI MRP and see whatever assistance we can provide to them.

MR. FORD: Thank you very much. John Wood has some concluding remarks.

MR. WOOD: We're attempted to describe the discovery, the evaluation, and the root cause of the degradation recently found at DB. We understand there is more to be done in regard to the technical issues and the management aspects, and we're developing the repairs, as you've probably heard us talk, we're going to have a meeting tomorrow with the staff to discuss repair concepts.

We understand programs like boric acid corrosion program and ISI program need to be refocused to accomplish their goals, and we know the basic steps we need to take to internalize the event at the site and to revamp the organization to prevent recurrence. So, we hope we've given you the information that you're looking for in putting us on the schedule.

MR. FORD: Thank you very much indeed. Could I ask the staff to --

MR. KARWOSKI: My name is Ken Karwoski. A lot of this has already been discussed, but what I'd like to do is basically just provide you with some of the generic regulatory actions we've taken in response to the Davis-Besse findings.

(Slide.)

As was previously discussed, the cavity was identified on or about March 7. What we knew shortly after that was that there was a history of boric acid-like deposits on the head for several cycles, and that the degraded area around nozzle 3 was associated with a nozzle that had a through-wall crack. The root cause was being investigated at the time, and we couldn't rule out whether or not the corrosion was from the top-down, as a result of the boric acid deposits from the flange leaks or from the crack in the nozzle, or some combination of both, and we're still evaluating the root cause.

(Slide.)

Shortly after identifying the cavity, we began several steps. We issued an Information Notice about a week later. We also contacted the industry, NEI, Nuclear Energy Institute, and also the EPRI Material Reliability Project, and we posed several questions to them. We asked for the plants that had completed their Bulletin 01-01 inspections, tell us were those inspections capable of detecting the type of degradation observed at Davis-Besse; for the plants that had not completed their Bulletin 01-01 inspections, what was their justification for continued operation as a result of the findings, and also to provide a risk assessment.

The industry conducted a survey and posed four questions to the various licensees, and I've got those listed on the slide, and I'll discuss those real quickly.

(Slide.)

As the industry was doing that survey, the staff was preparing a bulletin. That bulletin was issued on March 18, and it requested several different items. Within 15 days of the bulletin, we requested licensees to provide the following information: a summary of the reactor vessel head inspection and maintenance programs; evaluation of the ability of those programs to detect degradation similar to what was observed at Davis-Besse; a description of the inspection findings; we also asked them for their plans for their next outage, and also we asked them for a justification for continued operation.

We also requested within 30 days the completion of their next outage, for the results of those inspections, and we also asked a broader question with it, that they provide us an evaluation of their boric acid corrosion prevention program, and that response is due 60 days after the date of the bulletin, so that will be coming in in about another month.

(Slide.)

With respect to the staff activities, the industry categorized the plants based on the results of their survey, and they had five categories, and it really had to do with the extent of the condition on the top of the head with respect to whether or not they did a visual examination, how thorough that visual examination was, was it 100 percent bare metal, and could they rule out boric acid on top of the head.

Like I said, they categorized, and they had five categories. We focused on the highest category which they called "Other". We contacted all the plants in the "Other" category in order to understand why they were categorized in that category, and to get an assessment of whether or not we thought there were some issues. Several of those plants are down for an outage now. One of them is coming down for an outage in a month. Based on our review, we're still pursuing discussions with one licensee to get additional information with respect to their inspection findings last fall.

The NRC is currently contacting plants in outages. In the 15-day period while we were waiting for the responses, we wanted to make sure we understood what plants were planning to do in their outages, and then what they were finding as a result, to factor that into any other generic action we may need to take. We are still conducting those post-inspection phone calls. To date there have been no significant findings -- and by significant -- there may have been minor degradation, and there have been nozzles with indications, but nothing to the extent of what was observed at Davis-Besse.

We have started our review of the bulletin responses. We're categorizing the results similar to what the industry has done, and we're reviewing those right now. The categorization basically just provides a priority for our review. We're focusing on the ones with the higher ranking and, if we have any additional issues, we'll pursue them with those licensees.

That's basically all I wanted to say, is that generically we have been acting and we continue to do the plant-specific evaluations.

MR. FORD: Thank you very much indeed, appreciate it. What I'd like to do is I'd like to ask, from the NEI perspective, Larry, do you have anything?

MR. MATHEWS: We have a brief presentation, but he covered a lot of it, but there might be a couple of slides we might go ahead and talk about.

MR. FORD: Why don't we leave it up to the two of you as to how you want to give the final --

(Simultaneous discussion.)

MR. FORD: If you could take about no longer than ten minutes, if possible, and then we'll follow it with, Alex, you, and then Jack, ask you just to finish off with the staff's perspective.

MS. KING: All the stuff is contained within your packet.

MR. FORD: Yes, we've seen that. I'm not too sure I understand it.

MR. MATHEWS: This may be slightly updated from Al's presentation.

(Slide.)

If you look at this, we've tried to do everything through today, as far as the visual inspections and known leakage. We've also -- these are the plants that plan spring outages, and this is plants less than 30 years EFPY from being equivalent. We don't have the plants that are way out there on this graph, but even many of those plants that have spring outages were doing bare metal inspections of their heads, if they could not rule out the possibility, and even the ones that didn't think there was any way they had any boric acid on top of their heads, some of those were even doing inspections.

But if you look at the blue open diamonds, those are the plants that have spring outages and have to do some kind of inspection per 2001-01. So there's quite a number of those plants will have looked at their heads by the end of this spring. I guess they are kind of -- I started to say "rust" -- red circles, those are the plants that are scheduled for the fall outages when they will be doing their inspections, and then the four green squares that are on cycles that get them into the Spring of 2003.

MR. FORD: So the take-away message from this is that the prioritization algorithm you've got right now seems to work into a first approximation that should be more definitive after the spring outages, is that the take-away message?

MR. MATHEWS: We'll fill in all these blue diamonds at the spring outages, at least from a visual inspection perspective. And if you look, the red triangles are all to the left of the graph. There's a couple of plants with cracking out in the middle, but as far as I know those plants were not through-wall cracks.

MR. FORD: And the other obvious take-away message is you'll get a crack eventually, unless you manage it before.

MR. MATHEWS: Yeah. I hate to say some plant that has a cold head that on our histogram is

200 years away from being equivalent to Oconee 3 will crack --

MR. FORD: I agree.

MR. MATHEWS: -- but as far as these other plants, there's a good chance. There's no guarantee, but at least it's being borne out so far that this may be a good model, or sort of a good model anyway -- nothing is perfect.

Well, I think he talked about this. Why don't we put the list up, this is the one with the plant names. It's in your handout. I think this has been supplied to the NRC.

(Slide.)

MR. FORD: It has.

MR. MATHEWS: I guess I'm obligated to tell you we've received at least two phone calls this morning to say Watts Bar has found more documentation and want to be classified in Category 4 instead of "Other".

MR. FORD: Can you tell me -- I have looked at this slide quite a few times -- I have not the foggiest idea what the take-away message from this is.

MR. MATHEWS: The take-away message is that most of the plants out there, almost all of the plants out there, feel that they have a very good position that they don't have the kind of boric acid corrosion going on on top of their heads that has been experienced at Davis-Besse. Almost all the plants are in that boat right now.

The plants in the greater-than-30-year category feel they don't have the source to wet their head -- all of those.

MR. FORD: And there's no correlation at all -- they're just looking to scatter those numbers between boric acid on the head and cracking susceptibility. Is that the way -- I mean, the categorization --

MR. MATHEWS: Oh, okay. The categorization was based on how people answered those questions, and the four categories -- maybe we can go back to that one slide --

(Slide.)

We had four questions and they came over four categories in another. Category 1 plants at their most recent inspection, they did 100 percent bare metal inspection, and there was no boric acid on the head and none coming from above the head.

Category 2 plants, they were doing the inspection. There was some boric acid accumulation detected. It was removed and the head inspected and the source determined and corrected. Those are the plants that -- you know, they've gone and looked and they don't have a problem.

Category 3 plants, bare metal inspection was limited for some reason, or they were not able to be performed, but they've reviewed the plant history over the whole life of the plant, and there's no evidence of leakage coming from above.

Category 4 plants, in limited inspections, but when they review their history, there may have been some leakage, but none of it reached the outer surface of the head -- you know, little seal leak that -- you know, there's no evidence that the boric acid got all the way down to the head or anything like that, or the affected area, if it did get to the head, was cleaned off.

And then there was the other category which, for a number of reasons, they may not fit any of these, or there may have left some boric acid on the head. Those were the four categories and the Other group. So, if you look at it, everybody basically in Category 1, 2, 3 or 4 felt they had a pretty good story for why they don't have boric acid on top of their head.

MR. FORD: There's a whole lot of subsidiary questions to ask on that one, but we're not going to take the time.

MR. MATHEWS: Okay. Put up the summary slide.

(Slide.)

Basically, all the plants of less than ten years will have inspected by the end of the Spring 2002 outages, and have reasonable assurance that none of them have been returned to service with significant corrosion of the head or CRDM leakage. And of the plants that are left in 30 EFPY, 34 out of 40 of those plants will have done inspections by the spring. And then five more in the fall, and then six of them do make it over into the 2003 time frame.

MR. FORD: I've only got one question. You're assuming that if you don't see boric acid on the head, then you have no problems?

MR. MATHEWS: Yes, I guess that's the next --

(Simultaneous discussion.)

MR. MATHEWS: So far, in the industry, I think 34 penetrations, leaking penetrations were detected by visible evidence of boric acid during visual exams from the top of the head, or could have been if they weren't masked by other boric acid deposits. A total of 203 nozzles have been inspected by NDE, and by that I mean UT or AD-current from underneath the head at nine plants where the leaks have been found, and NDE confirmed the through-wall leaks in all 34 penetrations which showed the visible evidence, and it did not detect through-wall leaks in any of the additional 169 penetrations that were examined.

MR. FORD: And yet in the EPRI -- you're going toward the conclusion that you can manage by leakage detection, and yet EPRI, in their Boric Acid Corrosion Manual, say that for these particular head penetrations you cannot rely on visual detection on the head for what is happening down at the bottom --

MR. MATHEWS: To quantify that, I would think that may be true, and that's something we're looking at -- you know, can you get a cavity down here. I guess the basic message we're saying right here is, we don't see any way to get to cavity without getting something on top of the head simultaneously. I mean, the stuff --

MR. HUNT: Steve Hunt. As the author of that statement -- the statement in the Boric Acid Guidebook is correct, as it stands, that you cannot see the cavity which is underneath the surface, but you will be able to see the pile of boric acid crystals on top that led to the formation of the cavity, and we're in the process of trying to quantify that right now.

MR. SHACK: I guess that's my question, the 34 leaking penetrations, are they all sort of like at Oconee 3, or do you see very small amounts of boric acid, or have we had any significant amount of boric acid buildup?

MS. KING: Most of them have been similar to the initial deposits identified at Oconee.

MR. MATHEWS: As I recall, even the ones where it was a weld crack that didn't go into the tube at all, it was the same sort of stuff -- you know, a little bit of accumulation on top, not any massive amounts of boric acid buildup anywhere.

Anybody in the audience remember any?

(No response.)

No, I didn't think so.

MR. KRESS: The NDE results, would they have found the cavity, if it had been there?

MR. MATHEWS: They were not typically designed to look for that kind of thing. They were looking for flaws, and the leakage path stuff that was shown by Davis-Besse showing the lack of hard contact between the penetration in the head bore was something that just kind of popped out after-the-fact as they were reviewing some -- not Davis-Besse -- but as Framatome was reviewing data, and going back and taking a look at it.

Cavities, no. The NDE that we have used to date could not detect the cavity. The best it could do is tell you that there is a lack of hard metal contact, if you're using the right techniques and looking at it in the right way. But as far as is it 2 mls or quarter of a mile, I don't think we could tell the difference with these techniques. But that is not to say we are not working on or looking into is there -- are there techniques out there that could be used to detect how far away the carbon steel is or to actually measure any wastage. We don't know where we're going with that right now, but it's certainly something we're looking into.

Other than the ones at Davis-Besse, the 31 nozzles, there's been no evidence of any significant corrosion, I think we know that.

MR. FORD: I'd just underline as a fact, we'd better understand why.

MR. MATHEWS: Yes.

MR. FORD: Okay. Thanks so much, indeed.

MR. MARION: Alex Marion, NEI. just a couple points I'd like to make. The industry is extremely concerned about the Davis-Besse experience. We are, quite frankly, anxious to obtain a copy of the final root cause analysis, and we're also interested in getting a copy of the NRC's augmented Inspection Team Report. As that information is made available, we'll integrate it into the program, as Larry touched on during his presentation.

This Thursday, we're having a meeting with the industry chief nuclear officers. This topic is on the agenda. Mike Cockman (phonetic) is one of the executive sponsors of the MRP, is planning to give the presentation.

We've additionally had conversations with INPO, the Institute of Nuclear Power Operations, to get a sense of what they can do relative to some of the programmatic activities in boric acid corrosion, et cetera. So we're going to be doing some additional enhancements as time goes on.

Let me just speak briefly to the policy issue that the NRC staff identified this morning about continuing to rely on detection of leakage versus some other form of nondestructive examinations.

We had a meeting of the PWR, Pressurized Water Reactor Materials Management Program Committee -- if I got that right -- the executive steering group that over sees the MRP and the steam generator projects at EPRI, and at a meeting in March they gave a recommendation to the technical staff that visual examination alone is not effective as a long-term strategy.

So, as we're getting the results of the spring outages and we're getting the results of the Davis-Besse experience, we're going to try to pull all that together into a cohesive long-term program.

Lastly, I want to let you know that we are going to be updating our survey results and sending them to the NRC at the completion of the spring outages, which will likely be in the June time frame, I would think, June-July time frame.

And, finally, I'd like to thank you for the opportunity to discuss the industry activities on these two important bulletins, and we'll be more than happy to brief the subcommittee and the full ACRS in the future as we move forward with the NRC in trying to understand the implications of this problem.

MR. FORD: Thank you so much.

MR. STROSNIDER: Jack Strosnider, of the

staff. You've heard a lot of information this afternoon. I guess there was a suggestion at the beginning of this that I was going to summarize it, which might be a little ambitious. But I think it's always worth looking at these issues in terms of the NRC's performance goals and just reflecting on that for a minute. The first of those goals, and the most important, is maintaining safety.

The Davis-Besse degradation of the reactor vessel head is a very significant issue, everybody recognizes that significant degradation of the reactor coolant pressure boundary.

Ken Karwoski went through fairly quickly what we've done with regard to the bulletin we put out, but I'd just like to point out that if you look at both our interaction with the industry and the actions they took and the information they provided and the bulletin we put out, it was in a very short time frame. If you look at how long it typically takes to get these out, you'll see that the significance of this issue was certainly recognized.

In addition, we're casting a wide net in that bulletin and also in our responses. Without a well defined root cause, we have to take that conservative approach. So, for example, a plant has had seal or flange leaks, but is low susceptibility, if they can't show that those leaks haven't reached the head or that they've taken some action, we'll probably be talking to them, and we expect that it's going to take a lot of digging into these responses, but we're talking on the order of weeks before we identify what plants we might need to follow up on.

Having said that with regard to the Davis-Besse degradation, we need to make sure we don't lose sight of the control rod drive penetration cracking, which is also a significant issue. There may be some relation, but in and of itself it's significant.

And we summarized the results of the inspections done in response to last year's bulletin. Based on what we've seen, we think that the actions being taken are dealing with that issue in the short-term, but as we pointed out, this issue will not go away. It's going to be more broad-spread, and we need to have that long-term program put in place in order to maintain safety in the long-run, which brings me to the next performance objective of increasing efficiency and effectiveness.

Until we get that long-term program in place, frankly, we're being pretty inefficient because we're dealing with all these issues on plant-specific basis, and that takes resources for the NRC and the industry. So we certainly have a motivation to do that as quickly as possible. And to be frank, I think we have lost some ground because the industry and NRC -- we had to deal with the Davis-Besse issue when it came up, and that's had some impact.

We had hoped to be here at this meeting providing the committee some of the technical basis for that long-term program, and we're not there yet. We need to come back with that. And until we do that, we're going to be paying the price of spending more resources on a plant-specific basis and probably with more conservative decisions than might be necessary until we can get all that technical basis laid out. So we do need to come back to the committee with that, and we need to do that for our own good.

With regard to reducing unnecessary burden, there's going to be necessary burden associated with this issue. The industry recognizes that. They are putting the resources into it, and NRC as well, so I think everybody recognizes they are going to have to do what's necessary to deal with this.

Finally, with regard to public confidence, there is a lot of interest in this issue. Our public meetings have been well attended. We've had a lot of questions. I would just point to the Web site where we're getting a lot of positive feedback in terms of the information that's there and trying to keep people onboard with what we're doing. So, I think in the short-term we're dealing with the issues. We've got this longer-term activity that we do need to get underway and we need to make progress on.

MR. FORD: Thank you. If I could finish off by just going around to my colleagues and asking them to just give a very brief synopsis of their thoughts at this stage, and also some information that we can give to the presenters for Thursday, when we have a two-hour presentation to the full ACRS -- in other words, what's keeping you awake at night. Mario?

MR. BONACA: Well, just two observations. One is, you know, there have been 34 leaking penetrations and, of those, one of them has shown significant wastage on the outside. The others haven't. We concluded somewhat in the conversation that most likely it is because it is a very old one. I don't think we should jump to conclusions. There may be some degradation mechanism. He has suggested possible impingement, I don't know. I'm not postulating anything, just simple I think we need to understand what made this different from the others.

And the second observation I would like to make is that right now the whole program on CRDM cracking is focused on essentially building a schedule based on the vulnerability of the units, and then do visual or UT measurement for detection, that detection. Yet, we have learned from the Davis-Besse event that they had indirect indications -- you know, the containment had cooler clogging, containment radiation, monitor and filter clogging, and then plate out of boric acid on cold surfaces, and I really wonder if, in fact, the unit shouldn't have simple observation program internally as part of this that says let's monitor this indication, that was significant for Davis-Besse, so that will give us an indication as a minimum that something beyond the cracking is occurring, which is essentially a significant leak as they had at Davis-Besse, I don't think is a burden and probably just part of normal observation in walk-downs and things of that kind. I think it would be appropriate because I think for Davis-Besse they provided significant indication that's a lesson learned. That's all.

MR. FORD: Tom.

MR. KRESS: I would like to second everything he said, plus add one other. We saw a chart of the thickness of -- the mapping of the cavity was obtained some way, and it seems to me like it's possible to inspect for cavity as well as the cracks. And I think that ought to be part of the process of the inspection. There ought to be something -- and we heard that they are thinking about things, but that ought to be part of it, inspect for a cavity as well as for cracks.

MR. FORD: Steve.

MR. ROSEN: I'm looking down the road quite a way and thinking about the time when Davis-Besse has repaired its head or bought a new one or somehow gone back into operation, but there are other damage that needs to be repaired besides the physical damage, and it was alluded to, I think, by the Davis-Besse people, in particular, thinking about it in terms of the precursor decision not to improve reactor vessel head access, and then later on the lack of a questioning attitude that Mario referred to with regard to the performance of the containment coolers and the radiation monitor filters, which is a weakness that has important impacts on the corrective action program and attributes for the corrective action program, that lack of questioning attitude. So, the corrective action program needs to have a look, and I'm sure that Davis-Besse will be working on that.

And if you have a weakness in the corrective action program, you need to be thinking broadly about safety culture in the plant because it's such an important piece of -- the corrective action program is such an important piece of the safety culture. So, those broader questions occur to me as I think about this, and in the long-term future of Davis-Besse and focusing on the macroscopic rather than the microscopic.

MR. FORD: John.

MR. SIEBER: Well, I agree with Mario, and also Steve, on the issue of inspecting for excavations in the head, so to speak. Since the policy right now is to rely on leakage rather than volumetric examinations, I don't think that you could imply that there is a way to detect cavities by what licensees are now doing. I'm not also familiar with directly a volumetric examination of the head, how you would do it by looking through the nozzle because of that interface there. You just can't get across the boundary.

I think the decision of leakage versus

volumetric still needs to be made, but I think that I would prefer the staff to tell us what decision they come to rather than we suggest to them what way they ought to go because I think there is a case that says leakage measurement may be good enough for this kind of mechanism.

One thing that I feel -- I thought all the presentations were very good. I believe, however, that there were a number of hypotheses involved in what causes this, the root cause analysis, and so forth, and we end up with perhaps a difference of opinion or, in my own case, maybe a different opinion versus time as we go along, that tells me that there ought to be a greater reconciliation with the hypothetical causes of things and physical observations versus the body of scientific data that's out there. And the reason that is is to try to confirm the validity of the hypotheses that's applied to why didn't I observe this, why did this occur, and so forth down the line. I would like to see a little bit more rigor in this process as we go along, so that we really understand what's going on and we can say truthfully, as scientists and engineers, that this is reasonable based on the body of corrosion data, for example, that's out there. And so I would have liked to have seen a little bit more meat on the bones in that area. Otherwise, I'm pretty well convinced that NEI and EPRI and the MRP are dedicated to resolving the issue. I see the licensees acting responsibly with regard to at least the first bulletin. The answer to the second one probably isn't due in yet, except for maybe the 15-day response, but I'm heartened by the fact that licensees are doing that, the staff is paying attention and putting this as a high priority and the industry groups are doing the same.

So, those are basically my thoughts at this point in time.

MR. KRESS: Let me comment for just a moment on my comment on looking for wastage directly. You surely would get leakage if you had that extent of wastage, but you can't take that in the negative sense and say, okay, I've got leakage, I've got wastage. You can do that with a crack. So, you need a way, I say, in the program to decide whether or not you have wastage, and you can't do it with leakage. That could be an indicator that you've got it, but it is not an extent as it is with cracks. If you've got the leakage, you pretty well know you've got cracks. That was the nature of my comment.

MR. SIEBER: Yeah, and I think there is a way to use leakage as a way of determining whether wastage is occurring or not.

MR. KRESS: I don't think so, that's my problem.

MR. SIEBER: Well, the rivers of iron coming down the side, to me, tells me there's wastage going on.

MR. KRESS: That may be. You may have a way there.

MR. SIEBER: When everything turns brown --

MR. KRESS: I think it's too late, maybe.

MR. SIEBER: -- in nuclear, that's iron.

MR. LEITCH: I guess one comment I'd like to make, although I'm not familiar with Davis-Besse and it's always easy to jump to conclusions, I'd like to echo my concern that there seems to be a lack of a questioning attitude. It looks as though there's a number of opportunities that were missed that could have, if not prevented this, certainly have prevented it from getting as far as it got.

It's always difficult, and I certainly sympathize with the plant people, it's always difficult to look at a couple different points and say there's a lack of a questioning attitude, but yet from the data that's been presented here, it seems to me that that is something that may be an issue there. Can't say definitively that it is, I'm just not that familiar with it, but certainly there's a couple of data points here that would seem to suggest that.

The other thing that I would like to have heard about, and I guess it's still future, is just what is the final vision for how Davis-Besse is going to be returned to service. We alluded to just -- there was a very brief allusion to a drilling operation there and fixing it, but what is the nature of the final inspection of the head going to be? In other words, are we going to get a good solid bare metal inspection of this head, are those modifications that were suggested in 1990, or whatever it was, to facilitate future inspection of the head, are those modifications going to be installed at this time? And I know those issues are still under discussion and some of them just cannot be answered at the moment, but what I'm saying is that's an area where I'm curious about just what are the next steps.

Included in that perhaps is this issue -- and, again, it was just briefly referred to and, again, I think it's a subject of another meeting --

about the thickness of the stainless steel cladding and that it would have been able to withstand 5,000 pounds or something like that. And my question there was is that the actual stainless cladding, or was that the design stainless cladding, are the two the same, is there a nominal thickness or an actual thickness that's used?

MR. SIEBER: How many cracks are in it.

MR. LEITCH: Yeah, right. But it seems to me that this was coming very, very close in spite of those calculations, at least my gut seems to tell me that it was coming very close to being a very significant LOCA.

I guess the other questions relate more to the rest of the industry. I see plants in categories -- I'm not sure I remember the categorization numbers -- 3, 4 and Other, I guess -- and, again, this is something that I know is in progress and is a very current subject and is being worked on, but it sounds as though there's a great number of plants that, for one reason or another, cannot make a really good bare metal inspection of the entire head. I guess I'm wondering how, if that is the case, how are they satisfying the general design criteria that says that's what we're supposed to do.

I guess, as I say, all these things are future and still under discussion, but my questions were not so much with what was presented today, but where do we go from here.

MR. FORD: Bill?

MR. SHACK: You've said so much, I'm not sure there's anything left to say except I probably disagree with my friend, Dr. Kress, and probably disagree with you, but we'll discuss that later at dinner.

Like Mario, I'm still puzzled by the 33 and the 1, and I certainly agree with Steve and Graham, there does seem to be a problem with the questioning attitude here, maybe in particular, for this particular case. It seems to that both the staff and the industry are making progress in addressing the issue, so we'll just have to wait and see what happens.

MR. FORD: The thing that keeps me awake, I guess, is the same as we've all alluded to, is the root cause and the way the hypothesis is going -- this is for the degradation issue -- is that any axial crack could give you degradation, according to the hypothesis that we've got right now, and we don't have a clear algorithm to say why we'll get excessive degradation at this plant and not at these others, and in terms of the annulus size or the temperature or whatever it might be. We don't have that algorithm and we'd better have that algorithm fairly quickly.

So, a good root cause -- quantitative, predictive root cause analysis backed up by, as you say, Jack, information from literature and from mockups.

Another thing that keeps me awake is, well, okay, then, what's the risk associated with this? We haven't heard -- I know there have been published some risk analyses, but we didn't see any today. I suspect that's what might, if it can be made available in time, might interest, for instance, George Asposkolocaz (phonetic) and Dana Powers, who will be available on Thursday and who are not here today. Those are the things that would keep me awake and which I would like some clarification on.

Apart from the management aspect, I am absolutely convinced on both bulletins we are moving forward as quickly as we can. We'd love to see it moving forward faster. We'd love to see better communications, if that's necessary, between all the parties in this huge matrix organization, if not industry, but those are management questions, not things that we can solve here.

On that point, if anybody has any questions on what we should be discussing in the short time we have, two hours on Thursday, come and chat with us.

Well, on that basis, thank you very much, everybody. It's been very interesting. This is now adjourned.

(Whereupon, at 6:15 p.m., the joint Subcommittee meeting was concluded.)

CERTIFICATE

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

Name of Proceeding: Advisory committee on Reactor Safeguards Materials and Metallurgy and Plant Operations Joint Subcommittee Meeting

Docket Number: N/A

Location: Rockville, Maryland

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

/S/ Phyllis Young

Phyllis Young
Official Reporter
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