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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

511th FULL COMMITTEE MEETING

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FRIDAY,

APRIL 16 , 2004

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ROCKVILLE, MARYLAND

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

COMMITTEE MEMBERS PRESENT:

MARIO V. BONACA, Chairman

GRAHAM B. WALLIS, Vice-Chairman

STEPHEN L. ROSEN, At-Large

F. PETER FORD, Member

THOMAS S. KRESS, Member

DANA A. POWERS, Member

VICTOR H. RANSOM, Member

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

NRC STAFF PRESENT:

RUSS ARRIGHI	GREGORY SUBER
HANS ASHAR	CHENH-IH WU
STEWART BAILEY	MATTHEW MITCHELL
WILLIAM BATEMAN	SCOTT PWALL
JENNIFER BOBIAK	I. RAYAN
DAVE CULLISON	ERIC REICHELT
BARRY ELLIOT	
JOHN FAIR	
DANIEL FRUMKIN	
RICH GUZMAN	
M. HARTZMAN	
STEVEN JONES	
WILLIAM KOV	
P.T. KUO	
JAMES LAZEVNICK	
ARNOLD LEE	
SAM LEE	
Y.C. (RENEE) LI	
LOUISE LUND	
JOHN S. MA	

I-N-D-E-X

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

8:29 a.m.

CHAIRMAN BONACA: Let's start. First, the meeting is being kept, and it is requested that the speakers use one of the microphones, identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

I would like to remind you that during today's lunchtime, I believe at 12:45, Mr. Szabo of OGC will provide ethics refresher training to the members. Also, representatives of the Office of Administration will brief the members on computer security issues and other administrative matters.

With that, let's move on to the first item on the agenda. I believe that the first item is the license renewal application for the Ginna Nuclear Power Plant. And with that, I turn to Mr. Kuo.

MR. KUO: Thank you, Dr. Bonaca, and good morning. For the record, I'm P.T. Kuo, the Program Director for the License Renewal and Environmental Impacts Program. On my right is Dr. Sam Lee, Section Chief for the License Renewal, and the far right is Russ Arrighi. He's the Project Manager for Ginna Safety Evaluation Report. And Russ is going to make the first staff presentation today.

I might add here that this is the last day for Russ being with us. He's getting a promotion in the Office of Enforcement, so the net result is that we are going to lose another experienced person. Sorry about that. And with that, I'd really like to the presentation first over to the Applicant, then Russ will follow.

MR. WROBEL: Okay. Thank you. Hello. My name is George Wrobel. I'm the License Renewal Project Manager with Dave Wilson, our licensing and principal contributor to the report, Joe Widay, our Plant Manager, and Gerry Geiken, our Materials Engineer.

We had a Subcommittee meeting on November 4, 2003. Many of the agenda items are similar, but we have updates on most of them. So we'll be going through all of those. I don't think you need to read through those. We can go on to the next page.

Okay. As you probably well know, Ginna is Westinghouse two-loop 1520 megawatt PWR. It was originally licensed in 1969, so it's the oldest PWR operating in the country, and we will be the first plant to actually implement license renewal, at least from a PWR standpoint.

We had an initial power uprate from 1300 megawatts to 1520 megawatts in 1972, and we remember the Systematic Evaluation Program. SEP was a reevaluation of the plant against the standard review plan at that time, which has been updated since then but it was a very thorough review. Two topics were looked at. I've got another slide on that.

CHAIRMAN BONACA: I have a question on that. Oh, you have a slide later on?

MR. WROBEL: I have a slide on SEP. Hopefully it will answer most of them, if not more. Anyway, it ended up resulting in converting our provisional operating license to a full-term operating license in 1984.

The other thing that we've done since then we did have our construction permit operating license recaptured. That was a 41-month construction tenure back in those days. We got that back in 1991. That's probably what the new advanced designs will be like too.

We did convert to improve standard tech specs in 1996. Currently, all of our performance indicators and inspection findings are green, and, as you probably well know, we have a plant sale that's going to be consummated within the next couple or months -- we hope, we believe.

Just a little more on SEP, and then you can ask more questions. It was basically all of the older power plants at the time, about half of whom are still with us, lost a couple of plants that were newer, like Palisades and Ginna, that had original operating licenses were administered under the auspices of the Systematic Evaluation Program. There were a total of 92 very diverse topics that were reviewed at that time, and we really ended up with what I think is actually a very useful product. We have SERs on many of the current topical issues, so that we actually have a current licensing basis that's easily retrievable. I think that really helped us during our license renewal application. We were able to find our CLP pretty readily, and that was a big help.

Some of the major issues that we looked at were high energy line breaks, both inside and outside containment, and the separation that was required because of that. We made certain changes in the seismic stability of the Plant, which helped us with our IPEEE submittals as part of the RA. Tornado protection and containment isolation valves and the arrangements for the GDC, we didn't meet it explicitly but we were able to review it against the criteria and show we have comparable safety.

CHAIRMAN BONACA: Did you have many physical changes in the Plant because of SEP?

MR. WROBEL: We had probably at that time I'll say $20 million, give or take, physical changes.

CHAIRMAN BONACA: Well, I was thinking specifically about your auxiliary feed water system with those five trains. I mean how come you've got those --

MR. WROBEL: That was actually done as part of the high energy line break criteria that was actually implemented prior to SEP, the O'Leary Letter of 1972 or so.

CHAIRMAN BONACA: Okay.

MR. WROBEL: Where we had the steam line and the feed water line in the same building as all three aux feed water pumps that we had at that time. So because they were not environmentally qualified for that, we separated them. We had the standby auxiliary feed water system that's totally independent of the regular normal auxiliary feed water system.

CHAIRMAN BONACA: How separate is it, physically?

MR. WROBEL: It's a separate building, and it goes through a separate building, and it enters the feed water line through the separate penetration inside containment --

CHAIRMAN BONACA: And it's separate also the controls and electrical?

MR. WROBEL: The only thing that's comparable is it runs off the same power supplies, but there's an interlock so that you can only run aux speed or standby aux speed. You can't run them both at the same time.

CHAIRMAN BONACA: Does that kind of ability provide you help, I imagine, for some of the external events?

MR. WROBEL: All of them.

CHAIRMAN BONACA: What about fire?

MR. WROBEL: Well, it certainly helps on fire, because if we have a fire in the intermediate building that takes out auxiliary feed water, we have standby auxiliary feed water. Again, I think the only commonality that we have are buses 14 and 16, which are the power supplies to them. They have the same power supplies. But buses 14 and 16 are separated in terms of fire zones, so there's a lot of separation -- physical separation for auxiliary feed water at our plant. You can use it as part of our recovery methodology, both for seismic, tornadoes and flooding and high energy line breaks. So it's been actually a very useful modification.

MEMBER POWERS: You mentioned your IPEEE. Can you give me a feeling for where you stood for IPEEE risk?

MR. WROBEL: I don't have the actual number for IPEEE risk. You mean for seismic? I think internal and external are about half and half. So since our total is 4E to the minus 5, our IPEEE is probably 2E to the minus 5. Now, these mods for SEP were done prior to 8820 Supplement 5 coming out, so these were already -- the mods were already according our initial IPEE model.

CHAIRMAN BONACA: You said your total CDF is 4E to the minus 5?

MR. WROBEL: Yes.

MR. ARRIGHI: This is Russ Arrighi. I checked on those numbers. The total CDF is about four. It's 3.977E to the minus 5 per year, and the fire is the single largest category contributor to the risk profile. It's about 28, 29 percent of the total risk profile.

CHAIRMAN BONACA: And did you have a full PRA?

MR. WROBEL: We have a full PRA now. We

do not have a seismic PRA, but we have the shutdown PRA and the internal and fire and level 1, 2 and 3.

MEMBER ROSEN: Does that 4 include shutdown?

MR. WROBEL: Four includes shutdown.

CHAIRMAN BONACA: I think that's very low.

MEMBER POWERS: And fire is 30 percent of this?

MR. WROBEL: About 30 percent, yes.

CHAIRMAN BONACA: I'm not surprised.

MEMBER POWERS: What did you say?

CHAIRMAN BONACA: I'm not surprised.

MEMBER ROSEN: I'm surprised it's as low as that.

CHAIRMAN BONACA: Yes.

MEMBER ROSEN: With external, internal and shutdown included for an older plant. Getting to four is -- I'd be interested in tracking the numbers, but I don't believe more than that.

MR. WILSON: This is Dave Wilson, RG&E. Part of the lessons that we learned in doing the IPEEE process and the PSA process drove some plant modifications to make those numbers lower. For instance, we learned that we had an internal flood risk contributor that was very high with respect to our batteries, and we ended up relocating pipes. So we used our PSA pretty proactively when it was developed and actually modified systems that we could reasonably modify to lower our numbers from the original values.

MEMBER ROSEN: Well, that's a good explanation.

CHAIRMAN BONACA: Yes. I would expect those feed aux system would give you a lot of help. I mean I know it because I was involved with a plant which was in the SEP and did not have that system, and every time we looked at what an additional aux feed -- traditional aux feed train would do for us, we were solving all our problems.

MR. WILSON: Yes. From our perspective, sir, it was interesting that our sister plants in Switzerland, the Beznau units, actually came out and visited our plant to examine our standby auxiliary feed water system, because they had installed a dedicated shutdown system which included the high pressure injection. When they did their risk models, they asked the same questions: "Why are your risk models lower than ours and our plants are, although not identical, essentially, technically, designed the same?" And the answer was standby auxiliary feed water. It was the decay heat removal portions.

CHAIRMAN BONACA: Sure.

MR. WILSON: And they actually sent one of their presidents and some of the engineers out to look to see how we configured this with the physical independence and distance and things to -- I don't know what the results of that were, though, sir, whether or not they go further and change, but they were interested enough to come and look from Switzerland.

MR. WROBEL: Other major changes that we've made, at least since 1996, have been -- certainly, you've heard about some of the earlier ones in that. We replaced our steam generators in 1996. Those steam generators have about a 20 percent higher tube surface area, so we built in quite a bit of margin in the steam generator replacement.

We were one of the three plants to do baffle-barrel bolt inspections in 1999, and we found very little stress corrosion cracking in those bolts. I think the ones that we actually found quantified, we will quantify less than about one percent of the bolts that actually had damage there.

Did our reactor vessel head inspection in 1999, and then we replaced it in 2003. So we've been working very hard on Alloy 600 minimization. The only Alloy 600 we have that's part of reactor coolant pressure boundary now are the bottom-mounted instrumentation nozzles. There's no other pressure boundary that's Alloy 600. There are a couple of the locations that are Alloy 600, the radial support plugs and tubesheet, RCS cladding, but there's no other areas.

MEMBER ROSEN: Have you had a look at your pressurizer lately?

MR. WROBEL: I personally haven't, but I think we have. There have been a lot of issues on the instrumentation -- the bottom heater tubes or the heater nozzles. We have not seen any indications. Ours are stainless steel.

MEMBER SIEBER: Right. The only concern you have is the weld, right, stainless to the base model?

MR. WROBEL: Yes.

MEMBER ROSEN: That's stainless but you've also looked and didn't see anything.

MR. WROBEL: we haven't seen anything, but, Joe, do you know if we've had any detailed NDE up there or what, physically or visually?

MR. GEIKEN: Well, we've done visuals by

-- this is Gerry Geiken from Ginna Station -- we've done visual inspections. In fact, this last outage we did an extensive RT and UT of all the tophead nozzles and the surge line nozzle of the pressurizer. I believe we also looked at some of the penetrations that were exposed when we removed insulation, and we've seen nothing there, no ominous leakage at all. There's no Alloy 600 in our pressurizer, weld metal or base metal.

CHAIRMAN BONACA: If I remember, you also replaced the control rod package.

MR. WROBEL: As part of the reactor vessel head, yes.

CHAIRMAN BONACA: Is it normal, I mean when you replace the head?

MR. WROBEL: Well, they were 30, 35 years old and --

CHAIRMAN BONACA: Okay. So you --

MR. WROBEL: -- we're planning on another at least 25 to 45 years of operation. You haven't seen our next application yet, but you will see it.

(Laughter.)

MR. WROBEL: In 2009, we'll be here again.

We did do an extensive evaluation or inspection of our lower head, the lower head nozzles this past outage. Did not find any evidence of leakage, no boron, at least nothing from the penetration.

MEMBER SHACK: But you can do a bare metal inspection of your bottom?

MR. WROBEL: Yes. We can and we will continue doing them. Is it going to be every outage, Gerry?

MR. GEIKEN: At this point, every outage.

CHAIRMAN BONACA: At the Subcommittee, you showed us some pictures of it. Do you have them with you?

MR. WROBEL: We do have the pictures. We didn't find any really better ones than we had, but we can look at them again.

MEMBER ROSEN: What is the T-hot for this plant again, remind me?

MR. WROBEL: Five-ninety. It's pretty low right now. About 592, 590, yes.

CHAIRMAN BONACA: It's low.

MR. WROBEL: It was 601 before we did the steam generator replacement, and we got it down to 590.

MEMBER SIEBER: Are you anticipating any kind of a power uprate?

MR. WROBEL: Yes. You're reading ahead. Yes, we have some discussion of a potential power uprate that we're discussing, and we do have some information on that.

MEMBER SIEBER: Well, you've got a lot of surface.

MR. WROBEL: Yes. Our T-hot will go back up to probably 603 or so, which is what it was before. Still not way high.

MEMBER SIEBER: So you're talking about five or six percent.

MR. WROBEL: Seventeen?

MEMBER SIEBER: Seventeen percent?

MR. WROBEL: Seventeen percent.

MEMBER SIEBER: What's TeV?

MR. WROBEL: TeV will be -- well, right now it's 561. It's going to go up to 573.5, which is what it was before steam generator replacement. We built in a lot of margin when we put these generators in, not necessarily for operate or for renewal but it certainly is working for both of them.

CHAIRMAN BONACA: So tell us what we're looking at, water penetration on the bottom?

MR. WROBEL: Yes. Gerry, this is your time to shine.

MR. GEIKEN: That's the penetration as it enters the Inconel pad, the Alloy 82/182 pad, that's welded around every penetration on the bottom head of the vessel. The entire bottom head, in fact the entire external surface of the vessel is painted with zinc-rich paint.

We did sample some evidence of white deposits that we observed running down the side of the vessel. They were from leakage from above. And all of those were determined isotopically to be not within the recent past.

MR. WROBEL: And they weren't from the bottom nozzles either.

MR. GEIKEN: We saw nothing around any of the bottom nozzles that indicated leakage.

VICE-CHAIRMAN WALLIS: And that purplish hue is from what, a coating of some sort, in the other figure?

MR. GEIKEN: Yes. That's zinc-rich paint.

VICE-CHAIRMAN WALLIS: That's the paint.

MR. GEIKEN: That's zinc paint. It's Carbon Zinc 11.

MR. WIDAY: And the benefit we have -- this is Joe Widay, Plant Manager -- the benefit we have there is you notice the build-up of the weld material there allows for a natural flow of moisture. If you did have a leak from above, it typically wouldn't migrate into that crevice area there. So it does keep the two systems separate so any leakage that we may have had from above in the refueling process wouldn't evidence itself.

MEMBER ROSEN: Because, Joe, it drips off at the lip, is that what you mean?

MR. WIDAY: That's correct, yes.

MR. WROBEL: I think you have this. This is going to be an every 18-month inspection. We are on Slide 4.

Again, during the past outage, we did a detailed review of our sump for any sump issues. We found a couple of areas that -- a couple of openings that were larger than we had anticipated. They were fixed during the outage and modifications were made.

MEMBER ROSEN: Did you look at the other sump?

MR. WROBEL: Yes, sir.

MEMBER ROSEN: This says Sump B.

MR. WROBEL: Oh, Sump B is the ECCS recirculation sump. Sump A is our normal sump, and we do -- actually, we did a detailed review of the Sump A this year as part of the structure monitoring program.

MR. WILSON: Sump alpha is the sump we had to enter to do the bottom head inspections.

VICE-CHAIRMAN WALLIS: Any unusual material in those sumps?

MR. WILSON: Not anymore.

(Laughter.)

MR. WILSON: There was some boric acid on the bottom of the -- on the floor there that was cleaned up, and there were --

MEMBER POWERS: Sumps lined?

MR. WILSON: Say again, sir?

MEMBER POWERS: Are the sumps lined?

MR. WILSON: Yes, sir, although the bravo sump, the recirculation sump is lined underneath the concrete, it's got a concrete facing on it.

MEMBER POWERS: Amazing. How thick?

MR. WILSON: I don't know what the thickness is, but I'm thinking three inches.

MEMBER POWERS: Okay.

MR. WILSON: And then metal and then the actual concrete.

MEMBER ROSEN: And why was that done?

MR. WILSON: Say again, sir?

MEMBER ROSEN: Why was that construction

done that way? It seems unusual to --

MR. WILSON: I'm personally not certain. I don't know.

MR. WROBEL: The whole containment floor is done that way. It's concrete, then steel, then concrete. Three feet, three-eighths-inch, then three feet. So the actual leakage -- I guess the concrete is for structural stability, and then you've got the leakage barrier is actually the steel, and then you have more reinforcement just for structural strength. I didn't bring my slide.

MEMBER POWERS: I'm not absolutely certain, Steve, but I think it was popular construction at the time, and I think it was contamination control.

MEMBER ROSEN: I see.

MR. WROBEL: Just very briefly, we're also looking at an uprate. The uprate would be consistent with what the Kewanee Plant is currently uprated to, which is 1775. They were just approved within the last couple of months. We basically have the same NSSS system and Kewanee does right now, and so even our uprate would be a 17 percent uprate, which would be an EPU and we get to visit you again. It's really not much different than the Kewanee uprate which was more of a stretch.

VICE-CHAIRMAN WALLIS: How much EPU?

MR. WROBEL: Seventeen percent.

VICE-CHAIRMAN WALLIS: Seventeen.

MR. WROBEL: Fifteen to 20.

VICE-CHAIRMAN WALLIS: So it's substantial.

MR. WROBEL: Substantial uprate but not any different than Kewanee's currently experiencing. We've had a lot of discussion with our sister unit there. Our steam generators that we've replaced now are the same as -- they're pretty much the same as their current ones. We have a lot of surface area there.

I thought I'd get actually into the license renewal application for a while now. We did the -- it was about a three and a half year effort. I think we started in 2000. Primarily, it was in-house. We had matrixed staff, some much more dedicated than others I mean in terms of time. Certainly, all of them dedication. We did use contractors where we needed to where we didn't have the expertise in-house, like Framatome did our reactor vessel work, Westinghouse did some of our entry plus work for TLAAs; Constellation, environmental. We did use the guidance of 9510, standard review for plant format, and we're the third plant to use GALL, so we had our GALL experience.

All of the interactions were good, particularly the inspections and the audits, the regional and the NRR people that came to the site. That was a very good interaction. The processes, procedures all worked through well. All the milestones were met, everything was done on time, so we did not have any issues at all with the inspection methodology.

What resulted out of the license renewal application, basically, were programs and commitments. I'll talk a little bit more about that. But once we stoked and screened everything in, then really the hard part is getting all the programs implemented, and that's what we're working on right now.

Some of the major issues that came out of license renewal that may be an update from the Subcommittee meeting that we had, we did finish all of our 50.49 calculations, all the EQ calculations extending the life of electrical equipment from 40 years to 60 years. Having completed, documented and --

CHAIRMAN BONACA: The PLAs?

MR. WROBEL: All the PLAs are complete of the equipment that we decided we would extend to 60 years. There's some items that we're going to replace, so we didn't complete the PLA on those.

As the staff will show you later, our upper shelf energy for Reg Guide 1.99 Rev 2 is anticipated to be below 41 foot pounds using that methodology. We knew that going in, and so we had Framatome perform at equivalent margins, fracture mechanics plastic -- it's on the next slide -- elastic-plastic fracture mechanics analysis for the limiting beltline weld. Even though we don't meet the 50 foot pounds, the Appendix K criteria for Section 11, which is the alternative of Appendix G analysis that's allowed, shows, as you can see, substantial margin of either greater than five or greater than three for the different transient levels and accident levels. So we feel that we have significant margin even though we don't meet the 41 foot pounds for upper shelf energy.

MEMBER SHACK: Did you project at 80 or life?

MR. WROBEL: I have that for PTS if you'd like. Certainly, I think with a factor of two to six, Gerry, I'm sure we're going to be greater than 1.0 at

80, right? Say yes.

MR. GEIKEN: Yes. Bear in mind -- this is Gerry Geiken, these analyses are going to have to be redone for uprate.

MR. WROBEL: Yes.

MR. GEIKEN: We'll have higher fluences.

MR. WROBEL: Also for a station blackout, one of the issues we talked about at the Subcommittee was the scope and the off-site power cables, that power Buses 17 and 18 are in scope. We did add those into scope. I think Russ is going to go over that in a little bit more detail.

So I think we've completed all the major issues, all the TLAAs that we had anticipated to do that for 60 years. And even for power uprate we did do the PTS calculations for power uprate for 60 years. Actually, we did them for 80 years too. And there's significant margin in that area also. Even at power uprate conditions for 60 years, we're at 276 degrees instead of 300, so we still have quite a bit of margin on PTS.

MEMBER SHACK: Now, do you run a low flux, I mean low leakage core?

MR. WROBEL: At this point, yes. We've been running a low leakage core since about the mid-

80s, mid-80s to late-80s.

MR. GEIKEN: Mid-80s.

MR. WROBEL: Mid-80s. That is going to change somewhat. We don't know what the uprate calculation's going to be exactly. We've done some bounding calculations which are less -- there's going to be more leakage for a bigger core, but at least the calculations we've done so far indicate that we still have substantial margin even with the uprate, otherwise we wouldn't do it.

Programs, we had a total of 34 programs that we implemented or credited for license renewal. Four of them were new programs that we obviously didn't have before. That's why I call them new. Thirty were existing programs, and many of them were consistent with GALL. We did take exception to several of the programs where we were, like the Kaplan cooling water or diesel fuel oil. We took a few exceptions. They were all justified with the staff. We are either making or have made enhancements to many of the other programs for license renewal issues that came up. Most of those are including additional equipment and scope or structural monitoring, systems monitoring, preventive maintenance. So a lot of it is scoping issues that have been brought in. The actual methodology, the walkdowns that we do, are basically the same except we have more detailed worksheets, and I think we've made a lot of improvements in that area there.

We have implemented pretty much all except ten of the programs. All procedures have been reviewed but not completely signed off for license renewal, but we anticipate most of the programs being implemented well, well before 2009. We're not waiting for 2009 to implement the programs. We give more detail on the next slide.

We have 37 commitments that are in SER Appendix A. The schedule is in there. The 122 individual commitments include the 37, and those are in much more detail. For example, we committed to write program basis documents for every program. All except three, I believe, have been signed off already, so we have 34 other commitments match the one up there. Many of the other commitments have to do with periodic inspections, and we have spaced out the inspections. We've already done some of them in 2003. We continue spacing them out till 2009. We're not going to do all the inspections right in 2009. So we've doing them all along. We have had some success. We've already, like I say, done some of them in 2003, and all of the commitments are in our commitment action tracking system. Most of them have been assigned to individual plant engineers already. A couple of them that we haven't completed yet, there's a couple of commitments that we will complete after 2009 just because of the timing on it. We have a couple of structural integrity tests that we said we would commit to, and those are, I think, scheduled for -- I think the first one is scheduled 2015, and then the standard sprinkler had 50-year either replacement or a detailed review at 50 years, and 50 years is going to come up after 2009, so we'll do it at that point. Although we've been replacing sprinklers all along, so we have a pretty good feel for how good they are.

We do have a few modifications. There's some change anticipated due to the power uprate. Currently, we have a commitment to do our reactor vessel surveillance -- pull the next surveillance capsule in 2005, because that's when we had calculated we would get to the 60-year fluence. If we uprate, then the 60-year fluence we won't get to in 2005, so we're not going to pull the capsule. So we've currently calculated either the 2008 or 2009 as when we get to the equivalent 60-year fluence, so we'll revise that commitment to take the capsule out at that point. We'll have one capsule left that we'll keep in the core for the 80 years in accordance with ASTME 185. We'll be doing that, and I believe that's going to be a license condition anyway, but we're going to do it anyway.

MEMBER SHACK: Have you done any piping replacement as part of your FAC Program --

MR. WROBEL: Yes.

MEMBER SHACK: -- in your secondary system?

MR. WROBEL: Done extensive either piping replacement or coating it with chromium.

MR. GEIKEN: It's been replacement with chromium aluminum or chrome moly of plain carbon steel components.

MEMBER SHACK: Any trouble with meeting the welding requirements?

MR. GEIKEN: No. We do it all in-house. All of it was done in-house.

MEMBER ROSEN: What components were replaced? Give me a feel for where you made those replacements.

MR. WROBEL: For our pre-separator tank?

MR. GEIKEN: Yes, that's a good example.

One of our pre-separator tanks.

MEMBER ROSEN: The moisture separator tanks?

MR. GEIKEN: Pre-separator tanks.

MR. WIDAY: Our pre-separator tank is the extraction steam coming off the high pressure turbine.

MEMBER ROSEN: It's wet, right?

MR. GEIKEN: It's wet.

MR. WIDAY: Yes.

MR. WIDAY: Another one, Gerry, was the feed water regulating of bypass valves.

MR. GEIKEN: That's correct.

MEMBER ROSEN: Feed reg bypass valves?

MR. GEIKEN: That's correct.

MEMBER ROSEN: And the piping around the bypass valves?

MR. GEIKEN: Right.

MR. WIDAY: The piping --

MEMBER ROSEN: Did you replace the valves too?

MR. GEIKEN: Yes. Yes, I believe they were replaced, yes.

MR. WROBEL: Try to do the last slide and then some.

CHAIRMAN BONACA: Under programs, you

specifically pulled out the Fire Water System Program --

MR. WROBEL: That's because it didn't add up.

CHAIRMAN BONACA: -- as one having a lot of exceptions and enhancements?

MR. WROBEL: Yes. Pulled that one out because there are quite a few exceptions that we did at plant-specific detail design analysis on what the periodicity should be of the various inspections of fire doors and seals. And we were able -- you know, we did the design analysis, it was reviewed by NRC inspectors, and we got concurrence that we would do on that schedule a little bit different than what the GALL called for. The enhancement was primarily we didn't have a 50-year sprinkler head replacement, so we put that in. I only called that one out separately because they didn't add up and I got comments that they didn't add up to 30, so we'd better explain it. You guys were math wizards.

MEMBER ROSEN: I don't know about math wizards but some of us can add.

MR. WROBEL: Yes. We go all out with math wizards here.

Joe, plant ownership, do you want to make any --

MR. WIDAY: Sure. With the slide up there, if I can speak back here since I've got the microphone in front of me. First of all, if you're aware that in November of 2003 is when we formally entered contract negotiations for the sale of the plant, and the successful bidder was Constellation Generation Group. As you're well aware, Constellation is well known in the industry as one of the key players with their overriding principles of safe operation of a facility, and we've heard that message loud and clear from them already in town meetings that they've attended and make sure that they reinforce that message to us.

And we are looking excitedly towards the transfer of ownership here. The transfer of ownership is contingent on two major milestones. One of them is in the Public Service Commission arena and the Section 70 proceedings that are currently ongoing. Section 70 is transfer and sale of the asset, so that's got to get approved through the Public Service Commission. And then the second one is the initiative we have ongoing here today with the license renewals. So two of those issues have to come together for the final consummation of the sale of the Plant.

I'd like to talk a little bit about the benefits that we saw in the license renewal process, because just the formality of applying for the license and going through that process there's a lot of side benefits that we saw come out of that. First of all, there's the investment in the future here, obviously. But that wasn't something that occurred just as a result of the license renewal. Our Life Cycle Management Program already was well underway to help support the license renewal process, evidenced by 1996, the replacement of our steam generators. That was a $110 million undertaking by the Corporation with the intent that we wanted to make sure that the Plant continues to runs safely. Obviously, a side benefit of that is that it did position us for a license renewal, which we formally engaged in, as George pointed out, in the year 2000. So that was definitely we saw a benefit there.

What it also -- and I'm not sure if this was the chicken or the egg, which came first on -- but the ability for us to retrieve our records. I think Russ pointed out earlier in the introductions that we did have the capability to electronically retrieve a number of our records to ensure that we had our current licensing basis captured. And what we're seeing as a result of that, that electronic media has helped to position us for the future here. It's a resource that in particular our Engineering group uses on a daily basis, but it also overrides our entire organization. Key stakeholders have easy access to that data and information, so as an organization it has helped strengthen us. And, again, the license renewal application process, I think, just gave us more opportunities to enhance that database.

We're looking at continuing the positive relationship we have with our community. Ginna has positions itself over the years to be a key player in the community, and we've gained a lot of respect from that, and I think the license renewal process, especially the environmental impact arena, we are getting very positive accolades from the community. And Constellation has that same type of value system and approach, that they feel it very beneficial to be a key player in a community. In fact, they are meeting with our town officials as we speak just to continue to foster that relationship that we have.

And as far as the plant uprate, I think we spoke about that in some terms already. Obviously, there is a value to the asset itself by going through the power uprate, but it also allows us the ability to continue to look at our licensing basis and the ability of our equipment to operate, to maintain a safe operation of the Plant. So there's a lot of analysis that is ongoing to support that plant uprate study, and the results of that, I think, will just continue to increase the safety of our unit.

So those are the comments that I'd like to make there, and the last bullet there, of course, with the commitment transfer to Constellation it definitely makes it easier to identify who the owner is and who is responsible. And in this case here with Constellation assuming all of that responsibility, we have one person to go to, and it just makes it easier, less complicated as far as identifying that issue.

So those are the points that I'd like to make, and I appreciate the effort that's been put forth. I call it a fast track of what we are able to accomplish over this time frame, and it's not that we overlooked anything. I think it was our ability to work together to set targets and work to them that we're able to sit here today and discuss what we are. So thank you.

CHAIRMAN BONACA: I hear you're planning to go to uprate the power of the Plant. So now your temperature -- we asked you before about your temperature, where will it go? Do you know already?

MR. WROBEL: About 603.

CHAIRMAN BONACA: Six-oh-three. So that will go roughly where it was originally.

MR. WROBEL: Yes. Maybe a degree or two higher. We've done the feasibility study. I can't say to the tenth of a degree but that's pretty close.

CHAIRMAN BONACA: Yes.

MR. WROBEL: So we've had experience in that. And, of course, having gotten rid of the Alloy 600 in the upper head, that at least puts us in a low susceptibility category even if we hadn't -- I mean irrespective of the temperature. And that's not particularly high either.

CHAIRMAN BONACA: So then you have a change that it's going to cascade, there are a number of changes in process, barometers. Are you going to have -- how do you assure that all the impact of these changes is going to be reflected in your commitments to license renewal? Do you have a process by which you make a change and you go back to these programs?

MR. WROBEL: Actually, I'm transferring to power uprate as soon as this is over.

CHAIRMAN BONACA: Yes.

MR. WROBEL: So at least that's a partial answer. Yes, all the commitments -- when we do power uprate all of the parameters within that are reviewed against our commitment tracking system, and it's basically the same engineers. Very few of them are dependent on power level and fluence. The ones that are are the TLAAs, and all the TLAAs will have to be redone for the higher power level. We started doing those already.

CHAIRMAN BONACA: Okay. All right. So this completes your presentation?

MR. WROBEL: Yes. This completes our presentation.

CHAIRMAN BONACA: All right. Any questions from the members before we hear from the NRC staff? If none, then --

MR. ARRIGHI: Russ Arrighi, Project Manager. Good morning. My name is Russ Arrighi. I'm the Lead Project Manager for the Ginna license renewal application. Ginna is a two-loop pressurized water reactor located in Waynes County, New York. It's one of the plants that had went through the Systematic Evaluation Program. The application was submitted to the staff on July 30, 2002. On November 4, 2003, we had the ACRS Subcommittee meeting, and then on March 4 of 2004, we issued the final safety evaluation report.

Based on the staff's review of the license renewal application, inspections performed by the region and by the audits performed by the staff, the staff concludes that the Applicant has met the requirements of 10 CFR 54.29. Also, the requirements of 10 CFR 51, the environmental protection regulations, have been satisfied.

The NRC performed two audits and two inspections at Ginna. The scoping and screening methodology audit determined that the methodologies satisfies the requirements of the rule. The staff also performed an audit of the aging management programs, and we determined that all the programs were consistent with the GALL except for the Fire Protection and Fire Water System Program. The Applicant in the application stated they were consistent with GALL. During out audit we determined that there were some exceptions. We identified eight total exceptions. The Applicant was aware of three of those exceptions; however, due to an oversight or what not they didn't inform the staff. We issued an REI and the Applicant responded on the docket. We reviewed those exceptions and we found those to be acceptable.

MEMBER ROSEN: Would you characterize a few of them for us so we know what was the nature of these kinds of exceptions?

MR. ARRIGHI: Yes. For the Fire Protection Program, there were three exceptions. The one identified by the staff was the fire door surveillance called out quarterly versus biweekly, as indicated in the GALL. Two, that the Applicant had identified -- had to do with the halon frequency testing. They wanted to test the halon system every two years versus every six months. And there was an issue with the qualification of personnel performing visual inspections.

In the Fire Water System Program, we identified -- there were four total exceptions, and the staff identified three of those. One had to do with the sprinkler system not examined for microbiological filing. The visual inspection of the fire hydrants, the Applicant wanted to inspect those at windows of opportunity versus every six months. And another one had to do with the hydrant flow testing on a periodic basis versus annually. And the Applicant did submit those to the staff, and they were reviewed and determined to be acceptable.

MEMBER ROSEN: Thank you.

MR. ARRIGHI: The region did two inspections, the scoping and screening inspections, and they determined that the Applicant was successful in identifying those systems subject to -- that needed aging management review. And the final inspection, the Aging Management Program inspection, they determined that the effects of aging would be appropriately managed during the period of extended operation.

This is similar to what the Applicant pointed out. Again, there were 34 total aging management programs. Thirty-one were consistent with GALL or consistent with some exception or deviation. There were three non-GALL programs. And as a result of the staff's review, the Applicant did add two aging management programs as a result of staff questioning. One had to do with electrical cables not subject to EQ used in INC circuits, and the other program was medium voltage cables not subject to emergency -- to EQ, and they added that. They pointed out earlier that the off-site power cables that powered the safety bus for service water once they brought those two cables in scope they added a new aging management program, and that program was consistent with GALL, and those were reviewed by the staff.

Open and confirmatory items, our review resulted in a total of eight open items and seven confirmatory items. At the Subcommittee meeting, all but four of those items had been resolved. We have four listed here. The first one had to do with the fire service water booster pump, called the jockey pump. Initially, the Applicant did not have that in scope of license renewal. The outcome of that was that the Applicant did indeed include that in the scope, so the staff was satisfied with that.

The second item had to do with the two off-site power supply cables to the service water train, for the service water pumps. Originally, those cables were not in scope, and, again, the resolution of that item was that the Applicant did add those two cables in the scope of license renewal.

The third item had to do with -- there were five of the ten attributes for the Thimble Tube Inspection Program required clarification. They did provide that clarification on the docket, and we found that acceptable. Some of those items had to do with the locations of the tubes to be inspected, the frequency and the basis for testing. That wasn't clear in the application, and, again, the Applicant did provide that information to the staff, and we found it to be acceptable.

And the last item was the Applicant changed their methodology for determining the PTS value from one that was based on the chemistry factor to one that was based on surveillance data. The staff had an open item that they wanted to review the surveillance data and the calculations to ensure that they met the credibility criteria of 10 CFR Part 61. All those items have been satisfactorily resolved.

MEMBER FORD: I seem to remember on that last item there's a question of the Applicant didn't want to use one of the surveillance samples, is that correct, and you were wanting to do so. How did that resolve itself?

MR. ARRIGHI: I'm going to call on Barry Elliot to describe that.

MR. ELLIOT: NO, no, no. They used all the data for this Plant. The issue here was that 10 CFR 50.61 has certain criteria that should be satisfied if you want to use the surveillance data, and we just asked them to provide their -- to show us that their surveillance data met all those attributes. And they were able to convince us and show us that it did, and then we were willing to accept the chemistry factor and the radiation brittlement estimate. The reason that they wanted to do this is because it resulted in an advantage for them in that if you went just according to the tables in the rule, they would have a higher PTS value, and this lowered their PTS value. And I assume it's because they know they're going for power uprate, and this would probably be a big factor for them for that. It really wasn't a factor here for license renewal. They would have passed anyway, but they did get an advantage doing this, and we just wanted to make sure that they had followed -- the program did what it was supposed to do.

MEMBER FORD: So will this issue arise again when they come for power uprate?

MR. ELLIOT: It will be to their advantage in power uprate. As I said, I don't know how much fluence increase there's going to be for the power uprate, whether they would have passed using both methodologies or not, I can't tell you that, but there was an advantage they got here.

MR. WROBEL: Yes. We did do the calculations for power uprate out to 60 years, and the value was about 276.5, so we still have quite a bit of margin even at that point. Now, that hasn't been verified by Barry, but that's our own calculations.

MR. ELLIOT: Yes. One of the things I just wanted to point out is this vessel has forgings in it, so they only have circumferential welds in the beltline. So that's why you see the tremendous margins on equivalent margins analysis. They don't have any axial welds that are -- and that's where our problems are going to be in a nuclear pressure vessel. It isn't going to be in the circumferential welds. There's just not enough stress there to cause a problem.

MEMBER SHACK: Okay. Now, do they have enough capsules to get them out to --

MR. ELLIOT: Yes. Because they said they have -- one they were going to take out in 2005, and that was a big discussion. That was really a discussion now that I remember, was when they were going to take that capsule out. That's what the discussion was. And then one standby, but when they were going to take out that next capsule was a big discussion. And we convinced them to keep it in a little longer so they can get more fluence, and I'm good to hear that they're going to keep it in to get enough fluence to get power uprate too. And so we'll be able to confirm the equivalent margin analysis and we'll be able to confirm the PTS evaluation.

MEMBER SHACK: Thank you.

MR. ARRIGHI: The time limiting aging analysis meet the requirements of 54.21. The staff reviewed the equipment qualification TLAAs to verify that the assumption of the methodologies were adequate. Initially, I believe the staff reviewed approximately 40 percent of the ones that had been completed at the time of the license renewal application. As George Wrobel pointed out earlier, they have subsequently completed 100 percent of those calculations. And based on the review, the staff concluded that the effects of aging will be managed during the period of extended operation.

Reactor vessel upper shelf energy, the limiting weld is projected to be less than the 50 foot pounds screening criteria. The staff did review the Applicant's equivalent margins analysis calculations and performed an independent analysis, and they verified that the reactor vessel would have margins of safety against fracture equivalent to those required by Appendix G to Section 11 of the ASTME code.

CHAIRMAN BONACA: Okay.

MR. ARRIGHI: And for PTS, the projected value is within the screening criteria.

CHAIRMAN BONACA: And all the other PLAs

have been completed, I understand, right?

MR. ARRIGHI: Yes. Our license conditions for the Plant, the Applicant will include in the UFSAR supplement -- will include the UFSAR supplement in the next update as required by 10 CFR 50.71(e), and future activities identified in the supplement will be completed prior to the period of extended operation. Again, the Applicant pointed out there are some inspections that will be after the period of 2009.

Also, there's another --

MEMBER ROSEN: How does that square with the idea that it will be completed before the period of extended operation if you're not going to do the inspections until you --

MR. ARRIGHI: Well, they're going to -- all the commitments -- the staff reviewed all the license commitments, and, again, all commitments will be completed as identified in Appendix A to the SER. The staff did look at all those commitments and agreed that those time periods specified were sufficient.

MEMBER ROSEN: But if you're not going to do the inspections until you enter the period of extended operation, then --

MR. ARRIGHI: There's only one or two commitments. It's the --

MR. WROBEL: I can clarify that -- George Wrobel. All of the commitments that will be done after 2009 are part of programs. All of the programs will be implemented prior to 2009. There will be some minor specific activities that will be done after that, but, for example, in our one-time inspections or our periodic inspections, we'll be doing several of them before 2009. We're going to continue those through 2029, so all of these programs are living programs anyway. The only ones that -- like, for example, one of the commitments that we made for a phased bus inspection will be done in 2012, but we did one in 2002 already, so it's like a ten-year periodicity between them. So the concept is all done prior to 2009, but there's some specific activities that are done after that, but they're really part of a program that's already been implemented.

MEMBER ROSEN: Is this the first time we've had this condition or is this typical of what happens? It just seems different to me.

MR. ARRIGHI: Again, as George pointed out, the only thing we called out why the commitments looked different is because it's what is the frequency of some of these inspections. Like George said, they have done an inspection already. The staff just wanted to ensure that they do continue those at a certain periodicity. I haven't read the other commitments from the other applications to see if it called out to that specification.

MEMBER ROSEN: Sam or P.T., can you help me with that?

DR. LEE: I believe this is a typical commitment for all plants.

MEMBER ROSEN: Okay. So this isn't different, you're saying.

DR. LEE: This is not different.

MR. KUO: I think this is no different. Like George was saying, they happen to have done some inspections in 2002, so the staff just wants some more. Usually, people have not done any inspection, so we make sure they at least do one before they enter the extended period.

MEMBER ROSEN: Yes.

MR. KUO: So in this case, they've already done one, but it's been a couple years back. We just want them to do it again but not too close to the first one they've already done.

DR. LEE: Just continuous. Basically, the periodic inspection will continue later on.

MEMBER ROSEN: Okay. All right. Thank

you.

MR. ARRIGHI: The other license conditions I show here, there's one that hasn't been displayed at the full Committee meeting. This has to do with the -- to ensure that the requirements of 10 CFR 50 Appendix H, the Reactor Vessel Surveillance Program requirements, are extended beyond 40 years. And Ginna does have a commitment to do that, but that is now a license condition that we're imposing. It ensures that all capsules in the vessel that are removed and tested must meet the requirements of ASTME 185 to the extent practical, and any changes to that withdrawal schedule must be approved by the NRC.

In conclusion, again, based on the staff's review, we conclude that the Applicant has met the requirements for license renewal, and that concludes the staff's presentation unless there are any questions.

CHAIRMAN BONACA: Any questions from members? I have a question for the Applicant here, if I could. You do have, you said, a Level 3 PRA in the Plant.

MR. WROBEL: That's correct. For sampling we did that.

CHAIRMAN BONACA: Do you maintain it? Do

you keep it as a live PRA?

MR. WROBEL: Yes. We keep our PRA up to date. We'll probably revise it on almost an annual basis with the plant modifications and peer reviews and comments and things like that. So we're --

MEMBER POWERS: Who leads your PRA? I mean which individual is responsible for that?

MR. WROBEL: Well, we have a PRA group within RG&E and we maintain it pretty much in-house, and we'll probably get some help from Constellation in a few months. But, yes, we do it in-house.

MEMBER ROSEN: You said you have Level 3.

MR. WROBEL: The Level 3 was -- yes, Level 3 was done by an outside contractor.

MEMBER ROSEN: All right. Now, that includes population.

MR. WROBEL: That includes population.

MEMBER ROSEN: And you have to track population shifts and that sort of thing when you do your uprates, right?

MR. WROBEL: Right. It's consistent with Chapter 2.2 in the FSAR, I think, that does population distribution. So when we maintain it up to date we could use that data for the 2003, although I think when we did our Level 3 PRA I think we used population estimates or projections out to -- I think we averaged 2009 to 2029. I think we might have used 2019. I don't remember the exact number but projections out to there. If you've ever been to Upstate New York, the population does not change appreciably, except we lose some people in the snow once in a while.

CHAIRMAN BONACA: Do you have a risk monitor?

MR. WROBEL: Yes. We have an online EOOS risk monitor, and we use that on a daily basis for all plant evolutions.

CHAIRMAN BONACA: So you do have a PRA person in the Plant or do you have them all in the --

MR. WROBEL: Yes. We have a PRA person in the Plant. Now, the risk monitor is actually used by Planning and Scheduling as well as Operations more than the PRA people.

CHAIRMAN BONACA: Yes. Okay. Thank you. Any other questions for Mr. Arrighi? Any questions from the public? If none, thank you for the presentation. It was informative.

we're well ahead of time and I think what we're going to do, I'm going to give you an interim report or our interim review of the license renewal application for Dresden and Quad Cities. I don't think we need the recorder for this, right? We're going to be off the record until 10:15 when we go to the next item on the agenda.

(Whereupon, the foregoing matter went off the record at 9:30 a.m. and went back on the record at 10:17 a.m.)

CHAIRMAN BONACA: Okay. We're back in session and we're going to hear about a proposed bulletin. Good morning.

MR. BATEMAN: Good morning. My name is Bill Bateman. I'm Chief of the Materials and Chemical Engineering Branch in the Division of Engineering at NRR. With me this morning is Matthew Mitchell, a senior staff member in my branch.

What we're here to discuss with you this morning is a bulletin that is in the process of being issued by the staff to all pressurized water reactor licensees or the purpose of gathering information with respect to the status of the similar metal welds on and about the pressurizer. And with that, I'll turn it over to Mr. Mitchell.

MR. MITCHELL: Okay. Thank you, Bill. It is once again a pleasure to be back with you today. We, of course, did a similar presentation about two weeks ago for a couple of days here of subcommittees, and I'd just like to note that the staff is very appreciative of the comments that we received at the subcommittee meeting, and what we took away as a unanimous vote of support at that time for the actions that the staff had planned with regard to this proposed bulletin. So with that, I'd like to quickly sort of give you an overview of what the main message points are from this presentation; and that is, of course, that the staff has developed a proposed bulletin to address the inspection of Alloy 82/182/600 locations in the pressurizer boundary, which are susceptible to primary water stress corrosion cracking, and to clarify what that statement means.

We have notably excluded the potential bimetallic weld between the surge line and the pressurizer shell from the context of this bulletin. The staff, as you will see in the text of the draft proposed bulletin, the staff is having further deliberation internally with regard to what to do about large bore bimetallic piping wells. And that particular location more readily fits within the scope of any potential future actions the staff might wish to take rather than the other types of penetrations which are addressed in this proposed bulletin. So if you will, one way of thinking about it is the boundaries for this proposed bulletin start just above that bimetallic weld location, and then anything above that would be within the scope of what we're talking about today.

The proposed bulletin is intended to request information from the PWR licensees regarding their past, present, and future inspection plans, locations that are covered within the scope of the bulletin, and their basis for concluding that the inspection program that they are planning is adequate. And it is adequate in terms of continuing to meet all the appropriate regulatory and licensing criteria for maintaining reactor coolant pressure boundary integrity for their facility. And it is the staff's position that the information we're requesting is necessary for us to determine if additional regulatory action beyond the bulletin is required to make sure that that integrity is being maintained.

As I think the Committee is aware, we do have extensive operating experience which has demonstrated that these Inconel Alloy materials when exposed to an environment like that found in the pressurizer can lead to primary water stress cracking, and this would include Alloy 600 heater sleeves at combustion engineering design facilities, Alloy 600 diaphragm plates in the pressurizer heater bundle design used at the Babcock and Wilcox design facilities, as well as various instrument lines and spray or safety and relief valve lines which are common to many of the pressurizer designs. And for reference, if you'll allow me to flip to the next page very quickly, we've included sort of a typical drawing of a combustion engineering or Westinghouse designed facility's pressurizer, and you'll note although it's not –- we don't have a legend on this particular diagram that you have in front of you, some of the locations which are numbered there would include like at number 3, a spray line coming into the top of the pressurizer, 4 and 5 would be general locations where you might have safety and/or relief valve lines coming off of the pressurizer steam space. Locations 5 and 7 would be instrument taps potentially, which may include these materials. And then down at the bottom you see heater sleeves coming into these particular designs.

If you think about or wish to consider a Babcock and Wilcox designed facility's pressurizer, you would see instead of the heater sleeves or the heater elements coming in from the bottom, you would see a bundle coming in from the side. What has been -

although I've never actually looked at my hot water heater at home, it's been given to me as the analogy would be it looks something like what you would expect to see in your home hot water heater with a grouping coming in from the side.

MEMBER POWERS: Let me ask a question undoubtedly with a great deal of ignorance on my part in this particular field. We're always very careful to say primary water stress corrosion cracking, and I'm wondering what the significance of the primary water is. Is it the temperature of that water or its composition?

MR. MITCHELL: We use the term primary water stress corrosion cracking more as a way of differentiating the environment in which you are seeing the cracking occur versus something like an inner granular stress –- water stress corrosion cracking is an example of, or very similar to inner granular –- it's actually primarily in ferritic cracking. But really, the term primary water just is intended to transfer that –- we are talking about a PWR environment in which you have a contained and controlled chemistry that has very low amounts of oxygen and other contaminants in it which you would normally associate with stress corrosion cracking.

I'm not sure if I fully answered your question, or if there's more that you'd like to have.

MEMBER FORD: I think the main thing is that this -- it is related to the environment but not so much to the cationic condition of it. It's a fairly buffered solution. If you go beyond those, like going to the acid side or alkaline side because of the boric acid/lithium hydroxide balance, it will change the cracking kinetics, but generally you fairly proffered a known pH value. You don't have boiling, you don't have crevice corrosion, heater interchange or phase concentrations, so it is primarily temperature driven. That's why their algorithm use temperature as the main variable.

MEMBER KRESS: Primary temperature and stress.

MEMBER POWERS: Well, those are some we will discuss. Obviously, there's material stress and environment parameter if temperature --

MEMBER SHACK: This was first observed by Corio back in the 60s. It was called pure water, because people always had the notion that stress corrosion cracking required some sort of intrusion, you know, chloride. It was always going to take some -- well, the wonderful thing about Alloy 600 is it will crack in completely pure water without any --

MEMBER ROSEN: It was designed to crack, I think.

MEMBER SIEBER: No, but it was such a surprise at the time that it was discovered, that they called it pure water cracking to denote the lack of ions.

VICE-CHAIRMAN WALLIS: Peter, you said there's no boiling. Now this is a pressurizer.

MEMBER SIEBER: You don't need boiling.

MEMBER SHACK: But he's comparing with the secondary side to concentrate --

VICE-CHAIRMAN WALLIS: How is vaporization in the pressurizer during transients? And these heaters are designed to heat the water, so there are probably local areas where there is --

MEMBER SIEBER: There's boiling on the heater tubes.

MEMBER ROSEN: We draw bubbles in the pressurizer.

VICE-CHAIRMAN WALLIS: So why did you say -- is the formation of bubbles important or not? You said there's no boiling.

MEMBER FORD: I was trying to answer Dana's question, and the reasons behind it. And yes, you can have areas where you could have slight pressurizer. Now would that give a problem? Maybe.

MEMBER KRESS: I don't think you boil on the surfaces we're talking about.

MEMBER FORD: Yeah. I think boiling at the actual --

VICE-CHAIRMAN WALLIS: We don't know, because we don't quite know what the temperature distribution is around these heater plugs.

MEMBER SHACK: It's not like the crevice on the secondary side of a steam generator where you get such concentrated boiling that you can get concentration levels that are a million times the bulk chemistry, and that's really what you're looking for here is, you know, despite the fact that my feedwater is extraordinarily pure, I can actually get a concentrated environment in the steam generator crevice because I have such enormous amounts of boiling. Well, that just doesn't happen on the primary side. I mean, you can get some boiling and some kind of concentration level.

MEMBER SIEBER: In fact, you don't need boiling in order to get the crack.

MEMBER FORD: Oh, no.

MEMBER POWERS: Let me ask you this

question as well, Peter. What is the significance of radiolysis products in this cracking phenomenon?

MEMBER FORD: The main radiolysis product you're talking about for this instance would be gamma radiation, and that does not change the corrosion -- what you're really interested in is radiolysis products is changing the species that are the thing. For instance, the BWRs is primarily hydrogen oxide radiolysis product. Oxygen, of course, is retained in the BWR because of the partitioning of hydrogen and oxygen to the steam fittings.

The other thing is changing the constituents, hydrogen peroxide in PWR, and to also change the corrosion potential. The current potential as far as that is concerned might be changed by gamma. In fact, it was not changed very much at all.

Cross neutrons could change the corrosion potential. The ones I know of primarily as the results of BWRs, and there are algorithms to relate cross neutron flocks to corrosion potential, and thereby accelerated cracking in the core.

I don't know of any similar studies that have been in PWRs.

MEMBER KRESS: Is boric acid a player in this?

MEMBER FORD: No. If you go -- have so much boric acid you go outside the buffered range and you start to go into the acid region.

MEMBER SHACK: But I mean there is great difference between -- in a BWR without control of the chemistry your potentials are hundreds of millivolts higher than they are in a PWR where you do maintain the hydrogen over-pressure.

MEMBER FORD: And that's why in the BWRs you have such a strict, very, very strict control over the impurity contents. And we were approaching purity water in the --

MR. MITCHELL: And that control and maintenance, are they very — what would assume to be a less aggressive environment that goes back to the bit about why we give it as being the primary water stress corrosion factor and to differentiate it.

MEMBER FORD: That's why in general, we understand the primary water side better than we do the secondary side. The secondary side is a mess as far as understanding.

MEMBER POWERS: That's because you don't have good chemists working on that one.

MEMBER ROSEN: They handed us these pictures or drawings. Are you going to go over that a little bit?

MR. MITCHELL: I will use those to the extent that you would like me to explain --

MEMBER ROSEN: Well, when you say diaphragm plate in the pressurizer heater bundle, I just go blank. In a B&W plant, the light --

MR. MITCHELL: Sure.

MEMBER ROSEN: And then I start maybe a little bit to understand.

MR. MITCHELL: Then let me bring up this particular background slide that I've got, which is actually a slide we received from TMI in the context discussions we had with them in the fall of 2003 regarding diaphragm plate cracking and leakage, that they had occurred at that facility. And what this shows is sort of a blow-up of a typical B&W design, feeder bundle coming into the side of a pressurizer. And I think I've got it oriented now, so you can imagine it coming into the side of the pressurizer.

MEMBER ROSEN: You mean their heaters actually go into the side of the pressurizer, not the bottom?

MR. MITCHELL: That is correct.

MR. BATEMAN: They're on a separate plate. They're in an assembly that's slid in and then bolted on and sealed.

MEMBER ROSEN: See, I have no familiarity with it so I don't --

MR. MITCHELL: The individual heater elements come in through this, which is a strong back, which provides the actual structural support for the assembly. And it is bolted to the pressurizer.

MEMBER ROSEN: That's a pressurizer nozzle on the right hand side.

MR. MITCHELL: Yes. This is the pressurizer shell.

MEMBER ROSEN: Shell, not nozzle?

MR. MITCHELL: It's integral nozzle. It's integrated into the shell.

MEMBER ROSEN: Okay. So it's -- and this thing, you say, is not welded. This thing on the far right is not welded to the shell of the --

MR. MITCHELL: It's seal welded, but it's not structurally welded. This is the pressurizer nozzle or shell. This is a diaphragm plate to which the individual heaters are attached. It slides into this opening essentially. It mates up at this location. It's seal welded here around the circumference of the diaphragm plate, but the structural support is provided by this bolted strong back which is bolted into the shell of the pressurizer.

MEMBER ROSEN: So the way they assemble this thing is they stick this diaphragm plate in first and seal weld it. Right?

MR. BATEMAN: They bolt it up and then they seal weld it.

MEMBER ROSEN: They bolt this whole assembly up? How do they get the --

MEMBER POWERS: They weld it.

MEMBER ROSEN: They're welding in that little gap?

MR. MITCHELL: I believe the details, I think they may have to do the seal welding prior to attaching the bolting on the strong back.

MEMBER ROSEN: I think so.

MR. MITCHELL: But how they exactly support it in place --

MR. BATEMAN: Well, they got to hold it in place in order to do the seal welding.

MEMBER ROSEN: Yeah, so how do they hold it in place? Well, they could put a jig or something --

MR. BATEMAN: They could put a jig or they could bolt part of it, weld part of it. When they've got the weld around the part that doesn't have the bolts, they can move the nuts over to those. There's various ways they could do it.

MEMBER FORD: Isn't the diaphragm -- there's two parts. There's a strong back and a diaphragm. The diaphragm is welded in easily, and then the strong back is bolted on.

MEMBER ROSEN: Yes. So I think the sequence is they put the diaphragm in welded so they have plenty of room around. They could get a good seal.

MR. MITCHELL: Right. That would be plausible.

MEMBER ROSEN: And they hold it in place with some sort of jig or something. Maybe they just press it in there or something.

VICE-CHAIRMAN WALLIS: Well, it's also supporting the weight of those heater rods that are sticking out.

MEMBER ROSEN: No, they're not in it.

VICE-CHAIRMAN WALLIS: They're not in it yet.

MR. MITCHELL: Yes, they are.

MEMBER ROSEN: Oh, they are?

VICE-CHAIRMAN WALLIS: Yes, because

they're welded to the --

MEMBER ROSEN: They welding the seal with the heaters installed already?

MR. MITCHELL: Yes. The heaters would have been attached to the diaphragm plate at that point.

VICE-CHAIRMAN WALLIS: To replace the heaters do they have to cut a weld or something?

MEMBER ROSEN: Well, that just makes the jig a little more complicated.

VICE-CHAIRMAN WALLIS: Everything is welded up.

MEMBER ROSEN: I'm just trying to think about what -- you know, how you get this thing put together first before --

VICE-CHAIRMAN WALLIS: How do you fix anything?

CHAIRMAN BONACA: Well, it's welded there.

MR. MITCHELL: For the purpose of this discussion, I guess what we were trying to focus on is the key point that this plate, at least at some utilities, at some designs has been manufactured from an Inconel 600 material.

MEMBER ROSEN: Which plate, the diaphragm plate?

MR. MITCHELL: The diaphragm plate which is shown in this cross-hatch region here.

MEMBER ROSEN: Okay.

MR. MITCHELL: And is, thus, potentially susceptible to getting primary water stress corrosion cracking.

MEMBER ROSEN: It's pretty thick though. How thick is it?

MR. MITCHELL: Well, it's -- that dimension I do not have off the top of my head, but at the TMI -- for the TMI event what was actually observed was that the cracking occurred up in the region of where the seal weld is. It actually was --

MEMBER ROSEN: There's no water up there.

MR. MITCHELL: There is actually a contact or a leak path where water can get up through --

MEMBER SIEBER: To the back of the seal weld.

MR. MITCHELL: Yes.

MEMBER SHACK: There's only a seal weld at the top. The rest of it --

CHAIRMAN BONACA: Right. The rest of it is just contacted.

MR. MITCHELL: It's just a flush contact.

MEMBER SHACK: It's a crevice.

MEMBER ROSEN: Oh, yes. It's one of those crevices.

MR. MITCHELL: And what they had observed was actually cracking in the heat affected zone of the seal weld, is where the cracking occurred and gave them leakage during the TMI situation.

MEMBER ROSEN: Okay. Good.

MR. MITCHELL: Okay? It is a bit complicated if you're not readily familiar with this particular joint. It looks a whole lot --

MEMBER ROSEN: Well, I'm getting familiar. You're helping me there, but I wasn't before.

MR. MITCHELL: If you'd like me to flip over to the other design for just a moment, just if you want to compare this to an individual penetration that you're probably more used to seeing in the CE design and Westinghouse design pressurizers. This gives you a sense that a bottom-mounted heater sleeve looks very much like a bottom-mounted instrumentation nozzle off of a vessel, typical J-groove weld.

MEMBER ROSEN: And there's the same gap there that provides a pathway to leak out if you crack the J-groove weld.

MR. MITCHELL: That is correct, or if you crack the tube around the J-groove weld. If you get leakage there, it is a design gap of approximately 4 mils around where that heater sleeve slides into the pressurizer shell. But yes, it is not an interference gap.

MEMBER SIEBER: That gap is not ordinarily wetted.

MR. MITCHELL: Should not be wetted unless you actually have cracking and leakage.

MEMBER SIEBER: Yes, unless it leaks.

MR. MITCHELL: That's correct. And I should take this opportunity to note that at least as far as the Westinghouse design facilities go, as far as we are aware at this time, none of them have employed Alloy 600 heater sleeves. Their heater sleeves are uniformly stainless. It's the CE design facilities that chose to use Alloy 600 sleeves, so this particular aspect seems to be localized to the CE design.

MEMBER POWERS: And that's because of the Alloy 600, but because of its corrosion resistance?

MR. MITCHELL: They may have chosen it for a number of reasons, either thermal expansion issues or potentially if they recognized an advantage in terms of corrosion resistance.

MEMBER POWERS: Very strong.

MEMBER ROSEN: So what cracks in this design is the J-groove weld again?

MR. MITCHELL: No. Actually, the cracking that has been observed to-date in the CE design facilities has been, as far as we're aware, isolated to tube material itself. So you would get cracking in this cross-hatched zone that I've colored in on this particular picture in the area of the tube which sees significant residual stresses from the J-groove weld, but the cracking has been in the tube material.

MEMBER ROSEN: And then it leaks into the gap.

MR. MITCHELL: Yes, it leaks around --

MEMBER ROSEN: Around the J-groove weld.

MR. MITCHELL: And then down.

MEMBER ROSEN: Which is just the opposite of what South Texas saw on its bottom mounted, where they saw the cracking in the J-groove weld.

MR. MITCHELL: No. Actually, the cracking for South Texas, that was also present in the tube. There was a flaw in the J-groove weld which contributed to establishing an environment in the lack of fusion zone between where the weld and the tube mate up, but the actual primary water stress corrosion cracking that was evident at South Texas was in the tube material. It was also at --

MEMBER ROSEN: But in order to get --

MR. MITCHELL: Yes, there was a different set of conditions. The fabrication related flaw in the weld that we believe abetted that cracking in South Texas, which we don't have evidence of in these penetrations.

MR. BATEMAN: Something just to clarify here. The industry -- the state of the industry at this point is such that other than being able to do a surface exam on one of these J-groove welds, they cannot be examined volumetrically, so when we say there's no flaw in the weld, that's because, in part, we found a flaw in the base material, but that is the housing. Now whether there's also a flaw that goes all the way through in the weld or not, we don't know. All we can tell -- there was surface exam, but there's a crack in the surface. Whether it goes all the way through or not, we don't know. Unless we did a volumetric inspection of the tube, didn't find any through-wall flaws there and we did have evidence of leak, we could come to the conclusion that you had a through-wall flaw in the weld, but we haven't seen that yet.

MEMBER ROSEN: Or if you took it out like they did at South Texas and sectioned the weld.

MR. BATEMAN: But they only took out a portion of the weld. They didn't take out the whole weld.

MEMBER ROSEN: They took out a section of it and found it's been flawed.

MR. MITCHELL: That's correct. But I think we also have a sense that because of the difference in environmental conditions between the pressurizer and the bottom head, where you're talking about a range of 100 degrees Fahrenheit roughly, that we wouldn't anticipate that you would need to have the same set of pre-existing conditions to get these penetrations to crack, as appear to be necessary to get the bottom-mounted instrumentation nozzles at South Texas to crack.

MEMBER ROSEN: It's much cooler at South Texas than this --

MR. MITCHELL: Absolutely.

MEMBER SHACK: Just a question, Bill. They actually did an enhanced VT-1 then to look at the J-groove weld, and they can't see any surface cracks in it?

MR. BATEMAN: In the pressurizer? No.

MR. MITCHELL: No.

MR. BATEMAN: We haven't done that kind of -- the only thing we've done on the pressurizers is basically volumetric inspection of the housing.

MEMBER SHACK: So you've only just come up inside and looked around.

MR. BATEMAN: Right. That's it. Not a whole lot of data from that method either up until now.

MR. MITCHELL: But the only thing that you can say is that when they have gone in and looked at ones which had shown evidence of leakage, they had found flaws in the tube material that would have supported the leak path and what was getting deposited to the outside.

MEMBER SHACK: So you don't need to have a crack in the J-groove weld now.

MR. MITCHELL: Does not appear to be, yes. We don't need to have that condition.

VICE-CHAIRMAN WALLIS: Can I ask about thermal cycling when you have insurge from the surge line against the bottom of the pressurizer. There is some temperature change going on around this region.

MR. MITCHELL: There would be.

VICE-CHAIRMAN WALLIS: Is that a significant effect as far as crack growth goes?

MR. BATEMAN: Well, Matt, I don't know right off the top during steady state 100 percent power operations how much surge flow we get. I would suggest we're at steady state conditions and in the normal 100 percent operation you wouldn't see much.

MEMBER SIEBER: The spray flow keeps the surge line warm.

MEMBER ROSEN: You're going to send this bulletin that you're proposing to all PWRs or just CE and BNW?

MEMBER SIEBER: All of them because Westinghouse has a lot of 82/182 --

MR. BATEMAN: This covers more than the pressurizer heater sleeves. This bulletin covers all the dissimilar metal welds on the pressurizer, which would include instrument penetrations, the lines that come off the top of the pressurizer, those types of things. I mean, it could be confusing when you think maybe Westinghouse doesn't use Alloy 600 J-groove welds in their heater sleeves, but we're covering more than heater sleeves in this bulletin.

MR. MITCHELL: When you consider the instrument taps, when you consider in particular the vent lines that come off the top, we have seen evidence -- we've gotten responses from Westinghouse design units that they did, in fact, use this material in those locations.

MEMBER KRESS: What is the ultimate risk of these cracks? Do they lead possibly to a small break LOCA?

MR. MITCHELL: Well, you're kind of jumping ahead to my punch line at the end which reflects back on the question that Dr. Ford asked during the subcommittee meeting. It's our best understanding at this point in time that we can anticipate evidence of leakage, and therefore, the use of 100 percent bare metal visual inspections as an appropriate management tool prior to putting ourselves, or having the industry put themselves at an unnecessary risk of having a small break LOCA.

MEMBER KRESS: But it is a small break LOCA you're worried about.

MEMBER SHACK: It's 1.2 inches, yes.

MEMBER KRESS: Where does that size LOCA fit on the risk curve for these plants? How much contributing --

MEMBER POWERS: For a small break LOCA, that is right in the regime for the plants that have dominant small break LOCAs --

MEMBER SHACK: Which combustion plants

probably would be.

CHAIRMAN BONACA: Why don't we let him finish his presentation --

MEMBER FORD: You can see that materials is a very important subject. A very popular subject, rather.

MEMBER POWERS: Yeah, but it never comes to resolution. It takes forever. I mean, we've been working on heavy section steel since the dawn of time.

MEMBER FORD: I think Tom's question while we're on the subject was is there a CCDF, and I think one was quoted.

MR. MITCHELL: Yes, one actually -- just before I go to the next slide, just to try to close the loop on that - what I understand the CCDF to be for a small break LOCA at these facilities is something on the range of 10 to the minus 4, 10 to the minus 3 range for a small break LOCA. I'm not a risk analyst, but those are the numbers I recollect.

MEMBER KRESS: Okay. That's significant.

MEMBER POWERS: That's get your attention, doesn't it?

MEMBER KRESS: It's worth looking at.

MR. MITCHELL: Moving on to slide 5 then --

MEMBER POWERS: Even though we have to put with the --

MEMBER KRESS: Yeah, you're going to have to put up the materials, blacksmith people.

MEMBER ROSEN: Well, if they didn't break our vessels, the PRA guys wouldn't have to analyze it.

MEMBER KRESS: Put us out of business.

MR. MITCHELL: Thank you, Peter.

MEMBER FORD: That's quite all right, Matt. I have to put up with this every day.

MR. MITCHELL: We do have also extensive recent operational experience with this type of cracking in the pressurizer environment. And this includes from the fall of last year, leakage which was observed at Millstone, you had two, in Waterford you had three. In those instances, the cracking was confirmed to be axially oriented PWSCC in the pressure boundary portion of the heater sleeves, again with the caveat regarding the limitations about actually inspecting the welds. There was evidence of this type of cracking leading to the leakage.

The most significant event was in October of 2003 when Unit 2 at Palo Verde discovered circumferentially oriented PWSCC actually in the non-pressure boundary portion of five of their pressurizer heater sleeves when they were in the process of doing a proactive replacement of these penetrations with Alloy 690 half nozzles. So once again briefly jumping back to this diagram since they are a CE facility, you'd be talking about circumferentially oriented cracking just above the area of the J-groove weld. So in the non-pressure boundary portion yet, in a portion of the sleeve which is subjected to substantial residual stress --

MEMBER ROSEN: I'm beginning to believe that when somebody tells me that there's axial cracking, that all they know is that there's axial cracking now that hasn't yet become circumferential. And every time we hear about axial, pretty soon somebody says and then we found the circumferential crack.

MR. MITCHELL: And in some way -- and that is essentially a very -- that's an accurate characterization of how we have seen cracking of this nature develop if you look across a meaningful length of time. Axial cracking, then circ cracking. And there is a big reason for that, if you consider the differences in the stresses that would lead to axially oriented cracking versus circumferential --

MEMBER ROSEN: It may initiate axially,

and then begin to swing -- is it the same crack or is it a different crack? When you get a circumferential crack, if you could trace it back in time with time lapse photography, you would have originally seen an axial crack.

MR. MITCHELL: In the case of what was seen at Palo Verde Unit 2, no. Those were independent circumferential cracks. My recollection of the information we got from Palo Verde Unit 2 was there was no axial component associated with that crack. It was a circ crack.

VICE-CHAIRMAN WALLIS: All these four events in 2003, were these the first events? The first discoveries were in 2003?

MR. MITCHELL: Oh, absolutely not. Our history --

VICE-CHAIRMAN WALLIS: There's a long history before that.

MR. MITCHELL: Back into -- actually, even into the 80s there was evidence of cracking here.

VICE-CHAIRMAN WALLIS: But axial cracking.

MR. MITCHELL: That cracking we believed to have been or confirmed to have been axial. Circumferential flaws at Palo Verde Unit 2 were our first evidence of a circumferential mode of this cracking in these locations.

MEMBER ROSEN: I'm sorry I have to interrupt again, but I really need the information. Millstone 2 and Waterford 3 are CE plants both, right?

MR. MITCHELL: That is correct.

MEMBER ROSEN: And so is Palo Verde. Okay.

MR. MITCHELL: That is correct.

MEMBER ROSEN: And Tsuruga is Westinghouse. Right?

MR. MITCHELL: I believe that's correct.

MEMBER ROSEN: All right.

MEMBER POWERS: I noticed on item 2 they're replacing with Inconel 690, and 690 is chosen because it's immune to all this?

MR. MITCHELL: I would not use the word "immune". I would use that it is believed to be more resistant to this type of degradation. I don't know of anyone who would make a claim that it is de facto immune to PWSCC at some point in the future.

MEMBER POWERS: And the belief in this immunity comes from religious fervor or --

MR. MITCHELL: We've had, of course, extensive operating experience with people, for example, replacing steam generator tubes and going from Alloy 600 to 690 steam generator tubes. And the track record of those has been rather exemplary in the length of time they have been used, so we have reason to believe that this material should be, and in fact is performing in a way which demonstrates that it is more resistant to this crack.

MEMBER ROSEN: Now if you took the early experience with 690, it shows nothing, and pushed it back in time and overlaid it over the early experience of 600, would you see that it looks just the same as 600 did in the early years?

MR. MITCHELL: I don't believe you would be able to make that kind of a claim. I think, in fact, at accelerated forces testing of 690 would also support the fact that even if it had reached the same condition as 600 has reached since being in a plant from day one of operation, would not expect to have seen the same -- certainly not the same magnitude of degradation.

MEMBER ROSEN: We're not fooling ourselves, you're saying.

MR. MITCHELL: I do not believe we are. I believe we have good solid reason to believe that 690 is a much better material, but not immune.

MR. BATEMAN: Just as a point of interest, one of the things we put on the industry's plate is -- it relates to the upper vessel head. We have an order out there that dictates the inspection frequency, depending on what susceptibility category you're in. Plants that have replaced their heads and used Alloy 690 material we've said to industry you're going to stay in the same inspection regime until you can show us, provide data to us that 690 is as good as you say it is.

We had a meeting with industry earlier this week, wherein they presented some technical data on the performance of 690, and they've been unable to get it to crack, so that's pretty good stuff. I mean, the data, we're in the process of getting it up on our website. It'll take a while because I think we've got like 1,200 pages at that meeting. But there's data out there, and this stuff is very well resistant, this type of cracking at this point. And I think like Matt referred to the steam generator tubes, and there were some other data that wasn't specifically related to tubes, but other Alloy 690 material that hasn't cracked either. Peter, you may know more about this, as well.

MEMBER FORD: Yes, I just wanted to -- your question, are we fooling ourselves in taking analogy to 600. There are no materials which are immune in a thermal dynamic sense to cracking. What most people have done in the -- reactor builders, they cite a factor of improvement. They say the factor of improvement is such and such, factor of 10, factor of 2, whatever it might be to mitigation action. That means, therefore, that if you wait enough time, you will see cracking in this improved material. And we've seen it time and time again.

The question is how long will it be before you will start to see the cracking, not see the practical operating condition. It could be beyond 80 years, and forget about it. Matt is absolutely correct, Alloy 690, the leader of the fleet experience in the steam generator. That has been very good, and there's a lot of steam generators, especially in France, operating for many years. And okay, it's not the same stresses, it's not necessarily the same temperatures.

MEMBER POWERS: Yeah, they drink lots of red wine, and --

MEMBER FORD: I have tonic -- but whenever people say immune, you take it with a big pinch of salt, no numbers on it.

MEMBER ROSEN: So what is the factor of

improvement do you think?

MR. BATEMAN: Well, they did present some data on factors of improvement, and range from 13 to 26.

MEMBER SHACK: But those factors are almost calculated how long you're willing to wait in the test. You know, if you stop the test you can only say it's at least this much. You can't get it to crack.

MEMBER ROSEN: So you're saying it's at least 13, in the range of at least 13 to 26.

MR. BATEMAN: At least 13.

MEMBER POWERS: How does this compare to Alloy 800?

MR. BATEMAN: Alloy 800 is not as good in laboratory testing. It is also considerably more resistant than Alloy 600, but I don't think it's as good as Alloy 690.

MEMBER FORD: An analogy, the Germans keep saying that they have any problems. You could reasonably say that if you take the experience of, for instance, the use of 316 BWRs, you can crack 316 and you will start to see it. The Japanese didn't see cracking of their 304 for a decade after we did, because they operate different water conditions. So you've got to take all these things into account. 800, I'm convinced, is certainly not immune. That's for sure. Is it better than 690? I don't think so, so you might well say, you're going to see cracking in the German steam generators before we start seeing cracking in 690 steam generators.

VICE-CHAIRMAN WALLIS: Are these magic numbers just brand names, like Boeing 747s, or do they indicate the proportion of something in this material?

MEMBER SHACK: These are generic. Ancillary 800 is the proprietary brand, Alloy is generic.

VICE-CHAIRMAN WALLIS: 800 has nothing to do with --

MEMBER FORD: We just associate it with ASME.

VICE-CHAIRMAN WALLIS: So we don't know what's going on when you change these numbers.

MEMBER SHACK: Oh, no. It's Chromium content. Alloy 800 is a high class stainless steel, 690 is --

CHAIRMAN BONACA: Let's move on with the presentation.

VICE-CHAIRMAN WALLIS: So there is some --

MEMBER SHACK: Oh, yes. There's a very

definite composition.

MEMBER FORD: Okay, guys. We're jumping in on your, Matt.

MEMBER SIEBER: Yes, why don't we talk about the bulletin?

MEMBER POWERS: Why? We could read the bulletin.

MR. MITCHELL: And I'll try to expedite the rest of this presentation to get you back on schedule as best I can. Just note on the third bullet down, also of interest was the Tsuruga Unit 2 experiments in Japan, which showed evidence of cracking of this same type, axially oriented PWSCC in the nozzle-to-safe end butt welds in lines in the unit's steam space. So now we're talking at the top of the pressurizer.

MEMBER SHACK: But then this looks like a V.C. Summer weld, so it's an axial weld crack?

MR. MITCHELL: Yes, that would be correct.

MEMBER SIEBER: This would be like spray line.

MR. MITCHELL: Spray line.

MEMBER SIEBER: Safety valve line.

MR. MITCHELL: Relief valves, yes. But again, what caught the staff's attention most forthrightly was the circumferential cracking evidence at Palo Verde Unit 2, based upon which the staff engaged the Westinghouse Owner's Group who now has ownership of the CE design facilities, as well, and asked them to provide an operability assessment to justify continued operation over the near term for those in light of that new cracking experience, as well as a long-term inspection program for addressing what inspections would need to be done to ensure that integrity is being maintained at these locations.

And I'll note on slide 7 that, in fact, the operability assessment was submitted in December of 2003. The staff is still in the process of reviewing that particular assessment. We did issue a request for additional information to the Owner's Group, I believe it was back in January when that went out, and we're still waiting for a response to clarify some of the details regarding their analysis and their assessment.

MEMBER ROSEN: How long is your patience on this going to extend? I mean, it's now what, four months?

MR. MITCHELL: Probably more like two to three months.

MEMBER ROSEN: Since the discovery of the cracking. Now you've issued RAIs and are waiting for responses. You seem to be laid back on this subject.

MR. MITCHELL: I think that the fact that we are issuing or we are in the process of just debating a proposed bulletin is the first step in noting that we are -- our patience is running thin regarding getting some actual physical action taken to put inspections in place which should address this.

The JCO or the operability assessment is, if you will, an engineering paper exercise to give you a warm feeling regarding the current condition of these penetrations.

I think based upon our observations on what we did receive even in December, we feel that there is a good reason to believe that obviously these plants remain safe to operate, and we have reasonable expectation that we will see leakage before any type of wholesale failure would be expected. So I guess what I should convey to the Committee is, we are asking about details of the analysis; however, the bottom line of the analysis provided by CE Owner's Group, that the continued operation is justified at this time is not in question.

MEMBER ROSEN: But you've got two windows when inspections are typically done, the fall and the spring.

MR. MITCHELL: Yes.

MEMBER ROSEN: We've missed the spring window, basically, with regulatory action, so are you going to make the fall window?

MR. MITCHELL: Certainly the intent of the plan that the staff has internally is to get th bulletin, if and when it is issued, out in such a time frame that we can get information back from the licensees prior to the fall outages. So we are looking at a time step such that we have a chance to look and evaluate that information before the fall outages start. So yes, we are trying --

MEMBER ROSEN: So you'll get information back before the fall outages, but then you'd have to get an order out, or some sort of requirement to do the inspections if you believe they're required, or to do something. All you're doing is collecting information. You are not requiring any additional inspection.

MR. BATEMAN: It's an information request. And then parallel with this, I think we were having a little discussion before the meeting got started on an April 2nd memo that was issued by the MRP, requesting that licensees inspect all dissimilar metal welds in the reactor coolant system, which would include those on the pressurizer, some time during the next two outages. So we'll probably get some additional data this spring outage season just from that request alone.

MR. MITCHELL: Let me also say that although we haven't taken formal regulatory action with respect, obviously, to the spring outages, we have been having phone calls, teleconferences with each licensee who is entering a spring outage to get an idea of how they would respond in terms of what inspections they will be doing this spring on these same penetrations. And uniformly, the responses I've been getting from them is that they are doing 100 percent bare metal visual exams. We have been, at least, getting that amount of information from the spring outage facilities.

MEMBER POWERS: Would you explain to me a little more about this bare metal visual? When I look at metals that Dr. Shack cracks in his laboratory, he has to show me the crack because I can never find it. Are you looking for cracks, or are you looking for leakage?

MR. MITCHELL: You're looking for deposits.

MEMBER POWERS: Deposits.

MR. MITCHELL: You're looking for the Boron deposits.

MEMBER POWERS: And why is that satisfactory? Because, I mean, obviously the leak is through the wall at this point. Don't you want to catch it before it gets that far?

MR. MITCHELL: Again, because it -- ideally, yes. Yes, one would like to find cracks before they would penetrate the reactor coolant pressure barrier. We have had, however, good experience now since the late 80s with licensees being able to locate these cracks, repair the damage, fix the penetration that shows evidence of leakage before we have any other consequential effects, like Boric Acid corrosion at the pressurizer shell, et cetera.

MEMBER SHACK: With one significant exception.

MR. MITCHELL: Well, yes, I was not -- didn't want to include that particular part in the discussion.

MEMBER SIEBER: Well, tell us about it.

MEMBER POWERS: Well, it seems to me that that's true if everything you saw was axial in nature.

MR. MITCHELL: Yes.

MEMBER POWERS: But now you've seen these circumferential --

MR. MITCHELL: Well, we have seen circumferential cracks, but the evidence at Palo Verde is that has been in non-pressure boundary portion, so that would not - did not lead to any type of leakage. That was entirely internal to the pressure boundary.

MEMBER POWERS: So that was all driven just by residual stress?

MR. MITCHELL: Correct.

MEMBER FORD: Matt, maybe it would be an idea if you put up the diagram, because this topic came up for a lot of discussion, Dana, the adequacy of bare metal visual. Maybe you could point out where the --

MEMBER ROSEN: Where the non-pressure boundary, what do you mean?

MR. MITCHELL: Well, going back to this diagram, if you see the dashed line that I've superimposed upon this diagram, anything above that dashed line would be non-pressure boundary. So essentially, it's the extension of the heater sleeve up inside the pressurizer. Going down from that dashed line, if you have cracks in that region, you would consider those to be pressure boundary flaws, because those would eventually breach the pressure boundary and lead to leakage.

And the experience that we've had to date regarding cracks in the pressure boundary has been when people have done inspections, that those have been axially oriented. And that is, in part - that experience is what leads us to believe that we can continue to accept as a first inspection the use of bare metal visual exams looking for evidence of leakage.

MEMBER POWERS: I mean, you confused me a little bit. You see circumferential cracks and you said oh, my God, I've got to get a bulletin out. Now you tell me well yeah, but they didn't really count.

MR. MITCHELL: Well, going back to Dr. Rosen's observation that we have seen a consistent development trend in cracking of this nature, from axially oriented in an earlier time period, to circumferentially oriented. We are trying to get ahead of the game, believing that at some point we may face circumferentially oriented cracking within the pressure boundary, which is why a part of the bulletin, a significant part of the proposed bulletin is we want licensees to acknowledge a need to go in and characterize any penetration in which they see evidence of leakage. We want to be able to find the first onset of circumferential cracking in the pressure boundary when it leads to evidence of leakage as soon as possible.

MEMBER POWERS: Okay. So there is some theorem of metallurgy that we get circumferential cracking only after we have seen Boric Acid on the outside.

MR. MITCHELL: No. But we have -- the analyses to-date has suggested that as far as circumferential cracking would go, if you postulated circumferential cracking to occur in the pressure boundary portion of, in particular, these heater sleeves.

MR. BATEMAN: And we've never seen this.

MR. MITCHELL: Which we have never seen, you would expect it to drive itself through a wall, and show evidence of leakage prior to, in any way, approaching a size such that it could lead to wholesale gross rupture of the --

MEMBER ROSEN: When you show evidence of leakage, if you're leaking water, primary water, but what about in the steam space? What if you crack in the steam space? Do you get enough Boric Acid in the steam?

MR. MITCHELL: Actually, the cracks at Tsuruga were initially identified, the Japanese plant which had cracking of the steam space vent line, were originally identified due to the fact that they identified deposits in those locations. So with that experience, I would think --

MEMBER ROSEN: So that what they call it, sometimes a decontamination factor or separation factor during the boiling is not large enough to make leakage that occurs through a steam space crack to result in just water that doesn't -- leaves enough of a deposit anyway, is what you're saying, at least from the Tsuruga experience.

MR. MITCHELL: That would be my understanding. Yes.

MEMBER ROSEN: I'd like to understand the chemistry. I mean, is there someone who knows the chemistry well enough who can talk about separation of Boric Acid between liquid and steam?

MEMBER POWERS: I believe on a time scale of every four years this question comes up.

MEMBER ROSEN: Oh, does it.

MEMBER KRESS: If the boiling takes place at high pressure, you will leave a good fraction of the Boric Acid with the liquid, and the steam won't carry much out. If it takes place at low pressure, just stops and occurs, you carry a lot of it out, and you can with the steam. So you can take that to see what you can do with it.

MEMBER ROSEN: So what is the boiling occurring here, at high pressure or low pressure?

VICE-CHAIRMAN WALLIS: High pressure.

MEMBER ROSEN: High pressure.

MEMBER KRESS: It has to do with the solubility and the partitioning between the gas phase and the liquid phase, as well as the ability of the steam to carry that stuff out as it's partitioned. A lot of it is governed by the fact that you're not carrying much steam volume out at high pressure.

MEMBER ROSEN: I think what Dr. Kress has said is that you're not going to see much. I mean, most of it because it's boiling at high pressure here in the pressurizer, most of it --

MEMBER KRESS: It leaves it behind in the water.

MEMBER ROSEN: It leaves it behind in the water, so it may have been fortuitous that you saw it in Tsuruga, or there was a lot of leakage before you got -- you're not going to get it early is what this says.

MEMBER SIEBER: The steam in the pressurizer does have a quality factor. I mean, it's not dry.

MEMBER KRESS: Well, that's another content. Yes, now my analysis did not include that. And if you get any liquid carried out with it, it's going to carry it content of Boric Acid.

MEMBER ROSEN: See, all of these are very erudite people around me, leave me with a question as to whether how good a tell-tale steam space leakage is for Boric Acid. I'm not --

MEMBER SIEBER: It takes more leakage.

MEMBER ROSEN: Anyway --

MEMBER SIEBER: For a given size of the deposit.

MR. MITCHELL: We will carry that back as a comment.

MEMBER ROSEN: Something to think about.

MEMBER POWERS: Let me go back one step. It's repetitious, I know, but I'm slow. You showed on a previous slide a number of instances of circumferential cracking that was not in the pressure boundary. Did you also find in those same locations lots of axial cracking?

MR. MITCHELL: In those particular things at Palo Verde, the ones that showed evidence of circumferential cracking, my recollection is that there was not axial cracking in the same penetration.

MEMBER POWERS: So the Rosen evolution seems not to be true.

MEMBER KRESS: Under some conditions.

MR. MITCHELL: I don't -- and when I was --

MEMBER POWERS: I have learned that that's the case here.

MEMBER ROSEN: Oh, it's only a matter of time until I'm proved correct.

MR. MITCHELL: If you're talking about a physical connection between axial cracking in a particular tube, heater sleeve, then turning circumferential - yes, that is not substantiated. What I was trying -- the evolution point that I was trying to make was that if you look at the cross experience of the fleet, you see axial cracking showing up throughout the fleet first before you begin to get evidence of circumferential cracking.

MEMBER POWERS: But the question is, is it a case that in a given plant, in given circumstances, in a given location that you will see axial cracking first, and then circumferential cracking, or do the two seem to be disjoined distributions?

MR. MITCHELL: I can't point to concrete evidence which would support saying that you would always get axial cracking in a given plant, at a given location prior to getting circumferential cracking. I can only speak to it in terms of the general evolutionary trend across the fleet.

MEMBER POWERS: So you're looking at an ensemble average instead of a time average. I understand what you're doing. I don't know whether to be more concerned or less concerned.

MEMBER KRESS: I draw some comfort from his comment that they've made analysis that show if you do have a circumferential crack that it in itself will leak before it reaches a stage where it goes to a small break LOCA. I find some comfort in that. I'd like to see that analysis, but --

MEMBER SHACK: If you look at what's happening here, I mean the reason you're getting residual stresses is you're heating this stuff up. It's expanding, plastically deforming and then cooling down. And you're in a constrained situation where you're expanding about as much this way as you are this way, and you're about as constrained in one direction or another, so what you typically find here is that the difference in residual stresses isn't all that dramatic. You've got high stresses axially and high stresses circumferentially --

MEMBER KRESS: So it doesn't carry a circumferential reaction.

MEMBER SHACK: Well, you get either one. Now it may be they're a little higher axially, so you'll get a predominance of axial cracks. But in the statistical sort of thing here, you've got a high stress in both directions, and it's very unlikely that you're immune to circumferential cracking. You just may have a slight -- you may have a propensity to go axial, but depending on what the welder did and just how everything worked out --

MEMBER ROSEN: Is this a bipolar situation, Bill? Either you go axially or circumferentially? Can you go 45?

MEMBER SHACK: No, you can go 45.

MEMBER ROSEN: Okay. Now see.

MEMBER KRESS: But how do you feel about the concept of an axial crack, I mean a circumferential crack will leak before it's near breaking? That's a pretty solid --

MEMBER SHACK: These are -- Matt also showed that these are wonderfully unaxi symmetric situations again. The nozzle you probably worry about most is th one right down at the bottom, but this guy's got this –– and if you look at this, you'll find out there's a significant azimuthal variation of stresses around there, so you're going to grow through somewhere, get some growth.

But the other point I would make is that without doing a detailed stress analysis, I would suspect I have high stresses above that weld, and high stresses below that weld. Whether one is slightly higher than the other, without an abacus analysis I'm not going to venture to say. But they're all going to be high, so the fact that it cracked above the weld doesn't give you a great deal of comfort.

MR. MITCHELL: It would be fair to say, and just reflecting again on the analysis that has been provided by the industry, although again, we do have questions on the docket regarding their analysis - their results were indicating that the stresses above the weld were slightly higher than perhaps 25 percent or so, than the stresses below the weld.

MEMBER FORD: So in terms of just looking at the risk associated with this idea that we're going to use the appearance of Boric Acid at the bottom of that annulus, has been the telltale, before you start to go into a detailed volumetric analysis. It depends on a crack initiating on the inside of the tube situs to the J-weld. That's correct? I'm propagating circumferentially but not uniformly around the circumference. It will go through at one point because of the azimuthal variation in residual stress. Is that right?

MR. MITCHELL: I believe that characterization is correct, yes.

MEMBER FORD: And so to back up that, you're relying almost entirely on Bill's observations, which are correct, that the azimuthal and asymmetric weld, the azimuthal variation of residual stress would be up and down.

MR. MITCHELL: Yes.

MEMBER FORD: Okay.

MEMBER KRESS: Now if you get a circumferential crack that starts to leak but it's early in the time between refueling outages, you didn't see it before, I mean during the refueling outages, but it happened a short time thereafter, you've got two years of leaking without knowing about it, because you don't go visually inspect it until the next refueling outage. Is that enough time for this circumferential crack to grow and become near the point of creating a small break LOCA, or not?

MR. MITCHELL: Based again upon the analysis that the licensees provided, the Westinghouse Owner's Group provided in their operability assessment, the answer to that would be no. They showed significantly more time would be required, particularly given the fact that you would eventually have to grow the crack into a much less tensile stress field. And, in fact, you may expect to get compressive stress fields at some point around the circumference, would inhibit the ability of that crack to grow and be very large in the circumferential direction within a two-year time span.

MEMBER ROSEN: I know our Chairman wants to move ahead, but tell me what would happen if it did go circumferentially? Would that sleeve eject?

MR. MITCHELL: If you got a large enough circumferential flaw --

MEMBER ROSEN: Completely severed, what happens?

MR. MITCHELL: It would eject.

MEMBER ROSEN: Why?

MR. MITCHELL: If it were below the weld?

MEMBER ROSEN: Yes. Why? What drives it out?

MEMBER SHACK: 2,000 psi.

MEMBER ROSEN: Well, I don't know. It's not acting on the --

MEMBER POWERS: It's a cross-section layer of the tube.

MEMBER ROSEN: A cross-section area of the tube -- yes.

MEMBER KRESS: That's a big pressure. That's a big force.

MR. BATEMAN: That whole area of the tube that goes down beneath the pressurizer continues on down until where you have the heater element itself welded in. There's another pressure boundary at the bottom of the sleeve which is where you weld the computer element.

MEMBER ROSEN: So that -- it tries to be forced out, but doesn't it butt up against something?

MR. BATEMAN: At the bottom?

MEMBER ROSEN: Yes, where does it go?

MR. MITCHELL: I don't believe there's any structure that you could justifiably would say would prevent that component from being ejected. There's nothing that you would be able to give credit for.

MEMBER ROSEN: It's just wires, or cable, or something like that?

MEMBER POWERS: Well, I mean if this is to scale, and I think it's roughly to scale here, that device would simply buckle if it ran up against anything.

VICE-CHAIRMAN WALLIS: It would spear the surge line.

MEMBER SHACK: But I've got 3,000 pounds pushing it out.

CHAIRMAN BONACA: Just a question I have, do you think that this operating experience has been factored in in the 50.46 elicitation process? I mean, if this is new information, do you think they considered this?

MR. MITCHELL: I cannot speak directly to that, although I have been in part, at least in the early phases of the 50.46 Option 3 work, I've been in communication with the folks who are working on that. A substantial amount of the information regarding, obviously, the potential for primary water stress corrosion cracking was considered by the expert elicitation panel. I can't tell you whether the specific experience with the non-pressure boundary circumferential cracking in the heater sleeve of Palo Verde Unit 2 was brought to the attention of the expert panel in sufficient time for that to figure into their evaluation.

CHAIRMAN BONACA: That was my question, in fact.

MR. MITCHELL: Okay. Very quickly, just to move to the bottom bullet. Certainly, the Owner's Group provided a final proposal on January 30th with respect to an adequate inspection program, and this was, again, offered up in the context of the inspection of CE pressurizer heater sleeves, because that was the dialogue we were having with them at the time regarding 100 percent bare metal visual inspection of heater sleeves every refueling outage, follow-up NDE to characterize flaw orientation during the refueling outage when leakage was observed, so immediate follow-up characterization. And then potential expansion of the NDE to other non-leaking sleeves if circumferentially oriented cracking was observed in the pressure boundary of the leaking heater sleeve.

I should note that we had some subsequent telephone conversations with the industry in which they made it clear that they were not intending to preclude the possibility of licensees taking action to expand their inspection sample if they found circumferential cracking in the non-pressure boundary portion.

So based upon that exchange, the staff took this issue to NRR's executive team, and we were directed to develop a proposed bulletin which would be broader in scope than simply the CE pressurizer heater sleeves, but would, in fact, address all of the Alloy 82/182/600 materials exposed to the pressurizer environment.

So as addressed in the proposed bulletin, an acceptable degradation management program to the staff would include bare metal visual examinations of all 82/182/600 pressurizer penetrations and connections every refueling outage. And then immediate NDE to characterize any evidence of leakage. And then if circumferential cracking is found, either within the pressure boundary or within the non-pressure boundary portion of the penetrations or connections, additional discussion between the licensee and the staff to determine what the appropriate scope expansion would be to determine the extent of condition of their pressurizer. So we've essentially generalized the proposal that was provided by the Westinghouse Owner's Group in their January 30th letter.

Our slide 9, the proposed bulletin

requests generally, the details you'll find actually in the text of the bulletin, a description of pressurizer penetrations and connections, sort of a layout of where particular licensees have this material. A description of the inspection program that has been implemented by the licensee in the past, their plans for future inspections at their upcoming and in future refueling outages. Then an explanation of why their planned inspection program is, in their evaluation, adequate for the purpose of maintaining the integrity of the facility's reactor coolant pressure boundary and meeting all applicable regulatory requirements. And then finally in item 2, after the performance of the inspection, a report of what their results were. So it's a plan and then a response after performing the inspection.

MEMBER ROSEN: Which would apply to the next inspection in the fall.

MR. MITCHELL: That is correct. Or whatever that licensees next inspection might be. It could be spring of 2005.

MEMBER ROSEN: Right. And all to be issued by -- when do you think you'll get this out, so when does the clock -- when does it start?

MR. MITCHELL: Again, I don't want to try to put a specific date on it since that might be interpreted as being somewhat predecisional. Again, the staff is -- I can say is working to get this out soon, such that we have ample opportunity to look at the information before the fall outage.

MEMBER ROSEN: That's what you said earlier in response to a similar question.

MR. MITCHELL: I try to remain somewhat consistent.

MEMBER ROSEN: At least with yourself.

MR. MITCHELL: Yes. So then with regard to conclusions, obviously, the high operating temperatures in the vicinity of the pressurizer should make these locations highly susceptible to primary water stress corrosion cracking since it is a temperate, in part, driven phenomena.

Adequate inspections for the purposes of identifying deposits resulting in flaws may include performing bare metal visual examinations. Adequate inspections are necessary to promptly identify and correct failures to the reactor coolant pressure boundary, to ensure that facilities continue to operate within their technical specifications, which by and large are uniform and do not permit operation with reactor coolant pressure boundary leakage.

And again, the staff requests this information so that we may make a determination whether any additional regulatory action would be required.

MEMBER FORD: You mentioned at the very beginning, Matt, that you were thinking about another sort of communication relating to surge lines and other large diameter lines. Is that on the books, or what's the plans?

MR. MITCHELL: I think what I said was we are considering what options might need to be taken. And that's the phase we are at this point, in terms of --

MEMBER FORD: What would trigger you to do that?

MR. MITCHELL: I'm certain part of what we will figure in are interactions we continue to have with the industry with respect to their ongoing development of a revision to the MRP 44 Part 1 report, a topic which we should be having discussions on in fact today with the materials and reliability program or project. But it would be fair to say that there is concern amongst the staff regarding the condition and the current inspections which have been performed on piping butt welds. And that there is an interest in having a regulatory footprint to provide assurance that the staff is engaged in making sure that issue comes to a prompt resolution with regard to susceptibility of those bimetallic welds to the primary water stress corrosion cracking.

MEMBER FORD: And would you estimate the conditional core damage frequency for a failure of one of these other large diameters lines would be about the same, 10 to the minus 4, 10 to the minus 3?

MR. MITCHELL: That answer would be dependent on a number of factors, including whether or not that particular line perhaps was granted leak before break approval in the past, which would have permitted a licensee to remove pipeway restraints, jut impingement shields, which would have been normally installed to mitigate dynamic effects of a rupture. That could significantly change the risk associated with a break of any particular postulate -- I don't think there's a single answer to your question.

MEMBER SHACK: But you are going to have to have a residual about leak before break for these sorts of things, because the current situation essentially is not consistent with the assumptions that you made when you granted leak before break. I mean, you sort of skated that one on the summer license renewal because they had actually done some missive to improve the situation. They're probably the only people that have actually done anything. Right?

MR. MITCHELL: We certainly recognize those inconsistencies between the basis upon which leak before break approvals were previously granted to these lines which contain dissimilar metal welds, and our current state of knowledge about the potential susceptibility of those welds to primary water stress corrosion cracking. I believe that was publicly acknowledged in a recent response that the staff sent to NEI regarding issues surrounding GSI-191. And the spectrum of breaks to be postulated for sump strainer sizing and the proposal that leak before break might be extended to address that particular topic, and the staff declined to take that action, in part because of this recognized disconnect that's developed regarding PWSCC and the --

MEMBER SHACK: Well, there's roughly a third of the fleet that doesn't have the 182 weld. Right? Something like that, PWRs.

MR. MITCHELL: Roughly a third.

MEMBER SHACK: I'm trying to remember in my head - there are some PWRs that have the 182 butter, and there are PWRs that don't. I think about two-thirds do and one-third don't.

MR. MITCHELL: It certainly depends upon the design. The majority of the BNW and CE design facilities, obviously, if you're talking about the main coolant loops, because those are --

MEMBER SHACK: No, I was thinking Westinghouse plants.

MR. MITCHELL: Oh, you're talking Westinghouse plants. I don't remember the numbers. We have received some feedback from the industry in the draft MRP 44 Part 1 --

MEMBER SHACK: That's where this is coming -- that's my memory of what's in the draft MRP 44.

MR. MITCHELL: You may be correct. It may be one-third/two-thirds, but I can't substantiate that off the top of my head.

MEMBER ROSEN: Now unless you get a leak, somebody does the inspections that you're asking for and a leak is found, then you'll get some NDE, which will characterize that sleeve, I assume, in some detail, so you'll know whether that was the only crack that leaked, or whether there were dozens and dozens of cracks and that was just the first one. Unless you get such a leak, you'll not know anything about it.

That's a situation I find a little uncomfortable. First off, I don't think -- it probably won't happen. I mean, we'll probably find some leakage, some places where there's some leakage, you'll get some NDE information. But if that didn't happen, then I'm left with not knowing the condition of these sleeves. All I know is that nobody found any leaks. That's good, but the question is, are these sleeves out there with near leaks all over the place?

And it seems to me you would want to go in and take a small sample of the ones that aren't leaking, and just do some NDE just to say yes, they're not leaking and there's no evidence of any crack. Or they are not leaking, but my gosh, there's dozens and dozens of small cracks in these things. You'd want t know which situation you're in.

MR. MITCHELL: And I think we can sympathize certainly with that type of a desire. The thing the staff has had to consider, particularly with regard to doing any types of inspections to these heater sleeves for the CE design facilities is, you could only call this a non-destructive examination in the most broad sense of the word, because you actually have to cut the pressure boundary lower on that sleeve to take the sleeve out to get access to do that inspection in the first place. And I think we have concerns regarding radiation exposure, the potential for actually making the situation worse by having someone have to cut the pressure boundary and then reweld it lower down in order to put the heater sleeves back in place. It's not -- this is not a readily accessible location to do these inspections; hence, we have at least -- until we have further evidence that circumferential cracking of the pressure boundary is a real phenomena which is beginning to manifest itself, we are relying at this time on 100 percent bare metal visuals, and our analytical knowledge regarding the low likelihood of a circumferential flaw in the pressure boundary leading to a complete sever. I do certainly sympathize with the thought, but there are some practical considerations that are very real.

MEMBER ROSEN: Yes. I'm not talking about a broad scale thing. I'm just talking about a one time or several time verification that sleeves that are not showing any leakage are, in fact, not cracking, just as a -- it's not academic. Anyway, I've said my peace.

MEMBER SHACK: This is a statistical sort of thing. I mean, you would expect a relatively small fraction of these things to be cracked. And, therefore, your odds of picking the right one to look at, you know, unless you're going to look at a reasonable number, I'm not sure that you could take a whole lot of confidence, and I have to sort of sift through and figure out a sample size, but looking at a couple wouldn't buy you much comfort.

MR. BATEMAN: Yes. We actually got into a discussion when we were talking about the upper vessel head, and our statistician at the NRC said you don't gain any confidence from inspecting any less than the full amount when you're talking about these small quantities.

MEMBER FORD: Just for the benefit of those members who were not at the subcommittee meeting, this presentation being given by Bill and Matt was for information purposes. They were not requiring us to write a letter on this. Many of these topics will come up again in our June the 1st subcommittee meeting, which is the wider issue of the whole question of PWSCC. If there aren't any more questions from the group - anybody else? I hand it back to you, John. Thank you very much indeed, Bill and Matt.

CHAIRMAN BONACA: Thank you.

MEMBER POWERS: I want to just interject, I appreciate very much the forbearance of the speaker and the clarity and care of this --

MR. MITCHELL: My pleasure.

CHAIRMAN BONACA: Thank you.

MR. MITCHELL: Thank you.

CHAIRMAN BONACA: With that, we have some time before noon time, and the first thing I'd like to do is to do the conciliation of the ACRS comments. We'll go off the record now.

(Whereupon, the proceedings in the above-entitled matter went off the record at 11:34 a.m.)