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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

COMBINED THERMAL-HYDRAULIC PHENOMENA/

FUTURE PLANT DESIGN: SUBCOMMITTEE MEETING

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WEDNESDAY

FEBRUARY 13, 2002

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, T2B3, 11565 Rockville Pike, at 8:3 a.m., Graham B. Wallis, Chairman, presiding.

COMMITTEE MEMBERS:

GRAHAM B. WALLIS, Chairman

THOMAS S. KRESS, Member

DANA A. POWERS, Member

VIRGIL SCHROCK, Consultant

WILLIAM J. SHACK, Member

JOHN D. SIEBER, Member

STAFF PRESENT:

PAUL A. BOEHNERT

MAGGALEAN W. WESTON

ALSO PRESENT:

PAUL DAIBER

RICK LANE

MILTON HUFF

RICH SWANSON

DENNIS BOYD

MEHRAN GOLBABAI

ROGER WILSON

DOYLE ADAMS

DALE JAMES

DAN SPOND

KARL HASLINGER

JAMIE GOBELL

JOE CLEARY

DAN FOUTS

TAD MARSH

CHU LIANG

TOM ALEXION

DAVE CULLISON

RICH O'DELL

KAMAL MANOLY

BARRY ELLIOT

<u>ALSO PRESENT</u>: (CONT.)

MICHELLE HART
MARK CARUSSO
DANNY HARRISON
MARK RUBIN
STU RICHARDS
KEN KARWOSKY
TONY ATTARD
FRANK ASTELUWICZ
SHI LANG WU
CHRIS BARCHEVSKY
ALAN HIZER
JOE WILLIAMS
DALE SPENCER
BOB KERESTES
JERRY BLANTNER
HAROLD CROCKET
SAM RANGANATH
KEITH MOSER
FRAN BOLGER
KENT SCOTT
TIM BYAM
JASON POST
ERIC SCHWEITZER
DAN PAPPONE

I-N-D-E-X

I-N-D-E-X

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

(8:33 a.m.)

CHAIRMAN WALLIS: The meeting will now come to order. This is a meeting of the ACRS Combined Subcommittee on Thermal Hydraulic Phenomena and Future Plant Designs. I'm Graham Wallis, the Chairman of the Subcommittee on Thermal Hydraulic Phenomena, and Tom Kress the Chairman of the Future Plant Design Subcommittee will chair the meeting session beginning at 1:00 on February 14, 2002.

Other ACRS members in attendance are Dana Powers, Bill Shack and Jack Sieber. The ACRS consultant in attendance is Virgil Shrock. The combined subcommittee will first begin review of the license amendment requests of Entergy Operations, Incorporated for a core power uprate fo the Arkansas Nuclear One, Unit 2 Plant, and secondly we will begin review of the license amendment request of the Amer-Gen Energy Company for a core power uprate for the Clinton Nuclear Power Plant, Unit 1. And thirdly, we will continue review of the Phase 2 pre-application review of the Westinghouse Electric Company's AP1000 plant design.

The subcommittees will gather information, analyze relevant issues and facts and formulate

proposed positions and actions as appropriate for the liberation by the full committee. Mr. Paul Boehnert is the cognizant ACRS staff engineer for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting, previously published in the Federal Register on January 29, 2002. Portions of the meeting may be closed to the public, as necessary, to discuss information considered proprietary to General Electric Nuclear Energy and the Westinghouse Electric Company.

A transcript of this meeting is being kept and the open portions of this transcript will be made available as stated in the Federal Register notice. It is requested the speakers first identify themselves and speak with specific clarity and volume so that they can be readily heard. We have received no written comments, nor request for time to make oral statements from members of the public.

Now this should be a very interesting three days. We have two different power uprates for different kinds of reactors, and then we have a review of the AP1000, which some might claim is in some way resembling a 70 percent uprate from the AP600. So we have three different power uprates to discuss, and it should be a very interesting time.

I'd like to begin this meeting, and I call upon Rick Lane?

MR. LANE: Yes.

CHAIRMAN WALLIS: Of Entergy Operations to begin.

MR. LANE: Good morning. My name is Rick Lane. I'm the Director of Engineering Projects for Entergy, and we appreciate the opportunity today to come and visit with you about our plant power uprate of Arkansas Nuclear One, Unit 2.

First of all, I'd like to introduce our presenters. First we have Milton Huff. Milt recognize yourself. He's with our designers group. Brian Daiber, safety and analysis, Rich Swanson, with operations, Dale James over here with the engineering programs components, and Jamie GoBell, design engineering also. We also have, as noted here, some other support staff with us today from Entergy and with Westinghouse.

Next, I'd like to talk about our primary goals in performing this uprate, and first and foremost was safety. We wanted to make sure we safely uprate the unit, doing the appropriate analysis, and modifying the plant as required to achieve the 7.5 percent uprate. We want to make sure we maintain

adequate operating and design margins as we did that. We want to use accepted and proven methologies to achieve that.

And also, one other strategy we have, a major goal was to have one cycle of operation on any major modifications that were going to be necessary to accommodate this, and we'll talk about that further. We've already made some substantial modifications in our previous outages to accommodate this and to allow us to build with an uprate at the higher percentage.

As far as the project team, our Entergy staff really was the AE on this effort. We performed the necessary system evaluations and modifications to accommodate the uprate. We did utilize some contractor staff to augment our people, but we were always in the lead and had the oversight of that activity as the AE for the effort.

In addition to that, we had Westinghouse involved with us, formerly Combustion Engineering, who was the original SSS vendor for the ANO Unit 2 to perform the associated SSS related analysis for our safe analysis, structure analysis and so forth, to support us in this effort. And, as indicated here, it's a very substantial effort, a lot of man hours over a few years here have been spent in planning and

to help us to be ready to execute this effort.

From the overview spent at standpoint again, as I mentioned earlier, it's a 7.5 percent uprate. We have also, and as is true in our 14 outages mentioned here, have made some substantial changes, one of those of which was replacing the steam generators, and that was key in our overall effort as far as determining what kind of a size power uprate. We factored that into the design and the implementation of that replacement effort that was achieved at the last refueling outage for ANO Unit 2.

We also, as part of that, re-rated the containment for higher design pressure, and we'll talk more about that today as far as exactly what was involved there and what pressures and so forth we uprated to. And in the overall implementation schudule -

CHAIRMAN WALLIS: Excuse me.

MR. LANE: I'm sorry.

CHAIRMAN WALLIS: When you replaced the steam generators, you still have the same amount of surface, or did you change?

MR. LANE: No.

CHAIRMAN WALLIS: You changed the surface?

MR. LANE: We changed the surface area and

we'll talk -

CHAIRMAN WALLIS: Are you close to the maximum surface you can get in there now?

MR. LANE: That was one of the limitations. We'll talk about that. We have increased the diameter of the generator, increased the surface area, and we'll talk more about that. So we pretty well maxed out as far as what we felt we could reasonable accommodate for the configuration within the containment building.

And again, our overall implementation schedule is for our 2R15 outage which is coming up this spring, is to come up out of that outage and go through a rigorous test effort and go into an uprating condition. That's our current schedule.

As far as the reactor design rating, the original core design rating is 2815 Mwt. The Post 2R15 uprate again is 7.5 percent is at 3026. This is our first request for a design re-rate for this unit.

MEMBER POWERS: Does that imply that we can expect more requests in the future?

MR. LANE: One of the things that we have not, that we are going to be looking at is Appendix K type of uprate potentially to take advantage of the margins there and we will look at that and post the

rerate here to see if the appropriate margins that are there possibly for an Appendix K uprate.

MEMBER POWERS: Are you speaking of an instrumentation?

MR. LANE: Instrumentation. As far as uncertainty, the two percent -

MEMBER POWERS: Relatively.

MR. LANE: We're talking about maybe a percent and a half, something like that would be a potential uprate that might, we might look at that.

MEMBER POWERS: You are not discussing going to a more realistic analysis for Appendix K then?

MR. LANE: No. We're talking about just taking the instrument of uncertainty that's available there is all we'd be talking about.

Next slide please. Our submittal that we provided here we feel was in accordance with the guidelines out there available, the Westinghouse WCAP topical, the guidance in the GE topical, also the SECY document 97-042, and also we utilized the Farley uprate submittal, as again guidance for us to make sure we were being consistent with what the expectations were, as far as our submittal.

CHAIRMAN WALLIS: That Westinghouse topical

is quite old, isn't it?

MR. DAIBER: 1983.

MR. LANE: Yes, 1983. We tried to use the companion data out there to help us make sure we were providing the required information to address the appropriate requirements.

MEMBER POWERS: I guess I'm a little perplexed on how a Westinghouse topical is helpful for a combustion engineering plant.

MR. LANE: One aspect of that is to recognize that Westinghouse was the provider of the replacement steam generators, and that was part of our effort. But as far as the topical applicability -

MR. BOYD: This is Dennis Boyd. I work in the licensing department. Back when we were formulating our plans for uprating in power, we tried to find, assimilate all the guidance that was out there, in order to make sure we got the right kind of information to the staff for review.

What we found was there wasn't a lot out there for PWRs, so we use this 1983 document, which like you say, it's a Westinghouse document, but it is for PWR. We also gathered as much as we could out of the GE topical, and then we looked at the 1997 SECY document and those three things, other than the

uprates that were already out there, was all that we could put our hands on at the time.

MEMBER POWERS: So what you're going to tell me is that you're going to take this plant up to, what is it, 3065 MWt, and there is absolutely no date, not one data point in the world on this type of plant operating at that level, right?

MR. BOYD: Bryan, do you want to.

MR. DAIBER: This is Bryan Daiber from Entergy. The ANO 2 plant is a CPC plant. It's a CE designed plant and it's similar, although a smaller version of the System 80 plants, the Songs (phonetic) Plant, the Waterford Plant, and the Paliverde Plants, all of which have higher rating than what we're planning to go to with the ANO 2 unit.

So there are comparable or similar CE designed plants out there already at higher power ratings and they are higher rated than where the ANO 2 is going.

MEMBER POWERS: Your statement is similar to hear. It is a general one. I mean, it's not specific to the things that I would use, like Wendell's numbers and whatnot are exactly the same in the two.

MR. DAIBER: With respect to the rapid

protection system design considerations, the fuel design considerations, the geometry, the layout, they're all CE designs using a comparable rapid protection system and design considerations.

CHAIRMAN WALLIS: Now you said this is all you could lay your hands on. You didn't get anything from the staff by way of guidance?

MR. BOYD: The staff requested that we use the Farley submittal.

CHAIRMAN WALLIS: That's for the use of the - because they don't have any review plan.

MR. BOYD: Not to my knowledge, no.

CHAIRMAN WALLIS: So they requested that you use Farley?

MR. BOYD: Yes, sir.

CHAIRMAN WALLIS: Okay.

MEMBER SIEBER: Farley was based on what we get.

MR. BOYD: That's correct.

MR. LANE: Okay. As a final point I'd like to make as far as we feel we have demonstrated compliance with the applicable regulations and safety limits. In doing the analysis for this effort, we looked at reactor operating conditions, accident conditions, transients, radiological consequences,

probabilistic risk, and the programmatic evaluations. We'll talk more about that in the presentation today, to address that in more detail for you.

So that pretty much concluded my introduction, and what I'd like to do now, unless there's other questions, is to really turn it over to our next presenter.

MEMBER SCHROCK: I had -

MR. LANE: Yes, sir.

MEMBER SCHROCK: - a point that I'd like to raise and that is the kind of agreement that you had with the staff about proceeding as you have with substantial capital investment up front, to be followed by a review of the methology to justify the uprate. It seems to me that that is an awkward position to be in , an awkward position on both sides. Was that discussed with the staff prior to installing these steam generators?

MR. LANE: The major capital investment, like the steam generators, were driven more from steam generator tube integrity and a new to do that particular change irrespective of whether we were going to uprate or not. It's just that when we did uprate, when we did replace the steam generators, we make sure we accommodate, as we have in other changes.

MEMBER SCHROCK: In the documentation, you determined the level of 7.5 based on an economic consideration, that you would be able to recover the capital cost if you could get to 7.5, 6.5 was problematic. Did I have that right?

MR. LANE: The increase of 6.5 to 7.5 was when we really got into sizing the steam generators and looked at what was available as far as the -- again, we talked about earlier about surface area and size and then we went from the 6.5 to the 7.5. But it's a combination on any of these uprates, a combination to look at the technical aspect and the economics aspect of what's the various pinch points and plateaus that make good sense as far as going to it.

MEMBER SCHROCK: Thank you.

CHAIRMAN WALLIS: Yes, sir. Aren't you going to introduce yourself?

MR. WILSON: Yes. I'm Roger Wilson. I'm with Entergy. We made some attempts to talk to the staff as early as possible about the potential for the uprate, but really we proceeded at risk with the increase in sizes. There was no dialog with the staff of agreeing that they would approve the 6.5 or 7.5 uprate. We proceeded at risk. When we were changing

the steam generator to put the surface area in there, which is about 24 percent more surface area in there, but we did that at risk.

MR. LANE: What I'd like to do now is turn it over to -

CHAIRMAN WALLIS: While we're on the overview.

MR. LANE: Yes, sir.

CHAIRMAN WALLIS: About what's changed, I noticed an increase in the containment building design pressure?

MR. LANE: Yes.

CHAIRMAN WALLIS: It's the same building though, isn't it?

MR. LANE: Yes, it was.

CHAIRMAN WALLIS: So what's happened?

MR. LANE: What we did, as far as, and Bryan will talk more about that, when we get into looking with the larger steam generator and then look at the boil down and so forth you get, we got an increase in building pressure, and so it's just a re-rate to the existing structure, and we went through the appropriate structural integrity testing and so forth to basically, you know, demonstrate that along with the analysis effort. And it's really about five

pounds, from 54 to 59 pound increase that was involved as far as the re-rate of the existing structure.

CHAIRMAN WALLIS: So we'll hear about that later?

MR. LANE: You will hear about that later, yes, yes.

MEMBER POWERS: As we go through these presentations, will you be discussing how you know that you maintained adequate operating and design margins?

MR. LANE: Yes, we will.

MEMBER POWERS: I'd be intrigued to see this with the relative absence of guidance on how you know that they're adequate.

MR. LANE: Okay, we'll try to be sensitive to that and address those points as we get to those sections where we talk about the margins and so forth. The next topic on the agenda is talking about the plant changes to accommodate the power uprate, and I'm going to turn it over to Milton Huff to have that discussion with you.

MR. HUFF: My name is Milton Huff. I'm with Entergy. I was the engineering supervisor on the power uprate project. The power uprate project has been a plan in process for about the last six years or

so. And before we even started this formal process, our site management, any modification coming into the site would have power uprate considerations.

All modification to accommodate the 7.5 percent uprate condition, that was part of that strategy, modifications implement over the last four cycles. The point there I want to stress is that we've have opportunity to make the operations staff familiar with the large components that we have installed, evaluate the synergistic effects. So we've kind of with this planning effort and the way this project's been laid out has given us opportunity to feel comfortable with the changes in the power plant.

The majority of the major modifications are installed. Go to the next slide and we'll go through these. As Rick mentioned earlier, at the heart of this uprate is the steam generator replacement and that surface area increased from 86,000 square feet to approximately 109 square feet.

The issue that drove us to the generators, as Rick mentioned, was the tube degradation and we took the opportunity to improve our power plant performance with these generators.

MEMBER SHACK: Now how did you get that increase in area. You changed the pitch of the tubes?

MR. HUFF: The actual, yes the vessel size is approximately four inches bigger diameter. It's a smaller tube. It's Alloy 690. Dale James will go into tube integrity issues, but that's basically the -

MEMBER SHACK: There's a smaller tube?

MR. HUFF: Yes, smaller diameter.

MEMBER SCHROCK: What about the other plant components, such as heat exchangers and smaller pumps?

MR. HUFF: I've got these on these next slides.

MEMBER SCHROCK: Oh, okay.

CHAIRMAN WALLIS: What were your units? You said 109?

MR. HUFF: Yes, sir. The original was 86,000 square feet. We went to approximately 109,000 square feet.

CHAIRMAN WALLIS: I wasn't sure I heard the thousand. I was puzzled.

MEMBER SIEBER: Could you give us a little bit of an idea how the primary system DP across a steam generator changed in area?

MR. HUFF: I think Bryan -

MR. DAIBER: This is Bryan Daiber from Entergy again. From the pressure drop across the steam generators, we went with quite a few more tubes,

and the smaller diameter. However, the tubes, the drawing process has improved so that the slickness, the roughness has gone down, and what we effectively designed for in the overall steam generator design through the tube sheet, was a comparable delta P as the original steam generators before 220.

MEMBER SIEBER: So RCS was the same as it used to be?

MR. DAIBER: We restored RCS flow back to essentially where it was, prior to a significant level. Yes.

MR. HUFF: These next two modifications, the condenser and the separator, even if we weren't doing uprate would have required replacement, because of the copper alloys present in the original component. The condenser, we uprated the size of it also to accommodate the higher steam flows, went with the Titanium because we are on the Arkansas River, which is border to brackish, so that was the reason for the Titanium tube support plate. Spacing is such that we won't get excessive vibrations, so we designed these new modular condensers for this uprate steam flow.

MR. SEIBER: So the spacing of the tube support plates is closer?

MR. HUFF: Yes, that's correct.

MEMBER SIEBER: What is the distance from the tube sheet to the first support plate?

MR. HUFF: It's approximately two feet. Well, it's in the two feet range. It reduced about a third. I don't have the exact number, but we can get that.

MEMBER SIEBER: And you've operated with that condenser?

MR. HUFF: Yes, two cycles.

MEMBER SIEBER: Is its performance equal to the original? Can you maintain the same vacuum with the same cooling decline?

MR. HUFF: Yes, sir. Actually it's more efficient.

MEMBER SIEBER: More efficient.

MR. HUFF: More surface area, and obviously because of the change, we had copper nickel, there was an offset in surface area just to go to the same thermal performance, and then for the anticipated power uprate, we expanded that surface area even larger.

MEMBER SIEBER: How do you know that? I mean, it hasn't been operated at a higher level.

MR. HUFF: It's standard heat exchanger, we

use the HEI standards in the sizing of that head exchanger.

MR. WILSON: This is Roger Wilson again from Entergy. The condenser, we went up about 13 percent more in surface area, but with the slight decrease in conductivity through the Titanium tubes, effective surface area is around a 9 percent increase, adjusted for the Titanium tubes. We also put in an AmerTap system cleaning system, and during Cycle 14, when we were at degraded conditions, our secondary flow rates were up.

In order to correct for the lower steam pressures, we raised our flow rates. So our flow rates were up at Cycle 14, the last cycle at the steam generators, comparable to where we're going to be with power uprate. So we have operating experience with that, plus we made improvements on our condenser vacuum system, air removal system. So we've had very good experience with these new condensers.

MEMBER SIEBER: Generally when you go to Titanium tubes, one of the issues is tube vibration. I presume, have you measured that in any way, and did the decrease in spacing of the support plates correct it?

MR. HUFF: Well, the tube support spacing,

there are several things we did to it to address that. The steam lanes where we had the highest, you know the introduction into the bundle, we went with a higher gauge wall on top of the spacing, and there were also along the top, the top row is solid bar for impingement, because that was one of the big design concerns for Titanium was moisture impingement. So we put a lot of extra design features in there to protect those bundles.

MEMBER SIEBER: You didn't have to do anything like staking or?

MR. HUFF: No, that's correct. Had we had a stainless condenser, we would have had - if you can't change your support plate spacing, then you have to put the stakes in or something like that to stiffen it.

MEMBER SIEBER: That's sort of the fallback position if you start to get tube leaks caused by sweating.

MR. BOEHNERT: Closer to the mike, Jack. She's having trouble hearing.

MEMBER SIEBER: Okay, so that's the fallback position that you would have to take.

MR. HUFF: Right.

MEMBER SIEBER: Should you begin to get

leaks.

MR. HUFF: That's the big advantage I guess we have over this period of time and the age of the plant and the opportunity to design these components to accommodate these increased mass flow conditions. The condenser is designed for the higher flow rates. I think we have ample design features in there to protect that and give us satisfactory performance.

The moisture separator reheaters fit in on the side are also. Primarily what drove it for the protection of the generators, was to remove the copper. We took the opportunity, we've improved the moisture separators in 2R12, and then changed the bundles out to 439 stainless, increased the surface area of this heat exchanger by approximately 50 percent.

MEMBER SIEBER: What about copper and feedwater heaters and steam condenser ejectors and things like that. Is all the copper gone there?

MR. HUFF: All the copper is gone. The high pressure turbine, the first three stages with uprated condition represented a choke flow, so we were having to go into our HP turbine. So we took the opportunity, again, to pick the GE advanced design to get additional efficiency megawatts out of that

modification. The low pressure turbines, we changed those out, put high efficiency turbine blading in, and just from the efficiency gain for these two modifications, separate from uprate, we're gaining about 42 megawatts for those two.

Other major modifications, we rewound the generator this past cycle, past outage. That took it was 1046 Mega Bars to 1133. That would be the rating after we've put the auxiliary components in here to support that re-rating. Hydrogen coolers, analysis showed we needed to replace those to support the uprate generator.

Standard piping, we made a configuration change. The Stator cooler and series with the main cooler, so it picked up, that flow path picked up heat so we separated them and put them in parallel paths to insure a cooler source of water for the Stator coolers.

I think Bryan will discuss this when he gets into the containment analysis. One thing we had to do, because the containment analysis results in a higher peak pressure, it has more load on the containment building fans and motors. To accommodate that requirement in increased load, we changed the pitch approximately three degrees, retarded the air

flow to accommodate the change in pressure.

To counter that, from a standpoint of normal cooling, the containment chill water coils are the normal coolers. We increased the surface area there, and the result of this mod, we've already seen a 10 degree drop in normal containment building temperature. So we took the opportunity to improve, accommodate those conditions in what we currently have.

CHAIRMAN WALLIS: How cool is the chilled water?

MR. HUFF: Chilled water coming in, approximately 45 degrees, is that correct?

MEMBER SIEBER: Another question on the change to the turbine. Is the exit moisture content higher or lower or about the same as it was before?

MR. HUFF: Bryan, do you have the heat balance?

MR. DAIBER: Yes, it's higher. It's more efficient, so on the high pressure turbines, of course, it increased our loads on our heater drain pumps. It's a more efficient turbine.

MEMBER SIEBER: So you would expect more blade erosion because of that?

MR. DAIBER: I'm not the expert on that.

I'm sorry. I believe it's been designed for that. I know we were able to increase the number of years between inspections, so I believe there's some advanced features in that too.

MR. HUFF: Well that design, that blading, GE provided the heat balance, and designed the blading off that.

MR. WILSON: Again, this is Roger Wilson. We replaced the whole high pressure steam path. It's not just three stages, but it's a whole new high-pressure turbine stators and rotors. The only thing that remains is the casing.

MEMBER SIEBER: Ok, thank you.

MEMBER SCHROCK: You mentioned GE in this regard.

MR. HUFF: Yes, sir.

MEMBER SCHROCK: Stepping back a moment, I was a little puzzled as I read the documentation to find that your basis in part if GE proprietary documentation for uprates. I'm unclear as to what the GE involvement is in this particular uprate. Can you give a very brief explanation of that?

MR. BOYD: Let me take a shot.

MR. HUFF: Okay, this is Dennis Boyd again.

MR. BOYD: What I was trying to convey

earlier was, we used the GE document just as a basis for knowing the types of information to include in a power uprate submittal on the PWR side. So we only used that, as I stated earlier, for lack of having a specific topical form like a CE PWR plan. So we just used it for content.

MEMBER SCHROCK: Well, my question pertains to the proprietary nature of the document that's cited in the references here. How do you have access to a proprietary GE document is really what puzzles me.

MR. WILSON: I don't think there was any. Again, correct me, Dennis - Roger Wilson. I think it was all just a CE. See I don't remember any GE proprietary, did we?

MEMBER SCHROCK: Well, the one that you reference is proprietary. It's in the title of the report.

MR. WILSON: Oh, I don't know how we got a hold of that.

MR. HUFF: I'd have to go back and pull the string on that.

MR. WILSON: Yes. I guess we got it from a brother plant that's GE PWR.

CHAIRMAN WALLIS: That's the first time I've heard brother plant. Sister, they're usually

female.

MR. HUFF: This slide represents the major modifications, hardware modifications left to go at this point for the Cycle 16 upcoming spring outage. We plan to put in the Stator water heat exchangers, replace those. We're also upgrading the Isophase bus cooling fans. The coolers were replaced last cycle, last outage, and the fans and housings are being changed out to this outage to improve that capability.

Heater drain pumps, on the feedwater side, the heater drain pumps are really the only major component to be changed out there, and that's with the more efficient heat cycle that we had, as Roger explained. We're going to have more drain flow, so the capacity of these pumps had to be increased and we also improved and redesigned three stages of the pump, and larger motors and recirc lines. There will be a change there.

The rest of the feedwater heater system isn't far from the original design. Each loop approximately capable of 80 percent power operations. So this is the last of the components that we saw we needed to change, and with the uprate - a footnote here. With the uprate conditions, feedwater system grids will be capable of approximately 65 percent

single loop operations.

CHAIRMAN WALLIS: The transformers are okay?

MR. HUFF: The transformers, yes they were okay. There was an increased load, but from a life cycle, the load on the transformer will increase where degradation or the life cycle will be shortened. But there's no need to replace those to support uprate at this point.

CHAIRMAN WALLIS: There was a remark that I didn't quite understand about the load on the transformers being highest in the winter, highest in the summer?

MR. WILSON: Yes. I don't remember that. This is Roger Wilson. I don't remember that. The highest loads are in the summer. Our peak loads are in the summer.

CHAIRMAN WALLIS: That's what it says in there.

MR. WILSON: Well, I think what it says is you could load it higher in the winter.

CHAIRMAN WALLIS: You could load it higher in the winter, but it's going to be stressed more in the summer.

MR. WILSON: It's stressed more in the

summer. Our peak time is definitely in the summer in Arkansas.

CHAIRMAN WALLIS: I didn't understand why that was relevant to deciding things were okay.

MR. HUFF: Ambient obviously has a lot to do with transformer performance and cooling. But I think the point they were trying to make there, during the summer period because of the limitation on the cooling power, the climate affect on cooling tower performance, you will get some lower megawatt predictions, a droop there in summer operations.

CHAIRMAN WALLIS: So it says here that the proposed 105 to 109 percent loading, which will occur during only the wintertime is acceptable. So what's going to happen in the summer? Are you going to operate at a lower loading?

MEMBER SHACK: Right, 101 to 103 is what it says.

CHAIRMAN WALLIS: So you're going to be stuck with a lower loading in the summer.

MEMBER SHACK: Right.

MR. WILSON: This is Roger Wilson again. As Milton said, because of our back pressure on our condenser, we do have a sag off of approximately 12 megawatts in summer because our back pressure in our

condenser goes up as a result of those in the cooling tower. Those loads are taken off prior to the main transformer, so the load onto the transform is lower.

CHAIRMAN WALLIS: So the two things go together.

MR. WILSON: Yes.

CHAIRMAN WALLIS: You produce less power because of the efficiency of they cycle.

MR. WILSON: That's right.

CHAIRMAN WALLIS: And the transformers can handle so much anyway, so it all works out all right.

MR. WILSON: Yes.

CHAIRMAN WALLIS: So the uprate we're approving really is for the winter?

MR. WILSON: No, it's a year round operation. That's incorrect.

MR. HUFF: Setpoint changes, we've kind of got this broken up into two parts of our discussion. Bryan, the Director of Safety Systems will discuss those setpoints, the ones that in my area here that we modified on the secondary side, such things as feedwater water control setpoints, seamed up bypass control setpoints, NRS release valve setpoints, things of that nature were changed.

All these setpoint requirements and the

modifications, this process we've gone through is a system-by-system evaluation. We have an engineering request that we put out on each system, and that's what drove the modifications, is what drove the setpoint changes.

MEMBER SCHROCK: Your feedwater heaters, you say they were so robust in the original design that you didn't need to make any changes there, but there must be some reduction in performance.

MR. HUFF: And I have two per training I'm having to re-rate, the 3s and 4s, simply on temperature, not pressure. We've had Yuber do a detailed evaluation from thermal performance, design from a tube vibration issue, so from the standpoint we had the OEM on the heat exchangers validate the performance of those feedwater heaters, and they would be on site, along with the code inspectors, to re-rate the 3s and 4s on both loops.

The equipment and structure re-rates, Rick touched on it earlier, the containment uprate in the feedwater heaters are the two things that are having to be re-rated, and the containment went from 54 pounds to 59 pounds. Bryan will discuss in his presentation what drove that, and the details on that uprate.

In conclusion, is the balance of plant structures. Systems and components are acceptable for power uprate by either modification or evaluation. At this point, the modification section I'll turn over to Bryan.

MR. DAIBER: Let's see if I can do this without knocking the mike off. I'm Bryan Daiber. I work for Entergy. I've been involved with the RSG and power uprate programs for the last five years or so, and I was the safety analysis lead for the power uprate project.

The first thing I'm going to go over is one other plant modification for consideration at ANO that we took into account for the uprate condition was related to the fuel design. For Cycle 16, which is our next cycle, the first uprated core design, we're still using the standard 16 x 16 fuel assemblies that we're currently using. We're still maintaining the same number of total assemblies of 177 in the core. We are adding 80 fresh assemblies to the core for the first cycle of operation.

We are changing burnable poisons, however. WE're going from Gadolinia to Erbia.

MEMBER POWERS: I guess I don't understand the significance of 80 fresh assemblies being added to

the first cycle.

MR. DAIBER: My next slide will get into that a little bit more, if you can just wait.

MEMBER SIEBER: From Baddinia to?

MR. DAIBER: Erbia.

CHAIRMAN WALLIS: You mean you take out 80 old and put in 80 new?

MR. DAIBER: That's correct.

CHAIRMAN WALLIS: So it's an exchange.

MEMBER SIEBER: Basically that's what's happening.

MR. DAIBER: Right, we're exchanging 80 assemblies with 80 fresh assemblies.

MEMBER SIEBER: Are all 80 the same enrichment, and if so, what is it?

MR. DAIBER: There's a range of enrichments for the assemblies. It varies. It's around four and a half weight percent, plus or minus about a half percent, is that correct, Mehran, the enrichments for Cycle 16, four and a half plus or minus about a half percent.

MEMBER SIEBER: And per given assembly, is it zoned fuel or is it all the same enrichment in a single assembly?

MR. DAIBER: In a single assembly, I

believe it varies slightly within assembly, is that correct? There may be one or two zones in an assembly.

MR. BOEHNERT: You need to get to a microphone. There's a microphone there.

MR. GOLBABAI: I'm Mehran Golbabai. I'm from Westinghouse. I believe most assemblies, the enrichment within the assemblies are the same.

MR. BOEHNERT: Thank you.

MR. DAIBER: We're also changing Tcold. We're increasing Tcold 2° from where we're at in Cycle 15, from 529 to 551, and also to accommodate power uprate, we're reducing the radial peaking factor. In the next slide, I'll get to some of the numbers in the following slides.

From the change in burnable poisons, we're currently using Gaddolinia, and we're moving to Erbia. Now the reasons for that has to do with the poison itself. Erbia is a much more dilute poison. It allows us to have better power peaking control, better moderating temperature control. It gives us more smooth power considerations, and this transfers, not just only during normal operations but also during an anticipated transient, such as CA withdrawals, the peaking considerations are controlled better with

Ernia burnable poisons.

MEMBER POWERS: How does the Erbia change the oxygen potential of the fuel relative to what Gadolinia does?

MR. DAIBER: The oxygen potential?

MEMBER POWERS: Right.

MR. DAIBER: I'm sorry. I don't know the answer to that. We'll have to get back to you on that.

MEMBER POWERS: If it makes it worse and you have a stronger clad interaction, then it's not good.

MR. DAIBER: Are you talking about the oxide thickness?

MEMBER POWERS: Inside attack on the clad.

MR. DAIBER: On the clad.

MEMBER POWERS: By the fuel. It may not be a less adverse response to transients.

MR. DAIBER: I don't know about the exact oxide thickness, relative to the other core designs. We did look at that from the overall magnitude or the result of the oxide thickness, and I believe 100 microns is what we used as an acceptance criteria for that, under power grid conditions.

MEMBER POWERS: How much is the power plate

dependent on the changes in the fuel?

MR. DAIBER: With respect to the change from Gadolinia to Erbia, we gained quite a bit of margin in the peaking considerations, and we gained about five, six percent operating margin with respect to that.

MEMBER POWERS: This is because of the way things develop over the cycle?

MR. DAIBER: With respect to the challenges, with regard to peak considerations during normal operation and also during transient conditions.

MEMBER POWERS: Are you going to change the fuel again for the next cycle?

MR. DAIBER: With respect to the burnable poison, no. The intent is not to do that.

MEMBER POWERS: You're going to keep reloading with Erbia?

MR. DAIBER: Yes.

MEMBER POWERS: So you're going to have all Erbia after a while?

MR. DAIBER: That's correct.

MEMBER POWERS: How about the 80 fresh assemblies?

MR. DAIBER: The 80 fresh assemblies are all Erbia assemblies.

MEMBER POWERS: No, I mean you're starting the cycle with 80 fresh assemblies.

MR. DAIBER: That's correct.

MEMBER POWERS: Okay, now we're going to come to the next cycle. Are you going to put another 80 in?

MR. DAIBER: That will vary depending upon cycle length and the energy requirements for each individual cycle.

MEMBER POWERS: I'm still trying to understand what the significance of putting 80 -

MR. DAIBER: Go to the next slide.

MEMBER POWERS: And then the next cycle, there's going to be some different number.

MR. DAIBER: Yes, it will. It varies from cycle to cycle. With respect to the number of amenities with Cycle 14. In Cycle 14, we added 80 fresh assemblies. The current cycle we're in, we added only 68 assemblies. The next cycle we are looking at adding essentially 80 assemblies.

Now that value, that number of assemblies is dependent upon the energy content, and what this slide compares here or shows effectively is for Cycle 16, the energy and content in Cycle 16 is actually less than the energy content required for Cycle 14,

due to the decrease in cycle length, and secondly due to the decrease in cycle length, even though we are operating at 7.5 percent for Cycle 16.

MR SCHROCK: What has been the past practice on exchanging fuel? How many cycles will they bundle experience in the core?

MR. DAIBER: Usually up to three cycles.

MEMBER SCHROCK: Up to three, meaning that some fractions go up to three, but some only do two.

MR. DAIBER: That's correct.

MEMBER SCHROCK: So what is the ratio of those?

MR. DAIBER: From cycle to cycle?

MEMBER SCHROCK: Do most of them do three? Do a few do three?

MR. DAIBER: A very small fraction of them do three, 10, 20 percent would be in there for three.

CHAIRMAN WALLIS: So you have to continually check that the fuel is satisfying all the margin requirements and all those things?

MR. DAIBER: Yes. That's done on a cycle specific basis.

CHAIRMAN WALLIS: It is. Well, I guess the staff has to be satisfied that you are continually doing that. This is not going to limit the power that

you can get out.

MR. DAIBER: That's correct. On a cycle specific basis, we continue to look at the core designs.

CHAIRMAN WALLIS: So is this a step forward that's made possible with new fuel, this upgrade of 7.5 percent? If you didn't have Erbia, you wouldn't be able to do it?

MR. DAIBER: It would have been a lot more challenging with Gadolinia. There are several other modifications - not modifications per se, but changes in the fuel design that also have helped accommodate power uprate; in particular, the original core designs did not credit or did not use the integral burnable poisons, such as Gandolinia and Erbia. They used shims.

So we removed those shims over the past several cycles, and now effectively, there's usually maybe one of the few assemblies that may still have the shims in it. But for the most part, we removed all those. That alone has increased the fuel pin percent by about five percent alone there.

CHAIRMAN WALLIS: Is experience with Erbia poison fuel over three cycles in other plants?

MR. DAIBER: Yes. Most the Westinghouse CE

Plants using the integral burnable poisons are using Erbia.

CHAIRMAN WALLIS: So there has been experience over the full life of the fuel?

MR. DAIBER: Yes.

MEMBER SIEBER: What is the assembly average discharge burn up poison burning fuel?

MR. DAIBER: I believe the number is around 58,000 plus or minus about 500. That's the peak rods. You're talking about the average assembly?

MEMBER SIEBER: The average assembly, yes.

MR. DAIBER: Mehron, do you known the average assembly numbers?

MR. GOLBABAI: (Off mike.)

MEMBER SIEBER: And I presume the Thot is the same for every cycle and if so, what is it?

MR. DAIBER: For power uprated cycles, as I mentioned, we're increasing Tcold by 2° from 549 to 551 and with the increase in power uprate, the Thot is expected to go to 609 for Thot.

MEMBER SIEBER: And that's right around the activation temperature for Alloy 600. What components in the plant, for example, control rod drive mechanism and so forth that are IC600.

MR. DAIBER: Dale James will be talking

about that in a later presentation. So if we could defer that, I'd appreciate it.

MEMBER SIEBER: Thanks.

MR. DAIBER: So with respect to the fuel design, we're changing the burnable poison. Another key factor here is part of the Cycle 16 core designs are we are reducing the radio peaking factor considerations and that reduction in radial peaking factor relative to prior cycles, is greater than the 7.5 percent uprate.

MEMBER SHACK: Is the core protection calculator qualified for these fuel change designs?

MR. DAIBER: Yes. Yes, it doesn't necessarily look at the fuel itself, obviously. It's looking at the thermal hydraulics into the assemblies.

MR. BOEHNERT: Well, has that changed? Do these new assemblies have any modifications relative to the thermal hydraulic parameters?

MR. DAIBER: The CPC is the only one monitoring the Coles, the plant monitoring systems. They look at the RCS inlet temperatures, the flows, the in-core considerations with regard to flux mapping,a nd all of that is effectively staying the same, even with the new fuel. It's not any real different within the current Gadolinia core design.

MR. BOEHNERT: No, I'm asking if the assemblies themselves, have they been modified or never been changed at all?

MR. DAIBER: No, there are no physical modifications to the general geometry of the assembly and the pins and the grids.

MR. BOEHNERT: Compared to what you were using?

MR. DAIBER: Compared to what we're currently using, that's correct.

CHAIRMAN WALLIS: Are you going to reach the conclusion that everything's okay, and that means that you still got a margin to all the various limits classified for fuel.

MR. DAIBER: Yes.

CHAIRMAN WALLIS: You haven't shown us any of these margins, so we don't have any direct evidence that you are below the margins, or how far you are below the margins. Do you care to explain that?

MR. DAIBER: With respect to the core designs and the considerations, we've looked at all those, with respect to current core designs and previous core designs, and with these modifications that we're making here, the challenge with respect to fuel considerations are really bounded by what we've

seen in the past for Cycle 14 type core design considerations.

Now there are a few areas where we did go beyond past core designs. MTC is one of those. We went with - these core designs do result in a slightly more decative modulary core coefficient, and all the safety analysis have been updated to accommodate that with adequate margin. Pin pressure have gone up slightly, as a result of the core designs. But again, to insure that the pin pressures stay within acceptance criteria, we have limited our linear heat rate considerations after about 200 EFDP, we insure that the linear heat rate is limited to insure that pin pressures aren't exceeded.

Other than that, for the most part, the parameters and other considerations with the core designs that we're seeing for this cycle and several other cycles, when we looked at this power uprate effort, we didn't just look at Cycle 16, we did various core designs beyond Cycle 16 and looked at the general range of parameters that we look at on the cycle specific basis, and all those core designs effectively fell in with the ranges that we had essentially used when we established the Gadolinia core designs back in Cycle 13.

So a lot of the parameters and considerations that we are still using now in all their downstream analysis and considerations were established when we first went to integral burnable poisons.

CHAIRMAN WALLIS: And the staff has audited these methods that you're using.

MR. DAIBER: The methods that we use with respect to pin pressures, oxide buildup and those considerations, the fate methodology essentially, we use methodologies for considering fuel performance design considerations.

MEMBER POWERS: You tell us that all of them are the same, but I can think of at least one that surely must not be the same. I mean, if you were letting fuel up to 58,000 megawatts per ton, surely you can't have the fuel survive a rod ejection accident and put 240 calories per gram into it.

MR. DAIBER: I'm not thinking the high burn-up assemblies are typically limiting with respect to ejection analysis. Typically, it's the higher burn-up assemblies, correct me if I'm wrong, Mehran am I wrong, but typically the lower burn-up assemblies are more limiting with respect to route ejection and energy addition considerations.

MR. GOLBABAI: The peak burn-up limit has not changed, so with respect to burn-up, even with operated power, the 60,000 megawatt per day per ton remains the same. So we did not extend that in response to your question.

MR. DAIBER: So in conclusion, we looked at the core design and we feel that the core design itself has met the design criteria and is acceptable for power uprated conditions.

The next area I'm going to go into will deal with the boric acid makeup tank volume and weight percent design criteria. The ANO operates with a high concentrated boric acid tank, the BAM tanks that we refer to, and the design of these tanks is essentially developed based on what we refer to as a cool down without let down situation. We go from Mode 1, which is power operations down to effectively Mode 4, and during this transient consideration, we looked at the cool down during that let down available.

We start the cool down at about 26 hours with essentially Xenon at its started 2K at that point. Similar offsite power, end of cycle conditions with respect to initial Boron concentration and MTC considerations, and during that cool down, we insure that the tank concentrations and inventory there are

enough to insure that we have five percent shut down margin during that cool down.

In a similar fashion, we do a Mode 5 and 6 cool down scenario, again making sure that the boric acid concentration and inventory is sufficient to cool the plant down and maintain a five percent shutdown margin in the tank.

As a result of the more negative MPCs that we are seeing, we did have to impose a slight increase in restrictions on the tank concentrations. The current tank concentrations can vary between 2.5 weight percent and 3.5 weight percent. We've narrowed that band to the 3.0 to 3.5 weight percent, and inventory in the tank has increased slightly, also as a result of the demands.

But, all of these requirements with respect to the tank themselves, are within acceptable limits and design considerations for the tank and system.

CHAIRMAN WALLIS: Is somebody going to talk about mixing in the core. It seemed to be an issue in the SER.

MR. DAIBER: That's dealing with the long-term core, boric acid considerations on ECCS. So if we could wait until we get the ECCS analysis, we'll

discuss that. So with respect to the BAM tank considerations, we reviewed design requirements on it and found it to be acceptable.

The next item I'd like to move on to would be the pressure temperature limits, the PT limits for active vessel limits of 4 ANL 2. The current PT limits were set in the tech spec to expire at 21 EFPY; however in response to generic letter 9201, the limiting material was changed and the effective EFPY was reduced to 17. Associated with that, more limiting material.

At the end of Cycle 14 operation, which was our last refueling outage, we had effectively reached about 15.5 EFPY. So to make sure we could meet the 17 EFPY considerations, we pulled a reactive vessel specimen at that point in time. We had that specimen analyzed and we have developed new PT curves as a result of that. The results have been submitted to the staff for review in October of last year.

In the development of that PT curves for that effort, we did account for the increased power uprated core designs in those PT calculations. The fluence to the specimen was based on the proved methodology, FTI's methodology BAW-2241P-A. We used that methodology to estimate the fluent and accounted

for also the power uprate effects in the PT curves. Fluids outed 32 EFPY.

CHAIRMAN WALLIS: Is this something you submitted since the draft I see that we have?

MR. DAIBER: This was submitted to the staff in October.

CHAIRMAN WALLIS: I was puzzled by the SE we have because it talked about neutron fluence and everything seemed to be okay up to Cycle 16. I mean it's now or tomorrow.

MR. DAIBER: That's right.

CHAIRMAN WALLIS: I couldn't see why it was okay after that. You were going to submit something.

MR. DAIBER: Yes, and this is the submittal now.

CHAIRMAN WALLIS: Something which is since this document.

MR. DAIBER: That's correct.

CHAIRMAN WALLIS: Which I haven't picked up yet. I need to find it or read it or something, or the staff will explain it perhaps.

MR. DAIBER: Yes.

CHAIRMAN WALLIS: It's very puzzling that you were sort of okay until the next cycle. That's not a very comfortable feeling. You want to be okay for

quite a few.

MR. DAIBER: That's right. The justification only went into about three weeks of Cycle 16, which is the uprated core design.

CHAIRMAN WALLIS: You uprate and then you shut down a few weeks later.

MR. DAIBER: Hopefully not. So we have submitted these new PT results, and the results of the PT limits actually have opened the operating space a little bit. And the reason for that is two reasons. One is the fluence that we've seen that the original PT curves were based on, were based on a specimen poll that occurred at 1.69 EFPY. Those early core designs which were effectively the first two core designs that that first specimen saw, were highly rich core designs.

In Cycle 6, we essentially started to go to low leakage core designs and we continued to implement core leakage designs even under the operating conditions. So the fluence values on your uprated conditions are essentially expected to be less than what the vessel was seeing in the first five cycles of operation.

And also, in the PT curve development itself, we referenced ASME coke case, N-641 in

development of curves, which wasn't available when the original PT codes were developed.

So as a result of that, we've developed a new PT curves under power uprated conditions and the new PT curves have been determined to be acceptable under power uprated conditions.

MR. WILSON: This is Roger Wilson again. We made our original submittal back in December of 2000, and we provided the additional information on the PT curves on July 24, 2001. I have a copy of the letter here.

MR. DAIBER: Yes, I believe the vessel specimen results, the PT codes were in October.

MR. WILSON: October, that's right.

MR. DAIBER: I'd like to move on to the third agenda item, compliance with regulatory requirements at this time.

CHAIRMAN WALLIS: We're just about on schedule. I'm making a rough calculation. It looked to me as if you were on schedule. Is that the way you feel?

MR. DAIBER: I think we are.

CHAIRMAN WALLIS: Because we've got other things going on later in the day. Is that about right?

MR. DAIBER: It's about right. Compliance with regulatory requirements, from an analysis perspective, we started power uprate considerations back when we were doing the RSG design and implementation and all the analyses done at that time, in addition to the new analyses, specifically for power uprates, with respect to the containment analyses, the LOCA analysis, the 50-46 analysis, the non-LOCA transient analysis, all these events and considerations were performed with approved methods.

So all those analyses were performed with a few slight exceptions here, where we applied new applications of approved methods. In these cases, for large break LOCA and boric acid precipitation, we use approved methods, but this is the first time application for ANO 2 on these methods. And we'll get to both of those a little bit later on.

Also with respect to offsite releases and control room doses, again what we utilized here is we utilized methods consistent with what we had used in the RSG effort. The doses specific to power uprate were performed with the same methodology that we had used for RSG considerations, with respect to the control and dispersion factors in offsite releases.

MEMBER POWERS: When you calculated your

control room doses, what leakage?

MR. DAIBER: When we did our original control and dose calculations, the limiting event is the MHA LOCA, and we did that with 10 CFM in leakage. And subsequent to that, we have done a test which has greater in leakage, and I'm going to go into that issue a little bit later on.

There was one area where we felt there was a new method that was applied and that was for feed level line break. Here the new method really deals with a credit for low level actuation in the affected generator. In prior analysis we had conservatively waited until low generator level occurred in the unaffected generator. With respect to the power uprate application, we've credited low level actuation in the affected generator for the first time.

Also when we performed the analysis, we looked at the acceptance criteria required for those particular evaluations and made sure that we met all the acceptance criteria and we also made sure that we applied all the appropriate regulatory guidance on those areas.

When we were using NRC approved methods, we also verified that all the limitations and constraints confined for those methodologies were

appropriately accounted for in the application of those approved methods.

In conclusion, all the safety analysis that we performed for the RSG power uprate combined effort, we use verified, approved methods. We verified compliance with all the applicable regulatory guidance. We verified the acceptance criteria was met. We also verified that the limitations and constraints in the SERs were also met.

MEMBER POWERS: You're going to give us some more details later, are you?

MR. DAIBER: With respect to the LOCA analysis, we'll be going into more detail in that, LOCA containment analysis.

MEMBER POWERS: And the control room, you're going to go into more detail?

MR. DAIBER: That's right, yes. With respect to plant margins now, I'm going to kind of go over an overview in these areas. In the first part here, Milton Huff had presented mostly the balance of plant component considerations, and when we looked at the balance of plant design, we verified that those components would be able to operate within those design requirements for those systems.

For any of those components or systems

that were not meeting the design requirements, appropriate modifications have been installed or will be installed to insure that we can meet those design requirements and margins.

MEMBER SIEBER: When you talk about the electric power portion of the plant, did you consider and have to make any changes to circuit breakers, since you're interrupting capability margin is probably reduced to some extent, current carrying capacity?

MR. WILSON: This is Roger Wilson. I don't remember any modifications to any of those, but all of those were reevaluated. We did detailed reevaluations in all of those areas. We have very detailed calculations on all that.

MEMBER SIEBER: All right.

MR. DAIBER: In a similar fashion, we also looked at the NSSS, and the NSSS, which includes reactor coolant system, the volume control system, the safety injection systems, and your shutdown cooling systems. We looked at the design requirements for those systems and components, and made sure that we could maintain the same design requirements, which we were originally licensed to.

And after reviewing those systems and

components, we were able to verify that no modifications were necessary to insure that the NSSS was able to meet its design requirements.

We also looked at the control systems. The control systems including the pressurizer pressure and level control systems, the feedwater control system, steam dump and bypass control systems. We also looked at the plant protection systems, and the plant monitoring systems to insure that the setpoints associated with those systems and those control systems also would operate and function properly under power operated conditions with the appropriate design margins.

In those situations where adjustments to setpoints were necessary, we've implemented and will be implementing as necessary, setpoint changes.

From the containment perspective, when we did the RSG analyses, we did indicate an increase in peak building pressure design requirements. So, we have, as part of the RSG effort, we underwent a re-rate of the containment design from 54 pounds to 59 psig. During that effort, we looked at all the equipment inside containment and verified that the equipment inside containment could operate under the uprated pressure of 59 pounds.

CHAIRMAN WALLIS: How does it explain what's going on here. You have the same building, and somebody naive would assume that it's designed for 54 psig. That's what it's designed for. How do you manage to change its design pressure?

MR. ADAMS: My name is Doyle Adams with Entergy. I was working with the RSG when they did all that, and also was the RPE for the repairs, modifications to the containment, and also the testing as it came out of the outage 2R14.

To answer your question, we had some slides. Due to the modern ability of everything, we managed to lose those things. So I'll try to go through what I had prepared and then try to answer all your questions you have there.

What we have ANO is a Bechtel containment, designed in '68 to the early '70s when it was actually designed. It's a three butress plant. It's a sphere dome cylinder walls with a nine-foot thick concrete normally reinforced base mat. We have a quarter inch thick steel liner on the inside of it.

It was regularly designed for 54 psi at 300 degrees Fahrenheit. We uprated the containment to 59 psi and still used 300 degree Fahrenheit number for that. It was originally designed and still is to ACI

318, '63 version of that code. And what we did, when we came out of the outage, we actually tested it again. I guess we're probably the only containment that's been uprated that way and actually did another structural integrity test on it.

And we came out using, read at 1.18 to do that test, with minor modifications to some changes in it that we dropped as far as amount of instrumentation we did and things like that, mainly due to the fact that we already had, the second time we had unit 1, which is basically the same plant, and Unit 2 we'd already done a SIT on it. So we knew how the building was reacting, and we wanted to confirm that as we went out.

We also subjected our containment to ILRT, which you would have to anyway. But to keep from recycling and more cycles on the containment, we actually performed the SIT and the ILRT at SIT pressures. So we did it - normally, you would have it in about three to four hours at SIT pressure. It's dated for 11 hours. We also had -

CHAIRMAN WALLIS: I'm sorry, what is SIT?

MR. ADAMS: It's structural integrity test.

CHAIRMAN WALLIS: Okay.

MR. ADAMS: As opposed to SIT tanks. But

due to some construction issues, we also had two tenants that we want stressed up. We had one vertical and one horizontal.

CHAIRMAN WALLIS: What is the pressure of these tests?

MR. ADAMS: 68 PSI, 1.15.

CHAIRMAN WALLIS: Well, I don't know how long it's going to take, but is the basis for operating it that you did tests at higher pressures? You changed your basis of analysis?

MR. LANE: He's looking for the basis I think. You did a combination of analysis and tests, right?

MR. ADAMS: Oh, yes.

MR. LANE: Answer the question, you know, as far as the basis of how we re-rated the containment.

MR. ADAMS: The basis, okay. Well that was the next slide.

MR. LANE: How did you do this then?

MR. ADAMS: Okay. How we did this was we went through and we did all new analysis. We used Bechtel BCEP analysis, which is a fine idea on analysis developed and used for concrete containments. It was developed and is being used for, the San Onofre

Plant used that particular code. It consists of a finite element, which gives you your moments and forces. Then it has a post operative system which you go through that compares it, does the load combinations and compares it to, in this particular program, actually compares ASME Section 3 Div 2, 75 addition of code.

CHAIRMAN WALLIS: So you did a different analysis?

MR. ADAMS: Yes.

CHAIRMAN WALLIS: To get the power pressure.

MR. ADAMS: We did a complete reanalysis of the containment.

CHAIRMAN WALLIS: Using a different code?

MR. ADAMS: Yes.

CHAIRMAN WALLIS: Okay.

MR. ADAMS: Okay, as we went through, and I'm sure you're wondering where we got all the extra. When you design a plant you get to have the capability of adding in extra capacity as you go, and what they did originally, they had three additional tendons in there for surveillance, calling for surveillance for each grouping, both dome, vertical, and hook tendons.

They actually had a few more that were

added in toward the last, probably for construction reasons. We lost some in Unit 1. We lost two hook tendons as we went through the construction issue. We used all tendons as we came through the re-analysis. All of them are credited in this particular analysis.

CHAIRMAN WALLIS: So there's something physically different. You're now using more tendons?

MR. ADAMS: No we did not change any tendons in there, but in the analysis, we used all the tendons.

CHAIRMAN WALLIS: In the analysis assumption, are you using more tendons than you used before?

MR. ADAMS: That's correct, sir.

CHAIRMAN WALLIS: So there is something different about the physical basis?

MR. ADAMS: There's nothing we did to modify the containment to get to where we were. The other thing that we had some additional capacity in was through the creep values. We used a very conservative creep value when they went through the first time around to do the analysis, and they used it because in Unit 1, they didn't allow time to go all the way through the creep testing.

So they went through part of it and they

just used that value. We gathered data off of Unit 1, based on all of the tests that we did over the period of time that we had, because we had to do liftoffs and everything in Unit 1, where Unit 2 being a cinder type plant, we didn't have to do that over the years. But it's basically identical, the same concrete, basic mix, and tendons were the same, just a different number of them in Unit 2 based on the pressures that are there.

MEMBER SCHROCK: Your reference to creep is in the tendons?

MR. ADAMS: NO, this is creep in the concrete.

MEMBER SCHROCK: All right.

MR. ADAMS: But the rest of everything we used the same. We did not change the seismic values. In fact, we made real sure that we made sure that we did not do anything different in the seismic that would change how that actually got into the analysis.

MR. WILSON: Excuse me. This is Roger Wilson. One thing I don't think we have told him is that a Unit 1 design pressure is 59 pounds. So when he's comparing against Unit 1, he's comparing against a containment that is designed for 59 pounds. But the original analysis for Containment 1 was 59 pounds

versus 54 pounds for Unit 2.

CHAIRMAN WALLIS: These were essentially the came containment?

MR. WILSON: They essentially are the same containment, very close.

MR. ADAMS: Except for the fact that we have a different number of tendons in it.

MR. WILSON: Right.

MR. ADAMS: And they did reduce the tendons in some areas, based on how much pressure was actual design.

MR. WILSON: But we had spare tendons.

MR. ADAMS: We had additional spare tendons that were in there. That's where those numbers came from.

CHAIRMAN WALLIS: The tendons are what holds the concrete together.

MR. ADAMS: That's correct. Your design is such that you don't allow it to go into tension under certain conditions in your design basis.

CHAIRMAN WALLIS: Are you pre-stressing?

MR. ADAMS: We pre-stressed, yes.

CHAIRMAN WALLIS: That's where the creep comes in then?

MR. ADAMS: These are large tendons, and as

I said three butress is what we have. They are basically tensioned up to about 1.4 million pounds. They're 186 wire tendons, massive things.

CHAIRMAN WALLIS: Yes, that's probably enough. Maybe we'll ask the staff to send questions.

MR. ADAMS: Is that enough?

MR. DAIBER: Thank you, Doyle.

MR. ADAMS: Okay.

MR. WALLACE: Thank you very much.

MR. DAIBER: Along with containment design, some of the things we did incorporate in the RSG program to try to minimize the impact of containment pressure challenges with the new steam generators, the new steam generators did incorporate an integral flow restrictive nozzle which was not available in the OSGs, the original steam generators.

Also we installed a containment spray actuation signal to isolate feedwater and steam. Prior to the steam generator replacement, isolation was only based on those steam generator level. We incorporated an additional isolation signal on high containment pressure of the main feed and main steam. Fuel design considerations. As I discussed before, we switched over to the Erbia burnable poisons to assure fuel design considerations.

So in conclusion, with respect to plant margins, we removed the plant -

MEMBER SCHROCK: I'm still not completely clear on how you get to a change in the radial peaking by changing the burnable poison. You burn out more rapidly than you did with the Gadolinia, is that right? And so, you'd have more reactive old element in the periphery of the core?

MR. DAIBER: The peaking factors are actually more of a design other than in relation to the burnable poisons. The radial peaking factors I'm referring to here are designed into the actual assembly designs with respect to whether it's Erbia or Gadolinia. So, with Erbia core designs, there is the potential that future poisons –

MEMBER SCHROCK: Is there someplace in the documentation I haven't found that I could understand what this all means about the change in the radial peaking factor? What you do to come up with those numbers and why the physical changes in the fuel result in that change?

MR. DAIBER: With respect to the peaking factors, there's some information in the power uprate, though I don't think it's very extensive on that. Most of that work is done on the reloads.

MEMBER SCHROCK: See this is a problem I have. I mean we try to evaluate the technical details of what you're arguing. But it's difficult to do that when what you hear over and over again is that we've complied with all existing regulations. It doesn't tell us how you do the analysis in any technical sense. It tells us in a compliance sense that it's being done using methodologies that are approved, et cetera, et cetera. What I need is a little more technical explanation of how you come to a change in such numbers at the radial peaking.

MR. DAIBER: The radial peaking factor, the decision on the lowering the radial peaking factor, is based on some recent data that's been gathered at Calvert Cliffs and Palo Verde Plants. There are concerns with the higher, more aggressive core designs resulting in actual offset anomalies, sub nuclear boiling considerations.

Westinghouse has reviewed that data as a result of those other core design considerations, and they've developed a thermal hydraulics code. I forget the name of it, but they've developed a methodology to try to predict when that sub nuclear boiling would be onset and the conditions that would onset that. Then we went back and we looked at the Cycle 16 core

designs.

MEMBER SCHROCK: See, this is precisely the point that I'm making. This is Thermal Hydraulics Phenomena Subcommittee. You're talking about now a thermal hydraulics consideration which somehow depends on a new analytical method developed in Westinghouse. I don't know what it is.

MR. DAIBER: That information has been provided to the staff in response to an RAI question in respect to the thermal hydraulics considerations there. There was an RAI on that. The staff had requested additional information with respect to how we were accommodating the data that was recently collected at Calvert Cliffs and provided some information in that area.

CHAIRMAN WALLIS: Maybe you can tell us where to find it.

MR. BOEHNERT: Can you reference that RAI, because we should have that?

MR. DAIBER: I was trying to find it.

MR. WILSON: October time frame, I think it's in the letters there.

CHAIRMAN WALLIS: Maybe at the break, you can call our consultant.

MR. BOEHNERT: Yes. We have these RAIs.

MR. SHROCK: I've looked at a lot of RAIs and none of them have presented anything like the kind of explanation that I'm talking about. But what I find absent in all the discussions is any technical explanation of the phenomena that are involved here. But what we have instead is reference to a code we don't know, or may not know, something which meets the requirements in your view of the staff, and then we'll hear from the staff whether or not it has met these requirements.

But nowhere are we hearing a real technical explanation of how one gets a reduction in the radial peaking factor as a result of the modification in fuel.

CHAIRMAN WALLIS: Maybe we can take that on some sort of advisement.

MEMBER SCHROCK: I want to understand how and I want to understand how well you have the number that you're getting.

CHAIRMAN WALLIS: We're going to come back later in the day. Perhaps you folks can prepare a more detailed explanation for us.

MR. DAIBER: I think Mehron may be able to. You're referring to the actual fuel design and how we build in that radial peaking factor into the core

design itself to lower it in the design itself, versus -

CHAIRMAN WALLIS: Maybe you've got some other slides that show a sort of typical -

MEMBER SCHROCK: The power of the plant, and to increase the power to the plant, you have certain constraints, and some of those you may be able to negotiate more freedom on. Others you may not. But it becomes terribly unclear as to exactly how you achieve a comfortable increase in power by 7.5 percent.

I don't know how I can say it more simply. The technical basis for it does not come through clearly, through all of these graphs and thick documentation of what has been done to achieve the change in the power, using all approved methodologies and all of that.

MR. GOLBABAI: May I?

MEMBER SCHROCK: Yes.

MR. GOLBABAI: My name is Mehron Golbabai. I am with Westinghouse. I'm not a core designer, so I'll try to make a brief explanation, and if that doesn't satisfy you, I'll get in touch with someone. Our understanding is there are three elements that are involved. One is originally these cores were

designed, of course, with shims and now we have burnable absorbers. That gives about, let's say three percent more number of fuel rods that you already have, compared to when these cores originally were designed.

The second element of course is the number of batches. You put up a few more assemblies for every number of reloads and that reduces the general power that each assembly has to generate. And then the third element is the Erbia. That being a diluted poison, that allows the power within each assembly to be more uniform. Therefore, the peak in a given assembly is not high with respect to the rest of the rods in that assembly. So those three elements combined, but if you like to, I can get more of an explanation.

MEMBER SCHROCK: That's a local peaking consideration, not a core. That's not something you can explain here in five minutes. What I'm saying is, the documentation ought to provide enough technical detail about exchanges and, instead, the documentation is voluminous but doesn't convey an awful lot of technical information. That's basically the problem I have.

MEMBER SIEBER: It seems to me you

ordinarily find the detailed explanation of the analysis as part of the safety evaluation for each core, which is usually prepared two or three months before the refueling occurs. And the way those are done is, at least in the old days, they would use some steady state core model, which was a diffusion code, describe the flux and the relationship between flux and power, both locally within an assembly, and across the core.

And then from that, they would use correlations of thermal hydraulic mixing correlations to determine what the rod temperature would be in each case and the numbers are the peak clad temperature of 2200, which was the final acceptance criteria for ECCS plus DMBR and these are expressed in terms of peaking factors that you can measure by looking at things like axial offset and so forth.

I really didn't expect to see that detail in this application, but I know that before you can start up, you have to have an approved safety evaluation for the reload and modern RSEs don't have a lot of documentation either, because they rely on preapproved topicals that all the fuel vendors put in. So they just list all these and say, this is how the answer came out, and here are all your limits.

It is, I agree with you, difficult to understand exactly what they're doing because they've been doing this for so many years over and over again, using basically the same methods that they sort of cut it short I think. Do you agree with that, sir?

MR. GOLBABAI: Yes, things that we are discussing here are well within the range of what we've been experiencing in all our plants, and the analyses are the same methodologies.

CHAIRMAN WALLIS: I think the problem is you have a big computational system for all kinds of computer calculations. When you look at the details as we did with some of the GE cores, we find that the sort of power distribution jumps all over the place, depending on how things are reloaded, which is a burner which is not running. And it's difficult for someone to get sort of the perspective with all those details there. How do you actually achieve this power distribution on the average? You're lost in the detail.

MEMBER SIEBER: When you do core design, you design for whatever works, as opposed to having a code system that will optimize fuel. Generally that comes from experience. There are insertable, burnable poisons. There are codings. There are integral

burnable poisons like Gadolinia, plus you can zone the fuel, different enrichments within a rod or different rods within an assembly. And it's sort of a guessing game and you keep trying designs until you get one that works. And then once you get one that works, that's what you end up building.

MEMBER KRESS: Basically you have to have more neutrons, more power in the radial directions.

MEMBER SIEBER: That's correct.

MEMBER KRESS: And you do that by putting in more fuel and taking out some of the poisons.

MEMBER SIEBER: Right. Iron enrichment and then you'd have to shape that.

MEMBER KRESS: You have to shape it.

MEMBER SCHROCK: Well, when you put this together with the fact that an uprate of 7.5 percent is requested based on methodology that is archaic, it leaves a lot of unanswered questions. I mean there have been very, very developments in reactor neutronics analysis in the 19 years that this thing was put on the street, the Westinghouse plan for uprates 1983.

MEMBER SIEBER: Right.

MEMBER SCHROCK: And I'm confident that some of the basis justifying the request is embedded

in new analytical methods that are available and that in some way are being used. But it is very unsettling to understand that the decision finally is going to be based upon thermal hydraulics analyses that are so archaic as to essentially reflect no improvement over those 19 years. It's not a satisfactory situation. That's my view.

MEMBER KRESS: How well do you know, after the fact, what your power distribution is?

MR. DAIBER: The cold system on my monitoring system does verify the core power distribution.

MEMBER KRESS: It verifies that you've got the power distribution you thought you had.

MEMBER SCHROCK: On an assembly basis.

MR. DAIBER: Yes, on an assembly.

MEMBER SCHROCK: Not on a rod basis.

MEMBER KRESS: But that's close enough to give you a pretty good average.

MR. DAIBER: I think so.

CHAIRMAN WALLIS: So you say even though it's not a method that's been checked against many of these real cores, it's really got a solid basis of empirical evidence behind it?

MR. DAIBER: Yes, and obviously we use

Westinghouse for our core designs, and they've been designing the cores for comparable CE plants. They have a wealth of knowledge and experience based on their prior core designing considerations, and they use that when looking at our Cycle 16 specific core designs.

MR. KRERSS: And there are tech spec limits on these core power distributions that you can't exceed, or not?

MR. DAIBER: There are with respect to ASI indices. There are limits, and the verification, there's more of a tech spec with respect to verifying that the actual predicted and actuals are within compliance. The verification of the inquiries that they're measuring is verified I believe on a monthly basis. Is that correct? On a monthly basis to the predicted method, the predicted core powers.

MEMBER KRESS: Thank you.

CHAIRMAN WALLIS: Now you have another 10 slides or so before the next speaker?

MR. DAIBER: Yes.

CHAIRMAN WALLIS: Can we get through this by about quarter past 10:00, we have a break then. That should decide how it's going for you. But I think it appropriate to have a break after you

presentation, unless you get really stuck along the way.

MR. DAIBER: Like I was now? With that, I'm going to move on to the fourth agenda item, which are review issues. And within the review issues, we've kind of reordered some of the sub-bullets here. The first one we'll be going over is ATWS, and then containment, and then I'll turn it over. We'll go to break possibly at that point before we go to the operations.

MEMBER POWERS: Just glancing at your slides, when you introduce this discussion of ATWS by explaining an ATWS transient to the panel?

MR. DAIBER: With respect to the PWRS, the ATWS transients, we consider a lot of the same initiating events with respect to loss commensurate backings, loss of feedwater type events, in which the plant does not, would not have scram by the normal reactor protective system, and hence resulted in increased pressures and core powers due to loss of feed potentially too as a result of that.

When we analyzed - as far as the CE design considerations with respect to ATWS, we don't analyze those specific events. Based on compliance with 10 CFR 5062, the CE design approach was, rather than to

actually analyze those events where the scram and feedwater actuations may not have occurred, we have rather committed to and have already installed a diverse scram system, a diverse turbine trip system, and a diverse emergency feedwater actuation system.

So from our design consideration standpoints, we don't analyze a specific event. We insure that the probability of design is low enough and reasonable enough for us to consider. Again, that's achieved with the installation of the the DSS, DEFAS and DTT. Those systems that we've installed, we've verified those design criteria with respect to those redundant systems, to make sure that under operating conditions, that the design criteria were still met.

CHAIRMAN WALLIS: These design criteria, you have diverse systems so that it never really happens or the probability of it really happening is very low. Do you have numbers to put on those probabilities?

MR. DAIBER: I don't have numbers with me.

CHAIRMAN WALLIS: Is the decision made by the NRC based on some quantitative probalistic analysis or by some expert estimates or what? How do you decide it's good enough.

MR. DAIBER: I believe that was decided with the NRC through the development of the rulemaking where there is acceptable criteria.

CHAIRMAN WALLIS: A long time ago. It probably says if you have enough diversity, it's okay. It probably doesn't stick numbers on it.

MR. DAIBER: I don't know if there were actual numbers generated at the time.

MR. BOEHNERT: Yes, there were.

CHAIRMAN WALLIS: Okay, there were.

MR. BOEHNERT: I don't remember them but I know there was extensive work on probablistic valuations for the development of the rule.

CHAIRMAN WALLIS: From a mathematical basis. It's not just somebody's estimate?

MEMBER SCHROCK: From the standpoint of protection of capital investment, wouldn't it be prudent to know what an ATWS analysis results be?

MR. DAIBER: From the risk perception -

MEMBER SCHROCK: Ever been done on the plant?

MR. DAIBER: No. ANO 2 specific analyses were never looked at. Back during the development of the rulemaking considerations, there were some generic analyses performed in bounding nature for the CE class

of plants, the 2800 megawatt thermal and then the 4000, 3800 megawatt thermal plant range.

So there were some generic analyses done at that point in time, and the decision at that point was, rather than to pursue analytical methods to mitigate these, we actually installed additional hardware to insure that the increased pressures would not occur, rather than rely on operator action.

The hardware installed from the diverse scram system is a totally independent diverse and redundant system to the normal reactor protection system. In addition to the normal reactor protection system on high pressurized trip, the CPC plants also have a high range high pressure trip in the CPCs that also fits.

In order for an ANO 2 CPC type plant to get to this point, CPCs would have had to fail, the normal high pressurized trip system would have had to fail, plus the reverse redundant, the scram system that we've installed would have had to fail. So getting to that point is very, very low on the CPC type plants.

CHAIRMAN WALLIS: There's no operator intervention which would somehow short circuit all these systems?

MR. DAIBER: No. No.

CHAIRMAN WALLIS: The sequence you described as being unlikely is independent of operator action?

MR. DAIBER: It's very quick. In the times we're talking, a very rapid trip response. Now the operators do have an additional DSS and DEFAS actuation should all of that still fail. They do have that luxury. But the timing of such shouldn't be necessary.

With respect to the DSS system, the way the system was installed, again it's a reverse redundant scram system, installed at ANO 2. The setpoint it was at on that is set such that it actuates after the normal reactor protective system setpoint would actuate, but prior to this primary safety valves lifting. And the timing on that trip and the setpoint itself are verified to make sure that it doesn't interfere with the normal reactor protective system trip on high pressure.

We reviewed those design criteria and insured that the current setpoint and settings and response times are acceptable under operating conditions.

MEMBER KRESS: Is this power uprate

strictly for ANO 2?

MR. DAIBER: Yes.

MEMBER KRESS: And does ANO 1 claim to have one at some time or has it already had one?

MR. LANE: This is Rick Lane again. We're initiating some studies this year to look at that. We've done a previous study back in the mid-'90s and we're going back and re-reviewing that and seeing what the potential is for ANO 1. But at this point in time, it's strictly in the study phase.

MEMBER KRESS: And they're both on the same site?

MR. LANE: Same site. They're on the same site.

MEMBER KRESS: And that's the only two plants on that site?

MR. LANE: That's the only two plants on that site.

MR. ADAMS: They (off mike).

MR. LANE: Yes.

MR. DAIBER: With respect to the DEFAS in a similar fashion, we have installed the diverse emergency feedwater actuation system, and it also has a redundant or a low steam generator actuation on DEFAS. So the normal RPS system actuates EFW at about

22.2 percent, and the diverse actuation occurs at about 16 percent. The setpoint is set lower, and response time is set such that won't interfere with the normal reactor protective system response considerations.

Those were reviewed with respect to power uprate considerations and verified still to be acceptable under power uprated conditions. So in conclusion, we reviewed the ATWS design requirements for ANO 2 and found those to be acceptable.

I'll move on to the containment considerations and real quickly, I'm just going to go over it from the analytical perspective now, what we saw during the RSG effort.

From an overview perspective, we've looked, when we did the RSG project, we made sure we accounted for power uprate in those analytical efforts. Analyses and the methods we used for determining peak containment pressure design were based on approved methodology. We used the Westinghouse former CE methods for determining mass/energy release for both the LOCA and main steam line break analyses.

We looked at a spectrum of break sizes, and we also looked at various power for the steam line

break considerations. We also looked at various single considerations. He mass and energy released that's generated with the Westinghouse method is then put into the Bechtel COPATTA code for determining peak building pressure.

MEMBER SHACK: What's the limiting break here?

MR. DAIBER: The limiting break is just every so slightly a LOCA over a steam line break and it's a discharge pump break.

MEMBER SCHROCK: But the number of break sizes specifically shown in the documentation was three. It's difficult to make a case that you found the peak in the relationship that peaks within the range of those three data points by selecting the highest among them.

MR. DAIBER: You're referring to the LOCA consideration?

MEMBER SCHROCK: Right.

MR. DAIBER: Yes, from the LOCA consideration, the double-ended -

(Simultaneous voices.)

MR. DAIBER: Yes, I jumped to combusted steam line. The limiting is LOCA. And from the LOCA consideration, the double-ended slot area break, which

is effectively the cross-section of the cold leg pipe put into a slot formation has historically been determined to be the peak break consideration for the last many years.

MEMBER SCHROCK: Let me rephrase the question, because I think you're not getting it. If one has to determine the maximum in a value from several determinations, it's not possible to find the maximum or to justify that it is the maximum by saying that the one in the middle is the highest and the two on the extremes are lower, and we take the one in the middle from a three point evaluation as being the max.

MR. WILSON: Bryan, what he's asking if I could help. That's what we presented just to show it was, that we had looked on both sides. But they looked at other sizes. The way we submitted it was to show a size on both sides of the one we picked as a peak one, but that's not all I believe we looked at.

MEMBER SCHROCK: Let me just say, the documentation does not show clearly that you in fact had found the maximum.

MR. WILSON: That's right, it didn't.

CHAIRMAN WALLIS: I take it the argument is that you have from past experience, from calculating many breaks on low power -

MR. WILSON: Right.

CHAIRMAN WALLIS: - you have sort of the curve.

MR. WILSON: Right.

CHAIRMAN WALLIS: Now you've got a curve and you've got three points which have moved a little bit from that curve. So it's not perhaps unreasonable to draw in a curve like the old curve.

MR. WILSON: Right, and then we presented the maximum one and the one on either side of it.

CHAIRMAN WALLIS: You're saying you already have the curve.

MR. DAIBER: I think I may be confused here. When we do the 5046 compliance on peak temperature, we look at a spectrum of break sizes, and have looked on both sides. With respect to the peak building pressure, containment pressure analysis, the limiting break historically has been determined based on a four guillotine slot leg break orientation, and that's what we've looked at here when we did these analyses.

So based on historical perspective, effectively used the same methods that we used originally, and we zeroed in on those classic limiting break sizes, again using Westinghouse methodologies

and Westinghouse experience on doing these for not just ANO 2, but other CE plants, some of which are a significantly larger power rating than us.

And based on that, we developed our peak limiting breaks, based on their knowledge of what is a limiting break, which is a double ended guillotine slot orientation for the cold leg, and we also looked at hot leg breaks. We looked at suction, discharge and hot loge considerations.

Again, all those configurations are based on the double and the guillotine configurations and size for determining peak building pressure.

CHAIRMAN WALLIS: Did you resolve the question of mixing in the containment which the NRC raised with you?

MR. DAIBER: Yes, with respect to the dose analysis considerations, we did resolve that.

CHAIRMAN WALLIS: That's only for dose analysis. You don't worry about that for calculating pressure?

MR. DAIBER: No. That issue that raised with -

CHAIRMAN WALLIS: Is this one node? How many nodes are there in the containment?

MR. DAIBER: Under the large break LOCA

mass energy release considerations for peak pressure we model it as one node.

CHAIRMAN WALLIS: It's a well mixed containment?

MR. DAIBER: Yes, under those turbulent condition, it's a well mixed.

MR. WILSON: Excuse me. Bryan Wilson. Was there not a confirmatory analysis in one of those?

MR. DAIBER: Yes, that's correct from the peak building pressure standpoint, there was - the NRC did perform a confirmatory analysis on the peak building pressure analysis evaluation.

MR. WILSON: And found, I believe in their analysis they came up with lower numbers than we did. They found our analysis to be conservative.

CHAIRMAN WALLIS: Okay, so we can ask them about that then.

MR. WILSON: Yes.

CHAIRMAN WALLIS: Thank you.

MR. DAIBER: So we did perform these analyses using the methods, approved methodologies that we've used in the past. The results were bounded for power uprate, and again this was all done as part of the RSG effort and approved under the license amendment 225 already.

The limiting consideration. Again, we looked at large break LOCA and steam line breaks. We did look at single considerations, limiting single fire for the LOCA was a loss of 80g. For a steam line break, the prior evaluations had indicated a 2770 megawatt thermal power level that is limiting.

We went through a power level verification as part of the RSG effort, and determined that the zero power level indication or power was more limiting under power uprated conditions, and it's really more a matter of the new steam generator design, the integral flow restricting nozzle, and the CS AS actuation signal that we implemented, caused that change in power level for limiting steam line break.

The peak pressure is actually calculated with 57.6 per LOCA and 57.4 for the hot zero power steam line break. There's a typo on the slide there. So in conclusions, the peak pressures that we calculated there were within the new uprated design pressure of 59 pounds, and therefore found to be acceptable.

CHAIRMAN WALLIS: These peak pressure are calculated with conservative assumptions, so there's no need to discuss uncertainty and predictions.

MR. DAIBER: Through the whole process of

developing containment analysis, the LOCA analyses, 5046 analysis and non-LOCA analysis process, when we developed input considerations, we interfaced with the field vendor on those methodologies for the most part, and the methodologies there, or the inputs associated with that are documented in what we call the ground rules.

So, before we kicked off this effort to do both RSG and power uprate, we did a thorough review of those ground rules that we interfaced with and made sure that we accounted for current operating conditions and made sure that we accounted for any conservatisms, and values that we felt we may want to accommodate additional margins in.

CHAIRMAN WALLIS: That's what I'm asking about. You give us 57.6. That I think is calculated with conservative assumptions. The realistic value would be much lower?

MR. DAIBER: That's correct.

CHAIRMAN WALLIS: Because if this were realistic value, we'd be really interested in the uncertainties.

MR. DAIBER: Yes.

CHAIRMAN WALLIS: It may be the uncertainty of five psig would be significant.

MR. DAIBER: Yes. Yes, definitely. When we developed those inputs, we developed a set of inputs that we thought would be very conservative and very bounding. So the peak pressures that we are calculating are considered very conservative.

CHAIRMAN WALLIS: If you knew they were conservative.

MR. DAIBER: Yes.

CHAIRMAN WALLIS: You knew that with good reason.

MR. DAIBER: Yes. We feel that, we know that they're conservative. In fact, during -

CHAIRMAN WALLIS: Not feeling. Feelings aren't allowed here.

MR. DAIBER: We know they are conservative because during the steam generator replacement process, we did try to keep it down below 54 pounds, so we did pull out some of those conservatisms to get it down to 54 pounds, and if we really had to get it down to 54 pounds, we could have gotten it down below 54 pounds.

But based on previous experience, we were running right at 54 pounds for many years. We always were bumping up against the limit and therefore, we wanted to continue to run up against that limit. We

went ahead and went over 54 and put margins in the input assumptions to go along with it.

With that, do you want to take a break? Or, we could turn it over to Rich.

CHAIRMAN WALLIS: No, I think it's a good time to take a break. You've finished almost exactly on time. Thank you very much. We will take a break until 10:30.

(Whereupon, the above-entitled matter went off the record.)

CHAIRMAN WALLIS: Ready to go? All right, now we are ready to go.

MR. SWANSON: My name is Rich Swanson. I'm an operations shift manager and I have a senior reactor operator license on Unit 2. I'm the officer representative on the power uprate project, and before that, I was also on the steam generator replacement team.

My main functions on the project were to provide operations oversight, review all the modifications and evaluations for impact on operations, and also to review the impact on emergency operating procedures.

Training on the uprated plant has already started. The simulator has been changed to

accommodate the new uprated plant. We can swap it back and forth for current cycle and future cycle to accommodate just in time training. We're providing two crew training cycles, pretty much dedicated to power uprate training, and each crew will be evaluated on the uprated plant prior to outage.

Now I want to point out the changes we're doing for power uprate have much less impact in steam generator replacement. Controls and display changes are minimal or none. There's no physical modifications to control stations due to power uprate, and no changes to the formal of the safety parameter display system. Some display ranges will be re-scaled, however, to accommodate higher flows and pressures we'll be seeing.

We have approximately 75 procedures to change for power uprate. It included emergency, abnormal, normal operating procedures, but there's no changes to the type and scope of procedure and we didn't write any new procedures for power uprate.

There's no changes in the type of nature or actions in our emergency operating procedures, and we didn't have to add any new actions to our EOPs.

The power ascension testing will be heavily coordinated and controlled by operations.

We're involved in development and implementation of all the tests. We had test teams designated to perform the testing. During our outage, we'll have two crews working outage and we'll have a team on each crew, and these are experienced operators. The leads on each team were also involved in the testing for the steam generator replacement.

The power ascension testing will be basically normal testing until we get up to 90 percent of the new rating, which is approximately 98 percent of our current power. From there, we'll step up in 2.5 percent increments with about a 24 to 48-hour hold at each increment of power, and we'll be doing walk downs, control system checks and verifying all the parameters we're seeing against our design parameters, and any issue that comes up will be resolved prior to going to the next power level.

MEMBER POWERS: What are you going to be looking for in the walk downs?

MR. SWANSON: We're walking down for vibrations mostly and systems. We'll have engineers out actually taking and measuring vibrations, and we'll have the operators out there looking at the systems and making sure it looks right to the operators, because the operators can see things the

engineers can't.

MEMBER POWERS: So it's actually more than walk downs. You're actually doing the monitoring for vibrations?

MR. SWANSON: Yes. Here's a power ascension profile that testing, what we're going to be doing coming up out of our next outage. Basically up to 90 percent in CR standard turbine over speed trip testing, we have three power holds for physics testing, and then after we get to 90 percent, you show going up in two percent increments, up to 100 percent.

MEMBER POWERS: How do you decide whether it's 24 or 48 hours?

MR. SWANSON: However long it takes for engineers to collect their data and for engineering and operations to be comfortable with the plant and that what we're seeing is actually what power we're making.

MEMBER POWERS: So you're not looking for something that's time dependent. It's just operational time?

MR. SWANSON: That's correct. There's no time limit. There's no actual limit on that, but it will take at least 24 hours to collect the data and analyze it.

And in conclusion, impact and power uprate on operations training procedures and response time has been evaluated and it's found to be acceptable.

CHAIRMAN WALLIS: There's some response to that since it's changed significantly?

MR. SWANSON: As far as emergency operating procedures, no. We do have, for instance, on a main peak pump trip, we would have to respond faster to keep the plant from tripping. But it's faster than it is this cycle, but it's not faster than it has been in previous cycles. We gained extra time. We replaced steam generators to respond to main peak trip.

CHAIRMAN WALLIS: Right.

MR. SWANSON: And that with power uprating, it basically goes back to about where it was. And if there's no further questions, I'll turn it over to Dale James. He can talk about Alloy 600.

MR. JAMES: Thank you, Rich. Good morning. My name is Dale James. I'm the manager of engineering programs and components at Arkansas Nuclear One, and my group has responsibility for the steam generator integrity, fact program and the Alloy 600 program.

I'd first like to talk about Alloy 600 and the impact that we see associated with power uprate. As has been mentioned, we will be increasing the Thot

from it's current condition of just a little over 604 to about the 609 range. Of course, we had a history of Thot changes ANO. We began at somewhere around 607 during the early operations.

We reduced that temperature back in the mid '90s to preserve the steam generators down to the 600 level. It's slightly increased, and then with the steam generator in place, we went up to the 604 area, and now with power uprate, we'll be going to 609. So we have a history of changes in Thot at ANO.

MEMBER POWERS: I'm puzzled by the line on your slide. It says power uprate results in only a slight change of Thot, but a slight change of Thot was presumably a significant change of Thot in the past to preserve steam generators. Why is this one not significant in the other direction?

MR. JAMES: We felt like when we reduced Thot on steam generators that we were doing the right thing. We could continue to generate the power levels that the plant was designed to, while preserving for it adding margin. The exact impact of that reduction in temperature is really not known. Obviously -

CHAIRMAN WALLIS: Then are you doing the wrong thing, increasing the Thot?

MR. JAMES: We will be decreasing margins.

The extent of that decrease is not known. What I will present to you is how our programs will or will not change as a result of that increase with respect to Alloy 600.

POWERS: Thot is a good representation of your head temperature?

MR. JAMES: Actually not. Actually on the ANO Plant and several other combustion plants, I'm not sure about some other Westinghouse plants, but we do have a bypass flow into the head region from the cold leg, and get mixing in that area such that the head temperature is about 14.5 degrees cooler than the actual Thot.

MR. JAMES: So with respect to the power uprate and its implications as far as increasing hot leg temperatures, what we're going to be looking at its effect on the reactor vessel head penetrations. That would include the control on the dried mechanisms as well as our in coil instrument nozzles, and we have one head vent.

Just for references, 81 control on that dried mechanism nozzle, 8 ICI nozzles and one vent on the head.

MEMBER SHACK: Now presumably there's an Alloy one maybe two weld on each of these nozzles,

right that would be focused on Alloy 600? This is a CE plant, so there's no Alloy 182 butters between carbon, steel and stainless anywhere in the system?

MR. JAMES: Dan, can you help me out on the specific design of the welds.

MR. SPOND: Yes. My name is Dan Spond. I'm an energy engineer. We have butter welds, but they're not at the CE DM location. The CE DMs, well they are welded to a butter joint at the J-groove weld on the erector head. Yes, with 182, and that's really the same weld metal that the rest of the industry uses.

MEMBER SHACK: Right. Now do you have a stainless fluridic steel butter anywhere that you've got a way to weld, aside from these 600 compounds? Do you have a stainless 182 fluridic? You know, like Westinghouse has their -

MR. SPOND: No, we do not, not on say the hot legs of the RCS piping.

MEMBER SHACK: No, you wouldn't have it on the hot leg, but there's nothing in the presurizer, no stainless butter?

MR. SPOND: The pressure on the surge line is stainless steel, so we do have it coming off of the hot leg, I guess. And that is part of the ISI

program. So we do inspect those welds.

MR. HASLINGER: Karl Haslinger, Westinghouse. There are a few locations which have the 82 182 weld in all the C plants. Typically, there would be, with the exception of two plants. One has stainless steel made in coiled loop piping. The other plant, well - most of the plants have 82 182 weld at the nozzle to the tributary piping weld locations at the safe ends, and those are being evaluated currently on the MRP project.

The other location is on the pressurizer, such as the surge line nozzle, on both ends as well as the spray nozzles and the relief valve nozzles. So there are a variety of locations in C plants that have this problem, which is sort of a result from the VC Summers evaluations, and those are being looked at right now from a stress corrosion point of view.

MR. JAMES: Okay, so as far as other nozzle locations by Alloy 600 material, we also have cold leg nozzles. We're not going to talk about those, because actually cold leg temperature has decreased from our original design down to 551. It's increasing from this previous cycle to the current cycle, from 553 to - excuse me, 529 to 551. Thank you Bryan.

That's fairly far from the activation

cooling for Alloy 600, so really we anticipate minimal impact on the cold legs. Also the pressurizer conditions are not changing as a result of power uprate, so those nozzles in the pressurizer should not be impacted as the result of power uprate conditions.

MEMBER POWERS: Can you explain to me what you mean by the activation point?

MR. JAMES: Well, I think the industry indicates that somewhere close to 600 degrees is a point where the Alloy 600 material becomes impacted as a result of temperatures. That's what we're using as far as our evaluations on the head with respect to evaluating it against the conditions that were evaluated at Oconee, and I'll talk about that in just a little bit.

MEMBER POWERS: I guess I'm still perplexed. We're talking about a chemical process, and you're saying it has a threshold temperature to it?

MR. JAMES: I think that is a common belief that there is a threshold somewhere close to 600 degrees, yes.

MEMBER POWERS: Unremarkable.

MEMBER SHACK: Yes, I would think a lot of people would disagree with that. I mean it is

probably true that the rates go down as the temperature goes down. There would be very little disagreement about that. But an actual threshhold.

MEMBER POWERS: Unusual in chemistry to find, except phase transitions.

MR. JAMES: Okay, Dennis, let's go to the next slide. We're going to add our small bore nozzles. By small bore, I'd be referring here to the hot leg nozzle. I'm going to cover the head nozzles in my discussion in the next slide.

We have a program currently underway to evaluate or to assess damage to these nozzles as the result of their being exposed to elevated temperatures, and that basically what we do to address that is we form inspections. The first inspections that we perform are generic letter 8005. Those are the basically boric acid walk down whenever we go hot shed down, looking for indications of any leakage from those nozzles.

In addition to that evaluation though, each refueling outage, we do a bare metal examination of those hot leg nozzles, as well as the nozzles on the pressurizers to determine if there is any indications of leakage from those nozzles.

That's how we're addressing it. That's

how we will continue to address the Alloy 600 issues, associated with these nozzles. But in addition to that, as we identify leakage and have performed preventative change outs, we are changing that material out to a 690 material that has been determined to be much less susceptible to primary water stress corrosion cracking.

We have done that on nine of the 19 hot leg nozzles. All the nozzles below the mid loop level on the hot legs have been repaired with 690 material already.

MEMBER POWERS: I'm puzzled by your first sentence. It says that you have a higher susceptibility to failure, but no change in safety significance. That means you've evaluated something like the risk reduction or risk achievement and the number doesn't change?

MR. JAMES: What I mean by that is the failure mechanisms that the industry is saying, regardless of the temperatures that the small bore nozzles have been exposed to, have typically been the traditional axial flaws in the base metal material, and we have not seen anything that would indicate there would be any changes in that as a result of the power uprate for the small bore nozzles that we would

continue to see.

When they do demonstrate indications of damage, it would be an axial flaw that would not represent a safety concern with respect to significant leaky bore ejection. Okay, let's go to the next slide. We're talking about the upper vessel. We're talking about the head penetrations. Again, we are dealing here with the control and dry mechanism nozzles, as well as the ICI nozzles and the vent nozzle on the reactor vessel head.

Basically these nozzles have been evaluated by the industry in accordance with generic letter - or bulletin, excuse me, 2001 01. Industry response was repaired by that, by the materials reliability program group, a subcommittee of EPRI, and their results were documented in the NPR report 48.

And basically what that report did was perform a ranking of the facility based on the number of EFPY of operation required for that unit. In this case, ANO 2, to reach the same number of EFPY as Aconee Three, normalized for the difference in head temperature, and using 600 degrees as the starting point for initiation, that's how they normalize this.

And what we found out when we did that evaluation originally under the power uprated

condition that we had essentially 17.1 effective full power years before we would reach a condition similar to that that Aconee had experienced on March 1st with Tzero being March 1, 2001.

We then performed an evaluation with the uprated temperature of the erector vessel head, associated with the power uprate, and that number reduced down from 17.1 to 14.2. What that resulted is, the NRC asked - or the industry and NRC agreed to a categorization with respect to the response of the utilities as a result of that evaluation back to Aconee.

ANO 2 originally hit the 17.1 and even at the 14.2 fell into the moderate category of the third category. Those are plants that were five to 30 EFPY away from Aconee conditions. So the response essentially is unchanged. That response is that we would perform a visual. It required us to provide an effective visual examination of the head, which is basically if you were capable of performing a 100 percent visual examination of the head, you could use that to determine any risk significance associated with primary stress and cracking.

Unfortunately for us, the insulation materials on the Unit 1 head follow the contour and do

not allow for visual examination. So we will be performing a 100 percent NDE examination during our upcoming refueling outage to monitor for any type of damage to those nozzles.

MEMBER SHACK: So that means UT?

MR. JAMES: That is the plan, UT from below the head.

MR. DAIBER: Excuse me. That's using Westinghouse Robotics system from underneath the head during the inspection.

MR. JAMES: Exactly what the long-term plans will be is going to be dictated based upon what the industry sees as the result of these early examinations and further evaluation of that to predict what to project, what additional scope of inspections will be in the future.

So in summary, the vessel had penetrator susceptibility as chacterized being in this moderate category. Even under the power uprated conditions, essentially our activities or plans to address that will remain the same. That will be 100 percent UT examination of those head penetrations. The programmatic reviews and our continued review of the industry data will dictate to us, you know, what we'll be doing going forward to insure that these small bore

nozzles, as well as the head penetrations do not represent any safety issues associated with in canal cracking.

So we believe that the plant can safely be operated considering the Alloy 600 concerns, even in the power uprated condition.

Let's go onto flow accelerated corrosion. Of course, flow accelerated corrosion or FAC as I'll refer to it as, it affects carbon steel components in the steam cycle where a processed temperature is above 200 degrees, and there's many factors that go into the degradation rate. Probably one the significant is the material composition of the piping itself.

What we've seen is piping with even minimal contents of chrome are significantly less susceptible to FAC damage than normal carbon steel. Also geometry plays a part. Steam quality temperature, oxygen, the flow of velocities, and Ph of the liquid itself.

What power uprate is going to do to us primarily is going to result in increased flow rates. We also evaluated the impacts on temperature and pressure changes and industry changes. Chemistry essentially remaining unchanged under the power uprating condition.

MEMBER SHACK: Now when you took out all the copper, did you up your ph and your feedwater?

MR. JAMES: We're running above 9.5 ph right now.

MR. DAIBER: Yes, we did.

MR. JAMES: Which is good for FAC. What we did to evaluate the impacts of these changing conditions on the power uprate is basically use the industry Checkworks program. Of course, that's a program that's been developed by EPRI. That is a standard program for all the utilities used to do FAC evaluations.

We plugged these increased parameters, or these changing parameters into our Checkworks program to determine what increased conditions, or what additional susceptibility we may have with the main stem, main water, reheat steam, high pressure extraction, low pressure vents and drains, high pressure vents and drains, all those systems that could be impacted.

MEMBER KRESS: Had you used Checkworks on the previous level?

MR. JAMES: Yes.

MEMBER KRESS: So you had already done the uprates?

MR. JAMES: Yes, sir. In fact we went back based upon our most recent inspection, or Checkworks program prior to performing this evaluation and going forward with it. But Checkworks has been used at ANO, as well as many other plants, most of the other plants in the industry for many years now.

CHAIRMAN WALLIS: What sort of rates do you measure? What are the highest rates you've been measuring?

MR. JAMES: It depends on the system, and basically what we have seen as a result of the most susceptible system, we're looking a like a five mil increase in the wear rate per year. It just depends on the system as to -

CHAIRMAN WALLIS: What was it before then? Because 5 mils the increase. What was it before?

MR. JAMES: There's a range from zero to 20, 30 mils, and most of the higher wear rate systems have been replaced with higher alloy chrome. Geometries have been rearranged to minimize the conditions associated with geometry, so a lot of those higher wear rate systems, they've already been addressed, and been replaced building margin into the system as a whole.

To do our evaluation that we did, used

worst case conditions, used maximum steaming rates due to the turbine valves wide open, and basically the result of the evaluation using the Checkworks program indicated that we would see no more impact as a result of the power uprated condition.

Those results are consistent to what other licensees have predicted, utilizing Checkworks program associated with power uprates. Also it's consistent with actual measured values following our power uprated conditions. So we feel good about that.

Of course, we will continue to monitor our piping systems as part of our FAC program. We'll be looking at those piping systems that we believe are most susceptible as a result of the power uprate during the next outage, and a part of that process will be feeding back any deviations from what were predicted into the checkworks program for future projections.

So, in conclusion, the evaluations that we performed indicated that FAC wear rate should be minimally impacted by the power uprated condition and we will continue to monitor those components that are affected, to assure that those predictions are, in fact, accurate and we'll factor in any deviations into future projections.

Finally, I'd like to talk about steam generator integrity, and I think first and foremost with respect to this part of the presentation is that the steam generator replacements, which we've already talked about back in the fall of 2000, the steam generators that we replaced, our original steam generators were specifically designed and analyzed for the uprated power conditions.

There are many significant design enhancements that were implemented as a result of the steam generator replacement that were not part of our original steam generator design, and I could go into all of these that you'd like. We're very proud of our new steam generators, and I'm sure Westinghouse would be glad to do the same for you.

But I think most important is the change of the tubing material to the 690 thermally treated material. Also, the increase in the heat transfer area from a little over 69,000 square feet to a little over 108.7 thousand square feet. That increase in heat transfer area, not only allowed us to accommodate power uprate, but it allowed us to accommodate any plugging margin, as well as kept the Thot increase to a fairly minor increase by pushing that much heat transfer area into the generators.

MEMBER SHACK: Who manufactured these generators?

MR. JAMES: These replacement steam generators were manufactured by Westinghouse, and the design also is typical of a replacement design. These generators have the most recent enhancements, but generally speaking the Unit 2 steam generators are very similar to most of the Westinghouse newly-designed generators, and these flow rates that we'll be experienced in the power uprate conditions are typical of the new generator design.

We did perform an evaluation for the repair criteria in accordance with the NRC Regulatory Guide 1.121. That evaluation considered the structural integrity margins and leakage margins required. We dried a 40 percent through-wall plugging criteria for the new steam generators, which is consistent with the original steam generator design, even though we're using smaller tubing with thinner walls. Included in that evaluation was a wear rate in the upper bundle.

MEMBER SHACK: What is the actual tube diameter? Everybody keeps saying smaller.

MR. JAMES: We went from a 3/4 inch tubing to a 11/16.

(Off mike conversation.)

MR. JAMES: Included in that evaluation was a wear rate calculation for the upper bundle, where most of the wearing will occur at the anti vibration bars. Their anticipated maximum wear rate is around 0.34 percent per year, so that was evaluated and was included in this repair criteria as far as growth rate. We didn't anticipate on any flaws.

We will have 400 percent baseline inspection before the generators are actually installed, and will be performing another 100 percent examination during this first refueling outage to validate the projections associated with the new steam generators in accordance with EFRI guidelines.

So, in conclusion, the replacement of steam generators specifically analyzed and designed for the power uprated condition, incorporating many enhancements over the original steam generator design. Inspections of those generators will be performed to insure the integrity of the tubing under this uprated condition. Thank you very much.

CHAIRMAN WALLIS: Thank you.

MR. JAMES: By the way, let me introduce Jamie GoBell. Jamie's out of our design engineering group and will be discussing our piping analysis.

MR. GoBELL: Good morning. The scope of the analysis that was performed can be defined basically on the changes that we did that caused us to reanalyze the piping and the physical boundaries of where the piping was.

The changes in the replacement steam generator and the power uprate, and we have piping inside containment and piping outside containment, and those are physically structured separated from analysis perspective.

Most of this analysis was done for the replacement steam generator effort. It was done at power uprate conditions. But I'm going to go ahead and talk about what was done for replacement steam generator just for completeness, even thought the impact from power uprate was minimal.

Inside containment, we started out by validating the original design basis and verifying we knew what the margins were and what was contained in that. For most of the piping inside there, we performed rigorous re-analysis at power uprated conditions. Because the replacement steam generators were heavier, we had to analyze for new seismic and dead weight loadings. Because the containment pressure went up, we had to look at the piping of

vessels inside containment to make sure they were qualified for that external pressure both for the design and the structural integrity test pressure.

As part of our re-analysis of a lot of that piping, we implemented leak for break analysis, or technology, where we switched from the main coolant line breaks to the branch line breaks and the tributary lines, and we also included asymmetric compartment pressurization loads on the vessels and the pumps.

We looked at our design transience and revised those to reflect the operating -

MEMBER SHACK: When you did the leak before break, what did that let you do?

MR. GoBELL: The original analysis used breaks of the main coolant line piping, and we were able to eliminate the dynamic effects of that so the loads that we had to impose on the piping and the vessels we were able to reduce significantly because now we only consider breaks at the tributary line connections.

MEMBER SHACK: But did you make any physical changes in the plant? Did you get rid of any snubbers?

MR. GoBELL: No.

MEMBER SHACK: No, nothing.

MR. GoBELL: No changes because of that analysis. On the transients, we updated those to reflect any impact from replacement steam generator and power uprate and to reflect any operating history of the plant, the number of cycles we've seen.

We also, in anticipation of a license renewal, we went ahead and increased the cycles. We did the analysis to a 60-year life to qualify at license renewal effort. We maintained and improved the original code of record, and the analytical techniques that we used in the design basis, and the goal of course was to satisfy the code stress and fatigue usage requirements on that piping.

MEMBER SIEBER: What is the code of record that you used?

MR. GoBELL: It's very - that depends on what you're talking about. The different piping systems and the different components are designed to different codes of record. Examples would be the coolant pumps I believe for 1965 through '67 addenda. A lot of the piping was 1971 vintage for the code of record.

MEMBER SIEBER: And this is B-31 at one point?

MR. GoBELL: On the secondary side, yes it is out on the secondary side. I can classify it on the primary side and Class 1 and 2 was ASME, Class 1, 2 and 3, 1971 typically.

MEMBER SIEBER: All right.

MR. GoBELL: And onto the piping outside containment. The main changes there were changes in pressure and temperature of the process fluids. We evaluated those systems against the analysis of record. Usually if the change in pressure or temperature, we developed a scaling factor, which we multiplied the highest stress in that system or nozzle load, support load type thing, against a scaling factor that was basically a ratio of the increase, and showed qualification of the system based on that.

We also did, looked at the dynamic loading, specifically on the main steam line because the mass flow rate had increased and the pressure has increased. We developed new reinforcing functions for the stop valve, fast closure transient, and qualified the piping associated with that to those new loads.

MEMBER SHACK: It says that the mass flow rate increases, the steam velocity of kinetic energy dropped.

MR. GoBELL: From the Cycle 14, was the

last cycle we had the degraded old steam generators in.

MEMBER SHACK: Everything's in comparison to Cycle 14. If I went back and looked at Cycle 12, I'd find what I expect to find.

MR. GoBELL: Yes.

MEMBER SHACK: Yes.

MR. GoBELL: Yes, we are going to be higher than original design which would be Cycle 12, but lower than what we were experiencing in Cycle 14.

MEMBER SHACK: In 14.

MR. GoBELL: That's just a function f the main steam pressure we reduced to degrade the steam generators.

We also looked at the changes that the pressure and temperature could have on the downstream effects, things like line break, missile hazards, corrosion, minimum wall thickness required for FAC evaluations, thermal movement of the piping situations FAR evaluations that may have been performed in the past that could be affected by those changes and the effect on the expansion joints and piping.

And in conclusion, we only had a couple modifications that were directly related to the piping. We changed the setting on a couple spring

cans just to reduce the nozzle loads on dry turbines, and we have a modification that's going to be implemented in the upcoming outage. It's really resulting from a heightened awareness of vibration. We're going to go in and harden a lot of the small bore dents and drains and branch lines off the main steam feedwater. We have a section we're going to reduce mass, try to increase natural frequency and just make it more resistant to vibration.

We performed comprehensive review and analysis of all the systems involved and all the changes that we're looking at and the conclusion was the piping remains qualified for all those changes.

MEMBER SHACK: Do you have a plant history of failures in small diameter lines due to vibrations?

MR. GoBELL: That is typically where you see your vibration failures, usually in the socketweld of the small branch vent or drain. We haven't seen that in large - oh yes. We've been addressing that and have become a lot more sensitive to it over the last five to seven years. We've got a lot of operators calling us saying, hey this is shaking. Come look at it, and maintenance, that sort of thing. So we've done quite a bit of work.

MEMBER SIEBER: Have you ever gone through

the reactor cooling system when you were hot on the power and measured the vibration on the branch lines to try to predict which one's going to fail first, or which ones?

MR. GoBELL: We have gone in and gotten handheld vibration data at different locations where we found leaks in the past. We've looked at a lot of the systems, especially around the reactor coolant pumps. We had the 100 Hertz driving frequency and that sort of thing and gotten a lot of data there with actual operating conditions.

MEMBER SIEBER: One of the problems is that when a lot of these plants were constructed, they would take the vents and drains and make them pretty long and then put a heavy valve at the top, which it would do a real job on the socket weld.

MR. GoBELL: Well that concludes the piping analysis. I'd like to turn it back over to Bryan to talk about the next agenda item, the ECCS.

CHAIRMAN WALLIS: Thank you.

MR. DAIBER: Before I start into the ECCS, I'd like to go back and try to cover a few items. I want to make one clarification. I want to make sure that there's no confusion. There's several topicals, a GE topical and a Westinghouse topical that we

referenced. We're not a GE plant, obviously, or Westinghouse plant, so we didn't use the methodologies defining those topicals. We used CE methodologies when we did all of our analysis work from field design LOCA to non-LOCA considerations.

Those methodologies were really just utilized as a guideline to give us an insight into what kind of information we needed to provide in our submittal and what we need to look at to do power uprate efforts.

MEMBER SCHROCK: But you cited proprietary reports. My question was how you arranged to have access to a proprietary report.

MR. DAIBER: Entergy does have a lot of power plants. Some of them are GE boilers. With respect to the fuel design codes and considerations, those thermal hydraulic codes that are used and the FACS code and the ROCS codes for flux considerations, those are really looked at from an ongoing basis.

The ROCS codes, we look at the core flux designs and we benchmark. Each CPC plant updates their verifications on their flux with predicted values, and those codes have been proven to be very reliable in predicting the fluxes in past cycles, and so we continue to believe that they're going to do a

good job on the future design code considerations.

Also from the core design and thermal hydraulics standpoint, where we expect to go with the Unit 2 uprated core design, we don't believe we're moving into a region that hasn't already been operated at by other CE plants with higher power ratings, given all the input considerations with respect to peaking factors, RCS flows and the cold hot considerations.

So I wanted to clarify that. With respect to the ECCS analysis, again we used, if it's all right I'm going to call it CE methods. We used the CE methods for performing the large break LOCA, the small break LOCA and Boric acid precipitation considerations when we did the power uprate efforts. And real briefly, I'm going to go through the methodologies, assumptions, acceptance criteria and results for each of these various areas, starting with the large break LOCA.

The large break LOCA, as I discussed earlier, we changed methodologies for large break LOCA. We did use an approved methodology. It's the latest approved methodology. It's what's referred to as the 1999 EM. It's the latest approved methodology that CE has and we applied that methodology to ANO 2 for under the operating conditions. It's documented

in CENPD-132.

MEMBER SCHROCK: Can you give us a summary of what's new about it?

MR. GoBELL: Joe Cleary's here from Westinghouse Combustion. He can discuss those methodology changes and the topical report much better than I can.

MR. CLEARY: My name is Joe Cleary from Westinghouse. There were three major types of changes made to the 1999 EM. The version of EM that it replaced, by the way, is the 1985 EM and they're both Appendix K evaluation models. The three types of changes, number one were process changes basically, to allow us to run the code in a more unified way, less analyst intervention, transferring data between the codes.

The second modification was the removal of Dougall-Rohsanow as required by 5046 in Appendix K for changes that are within Appendix K.

The third set is number of improvements. There were roughly five or six minor changes, the low hanging fruit, so to speak, changes that we were able to make with very little regulatory risk. In sum total, they may have produced a reduction in peak clad temperature in the ballpark of 150 degree, peak

cladding temperature.

The type of changes in particular, I'll give you a few examples. There was a change to the reflood methodology to decrease the steam venting resistance during reflood. We incorporated a steam generator heat transfer model that removed some of the energy from the steam so it was less super heated.

The previous version of the model just had a constant temperature, or constant specific volume really for the steam. We improved the model that represents the interaction of steam and water with nitrogen, during the nitrogen discharge phase of the safe ejection tanks.

We made a small change to our Flec base reflood heat transfer coefficient correlation to make use of some FLECHTSEASET data that was not used as the basis for our earlier model. We improved the one aspect of the blow down hydraulics code to introduce a variable gap pressure during the blow down transient.

Those are probably the most significant changes that we've made to the model. In sum total, like I said, none of them presented a significant change by themselves, the peak cladding temperature, but in total approximately 150 degrees in the sample

calculation we showed in the topical.

MEMBER SCHROCK: You have a peak clad temperature prediction in large break LOCAs, as I understood it, of 2166, and that results from analysis which reduced that prediction by 150 degrees roughly compared to older predictions by the Appendix K method?

MR. CLEARY: Yes, the methodology results in approximately a 150 degree decrease.

CHAIRMAN WALLIS: So I'm not quite sure what you're saying. If you'd have gone by your method, would you have a higher temperature?

MR. CLEARY: Yes.

CHAIRMAN WALLIS: 2300 and something.

MR. CLEARY: If we had used the older - in addition to changing the methodology and the power uprate, there were a few other changes to the analysis. All other changes - all other things being equal, we would have calculated temperature approximately 150 degrees higher with the new methodology versus the old.

MEMBER SCHROCK: Have you - the conclusion for a position as to whether 7.5 percent is the limit of uprate that could be achieved using Appendix K, and did you have any interest in pursuing the best

estimate approach, rather than Appendix K?

MR. DAIBER: At this point in time, with the current 7.5 percent uprate and even considering the potential for an ECCS uprate, we feel it's more than adequate margin in the methodologies we're currently using, the 1999 EM. So, under -

MEMBER SCHROCK: I don't understand that statement. The residual 36 degrees you characterize as more than adequate.

MR. DAIBER: Again -

MEMBER SCHROCK: Is that what I've heard?

MR. DAIBER: Yes. Well, there's also margin in the input assumptions. Again, when we did this process, we made sure that we developed input assumptions that were very conservative and very bounding for where we expected to operate the plant.

So the input assumptions along with the methodology itself, provide conservatisms that are there. So although there's only a 36 degree margin to the limit, the assumptions we used are very conservative and very bounding for where we anticipate to operate the plant.

MEMBER SCHROCK: But with regard to the other question, have you considered would it be to advantage to use best estimate, and would best

estimate be needed if you were going to go for a higher uprate?

MR. DAIBER: Yes. If we went to a substantially higher power rating than the 7.5 percent that we've considered, then definitely we'd look at a combination of best estimate, large break LOCA and I believe CE Westinghouse are comparing their methods now that they're one, and I believe they're showing some benefits with just the Westinghouse approach or with CE approach.

MR. CLEARY: CE does not have best estimate methodology. Westinghouse has a best estimate large break model, as I'm sure you're well aware. We've done a little bit of comparison and we've concluded that the Westinghouse Appendix K model calculates lower peak cladding temperatures than our Appendix K model, and their large break, best estimate model obviously produces lower peak cladding temperatures than either of the Appendix K models.

At this point in time, we don't have any commercial drivers to warrant submitting the Westinghouse best estimate model to NRC review for application to CE design and SSSs. If that changes in the future, if we need it for support of any of our uprates, then that's a path we are prepared to go

down.

CHAIRMAN WALLIS: So this new methodology is 1999. That's something that was carefully looked up by the staff and they've approved all those changes that you made?

MR. CLEARY: Yes. It's an approved valuation model in compliance with Appendix K.

CHAIRMAN WALLIS: You seem to have gained a lot, 170 degrees?

MR. CLEARY: 150 degrees, yes.

CHAIRMAN WALLIS: Is it the reflood heat transfer coefficient that's the main actor there?

MR. CLEARY: It's the reflood related, yes. Both the improvement to the flood correlation and the hydraulic aspect of decreasing the steam venting resistance, and therefore getting higher reflood rate, particularly the less than one inch per second reflood rate that drives the flood correlation.

MR. DAIBER: As Joe alluded to, when we applied the 99 EM, we obviously accounted for power up. Next slide, Dennis. We obviously accounted for the increase in the power rating, but we also changed some of the other input parameters. Linear heat rate was increased from 13.5 to 13.7, and the range of SIT Tank pressures and inventories was also increased in

the analysis arean.

So the analysis incorporated very conservative boundary assumptions with respect to the SIT tank conditions, although the current tech specs and operating conditions don't exercise that broad a range currently.

The results of the large break LOCA analysis, the spectrum was revisited. The limiting peak clad temperature was 2154 for the .4 double ended guillotine pump discharge break, which is slightly different than the .6 break size currently is our limiting break size, using the 1985 evaluation model.

So, we also compared the results fro Cycle 15 to Cycle 16, realizing the methodologies here are different than some of those parameters I just mentioned have just changes. For Cycle 15, when we looked at the new RSGs, the peak clad temperature there was 2029, and for Cycle 16 we're now at 2154, as I just mentioned.

With respect to the maximum oxidation, core wide oxidation, we also verified acceptable results there, making sure within 10 CFR 5046 compliance on those criteria.

CHAIRMAN WALLIS: To get back to the previous slide, is there something in the regulations

that says you should evaluate these particular break sizes? I'm going back to my colleague's earlier question. If you had looked and it's 8.5, it doesn't mean that wouldn't have been above 2200.

MR. CLEARY: The regulations specifically address looking at the three discharge coefficients of 1.0.8 and .6. We start out our analysis looking at those three and if we find that the .6 is of more limit, the most limiting of those three, we go down using the same increment, i.e. to .4 guillotine.

This is our first analysis where the .4 was shown to be limiting. So we continue to decrease the break size to get a break that showed a local peak, and we decided to drop by a tenth of a fraction rather than two-tenths in that case, because now the absolute values of those numbers are getting lower.

CHAIRMAN WALLIS: It's a funny shaped curve, because everything is between 2200, except for that 2154. So it looks as if it's above peak. It's more or less a plateau. It's a bit odd. Why is that. Do you have any idea?

MR. CLEARY: There is one hydraulic difference between the four biggest breaks there that I think is the major contributor to that dissimilarity and that is the tying of the reflood rate drop below

one inch per second. It was earlier for the .4 guillotine comparatively speaking looking at the trends, than for the breaks. Consequently, there is a somewhat larger period of time, I'm talking maybe 15 to 20 seconds during reflood that the temperature is using the lower one inch per second reflood rates for that break size compared to the others.

CHAIRMAN WALLIS: So is this a step in the calculation method or something when you go to these lower?

MR. CLEARY: Yes, it is required by Appendix K. One can not use the flood heat transfer coefficients below where reflood rate is.

CHAIRMAN WALLIS: It's a step in the calculation procedure to do this sort of step in the results. So it's a peculiarity of the sort of non-smoothness of the Appendix K method.

MR. CLEARY: That's right. Discontinuity in two ways, one for any break size, there's a dramatic change in the reflood heat transfer coefficients once the reflood rate falls below one inch per second.

CHAIRMAN WALLIS: Physically incorrect.

MR. CLEARY: That's correct.

CHAIRMAN WALLIS: It's a requirement.

MR. CLEARY: That's right. Substantive research since '74 has shown that there really is no change in phenomena for the reflood rates as they step below one inch per second. The other similarity is now between the .4 and the others in that the hydraulic analysis calculated a little bit earlier time for that. So the discontinuity occurred somewhat earlier for that one break.

MEMBER SCHROCK: It seems that if you look at the big picture here it was far more important for you to change your Appendix K model than it was to attempt to do any peak shaving or flux flattening in the fuel design. Is that correct? You just wouldn't have been able to ask for an uprate.

MR. DAIBER: Yes, it was necessary for us to move to the 1999 EM. In fact, we did request that the review schedule of that be consistent with our need for power uprate. So the 1999 EM was approved in relation to the need for ANO 2 as a part of the uprate effort, yes.

CHAIRMAN WALLIS: Did the ACRS ever see this '99 valuation model? I don't think they did.

MR. CLEARY: No, it was not discussed with ACRS.

CHAIRMAN WALLIS: But this is a key aspect

of the upreate.

MR. DAIBER: Move onto the small break LOCA. The methodology for small break LOCA, we used the same current analysis methodology of record for Cycle 16 uprated conditions, referred to as the S2M document in CENPD-137, Supplement 2-P-A. This methodology was the same, which will help in comparison in later slides with Cycle 15 analyses.

Some of the assumption changes with respect to small break LOCA, obviously again the power uprate was considered, linear heat rate was also accounted for. That broader range of SIT tank pressures was also accommodated in the small break LOCA and I note here the high pressure safety injection flows were kept the same in Cycle 15 and Cycle 16. That's a critical parameter there.

The results of the small break LOCA analysis indicated that the .4 square foot pump discharge break, which is our current limiting break remained the same. The peak clad temperature is now 2066, with a little footnote that it's actually 2090. There was a code there identified after we ran our analyses and the limiting breaks was rerun correcting that and the official -

CHAIRMAN WALLIS: Did you miss slide 78?

I was going to ask about the core wide oxidation.

MR. DAIBER: Sure.

CHAIRMAN WALLIS: I wasn't sure that that was something that could be predicted. And then you've got a .99 versus a criterion of 1.

MR. DAIBER: The methodology there --

CHAIRMAN WALLIS: In all cases?

MR. DAIBER: Yes, the methodology there is very conservative. I believe it's based on the peak pin through the whole core.

MR. CLEARY: In small break. In this case, we a number of years ago started reporting the core wide oxidation result as less than 0.99. In actuality, the actual calculated numbers for that break spectrum is in the ballpark of about .4 for the corewide oxidation.

CHAIRMAN WALLIS: Why didn't you report 4.4. That would give me a much better feeling.

(Laughter.)

MR. CLEARY: I guess the answer is to avoid having to make cycle to cycle variations to that number by -- in the reload safety valuation reports. If we continue to show less than .99 --

MR. BOEHNERT: Oh, so that should less than .99?

MR. CLEARY: Yes, that is correct.

MR. BOEHNERT: That's the problem.

CHAIRMAN WALLIS: This is oxidation from the outside in?

MR. CLEARY: Yes, and also in our methodology we assume that the entire core ruptures at the same elevation that we predict rupture for the hot rod and the inside of the cladding, after ruptured node oxidizes as well and contributes to the corewide.

MEMBER SCHROCK: What is your accuracy level for that prediction?

MR. CLEARY: I'm not sure if I can address accuracy. It's a very conservative model based on Baker-Just oxidation model. I guess, could you explain what you mean by accuracy in this case?

MEMBER SCHROCK: Yes, compare it with some data and so what kind of predictive capability do you really have as compared to some real experimental data?

MR. CLEARY: The basic --

MEMBER SCHROCK: Dr. Wallis' comment about the .99, for example, do you believe you can predict it within 1/10th of 1 percent, 1/100th of 1 percent, whatever?

MR. CLEARY: Well, from my perspective

we're not trying to predict reality with an Appendix K model. We have conservative component models, in particular in this case, Baker-Just driving the calculation. So to the extent that the Baker-Just model predicts reality, or predicts an oxidation we report that as the -- using very conservative pin sensors for representing the power in all the rods in the core and other conservatisms in the methodology.

So I would say --

MEMBER SCHROCK: Essentially, being Appendix K evaluation means that there is no consideration of repeal of the ability of the predictive method? That's not a consideration. It's only a question of whether the method was approved.

MR. CLEARY: I think the sensor rod here, the point you're making, that's correct. The actual calculated number of about .4 probably is very conservative relative to a realistic calculation of corewide oxidation.

CHAIRMAN WALLIS: This is .4 for cycle 16 with the new upgrade?

MR. CLEARY: It's .4 for a bounding calculation that is expected to apply for cycle 16 and going forward as long as the plant configuration --

CHAIRMAN WALLIS: What is it for cycle 15

if it wasn't .99?

MR. CLEARY: I didn't review those numbers before this meeting. I believe they would have been a little bit higher than the .4 that we calculated using 1999 EM, primarily because the 1999 EM with the automated code system does a more precise application of our methodology.

Previously, when we did it by hand, the analysts took conservative measures to do the analysis one time and not have to repeat the somewhat cumbersome calculation, so adding in those discretionary conservatisms generally resulted in numbers that were higher than .4, but less than .99.

CHAIRMAN WALLIS: This must be 40 or 50 years old.

MEMBER SCHROCK: Not very good either.

MEMBER POWERS: It depends on how much you believe in breakaway oxidation. If you believe in breakaway oxidation, the ability under dynamic events, Baker-Just is not all that bad.

MR. DAIBER: Moving to slide 81 on small break LOCA results, compares -- looking at the results here, again the limiting break size stayed the same at .04 with a peak clad temperature of 2090.

In the next slide we compare the results

to the acceptance criteria, but we also compare it to cycle 15 results. Here, the methodology stayed the same and the input assumptions relatively stayed the same except for core power and the peak clad temperature went up from 1905 in cycle 15 to 2066 in cycle 16. That comparison is based on the same version of the code.

The results for cycle 16 all indicated acceptable results with respect to 5046 acceptance criteria.

MEMBER SCHROCK: Did you skip over some slides?

MR. DAIBER: We jumped back. Moving on to the boric acid precipitation analysis. For boric acid precipitation analysis, we did switch methodology in cycle 16. We utilized again an approved methodology. It's the CE approved methodology for boric acid precipitation. This methodology that we applied we know is more conservative than the methods that we were currently, originally licensed to.

We did account for the power uprate and the original analysis of record from cycle 1 had been maintained over the last 15 cycles so there were various other miscellaneous input parameters that we updated when we did the analysis.

The results of that analysis indicated that assuming a hot leg injection started at 5 hours, the maximum boric acid concentration attained a weight percent of 23.3. This is less than the acceptance criteria of 27.6 weight percent. And verifying that our current DOP guidance that we've used over the years of initiation of hot leg injection between 2 to 4 hours still remains valid under the power uprated conditions.

CHAIRMAN WALLIS: Is this where we get to the mixing part?

MR. DAIBER: Yes, this is the mixing issue. There was an issue raised by the staff with respect to the volume assumed in our analysis in implementing this new methodology. The volume we used includes the core region and the region of the lower plenum below the core for that mixing. That's consistent with what we had used in our original methodology and we consistently use that same volume when we apply --

CHAIRMAN WALLIS: It's not easy for me to see why they should be well mixed together. The core is up here with all kinds of stuff in it and the lower plenum is down here. It's not clear to me why they should mix.

MR. DAIBER: There possibly are some valid considerations with respect to the mixing concerns. And taken as an individual issue, it's one thing, but taken with respect to the overall conservatisms embedded in the methodology, we believe that the overall methodology utilized to determine long-term core cooling is a very conservative methodology.

CHAIRMAN WALLIS: You said something about a recriticality or something. What's the concern? Why worry about this?

MR. DAIBER: Flow blockage, boric acid precipitating out and causing flow blockage consideration.

CHAIRMAN WALLIS: Flow blockage, coolability of the core. Nothing to do with nuclear behavior?

MR. DAIBER: That's correct.

CHAIRMAN WALLIS: Is this something that's well understood, this precipitation of boron?

MR. DAIBER: The time at which or the rate concentration at which it precipitates out has been looked at and there's some data available with respect to what point and what weight percent versus temperature at which the precipitation would occur. The phenomena here is dealing with a cold leg break

situation where the excess ECCS fluid is spilling off the side and you're only really getting boil off in the core and steaming since leaving behind the boric acid consideration. So it's a very conservative assumption and modeling consideration.

CHAIRMAN WALLIS: So you're boiling and it's getting richer and richer in boric acid?

MR. DAIBER: Right, that's the conservative modeling assumption that's utilized to develop this time --

CHAIRMAN WALLIS: It precipitates, it sticks. It doesn't fall out or --

MR. DAIBER: That's right, right. It's assuming that once it reached that weight percent, it does --

CHAIRMAN WALLIS: Is there an experimental basis for all of this? People have actually done realistic experiments to figure out what the precipitation is and how tough it is and what its shape is and all kinds of things, issues that I can think of. I just wonder what the basis is for understanding it.

MR. CLEARY: I think by calculating a concentration using conservative methodology that a maximum concentration that's below the solubility

limit it avoids having to address all those issues which you bring up.

CHAIRMAN WALLIS: It assumes it's mixed. There aren't regions where, for some reason or other, it's got more concentration?

MR. CLEARY: That's correct, within a mixing volume and there was, as you pointed out, difference of opinion as to what constitutes an acceptable mixing volume. But within the mixing volume, yes, there is uniform concentration.

CHAIRMAN WALLIS: Do you agree with the staff eventually?

MR. CLEARY: We came to a resolution, an agreement that the Arkansas analysis is appropriately conservative. I believe the staff may be -- will be dealing with the CE methodology on a generic basis going forward in the future.

MR. DAIBER: From a conservative standpoint, we believe the methodology is conservative, eventually in the long term what we do is we initiate hot leg injection. Once hot let injection is there, then there's adequate -- we definitely know at that point there's going to be adequate mixing and adequate flow coming out of the top of the core and spillage and covering it. So it's

really just a matter of time at which you actuate that.

We also know that the methodology that CE Westinghouse uses here is very conservative. In fact, one of the most -- one of the conservative assumptions in the methodology is that all the charging flow which comes from the BAM tanks goes directly to the core. In reality, that doesn't happen. It mixes with LPSI flow at several thousand GPM. The charging flow is coming in at about 138 GPM. The LPSI flow is coming in at about 3,000 or 4,000 and LPSI-HPSI combination is well over 4,000 GPM and it truly mixes and most of that would actually fall on the floor and not go to the core.

However, here, we assume everything in that tank goes directly to the core, concentrating it very quickly, so the methodology in and of itself does embed some very conservative assumptions all with respect to the volume that's used and the spillage that's considered. We believe that the methodology in and of itself is very inherently conservative.

With respect to the ECCS analysis we reviewed the 5046 acceptance criteria and verified, as we indicated for small/large break LOCA and boron precipitation that we met the design criteria and

under operating conditions, power upgraded conditions, we believe that ANO-2 is acceptable.

With that I'd like to move on to the resolution of open items on the agenda.

There are no current open items with respect to the ANO-2 power uprate submittal. Due to the timing at which the draft SER went out and the resolution of several questions that were still open, there were in the draft SER several open items still identified. Since that time we have worked with the staff and provided them additional information to respond to those questions and at this time there are no current open items.

However, what I'll do now is -- there were three items there. We'll go through each of those items and address the issue and the resolution of those items, dealing with seam generator tube ruptures, radiological consequences, the MHA radiological consequences which is a mixing issue and the control and doses.

First, we'll go over the steam generator tube rupture dose considerations. During the original submittal to the NRC, we were using 30 minutes operator response time to generate our doses for tube rupture. Subsequent to that time we changed that to

60 minutes to give our operators more than adequate margin to address this particular event. Those calculations were submitted at a later time. They have now had the chance to review that and accept the results that we have presented for a steam generator tube rupture.

With respect to the LOCA, there were some issues with respect to the spray versus unsprayed region, the mixing that occurred and accredited in our off-site release calculations, also our limiting event for controlling dose considerations.

We do credit two interchanges between the sprayed and unsprayed regions per hour in our off-site release calculations and control room dose calculations.

In resolution of this issue with the staff, what we did was we went and we looked at where containment fans are located because at two interchanges per hour an assumption is based on the air flow coming from our containment cooling fans. We looked at the location of those fans where the intake was, where the discharge was and compared that relative to what we considered sprayed and unsprayed regions and we did an extensive review and verification of where those regions were and provided

quite a bit of information with the staff with respect to where the intake is and where the discharges are and we were able to demonstrate that the two interchanges per hour is a very conservative assumption.

CHAIRMAN WALLIS: Now is that based on just discursive arguments or is it some analysis?

MR. DAIBER: It's based on the geometry and the airflows with respect to where those volumes are. Most of the containment is sprayed, about 78 percent of it is sprayed and about 22 percent of it is unsprayed. The fans are located, themselves, under a roof per se. There's a concrete floor above them. But it's a very small volume at which they intake air.

CHAIRMAN WALLIS: So you look at the flow rates with the fans and the volume you have to clear and you figure out how long it takes to do that?

MR. DAIBER: Yes, the fan itself is drawing in what would be called an unsprayed region, but the volume that it draws in from is so small that it's effectively interchanging that volume.

CHAIRMAN WALLIS: So you're going to claim -- in reality it's more like 10 interchanges per hour or something, so you need credit for two? There is some sort of analysis behind it that says what it

really is is thus and so and therefore conservative assumption is reasonable?

MR. DAIBER: Yes. It's based on a qualitative argument based on the geometries and the intake in the sprayed regions --

CHAIRMAN WALLIS: Is this written down, this qualitative argument?

MR. DAIBER: Yes, it is, quite extensively written down.

CHAIRMAN WALLIS: Do you have it so we can read it over lunch or something?

MR. DAIBER: Yes, yes. In response to the NRC questions it's written down. And it's fairly extensive with pictures, all sorts of graphs.

The control room dose issue, as we discussed earlier our control room dose calculations were performed based on 10 CFM and leakage considerations. In November of last year we did a control room envelope in leakage test and the results of that test indicated a natural in leakage value of 134 SCFM.

MR. BOEHNERT: What kind of in leakage tests did you do?

MR. DAIBER: A tracer gas.

MR. BOEHNERT: Tracer gas.

MR. DAIBER: The 134 SCFM includes 10 CFM for operating ingress and egress.

CHAIRMAN WALLIS: 10 SCFM is very, very difficult to achieve.

MR. DAIBER: I'm sorry?

CHAIRMAN WALLIS: 10 SCFM leakage is very difficult to achieve.

MR. DAIBER: Yes, and the basis for that really goes back to just ingress and egress from the operators. So what we've done to resolve this particular issue is we've submitted to the staff a dose calculation associated with the MHA which is our limiting event for LOCA considerations, using 61 SCFM as the new bounding allowable in leakage and that value is actually back-calculated as the maximum allowable in leakage that we can have and still meet the GDC 19 control room operating dose considerations.

To further get our in leakage values down to verify that we're below 61 SCFM, we've also committed to replace the seals on VSF-9 which is one of the control room emergency ventilation filter fan housing units. That seal during the in leakage test was attributed to about 45 SCFM in leakage so we're replacing the seal on that to essentially eliminate that in leakage. The other area of in leakage was

related to the pressurization of the north wall of the back of the control room. We're also making commitments to ensure that that room would not pressurize. The pressurization comes from 2VEF-56 operating. So we've also made commitments to make sure that that room will not be pressurized to reduce the in leakage there by another 49 SCFM in leakage. Therefore, we're effectively giving our in leakage values down well below the 61 SCFM.

CHAIRMAN WALLIS: Are you doing to do some periodic testing?

MR. DAIBER: I'm sorry?

CHAIRMAN WALLIS: Are you going to do some periodic testing and checking of what the actual leakage is?

MR. DAIBER: At this point in time we are not committing to any periodic testing associated with that.

CHAIRMAN WALLIS: I remember this issue came before the Committee and we had all kinds of evidence about what really happens in these things. The main problem is that somebody leaves something open. Someone repairs something and leaves something open and then your leakage is 400 CFM or something and until someone realizes they've left something open

which may be days, your leakage is way beyond what you should be.

MR. JAMES: Bryan, this is Dale James. We are implementing a control room boundary program to address those very issues. There is some industry guidance, NUMARC guidance, NEI guidance, excuse me, out on control room boundary control programs which we will be implementing.

CHAIRMAN WALLIS: So you are going to monitor, not perhaps measure, but you're going to check all the things which contribute to linkage on a regular basis?

MR. JAMES: I'm not positive, but I think there is some criteria in there about periodic testing, depending upon the quality of the program.

MR. BOEHNERT: Yes, the staff has under consideration and I guess a generic letter and a set of Reg. Guides which we're going to hear about a little bit later this year.

MEMBER POWERS: Graham, the question I would worry about is you tested this thing, you've gotten this huge leakage from a couple of major sources. You fix those major sources. Are they hiding? Are those major leaks hiding, minor leaks, so if you went back and tested, instead of reducing to 94

CFM, you reduced it by 25, 30? I mean that seems to me to be the question that comes immediately to my mind.

The second question that comes up is you tested it for some set of conditions that you could reproduce conveniently and you're applying this to a different of conditions for an accident. It's not obvious to me how that changes your leakage.

MR. DAIBER: Dan, can you address some of this? I know when they did the testing on this, they did look at the action and condition configurations and I think Dan can address that better.

MR. FOUTS: Yes. I'm Dan Fouts. I'm supervisor of Safety Analysis. We actually did four tests. The first one was with 2 VSF 9, as we call it and we got 27 CFM leakage and we were able to account for all of that in leakage being upstream of the filter unit, so we knew where it was coming from and basically we were able to confirm we have an intact control room at that point.

The second test was at VSF 9 and I believe it was around 89 SCFM in leakage. We then turned on the 56 fans and noticed the pressurization caused us to go to the 134 which was the maximum that we got. So at that point we knew that the delta between having

the 56s on or not on, we knew the delta between the VSF 9 and the 2 FSF 9 fans and so we knew that if we took care of the leakage on the VSF 9, that we could reduce by the 45 and take care of the 56s being on, we'd reduce by the additional amount and get us down to where we are.

CHAIRMAN WALLIS: It's a whole system. And this VSF 56 is somewhere else.

MR. FOUTS: 2 VSF 56 --

CHAIRMAN WALLIS: The environmental pressure around the, on the north wall.

MR. FOUTS: The 2 VSF 56s suck out of the emergency switch gear rooms and they discharge into our controlled access area which is a wall just on the other side of the control room and pressurize that and we did make pressure sweeps of the whole area, so we knew what the delta pressures were between the different areas. When we did the testing we simulated accident conditions as best we could, so we turned off fans that weren't -- that may or may not be lost during the accident. We turned on the ones that could possibly come on, post-accident.

MR. DAIBER: Now in conclusion, as I had mentioned earlier, there are no current open items with the ANO-2 power uprate issues.

MEMBER KRESS: On this in leakage question again, you had that in leakage whether you have a power uprate or not and the power uprate doesn't really -- you got to deal with that whether you've have a power uprate?

MR. DAIBER: That's correct. The power uprate is only an incremental impact.

MEMBER KRESS: It gives you a little more dose?

MR. DAIBER: That's correct.

CHAIRMAN WALLIS: Are we going to make it to lunch?

MR. BOEHNERT: Yes. I think --

MR. DAIBER: This is the last topic. It's the risk impact.

CHAIRMAN WALLIS: Good topic to lose an appetite.

MEMBER POWERS: Think how fortunate you are not to have the chairman here and having to read the words qualitative risk.

CHAIRMAN WALLIS: Oh, I don't believe in qualitative risk.

MEMBER POWERS: Yes, but you don't get histrionic over it like the chairman does.

CHAIRMAN WALLIS: Do you want me to do an

impersonation?

(Laughter.)

MEMBER POWERS: Oh please.

MR. DAIBER: ANO-2 did address the risk impacts associated with power uprate. Our submittal is now the risk-informed submittal. However, a risk analysis was done in consideration of the power uprate efforts for ANO-2.

We did this in several forms. With respect to the level 1 and level 2 CDF core damage frequency, large early release fractions and fire vulnerability considerations, we did a quantitative assessment of those particular considerations.

A qualitative impact was performed at power uprate for the impacts with respect to the seismic vulnerabilities, external events and we also did a qualitative impact with respect to shutdown risk and I'll go into each of those.

MEMBER KRESS: Has your PRA gone through the industry peer review process certification for this?

MR. DAIBER: The model that we utilized for this particular effort has not or did not go through that certification. The revision 3 model which is our current model is going under that

certification review as we speak right now. The results from that model have reduced our CDF values lower than what I'll be talking about here.

When we started off this effort, we started with what we had available to us which was a 1997 plant model. We have updated the IPEEE model over the years to make sure the Level 1 internal event model most, as best we can represents the plant. With respect to the LERF considerations that model is effectively the same as that associated with the IPEEE submittal.

With respect to external events and fire considerations, we utilized for the fire the latest model available which had some updated initiating event frequencies associated with it. However, the P2 values conversion values from frequencies to core damage considerations, those were effectively the same as the original IPEEE considerations. And with respect to the seismic and the external events again we started with the latest available IPEEE models that were available at the time.

I'm now going to go over the internal event considerations on core damage frequency and we'll address the following areas: initiating events, frequencies, success criteria, component failure

rates, system fault tree analyses and operator responses.

The initiating events and frequencies, we first looked at those and made sure that there were no new initiates identified and no new increase in initiated frequency. There was one modification that we made. It was that CSAS actuation. That was very similar to an already modeled MSIS actuation which secures main feed and loss condenser. However, due to the fact that we've already modeled the MSIS to CSAS actuation signal wasn't a new initiator and the frequency of the MSIS was determined to be conservative with respect to the bounding issue of the new addition. And the reason for that was when we installed the CSAS actuation we installed it, keeping in mind trip hardening facets and we went back and we also trip hardened the MSIS actuation signals, so it's a frequency of an inverted MSIS which was actually reduced, even though we added the new signal.

As a result of that, there were no changes required to the current model for up rated conditions with respect to initiating event frequencies.

The success criteria was also reviewed as a result of the power up rate considerations and along the lines of success criteria, there was one change

that was noted to be necessary to update the success criteria and that was associated with large break LOCA, the amount of HPSI flow required at time of recirculation. The current evaluation model, the current power considerations uses two of four HPSI valves per pump as the acceptance criteria, recognizing the increase in decay heat associated with power uprate, we increased that requirement from 2 to 4 to 3 to 4 valves on the uprated conditions.

The other criteria associated with some of the transient event considerations, we went back and verified the success criteria there and the method of verification was the use of the code CENTS. CENTS is the CE Westinghouse methodology effectively used for doing the Chapter 15 events. We applied it in the best estimate fashion here to verify that the success criteria, the other success criterias remain value under uprated conditions.

So the only fault tree topologic change necessary for power uprate was the success criteria with respect to large break LOCA considerations at recirculation.

We also went through and looked at the component failure rates and the eventual impact of power uprate on component failure rates. And as we

discussed earlier this morning, all the plant systems and components were reviewed for verification that they could operate within the uprated conditions and still meet their design requirements. And appropriate modifications and/or set points were made to ensure that those components would still operate within the design considerations.

Based on that and the fact that we do have on-going monitored programs and look at the components themselves and trend components considerations, we determined that there was no adverse effects on the component failure rates associated with extended power uprate for Unit 2.

MEMBER POWERS: I guess -- explain to me again. Existing monitoring programs will account for additional wear. That means you'll know when it's occurring?

MR. DAIBER: Yes and/or --

MEMBER POWERS: Surely, the fact that it has occurred must increase failure rates?

MR. DAIBER: It will -- if there is -- if there is a result of that, we will pick that up as part of the monitoring programs and ultimately update the data base as necessary. But also, it allows us to watch the components and make sure we're performing

predictive maintenance on a more appropriate schedule as necessary.

MEMBER POWERS: But you've got to reflect the fact that the additional wear is occurring in your component failure rates that you use the PRA model. Surely, you can't say you're going to go fix something that's going bad on you, does not mean that you didn't experience a period of risk while it was bad.

MR. DAIBER: From the component design standpoint, we made sure that all the components were operating within the design criteria and upgraded the components --

MEMBER POWERS: That doesn't have anything to do with how you set your component failure rates.

MR. DAIBER: To actually try to predict some of that is very challenging. If the components, the pumps operating at a higher speed and the wear rate expected under the higher speed or conditions causes it to fail more frequently than if it were not, that data is not really available on a generic basis. We do take into account actual plant operating conditions to accommodate failure rates associated with components and based on that experience we do on a regular basis update component, the failure rate. So to the exact science of getting that data and

predicting that data, it's very difficult. However, from a long term perspective, the component failure rates for a specific components will be rolled into the model as we gain experience under the operating conditions.

MEMBER SCHROCK: Could you give an example of what that first bullet means and equipment verified to operate within design limits?

MR. DAIBER: With respect to components, design requirements, their ratings, their pressures, their flow rate requirements, they were all verified to be -- that the components actually were within what the vendor would recommend for the design of those components.

MEMBER SCHROCK: What does that say about failure rates?

MR. DAIBER: It gives us a good level of comfort that we're operating within where the vendor would recommend and that there would be no substantive change in the failure rates that we would expect for that component over what we've seen in the past.

CHAIRMAN WALLIS: So your failure rates are based on your experience of failure rates?

MR. DAIBER: A combination of generic plant data and review of our plant specific data with

respect to components.

CHAIRMAN WALLIS: It is based on experience of either your plant or a group of plants? It's not based on guesswork from what some manufacturer says?

MR. DAIBER: No. That's right. It's based on actual operating experience.

MEMBER KRESS: That's standard PRA procedure. There doesn't seem to be any other -- there doesn't seem to be any other way to do it.

MEMBER POWERS: No, it's not standard PRA procedure is to take into effect zero. You know it exists. I mean you're having to put things in here.

MEMBER KRESS: Yes, but you don't have any way to --

MEMBER POWERS: Yes, you do. Run a sensitivity analysis and say suppose my component failure rates change by the ratio of frequencies of repair.

MEMBER KRESS: You can do the sensitivity analysis.

MEMBER POWERS: Sure.

MEMBER KRESS: You don't know the ratio of frequency of repair just yet though. You will over time.

MEMBER POWERS: I will bet that the rotating equipment you can take number of revolutions.

MEMBER KRESS: That would be one process to do it, but the fact is there's just no way to estimate what a power uprate will do --

MEMBER POWERS: The worst way to do it is to ignore it.

CHAIRMAN WALLIS: That seems nonconservative anyway.

MR. DAIBER: We will have to -- I will point out that from the safety-related equipment that's typically required to operate post event, all that equipment was verified to essentially operate within the current design requirements. There were no additional design requirements identified associated with any of the safety-related equipment needed to mitigate these events most of the considerations with respect to where we'd come with normal operating equipment.

MEMBER POWERS: Which is the initiating events. There are two parts to the equation.

MR. DAIBER: Right.

MEMBER POWERS: There's the initiators and the mitigators. The mitigators are okay does not mean that the initiators are okay.

MEMBER SCHROCK: Failure rates, it seems to me, depend on the way the thing is operated, a wide range of things, the exposure to transients that may be damaging any number of things in the operation, but also to variations int he manufacturing process, what the thing was initially. Rotating machinery, surely related to maintenance factors. There's so many things that go together to do it, but what puzzles me is how any correlation is developed between design operation within design limits and the failure rate.

MR. DAIBER: The only --

MEMBER SCHROCK: Surely, if you operate outside design limits you would subject the thing to a higher failure rate, but how is that used in fixing failure rates that you're going to plug into your PRA.

MR. DAIBER: The real assurance that you get is the fact that you don't see any substantive changes in the component failure rates. Obviously, we're operating within what the design manufacturer recommends and although there may be small changes as a result, there are no substantive changes expected as a result of the failure, component failure rates.

MEMBER KRESS: It's just that PRAs are not sensitive to the level of a 7 percent power increase in terms of inputting failure rates and initiating

frequencies. You just can't distinguish those things at that level for a specific plant in a PRA and that's why one of the nice things to do with PRAs is to have a good uncertainty analysis. And I'm sure the uncertainty element would far and away swamp the change in 7.5 percent, but of course we don't get uncertainties when we get PRAs very often, but if we had them, I'm sure it would swamp anything 7.5 percent would do to those things.

MR. DAIBER: That's a good point and the other thing is as we'll get into later here, operator actions and response times were identified as one of the more critical areas and any sensitivities you would see as a result of component failure rates would be overwhelmed by the sensitivities we did see as a result of operator action considerations.

MEMBER POWERS: As far as I can tell it's all due to rampant speculation. I don't think you can substantiate your statements about uncertainty and I don't think you can substantiate statements about the relevant importance of operator actions and component failure rates. I mean it's just speculation. You just don't have the numbers.

MEMBER KRESS: I think you're right. If you don't have the numbers, it is speculation. Those

are tough numbers to come by.

I can do the uncertainty, probably, pretty well because there is enough data to incorporate uncertainties. I just can't do the other half and that's what the 7.5 percent of power uprate will do to that uncertainty distribution, I don't have that data.

MR. FOUTS: This is Dan Fouts. I would like to point out one other item here. We do use a substantial amount of generic data and the equipment components and so forth that we have in the plant that we're going to operate it at uprated conditions or current conditions is not seeing anything unlike what these components see all over the country as it is. So this generic data already includes to some extent whatever uprates we may be using.

MEMBER POWERS: I mean it's all bearing on unbelief here. I'm going to change things. I know clearly I am making it worse. Maybe it's incremental worse, I'm making it worse, but I leave things the same because I can't estimate the increment. I can estimate the increment, change the component failure rates by 10 percent and see if it makes any difference. I mean this is -- it doesn't strike me as even a typical thing to do. Change them by 50 percent, see if it makes any difference. If it

doesn't make any difference, then the point is substantiated.

MEMBER KRESS: I've got to tell you, it would make some difference if you changed it by 50 percent.

(Laughter.)

MEMBER POWERS: And if it did, then we would get down into a discussion of whether it was 10 percent or 50 percent is the appropriate thing.

CHAIRMAN WALLIS: Are you going to show us later on the operator actions dominate so you could be off by say a factor of two and component failure rates wouldn't make any difference?

MR. DAIBER: With respect to operator actions, the dominant effect in change in core damage frequency was on the order of 16 percent increase as a result of the reduced time available to operator action.

CHAIRMAN WALLIS: Are you going to argue if you had -- maybe you didn't do this, you didn't double your component failure rates and see the effect?

MR. DAIBER: No, we did not do a sensitivity analysis when we did this.

Again, we expected all the components to

be operated within current design parameters which is what generic data is based on and we may see a more rapid degradation in certain areas when we do our inspections, but that just means we would take correction action sooner, whether it's predictive maintenance or fact program or whatever. If there's an impact from power uprate on that, we would take action before we would ever get to the point that we would see a failure. And if we happen to miss all of that, then we'll pick it up in our periodic reviews of component failures and the other maintenance rule, updating the model for initiating event frequencies, whatever or a period of time. We're just not anticipating it based on our review of all the data that we've seen before.

Are you using generic data for that? Again, the safety related components, there were no significantly new challenge from the design--

MEMBER POWERS: I want to make sure that everybody understands. When you say you're using a generic data you mean you're using an applicable data?

MR. DAIBER: Applicable data --

MEMBER POWERS: Inapplicable data. When you say the word generic, you're admitting you don't have data for the existing thing. You're using the

best you have available and unfortunately, that's just not directly applicable.

CHAIRMAN WALLIS: So there's a lot of uncertainty associated with that.

MR. FOUTS: Well, we use generic data because we haven't had any failures on our plants so that's the best we've got available.

CHAIRMAN WALLIS: Can we move on now?

MR. DAIBER: Sure.

MEMBER POWERS: We may come back to this in the full committee.

MR. DAIBER: With respect to the system fault tree considerations, again we reviewed the plant modifications that were proposed for power uprate considerations and verified the impacts or lack of impact upon the system fault tree models. The only real modification that impacted the system fault tree models again was the CSAS actuation component. That CSAS actuation was sent to the main steam and main feed isolation valves. We did upgrade the system fault trees to accommodate that modification.

We did review operator actions associated with the PRA model. We looked at both current operating conditions and uprated conditions and to quantify the effect on associated operator actions, we

used a thermal hydroscope CENTS again in this situation and we ensured that the -- we quantified the actual change and available operator response times for a range of sequence of events in the uprated model. And we did that in a comparison basis both between current power and uprated conditions. We then were able to incorporate these new times in to the HRA models and quantify new HRA times and we did that, we went back and both quantified it, the CENTS is a new methodology that was not used originally for the original quantification for HRA, so we went back and we requantified the HRA at current power rate of conditions and to uprate it to make sure we had a good apples to apples comparison for the effect of HRA.

MEMBER POWERS: And for your human reliability analysis what were you using?

MR. DAIBER: The methodology?

MEMBER POWERS: Uh-huh.

MR. DAIBER: We used EPRI methods for the post-proceduralized operator action considerations and we used a combination of the most conservative of the cause based and cognizant reliability methods. So we looked at both of them, EPRI -- both of them based on EPRI methodologies and we take the conservative of the two, so we believe that our assumptions with respect

to HRA are very conservative and the implications of power uprate impacts are somewhat amplified due to that conservative approach that we take.

So we developed effectively two PRA models, what we'll refer to as the 2A, the pre-uprate model and then a 2B model essentially incorporated the changes in success criteria that we discussed, the changes in HRA considerations, where it rolled up into the 2B model. We quantified both of these cases and then did the comparison to get a change in CDF as a result of these impacts for power uprate considerations.

The change in CDF that we quantified on this was 2.7 E^{-6} which is essentially a 16 percent increase in CDF. This change in CDF falls within Region II, a small change per the guidance of Reg. Guide 1.174.

Then for the LERF considerations we reviewed the current IPE binning criteria that was established and verified that the power uprate considerations did not have any change or effect on those plant damage state considerations, in particular, those plant damage states related to the large early relief frequency considerations.

We then rolled in the Level 1 results that

we just discussed on top of those plant damage state fractions to come up with a change in the large early release fraction. The delta LERF then was calculated to be $9.3E^{-8}$ which effectively resulted in a 24 increase, 24 percent increase in the large early release fraction considerations. This now falls within Region III which is considered the very small changes with respect to Reg. Guide 1.174 criteria.

CHAIRMAN WALLIS: It's very interesting. There's nothing about the benefit achieved from these small changes in risk. It's an interesting way to regulate. Benefit is not part of the equation.

MR. DAIBER: The additional megawatts electric, ratio to megawatts electric, yes.

MEMBER POWERS: I'm perplexed.

CHAIRMAN WALLIS: You are what? You are perplexed?

MEMBER POWERS: I spend my life perplexed.

(Laughter.)

CHAIRMAN WALLIS: I think from the public point of view they're getting a benefit and they're getting an increased risk. All that the Agency measures is the increased risk and so it's okay. There's no risk benefit balance. In reality, that's what's going on.

MEMBER KRESS: If one had did the safety goals correctly, one would have factored the benefit to risk.

CHAIRMAN WALLIS: Yes, you have to do that.

MEMBER KRESS: So that would have been in the criteria in the first place.

CHAIRMAN WALLIS: I understand.

MEMBER POWERS: I'm willing to infer that they did do that.

MEMBER KRESS: They did account for it.

MEMBER POWERS: And they accounted to the benefit. What we, of course, don't have in these numbers is any quantification of the impacts of external events or shutdown risk.

CHAIRMAN WALLIS: Like some of the events that are coming up later on, I think.

MEMBER POWERS: We won't get any additional numbers.

CHAIRMAN WALLIS: Well, we're going to get something before 110 or something like that.

(Laughter.)

MR. DAIBER: There won't be numbers though.

CHAIRMAN WALLIS: This is well within the

regions and Reg. Guides, it's not near the boundaries?

MEMBER POWERS: I mean if you leave out half the effects, you get small numbers and everybody is happy with this myth.

MR. DAIBER: The internal fire analysis, we also looked at external events, including fire considerations. We reviewed their frequencies with respect to fire, the loading considerations and on the uprated conditions there were no effects on the combustible loading requirements, hence no change in the frequencies and the current frequencies used in the ANO-2 model are very conservative.

MEMBER POWERS: What is your prior IPEEE fire?

MR. DAIBER: We use EPRI 5 methodology for that.

MEMBER POWERS: And what did you come up with? There's a number there.

MR. DAIBER: The EPRI 5 methodology is a screening methodology.

MEMBER POWERS: Right.

MR. DAIBER: So it's utilized to screen zones. We don't do a thorough quantification of the actual risk associated with fire for using that methodology. It's used essentially to determine

insights and vulnerabilities and those places where enhanced operator guidances necessary is implemented as appropriate.

But as far as determining an explicit value we don't quantify that with respect to--

MEMBER POWERS: Is there a reported value?

MR. DAIBER: We report values based on the screening criteria, that is correct. For particular zones, we do calculate values and what we do when we do the screening though is we look at a particular zone. We assume everything in the zone is failed as a result of the fire, conservatively assume that it fails and see if it still falls below a screening criteria of $1E^{-6}$. If it falls below that, we're done. If it stays above that we may look at a little more detail. Or if it still falls within acceptance criteria at that point with appropriate operator action, we consider ourselves done with that point too. We don't necessarily look at it and truly say okay in this zone, in this particular region, this fire would only affect these particular components and only these particular components and look at it from that perspective. It's more of a graded approach and to point out vulnerabilities and show that we have adequate procedures in place to accommodate the risk

associated with fires in certain regions.

MEMBER KRESS: How many zones do you look at usually?

MR. DAIBER: I believe we have -- I don't know the total number that was used with respect to the unscreened, there were 15 unscreened zones. The rest of the zones screened out.

MEMBER POWERS: Somehow Dr. Shack reminded me that somewhere on this documentation I read 9.5 x 10^{-5th}.

MR. DAIBER: Yes, if you add up the values that we presented, I don't think I have a slide on that.

CHAIRMAN WALLIS: Are we going to get some?

MR. DAIBER: Yes, I do have a slide, a back-up slide.

CHAIRMAN WALLIS: It doesn't seem to be on your slide.

MR. DAIBER: No, I have a backup slide.

MEMBER KRESS: If you take the 15 and multiply it 1.5 times --

MR. DAIBER: 134, 135.

MEMBER KRESS: Probably where it came from.

MEMBER POWERS: My recollection of --

MR. DAIBER: 134, 135.

MEMBER POWERS: Insights document is this plant has a fire risk reported. It's adequately characterized in the nature of accurately characterized the nature of that number. I would be effusive in my abuse of the reliability of that number because it's as conservative as he says.

But I mean it does put in perspective the distinction between the normal operating events and fire as an initiator and yet we focus all of our attentions on the normal operating events.

MEMBER KRESS: Yes, the normal operating was something like CDF of 10^{-6}. The normal operating events was something like 10^{-6}.

CHAIRMAN WALLIS: Fire is an order of magnitude greater.

MEMBER KRESS: Yes, it is an order of magnitude greater.

CHAIRMAN WALLIS: Do you have the bottom line here?

MR. DAIBER: I don't have these added up.

CHAIRMAN WALLIS: You get to $1E^{-4}$.

MR. DAIBER: Right.

CHAIRMAN WALLIS: Which is above--

MR. DAIBER: That is correct. If you would add these numbers up, it comes up more than $1E^{-4}$.

CHAIRMAN WALLIS: So it looks as if fire is really a significant event for these plants.

MR. DAIBER: No, we don't believe that to be the case at all. We believe that if we truly went in and applied the same level of rigor to these numbers as we do to the IPE level of rigor to these numbers and to these events, we would get that number much lower. But that's not the methodology we utilized when we submitted our IPEEE results. The accepted methodology, the EPRI methodology that we did utilize did not require that to be done. So if one truly wanted to come up with a core damage frequency associated with fire, we would apply much greater rigor and reviewing what components truly would fail in a room as a result of the fire, what available operator actions are available, what backup equipment is truly available and apply all that additional recovery considerations to the CDF values.

So what we see here are very, very conservative numbers.

MEMBER POWERS: Let's also hasten to point out that the requirements for the fire equipment do

not approach the requirements they have for the recovery and mitigation systems in normal operating events. And so inherently you have something that is less reliable. You're not, for instance, required to meet the single failure criterion for fire protection equipment. So yes, you'd probably get some reduction, but I don't expect that it's going to be enormous reductions.

Then you run into a fundamental problem in the reliability of equipment, without redundancy, is limited. It's tough to get 10^{-6}.

CHAIRMAN WALLIS: Do we need to look at the other accidental events or external events?

MR. DAIBER: The other external events are --

CHAIRMAN WALLIS: It seems to be no impact to other external events.

MR. DAIBER: Right, with respect to other external events, the power uprate effects are really considered negligible. There is no real impact as a result of power uprates associated with all the other external event considerations.

You want to go back to --

MR. BOYD: I'm trying.

MR. DAIBER: So am I.

(Pause.)

MR. DAIBER: Seismic margins--

CHAIRMAN WALLIS: Maybe we won't need to go through all of this. There's nothing that --

MEMBER POWERS: I mean what you did is one assurance, the shutdown risk is not evaluated, but what you know is that operator times are a little bit shortened here and there, especially in mode 4 and that it's acceptable.

That's about all I expect out of human reliability analysis anyway, so it's not such a bad statement.

MEMBER SIEBER: So directly to Slide 111.

CHAIRMAN WALLIS: I'm suggesting we go to --

MR. LANE: I think that's my cue. Is there anything else you want to say relative to --

MR. DAIBER: No. I guess if that's -- real quick with respect to shutdown risks, we do look at shutdown risks. We look at the safe shutdown considerations of the plant. We do monitor that power uprate from the perspective of anything else that goes on during the outage is really within the range of what is considered during an outage and the risk associated that is managed by the plant

procedures and the automated ORAM code for consideration of all these risks.

That concludes our presentation and with great pleasure I now turn this over to Rick Lane.

MR. LANE: Thank you, Bryan. I'll go ahead and make my concluding remarks from here because I know we're getting close -- into the lunch period here,so we'll make it short. I would like to thank the ACRS subcommittee today. I really appreciate the interaction and also I would like to change the NRC staff. We've gone through a very thorough review here. We have worked hard to achieve, as Bryan mentioned earlier, the actions at this point in time with the staff and do appreciate the rigorous effort that this review has taken.

We feel that we have met the key objectives and goals that I identified in my introduction and that is first and foremost to safely uprate this unit by performing the rigorous analysis and modifications and the appropriate testing to make sure that we appropriately achieve and safely achieve the 7.5 percent uprate.

We also, very important to us, is to maintain adequate operating and design margins. We believe that the plant and the plant staff are ready

for this uprate and I thank you today for the interaction and that concludes my remarks.

CHAIRMAN WALLIS: Thank you.

MR. LANE: Thank you.

CHAIRMAN WALLIS: I think that concludes this morning's session and then we're going to hear from the staff on all of these matters this afternoon.

After that we have yet another topic to go into so we have a busy set of activities this afternoon.

In light of that, I'm wondering if we could have at least a somewhat shorter lunch break. Can we meet here at 12:15? Is that acceptable? 1:15, thank you very much.

Colleagues, please?

MEMBER KRESS: Yes.

CHAIRMAN WALLIS: Can we meet here at 1:15, is that acceptable?

MEMBER KRESS: Yes.

CHAIRMAN WALLIS: We don't need an hour for lunch, so we will recess until 1:15. Thank you very much for your presentations.

(Whereupon, at 12:29 a.m., the meeting was recessed, to reconvene at 1:15 p.m.)

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

(1:18 p.m.)

CHAIRMAN WALLIS: We come back into session. We are now going to hear from the staff on the application of Arkansas Nuclear One, Unit 2, for extended power uprate, and I believe that Tad Marsh of the NRC staff will get us going.

MR. MARSH: I do thank you. Good afternoon. My name is Tad Marsh, and I am the Deputy Director of the Division of Licensing Project Management at NRR.

The staff is here to present to you this afternoon two extended power uprate reviews. The first is going to be the seven and a half percent uprate for Arkansas Unit Two.

Just by background, this is the largest extended power uprate for a PWR that we have seen to date. Based on discussions with Westinghouse during the July 2001 meeting, the staff expects submittals for extended power uprates for PWRs in the range of 10-20 percent. So this is the first, the beginning.

Following our presentation for Arkansas, we will present the 20 percent power uprate for the Clinton plant. The Clinton power uprate is similar to Duane Arnold, Dresden and Quad Cities which you have

seen as late last year.

Clinton's application deviates from the ELTR-1 and 2 for the GD-BWR extended power uprates in four areas. These areas are transient analysis, LOCA analysis, stability and large transient testing.

We will discuss our review of these first three deviations with you, and we will also be discussing some of the background associated with the large transient testing.

Before we start our presentations, I'd like to touch on the feedback that we have received from the ACRS on Duane Arnold, Dresden and Quad Cities and our response to the ACRS in our letter of February 1st.

I'd like to start by emphasizing that our reviews of extended power uprate, we believe to be thorough and in depth. I believe that the issues raised in your letters are related to documentation of the review, not the review itself and, as we outlined in our letter, we received somewhat similar responses regarding documentation from the Office of the Inspector General on another issue.

In addition, our own self-assessment has identified documentation weaknesses which we will address. In order to improve the documentation of our

reviews, we are committed to a broad review of agency documentation practices. This effort is broader than NRR, and we are working with other offices.

In addition, at NRR we have included an issue of documentation in the NRR integrated quality plan to ensure that this issue receives the proper attention. We expect our documentation to continue to improve. I have seen significant improvements between our draft safety evaluations forwarded to the ACRS and our final safety evaluation reports. We will continue to strive for improvements in documentation.

We are attempting to ensure that our drafts meet the guidance contained in our NRR office letter LIC 101 and other guidance documents and management directives and the template safety evaluations for power uprates.

NRR management is committed to ensuring that our safety evaluations will continue to improve. We believe that the ongoing efforts related to documentation will more fully address the issues raised in your letters for further applications.

With regard to your recommendation for the staff to develop a standard review plan for power uprates, the staff has been tasked by the Commission to evaluate the merits of developing such an SRP, and

we have committed to complete such an evaluation by May 1, 2002.

Our evaluation will address -- and this is described in the letter -- the merits of developing an SRP section specifically for extended power uprates for the utilization of SE templates, building on safety evaluations already that are done, and any key improvements stemming from the integrated quality plan. We will keep you informed, of course, in this evaluation.

A key change to the review in BWRs is anticipated to occur on the approval of the GE topic report for CPPU. That's the constant pressure power uprate.

I would like to also say that in the arena briefing that we had with the Commission last week, there was a lot of discussion about power uprates, and the SRM coming from the Commission asks us to look at ways to improve the efficiency and effectiveness of the power uprate reviews.

We will get back to the Commission on a plan by June 26th, and there is a Commission meeting on license renewal and on power uprates on July 10th. There was a great deal of discussion with the Commission regarding the need for an SRP, quality of

safety evaluations, the number of plants that we see coming with their applications for power uprates. So this is an item of interest not just to the staff but to the Commission.

Moving on to the Arkansas and Clinton reviews, I would like to emphasize that we have conducted thorough reviews of these applications in all areas potentially affected by the power uprates, but the focus on the review is being on safety.

We have conducted our reviews consistent with the existing practices, including the lessons learned from the Maine Yankee experience. All the areas that are affected by power uprates have been reviewed and evaluated.

The staff has critically examined the methodologies and their application for these power uprate requests, and we have concluded that all of analytical codes and methodologies that have been used for licensing analysis are acceptable for these applications.

Although we reviewed information in many areas, we intend to focus our presentations today on areas which we believe to be the most important for power uprates. We also have NRR staff here to address any questions which you may like to be discussed.

Now I'd like to turn the presentation over to Tom Alexion, the NRR Project Manager for Arkansas. Tom will give an overview of the review process used for Arkansas application and the order of the presentations.

Before I do that, can I answer any questions you may have? Thank you.

CHAIRMAN WALLIS: Thanks very much.

MR. ALEXION: Good afternoon. My name is Tom Alexion, and I am the NRC Project Manager assigned to Arkansas.

By way of background, the seven and a half percent power uprate application by entity represents the largest PWR upgrade to date. The highest PWR power uprate previously approved by the NRC is five percent.

As you heard this morning, ANO-2 is a CE designed PWR. The architect/engineer and constructor were Bechtel. The full power license was issued on September 1, 1978. The current license maximum reactor power level is 2815 megawatts thermal, and the current net maximum dependable capacity is 850 megawatts electric. The ANO-2 has a large dry containment.

Also as you heard this morning, the steam

generators were replaced at ANO-2 in the fall of 2000. Some differences between the old and the replacement steam generators are listed on this slide.

The licensee has designed the replacement steam generators to accommodate the increase in power. I would also like to note that, when reviewing the power uprate application, the NRR staff relied upon analysis previously done at the uprated power level and supported license amendments that were issued to support steam generator replacement in the fall of 2000.

The NRR staff used the Farley five percent power uprate as a guide for the scope and depth of its review. For further review guidance in specific technical areas, the Standard Review Plan was utilized.

MEMBER SCHROCK: Excuse me. Was the Farley uprate reviewed by the ACRS?

MR. ALEXION: No, because it was a five percent.

MEMBER POWERS: We did, however, have one of our senior fellows go through the Farley uprate and provided us a brief assessment for it. Virgil, if you don't have a copy of that, we should get you one.

MEMBER SCHROCK: Thanks.

MEMBER POWERS: You are aware of that, paul?

MR. BOEHNERT: Yes. No, in fact, I think he has a copy. I think I sent it to him.

MEMBER SCHROCK: You think I have?

MR. BOEHNERT: Yes.

MEMBER SCHROCK: Probably.

MR. ALEXION: The staff reviewed the licensee's application of acceptable codes and methodologies to see that they are used within the appropriate restrictions and limitations and to ensure that they are applicable to the power uprate condition.

MEMBER POWERS: Can I bring you back to the -- Use the Standard Review Plan -- that's a massive document. It's on CD-ROM. So it's not too difficult to get around in it.

When you say they used the standard the Standard Review Plan, that was left to the discretion of each of the reviewers to pick and choose what they used out of that?

MR. ALEXION: That's correct.

MEMBER POWERS: Were they -- and of course, the presentation indicated to us what particular sections they used?

MR. ALEXION: I believe some of them do. I'm not for sure if all of them do, but I know, like for BOP, a very extensive list of SRP sections.

During the course of its review, the staff also issued many requests for additional information, and the licensee has responded to all of them. The staff also audited the licensee's risk evaluation for power upgrades, performed independent calculations with the dose assessments for those postulated accidents that result in increased dose consequences, and had a contractor perform independent calculations of the peak containment pressures and temperature following a postulated LOCA and main steamline break.

The principal areas of review are the NSSS and accident analysis, evaluations of systems structures and components, BOP systems, human factors, radiological analyses, and the risk assessment for power uprate.

MEMBER POWERS: Will you -- Did you look at a rod ejection accident?

MR. ALEXION: I think Reactor Systems did, yes.

MEMBER POWERS: And then when you come to the ability to fuel the sustained -- the powered input, what do you do there?

MR. ATTARD: I'm Tony Attard from Reactor Systems. That's one of the Chapter 15 events. So that's where we -- you know, when we did the review to make sure that that was done in accordance with the criteria specified in that section.

MEMBER POWERS: But we knew that the fuel at modern burnups can't sustain 225 calories per gram power inputs or even 100 calories per gram power inputs. What do you do?

MR. ATTARD: Well, I believe those kind of calories were for particularly high burnup fuel. So we made sure or see that they still meet the 280, you know, for new fuel like they specify.

MEMBER POWERS: Okay. So you essentially go in and say did the rod ejection accident produce 280 calories per gram. Answer is no. Therefore, everything is okay.

MR. ATTARD: Well, if they meet the criterion and they used approved methodologies, we accept it.

MEMBER POWERS: I understand.

MR. ALEXION: The order of presentation is as shown. The only open items in the draft safety evaluation were the radiological assessment area. All of the open items have since been closed, and the

closure of these items will be discussed in the radiological assessment presentation.

CHAIRMAN WALLIS: How many of these reviews contained confirmatory analyses by the staff -- by any staff?

MR. ALEXION: I think we just had the ones I mentioned.

CHAIRMAN WALLIS: You did something on the containment, I understand, didn't you?

MR. ALEXION: Yes, we had somebody -- Pressures and temperatures, we had those consequences. You said independent calculations was your question? I believe those were the two. Staff can correct me if I'm wrong.

MR. RICHARDS: Why don't we just ask the presenters to make sure they touch on that, if they did do some of those.

MR. ALEXION: As was previous discussed, the NRR staff has no open items. That concludes my opening remarks. With that, we'll go to the Reactor Systems presentation.

MR. LIANG: My name is Chu Liang. I'm a Reactor Systems Branch reviewer to review this ANO Unit 2 power uprate. There are a few other staff of the branch also participated in this review in

specific areas. Next slide.

(Slide change)

This slide identified the major review areas that we performed in Reactor Systems Branch. The first is the reactor cooling systems, ECCS and shutdown cooling systems. These safety reactor systems are reviewed and verified that there are no system modifications required to perform their design safety function under power operated conditions.

The second item, we reviewed the fuel performance. We verified that all fuel design requirements and limits are met under power operated conditions -- operating conditions.

We also reviewed --

CHAIRMAN WALLIS: You say you verified. You mean you had a statement from the licensee that they had made these calculations?

MR. LIANG: The licensee provided some analysis per our request, and verified a few things, that there were a few the review has some concern, and we review them, and we confirm that all the design requirements are met.

CHAIRMAN WALLIS: And you are convinced that they have done them correctly, because of, what, a history of doing them using approved methods, or

what? How do you assure yourself that these calculations are okay?

MR. ASTELUWICZ: This is Frank Asteluwicz, the Reactor Systems Section Chief. The answer to your question is some yes and some no. We do rely on the fact that the methods have been approved in the past, and we did look at the limitations imposed on those methods as part of our review, and confirmed that, in fact, the licensee satisfied whatever limitations were imposed on the application of those particular codes.

In most cases, we did not do an independent analysis that stuck numbers into the codes to confirm that the numbers calculated are, in fact, the numbers that the licensee generated. That's part of the way we do our analysis these days.

We rely heavily on the fact that the codes have been examined carefully or the processes are determined carefully, and then rely on the licensees to -- Basically, we audit the calculations and rely on the licensees to do them correctly.

MEMBER KRESS: Consider, for example, the ECCS code for Appendix K. Do you go back and review the validation basis for that to see if it -- including the kind of power profiles that you get with the upgrade or were they done with a different power

profile?

MR. ASTELUWICZ: The only thing I could answer -- The only way I could answer that question is that, if there were no limitations put on the use of that particular application at the time the staff looked at it, we would not generally go back to look at that. If we had some knowledge that there may be some issue in dispute, then we would go back and look to make sure that the range of applicability still occurred, but absent some unique knowledge, we would not do that.

CHAIRMAN WALLIS: So it sounds as if you are not raising new questions. You are going back to see that the old questions were suitably answered in sort of the historical record, but you don't come up with new questions to ask.

MR. ASTELUWICZ: Well, no, we do ask new questions. I'm not sure how to answer that question. We don't go back and challenge the foundation of the codes once they were approved, and I'm not sure that that's the question that you are asking. I mean, if you are asking are --

CHAIRMAN WALLIS: If somebody put limitations on the codes, it's not clear that they anticipated the kind of use that they are being put to

today when they put those limitations on. That's the thing I'm concerned about.

MR. ASTELUWICZ: I understand. We do question whether or not the codes are applicable in the range that they are being used, but we don't go back and resurrect the data and confirm for ourselves that that's true. I mean, we do ask questions about that.

MR. MARSH: Mr. Chairman, just with respect to the confirmatory analyses, the questions that you have been asking about that, whatever you would prefer doing in terms of answering that question, we can come back to the full committee at the full committee time and give you a complete and thorough list; because not all of the staff's reviews are here today, if you would like to have that type of a list.

In terms of confirmation of codes, in the Duane Arnold, Dresden, Quad Cities reviews in terms of the transient testing, recall that G.E. had said to us, and we had agreed with that, that the performance of the plant on which they were basing their transient testing hypothesis behaved very well with respect to the modeling. So there was a confirmation using empirical data of the models that were used for that

plant compared to how it actually behaved.

So there is some confirmation. I'm ont sure here with respect to the transients of the reactor coolant system or ECCS, but there is some at least in that context.

MR. LIANG: We reviewed steam supply system design transients. The licensee redefined them, and as modified slightly. Those design transients are used for design of the steam supply system to assure the system design as designed, were not -- during operation were not exceeding its stress limit, and other limitations, and we verify to assure that number of occurrences of any given transient selected for design purpose were exceeding the expected number over lifetime of the plant, and was a slightly change in the loss of feedwater transient. Change increased the number due to past experience, and changed the hydrotest requirement to less frequent due to ASME code changes.

We reviewed the LOCA and the Non-LOCA accident analyses to see there are some change in the code used, and the results of analysis meeting acceptance criteria. Next slide, please.

(Slide change)

MR. LIANG: The Reactor Systems Branch

review process: The first bullet is reviewed application to current licensing basis. We were just review the effect of the increased power to the current design.

Next we verify plant modifications meeting SRP acceptance criteria.

Many transients and accidents previously reviewed at the uprated power levels in previous Amendment submitted for steam generator replacement we already reviewed and accepted during that review.

The transient and accident analyses submitted in this submittal we reviewed against assure approved codes and the methodologies are used and the methodology codes are applicable to ANO Unit 2 to support power uprate. And we verified the results to assure the acceptance criteria for each event specified in the SRP are met. Next slide.

(Slide change)

MR. LIANG: Reactor System Branch review results for transient and accident analyses are meeting the acceptance criteria for each event specified in the SRP.

All transient and accident analyses were analyzed using staff approved codes and methodologies with all limitations and restrictions specified for

each code applicable conformed and is applicable to ANO power uprate application.

All transient and accident analyses inputs are conservative and consistent with tech specs limit.

MEMBER POWERS: In the presentation made by the applicant for one of his LOCA analyses, he indicated that a code error had been found. Could you tell us what that code error was?

MR. LIANG: Somebody help.

MR. ASTELUWICZ: We don't have that available to us right now. If you want to, we'll get back to you on that.

MR. LIANG: We also concluded the fuel design meets all design requirements and limits. That concludes our presentation.

MEMBER POWERS: Have the design requirement limits on fuel with Erbium poison in place of GadolinIum poisons been examined? Has there been any change?

MR. WU: This is Shu Lang Wu. Yes, we approved gadolinium and Erbium fuel for combustion engineering.

MR. POWER: So you've examined the peculiarities there. Now could you tell me how replacing gadolinium with Erbium changes the oxygen

potential of the fuel?

MR. WU: Oxygen?

MEMBER POWERS: Oxygen potential of the fuel

MR. WU: I don't know about the answer.

MEMBER POWERS: It must change it, putting in basically a trivalent element in place of a tetravalent element. So you have to induce some vacancies. It must change it.

MR. WU: You're talking about the number of rod or what? I don't --

MEMBER POWERS: No. I'm talking about the oxygen potential in the fuel itself. Propensity to oxidize the inside of the clad is what I'm most worried about.

MR. WU: Well, I'm sorry. I don't work with that.

CHAIRMAN WALLIS: There's no acceptance criterion for this?

MEMBER POWERS: I think there is not. I mean, there may be -- It may come in a round and about fashion because of total oxidation that you have to worry about, but it's a round-about.

CHAIRMAN WALLIS: So they are from the outside in, not inside out.

MEMBER KRESS: Yes, but it has to do with the failure of the clad.

MEMBER POWERS: You worry about the failure of clad. You also probably worry a little bit about the gap inventory changing as a result of it. I myself don't have any preconceived notions on this except --

MR. WU: Yes. We will get back to you.

CHAIRMAN WALLIS: Well, this is a summary slide that says everything is fine. Were there any particular transient analyses that you had to go back and carefully examine or anything in particular that caught your eye as requiring extra work on your part to check over or anything like that?

MR. LIANG: Yes. We asked a lot of questions, and the utility answered them, and we reviewed the assumptions, the input data to the transient and accident analysis of interest, and we also asked the code and the computed code and the methodology applicability to the ANO application, and we questioned these assumptions and got back the response to questions. We reviewed them, and we find that we satisfied some of them.

We asked questions, we have problem, because deviate from SRP a little bit, but we

confirmed that those assumptions are consistent with the current licensing basis. So we accepted them based on the current licensing basis be honored, and finally we conclude all the analysis meeting acceptance criteria and the analyses were conservative.

MEMBER KRESS: What code was used for the Appendix K LOCA analyses?

MR. ASTELUWICZ: I'm not sure. Your specific question is it was an approved topical. The number was on the licensee slide, CEN-199, whatever that number was. I don't recall off the top of my head.

MEMBER KRESS: No. What computer code did the licensee use to calculate the figures of merit for the Appendix K LOCA analyses? They used some sort of approved code.

MR. ASTELUWICZ: Yes. I'm not sure. I think Westinghouse, they used BASH and BART. Is that what you are asking? I'm not sure I understand the question.

MEMBER KRESS: Yes, that's what I want to know, the name of the code. I'd also be interested to know when it was reviewed and approved by the staff.

MR. LIANG: Yes. All the code -- In

response to staff's request, the licensee provided a big submittal of this proprietary information and identified each event, what code and methodology was applied, and the staff review SER, identified the restrictions and limitations and how they conformed them.

MEMBER KRESS: When were these restrictions and limitations placed on the use of the code?

MR. LIANG: This part is proprietary, and will be made available.

MEMBER KRESS: The when wouldn't be proprietary.

MR. LIANG: Yeah, yeah. The code, when approved, those limitations specified in staff's SER, topical reports.

MEMBER KRESS: Which was when?

MR. ALEXION: Each one has a different date.

MR. LIANG: Yeah, each one have different date. Start from 1975 and until recent, and different because we involve about 30 codes.

MEMBER KRESS: But these codes were vintage of like '75, that time frame?

MR. LIANG: Seventy-five to recent, and

the LOCA codes about 14 of them, and the non-LOCA transients using another 15.

MEMBER KRESS: They used 14 different codes?

MR. LIANG: Involved, you know, in this -- to support this application. In total, it's about -- a lot involved to support this power uprate.

CHAIRMAN WALLIS: Well, now I asked you about -- This is a very summary slide. So it doesn't give a story of something you worried about, and then you told me that when you did have concerns, you went back and had these RAIs and around and around and around and around.

MR. LIANG: Yeah, yeah. We tried to --

CHAIRMAN WALLIS: Is there some example you can give me of some concern you had that maybe you didn't bring it, but it would help a lot if we could sort of see your modus operandi. So if you could sort of convince us that the way that you went about things was thorough, then you got -- It would be nice if you had an example of thoroughness which we could look at and say, gee whiz, those guys were really thorough. Is there some example you can give us like that?

MR. LIANG: Examples, like --

CHAIRMAN WALLIS: Some example of where

you had to be thorough.

MR. LIANG: We've taken a look at their assumptions, and --

MR. ASTELUWICZ: Chu, let me interrupt. Let me try. This is Frank Asteluwicz again.

A specific example: One of the areas that we looked at carefully was the issue of long term cooling, the boron precipitation question, because we had concerns in that area.

Another area that we looked at were some of the control rod withdrawal events where in the course of a review at a sister plant, we uncovered the case where a potential tech spec was being violated, and we proceeded to probe that area on Arkansas and have them reassess it, and they are in the process of changing their tech specs to account for that particular concern.

Can I give you anymore specifics? Probably not off the top of my head.

CHAIRMAN WALLIS: That's the sort of thing, I think, would help, because otherwise it's just so general.

MR. ASTELUWICZ: I understand.

CHAIRMAN WALLIS: And if we are trying to evaluate -- I don't want to use the word credibility,

but something like that. I mean, I'd like to sort of get the good feeling that you've done a thorough job. How do I get that? I have to sort of see examples of a thorough job, which means digging in in some depth on some issue which is of concern.

MR. ASTELUWICZ: Right.

CHAIRMAN WALLIS: I don't know how we can get that.

MR. ASTELUWICZ: There will be other examples forthcoming in some of the other areas. The other -- I forgot which one I wanted to bring up, but -- I forgot. I'm sorry. But we did -- ATWS is another area we had a lot of questions, and you heard the discussions early this morning about how they have the DSS, and that was sufficient to meet the rule. We asked them, you know, to go back and make sure that the design of that particular facility -- or the design of that system would meet the intent of its function for ATWS.

CHAIRMAN WALLIS: This is the ATWS?

MR. ASTELUWICZ: Yes.

CHAIRMAN WALLIS: So to me, this is an unusual way of satisfying at ATWS criterion. Is this an unusual way of doing it?

MR. ASTELUWICZ: The rule in this area is

pretty specific. When the staff went back to rulemaking, the two specific reactor vendor types, the CE design and the B&W design, were viewed to have such a high frequency for ATWS events that the Commission felt it was appropriate to impose a modification at that time.

The Westinghouse units do not have that. So the variation between the Westinghouse designs and the B&W and CE designs are a little bit different, and we asked a different set of questions for Westinghouse units than we do for the B&W and CE types.

MR. BOEHNERT: Well, Westinghouse also had additional relieving capacity. So it had lower pressures.

MR. ASTELUWICZ: That's correct. It was a combination of everything.

MR. ALEXION: Go ahead.

CHAIRMAN WALLIS: So there's going to be -- What we are going to hear later on is going to come a little closer to what I was asking for with my last question?

MR. MARSH: Mr. Chairman, we produced some details we can give you in the containment analysis as well to demonstrate some in depth types of analyses, but I also want to point out that this review was done

in concert with the steam generator replacement review, too. So there's thoroughness that went on in that review, which you are probably not hearing right now as well.

CHAIRMAN WALLIS: I guess we didn't have the benefit of that here?

MR. MARSH: That's right. I think many of the analyses that were done associated with the power uprate were done in the context of the steam generator replacement. Okay, Tom, want to move on?

MR. ALEXION: Let's move on to the Plant Systems Branch review.

MR. CULLISON: Good afternoon. I am Dave Cullison from the Plant Systems Branch. With me is Rich O'Dell sitting over there. He performed the reviews -- the containment reviews for the steam generator replacement, and he can answer any of the questions about those reviews.

(Slide change)

MR. CULLISON: I'll start off with the next two slides are the list of the SRP sections I used as guidance for conducting my review.

MEMBER POWERS: Let me just ask, when should we ask about the steam generator reviews?

MR. CULLISON: I'll get to those a little

bit later.

MEMBER POWERS: Okay.

MR. CULLISON: I also used the Farley safety evaluation as a guide in performing my reviews.

(Slide change)

MR. CULLISON: Based on the review, essentially we found no significant impact on any of the these systems. We -- In other words, we didn't find anything that was unacceptable.

The areas I have marked with an asterisk are the ones that were reviewed for the steam generator replacement, and Rich can speak to those in a minute.

MR. ALEXION: Two slides over?

MR. CULLISON: Yes, two slides over.

(Slide change)

CHAIRMAN WALLIS: Are you going to say anything more about spent fuel pool coolant?

MR. CULLISON: Yes, I am.

CHAIRMAN WALLIS: All right.

MR. CULLISON: I had three areas which I focused on, basically because there wasn't -- I didn't think there was sufficient information in the submittal to draw a conclusion. So I asked questions of the licensee to provide that information.

Those were the fuel pool system, service water system and the emergency feedwater system. On the fuel pool system, they are a little bit different than probably most plants. They don't do a bounding calculation. They do a cyclic calculation, but their backup system is boiling, boiling from fill.

So we had discussions to make sure that they had -- We, really using administrative controls, we obtained their licensee basis of keeping the pool below 150 degrees, regardless of the heat load from the --

CHAIRMAN WALLIS: It depends on the temperature of the water they are putting in, doesn't it?

MR. CULLISON: Right. They do a combination of monitoring the reservoir water temperature and the decay time on the spent fuel, and they developed a graph so they could go to it, depending -- based on one pump, two pump.

CHAIRMAN WALLIS: So if the reservoir gets too warm, they just increase the flow rate. Is that what they do?

MR. CULLISON: Well, they can do that, and they also can let the fuel decay a little bit longer, do a calculation.

CHAIRMAN WALLIS: It may overheat while you're waiting for it to decay.

MR. CULLISON: Well, no, this is before they remove it for --

CHAIRMAN WALLIS: Oh, before it goes in?

MR. CULLISON: Before it goes into the pool.

CHAIRMAN WALLIS: Where is it then? It's in the reactor?

MR. CULLISON: It's in the reactor.

CHAIRMAN WALLIS: It's still decaying? Oh, you shut the reactor down --

MR. CULLISON: This is after they shut down, before they --

MEMBER SIEBER: Three days maybe.

MEMBER POWERS: I mean, in the past there have been some fairly heroic times. The thrust nowadays is to continuously shorten that time. I mean, it is the great fallacy that Mode 4 is such a low risk event. It's becoming higher risk all the time.

MR. CULLISON: The licensee's -- what they told me is that what they try to do is match the additional heat load from the spent fuel with the capacity of the cooling system. So they never really

increase the temperature of the pool. I found that to be acceptable.

On the service water system, I verified that the safety related service water system had the capacity to meet any heat loads -- any increased heat loads from the power uprate.

(Slide change)

MR. CULLISON: On the emergency feedwater, at the time I was doing my review there was a nonrelated license amendment to change the way they calculated the necessary amount of water in the condensate storage tanks. The idea was to go to a 30-minute supply, which would give them time to bring service water online to provide water to the emergency feedwater system.

That part of that amendment request was eventually withdrawn, and I had to go with the question to verify that they had adequate amount of water in the CSTs to meet the demands for the power uprate. They came back with the answer, and it was acceptable.

That's what I have. I have back-up slides on the continuing response analyses, and if you would like to see those or any --

MEMBER POWERS: Any areas that you listed

but didn't go into are interestingly labeled control room uninhabitability.

MR. CULLISON: That's a little -- I hadn't seen that before.

MEMBER POWERS: That's okay.

MR. CULLISON: But what that is is the -- if they have to evacuate the control room in the case of any event other than an Appendix R, that they have the ability to safely shut down the reactor. Based on my review of the information they provided, it's acceptable.

MEMBER POWERS: Okay. So this does not have to do with the dosage in the control room?

MR. CULLISON: No, it's different.

CHAIRMAN WALLIS: Are you going to talk about containment or is someone else going to talk about it?

MR. CULLISON: Rich O'Dell. I've got back-up slides. At the time I developed this presentation, I didn't know how much interest there would have been in the --

MEMBER SIEBER: I wouldn't mind having you go through that portion that you have as back-up.

MR. CULLISON: Okay, I'll go through the slides, and Rich can answer any of the questions.

(Slide change)

CHAIRMAN WALLIS: I think all you have in detail that illustrates thoroughness, the better off we'll all be.

MR. CULLISON: Okay.

CHAIRMAN WALLIS: As long as it doesn't take forever. I guess if it takes forever, we'll wait.

MR. CULLISON: One of the issues for the steam generator replacement was containment cooling. The licensee brought that up this morning. Based on their evaluations, they had to do equipment modification to the fan blades -- this is for the safety related portion of the system -- and --

CHAIRMAN WALLIS: Do you understand that business of the fan blades?

MR. CULLISON: They had to change the pitch.

CHAIRMAN WALLIS: Yes, but it did something odd, and I couldn't quite understand it. It changed the flow rate, and it changed the temperatures. I couldn't follow that.

MR. CULLISON: The changed capacity of each cooler minimized the capacity of each cooler.

CHAIRMAN WALLIS: It reduced the flow

rate.

MR. CULLISON: Reduced the flow rate.

CHAIRMAN WALLIS: Why would you reduce the flow rate if you want more cooling?

MEMBER SIEBER: Well, the issue is you burn out the motor on the fan.

CHAIRMAN WALLIS: Yes, that's right. So you protect the motor on the fan. So it's a restriction. So it reduces your ability to cool.

MR. CULLISON: Right. But to have enough capacity, they changed the tech spec to have both trains operable. They used to have -- required to have one train operable. Now they have both trains operable.

CHAIRMAN WALLIS: So now both trains are operable. Then does this involve also their analysis of mixing in the containment or they assume it's well mixed.

MR. CULLISON: I think it's well mixed. Go ahead, Rich.

MR. O'DELL: No. Containment mixing doesn't figure into this analysis. It's just heat removal capability.

CHAIRMAN WALLIS: But it goes back to the one node containment mode?

MR. O'DELL: It's a one node containment mode.

CHAIRMAN WALLIS: Are you satisfied with the one node containment model?

MR. O'DELL: The one node containment model?

CHAIRMAN WALLIS: Enough for this purpose?

MR. O'DELL: This is Richard O'Dell from Plant Systems Branch. The one node containment model is the standard model that most licensees use.

CHAIRMAN WALLIS: -- the paperwork.

MR. O'DELL: And the feeling is --

CHAIRMAN WALLIS: So they were concerned about mixing because of the spray for the thing, the spray in the unsprayed region. That's why you get involved with a more than one node idea.

MR. RICHARDS: Tom, correct me if I'm wrong, but I think that's addressed by a different tech branch later on in the presentation.

MR. ALEXION: Yes, that's in the dose analysis.

CHAIRMAN WALLIS: So at least there, there are about two different regions in the containment.

MR. RICHARDS: WE have a discussion about that coming up. It's just a little later in the

presentation.

CHAIRMAN WALLIS: So if there's a concern about containment cooling, then it might be worthwhile to revisit the assumption of adequate mixing in the containment. That's something I might do if I were a reviewer.

MR. O'DELL: The conventional wisdom is that a one node model is actually conservative, that if you have a one node model, you are mixing the steam with the air, and it reduces the heat transfer over the case where you've had stratification and you would have the steam at the top condensing rapidly, and the air forced down to the bottom.

So you have a part of the containment that has very good heat transfer and part that doesn't. As you know from another briefing, two licensees are planning to come in any day now with a map containment model that's a multi-node model, and the staff will have a chance to review that.

CHAIRMAN WALLIS: Are they going to come in with that before we get to approve the model itself? We had some questions about the model itself. We're getting a bit away from this, but I would hope that we get to thoroughly look at the basis for the model itself before these licensees come in and ask us

to accept the use of it.

MR. O'DELL: Well, it's pretty much at the same time, but yes, that will definitely be part of the review.

CHAIRMAN WALLIS: It's another one of these express trains we are standing in front of.

MR. O'DELL: We got a year, and then the train is at our intersection.

MEMBER SIEBER: I'd like to go back to the question of the fan coolers. What steps did you take after they decided they needed to change the blade pitch to assure that the motors would not burn out or fail during a DBA with full containment pressure?

MR. O'DELL: Is that an environmental containment issue? Is that an environmental qualification question you are asking?

MEMBER SIEBER: No. It isn't. It's a load question. You've got a very dense atmosphere in containment when you've got 60 pounds of pressure in there, and the motors have to drive the fans. They continue to run through the action. Is that not correct?

MR. O'DELL: I don't think -- Tom, correct me if I'm wrong. I don't think we looked at that. There are things like that when a licensee comes in

and says that they are making a change, an engineering change like that, and it appears to us, just from making the change, that they've thought through what needed to be done. That area wasn't looked at. The assumption is the licensee's engineering people can assess that.

MEMBER SIEBER: Know how to engineer it. Right. On the other hand, those fans do provide a function during an accident. Right? And are a part of the protection of containment to assure that containment will, in fact, function. Is that not correct?

MR. O'DELL: Yes, they are. They are, and your question is a legitimate question. It just wasn't addressed in this review. There's always more questions you can ask and, like I say, your question is legitimate. It's certainly a question we could have, maybe should have, asked. But we didn't.

MR. MARSH: This is Tad Marsh on the staff. Plant changes of that sort are conducted through a 5059 process which, as you know, has you do evaluations, and then they are audited by the staff as part of the inspection process or as part of the normal follow-up review.

It sounds like this type of change was not

part of the licensing process. This was another type of evaluation that they had done.

MEMBER SIEBER: Yes. On the other hand, it's a modification that you are making to accommodate a power uprate. So it's a -- To my mind, it's a condition that the power upgrade caused in the plant, and I'm curious as to whether you looked at it.

In an earlier life, I paid to have motors rewound. So there's reason for me to ask this question.

MR. O'DELL: This may be a good time to answer a previous question about specific areas that were looked at in the review that we spent some time on, and the fan coolers was an area where we had several telephone calls with the licensee and got some significant clarification from what was in the first submittal.

The licensee wasn't hiding anything. They made a statement in the original submittal that -- along the lines that they had done some analysis with the GOTHIC code concerning possible boiling in the service water, and we spent a lot of time with that and asking for the details of how the calculation was done, and they provided a lot of information that satisfied us that the boiling was a condition that was

temporary and would only be a problem at a pressure below the pressure -- the normal pressure of the service water system.

I also asked a couple of times about the technical specification requiring all four fan cooler units, because we had just -- I had just gotten done a little while before with an emergency tech spec amendment for another Entergy plant where they had a tech spec that required all four fan coolers to be operable, and one of them wasn't operable anymore, and it put them in a bad situation.

I questioned whether they really wanted to put themselves in the same situation. But at the time, there wasn't anything in the near term that could be done. So we approved the amendment as it was.

So that's an example, for what it's worth, of an area where there was discussion and a lot more information was asked for, and clarification, and results of analyses.

CHAIRMAN WALLIS: If you get boiling in a fan cooler, what happens? Does it come out into the piping? Do the voids come out into the piping or they stay in the fan cooler?

MR. O'DELL; It just limits the cooling.

CHAIRMAN WALLIS: Just a very local thing?

MR. O'DELL: Yes.

MR. MARSH: This was looked at in the context of Generic Letter -- help me. I believe it was 96-06 where we looked at the transient performance of fan coolers because of momentary heating because of temporary loss of flow. Licensees had to evaluate the performance of piping systems with the re-initiation of service water to ensure there wasn't any water hammer and loss of function of the fan coolers.

CHAIRMAN WALLIS: Been that route, too. Yes. But it's not the same thing. It's not the same problem, is it?

MR. MARSH: Well, if there's boiling in the coils of the fan cooler.

CHAIRMAN WALLIS: Unless the voids are transferred to the service water mains, it doesn't matter, does it?

MR. O'DELL: It just limits the heat transfer that you are expecting from the engineered safety feature.

CHAIRMAN WALLIS: Okay.

MR. MARSH: Okay.

MR. ALEXION: Want the next slide?

MR. CULLISON: Yes, go ahead with the next

slide.

(Slide change)

CHAIRMAN WALLIS: What is the ultimate heat sink for this?

MR. CULLISON: It's an emergency cooling pond which is a large pond that -- They actually have two. They have their reservoir and the pond, and the true ultimate heat sink is the pond, just in case the reservoir goes away.

In containment response analysis, this is an area where the staff did --

CHAIRMAN WALLIS: You're off this slide. There's a new one?

MR. CULLISON: Right. This is the one I'm on. And the containment response analysis -- this is also done as part of the steam generator replacement, and this is an example where a confirmatory calculation was performed.

CHAIRMAN WALLIS: Using a different code?

MR. O'DELL; We asked Los Alamos to do a calculation for us. They were comfortable with the MELCOR code. So they used the MELCOR code to do the analysis as a design basis analysis. It didn't include all the fission product and other types of models that MELCOR can handle and melting of fuel and

that kind of thing. It was just a design basis analysis of the containment. But they used the MELCOR code.

They looked at LOCA in a main steamline break, and it wasn't -- It wasn't a great example of a confirmatory analysis. There were problems. The contractor had an error it took a while to recognize and fix, and the licensee identified some changes they wanted to make to the input after a lot of our analysis is done. But the contractor did a lot of sensitivity studies, looking for what things were most important, and went back and adjusted the input and redid some of the calculations.

CHAIRMAN WALLIS: What numbers did they come up with?

MR. O'DELL: I believe the pressures were within a psi or so of each other.

CHAIRMAN WALLIS: A 57.6 or whatever?

MR. O'DELL: It was like 55 and 57, that kind of number.

CHAIRMAN WALLIS: That's after they adjusted some things?

MR. O'DELL: But I would rather not put too much stress on the final answers, because it wasn't that pretty of an analysis.

CHAIRMAN WALLIS: It is reassuring that at least some time in their confirmatory calculation is made.

MR. O'DELL: In the case of the steamline break, there was a very large difference between the licensee and the contractor's calculations, and we talked with the licensee, and the licensee identified to us that they used a very conservative value for the efficiency of the containment spray.

We went back and did a sensitivity study based on that, and got answers that were very close to the licensee's values. The licensee was much more conservative than the contractor's calculation.

CHAIRMAN WALLIS: These sorts of things are helpful to me, these kinds of details. Thank you.

MR. MARSH: Mr. Chairman, we were unaware that you wanted that level of detail for this presentation today.

CHAIRMAN WALLIS: We ask for whatever level of detail we think is appropriate.

MR. MARSH: We thought we were to give an overview.

CHAIRMAN WALLIS: Yes, but that's been the problem all along, I think. If you read between the lines of our letters, we say, yes, the overview looks

fine, but the real work is in the detail. So where's our assurance that the real work was good? That's the question we've been asking all along in these reviews.

MR. MARSH: Right. For today's presentation we were asked to come for an hour and a half to give you an overview.

CHAIRMAN WALLIS: I know.

MR. MARSH: Okay? And that's sort of where we are.

CHAIRMAN WALLIS: We don't have enough time.

MR. MARSH: Right.

CHAIRMAN WALLIS: But I think you understand why we are going to dig deeper.

MR. MARSH: And we would have come prepared differently.

CHAIRMAN WALLIS: That's okay. I mean, you're not prepared. Sometimes that's better.

MR. MARSH: Depends on your viewpoint.

MEMBER POWERS: I would just comment here that, as we progress through this, when we want a little more detail, that may want to color what we do in a final presentation on some of this stuff. Sometimes the oral expression is enough.

MR. O'DELL: Could I just add that the

calculations, the Los Alamos calculations, are in Adams. So they are available to the public, and --

MEMBER SIEBER: Well.

MR. O'DELL: Well, we all know where that stands. But they are available to the public, and the accession numbers referenced in the SER.

MEMBER POWERS: I'll just remind people that Los Alamos is north of Sandia.

MEMBER SIEBER: Well, getting back to this question, I think it's important that in some areas you give us some detail, as Dr. Wallis has said, so that we have a feeling as to what depth you went to to confirm the licensee's application; because otherwise it's -- you know, the acceptance criteria were met, and page after page after page of that, which doesn't help us.

So that's why I asked for this. I think we can go on and finish this up here.

MR. ALEXION: Okay. We'll go on to the next presenter then. The next presentation will be Mechanical Engineering Branch.

CHAIRMAN WALLIS: I think that's important. We know that you are going to say the acceptance criteria were all met, and we want to know what's behind it. That's the real question.

MEMBER POWERS: You know, they wouldn't even be here if the acceptance hadn't been met.

CHAIRMAN WALLIS: That's right. So we know that. That's a given.

MR. MANOLY: Good afternoon. My name is Kamal Manoly. I'm the Section Chief in the Mechanical Engineering Branch where the bulk of the review was done.

(Slide change)

MR. MANOLY: Just up front, I would like to let you know that the review in the mechanical area is pretty much the same in the -- for the pressurized as was in the boiler.

Just some components changed, like the steam generator and the moisture separators in the boilers, but the piping and the balance of plant piping essentially all the same. We look at fatigue usage in terms of compliance with ASME code they committed to.

So essentially, we're doing the same review we've done before. The components that we looked at are the reactor vessel, internals, nozzles CRDMs, the same. The steam generator is the only measured difference here, and the reactor coolant pumps, pressurizer and nozzles, and the NSSS and BOP

piping the same, and the safety related valves. That's similar.

(Slide change)

MR. MANOLY: Scope of review, still the same. We look at the methodology and the loads specified, stresses in the piping and components, and the usage factors for thermal fatigue, and also look at the acceptance criteria and the codes they committed to, and functionality of the valves, specifically in regard to Generic Letters 89-10 for MOVs and 95-07 for the pressure locking and thermal binding, and 96-06 for pressurization of isolated piping containment.

MEMBER POWERS: When you looked at fatigue, you were looking at cyclic mechanical loadings only?

MR. MANOLY: When I say COF is thermal fatigue.

MEMBER POWERS: Thermal fatigue? Okay.

MR. MANOLY: The cyclic for the flow induced, that's for the steam generator, and that's the next slide.

MEMBER POWERS: When you just mentioned that the scope was similar to the BWR, somehow --

MR. MANOLY: Yes, except for the steam

generator. That's all.

MEMBER POWERS: Well, obviously, the steam generator. There seemed to be more concern about flow induced vibration here and, in fact, I mean, the licensee made the comment that --

MR. MANOLY: Yes.

MEMBER POWERS: Is there more concern with flow induced vibration in these systems for some reason?

MR. MANOLY: You are on the last slide.

(Slide change)

MR. MANOLY: Okay, for the steam generator replacement, we looked at the finite element analysis done by the licensee. The used the ANSYS code which is one of the two mostly used codes in the country.

We looked at the CUF for fatigue and also for the allowables on the components and supports. The flow induced vibration for the steam generator, they maintained a stability ratio of .75, less than the limit of 1.0. So that was the limit imposed by the licensee on their tubes.

(Slide change)

MEMBER POWERS: Now is this, again, a piping analysis or is this a more full blown detailed stress analysis?

MR. MANOLY: The steam generator replacement, that is a piping -- components, just typical piping analysis, you know.

MEMBER POWERS: Even though they are using ANSYS?

MR. MANOLY: ANSYS, yes. The next one is pretty much identical to the boiler, NSSS and BOP piping. They used Bechtel ME101 which is used industrywide, and again you compare the limits -- the stresses to the limits in the ASME code, depending on the class of piping being evaluated.

They also calculated the CUFs for the Class 1 piping based on 60 years.

(Slide change)

MR. MANOLY: And the last slide that you were interested in was about the flow induced vibration in the main steam piping. The main steam piping was the most sensitive system to the flow induced vibration issue.

There's a study done by SWRI that the kinetic energy is basically driving force behind the flow induced vibration.

CHAIRMAN WALLIS: Doesn't seem dimensionally correct somehow.

MR. MANOLY: Excuse me? I didn't get the

point.

MEMBER POWERS: Take a derivative.

CHAIRMAN WALLIS: I think you mean a momentum flux or something like that.

MR. MANOLY: No. The kinetic energy --

CHAIRMAN WALLIS: No, I think you mean a momentum flux.

MR. MANOLY: As presented by the rho V^2?

CHAIRMAN WALLIS: Yes, something.

MR. MANOLY: Okay. That's what's proportional.

CHAIRMAN WALLIS: I think you mean a momentum flux. That's okay.

MR. MANOLY: It's flow induced vibration.

CHAIRMAN WALLIS: These always -- This always bothers me a bit, this assumption that all forces are proportionate to the rho V^2; therefore, flow induced vibration is; because flow induced vibration is a kind of coupling between mechanical and fluid, and sometimes you can get odd resonances or things happening --

MR. MANOLY: That's true.

CHAIRMAN WALLIS: -- that are not reflected just in the momentum flux.

MR. MANOLY: That's true, but also the

clear change in numbers and the values, like the cycle pressure was 769.

CHAIRMAN WALLIS: As long as you are away from resonance, it's fine. When you get near resonance, everything is quite different.

MR. MANOLY: Very true. But the fact is that the flow vibration issue is better with the replacement generators and the part operates regime. Despite that, they are going to be doing monitoring during start-up using the procedure in OM-3, using hand held devices which is acceptable.

CHAIRMAN WALLIS: What's a hand held devices? Hold it up to the pipe and see how much it's shaking?

MR. MANOLY: Yes. That's basically what we can prepare to address.

CHAIRMAN WALLIS: It's an accelerarometer or something or is it something you just feel?

MR. MANOLY: No, no. It is right against the pipe.

CHAIRMAN WALLIS: It's an accelerarometer, though, isn't it?

MR. MANOLY: Yes.

MEMBER SIEBER: It's the differential between how much the pipes are shaking and how much

the engineer is shaking.

MR. MANOLY: Are there any questions you might have?

CHAIRMAN WALLIS: What sort of frequencies does it vibrate at, range?

MR. MANOLY: I don't have the numbers. Maybe, Dr. Wu, do you have the numbers for the frequencies?

CHAIRMAN WALLIS: Order of magnitude?

MR. ALEXION: Low frequency.

MR. MANOLY: We can get it to you. We don't have it right now.

CHAIRMAN WALLIS: Well, is it hertz or kilohertz or --

MEMBER SIEBER: It may be hertz.

CHAIRMAN WALLIS: I'm just trying to see if they scaled it right.

MR. MANOLY: But I just didn't have the magnitude itself.

CHAIRMAN WALLIS: Is it sub-hertz?

MR. WU: This is a low frequency fatigue. So low frequency.

CHAIRMAN WALLIS: Less than a hertz, isn't it? Less than a hertz?

MR. WU: Well, it could be -- Should be

greater than one hertz.

CHAIRMAN WALLIS: Should be greater than one hertz?

MR. WU: One hertz, yes.

MEMBER SIEBER: Five to ten.

MR. MARSH: Five to ten.

MR. MANOLY: Any other questions? Okay, thank you.

CHAIRMAN WALLIS: Thank you.

MR. MARSH: Next we'll hear from the Materials and Chemical Engineering Branch.

CHAIRMAN WALLIS: Well, I'm just curious here. What sort of amplitude do you get? When do you get an amplitude that concerns you? Are you looking at amplitudes of a millimeter or a meter or what?

MEMBER SIEBER: That would be in the lower frequency.

MR. WU: Yes, lower amplitudes. They are measured by the micro-inch, very small, yes, very small.

MEMBER SHACK: The piece above the threshold for high frequency fatigue, he's got a problem.

CHAIRMAN WALLIS: Right.

MEMBER POWERS: What you want to do it

talk to Jit and have this -- when they go through this power ramping up, you can visit the plant and help the engineers do the hand held.

CHAIRMAN WALLIS: Well, when you go to oil refineries, you do get motions of several centimeters.

MEMBER SIEBER: Yes, and you do in power plants, too.

MEMBER POWERS: Not for a great deal of time, though.

MEMBER SIEBER: They don't necessarily occur at full power either.

CHAIRMAN WALLIS: No.

MEMBER SIEBER: You know, it could be at any power level. It depends on the tuning of the system.

MR. MARSH: Depends whether it's in a resonance region or whether you are far from resonance or not.

CHAIRMAN WALLIS: That's the whole question. That's why just rho V^2 doesn't really answer that.

MR. MARSH: Right. Sometimes they measure acceleration as well as velocities and displacements, because acceleration is a more meaningful parameter for some of these systems.

CHAIRMAN WALLIS: Okay, thank you.

MR. ELLIOT: Hi. I'm Barry Elliot from Materials and Chemical Engineering Branch. Next slide.

(Slide change)

MR. ELLIOT: We review -- In the Branch, we review nine systems components and analyses. They are listed up on the slide. We review the fuel pool capability to remove decay heat and fission products from the following power uprate.

I want to explain how I am going to do this presentation. The first six items I'm going to run through rather quickly, and the last three items I'm going to go through in a little more detail.

So I'm just going to say for the first six items what we review -- basically what we review. We determined if they were adequate.

The second item is we review the clean-up and shutdown capability of the CBCS following power uprate. We review containment spray systems' ability to remove iodine following LOCA for power uprate conditions.

MEMBER POWERS: Say that again. You look at the containment spray system for what?

MR. ELLIOT: Ability to remove iodine

following LOCA for power uprate conditions.

MEMBER POWERS: And find it's poorer all the time.

CHAIRMAN WALLIS: That's the only stuff it removes?

MR. POWER: That's the only thing they give credit in PWRs for. BWRs, on the other hand -- water is different in the two.

MR. ELLIOT: We review the impact of power uprate on the previous review leak before break analyses. We review the impact of increases in primary system temperature and secondary flow rate on the water chemistry program, and we review the impact of power uprate conditions on flow assisted corrosion program. Next.

MEMBER POWERS: Now you have elected to go quickly through the FAC analysis, but that strikes me as very important, and I'm concerned about the licensee's analysis here. I mean, he can't be very familiar with the code. He doesn't even spell the name of it correctly in his Vu-Graph.

So did you look -- I mean, what did you do to look at his analyses?

MR. ELLIOT: We know that there is a small increase in the corrosion rate temperature, and what

we just look at to see is if the code is capable of -- We were depending on our CHECKWORKS code to predict the locations that are susceptible and, therefore, need inspection.

That code still can be used for the power uprate. We determined that, and so we are relying on that code to predict where to look and inspect for the flow assisted corrosion.

MEMBER POWERS: And none of those vulnerable locations were found to change, I think.

MR. ELLIOT: I don't know if they're found to change or not. Chris, do you know if they found a change?

MR. BARCHEVSKY: I didn't hear that question.

MR. ELLIOT: The question is, did any locations change, critical locations change?

MR. BOEHNERT: Identify yourself, please.

MR. BARCHEVSKY: Yes, there was some -- Chris Barchevsky. There were some changes in the code which have to be modified. So the code was slightly modified to predict, you know, erosion/corrosion.

MEMBER POWERS: The question is: In the piping system that they have in the plant now, they have certain areas that they monitor closely for flow

assisted corrosion. Did any new areas appear that --

MR. BARCHEVSKY: No.

MEMBER POWERS: No? Just all the same places?

MR. BARCHEVSKY: The same places.

MEMBER POWERS: And you are content with that, I take it?

MR. MANOLY: Yes.

MEMBER SHACK: Now what changes were necessary in the code?

MR. BARCHEVSKY: Of changes? Well --

MEMBER POWERS: Changes in parameters or changes in the code?

MR. BARCHEVSKY: Yes. The changes were mainly velocity. The velocity is different. The velocity parameter had to be modified, hanged.

MEMBER SHACK: Okay. I mean, so we're talking about input changes.

MR. BARCHEVSKY: That's right, inputs in parameter.

CHAIRMAN WALLIS: Is this a rho V^2 effect, too?

MEMBER SIEBER: Everything is.

MEMBER POWERS: Well, you could certainly cast it as a rho v^2. We usually don't, but to

accommodate you, I think we could.

MR. ELLIOT: Next we are going to talk about the Alloy 600 program.

(Slide change)

MR. ELLIOT: The concern here is primary water stress corrosion cracking of piping that is connected to the RCS, the pressurizer and the vessel head penetration. Cracking in the vessel head penetrations were subject of an NRC bulletin, Bulletin 2001-01.

In this part of this program, PWRs were ranked by the MRP according to the operating time and effective full power years required for the plant to reach an effective time and temperature equivalent to Oconee Unit 3 at the time that circumferential cracking was identified in that unit.

The licensee has performed that type of calculation. It turned out that the uprate increases at T_{hot} from 604 to 609. The impact on the head was to increase the ranking to, I think, 14.5 EFPYs -- or decreased -- It would increase susceptibility and, therefore, its ranking was 14.5 EFPYs.

Also there is the increase in T_{hot} would not substantially increase the primary water stress corrosion cracking initiation in growth rate.

CHAIRMAN WALLIS: When you read these, it sounds as if you are the licensee. What makes it different when it's a presentation by you and the staff?

MR. ELLIOT: In this case here, we do check. We confirm the susceptibility ranking ourselves. Using the inputs from the temperatures, we confirm their ranking, and that's one of the things that we do for the staff.

CHAIRMAN WALLIS: How do you -- What process do you go through to confirm their rankings?

MR. ELLIOT: Well, we talk to them about what temperature the head is, what temperatures the nozzles are at, and we know how long they operate for. They give us that, and then we put the time and temperature into the equations --

CHAIRMAN WALLIS: Pretty simple.

MR. ELLIOT: -- and determine the effective full power years to reach equivalent to Oconee.

MEMBER POWERS: I guess I'm a little perplexed -- as I say, I spend a lot of time being perplexed -- that the numbers you quote up here for temperatures are not the temperatures of the head.

MR. ELLIOT: No, they are not. The

temperature at head is 14.5 degrees below those temperatures.

MEMBER SIEBER: It's a cold head.

MEMBER POWERS: See, when I try back of an envelope calculation here, and based on the changes in time, I come back, and say that you are using an activation energy for stress corrosion cracking, must be around 40 kilocalories. Is that roughly correct?

MR. ELLIOT: Alan, you want to tell them how we do this in more detail?

MR. HIZER: This is Alan Hizer of NRR. Actually, I think it was on the order of 32.

MEMBER POWERS: Thirty-two? Does that strike you as a little low for stress corrosion cracking? Not a bad guess, by the way, to get 40.

MEMBER SHACK: Actually, the growth rates are typically around 32. Initiation is typically more like 40 to 45. I think they actually use a slightly higher number for initiation. I thought it was like 40.

MR. HIZER: For the susceptibility rankings, since a lot of that was thought to be growth driven --

MEMBER SHACK: Growth driven, you use the crack growth initiation. Okay.

MR. POWERS; Okay. My numbers are roughly correct. Not a bad guess.

MEMBER SIEBER: On the other hand, the relationship between susceptibility and temperature is not linear. Right?

MEMBER POWERS: No, no.

MEMBER SIEBER: Okay. And the reason why this plant comes in okay is because it's a cold head plant. Is that true?

MR. ELLIOT: Right. We have plants that operate at higher temperatures than this.

MEMBER SIEBER: If the head were operating at 609, would you be concerned?

MR. ELLIOT: At what?

MEMBER SIEBER: Would you be concerned?

MR. ELLIOT: We would be a lot more concerned. We are only talking about five degrees here. You're talking about increases by 14. That's a lot.

MEMBER SIEBER: Yes, and it's nonlinear, too. Right?

MR. ELLIOT: Right.

MR. HIZER: Just as a reference point, before the power uprate conditions they had a susceptibility ranking of a little over 17 EFPY. So

just the five degrees dropped them by a little over 2 EFPY. So that's -- But it kept them within the same bin, if you will, from the Bulletin, the moderate susceptibility bin.

MR. ELLIOT: A higher temperature like you're talking about could put them in a higher bin. Just means they have to do a different inspection, but what they talked about this morning was they're planning on doing an ultrasonic inspection. So even if they were in the higher bin, they would still do -- they are coming out doing what would be necessary for a more susceptible plant.

MEMBER SIEBER: But when you look at susceptibility, regardless of whether it's a hot head or a cold head, you look at the hotleg safe ends. That should be an issue and an area that would gather more of your attention. Could you describe to us what you did related to the safe end welds?

MR. ELLIOT: -- two welds on this plant are piping connected to the reactor coolant pumps, and the --

MEMBER SIEBER: And the vessel.

MR. ELLIOT: No, the vessel is -- This piping is ferritic.

MEMBER SIEBER: Oh, okay.

MR. ELLIOT: So it doesn't have -- Then you have the surge line that has connections -- and then there's instrument lines that go into --

MEMBER SIEBER: Small bore, right.

MR. ELLIOT: Yes, that have that. So they are part of the Bulletin 2001-01 susceptibility ranking. For those, we are relying on the Generic Letter 88--5, walkdowns and the in-service inspection program. And the small increase in temperature really has no impact on the ability of those programs to do an effective job. They will still do their effective job on those types of plants that are not part of the head.

MEMBER SIEBER: And other than saying it's a small change, no other work was done. Right? This is more of a judgment call?

MR. ELLIOT: The key area here is that there is a change in the growth rate. It initiates sooner, but we have plants that operate higher than 609. They have operated many years higher than 609. Maybe it's a hotleg temperature, and so our experience with those are very good.

The programs that -- The walkdown programs and the inspection programs are adequate. So they should be adequate for this plant, because they aren't

increasing it that much temperature.

MEMBER SIEBER: Okay.

MR. ELLIOT: The rest of this slide is self-explanatory.

The next issue is really dear to my heart, neutron fluence and reactor vessel integrity. Appendix D, 10 C.F.R. establishes Scharpey upper shelf screening criteria, and 10 C.F.R. 50.61 establishes RT^{PTS} screening criteria for pressurized thermal shock.

Appendix G, 10 C.F.R. Part 50 established fracture toughness criteria for pressure temperature limits, and are also used for low temperature overpressure protection setpoints for operation of the reactor pressure vessel during heat-up, cooldown, and hydrostatic test conditions.

Now the upper shelf energy and RT^{PTS} values have -- are screening criteria. The pressure temperature limits are not screening criteria. They just updated based upon the fracture toughness of the vessel.

CHAIRMAN WALLIS: Does the fluence go up or down at this?

MR. ELLIOT: The fluence goes up here with the powerup.

CHAIRMAN WALLIS: Does it go up