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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

THERMAL-HYDRAULIC PHENOMENA SUBCOMMITTEE

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TUESDAY,

APRIL 23, 2002

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ROCKVILLE, MARYLAND

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The subcommittee met at the Nuclear Regulatory Commission, Two White Fling North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., with Graham B. Wallis, Chairman, presiding.

SUBCOMMITTEE MEMBERS:

Graham B. Wallis, Chairman

Thomas S. Kress, Member

Graham M. Leitch, Member

John D. Sieber, Member

ACRS STAFF PRESENT:

Paul A. Boehnert

Sanjoy Banerjee, Consultant

Virgil Schrock, Consultant

ALSO PRESENT:

Zena Abdullahi, NRR
Singh Baywa, NRR
Herbert Berkow, NRR
Ralph Caruso, NRR
Richard Eckenrode, NRR
Raj Goel, NRR
George Georgieu, NRR
John Hanon, NRR
Donnie Harrison, NRR
Tai L. Huang, NRR
Thomas Kosity, NRR
Richard Lobel, NRR
L.B. (Tad) Marsh, NRR
Brenda Mozafari, NRR
K. Parczewski, NRR
Dale Thatcher, NRR
N.K. Trehan, NRR
Tony Ulses, NRR
Mike Waterman, NRR
Jim Wigginton, NRR
Cheng-Ju Wu, NRR
Terry Bowman, CP&L
Eric V. Browne, CP&L
Tom Dresser, CP&L

ALSO PRESENT:

Paul Flados, CP&L
Cornelius J. Gannon, CP&L
Mark Grantham, CP&L
Robert Kitchen, CP&L
Larry Lee, CP&L
Daniel Poteralski, CP&L
Mark Turkal, CP&L
Michael S. Williams, CP&L
Blane Wilton, CP&L
Larry Yemma, CP&L
Fran Bolger, General Electric
Hoa Hoang, General Electric
Carl Hinds, General Electric
Dan Pappoane, General Electric
Jason Post, General Electric
George Strambook, General Electric
Ben Gitnick, ISG, Inc.
Brian Hobbs, VYNPC
Lawrence Lee, ERIN
Emin Ortalan, PSEG
R.H. (Jackie) Wright, TVA-BFN

I-N-D-E-X

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

(8:31 a.m.)

CHAIRMAN WALLIS: The meeting will come to order. This is a meeting of the ACRS subcommittee on thermal hydraulic phenomena. I'm Graham Wallis, the Chairman of the subcommittee. Other ACRS members in attendance are Tom Kress, Graham Leitch and Jack Sieber. ACRS consultants in attendance are Sanjoy Banerjee and Virgil Schrock. I'd like to welcome Dr. Banerjee to this committee. Dr. Novak Zuber (phonetic) served us very well for many years and we're looking for a replacement that --

MR. KRESS: That's a hard act to follow.

CHAIRMAN WALLIS: -- that would be the caliber of Dr. Zuber. There's no way I could compare you to Dr. Zuber, you're completely different people but the caliber is certainly comparable. The subcommittee will begin review of the application of the Carolina Power and Light Company for a core power uprate for the Brunswick Steam Electric Plant's Unit's 1 and 2 and the NRC staff's associated safety evaluation.

The subcommittee will gather information, analyze relevant issues and facts and formally propose positions and actions as appropriate for deliberation 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 March 20, 2002. Portions of the meeting will be closed to the public to discuss information considered proprietary to General Electric Nuclear Company, Nuclear Energy.

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 that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard. We have received no written comments nor requests for time to make oral statements from members of the public.

We'll now proceed with the meeting. I would like to finish, if at all possible, the Brunswick presentation before lunch. We'll have a break at some convenient time in the morning and then move to the staff presentation in the afternoon hoping that that will be over before about 4:00 o'clock. So without more ado, is Bob Kitchen ready to present? It's all yours.

MR. KITCHEN: Thank you. Good morning. I'm Bob Kitchen, the project manager for the power uprate at the Brunswick Station. I'd like to start first --

MR. BOEHNERT: Use the microphone, Bob. Thank you.

MR. KITCHEN: Is that better?

MR. BOEHNERT: Yes.

MR. KITCHEN: I'd like to start first by giving you an overview of the project for power uprate at Brunswick and also to give you reference points to understand the current operation of Brunswick. Brunswick actually did a five percent uprate several years ago so our current power level relative to the original licensed power level is 105 percent.

We also operated on a two-year operating cycle which, I think, we're the first EPU for the committee on a two-year operating cycle. Our request for extended power uprate is actually an additional 15 percent increase from where we currently operate today and that will put the station at 120 percent operation relevant to our original license.

The difference from our previous uprate are one of the more significant ones for us. On our previous uprate, we did actually raise reactor pressure in association with that uprate. The extended power uprate proposed for Brunswick this times does not include a reactor pressure increase. The uprate, similar to the others that the ACRS has seen, will be performed in two steps with a license receipt. We will implement the first increment of uprate on Unit 1 to about 112 percent power relative to our original license. That's limited by our fuel load for base load operation during the cycle.

On Unit 2, we actually loaded fuel to the new fuel type that we need for the two-year cycle and uprate previous outage on Unit 2 so we were able to take a little bit advantage of that and our first step on Unit 2 will be a little bit higher in power up to 115 percent relative to original power.

Dr. Schrock: On the pressure, does the no pressure increase refer to the current pressure rating or the original pressure rating?

MR. KITCHEN: It refers to the current pressure rating.

Dr. Schrock: Thank you.

MR. KITCHEN: The second step --

MR. LEITCH: Bob, are you seeking at this time the license increase all the way up to 120 percent?

MR. KITCHEN: Yes, sir.

MR. LEITCH: So that in the cycle, the one cycle, between the first physical work and the second physical work being done, you would be operating at approximately 112 to 115 percent but during that interval, the license would be 120 percent?

MR. KITCHEN: Yes, sir, that's correct. We're actually limited by balance-of-plant equipment and I'll show you the modifications that we're doing and you'll see why that is.

MR. LEITCH: Thanks.

MR. KITCHEN: Just to give you some reference point on our core operation, originally we were licensed to 2,436 megawatts thermal. The uprate that we are proposing would take the plant to 2,923 megawatts thermal. That's a 20 percent increase again from our original license.

MR. KRESS: Are these identical for both units?

MR. KITCHEN: Yes, sir.

MR. LEITCH: So when you're talking about it, you're talking about both units.

MR. KITCHEN: Yes, sir. You can see the core steam flow, B flow, increase would be proportional to the power increase and you can see the pressure change from the previous uprate. We went from 1020 to 1045 and that will remain constant for this uprate.

Just to give you, this is our current power flow operating map. I know you've seen these before, just to show you where we are operating. The 100 percent on this map refers to current power operation, 100 percent, so that includes the stretch uprate to five percent shown in the green band on the power flow map. The extended power uprate region is shown in yellow and is the upper 15 percent that we're talking about on this power increase.

Modifications; we'll refer to the safety significant modifications that the plant's going to perform. We need to increase the Boron concentration in our standby liquid control system to provide cold shutdown reactivity requirements for standby liquid control. We'll be doing that prior to the second fuel load on each unit.

CHAIRMAN WALLIS: Is someone going to explain that? I read what you intend to do. I didn't see what -- is there an acceptance criterion you are trying to meet by this change in concentration?

MR. KITCHEN: Yes, sir, we'll talk about that a little more later.

CHAIRMAN WALLIS: You'll give us a logical explanation of why this meets some criterion.

MR. KITCHEN: We'll show you the reactivity requirements.

CHAIRMAN WALLIS: Okay, thank you.

MR. KITCHEN: We've also -- associated with this uprate, we've changed our power range neutron monitoring system. We've gone to digital instrumentation and that also involves a change from out thermal hydraulic stability solution. Currently we operate on one unit, that's stability solution E1A, that's Unit 2. Unit 1, which was the first unit to operate, has been converted to -- with the new system, to thermal hydraulic stability Option III. That system was installed during the refueling outage that we just completed on Unit 1 at the end of March.

And finally, we've got unit trip load shed modification which is an electrical modification to insure that under accident conditions that we would maintain the required voltage at our emergency busses. At Brunswick our emergency busses are fed from offsite through balance-of-plant busses. This modification is planned to insure that the required voltage is maintained under all conditions.

As you've seen, the extended power uprate really is much more challenging for balance-of-plant equipment than the previous uprate and more significant modifications to the plant required our balance-of-plant modifications and we have quite a list. The first is the high pressure turbine replacement. This is required to provide the needed steam flow for uprate as well as the power generation requirements.

Along with that is a change in our electro-hydraulic control system, EHC, that currently on one unit we operate on Unit 2 with 3-Arc, we're going to 2-Arc partial control.

MR. SIEBER: You expect, that means you have nozzle banks that aren't being used.

MR. KITCHEN: We operate the valves, yes, steam chest entry is staged with three valves first and then one valve as we go up in power.

MR. SIEBER: Do you worry about cracking of the nozzle bore?

MR. KITCHEN: Yes, sir, that's actually the reason why we changed from a 3-Arc to 2-Arc. As you mentioned, there is a pulse stimulus on the first stage high pressure turbine buckets because of partial arc and GE's design review of that indicated that we needed to go to 2-Arc which provides more fold around the nozzle block steam emission and reduces that stress level.

MR. SIEBER: All right, thank you.

MR. KITCHEN: Also we need to replace reactor feed pump turbines to provide -- also to meet design requirements for bucket loading as well as horsepower requirements for the turbine, for the pumps. We've got several feedwater heaters. You'll see this listed in both stages. Primarily those are changed because of tube plugging that we'd had over the years and with the uprate we needed to replace the heaters to support that.

We've got also some actions that were taken to improve grid stability under operate conditions. A couple of things factor into that and we're going to discuss that more in detail with our presentation later but as we increase the load on the units and also as our area transmission load increases we can effect stability.

A couple of modifications that we're doing there, we're going to discuss these with you later in the presentation, is the power system stabilizer which is a feedback modification on our generator as well as out-of-step protection to protect not only the grid but also the generator being installed.

MR. SIEBER: With respect to the feedwater heaters, these are going to be larger in surface than the originals?

MR. KITCHEN: Actually, the feedwater design that we have for the -- we have five stages of feedwater heating -- are adequate for uprate. Our design review indicated those that would be limiting because of tube plugging or other degraded conditions in the heaters just from normal service life. And those are the ones that we're replacing. Where we replaced them, we're trying to optimize the design. So, in fact, we do try to use a larger heater and that's really for efficiency more than uprate support.

MR. SIEBER: But that gives you a plugging margin, too, right?

MR. KITCHEN: Yes, sir.

MR. SIEBER: Okay, what materials are the tubes?

Dr. Schrock: You're not redesigning the feedwater heating system for higher thermal efficiency. It's basically the same thermal cycle as the original one?

MR. KITCHEN: Yes, sir, it's the same thermal cycle. We're just trying to take advantage of a new component with larger surface area for better heating on that heater.

I need to check. I think the tubes are stainless but I need to check on that.

MR. SIEBER: Were the original stainless?

MR. KITCHEN: I don't remember.

MR. SIEBER: Okay, thank you.

MR. KITCHEN: Yes, sir.

MR. SIEBER: That's not so important you have to go and check it.

MR. KITCHEN: Okay.

MR. SIEBER: Okay?

MR. KITCHEN: We're also going to -- our first uprate we pulsed more power out of the generator on the bus bars and we need to increase the cooling, our bussed out cooling, so we'll be doing some modifications there.

These are the mods that are being done for the first uprate. The modifications that you see listed here have been completed on Unit 1. We just finished a refueling outage at the end of March and we'll be doing these mods, similar mods on Unit 2 next year.

For the second uprate on each unit, we have additional modifications to perform. Our main transformers become limiting at about 115 percent of our original power, licensed power. So we'll be replacing those on each unit as well as putting in new feedpumps to increase capacity and provide better margin on our feedwater system with new feedpumps. We're going to upgrade our condensate pumps and motors. We want to maintain -- currently we run three condensate pumps and three condensate booster pumps in our system with -- we have those three pumps available. We run two pumps with one standby and our desire is to maintain a standby pump under operate conditions. So to support that, we're going to make some changes in the motors and pumps to enable a standby pump to be maintained.

And finally, we're going to moisture separator reheaters. Again, like feedwater heaters, there's really two drivers there. One is to insure that we don't have flow vibration problems, although our review indicated we would not, but also to gain significant efficiency improvement through the moisture separator bundles.

MR. KRESS: When you say you upgrade a condensate pump and motor, does that mean you just rewind the motor or -- and redo the rotor on the -- or do you replace the whole thing?

MR. KITCHEN: We would replace the motors where they exceeded their design rating.

MR. KRESS: But you'd keep the same pump attached to that?

MR. KITCHEN: Yes, sir, now the condensate pumps, we would actually make a modification to one of the stages to insure that we had adequate net positive suction head. So there are some changes in the pumps but the overall pump itself remains.

MR. KRESS: Okay.

MR. LEITCH: There's an auxiliary circulating water system or condensate cooling system that I read about, are you going to discuss that?

MR. KITCHEN: I hadn't planned to but we can. We're actually still reviewing the need for that system. That is a system of heat exchangers which basically just routes the condensate flow through two stages of heat exchangers, regenerative and non-regenerative heat exchangers that reject heat through a cooling tower system as designed. The driver for that is condensate temperature and the impact that it would have on sulfates and chemistry and we're still working through -- we're actually hopeful that we can avoid the need for that system and right now looking hard at whether we'll have to put it in at all.

If we do install it, it will be installed in the second uprate.

MR. LEITCH: Okay, I guess the -- it seemed like there was a couple of mechanic draft cooling towers. Would the plan be like a closed circulating water system?

MR. KITCHEN: Yes, sir. Actually, the make-up water, they're water cooled towers. They would be three towers located on the roof of one of our buildings in the power block, and the heat exchangers would reject heat to those towers. The tower make-up water would come from our county water system and then chemical control for normal cooling tower operation.

MR. LEITCH: Okay, but that whole issue is still -- there still is some doubt about whether you're actually going to do that.

MR. KITCHEN: Yes, sir. I think probably we will not need that modification.

MR. LEITCH: Then failing that, assuming you're not doing that, would the turbine operate at a higher back pressure? In other words, I'm picturing a higher condensate, a higher circulating water temperature.

MR. KITCHEN: Actually, the system would not effect our condenser vacuum. It's on the -- the system is installed on the inlet to our condensate demineralizer, so it's downstream of the condenser and it really would not have any significant impact on our condenser vacuum at all.

MR. LEITCH: Isn't there a concern about the temperature that the resin would be exposed to in your filter demineralizers? Where are they in the cycle? They're --

MR. KITCHEN: Our flow is through -- we have condensate filter demineralizers first that filter out particulate as well as some -- they are not resin coated and then the flow goes through condensate deep-bed demineralizers.

MR. LEITCH: Oh, deep-bed demineralizers?

MR. KITCHEN: Yes, sir, and you're exactly right, the concern is how much temperature can you allow and not cause a chemical release to be a problem? Sulfates are the only release of significance there at the temperatures we're looking at operating.

And we were hopeful that we're going to be able to not have to cool that condensate temperature to maintain appropriate sulfate levels.

MR. BANERJEE: Are you making any modifications to the chemistry control system for --

MR. KITCHEN: No, we're not.

MR. BANERJEE: Not at all.

MR. KITCHEN: No, sir.

MR. BANERJEE: You're adding zinc?

MR. KITCHEN: Yes, we did. We're going to talk a little later about our reactor chemistry control, specifically hydrogen water chemistry injection.

MR. LEITCH: Back on the safety related modifications, I was wondering if you had to do anything to the -- to avoid potential instability, if you had to make any changes. I guess, basically, my question is, how does Brunswick avoid an instability region on the power flow map and are you changing that at all?

MR. KITCHEN: No, sir. We changed our stability solution but it really is a desire to -- for a couple of reasons on the power range system, the driver was not the -- that we had to go to a new thermal hydraulic stability solution. We currently operate with E1A which is acceptable for power uprate but it's -- there are a little bit more operational restrictions with E1A than with Option III.

And with Option III we saw benefits in the automatic SCRAM protection and the -- a little bit more flexibility operationally for our situation. In terms of avoiding thermal hydraulic instabilities, you saw the power to flow map has not changed. Our operating regions remain the same. The only change for us is in the new system and the changes that it requires.

MR. LEITCH: So you are going to what is called Option 3?

MR. KITCHEN: Yes, sir. In fact, that is operable on Unit 1 right now.

MR. LEITCH: I see, and tell me again, I'm a little confused as to exactly what Option III means.

MR. KITCHEN: Option III is a stability algorithm. If you compare the two stability solutions, E1A is prevent solution and it has very large restricted areas or larger restricted areas in the power to flow map operating region. Option III also has areas of avoidance of course, but also provides automatic SCRAM protection based on stability algorithms.

The one that is safety related is called a period based algorithm and it looks for frequencies that are known to represent instability phenomena and provides an automatic SCRAM if certain threshold requirements are met. So you've got the operator manual actions and now also automatic protection.

MR. LEITCH: Okay, and that is active on Unit 1 right now?

MR. KITCHEN: Yes, sir. We installed the system on Unit 1 and it is operable.

MR. LEITCH: Yeah, thank you.

MR. KITCHEN: Just to touch on margins, the overall extended power uprate reduces margins in the plant and we're going to discuss those in detail under our fuel design and vessel reviews, et cetera, but I wanted to also show you the things that we're doing to try to maintain or mitigate margin reductions in the plant. We've touched on them in the review already but the SLC margin, we're going to increase the Boron concentration significantly.

In fact, right now to meet our SLC requirements at Brunswick, we require a two-pump operation. And with the changes that we're making we'll only have to have one that are accident situation so that's a bit of a margin gain for the plant operationally. Also the stability Option III which we just talked about --

MR. LEITCH: On the Boron, and maybe we're going to get into this a little more later and if so, I can defer this question, but I basically, don't understand what is meant by super Boron and I guess it -- I thought I read that you don't need to have heating with it and I'm wondering how the Boron stays in solution. I mean the problem was we used to have -- I'm picturing a curve in the tech specs that had temperature versus Boron concentration and it was very sensitive to temperature to maintain the right Boron concentration. It sounds like that's all gone by the wayside with this super Boron.

MR. KITCHEN: Yes, sir, it's an enriched Boron solution, atomic enriched solution, so that effectively it provides more concentration of Boron 10 in the solution. Also the solubility requirements are less restrictive so the heat trace that we have currently installed on the system would not be required with that Boron enriched solution.

MR. LEITCH: So it stays in solution at ambient temperature?

MR. KITCHEN: At lower temperatures, yes, sir. I don't remember exactly the temperature for solubility but it's much lower.

CHAIRMAN WALLIS: Super Boron has more Boron tenants (phonetic), is that what makes the difference?

MR. KITCHEN: That's correct.

MR. LEITCH: Why didn't we do this a long time ago? Is super Boron super expensive?

MR. KITCHEN: Actually, I think it's called liquid gold but it is expensive. I don't know how long it's actually been available.

MR. SIEBER: It's been around for awhile but it is costly.

MR. KRESS: You have to enrich the Boron. It's an extra step.

MR. KITCHEN: It's significantly more cost to install.

MR. LEITCH: So with this Super Boron and you only need -- you can -- the standby liquid control system can do its mission with just one pump then.

MR. KITCHEN: Yes, sir, because of the concentration increase that we're putting in.

MR. LEITCH: Yeah.

MR. KRESS: The overall concentration of Boron stays the same.

MR. KITCHEN: It's an effective increase.

MR. KRESS: Yeah, an effective increase of B-10.

MR. KITCHEN: Yes, sir. The stability option we talked about a bit and again, we didn't have to change solutions but we saw it as an improvement in operating margin and also it involved no change in safety margin since there are several stability solutions all of which are acceptable for operation.

The power range instrumentation, really the stability solution is a part of that. But the power range instrumentation also offers advantages to us. I should change that to say it's really improved operator interface, the digital displays. Also there is a bit of a liability because of the self-test features of the system. There are fewer surveillances to do, so there's less maintenance activities to do.

It eliminates the half SCRAMs from the power range that we used to get while testing so there are several advantages to a system change, and also for us it addresses an obsolescence issue with parts.

The condensate system we've already discussed but basically we just want to maintain our standby pump to get better reliability for the plant and finally the power system stabilizer which we'll talk downstream in our briefing here, which improves the situation on a higher plant load as well as higher grid load.

So we've tried to do some things that were supporting of uprate but also helped us out with the uprate. Some unique aspects for Brunswick, and again, we've got an electrical presentation here because it is a little bit difference for us than some other plants, depending on your geographic location and transmission system. So we want to talk a bit about that with the ACRS. Also I think we're the first plant with uprate that is hydrogen water chemistry. We do not use normal metal chemistry. We wanted to discuss that a bit with the ACRS.

And finally, our energy cycle requirements are pretty demanding at Brunswick. We -- as I mentioned, we're a two-year cycle which is of course, a higher energy load and we operate at a very high capacity factor. We manage to a 97 percent capacity factor. So the two combined with an uprate makes for a very large energy load for the plant.

MR. SIEBER: When you refuel what percentage of the fuel is new fuel?

MR. KITCHEN: Right now, we load about 39 percent. With uprate, we'll go to about 47 percent change-out.

MR. BANERJEE: Does the two-year cycle effect your cobalt levels radiation fields compared to shorter cycles?

MR. KITCHEN: In the fuel itself?

MR. BANERJEE: No, no, on the external

hoops.

MR. KITCHEN: The shutdown radiation levels are not significantly impacted. I mean, there is a radiation impact from operation directly to the power level.

MR. GANNON: Can I make a comment about the radiation levels? We use -- my name is Neil Gannon, Director of Site Operations at Brunswick. We've enhanced our practices with zinc injection and our experience over the most recent two-year cycles is about a 15 percent decrease in our radiation levels on Unit 1. So we're able to manage -- the two-year cycle has had no impact on dose rates.

Our use of zinc has actually allowed us to experience a slight decrease in those.

MR. BANERJEE: When did you start using zinc?

MR. GANNON: Oh, I think it was about four, five years ago.

MR. BANERJEE: And it's gone down.

MR. GANNON: Initially it remained flat, controlled very well and our recent practice to increase the amount of zinc is -- over this cycle on Unit 1 showed about a 15 percent decrease in dose rates in the driver, so this has been our first experience to actually see it decrease.

MR. LEITCH: Thank you.

MR. KITCHEN: Before we get into detailed presentations, there are some exceptions. We generally followed the extended license topical report. There were a few exceptions that we took in our submittal. Three of these are related to the constant pressure aspect of our uprate involving the thermal-hydraulic stability. The ECCS-LOCA analysis and reactor transients, and we'll discuss these in more detail in the closed session that we have later this morning.

The last item is large transient testings. As you know the ELTR requires for 10-percent uprates an MSIV closure test and for 15-percent uprates a generator load reject. We are also asking for exceptions from those tests. I'll explain why here in just a second but the exceptions that you see here are all in line with previous uprate submittals that you've seen for addressing Quad Cities as well, as Dresden.

The generator load reject test, unfortunately we had an event at Brunswick in September of 2000 operating at full power which again, for us is 105 percent relative to our original license, where we had a transformer failure that, of course, resulted in a generator load reject transient. So that in fact, we've had this transient and that's our basis for not including it as part of the uprate testing.

The MSIV closure test, we are asking for an exemption on. And the basis for that are, first of all the fact that we are maintaining a constant reactor pressure simplifies the analyses that are done for uprate as well as minimizes plant changes required to support uprate.

MR. KRESS: If you had not had this event, would you still have asked for an exemption on that large transient testing?

MR. KITCHEN: Yes, sir.

MR. KRESS: But that just gives extra evidence to it.

MR. KITCHEN: Yes, sir, the ELTR allows actual events, of course, to be included as a test and that's our basis but had we not had it, yes, we would have asked for the exemption.

MR. KRESS: Yeah, I think one of the other plants, I forget which one, had not had one.

MR. LEITCH: I don't think any of them did.

MR. KITCHEN: I don't know if Dresden or Dresden either have had one, I'm not sure.

MR. SIEBER: Dresden didn't and Quad didn't either.

MR. LEITCH: No, I don't think they did.

MR. KITCHEN: We would have asked for the generator load reject. We try to avoid these things. We do surveillances that confirm component performance. Then when you look at the transient test and what you're trying to demonstrate with the transient test, we feel that the component test that we do adequately demonstrate the components and when you look at the test itself, what makes the transient very significant is reliance on the SCRAM from flux as opposed to the -- we have an MSIV limit switch that actuates the SCRAM as well and of course, for the test we would not disable that.

And without that disabled, it certainly minimizes the severity of the transient very much. So it's nowhere near as challenging a transient under test conditions as what we use for the analysis. And when you look at what you are actually testing, the surveillances that we do on components demonstrates adequate performance.

MR. LEITCH: On that point, I guess what

concerns one in this situation is are the MSIVs going to be able to close in their required time, usually three to five seconds with the increased steam flow and how would you demonstrate that? Is that demonstrated by one of the surveillance tests?

MR. KITCHEN: Yes, sir, actually it is. Our surveillance requirement on MSIV is this closure in three to five seconds. We have a y-type globe pattern valve with steam flow over the seat so the steam flow increase actually tends to try to shut the valve faster. So the concern for MSIV closure would be fast closure.

We installed the modification several years ago that with the flow control valve in the hydraulic actuator is adjusted to set, the closure speed of that valve -- and by being on the hydraulic side of the valve it's independent of the steam flow. In other words, it maintains that constant closure rate because it's supporting the fluid from one side to the other. So our MSIV surveillances are performed routinely and satisfactorily.

MR. LEITCH: Okay, thank you.

MR. KRESS: You check those without any steam flow though.

MR. KITCHEN: Yes, sir, they're checked

during the refueling outage periods and adjusted, if required, to put them in the center of that --

MR. KRESS: Have you ever run a test with steam flow to confirm that steam flow actually doesn't change the closure rate?

MR. KITCHEN: No, we do stroke testing the valves at power but not a timing -- not a three to five-second timing.

The other basis for our request to exempt this is the codes that are used to analyze it are well-proven. The ODYN is used for the analyses and has been proven to benchmark against plant transients and it supports this transient as well. And finally, as I mentioned earlier, it's not -- it's a severe risk but it's not something that we would do if we had a choice. That's all I have on the overview. We're going to talk next about core considerations.

CHAIRMAN WALLIS: Thank you.

MR. DRESSER: Good morning. My name is Tom Dresser. I'm with CP&L's DWR Fuel Engineering Group. I'm going to speak this morning about five different types of analyses all related to the reactor core. The first two, the fuel bundle and core design and the anticipated transient without SCRAM or ATWS are performed completely consistent with GE's generic topical for extended power uprate ELTR 2 and 2. The last three, thermal-hydraulic stability, the emergency core cooling system, loss of coolant in accident analysis and the transient analyses each takes some kind of exception to the generic methodology.

And my presentations will contain material which GE considers proprietary so it's between the second and third topic here that we'll need to take a break to go to closed session. The complete package of fuel bundle and core design is performed in several different stages. The power uprate analysis itself develops the idealize concept of an equilibrium core where the core operates at full power uprate conditions for an entire cycle and then the fuel is shuffled, the same reload is put in again and the cycle cleanses itself reload after reload.

That equilibrium cycle is not actually seen often in reality but it's very useful for seeing what extended power uprate will and can perform feasibly in your plant and also necessary for providing to the other work scopes and power uprate the required fuel related input.

The reload analysis is what's done to actually develop the blueprints to which the fuel bundles are built and the loading patterns are developed and the reload analysis is what develops the core -- the fuel related operating limits that go into the core operating limits report.

Also with the reload analysis is performed a succession of reload cycles to carry us all the way from the current cycle out to essentially the equilibrium core. That might be two to four or five cycles, but that demonstrates that there's a good success path to carry us from the cycle we're designing out to the objectives we want to achieve. Looking first at the equilibrium core design, the design target for Brunswick are the same as the ACRS has seen on prior EPU submittals. The one thing as Bob mentioned in the intro, that's a little bit different about Brunswick is this should be the first plant that you've seen with a 24-month operating cycle.

Brunswick does operate extremely well with a load factor in the range of 97 or 98 percent, so a 24-month cycle with a 15-percent increase in the power generation is a very high energy cycle. To achieve those targets we had to make a number of changes to our prior strategy. First was to change the fuel design from the 9-by-9 GE 13 to the 10-by-10 GE 14. That gives us the benefit of a lower linear heat generation rate but even more important than that GE 14 is a heavier bundle. It's got about five percent more uranium dioxide.

In addition to the more UO_2, we increased the enrichment of the fuel in the vicinity of .4 weight percent.

MR. SIEBER: From what enrichment to what new enrichment?

MR. DRESSER: The fuel is built in several streams. The high enrichment stream went from about 4.0 to about 4.4.

MR. SIEBER: Okay.

MR. DRESSER: The -- I think Bob mentioned also that the amount of new fuel that we load increased substantially from about 39 percent of core to 12 bundles to about 47 percent of the core --

MR. SIEBER: So the discharged fuel is twice burned, right?

MR. DRESSER: That's right. Now, we had to essentially do everything, do all the options to increase the reactivity of the core sufficient to get the energy out. One thing that had to be done in compensation for loading so much more reactivity to get the energy was to make the change to the standby liquid control system Boron system. In analysis base, we analyze it as a change in concentration. That's about a 10 percent increase in concentration.

In practice, we will use the Super Boron but effectively it's the same thing. A 20-percent natural Boron or a 68-percent enriched just winds up being a difference in concentration.

MR. LEITCH: My question concerns this one cycle of operation when presumably we've approved up to 120 percent, yet the physical changes have not been made yet to accommodate that.

MR. DRESSER: I understand. As it turns out, the changes required to achieve the cold shutdown and cold shutdown is not driven so much by the power rating as it is by the overall reactivity of the core and by the fuel design. This first cycle for Unit 1 will have one reloaded GE14 fuel. The existing cycle on Unit 2, which won't be operated, also has one reloaded GE14 fuel. As it turns out for Unit 2, for our first uprate when we go to 112 to 115 percent and that kind of range, that is going to require a modification for the standby liquid control system for that unit and we have made a licensing commitment that by this August we'll submit a tech spec change to require that mod.

MR. LEITCH: I see, okay.

MR. DRESSER: And for this Unit 1 we'll do the same thing for the following August for the 2004 mod.

MR. LEITCH: Okay, thank you.

MR. DRESSER: The actual cycle for Unit 1 Cycle 14 we were able to meet all of the design goals with a slightly smaller reload fraction. It's about 46 percent instead of 47 percent of the core. And we did meet all the design targets with our standard expectation of design margins. This is -- the numbers that we actually achieved are shown on the slide.

The one thing that's of particular interest to you, like I pointed out, that a large amount of margin for the standby liquid control, 1.96 percent, that is with the existing Boron. I think our requirement will normally be about 1.0, so that's a lot of excess margin.

MR. SIEBER: Your fuel cost actually goes up with this kind of a design, does it not?

MR. DRESSER: Our fuel cost goes way up.

MR. SIEBER: Okay.

MR. DRESSER: See those big smiles back there.

MR. SIEBER: I'm sure you're happy about that.

Dr. Schrock: My eyes are not good enough to read the slide. What's the color mean?

MR. DRESSER: The colors, the green on the periphery is the highest enrichment. That would be the approximately 4.4 nominal enrichment. The gray is the next higher enrichment. The yellow is next higher enrichment. Those colored slots are all the new fuel.

And one thing I'd point out is that if you look at the interior, the checkboard in the interior of the fuel is that there's so much new fuel -- well, in this case, bringing in one Cycle 14, the loading pattern will actually continue to support our control cell core but by the time we go to a little bit more, we will have to go to a conventional core and sacrifice that control cell.

The largest implication for us of that is we'll have to do a little bit more control rod movement.

MR. KRESS: How much of your fuel gets up close to the same megawatt days in metric time, about as much as a third of it?

MR. DRESSER: No, I don't think as much as a third of it would drive the pellets up there. I -- a number I'm more familiar with is the batch rather than the pellet average. I think the corresponding batch average exposure would be about 50 kilowatt days per ton and the actual batch average winds up being in the range of a little bit less than 44.

So you'd wind up losing a lot of efficiency in terms of the amount of burn-up you'd be able to achieve with the fuel when you go to these high energy cycles.

MR. KRESS: Okay.

MR. DRESSER: But one thing you do pick up and I can't read the slide either as far as the numbers go so I did use a take-out box to magnify. The thing I think is most significant about the loading patterns, that is that the large reload impressions give us an extremely flat radial power distribution. I think if we look at the sub-batches here, the largest average power of recycle is about 1.22 on Cycle 14 and that's going to go down even more in equilibrium, down to about 1.19. It's very flat.

And as a point of comparison, the last power point presentation which was showing a similar kind of effect, the flat core, I think the corresponding number is about 1.27. So Brunswick has, you know, a pancake flat radial power distribution and that's going to effect a lot of things that you'll see throughout the course of the day.

MR. KRESS: You end up with about the same axial.

MR. DRESSER: It's a slightly more -- because of the higher void fraction, it winds up being a slightly more bottom peaked axial.

MR. KRESS: Yeah.

Dr. Schrock: I've got difficulty visualizing what's happening in terms of redistribution of the total core flow on these higher power bundles in the periphery and the central region. It does seem to me without some change in inlet orificing, which I heard previously is a no, no, that you don't modify the whole distribution of the core flow by putting in there higher powered peripheral bundles which have much higher steam generation.

MR. DRESSER: You're absolutely correct. It does modify the core flow. It's got some beneficial effects for us. It --

Dr. Schrock: Well, it could have but I haven't heard a clear explanation of it, that's my point.

MR. DRESSER: The --

Dr. Schrock: I think maybe it was clear to some, but it was not clear enough to me.

MR. DRESSER: Okay, well, the -- let me

give you a 5,000 foot explanation of it and that would simply be that, of course, the higher power generation is going to give us more voiding lower in the core, so you're going to have a lot more two-phase flow over the elevation. Of course, the two-phase flow is going to give us much higher pressure drop and that's -- you know, the overall pressure drop from a core perspective stays about the same.

So that's going to drive flow from the higher powered bundles to the lower powered bundles. Now, with the power uprate like this, we're not changing our design limits. So the peak generation -- peak power generation for any bundle remains the same. Heat generation rate doesn't change with power uprate.

MR. SIEBER: That has an impact on your stability, right?

MR. DRESSER: Absolutely. That is -- that, in and of itself, that is a stabilizing influence.

MR. SIEBER: Uh-huh.

MR. DRESSER: And so what we see overall is because the highest power bundles remain -- you know, can't get no higher. They remain at the design limit. And the core average must go higher to generate more power, you have the core as a whole, which is lower than the high power bundle is taking less of the total flow and the highest power bundles are getting more of the flow.

So as a core designer, it's a nice situation.

Dr. Schrock: Now, I guess in my mind it would be more satisfying if I heard some numbers put to the statements but that may not be possible here.

MR. BANERJEE: Do we have the flow rates anywhere through the bundles documented what you expect them to be?

MR. DRESSER: I do not have those numbers. Perhaps General Electric can give us something.

MR. BOLGER: This is Fran Bolger, General Electric. When the plant is operating at approximately 100 percent core flow, which is about 77 megapounds per hour, the bundles are seeing about 10,000 pounds per hour flow through each individual channel. The total leakage flow is about on the order of 15 percent of the total core flow. When you go to power uprate, it does increase slightly, maybe less than one percent.

You know the plant has some allowable variation in core flow which can increase it maybe up to 11,000 or so and slightly less. It doesn't have a very large range of allowable core flow at the full power uprate. But if you were to compare the channel flows at the current rate of power and at the EPU power, you may only see maybe a two percent variation in the channel flows.

MR. BANERJEE: Were the bundles -- were the channels orificed originally to give higher flow in the central and lower from the peripheral?

MR. BOLGER: Yes, that's correct.

MR. BANERJEE: Is that the same orificing that would be there now?

MR. BOLGER: Yes, that's the same.

MR. BANERJEE: So how do you keep the void fractions and flow rates relatively constant, because you're going to get higher pressure drop now in the peripheral bundles?

MR. BOLGER: You know, the overall core pressure drop will go up about one psi and there will be an increase in the pumping power requirement to achieve the same rate of core flow.

MR. SIEBER: This kind of a fuel design seems to result in high affluence to the reactor vessel; is that correct?

MR. DRESSER: That is correct and I believe we're planning to discuss that later in the day.

MR. SIEBER: All right.

Dr. Schrock: In the documents that I've looked at, there's mention that the inlet orificing is not the same for these two plants. Could you comment a little bit about that? I'm not clear about why it was different, what significance it may have for the uprate.

MR. DRESSER: The -- yes, the inlet orifices on the -- on Unit 1 are a little bit smaller. On Unit 1 they're a little bit larger. On Unit 2 they're a little bit smaller. The biggest difference that that makes to the power right now and also the power uprate is that that makes the thermal hydraulic instability for Unit 1 a little bit worse than for Unit 2 with the tighter orificing.

In terms of operation, it doesn't have a significant effect because the option both -- well, the E1A option is calculated specifically for the unit. The regent (phonetic) sizes correspond to the stability of the unit and for Option 3 the methodology will work in exactly the same fashion.

Dr. Schrock: What did that difference accomplish in the original designs?

MR. DRESSER: I am not -- I would have to look into that. I would expect. I'm kind of speculating here but I would expect that when one unit was built, it had some difficulty achieving as much core flow as we would like and so the orifices were relaxed slightly for the other unit to reduce the pressure drop.

MR. FLADOS: Paul Flados here, I'm with the plant. The original arrangement of our units was that Unit 2 went on line first. There was some transition between 7 by 7 and 8 by 8 fuel. At one time we had changed out the orifices on one of our two units. It was a fairly expensive mod but we physically had to, to meet licensing requirements. By the time we got to the other unit, we had changed fuel designs and done other implementations that allowed us to not change our the orifices. So that's how the designs ended up different.

CHAIRMAN WALLIS: You have actual variations. You have actual variations in enrichment and as burn-up proceeds the flux distribution changes and so on.

MR. DRESSER: That's correct.

CHAIRMAN WALLIS: When you do something like an ECC analysis, does everything get smeared out there or do you look at the details of these things which are different at different times in the cycle and so on? How do you decide which is the place where you're most likely to have DNB and all of that. It must be changing.

MR. DRESSER: Right, it changes through -- it does change throughout the cycle and I believe that the analysis is done to select the most limiting point in the cycle and that's been -- the LOCA is done just at that one point.

CHAIRMAN WALLIS: But knowing which is the most limiting point must itself involve some rather detailed calculation.

MR. DRESSER: Right, there is a -- the -- well, I guess I would not like to describe LOCA calculations. I'm going to ask Dan Pappoane from General Electric to describe that.

MR. PAPPOANE: Yes, this is Dan Pappoane of GE. I'm the LOCA process lead and with respect to the axial power shape, the location of -- when we're looking at the early boiling transition part of it, that -- we're looking at whether or not the high powered node in the axial peak goes into a early boiling transition. That's really more sensitive to core flow than it is to axial location.

So when we look at increased core flow

versus the lower core flow MELLLA, when we get to the MELLLA low core flow point, that's where we're more expecting to see that early boiling transition in the high node and the axial location doesn't make that much of a difference. But we have looked at the axial power shapes and we're -- over the cycle and the shape that we're using in the analysis gives us the highest PCT.

When you get to the end of the cycle and you have a top peak, the -- you may have bundle power on critical power limits but you don't have the linear heat generation rate on the -- on its thermal limit and it's really the -- the linear heat generation rate is the primary driver for the PCT. So we end up with a power shape that gives us a bounding calculation in the end.

CHAIRMAN WALLIS: So this MELLLA line is actually moving around.

MR. PAPPOANE: The MELLLA line is fixed. It's the core flow -- the core flow that we're analyzing is --

CHAIRMAN WALLIS: It's an envelope of a whole lot of calculations, the MELLLA line, is it?

MR. PAPPOANE: The MELLLA line itself is a generic licensing boundary. It approximates that power flow relationship that you get if you ran back the recirculation flow but it's not a bounding line in the fact that we don't go and analyze all the variations throughout the cycle but we draw the line and then the plant has to operate to the line.

CHAIRMAN WALLIS: I guess what I'm getting at is how detailed is this analysis? You don't have -- you don't analyze very bundle. You don't have a model for the core that breaks it up into all these separate bundles and then does a complete thermal-hydraulic calculation for everything. That would be an extraordinary number of nodes, wouldn't it?

MR. PAPPOANE: Not yet. We're working on that one but the safer model that we're using now models a hot bundle and an average bundle. The average bundle feeds the overall core conditions and provides boundary conditions to the hot bundle and then we assume that the hot bundles on both the critical power limit and the LHGR limit and we've got that bounding power shape in it. So we're doing a single bounding bundle for the calculation.

CHAIRMAN WALLIS: So knowing which is the hot bundle requires what sort of knowledge?

MR. PAPPOANE: Well, we start with -- well, since we were defining the limits for that hot bundle, the operational limits for that hot bundle, the part that we do need is coming out of the steady state thermal hydraulic calculation and there we model a bundle the same way. We've got the full core designed, the 100 and whatever bundles usually grouped into three regions and from that we get the flow distribution.

We'll have a peripheral region and an average core region and the hot bundle, and from that we get the flow distribution of what the flow is to the hot bundle versus the average bundle and that's what's used to initialize the steady state.

CHAIRMAN WALLIS: I guess what I'm trying to look at is, you've got this much fire power distribution and you've got this very sophisticated fuel and then you say there's a hot bundle. It would seem that there could be quite a few bundles competing for this hot bundle status --

MR. PAPPOANE: Right, and that's --

CHAIRMAN WALLIS: -- in different parts of the core and how do you deal with that?

MR. PAPPOANE: That's where the steady state flow distribution comes in and if we have more of those bundles essentially at that hot power, effectively what's happening is the average -- you end up with the hot bundle looking more like an average bundle and when you look at the flow distribution, its parallel resistance problem you've got essentially the same pressure drop across the core and as the resistance -- the flow resistance in the hot bundle and the average bundle come closer together, the flow distribution comes closer together.

So you'll end up with more of those hot bundles. The bundle that we're analyzing as the hot bundle will look like a larger percentage of the population. When we go through the LOCA the PCLAD (phonetic) temperature that we calculate will be representative of more bundles in the core.

But again, because we're setting that one hot bundle on limits and those -- we can't -- we're not going to allow any of the other high powered bundles to exceed those limits. We're still analyzing that one hot bundle.

MR. DRESSER: One place where that effect does show up more is in the safety limiting CPR because we do have more bundles that are operating closer to its limit, the safety limit must go up in order to keep the same number of bundles from going into the departure for nuclear boiling machine to 99.9 percent and so the effect Dr. Wallis, that you're referring to will result in the safety limit going up for this cycle from about 1.10 to 1.12.

That's included in the thermal margin of 7 percent here. If it hadn't been for that, we'd have had 9 percent margin.

CHAIRMAN WALLIS: So some day you're going to give us a calculation which treats all the bundles separately.

MR. PAPPOANE: Not all of them. When we get to the track model, when we get to that methodology, we'll be modeling more bundles. We'll have more bundles in the separate regions.

Dr. Schrock: On the neutronics calculation, how large a node is used?

MR. BOLGER: There is 25 axial six-inch nodes for each -- each channel is modeled separately.

Dr. Schrock: Every channel is a node, basically?

MR. BOLGER: Fran Bolger from GE. Each challenge is broken up into 25 nodes axially.

Dr. Schrock: Axially, but in the cross section, every bundle is a separate node.

MR. BOLGER: That's correct.

MR. DRESSER: Well, this has been a fruitful slide. If we don't have any more on this --

CHAIRMAN WALLIS: How are we doing with time? Are you on time?

MR. DRESSER: We'll be eating a late lunch at this rate. No, I'm not planning to spend long on this.

CHAIRMAN WALLIS: Well, maybe you can move things along.

MR. DRESSER: We'll conclude the fuel bundling core design. We're using the same current design tools and processes. We've got the same margin expectations and with that, it doesn't require any change to the fuel design limits to satisfy the extended power uprate design.

The thermal limits monitoring threshold, the tech spec changed from 25 percent to 23 percent, that is just to maintain the same absolute bundle power as is used throughout the GE link at 3.35 megawatts. So as far as the neutronic design goes, there is adequate margin demonstrated for the first operated cycle, all the transitions and the equilibrium.

The second topic is ATWS. The methodology that's used for Brunswick is the same as described in the generic ELTR. The four limiting ATWS transients were analyzed for the plant and the results -- I'll go over the results in just a moment.

The procedures and training at Brunswick for the actions taken by the operator are based on the BWR owners group emergency planning guidelines, the optimum mitigation strategy approach, where water level is maintained between the minimum steam cooling water level and two feet below the feedwater spargers. The actions that the operator takes are based on observing the condition of the core and reacting with the mitigation strategy.

Since neither the symptoms nor the actions the operator takes are changed from a big picture perspective, there is no impact on the operator actions.

MR. SIEBER: What about the timing of operator actions, does that change?

MR. DRESSER: Yes, the actual time at which the operator takes actions will change and I believe we're planning to address that later in the day in some detail, but yes, things will happen at a different rate but the operator will see symptoms and react the same way.

MR. SIEBER: Okay, so that changes the probability of the operator making an error, or does it?

MR. DRESSER: Well, I'm going to say no because the operator -- the assumptions at the time the operator needs to respond in are still the same. He does not need to respond quicker to be successful even though events might be happening quicker.

MR. SIEBER: All right.

MR. DRESSER: The standby liquid control system Boron modification is not required for the hot shutdown for the ATWS transients. The current levels are quite conservative for hot shutdown and finally, a calculation was performed for Brunswick for the relief valve for the standby liquid control. It was done for the worst ATWS transient and with very conservative assumptions including extremely rapid response from operator's action time and it verified that the pressure remained low enough the relief valve does not have to lift.

This is the results of the ATWS analysis together with a sensitivity study for the original license thermal power. The peak vessel bottom pressure goes up to 1487 pounds, that's 13 pounds below the ASME service level during the 1500 pounds. From a licensing perspective, that's okay, as long as it's below the limit. I guess as an engineer, that seems like it's fairly close and so I wanted to observe that this calculation has a number of -- it's a transient but it doesn't use nominal best estimate values for how the plant operates.

It's got a number of conservative inputs. Maybe the most dramatic one is that the SRV is very important to this event. They're assumed to pass only 90 percent of their actual capacity and also one of the SRVs is a soon to be out of service.

CHAIRMAN WALLIS: Were they tested at full scale, full pressure? How do you know the flow rate through these SRVs?

MR. DRESSER: Paul Flados will answer that.

MR. FLADOS: Paul Flados again. These are standard industry target safety relief valves. The original sizing and the design of them actually performed field testing of this type of valve, certified what the flow was, the ASME methodology then had them rate the valve at 90 percent of what it actually did.

CHAIRMAN WALLIS: So it's based on real experience with real valves, with real pressures and all right --

MR. FLADOS: Absolutely.

MR. BOEHNERT: Can you tell me what the

PRFO acronym is?

MR. KITCHEN: Yes, excuse me, that's the pressure regulator failure open position.

MR. BOEHNERT: Okay.

MR. KITCHEN: MISVC is the main --

MR. BOEHNERT: Yeah, thank you.

MR. KITCHEN: -- closed.

CHAIRMAN WALLIS: Now, this MSIVC whatever it is, that's what a one-shot thing or something? Why is -- why are these different pressures? The tech specs is 1325 and this is -- some of them goes up to 1500.

MR. DRESSER: Right, the tech specs is based on 110 percent of the design. I think they have different acceptance criterions for the different severity of accidents or frequencies.

CHAIRMAN WALLIS: Oh, frequency.

MR. DRESSER: Yeah, the 110 percent design is what the tech spec is based on. That was -- is a much less expected type of an occurrence. The one other thing that provides a lot of conservatism in this particular calculation is that the open model was used. That's a lot more -- a lot less real, a lot more conservative than a TRAC G calculation would have been which would have given us more than 100 pounds of margin.

CHAIRMAN WALLIS: What's the difference?

MR. DRESSER: Well, I'll let GE respond. TRAC G is a much more realistic and much more sophisticated model.

CHAIRMAN WALLIS: So there's some, what, conservatism.

MR. BOLGER: This is Fran Bolger of GE. As the problem changes to an ATWS type of event where you have a transient that does not have a SCRAM and void feedback is very critical to the response, the TRAC G model has a 3-D kinetics capability and with 3-D kinetics, you get essentially a credit with high power channels. As they begin to void, as you pressurize, you get void feedback. That type of feedback is not seen as significantly with a 1-D transient model such as ODEN (phonetic.)

As you get down more into nominal conditions with faster SCRAMs, more of the type of scenario where the Peach Bottom Turbine Trip benchmarks occur, then you start seeing that the models respond very similarly.

MR. BANERJEE: And the thermal-hydraulic model is similar to drip flux or what type of models?

MR. BOLGER: The ODEN is a drip flux type model and the TRAC G model is a two-fluid model.

MR. BANERJEE: Are there any significant differences in the voiding rates that you see on the average?

MR. BOLGER: No, the codes will predict, given the same channel, seeing the same type of pressure trajectory, they're predict similar type void responses.

MR. DRESSER: The other criterion for the ATWS have substantially more margin. The peak suppression pool temperature, you'll note that design limit that CP&L placed was not 220 but 207.7. That's to keep the design base accident LOCA as the limiting event for that temperature. The containment pressure there is allowable margin to the design limit.

The peak cladding temperature that is seen goes down to 1309 pounds, way below the 2200 degree design limit and that -- I believe that it was mentioned earlier about the axial power shape and some of the impacts we might see from that, the power shape being much more bottom peaked and the hot peak clad temperature occurring much lower in the core in this event, you get much better heat transfer to the water with less void and that's why this temperature goes down so much.

CHAIRMAN WALLIS: Are you taking any credit for this alternate rod insertion system?

MR. DRESSER: We take credit for recirc pump trip but we do not take credit for the ARI.

CHAIRMAN WALLIS: I was intrigued by that because it gets mentioned but you don't tell us much about what it does or maybe we should just ignore it, but I mean, is that an important design change to have an ARI system?

MR. POST: This is Jason Post with GE. That was the original design requirement of the ATWS modifications. If we took credit with it in our analysis, it wouldn't effect the peak bottom -- the peak vessel pressure very much. It would have a dramatic impact on suppression pool temperature. It would be a very mild event and so, therefore, we don't analyze it.

MR. DRESSER: In conclusion, on the ATWS all the criterion are met, including the 10 CFR 50.62 of course, which are less stringent than some of CP&L's design criteria. And the mitigation strategy for ATWS to comply with the emergency planning guidelines is unaffected by power uprate.

That's all I wanted to say about ATWS and so I'm about ready to go into my final three topics and some of these do contain GE proprietary information.

MR. BOEHNERT: Okay, we'll go -- I'm sorry.

MR. LEITCH: Just before you get there, can I just ask a question? I'm not sure if this is the right part of the presentation, but I'm still a little confused as to the status of Unit 1 at the moment. Have all the modifications and the current reload been designed such that we're now in a situation where the only thing that prevents you from going from a -- up from 112 to 115 percent power is the licensing situation?

In other words, as soon as you get NRC permission to do that, what do you do? Are you ready to go?

MR. DRESSER: That is -- well, yes, the core is designed and it's ready to go. What we would need to do is simply to install the operating limits for the fuel into the process computer and change the core operating limits report from the current power to the rated power and the core would be ready to go.

MR. BOLGER: This is Fran Bolger from GE. The reload licensing analysis were done assuming full EPU capability.

MR. LEITCH: Okay.

MR. DRESSER: So licensings basically go to 120. It's balance-of-plants that will hold us back to 112, 115.

MR. LEITCH: So then in a practical sense, once you've made these modifications to the computer, which can all be done on line, then what you do then is go over to the recirc pumps and increase the speed of the recirc pumps and see -- make sure you have enough feedwater pumping capability and that's what the limit is? I mean, you just go --

MR. DRESSER: Well, there's some testing. There's quite a bit -- I mean, from my perspective as a core designer, that's all there is but actually from plant operation there's a lot more.

MR. KITCHEN: This is Bob Kitchen. The modifications have been incorporated in the plant. They were performed during the refueling outage we just completed. Once we receive the license, as you mentioned, we can -- the license would allow operation to 120 percent. The plant modifications are in place to allow the plant to operate to 112 percent.

And we would implement that --

MR. LEITCH: When you say it's been a physical limitation, your ability to pump feedwater?

MR. KITCHEN: Actually, the limitation would be for base load operation, fuel load itself. And ultimately the main transformers would limit us to 115 percent of our original license power or less. But we could -- we'd have to make some set point changes. We're going to talk about the testing that we have to implement the license later but we would have to go through that process and very -- increase power very slowly monitoring plant components and various points we stop and run testing to verify plant response.

MR. LEITCH: Okay. I may have some more questions in that area later but basically what I'm getting the picture here is we're on the critical path here. In other words, you get this approval, you can basically come up to 115 percent --

MR. KITCHEN: Yes.

MR. LEITCH: -- on Unit 1.

MR. KITCHEN: Yes, sir, that's correct.

MR. LEITCH: Okay, thank you.

MR. BOEHNERT: All right, then we'll go into closed session. I would ask anyone who doesn't have an agreement with GE to hear proprietary information to leave the room. The transcriber can go to a closed session transcript.

(Whereupon, the subcommittee went into closed session at 9:45 a.m.)

(On the record at 10:31 a.m.)

CHAIRMAN WALLIS: We're back in session. And this is a non-proprietary session; is that correct?

MR. WILTON: That's correct.

CHAIRMAN WALLIS: Go ahead.

MR. WILTON: Good morning. My name is Blane Wilton and I'm the Supervisor of Reactor Systems at Brunswick Nuclear Plant. Today, I'd like to discuss the reactor vessel and internals with you. The areas I'll be covering are the scope, the EPU effects and impact, our preservation/mitigation strategy that we use, monitoring aspects. I'd like to go into a little bit on steam dryer and then the conclusions.

The scope of the internals in reactor vessels include all the components that were identified in the license topical report. All of those were considered within the scope for Brunswick. Implementation of the EPU includes the evaluation of the components, inspection, as well as mitigation. One thing I do want to point out is that no modifications were required as a part of power uprate to support for the reactor vessel or internals, to support the implementation of EPU.

Degradation modes that were addressed include stress corrosion cracking of both IASCC and IGSCC, fatigue and embrittlement. Effects and Impacts, our PT curves, our pressure temperature curves, were impacted by extended power uprate. Our current curves that we're operating on today have been approved for use with extended power uprate through March of 2003. We're developing new curves right now and we plan on submitting those curves in June of 2002, this year with updated fluence methodology in accordance with Reg Guide 1.190, as well, as including instrumentation uncertainty in the curves.

And like I said, that will be issued in June of this year. Fluence was effected by power uprate. The fluence impacts were not directly proportional to the power increase which is what we kind of expected initially going into this. The reason for that as Tom eluded to earlier in his presentation on the core, we flattened the power shape out and move a lot more power out to the periphery of the core, so therefore the fluence increase was greater than the power increase.

Embrittlement --

CHAIRMAN WALLIS: In your case, the fluence actually went up.

MR. WILTON: Yes.

CHAIRMAN WALLIS: In one of these other operators, we had, yes, you'd expect it to go up but because of an improved method of calculation it actually went down.

MR. KRESS: Well, that's his other one that he just covered on the previous slide.

CHAIRMAN WALLIS: Yeah, so you're going to recapture that with the RG1.190, okay.

MR. WILTON: Yes.

CHAIRMAN WALLIS: Okay.

MR. WILTON: Embrittlement, 10 CRF 50 Appendix G requires that your upper shelf energy be 75-foot pounds initially and you must maintain 50-foot pounds through end of life. Our plant does not have full Sharpy curves; therefore, 10 CFR Appendix G allows for an equivalent margins analysis to be performed.

That analysis was also effected by power uprate. That analysis has been recalculated and we're within our margins on that. So there really was not an impact on embrittlement, but we did have to redo that calculations on that.

MR. KRESS: When you say your plant doesn't have full Sharpy curves --

MR. WILTON: Yes.

MR. KRESS: -- that means you don't have the specs on the materials?

MR. WILTON: The materials weren't tested over a full range of temperatures.

MR. KRESS: The full range of temperatures.

MR. WILTON: Yeah, that you need to be able to show compliance with the 50-foot pounds. Therefore, we use the equivalent margins analysis.

MR. KRESS: I understand that.

MR. WILTON: Okay. Let's see, fatigue; another factor that was impacted as far as power uprate. All the components were addressed for fatigue and what we found is that all components remained qualified through end of life.

I'd like to go into our preservation and mitigation strategy. We protect our reactor vessel and internals against IGSCC. Brunswick implemented moderate hydrogen water chemistry as our strategy for protection back in 1989 on Unit 2 and in 1990 on Unit 1. Current injection rate will be maintained as part of power uprate. Right now we inject at 39-1/2 SCFM. That same rate will be maintained.

Our post-EPU protection will be as good or better under power uprate conditions with the same flow rate. We've done extensive modeling of our core using the BWRVIA software which is an industry developed code for modeling the radiolysis effects as well as the ECPs in our core. And the model shows this.

MR. BANERJEE: Where is the hydrogen injected?

MR. WILTON: It's injected in the feedwater.

MR. BANERJEE: And it goes through the sparger and mixes.

MR. WILTON: Yes, it goes down through the bottom and up through the center of the core.

MR. LEITCH: And depending upon the amount of hydrogen that's injected, varies the -- I say the depth of protection. Have you been able to protect all the vessel internals with your present hydrogen flow rate?

MR. WILTON: No. We probably should go to a backup slide on that, starting with this one.

MR. KRESS: Let Darrin help.

MR. WILTON: When we laid out our mitigation strategy, what we -- the area highlighted here in yellow is the area that we determined that we wanted to try to protect with hydrogen, okay? And what we've got is we are able to protect most of that area at minus 230. Some areas are above that, but those areas are typically areas that you couldn't protect regardless of how much hydrogen you put in, just because of their locations.

MR. LEITCH: I see. But the core -- okay, go ahead.

MR. WILTON: This is the outer by-pass region of the core. This is the inside of the shroud but external of the fuel channel. Okay, so that was one of the areas that we say we were trying to protect. And we are a 1.0 to 1.5 PPM plant. So you can see the levels. That's the bottom curve on this and we're down in the minus 270 range, in that region.

The -- if you look at another area that we're trying to protect, this is the downcomer region. This is the area external of the jet pumps and the annulus area of the core shroud. And you can see that at the very top part of the core, which is the first part, up in this are, regardless of how much hydrogen you put in, you're just not to get it negative enough to protect that area.

MR. LEITCH: Uh-huh.

MR. WILTON: But it all drops off and

we're operating along this curve here which is down to the minus 320 range, that area.

MR. LEITCH: Okay.

MR. BANERJEE: Is that -- the effect due to incomplete mixing on the downcomer? What do you think it's due to, that you're not getting --

MR. WILTON: You're talking about the region up in here? It's the height. This is what I believe it is. It's you're outside of the influence of the flux up in that area. You're above part of the core.

MR. BANERJEE: Right, yeah.

MR. WILTON: And flux actually makes the recombination reaction a lot more efficient. So because you're outside of the region of the high flux areas, then it becomes inefficient in that area and that's why you see the levels go up.

MR. BANERJEE: And the previous slide that you showed --

MR. WILTON: Yes.

MR. BANERJEE: -- are there areas which are inefficient there as well?

MR. WILTON: Well, this is inside the core shroud and it runs from below the core plate down to above -- I'm sorry, above the core plate to the bottom side of the top guide and just because of its proximity to fuel, you see in this region here at the very beginning up at the highest portions, you're seeing that it is going up and it's pretty stable along the entire region of the fuel.

Another area we're trying to protect is the inside of the jet pump area to mitigate that and you can see here that along this curve we're down around the minus 350 region. So again, we have protection. The last area that we're trying to protect here is the lower plenum, the bottom head region. And again, you can see where we're down low and it tails up. This area here is as it goes through the core plate and you can see the levels are starting to rise again.

MR. KRESS: You calculate these with TRAC?

MR. WILTON: No, we calculate these using what's a computer code called the BWRVIA model.

MR. KRESS: It's the VIA.

MR. WILTON: Yes, the VIA model that was developed and benchmarked on initially, I believe 23 plants.

MR. KRESS: It has to have flow distributions.

MR. WILTON: Yes. And what we have here

is this is not a generic model. We took the model and we took the Brunswick specific inputs for both geometry flow, we included the equilibrium -- this is for an equilibrium core, so we took the equilibrium core from the power uprate and used the actual fuel information and this is a Brunswick specific model that was developed for our plant.

MR. KRESS: This is the VIA model the flux also?

MR. WILTON: Yes, yes, that's a separate input to the model.

MR. KRESS: It's an input.

MR. WILTON: Yes.

MR. KRESS: Okay.

MR. LEITCH: And these curves are relatively unaffected by the power uprate.

MR. WILTON: Well, actually, I don't have the curves here for where we are today, but what we saw is, is uniformly, we saw a shift more negative with power uprate because the flux out in the periphery of the core is actually going up, so therefore, the effect is becoming more efficient. So power uprate is actually giving us better protection with the same amount of hydrogen.

Let's see. Okay, our mitigation strategy is one that is also supported by BWRVIP-62, which is the technical approach for relief of inspections using hydrogen. So the point I wanted to make here is we're not doing something different than what has been looked at. It is in accordance with the industry developed guidelines for a moderate hydrogen water chemistry plant. And what we're showing is that with moderate hydrogen water chemistry, we are protected in the areas that we're trying to protect.

MR. KRESS: Why did you decide that those were the areas that you wanted to protect?

MR. WILTON: Well, the only other areas that you can get into area areas like above top guide which no amount of hydrogen -- and if you look at the protection that you get from chem in that area, it's limited if -- the fuel itself which is something that is changed out on a cycle by cycle basis.

MR. KRESS: You don't even need --

MR. WILTON: The areas, you really don't need the protection in those areas. So we're trying to maximize the protection.

MR. KRESS: In fact, you may be even worse off with the hydrogen on the fuel.

MR. WILTON: Yes.

MR. BANERJEE: Do you have coupons

(phonetic) or anything that would actually show you're getting this or you're doing some monitoring?

MR. WILTON: Yes, yes. We do monitoring but our monitoring is actually our inspection program. Okay, we also have -- another part of our mitigation strategy is our water chemistry. We maintain water chemistry in accordance with the EPRI guidelines on water chemistry and our conductivity is kept low. It's on the average of .09 on an average for the cycle.

To make sure that our mitigation strategy works, we have a monitoring program. Our monitoring program confirms that our mitigation strategy is adequate and also provides feedback to us in case that we see something that we don't expect. It gives us time to adjust our program. Our inspection program is in accordance with the guidelines of the BWRVIP.

Our re-inspection results have shown no new crack initiation with moderate hydrogen and the crack growth rates for existing flaws is well below what's expected. You know, GE -- the NRC accepted number is minus five inches per hour which has been reduced for certain locations down to 2.5. We're actually seeing growth below the error band in the inspection equipment of what we can see.

We also are monitoring on fatigue. We've done our fatigue updates for post-EPU for limiting components for both units. We just completed detailed fatigue updates. We do those on a 10-year cycle. We also do interim updates following every outage to project where we think we'll be. The fatigue updates have been extrapolated through end of life plus 20 years and using EPU conditions and all components have been found acceptable through end of life plus 20 years.

Monitoring for embrittlement, we are a member of the VIP and therefore, we are also a member of the integrated surveillance program. Each utility in the program -- to be part of that program, each utility must comply with the specific requirements of the two documents which control it. VIP-78 is an overall, just a program, describes the program and BWRVIP-86 is actually the implementation plan. We are members of VIP and, therefore, we are part of this program.

Select utilities will pull test coupons. We are not one of those. We will be using data from a sister plant. VIP guidelines require licensee to calculate neutron fluence using compatible methodologies to be able to use a sister plant and we've already done an update per reg guide 1.190 to be able to do that.

Let me talk a little bit about steam dryer. We inspected the steam dryer on Unit 1 during our last refueling outage. We did observe minor cracking. This cracking had been previously identified back in 1988. We have cracking -- what we saw as cracking in our dryer bank vertical welds. We do not have drain channel cracking at this time. Our plan, we -- the cracking had grown from eight inches, which is what we initially found in '88 to about 11 to 12 inches in 2001.

We performed a conservative analysis that showed that the cracking is fine for continued operation for multiple cycles. Our plan is to go back in following uprate at our next outage and reinspect to see, just to verify that the power uprate is having no detrimental effects to our steam dryer.

MR. KRESS: Do you have any problems with the vessel supports. I mean, this is internal things here.

MR. WILTON: Right.

MR. KRESS: Because of embrittlement? These are Mark 1's.

MR. WILTON: Do you want to take that,

Larry?

MR. YEMMA: This is Larry Yemma from CP&L. I'm not sure I understand the question.

MR. KRESS: There was some question one time about radiating the structures below the vessel on the supported --

MR. YEMMA: Oh, the vessel support?

MR. KRESS: Yeah, not be deteriorating.

MR. YEMMA: Unfortunately, that's out of our jurisdiction.

MR. WILTON: We, essentially, from the safe ends into the vessel and just the internals itself.

CHAIRMAN WALLIS: Those cracks are due to vibration or something? What is the cause of the cracking?

MR. WILTON: The cracking was believed to be IGS60 initiated. In conclusion the RPV and internal components have been assessed for impacts of EPU. Our site program documents have been revised to include the impacts of the power uprate and all components remain qualified through end of life.

MR. KRESS: You don't have any pressurized thermal shock problems.

MR. WILTON: No.

MR. LEITCH: Blane, this auxiliary condensate cooling system which I now understand is likely not to be installed but one of the things that was concerning me when I read about that initially was particularly the tube material and I guess it would be the non-regenerative heat exchangers. I'm picturing this non-regenerative heat exchanger as having basically river water on one side of it and then used on an intermittent basis a couple months a year at most.

And I guess when you were talking about condensate conductivity, obviously, it speaks well of your main condenser. If we introduced this non-regenerative heat exchanger into the cycle, a tube leakage there would -- could be a significant problem and I think there is a propensity for those tubes to leak in that kind of service. But obviously, if you're not going to do it, you're not going to have that kind of problem. But I think if you do move forward with that, you have to be very careful about the selection of material for tubing in that non-regenerative heat exchanger.

MR. WILTON: Agreed.

CHAIRMAN WALLIS: Thank you very much.

MR. GRANTHAM: Good morning, I'm Mark

Grantham. I'm the Design Superintendent on our EPU team. I'll be talking about our containment responses to include a review of the methodology used for our containment analysis, the containment analysis results, impact on Mark 1 hydro-dynamic loads and as well as impact on MPSH for our emergency core cooling water.

The containment analysis was completed using the methodology that's currently approved in the ELTR. The analysis is actually broken down into a short term and a long term analysis. As short term, that's really the first 10 seconds of an event. The short term analysis, the focus of that analysis is on drywell temperature and pressure; whereas on the long term analysis the focus is on wetwell pressure as well as suppression pool temperature.

The short term analysis is completed using the LAMB code which is using Moodies (phonetic) slip critical flow model to develop blow-down flows and that's used as an input into an M3CPT code.

The long term analysis is using the Super HEX code. All of those codes are approved and the Brunswick power level for EPU is within the range of applicable -- that's applicable for those codes. This provides the actual containment analysis results for

DBA LOCA. The first data column there actually provides the current UFSAR values containment analysis parameters. For power uprate, a new analysis was performed using the same methods for uprated conditions as well as current rate of thermal power conditions. All of these are done at the 102 percent of thermal power.

So a comparison between the current methods, the current license thermal power and the EPU numbers will give a true indication of what the actual change is due to the power level increase. If you look at this for containment pressure, the peak value for EPU is 46.4 PSIG versus an acceptance limit of 62. The drywell air space temperature for DBA LOCA, 293 degrees, versus an acceptance limit of 340.

Wet well pressure is 31.1 PSIG versus an acceptance limit of 62. And suppression pool temperature, the peak value of 207.7 versus an acceptance limit of 220 degrees. So all these values are well within the acceptance limits. For the Mark I hydro-dynamic loads, we reviewed the pool swell, vent thrust, condensation oscillation, chugging and SRV discharge loads and for SRV discharge that included the initial actuation as well as subsequent reactuations. And all of those loads for EPU were within the original definition, load definitions that were established as part of the Mark I long term program.

MR. LEITCH: You have a HPSI and a RCIC that discharge into the tarus.

MR. GRANTHAM: Takes suction for the tarus, that's correct.

MR. LEITCH: It takes suction from the tarus.

MR. GRANTHAM: And a discharge into feedwater pipes.

MR. LEITCH: I mean the steam for the turbines.

MR. GRANTHAM: Yes, discharges into the turbine, or tarus, correct.

MR. LEITCH: To the tarus, yeah. So I guess the operation of HPSI and RCIC is unaffected by this uprate.

MR. GRANTHAM: That's correct, for DBA-LOCAs HPSI and RCIC are essentially assumed not to operate. The pressure goes down quickly enough to where you're essentially below their range of effective operation almost immediately.

MR. LEITCH: Okay.

MR. GRANTHAM: Due to the changes in

suppression pool temperature, we had to look very closely at our NPSH, net positive suction head. Brunswick is currently committed to safety Guide 1 which does not allow credit for containment over pressure. As a result of EPU we will now require containment over pressure for adequate NPSH and that is an allotment that is made in the ELTR 1.

For the NPSH evaluation, we looked at that short term and long term -- or short term, and that's the first 10 minutes of an event. We looked at the conditions where the core spray and RHR pumps are essentially in run-out conditions, where no operator actions for throttling them back is credited. Under those conditions, there's adequate NPSH available without any credit for containment over-pressure.

The long term NPSH evaluation after 10 minutes, the peak value required -- peak over pressure required is 3.1 psig. The available over pressure at that point is 11.3 psig and as apart of this license submittal, we're actually requesting credit for 5 psig.

MR. KRESS: Those numbers are at the same time in the transient.

MR. GRANTHAM: Yes, yes.

MR. KRESS: So --

MR. GRANTHAM: What we did for the ECCS evaluation, we made, I guess, a conservative analysis in that we took a combination of containment sprays as well as direct pool cooling. For suppression pool pressure, we assumed the containment spray case which gave us the lowest pressure.

MR. KRESS: Which gave you the lower pressure.

MR. GRANTHAM: For suppression pool temperature, we assumed the direct pooling, pooling case which gave us the highest temperature. So really you --

MR. KRESS: So really you combined those.

MR. GRANTHAM: Right, to get a worst case combination and --

MR. KRESS: So I don't have to ask what the uncertainty is in this number because --

MR. GRANTHAM: Right, and we --

MR. KRESS: -- you know which side of the thing it's on.

MR. GRANTHAM: Correct, and we plodded it out versus time and pick the worst case.

MR. BANERJEE: Do you have a plot of the changes with time, pressure and available -- what you need?

MR. GRANTHAM: I have a graphical reference. Yes, we do have that.

MR. KRESS: Could we see that some time because I've often wondered if there was some area in the timing associated with these things?

MR. GRANTHAM: Yes, I can show you that maybe at a break or something. We have -- I don't think we have a backup slide on it but we do have that.

CHAIRMAN WALLIS: Maybe right after lunch.

MR. GRANTHAM: Yeah.

MR. LEITCH: I guess it had been my understanding that the NRC was reluctant to approve credit for containment over pressure; is that -- I guess that's more a question for the NRC, but do you know if any other BWRs have --

MR. GRANTHAM: I know most BWRs credit containment over pressure. Ralph --

MR. CARUSO: This is Ralph Caruso from the staff. And this is just -- I'm in the Reactor Systems Branch. We don't review this but I have some knowledge of it. And generally what the staff does is controls this very carefully. They do a very detailed thorough review of requests to use that over-pressure in order to make sure that it isn't used creatively.

MR. LEITCH: Okay, thanks.

CHAIRMAN WALLIS: But it has been granted for other plants.

MR. CARUSO: Yes.

MR. BOEHNERT: Oh, yeah, Duane Arnold (phonetic) got it for their uprate.

MR. CARUSO: And not just for power uprates.

MR. GRANTHAM: And conclusions for the containment analysis, the containment temperatures and pressures remain within existing design limits. The Mark I containment hydro-dynamic loads are within the current load definition and adequate NPSH margin exists with the available over-pressure.

MR. BOWMAN: My name is Terry Bowan. I'm the electrical project engineer for power uprate. I want to spend a few minutes talking about the impact power uprate had on our power systems and how we are addressing that impact.

In Bob Kitchen's introduction he mentioned that we were replacing our main power transformers and we were upgrading our isophase coolers and that's pretty typical of plants that are uprating and you'll see that, that it's pretty common. But in our situation we also determined that there were two other areas that we need to evaluate and that's generator and grid stability and the voltage adequacy of offsite power, so I want to spend a few minutes talking about those two areas. They are somewhat unique to Brunswick.

The first area that I want to talk about will address the stability and with our increase in power output, our stability studies indicate to us that our stability margin would be reduced somewhat. So there are two modifications that we will be implementing to compensate for this reduction in stability and they are the out of step protective relaying modification and also implementation or installation of power systems stabilizers on our main generators.

MR. SIEBER: Does that mean if a generator on one unit slips poles that that unit trips?

MR. BOWMAN: With the out of step protective relaying which I'm going to address in the next slide, yes, to answer your question.

MR. SIEBER: Which will cause the other unit to probably slip, too, right?

MR. BOWMAN: No.

MR. SIEBER: You're sure?

MR. BOWMAN: I'll first talk about out of step protective relaying which I hope will address your question there. This is a two-piece scheme, if you will. One portion of the scheme will trip the generator on a major out of step event, a very severe event on the grid. And what that does is it does two things for us. One, it protects our generator from slip pole, the damage, but it also prevents cascading grid outages.

Whenever you have a machine that's on your grid that falls out of synchronism, it's very important to get it off very quickly. It's not going to regain synchronism, so you have to trip the generator. So that will help prevent any cascading grid outages. It will help prevent that machine from dragging down the rest of the grid.

The second piece of this is to help preserve off site power during an out-of-step event and the way we're going to accomplish this is the use of out-of-step blocking relays. There will be out-of-step relays located on the end of each transmission line, the remote end and the plant end and they will be monitoring for an out-of-step event out on the line in the sense that they will block tripping of those lines. That's very important because if we do trip our main generator, (tape fades) and so that increases the reliability.

MR. SIEBER: Now, what do you say -- whether you prevent the adjacent unit from tripping or not, depends on how many cycles you go through and how tightly -- how low the impedance is between the two of them.

MR. BOWMAN: That's correct and the -- this scheme has a very fast tripping ability. It's not -- it is conventional and out-of-step tripping but it also has another aspect, it's called anticipatory out-of-step tripping. It looks for closing faults that could cause that event and trips it very quickly, so the other generator does not go out of sync.

MR. SIEBER: Okay.

MR. BOWMAN: So that's the first mod that we're implementing. The second modification is the installation of the power system stabilizers on each of the main generators. These power system stabilizers sense changes in generator speed and power and using these inputs, they provide feedback to the generator's excitation system. And with that feedback, the regulator will actually produce a torque which is in opposition to the torques that are caused by the grid disturbance. So it has an ability to dampen out the oscillations that would occur after your disturbance of the grid.

MR. LEITCH: Is there under and over frequency protection on these machines?

MR. BOWMAN: There are volts for hertz protection on our main generators, but this is different.

MR. LEITCH: I guess I'm always concerned about these large machines operating at other than very close to 60 cycles, particularly vibration patterns that can be set up on the turbine blades. In other words the turbine blades carefully designed assuming that at power, the machine is going to be operating very close to 60 cycles. Does any of this allow -- permit operation further from 60 cycles?

MR. BOWMAN: I believe the power system stabilizer, what it will do is it will bring the machine back quicker. If you did have an instability event, it would actually bring it back quicker.

MR. LEITCH: Bring it back quicker.

MR. BOWMAN: Yeah. What typically happens is the machine is trying to catch up with the system so to speak, so, you know, as it's falling of synchronism, then it tries to overshoot and this will help dampen out those overshoots so that you can get back on line with the system.

MR. SIEBER: The transients that you're talking about here, they're all system generated transients as opposed to station generated transients.

MR. BOWMAN: That's correct. It may be an external fault somewhere on the system. It may be a lightening strike or some kind of heavy switching that's taking place and the power system stabilizer would help prevent the ringing or oscillation that might occur under that situation.

MR. SIEBER: How many transmission lines do you have coming into the station?

MR. BOWMAN: We have four transmission lines coming into each unit. The units are not tied, the switch arcs are not tied but we have four coming into each one.

MR. BOWMAN: I'll turn my attention now to voltage adequacy of the offsite power system. As we are adding load to our electrical distribution system, as a result of power upright there will be a number of loads added. That reduces our available voltage down to our sector laid loads. We have more voltage drop down for our distribution system and especially, you know, if it's feeding from offsite power, if it's feeding from the start-up transformer unit, ops transformer, it's all in the unit trip, we will see significant change in voltage there.

So to accommodate that, to compensate for it, we are implementing a modification called the unit trip load shed modification and that will help restore the margin. This modification provides selected load shed of balance-of-plant motors and in order -- they would receive the signal on a LOCA and/or unit trip. So we're in effect, dumping some of our load on our distribution system to improve the voltages down to the emergency busses and safety loads.

And that will help insure adequate post-unit trip voltages available at emergency busses.

MR. LEITCH: Terry, as I understood this, there was a selection that could be made and at various points along the way here, depending upon whether you're in Phase 1 or Phase 2 of this uprate program, the operator would administrate -- the selection of loads that would be shed would be administratively controlled.

MR. BOWMAN: They will be procedurally controlled.

MR. LEITCH: Procedurally controlled.

MR. BOWMAN: That's correct.

MR. LEITCH: After the second phase modifications are done, in other words, you're humming along at 120 percent, would they still be under administrative controls or would they be permanently locked in one particular position?

MR. BOWMAN: It would continue to be procedurally controlled.

MR. LEITCH: Would here be --

MR. BOWMAN: And that's to give you flexibility. For instance, initially we have two heater drain pumps that will be shed on the unit trip signal. We have three pump motors and one is basically a backup. So you need some flexibility to be able to swap which one is being shed. Two out of three operation, we will be able to have two that are shed. The third one doesn't need to be shed. It provides --

MR. LEITCH: But wouldn't you get to a situation where the loads to be shed could be permanently selected rather than procedurally controlled?

MR. BOWMAN: In essence that's what's happened. Our initial load shed of the heater drain pumps, that will be from here on out. We have -- we also have built in the ability to shed other loads in the future if necessary, if the grid conditions warrant that kind of thing. As load continues to grow on the grid, the ability to maintain offsite power voltage and adequate voltage is more difficult to achieve and so to compensate for that we may elect at some point in the future, to give up another load.

MR. LEITCH: I'm just a little concerned with procedural controls rather than something that could be permanently built into the system.

MR. BOWMAN: They are key locked so that, you know, somebody can't get in and inadvertently manipulate one of these things.

MR. LEITCH: They are key locked.

MR. BOWMAN: They are key locked and also there is a second verification that's performed when they put these in a load shed position.

MR. LEITCH: Okay, thanks.

MR. BOWMAN: That pretty much concludes what I wanted to talk about. Implementation of these three mods, load shed modification, out-of-step protective relaying and the power system stabilizer will help us insure the adequacy and reliability of offsite power.

MR. BOEHNERT: Will these be tested or have they been tested somewhere before so you know what to expect from them?

MR. BOWMAN: You're referring to the unit trip load shed?

MR. BOEHNERT: Yeah, the first two in particular, the out-of-step and the trip load shed.

MR. BOWMAN: They were tested, out-of-step protective relaying was tested on Unit 1 this past outage. It was implemented and then there was very extensive testing on it and unit trip load shed was also tested. And we will periodically -- actually, on unit trip load shed, we will periodically test that as well and out-of-step protective relaying, they will test that when they test the other protective relaying for offsite power.

MR. BOEHNERT: Thank you.

MR. SIEBER: Those are pretty common relay schemes anyway. It doesn't involve anything new as far as the relay.

MR. BOWMAN: And the Switzer (phonetic) relays are very commonly used for that system.

CHAIRMAN WALLIS: Okay, thank you very much. We'll move right along.

MR. YEMMA: Good morning. My name is Larry Yemma. I'll be talking this morning about flow accelerated corrosion and piping in general. I don't believe I'll bring anything new to the table this morning on these two topics. Brunswick is fairly typical when it comes to flow accelerated corrosion and their piping analysis. I'll talk about the program overview and then we'll discuss EPU impacts and conclusions.

Brunswick meets the generic guidance of Generic Letter 89-08 and NSAC/202L. We use the Checkworks software program as a tool to predict and track areas of significant wear. Additionally, we regularly check the industry OE data base for events in the industry that apply to Brunswick just from a fact point of view. These tools with program manager engineering judgment allows us to run an efficient and effective FAC program.

Brunswick typically inspects between 75 and 100 components each outage and since we have a dual unit, it comes out to be about 100 components a year, 100 components a year, correct. We do have a large data base of information. And the overwhelming majority of the wear rates that we see are conservatively predicted by Checkworks.

MR. LEITCH: Have you found any wear in the feedwater flow venturies. I guess picturing -- well, the BWR powers but usually inferred from the feedwater flow --

MR. YEMMA: We do see --

MR. LEITCH: What I'm saying is if you've got higher flow assisted corrosion in the feedwater venturies and wear some of that away, could you get a false indication of feedwater flow being somewhat lower than it really is?

MR. YEMMA: To my knowledge, we don't see anything unusual in the feedwater venturies.

MR. GRANTHAM: This is Mark Grantham. I think the feedwater flow venturies are actually stainless steel which are not susceptible to FAC.

MR. LEITCH: I think that's right, yeah. Yeah. That's good, thank you.

MR. BANERJEE: But you can get some deposition on them, so that depends on the coolant chemistry. That's a slightly different problem but have you ever had a direct check on the flow measurements. This is power or this is some other means of tracking the flow. There's a way of doing it with radio nuclides to see how accurate the flow measurement is. Are any such tests being made?

MR. GRANTHAM: This is Mark Grantham again. I think, it was about three or four years ago on both units we had an ultrasonic test that was performed using, I think it was the ABB system.

MR. BANERJEE: It was quite accurate?

MR. GRANTHAM: Correct, it compared very accurately back to our original weigh tank testing that was done at Alton (phonetic) Labs.

MR. BANERJEE: Okay, thanks.

MR. YEMMA: Okay, as you know, Brunswick went through a five percent uprate about six years ago and the results of that associated with flow accelerated corrosion showed no measurable increase in wear at any point. And as you can see, the flow increase of approximately 15.3 percent and we have a maximum temperature increase of six degrees fahrenheit. The impact on feedwater piping which we consider one of our more interested -- we're more interested in feedwater than in a lot of other systems.

Essentially because we have changed out extraction steam lines to the three and four heaters with chrome moli so we don't have any problems there any more. And the extraction steam to the five heater is of sufficient quality steam that our actual flow rates are predicted to decrease -- wear rates, rather.

And then that concludes my presentation on the --

CHAIRMAN WALLIS: About how thick is this pipe that's losing 20 mils a year?

MR. YEMMA: The feedwater pipe is approximately an inch and a half in thickness.

CHAIRMAN WALLIS: So it's going to lose a significant amount in a few years.

MR. YEMMA: It's predicted to but we've seen -- our actual wear rates are a lot lower than predicted.

CHAIRMAN WALLIS: How big are the actual wear rates?

MR. YEMMA: They're within single digit mils.

MR. KRESS: Checkworks is set up so you've got -- basically, in a sense you feed back in the actual wear rates?

MR. YEMMA: Yes, there are ways to modify the inputs and to tweak it to come closer to what you're actually seeing, yes.

MR. KRESS: You guys do it that way.

MR. YEMMA: We haven't --

MR. KRESS: I was trying to understand your statement about the estimated wear rates being bigger than the actual.

MR. YEMMA: Well, it's due to the inspection. We go out and inspect a lot of components and we're not seeing what they're predicting.

CHAIRMAN WALLIS: Then you'd revise Checkworks I would think.

MR. YEMMA: Well, that's the way -- yes, that's what we plan on doing.

MR. BOEHNERT: Have you had to replace any feedwater piping?

MR. YEMMA: Not due to -- not to my knowledge, in fact.

CHAIRMAN WALLIS: Checkworks is operated fundamental. It relies on a lot of experience.

MR. YEMMA: That's correct, and we use the standard EPRI inputs so -- and they're very conservative.

Okay, onto piping. Piping analysis is pretty typical for Brunswick as well. We have gone through the same steps as we went through in the five percent uprate. The piping was included in the five percent uprate actually bounds the scope of this uprate since this is a constant pressure uprate. So we don't look at anything other than what we looked at in the five percent uprate, which I just said here.

After we select the piping of interest, we gather the peak stresses for each line and we take the increases caused by the uprate, the temperatures mostly since there's no pressure increase, and we scale the stresses up, the combined stresses up in accordance with the increase in the impact of EPU and we just compare the increases with the code allowables and the results of that was everything was fine. Everything is below allowables.

We also evaluated nozzles, penetrations and pipe supporting systems as well with the same conclusion. In addition, we looked at high energy line break and no new break locations were identified.

MR. LEITCH: When I think about Brunswick, it brings to mind some pretty major problems that you had with pipe supports, maybe 10 years or more ago, where pipe supports were tied into block walls.

MR. YEMMA: Well, you sound like you have experience in that area. We did have challenges.

MR. LEITCH: I guess I'm wondering, it that problem all well behind us now?

MR. YEMMA: Yes, as a matter of fact, I was involved in reconstitution of the piping stress analysis about 12 years ago, and we went through every safety related system in the plant and upgraded it to the latest requirements; three dimensional earthquakes. And we replaced a lot of supports and we went through the whole system.

MR. LEITCH: Okay.

MR. YEMMA: So that's all behind us. Okay, the results that I show here is for a line that's inside containment. The lines outside containment show a similar -- there are some similar lines on the outside of containment that I didn't put down here but the stress ratio is very similar. We were up in the .8, .9 range for some of the lines.

And for feedwater, that came up to about a 2.2 increase, percent increase. In conclusion, piping and safety related components are -- related components are acceptable for EPU.

MR. BOEHNERT: Are you -- maybe you'll discuss this in your testing. Are you planning to do any vibration monitoring on the lines and so forth?

MR. YEMMA: Yes, yes, we -- the lines in Unit 1 are now instrumented and we will be -- it's feedwater and then main steam.

MR. BOEHNERT: Thank you.

MR. YEMMA: Uh-huh. Okay.

CHAIRMAN WALLIS: Thank you.

MR. YEMMA: Thank you.

MR. POTERALSKI: Good morning. I'm Dan Poteralski, Manger of the Nuclear Fuel Manager and Safety Analysis and I'm going to describe the results of the probablistic safety analysis for extended operate uprate for the Brunswick plant. Sitting next to me, I'd like to introduce Larry Lee from Aaron (phonetic) Engineering. Larry was one of the principals in the performance of the analysis for the extended power uprate.

The purpose of the analysis is to provide confirmatory insights and insure that no new vulnerabilities are created by extended power uprate. Extended power uprate is not a risk conformed submittal. However, the ACRS has requested a reg guide 1174 risk analysis for power uprates in excess of five percent.

MR. KRESS: Did the ACRS request that or did the staff?

MR. LEE: This is Larry Lee. The staff to support the risk application.

MR. KRESS: Yeah, I didn't think the ACRS made a request like that.

MR. POTERALSKI: I apologize. The analysis was performed to determine the risk impact of extended power uprate implementation. Based upon a comment that was made before the break, I would propose that -- I was originally going to talk about the scope of the analysis, the methodology, results and conclusion. I can skip over the methodology which will eliminate about five slides from the presentation or I can go through them. It's your pleasure.

MR. KRESS: Which five are you talking about?

MR. POTERALSKI: The ones that are titled -- I would skip the five that are titled methodology at the top, go right from scope to --

CHAIRMAN WALLIS: We're doing fairly well on time, so maybe you're skipping, you could just go very quickly through those slides.

MR. KRESS: I wouldn't want you to skip the one on success criteria.

MR. POTERALSKI: Okay, I'll go through them then.

MR. KRESS: And operator responses.

MR. POTERALSKI: Okay, the scope of the analysis was to analyze internal events using the Brunswick PSA model. We did both a Level 1 and Level 2 analysis. Level 1 --

CHAIRMAN WALLIS: You need to advance the slides.

MR. POTERALSKI: Thank you.

MR. KRESS: Is your PSA, has it been given the industry peer review?

MR. POTERALSKI: Yes, it was peer reviewed in September of 2001 after the submittal was made to the Commission.

MR. KRESS: And it was qualified for what level of usage?

MR. POTERALSKI: The qualification statement basically says that the PSA can be effectively used to support application involving absolute risk determination when combined with deterministic insights. This corresponds to an overall grade of 3 on a scale of 1 to 4, 4 being the highest.

MR. KRESS: Okay, that's good for power uprates, I understand.

MR. POTERALSKI: Right. And we submitted the results of the certification review in an RAI to the staff on November 30th, 2001. Level 1 addresses core damage frequency or CDF. Level 2 calculates large early release frequency or LERF. The external events portion was done based upon the original IPEEE study which was more qualitative in nature than the events analysis.

The results of the valuation were for fire was viewed to be non -- was determined to be non-significant. The seismic margins assessment had no effect. The other included external hazards such as tornadoes and hurricanes and they had negligible impact. We also did a qualitative assessment of shutdown risk and it was also assessed to be non-significant with a change according to the image frequency of less than one percent.

In order to evaluate the impact of extended power uprate on PSA we considered a number of things. We verified that the hardware changes that were mentioned by Bob Kitchen earlier did not introduce a new accident type or increase the frequency of challenges to the plant. The hardware had negligible impact because it was either a replacement or upgrade of existing equipment, except for the standby liquid control system where a system modification described by Mr. Kitchen to meet cold shutdown requirements for future core designs as described by Tom Dresser.

There are no changes to the PSA were identified as a result of potential emergency operating procedures severe accident management guidelines. Set points showed negligible impact. The power level had an impact on the timing of short term important operator actions and these were addressed in the human reliability analysis.

MR. KRESS: In the IPEEE where you were

talking about external events, did that include an analysis of a Class 5 hurricane hitting the site or were the analysis bounded by an earthquake bounding, Class 5.

MR. LEE: This is Larry Lee from Aaron Engineering. Yeah, the IPEEE evaluated all types of high winds and hurricanes and found the plant to be acceptable.

MR. LEITCH: It seems to me you're in a zone there where you could have --

MR. LEE: It probably would be evaluated as a very low frequency event.

MR. LEITCH: Very low frequency.

MR. LEE: Yes.

MR. LEITCH: Well, yeah, but you're -- it seems to me you're in an area there that is susceptible to hurricanes. Is that not true?

MR. LEE: That it true. We can -- if needed, we can relook at exactly what the submittal says to see what the frequency of a Class 5 tornado would be compared to the IPEEE core damage frequency guidelines. Usually if it's below 1 E^{-6} frequency of event, then it's considered below the margins requirement, below the screening criteria.

MR. LEITCH: Yeah, okay, thank you.

MR. KRESS: Are these plants located near the shore?

MR. POTERALSKI: Yes.

MR. KRESS: So they're susceptible to hurricanes?

MR. POTERALSKI: Yes.

MR. LEITCH: That includes storm surge, I take it?

MR. LEE: Well, I don't know if it includes exactly storm surge, but it does include, yeah, all high winds, hurricanes, tornadoes.

MR. LEITCH: Okay, I guess I'm really a little off the point anyway. All of this has nothing to do with power uprate anyway.

MR. LEE: Right.

CHAIRMAN WALLIS: Power uprated hurricane.

MR. POTERALSKI: I'd now like to describe the Brunswick PSA model. It was a -- again, we looked at both Level 1 and Level 2. We analyzed internal events, including flooding. The model has been --

MR. KRESS: When you say Level 2, does that include fission products? Level 2 usually includes fission products but when you're just doing a LERF it doesn't usually.

MR. LEE: Well, the Level 2 does include, yeah, the release from containment but it doesn't evaluate in terms of consequences with a Level 3 analysis. It was just Level 2 LERF in terms of large release frequency.

MR. KRESS: Yeah, but you don't -- maybe I'll ask it another way. Did you use MAP for that?

MR. POTERALSKI: Yes, we used MAP.

MR. LEITCH: Okay, that will answer my question.

MR. POTERALSKI: The model has been maintained up to date. It reflects the current plant configuration. It was based upon the original IPE model that was developed in response to generic letter 88-20. The model has been updated in 1993, 1996 and 2000 and underwent an NEI peer review in September of 2001 as I mentioned previously.

The process used to evaluate the impact of extended power uprate included an independent peer review of the PRA technical elements that were derived from the NEI RPA peer review guidelines, specifically in --

MR. KRESS: When you say independent, does that mean that you've brought in outside experts?

MR. POTERALSKI: That's correct. Before we started the analysis, we brought in a team to review the model before we did the analysis, before the submittal and then a few months later, we actually had the full peer review completed.

We looked at initiating events, success criteria, systems, data, operator responses, accident sequences. We evaluated the impact on thermal hydraulic parameters using the MAP code and then compared the results against the reg guide 1.174 criteria for core damage frequency and change in large early release frequency.

The impact on the human reliability analysis was developed utilizing the criteria of risk importance and short time to complete. The evaluation identified 42 significant operator actions; however, only four operator actions impacted by extended power uprate due to reduced time to perform certain actions. All of them involved level control during anticipated transient without SCRAM ATWS.

MR. KRESS: You did Fussel Vessley importance of operator action?

MR. POTERALSKI: Yes.

MR. KRESS: Did it come out to be -- that's not surprising I guess, it's that important. That's CDF Fussel Vessley, right?

MR. POTERALSKI: Yes, we did a Fussel

Vessley on the base Level 1 PRA model to see what operator actions were above Fussel Vessley of $5E^{-3}$ and in addition we looked at all short term operator actions below 30 minutes.

MR. KRESS: Okay.

MR. POTERALSKI: Operator actions necessary do not change due to extended power uprate. The time to perform the operator actions probably does not change significantly and the operator responds to the observed symptoms. The time available window does reduce from 30 to 24 minutes based upon the MAP thermal hydraulic calculations and the PSA postulates and increase in human air probability due to the reduced time available.

CHAIRMAN WALLIS: Could you tell us what these operators are doing while they're controlling level?

MR. LEE: While they're controlling level, they're going through the procedures to make sure that they lower water level in response to the fail to SCRAM event.

CHAIRMAN WALLIS: Well, are they continuously lowering or do they lower it once or do they --

MR. LEE: Well, they're going lower it and then try to control it at a lower level.

CHAIRMAN WALLIS: So their attention is focused very much on this level during that period of time?

MR. LEE: Yes, it is.

CHAIRMAN WALLIS: And they're actively controlling some valve during that period of time. They're not just doing it once. They're doing it continuously.

MR. LEE: Yes, they're controlling injection flow for either HPSI or RCIC, depending on which system they're using.

CHAIRMAN WALLIS: And is there any idea of how easy it is to maintain the level within required limits?

MR. LEE: Well, the operators are extremely trained on this type of event. We believe it is more difficult to control HPSI just in terms of the higher flow rate compared to RCIC, but for HPSI based on information from the operators, the time to get to this step and be able to control level near TAF would be approximately five minutes. And for RCIC it's an easier time so -- or an easier procedure, so it's estimated at approximately two minutes.

CHAIRMAN WALLIS: So how many corrections do they make during that period of time?

MR. WILLIAMS: This is Mike Williams. I'm operations manager at Brunswick. The response to the ATWS, it's not going to change as part of power uprate. Now, the response would be what we do is we lower level down till we meet certain conditions and we establish a level control band so there's really no set number of times at which you'd have to change or take different directions but you would lower level down until a specific set of criteria is met and establish a level control band and maintain level within that band.

CHAIRMAN WALLIS: This is a pretty benign transient. It's not as if this level is bouncing around and then trying to control it. It's actually trending in a fairly slow way in some direction or another, is it?

MR. WILLIAMS: Depending on the severity of the ATWS, if you do 100 percent rod pattern very high power ATWS, it moves -- the level will move around pretty quickly but it's consistent. It's not -- it's not moving all over the place. So you'll be able to set a band and control level. The way we do these in the simulator is pretty consistent in that we have high power ATWS is MSIVs closed and the operators are well trained to get level --

CHAIRMAN WALLIS: And you get simulation with the extended power uprate?

MR. WILLIAMS: I'm sorry?

CHAIRMAN WALLIS: Have you run the simulator under EPU condition?

MR. WILLIAMS: We have ran the simulator with extended power uprating, compared the old model with the new model and there's very little difference. There's some but it's not significant difference.

CHAIRMAN WALLIS: Thank you.

MR. POTERALSKI: There is very little impact on the risk profile. Specifically there was a slight change in risk importance of the four operator reactions. We adjusted the human error probability of the four impacted actions and then resolved the model to get new values for core damage frequency and larger early release frequency.

There was the same relative significance to the risk profile. There were no new significant actions due to extended power uprate and no actions became non-risk significant because of extended power uprate.

MR. KRESS: Do you use the EPRI models of the human error function of time?

MR. LEE: Yes, for the operator actions we used the EPRI HCR/ORE methodology and also the EPRI time cause based approach for the diagnosis error. Then we used the THIRT methodology from NUREG 1278 for the execution error.

MR. KRESS: Okay.

MR. POTERALSKI: The results of the analysis are shown on the next slide. There's no change in system success criteria, no new action sequences identified, no significant impact due to procedural changes, no significant impact due to hardware changes. And there was a slight decrease in time available for four operator actions.

MR. KRESS: Is one of your success criteria have to do with opening release valves?

MR. LEE: In terms for ADS for depressurization?

MR. KRESS: Yeah.

MR. LEE: Yes, the success criteria for Brunswick is to open three SRV valves for depressurization.

MR. KRESS: And that didn't change with this --

MR. LEE: It didn't change. In fact when we ran the MAP code, it looked like even two SRVs would be successful, so we maintained the three SRV success criteria.

MR. KRESS: When these open, do they open and close, do they chatter or do they open and stay open?

MR. LEE: I would believe for the depressurization function they would just remain open.

MR. POTERALSKI: The results of the analysis when compared to the Reg Guide 1.174 criteria, for extended power uprate, there was a change in the core damage frequency of $4.0E^{-7}$ or about 1.6 percent. This represents a very small change and puts us in Region 3 of the delta CDF versus CDF criteria. For large early release frequency, the change due to extended power uprate is 1.9 E^{-7} and that correspondence to a small change or puts us in Region 2.

MR. KRESS: Let me ask you that then. That 4.46 absolute value of 10^{-6} on your LERF, is that the sum of the LERF for both plants?

MR. LEE: That's for a single unit.

MR. KRESS: Why wouldn't you sum the two plants because you're changing the LERF for the site equally for both and why wouldn't you double both the delta and the actual LERF for comparison? I guess this is a question to the staff more than to you because I don't think it's clear in 1.174 what you do with multiple sites, but clearly to me it's -- LERF is a cite characteristic and your actual LERF for the site ought to be doubled and your delay LERF ought to be doubled. And I don't know where that puts you in which region.

If you're already in Region 2 it's getting you up closer to Region 1. I don't know if it does or not. That's a question to the staff, I guess.

MR. LEE: The border between Region 3 and 2 for LERF is IE^{-7} so we're still at the lower border of the region for Region 2.

MR. HARRISON: This is the slide --

MR. KRESS: What I was concerned with if you take your 4. -- 4.6, E^{-6} LERF and double that, that gets you up to almost 10^{-5} and you're just above the 10^{-7} which puts you close to the really dark area there in Region 1. See, my problem is, I don't think we're using 1.174 correctly but still this is a question to the staff.

MR. HARRISON: Yeah, this is Donnie Harrison from the PRA branch and I remember this question has come up in the past and there's been questions on the scale that if you should adjust the scale on the bottom line as well, and but again, I don't recall the full answer to your question. But I do recall this question from three or four months ago.

MR. KRESS: Yeah, I've asked it before and I will ask it again until I get the right answer.

CHAIRMAN WALLIS: Well, do we know the right answer?

MR. KRESS: The right answer is, yes, you should double and --

MR. HARRISON: And there is a revision of the reg going on but I don't think they're going to address that.

MR. KRESS: If we get to review it.

CHAIRMAN WALLIS: Do we agree that you should double? I mean, you've also doubled the benefit and there must be some kind of cost benefit here. It's not purely risk.

MR. KRESS: Oh, now you're getting too deep.

CHAIRMAN WALLIS: I'm thinking too deeply here?

MR. KRESS: Yeah.

CHAIRMAN WALLIS: Oh, okay, then I'll stop.

MR. KRESS: You're really correct. You

should adjust the -- you're saying you should adjust the pump safety go depending on the benefits you're getting and that's probably true but nobody's going to do that.

MR. HARRISON: And Dr. Kress, partly the answer in the past has been is this is, if you will, a generic plot. It didn't take into account populations densities and that's part of the problem we have.

MR. KRESS: Oh, absolutely and I think that's part of the answer. The other part of the answer is, of course, that they've changed the SLC and they actually get a decrease in both of these which makes it fine with me on this thing. I just wanted to raise the question because it's going to come up again some time and --

CHAIRMAN WALLIS: Well, the SLC has a big effect.

MR. KRESS: Oh, yeah, it has a better -- bigger effect than the uprate, I think. But, you know, if I double both your delta and your actual absolute value, that puts you right on the line of that Region 1 and, you know, that bothers me but it doesn't bother me because I agree that changing the SLC offset this and gets you down in the right region anyway.

CHAIRMAN WALLIS: So if you had four units, you'd say they were in real trouble.

MR. KRESS: Absolutely.

Dr. Schrock: Does the reg guide a require it anyway?

MR. KRESS: No the reg guide is silent on that.

CHAIRMAN WALLIS: Let's move on. We know that this is an issue we've raised before and we'll raise it again.

MR. POTERALSKI: With that lead into the next point I'm going to make, with the standby liquid control system modification, the success criteria improves due to single train operation where we only need to credit one out of the two trains.

MR. LEITCH: Let me make sure I understand correctly that last slide. The bottom line there is EPU with the SLC modification.

MR. POTERALSKI: That's correct.

MR. LEITCH: So the net effect is an improvement.

MR. POTERALSKI: Improvement for core damage frequency and it's an improvement of nine percent for LERF it's an improvement of 28 percent.

MR. LEITCH: And you are committing, I think one of the other speakers said, to the SLC modification.

MR. POTERALSKI: Right, with the second load of the --

MR. LEITCH: In my reading, it was still questionable, I guess, whether you were going to do that or not, so there is every intention of doing that or a commitment to do that now.

MR. POTERALSKI: That's correct.

MR. LEITCH: Yeah.

MR. POTERALSKI: In conclusion, based upon the current reg guide 1.174 criteria there's a very small risk increase in core damage frequency of about 1.6 percent, a small risk increase with large early release frequency of 4.5 percent. The qualitative assessment shows no significant risk impact on fire, seismic or during shutdown. When the changes in the shutdown -- excuse me. When the changes in the standby liquid control system success criteria are included, the impact is a reduction in both core damage frequency and large early release fraction -- frequency. That concludes my presentation.

CHAIRMAN WALLIS: Thank you very much.

MR. BANERJEE: What about early fuel

storage, the fuel has more radioactive material, so is there any sort of risk associated with that?

MR. LEE: Risk related to shutdown. So there's what the -- the potential that credit secondary systems such as fuel pool cooling or reactor water cooling as decay heat removal systems by themselves. Most of risk during shutdown is during the early times of the outage when you can only use RHR and fuel pool cooling wouldn't be effective.

MR. BANERJEE: And nothing is effected in this RHR phase? There's no additional risk that arises due to that?

MR. LEE: Not in terms of the additional decay heat load, no.

MR. LEITCH: I guess if I understand that last slide, it's incorrect. In other words, it's somewhat dated. If I was making this presentation, I'd get rid of that.

CHAIRMAN WALLIS: So it's a risk decrease.

MR. LEITCH: I'd say decrease instead of increase; is that correct?

MR. POTERALSKI: The reason the slide is shown the way it is, is the formal commitment to the staff has not been made for the tech spec change and this captures what was in the original submittal of a year ago.

MR. LEITCH: Okay, thank you.

CHAIRMAN WALLIS: Are we ready to move on. Thank you very much for your presentation.

MR. WILLIAMS: Good morning, I'm Mike Williams, the manager of operations at the Brunswick plant. I want to talk about the operational impacts, the training and the testing that we plan to do as part of the extended power uprate. Some of the operational impacts we have we've talked quite a bit about stability III versus stability Option E1A that we had previously. It's fully operational on Unit 1 right now. It is a good change for us.

It actually has an automatic detect and suppress. The E1A option has a detect function and it has an automatic trip function based on a flow versus power relationship but you could have instability and with only an alarm function and under E1A would allow the operator then to have to insert the manual SCRAM to suppress it.

Either one -- either option works well, but Option III I think is a very, very good change for us. The other part of -- thing that power uprate has done is we are implementing that power range neutron monitoring system. It's basically an upgrade for our power range system and it's going to have a much better operator interface than what we had previously. That's on the good side.

On the other side there's -- we will be doing more rod pattern adjustments. Currently we have to change our rod pattern approximately once ever four months. With extended power uprate. Once we get into it, we'll be doing that much more often, on the order of about every month. It's not a significant impact. Moving control rods is what we do and it's very well able to be controlled.

We also will have a slight reduction in operator action times and they're very slight. We have with the modeling we've done and with the simulator exercises we developed, the change in the operator response and the change in the plant response is there but it's small enough to where it's not a major impact at all and for the most part, from a transient response situation the operators won't be able to see the difference on the simulator.

MR. LEITCH: Has the preconditioning operating requirements all been taken away now with the fuel that exists? In other words, this control rod pattern change need not be accomplished with a power reduction and then gradually working your way back up the way it used to be?

MR. WILLIAMS: My understanding is it will still require preconditioning limits on GE14 as it has in the past.

MR. LEITCH: Oh, really?

MR. WILLIAMS: Now, I'm not 100 percent confident about that; is that correct?

MR. BOLGER: This is Fran Bolger from GE. There is some best practices for fuel maneuvering guidelines that are being followed. They're not exactly -- they're not pre-conditioning, per se, but there are other guidelines that are recommended.

MR. WILLIAMS: We're still following the recommended guidelines and we will continue to do that.

MR. LEITCH: So on a monthly rod pattern, one might expect power to be reduced and then work up again over a period of a day or so, something like that?

MR. WILLIAMS: About a shift, yes, sir, somewhere in that range.

MR. LEITCH: A shift. Okay, thank you.

MR. WILLIAMS: Operator training, we started early last summer to do a conceptual, I guess, overview of what was coming with power uprate talking in very large terms as to what we were going to do. We've gotten very much more detailed with that. So we actually did training four times last year on what was coming on power uprate. We started out very conceptual and it moved into a lot more detail as we got closer to the outage. Principally the large changes that we have with the power range neutron monitoring system, our management of thermal-hydraulic instability and the balance of plant modifications.

So we trained on those four times last year beginning with very conceptual based type stuff, up to a lot of detail by December of last year.

MR. LEITCH: Do you have a plant specific simulator at Brunswick?

MR. WILLIAMS: Yes, sir, uh-huh.

MR. LEITCH: And what is the status of simulator with respect to these physical changes in the plant? When is the simulator going to be changed?

MR. WILLIAMS: The simulator has been upgraded to be physically compatible with Unit 1 as in the new power range neutron monitoring system. All those things have been installed on the simulator. The new core model that is duplicating the 112 percent power is what we have right now. And we have -- we will be training on that starting in about a week.

The operators have not been trained with the new core model. They have been trained with all the new hardware power range neutron monitoring system.

Dr. Schrock: What kind of frequency do you expect on this automatic trip feature? Is it something that will be seen rarely or is it something operators are going to have to get used to dealing with or what?

MR. WILLIAMS: The automatic trip feature would only -- it's the detect and suppress part of the oscillating power range monitor. I would expect to not see that in the plant at all.

Dr. Schrock: Never see it.

MR. WILLIAMS: I don't think so. We will train on a simulator. Pretty much every time we go over there, you will see something along that line but I don't ever expect to see that in the plant.

Dr. Schrock: So how to you gain confidence that it's going to work if it's really the last resort?

MR. WILLIAMS: Well, we test the system when we put it in to verify that it's functionally, you know, doing what it's designed to do, so I have confidence that --

Dr. Schrock: Well, there are tests.

MR. WILLIAMS: We do test it in the plant, yes, sir. I mean, you know, not make instabilities and make it trip us but --

Dr. Schrock: Uh-huh.

MR. WILLIAMS: Now, in addition to that, I mean, the way we train the operators is that system doesn't even need to be there because if we detect instability, we'll shut the reactor down. Whether that system is there or not, it's pretty much independent.

MR. POST: This is Jason Post from GE. And also, the design of the instruction is such that it has a low level of response even for normal noise and so you have confidence that the instrument is working during normal stable operation as well.

MR. WILLIAMS: Okay, just a list there of the training things that we put into the cycle right before this last outage so that we made sure that we covered everything, the set point changes, tech specs, all our procedure changes. The procedure changes here were very minor. The set points, there were no fundamental changes in how we operate with the exception of the stability solution.

We -- before we go to uprate, we will go in and do training on the simulator, demonstrate transients, do transient response training, and talk about the test plan, the start-up test plan with the operators prior to going anywhere above our current license power level. There will be classroom and simulator training.

MR. LEITCH: Where do you stand in the INPO accreditation cycle. Has the operator training program been recently --

MR. WILLIAMS: We were accredited last year, I think it was and so we are now, I think on an 18-month cycle. I mean, INPO changed that from two years. We were put on 18 months so they could get the plant evaluations lined up with the accreditation evaluations. We're on an 18-month cycle.

CHAIRMAN WALLIS: This business about no operating procedure changes, there really aren't many, are there?

MR. WILLIAMS: Very few, and the ones that were there dealt with set point changes more than anything but also the instability change caused us to change our AOP going from E1A to Option III.

CHAIRMAN WALLIS: But it's not a major item, is it? I mean, you've got a bullet there. I just wondered if there was something significant under that bullet.

MR. WILLIAMS: There's nothing significant about what we changed in the AOP.

CHAIRMAN WALLIS: And there's nothing significant under EOP, the emergency operating --

MR. WILLIAMS: Fundamentally what we do did not change with the exception of --

CHAIRMAN WALLIS: The plant transient response is essentially the same.

MR. WILLIAMS: Right, yes.

CHAIRMAN WALLIS: So eliminate the slide, yes.

MR. WILLIAMS: I can do that, watch this.

(Laughter)

MR. WILLIAMS: I'm going to talk a few minutes about implementation testing. We're going through pretty much the LTR testing, chemistry radiation monitoring. We'll monitor those parameters on the way up to make sure we're staying within our limits. We have to recalibrate our main steamline flow transmitters because we'll be going to a higher steam flow and we have an MSIV isolation of high steam flow. We'll also be doing the APRM set point adjust up to the 120 percent of original license power.

We'll be doing performance monitoring as we always do on power increases. Our EHC, electro-hydraulic control system, pressure control system and our feedwater level control systems will be stopping every five percent power and doing step changes, regulator fail-over testing on those just as we did coming out of the outage to make sure that they're responding correctly at the above our current power level.

During that last outage we also installed our main steam and feedwater piping vibration instrumentation with monitoring data on the way up and we'll be doing all our balance-of-plant monitoring on the way up to look for anything in the plant that is going to be a limitation for us on the way up. But we'll be coming up very slowly in power, a little bit at a time, doing a lot of monitoring and deciding it's okay to keep going.

MR. LEITCH: I'm not so much concerned after you have all the modifications done, but when you bring the units up initially after only the Phase 1 modifications have been completed, what are the kind of things you'll be looking for. Someone mentioned earlier that the main transformer is one of the limiting factors. Are there other factors that could potentially be limiting?

MR. WILLIAMS: We have a large list of parameters that we'll be monitoring on the way up. We know our limiting point could be main transformers, it could be our bus duct temperatures, it could be the actual amperage on our condensate booster pumps as we currently are. So we have a list, procedure already made up that incrementally come up in power under those parameters and that they're okay to continue up to the next level.

MR. LEITCH: On that list would be things like condensate booster pumps, suction pressure and reactor feed pump suction pressure?

MR. WILLIAMS: Yes, all those things, lost amperage, temperatures, flows.

MR. LEITCH: Okay.

MR. KITCHEN: This is Bob Kitchen. We have a special procedure that's going to be issued with the license -- part of the license testing that coordinates the plateaus and the data to take during the power ascension in very small increments up to the test plateaus, which includes, as you mentioned the balance-of-plant, core performance, pressures, temperatures at various points in the plants. Steam line tunnel temperature for example, is an area of concern that we'll monitor, temperature on the main generator, isophase cooling, as well as the routine core performance parameters. We'll be doing that throughout the start-up.

We also have three management hold points built in, one prior to starting, power ascension above current license power level, one at the intermediate plateau and one prior to resuming normal operation.

MR. LEITCH: Now, what concerns me is that a license is granted for 120 percent power, yet, admittedly, you don't know of all the physical changes made to go to 120 percent power, so we're okay here and eventually we'll be okay there, but I guess what I'm concerned about is moving through this zone where you've got permission so to speak to go to 120 percent, yet not the physical hardware to move to 120 percent yet, so all those things have to be very carefully monitored and it sounds like you have a program to do that.

CHAIRMAN WALLIS: Can you run at this 120 percent power all year round or do you have environmental limiting conditions some of the time?

MR. KITCHEN: We'll be able to operate at the 120 percent power level year round. In terms of environmental, condenser or temperature limitations, we do have an environmental MPDS change in progress which was -- coincidentally it was due for renewal anyway and there is a slight change in our circ. water discharge temperature so that the mixing zone is increased. And we'll have to have that -- we'll want that in concert with the full uprate. We do not anticipate any limitations for environmental.

MR. WILLIAMS: To summarize the greater impacts of EPU augmentation, we have done extensive training and we still have training to do before we go above our current license power level and we have a very comprehensive test plan laid out to monitor the plant carefully as we're coming up above our original license power level.

The operational changes that we see have to do with extended power upgrade. As we have a new approach to instability, we will be doing more rod manipulations to maintain power and there is some small reduction on operator response time with respect to transients but it's very small and in most cases the operators won't notice the difference.

MR. LEITCH: Mike, one concern I have with this -- with these power uprates is, I have the perception and maybe it's incorrect, but I have the perception that it's going to be a great deal more challenging for the operators to maneuver rods without making a mistake. It seems to me we're encroaching on margins and I guess I'm concerned about thermal limits being exceeded as we operate these what I call designer fuels. And I guess, have you done anything to increase the operator training in that area or perhaps, even more importantly, the guy that really has the control in that situation and the way most plants operate is the reactor engineer.

MR. WILLIAMS: That's correct.

MR. LEITCH: And I'm concerned about the training of reactor engineers. Have you done anything different in that area?

MR. WILLIAMS: I don't know that -- I really can't speak for the reactor engineers. Blane may want to do that. I can tell you from the operator's side, we have a very strong reactivity management program that we use and we also have a very good relationship at Brunswick with the reactor engineers and the operators and you'll almost never see, unless it's something that we have to do, an ALP type situation, a power change in the control room that doesn't involve the reactor engineer being in the control room to help us monitor the thermal limits while the operators are performing that action.

As far as any additional training for

reactor engineers based on having to do more control rod manipulations, I don't know of any plan.

MR. KITCHEN: Well, right now the training to say it's changed, I'm not sure I could say that but the training that is given for operators as well as the engineers includes the reload plan and fuel cycle plan and impacts and it's also reviewed with the operators mid-cycle. So they get the core performance expectations twice during cycle on each unit as part of the routine training.

I don't think there's really a change in -- you know, in that. It's just the content of it would be different, certainly because of new fuel and different parameters are limiting.

MR. LEITCH: Some plants have a qualification program, if you will, for reactor engineers where a reactor engineer, in order to be a reactor engineer, one must pass through certain hurdles, including witnessing some draw rod pattern exchanges in the control room and so forth. I was just wondering if you have such a program.

MR. WILLIAMS: Yes, sir, we do.

MR. KITCHEN: And Blane, can you add anything?

MR. WILTON: Yeah. The way we control

that is really going to be the same way we've always controlled it, which is we have a predictor code that we have in the control room and before -- when we start getting tight on limits, before we do any manipulation which changes reactivity, we run the predictor codes, see where it's going to put us and then we march through those steps.

Our design margins really aren't going down with respect to the core. And at least for this cycle, we're still going to be in a control cell core configuration. So we really haven't planned any special training other than we do initial training. Our fuels group, after they've designed to core for the upcoming cycle, they do an extensive training session with the reactor engineering staff to let us know what the cycle is going to look like, what our limits are going to be, those type things and then do also emit cycle training session also.

So I don't see our conduct of operation really changing in the control room, which we're still going to be running our predictor codes as we planned. Our margins to our thermal limits from a design perspective really haven't changed. So I don't see really a change in operating strategy for us up there.

MR. LEITCH: Okay, I'm just concerned that if VWRs are becoming more complex to operate as we move to these higher power levels from a fuel management standpoint and I just want to be sure folks are putting the right emphasis on the operators and the reactor engineers and it sounds like you've got a program to do that.

MR. WILTON: Well, like Mike eluded to earlier, any plan change in reactivity is controlled with a reactor engineer in the control room, so those are covered. Any time there is an unplanned change, they have immediate reduction, power reduction sheets available to tell them --

MR. LEITCH: To stay calm.

MR. WILTON: Yeah, on what to do in those cases and then the reactor engineer is there to help with the recovery and those are going to remain.

MR. LEITCH: Thank you, that's good.

MR. GANNON: I'm Neil Gannon. I'm the director of site operations at the Brunswick plant. You look at our discussion on the various topics today, you can follow through this program of our analysis on the fuels. ECCS performance, PSA, we'll call your attention to the operational impacts.

In light of the change to the station and the potential challenges to the BOP system and the fact that we're changing the station, one thing that was incorporated into our evaluation of the extended power uprate program was a standing PNSC, plant nuclear safety committee, standing committee on power uprate itself to identify power uprate related issues as they impact operations.

Some of the things that came out of that was the concern on the impact to our chemistry performance index and things of that nature so that while not necessarily an obstacle to power uprate, operational impacts that we wanted to carry forward and resolve them as we implemented the program, an example being the condensate cooling modification which our subsequent activities indicate to us it may not be necessary but we'll follow those through to resolution.

Obviously, there's a business case to be made for extended power uprate. It increases the plant capacity, so that's one of the business plan aspects of this. We are also using the extended power uprate program at Brunswick to look at some of the operation strategies and our plans for the future of the plant.

Some of the features of that are we are using our plant staff as the extended power uprate program. This is not something that's out-sourced. Bob and a lot of the crew are people that came out of the line organizations so that we have that sense of plant ownership and we have that knowledge that's going to be institutionalized and come back to the plant when we're done.

We'll use this opportunity to increase our knowledge base at the station, the BOP systems and we're going to address some long term issues that, while not necessarily strictly power uprate related are challenges to us, equipment obsolescence, the power range neutron monitoring is something that we'll address. An equipment obsolescence issue and provide a benefit as well as just facilitating extended power uprate.

We have some components that we've identified here such as feedwater heaters that while not necessarily obstacles, are components identified as not going to serve to the existing license life of the plant and we're using this opportunity to go ahead and upgrade those and give ourselves a better plant when we're done.

We also feel that our plant staff capabilities will be increased, as I said before. The individuals that we're using to manage power uprate are people that came out of our line organizations; engineering, operations and other areas, and will return to the station when we're done. So this is something that's internalized and we'll have that available to us as we go forward and operate the station.

So we're proud of the work that's gone into this and pleased to present this material to you. If there are no other questions for me or anyone else here --

MR. KRESS: The upgrades and the improvements you've listed are all very good. Is the power uprate approval contingent on those being made or are they -- is that a separate issue? I don't know if that's -- that may be another question to the staff.

MR. HARRISON: Could you rephrase that question?

MR. KRESS: The question is, they're talking in order to make this power uprate or as part of the power uprate are improving the power range instrument, particularly increasing the SLC and upgrading the grid stability. My question is, if you're going to say we will approve this power uprate, is there something in that approval that says these things have to be done and it has to be demonstrated that these improvements and upgrades have been made before the power uprate takes place or not?

MR. HARRISON: Well, some of them, the one in particular, the safety -- the standby liquid control system modification won't be done until later on. They're going to make a license amendment later on this summer to revise the operation of the standby liquid control system and we're going to put a license condition in the license that says that they have to do that.

MR. LEITCH: Okay.

MR. HARRISON: But the rest of the modifications are being described in the documentation that has been submitted to the staff.

MR. KRESS: So that's part of the application.

MR. HARRISON: Part of the application and that will be done in order to --

MR. KRESS: But the SLC is the only one that's not part of that.

MR. HARRISON: I believe that's the only one that -- well, there are some secondary site changes, I believe, that -- what was it, the transformers and some other changes that won't be done until later.

MR. KRESS: Okay.

MR. HARRISON: But they can't physically get to that power level without making those changes.

MR. KRESS: Yeah, those don't bother me because they'll have to make those if they're needed, yeah.

MR. LEITCH: But did I understand -- well, maybe this is this afternoon's discussion. Let me just quickly ask a question. Did I understand you to say that power uprate will be conditional on SLC modification being installed?

MR. HARRISON: There's a condition that's going to go on the license that says that by -- what's the date?

MS. ABDULLAHI: I'm Zena Abdullahi, the reviewer. The license condition that is attached to the power uprate on the SLC is for the shutdown requirement that the change from 660 to 620 -- I'm sorry, 660 to 720 or whatever ppm, that is what that is based on and in any case, we're giving them an uprate of 20 percent and we don't know when they put in the second batch of G14 fuel what the reactivity requirement would be then. And this will insure that the staff will review it six months before the implement.

The SLC margin, though, is the licensee plans to make the change but the condition is not really there and we will be discussing it in our presentation.

MR. KRESS: So the change from one to two pumps --

MR. HARRISON: Two to one.

MR. KRESS: -- two to one, I'm sorry, will not be a condition on the uprate.

MR. HARRISON: No, the way the condition is currently worded, it says that the licensee shall submit a license amendment request to insure that the system remains capable of shutting down the reactor, demonstrating appropriate shutdown margin and continues to meet the requirements of 10 CFR 50.62 which is the ATWS requirement, by August -- I believe August 29th or August 30th. So there's a requirement in the license condition that they must submit a license amendment request to show that they meet the shutdown margin requirements and the ATWS requirements by August this year.

MR. KRESS: Yeah, but they could do that without making that particular change probably.

MR. HARRISON: Well, we don't believe that they can meet the shutdown requirements.

MR. KRESS: Okay.

MR. HARRISON: So that will allow us to review the other aspects of the system at that point.

MR. BOLGER: This is Fran Bolger from GE. As far as Unit 1 cycle 14, which is the first plant that's uprating, the shutdown requirements were met with the 6-60 as Tom Dresser has shown earlier.

MR. HARRISON: That's for the first cycle, but that's not to go to -- for the next cycle of operation, they need this in order to meet that next cycle of operation, to load a full batch of GE14 fuel. Is that correct, Fran?

MR. BOLGER: Yes, I believe it will be required for the next cycle.

MR. HARRISON: And that's why we allowed them to operate right now with this cycle with the current standby liquid control system as designed. That's why we insisted that we get a license amendment in August to support the next cycle.

CHAIRMAN WALLIS: Can I ask you how much of the cost of this uprate is what I call regulatory costs, preparing for presentations to ACRS, filling out paperwork?

MR. KRESS: A very small amount.

CHAIRMAN WALLIS: And how much of it is cost in the Super Boron, balance-of-plant and new fuel?

MR. GANNON: Well, the project overall is run at about $150 million over four outages for two years, two outages per unit. The breakdown in cost, I think for analysis and things like that it's about $10 million.

CHAIRMAN WALLIS: It's $10 million of this regulatory overhead or whatever you call it?

MR. KITCHEN: Are you talking about just the licensing effort itself?

CHAIRMAN WALLIS: Yes, how much of that --

MR. KITCHEN: That would be in the neighborhood of about 10 to $12 million.

CHAIRMAN WALLIS: So it doesn't sound unreasonable, does it?

MR. KITCHEN: No.

CHAIRMAN WALLIS: Well, what's the return on investment?

MR. KITCHEN: It's been awhile since I've looked at that number to be honest with you. The payback period, which I can remember, is about 2009 with the implementation on the time line we've requested.

CHAIRMAN WALLIS: It's 2000 --

MR. KITCHEN: 2009, the year 2009.

CHAIRMAN WALLIS: 2009, okay.

MR. GANNON: A relative merit when we had our treasury group price this out or do the cost justification, this -- and the cost benefit came out, number 1 for progress energy capital investment.

CHAIRMAN WALLIS: Are there any other questions for the --

MS. MOZAFARI: I just wanted to make a comment. I'm Brenda Mozafari, the project manager for Brunswick. I was not Duane Arnold, you may recognize me. I want to make sure that it's very clear that these are not all going to be license conditions. In fact, the power range instrumentation I believe, has already been approved. So some of these are done as separate actions and they've already been approved or will be approved.

Anything that is not approved or upgraded will be in the license condition and as I understand there's only one license condition at this point and that was the one --

CHAIRMAN WALLIS: You'll tell us more this afternoon?

MS. MOZAFARI: Hopefully, all you need to know. Thank you.

MR. LEITCH: Just one quick question, Neil and it's really not part of this discussion but could you give us any insight as to what your thinking is with respect to license renewal for Brunswick?

MR. GANNON: We have an active license renewal program at this point started and the individuals are on site doing the evaluation right now. In progress energy, you know, we have a program that's going to go through all sites to first plant, to go through the license life extension was the Robinson Plant. The Brunswick units will be following that.

MR. LEITCH: Okay, thank you.

CHAIRMAN WALLIS: Do you another question? You owe us a couple of things after the break, I think, that you're going to come back to us.

MR. KRESS: Timing of the net positive suction head pressure.

CHAIRMAN WALLIS: Show us some curves of pressure versus time and things like that.

MR. KITCHEN: So I understand, you wanted the feedwater line forces and the net positive suction head break time line.

CHAIRMAN WALLIS: Right. Is there

anything else that we need? I'm just about to break for lunch. We have mysteriously gained some time having lost some earlier. Maybe we should have spent some more time when we were asking questions earlier.

I propose that we meet again at 1:30 instead of 2:00. The staff has indicated they prefer to do that and it's going quickly in the afternoon and get us out of here, perhaps, a bit earlier, otherwise I'm going to break for lunch and thank you very much for all your hard work and presentations this morning.

(Whereupon, at 12:23 p.m., a luncheon recess was taken.)

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

(1:31 p.m.)

CHAIRMAN WALLIS: We'll come back into session, please. Does Brunswick have a couple of answers from this morning before we get started with the staff?

MR. GRANTHAM: Yeah, this is Mark Grantham. I've got a couple of slides for the MPSH.

CHAIRMAN WALLIS: Oh, that's --

MR. GRANTHAM: Can you see this?

CHAIRMAN WALLIS: You wanted a picture, Tom?

MR. KRESS: It says the pressure gets up pretty fast and stays there a long time. You know I didn't want to see a repeat. It comes up there and just hangs there a long time.

MR. GRANTHAM: Right, what this shows is right around 1.8 hours is where we actually lose our margin and our acquired credit for containment over-pressure. The actual peak occurs at about 7.3 hours. This is --

MR. KRESS: Yeah, but it's not much of a peak. It's pretty flat all the way up through there.

MR. GRANTHAM: Right, 3.1 psi is what was needed and we require a containment of under pressure out to about the roughly 18, 19 hour mark when it goes back positive and credit for containment over-pressure is not required.

MR. KRESS: Now, in this analysis for the containment pressure, you said you did have sprays operating?

MR. GRANTHAM: What we did was for containment pressure, we assumed that the spray is operated, okay. That gave you the lowest wet well pressure. Okay. For suppression pool temperature, we assumed direct cooling which gave you the highest pool temperature. So you got a worst case combination for MPSH of lowest wet well pressure and highest temperatures.

MR. KRESS: I'm just surprised that with the sprays operating that you kept that pressure up there for 24 hours almost at a high level. That surprises me for some reason. Where are the -- are these -- this is Mark I containment. The sprays are in the dry well?

MR. GRANTHAM: Dry well and suppression pool.

MR. KRESS: And suppression pool.

MR. FLADOS: The reason that the containment pressure stays so high is the fact that the sprays are taking the suppression pool water and spraying it down. The quenching effect isn't there because you don't have cold water.

MR. KRESS: It's already hot water.

MR. FLADOS: The pressure is really the overall contribution of water vapor pressure plus the pre-existing nitrogen at that temperature almost equilibrium conditions. So that's why it goes up and stays up until you start bringing suppression pool water temperature down. That drives pressure down.

MR. KRESS: Yeah, just by condensation. Okay. So that answers my question. I was worried that there would be a peak pressure and the timing might be such that if you didn't have that just right, you would miss it, but -- okay, thank you.

MR. GANNON: The other question, as far as the feedwater loading, GE is actually researching some information on that. We'll have a response back by the end of the day.

CHAIRMAN WALLIS: Okay. Before the end of the day.

MR. GANNON: Hopefully.

CHAIRMAN WALLIS: Brenda, are you ready to make your presentation?

MR. BERKOW: Good afternoon, my name is

Herb Berkow and I am the project director for Region 2 plants in the Division of Licensing Project Management, and, of course Brunswick is a Region 2 plant. The staff is here today to present the results of our review of the extended power uprate application for the Brunswick plant. Several members of the NRR management team are here to support the staff and the staff's safety evaluation and others will be joining us as we proceed through the agenda.

The Brunswick power uprate is similar to Duane Arnold, Dresden, Quad Cities and Clinton extended power uprates which were recently reviewed by the ACRS. The Brunswick application deviates from the approved ELTR 1 and 2 methodologies for BWR extended power uprates in five areas as discussed in the staff's safety evaluation.

This is consistent with the four areas of deviation identified by the licensee this morning. We just broke them out a little differently. In this respect the Brunswick power uprate most closely resembles the Clinton power uprate, even more so than the others. This review was consistent with existing staff practice and includes the Maine Yankee lessons learned. The results were transmitted to you in our draft safety evaluation last month.

Our project manager for the Brunswick plant is Brenda Mozafari and Brenda will guide us through the individual staff presentations this afternoon. As we proceed, the staff is available to answer any questions that might arise and at this point, I'll turn it over to Brenda.

MS. MOZAFARI: Good afternoon. I'm Brenda Mozafari. I've recently been assigned the project management responsibilities for the licensing portion for NRR of the Brunswick power uprate.

MR. LEITCH: Brenda, right on the first slide, I have a question that I was sort of wondering about this morning.

MS. MOZAFARI: Okay.

MR. LEITCH: And that's we refer to this as an extended power uprate.

MS. MOZAFARI: Right.

MR. LEITCH: And last week General Electric was here talking to us about constant pressure power uprate and this is a constant pressure power uprate but I guess my confusion is, is this just semantics or is there really something different about EPU versus constant pressure power uprate?

MR. SIEBER: One's approved and one isn't.

MS. MOZAFARI: Right.

MS. ABDULLAHI: This is reactor systems.

MR. HOANG: This is Hoa Hoang with General Electric. I'd like to address that question. The Brunswick submittal is actually based on the extended licensing topical report. So it's the ELTR methodology and guideline. ELTR methodology does provide a provision for dome pressure increase. And CPPU or constant pressure power uprate, that you were -- discussed with GE recently is the next evolution of ELTR.

As part of CPPU, we have taken the scope and the methodology and the generic evaluation from ELTR and further simplified them to be commensurate with a pressure uprate -- I mean, with a power uprate with no pressure increase, and, therefore, this submittal technically is still under ELTR with those specific exceptions that were discussed, presented to you.

MR. LEITCH: So it does not have those simplifications, if you will, that would be associated with CPPR.

MR. HOANG: That's absolutely correct.

MR. LEITCH: Okay, thank you.

MR. HOANG: With exceptions for those four areas that were mentioned in the presentation.

MR. LEITCH: Right, okay, thanks.

MS. MOZAFARI: Okay, just by way of reviewing a little setting the stage over what's been presented this morning, Brunswick is a BWR 4 Mark 1. They have requested a 20 percent power uprate from the original reactor thermal power, licensed power. They do include a constant reactor dome operating pressure. The five percent stretch uprate was approved in November 1996, so they've gotten the five percent. This would be 15 percent on top of that, bringing them to 20 percent.

There is two parts in their implementation. It would be done in two phases, a seven percent and an eight percent. It does include balance-of-plant modifications and it does incorporate the GE14 fuel further in their plant. The application for the most part follows ILTR 1 and 2. There are some exceptions as Mr. Berkow mentioned, to the ELTR 1 and 2 in predominantly four areas that the reviewer will be going over.

It is a non-risk informed submittal. However, Brunswick did submit some risk information to assist us in doing our evaluation of their submittal and the application incorporated experience from Hatch, Montecello, Duane Arnold, Dresden/Quad Cities and Clinton. They did go through, they looked at RAI's from the various plants, questions that may have been raised previously by ACRS, and tried to address them in making their application.

MR. KRESS: Your third bullet there, every plant so far has submitted this risk information.

MS. MOZAFARI: Right, right, but there is no requirement.

MR. KRESS: There's no requirement for it?

MS. MOZAFARI: There is no requirement.

MR. KRESS: Do you expect some plant will come in without it some time and what would you do if they did?

MS. MOZAFARI: I wouldn't know. I'm not in that position right now to make a decision but my management would tell me what to do.

MR. HARRISON: This is Donnie Harrison from the PRA Branch. Right now, it's in the GE methodologies that the topical reports ask for the risk information to be provided.

MR. KRESS: Oh, one of the topical reports has it.

MR. HARRISON: The ELTR actually asks for it and even on the constant power pressure uprate, it has a section in it --

MR. KRESS: So they could take exception to that.

MR. HARRISON: Sure, sure and then we'd evaluate the exception.

MS. MOZAFARI: They could.

CHAIRMAN WALLIS: Well, looking at how little really you have to worry about it in the PRA results, I would think they might -- it might be advantageous to have a risk informed submittal. It might reduce the work.

MS. MOZAFARI: According to Donnie, that does seem to be the case at times.

MR. HARRISON: I would argue for like Brunswick if they actually did the SLC modification where they could actually change from a two-pump to a one-pump success criteria, it would be worthwhile to submit it. That would be a open and closed book as far as I'm concerned on the power uprate.

MS. MOZAFARI: Okay, Zena Abdullahi, the lead reviewer in the reactor systems branch area for the Brunswick power uprate and she's going to do the next portion of the presentation.

MR. BOEHNERT: Excuse me, Zena, you or Brenda told me that you'll need to have a closed session for part of this?

MS. ABDULLAHI: I would think my notes would have something that would require me to have a closed session, otherwise I would have to edit myself throughout and that would be difficult.

MR. BOEHNERT: So you're suggesting we close this session?

MS. ABDULLAHI: I think so, then I could speak freely without worrying about it.

MR. BOEHNERT: All right. GE, would you make sure that on one's here that shouldn't be here? Transcriber, let's go into closed session.

(Whereupon, the subcommittee went into closed session at 1:44 p.m.)

(On the record at 2:37 p.m.)

MS. MOZAFARI: We were going to present the PRA, the PSA portion with Donnie Harrison but he's not here right now. He'd asked to have it done before 3:00 o'clock, so the next person would be Richard Lobel, who is going to give the plant systems portion of the staff's evaluation.

MR. LOBEL: He's here now.

CHAIRMAN WALLIS: So we're going back to PRA?

MS. MOZAFARI: We had a staff meeting in order to accommodate someone's schedule, so --

MR. HARRISON: I'll do better next time with my bathroom break.

MR. KRESS: You're here right on time. You can't beat that.

MR. HARRISON: Now, if this was a PRA --

MR. KRESS: You have negative margins, though.

MR. HARRISON: That's right. Hopefully, we'll go through this fairly quickly, at least the first few slides because you all -- some of this is almost motherhood now. What we look at is the same thing we look at, at all the other power uprates that have come through and how we do that. So we can probably move to like the third slide.

MR. KRESS: No, no, don't do that.

MR. HARRISON: Okay. I put these together last night so if they're off center, that's probably why. But what we do is we look at the internal events, external events, shutdown operations and we take a look at PRA quality, asking questions on those things and we also took a look at the SEs on both the OPE and the IPEEE and to get back to, I think, Graham Leitch's comment earlier about hurricanes and winds, that is in the IPEEE and it's four times 2^{-6}. You'll see it on the next slide.

MR. KRESS: Let me ask you a question.

MR. HARRISON: Okay.

MR. KRESS: Similar to the one asked before but a little different.

MR. HARRISON: Okay.

MR. KRESS: I know these are not risk informed submissions but suppose one of the plants came in and you found that your LERF or delta LERF or CDF or delta CDF puts you in the Region 1 on 1.174.

MR. HARRISON: Puts me into the black region.

MR. KRESS: Yeah what would you do?

MR. HARRISON: At that point, what we're

put into is there's a RIS (phonetic) on the street, I think it's 2001.02 which says are we -- and in the area where we're questioning adequate protection and at that point, then I'm instructed to inform my management and inform the licensee that we've got some serious questions that need to be answered.

MR. KRESS: You're questioning adequate protection at that point?

MR. HARRISON: And at that point, you're questioning adequate protection because it's not risk informed.

MR. KRESS: Uh-huh.

MR. HARRISON: If it were a risk informed application, you would be in a -- you know, you could pursue it directly.

MR. KRESS: But they meet all the regulations.

MR. HARRISON: Right. The --

MR. KRESS: So how can you question adequate protection?

MR. HARRISON: Well, what -- the conditions of adequate protection -- actually, I've got a slide on this.

MR. KRESS: Oh, okay.

MR. HARRISON: Slide 5 in the risk as we

bounce through my conclusions here, oh, never mind. The backup, yeah. Sometimes technology is not the best friend.

MR. KRESS: At this point, my computer would hang up and quit.

MR. HARRISON: Slide number 5. There is it, that's it. This is the top part of that RIS. In the back of the RIS is a nice page-long logic diagram. This is the top block. It's a decision block that says, you know, you get a non-risk informed submittal. You ask a question, does it raise issues that could rebut the presumption of adequate protection, just in case you wonder where I get those words in my SE. And if you do, then it's because you believe there's a special circumstance that exists and it gives a definition for special circumstance and that's on my next slide, slide 6.

And these are the two conditions for special circumstance. The first one says, you've found a problem that the regulations never thought of and I think the classical example here is the electrode sleeves for steam generators. And it was a condition they found. The regulations didn't cover the area and so it was missed and so now you can get in the process through that. The other condition says, I, as a reviewer knows something about this plant that would say if this was risk informed, we would deny it.

Essentially that's what it comes down to.

MR. KRESS: That's what I was looking for.

MR. HARRISON: The reason to believe that the risk increase would warrant denial. So at that point, if we get to that high a level -- and again, if I'm up in Region 1 in the dark region of the reg guide 117.4 chart, I'm going to invoke that and I'm going to start asking more questions.

MR. KRESS: Now it may not -- it just leads you to a further investigation.

MR. HARRISON: It leads me to a -- and it may result -- I think in Arkansas, we actually were up and just barely got up there but we saw that the fire analysis was so conservative that we convinced ourselves that it wasn't that bad and that if they'd done a realistic analysis, they wouldn't have been up there. If we're up in that region and we think we're up in that region, then we're going to --

MR. KRESS: Now, in the case of Brunswick, they didn't have any numbers for the shutdown contribution and seismic or --

MR. HARRISON: Right. You could -- well, actually there is a fire number and a wind number.

MR. KRESS: But they're -- it's internal events.

MR. HARRISON: Right, again, this is a --

MR. KRESS: If you added those in --

MR. HARRISON: Right.

MR. KRESS: Do you? Do you add them in?

MR. HARRISON: I take a look at them and as a matter of fact, one of the concerns I had on Arkansas was you were approaching the limit if you added everything together and then the fires just kind of blew the world apart. On this one, if you add them all together, you're still not there. If you --

MR. KRESS: Unless you double the LERF.

MR. HARRISON: Unless you double the LERF but -- and I've been thinking about your question on doubling the LERF. The reg guide's not --

MR. KRESS: The reg guide --

MR. HARRISON: It doesn't speak to it and I --

MR. KRESS: It's silent.

MR. HARRISON: Right, and I think partly because the concept was, it was done -- most of these analyses are done on a per plant and so that just carries through.

MR. KRESS: But the LERF is a site

characteristic. It's a surrogate for the proper safety --

MR. HARRISON: Right, the problem you have is your LERF may double at a site, but your dose release from an accident is going to be from one plant.

MR. KRESS: Yeah, but that release is frequency times the dose.

MR. HARRISON: Right, and that's the problem we've got. We've doubled -- the LERF doesn't directly tie at a dual unit site to a dose.

MR. KRESS: But it's a surrogate.

MR. HARRISON: It's being used as a surrogate but that's the problem we're in.

MR. KRESS: Yeah. You really should think of that because there ought to be a site characteristic. And this comes up, for example, with the modular reactors, you've got 10 modules. You're going to add up every one of those.

MR. HARRISON: Right.

MR. KRESS: Well, it's the same thing. It's just --

MR. HARRISON: On the LERF criteria, you could go there. The question becomes if I postulate an accident, I do my dose consequence part of it, I'm only going to postulate a single unit release.

MR. KRESS: Well, sure, but you're going to multiply the frequency to it.

MR. HARRISON: Right, right.

MR. KRESS: I mean, you're going to multiply the frequency.

MR. HARRISON: Right, it's just I didn't want to give the concept that we were actually doubling the dose somehow.

MR. KRESS: No, no, I realize that.

MR. HARRISON: Okay, right, in that case you've --

CHAIRMAN WALLIS: You're doubling the probable dose.

MR. KRESS: That's right, you're doubling the probable dose, that's right.

MR. HARRISON: I just wanted to make sure we were on the same page there. And I agree with you, it's the -- that would be an issue there. For doing it again, the reg guide -- I wasn't here when it was written but it was written with the idea it seems like, that it's on a per plant or a per unit basis. All the wording seems to go that way.

MR. KRESS: Now, suppose a plant came in with a power uprate request, clearly that would put them in the wrong range, but at the same time, they said, "Okay, we're going to do this and this and this, make these other changes to the plant", and that actually pulled them back out.

MR. HARRISON: Right. That would be acceptable.

MR. KRESS: Is that all right with you?

MR. HARRISON: Yeah, yeah. Like I said earlier, if Brunswick would make a solid commitment to make the mod to the SLC system that changes its success criteria to, you know, one pump success, that -- the uprate effects the K heat, it's primarily effecting the upper air actions in a ATWS. If you fix the SLC system, ATWS falls of the table.

MR. KRESS: Sure.

MR. HARRISON: At that point, you're making the plant safer by doing that. I'm not going to -- I'll cut back on my RAIs, I promise.

MR. KRESS: But then should you make it a condition for the uprate?

MR. HARRISON: If you were in a situation where you're trading off and you need the trade-off, yes, if you need it. What I did in this review because I wasn't sure where CP&L was going to be at the end of the process, my review for the most part does not reflect any mods to the SLC system. It still assumes that it's a two out of two pump success.

MR. KRESS: Where do uncertainties enter into this analysis on your -- say there are uncertainties on the LERF?

MR. HARRISON: Well, again, I would say that when you get close to the boundaries --

MR. KRESS: You didn't think about uncertainties?

MR. HARRISON: For this one, I don't go down that route unless I feel like I'm getting close to a boundary. Again, the example I would use would be Arkansas, where we were not only at the boundary but we kind of went a little bit on the other side of it and at that point, it's like how much confidence do we really have in what they're doing and how much confidence do we have in their conservatisms to back -- to have confidence that we really aren't going to be over that line.

MR. KRESS: Do you have a simple way or rule of thumb to go back to the actual site now and look at the wind rows and the population and density and distribution and say, "Oh, well, I could guess the LERF is going to change so much"?

MR. HARRISON: No, no, I --

MR. KRESS: You'd have to do the Level 3.

MR. HARRISON: You'd have to the Level 3.

MR. KRESS: You don't have any rules of thumbs.

MR. HARRISON: Right, at least I'm not -- it's been a long time since I've done a dose calculation and for me, you're in the Level 3 space and we've only got a few plants out there doing Level 3 analysis.

MR. KRESS: I think the combination of the wind direction and where the population is distributed within that region where you calculate the LERF could make a difference.

MR. HARRISON: Right.

MR. KRESS: And it's probably an easy calculation to --

MR. HARRISON: And you could use some --

MR. KRESS: You could ratio the --

MR. HARRISON: And you could use some common sense. I would say, you know, a plant down around Brunswick is probably a better plant than one near a large population.

MR. KRESS: That would be nice if the wind's blowing out to the ocean.

MR. HARRISON: Unless it's hurricane

season.

MR. KRESS: Well, we don't get those.

CHAIRMAN WALLIS: Then disbursal is pretty rapid.

MR. KRESS: Yeah, hurricanes are good for that.

CHAIRMAN WALLIS: Are you going to finish by 3:00 o'clock?

MR. LEITCH: I'm sorry, I'll quit. You were asking me the questions. I just wanted to get my point across.

MR. HARRISON: Yeah.

MR. KRESS: There are some things that need to be thought about.

MR. HARRISON: Right. And I've heard you. I hope -- Michael, you've heard him, right? Okay. I've just thrown up on this slide, this is just the bottom line result. Internal events, I've put everything up here for their worst case sensitivity results. They did some sensitivity studies. That's another way of addressing some of the uncertainty, by the way.

And really the driver for the worst case is they increased their turbine trip frequency by about 10 percent and ran that through and that resulted in about a seven percent increase in CDF and I forget what the percent increase was for LERF, but this gives the numbers. For external events, there's a fire number. There's a high wind number 4 times 10^{-6}, and that's not changed by the EPU. It's just what it was.

MR. KRESS: I know we're pressed for time but let me ask you one more question before you leave this slide. The conditional containment failure probability for late failures for these Mark Is generally run around .8?

MR. HARRISON: Uh-huh, it wouldn't surprise me, yeah, okay.

MR. KRESS: It makes me worry about land contamination and latent effects and --

MR. HARRISON: That's something I didn't even look at.

MR. KRESS: I just wondered if you'd even thing about it in terms of, you know, we look at LERF and CDF, that's it, but here I'd have a problem. I'd be worried about late containment failures and does the uprate effect the late containment, the probability and the conditional late containment probability.

MR. HARRISON: Yeah, I -- most of the Mark

I values even at early containment failure is like a .5 or you know, you get those high numbers, .1, .5, is done very conservatively. I don't know if that's really the real value of the --

MR. KRESS: Anyway, .8 something is already close to 1.

MR. HARRISON: You might as well -- right.

MR. KRESS: It's the CD that saves you anyway.

MR. HARRISON: Right, right.

MR. KRESS: But anyway, it seems to me like that ought to be something, well, anyway, when we redo 1.174, we might ought to think more about late containment failure as well --

MR. SIEBER: That's sort of a safety goal policy issue, is it not, because it's certainly not a LERF or addresses itself to protecting the public.

MR. KRESS: Well, in my mind it could be a long term latent condition. It could also be land contamination.

MR. SIEBER: But I think you need another term to describe that --

MR. KRESS: Oh, yeah.

MR. SIEBER: -- and another safety goal to say what's acceptable and what isn't.

MR. KRESS: Yeah, yeah, I don't think we have a safety goal that deals with it.

MR. SIEBER: I don't think you have the tools, nor do you have the goal.

MR. HARRISON: Again, yeah, the only way to get there is to do the Level 2 -- Level 3 analysis.

MR. KRESS: Yeah, it comes right out of MAX but you could use a surrogate for it just as well as you do a LERF. You'd have a LERF of even a late containment surrogate, but if you have the tools, you can do it with MAX.

MR. SIEBER: You don't have the policy.

MR. KRESS: You don't have the policy, that's right.

MR. HARRISON: Okay, and just my bottom line, nothing -- we didn't identify anything that would make us question adequate protection and again, so we don't have anything that throws us into that risk process.

If we go to the next slide, I just want to make these observations. At the Arkansas full committee, we were questioning about HRA methodologies and one of the suggestions that I think in a conversation between Dr. Kress and the full committee chairman, Dr. Apostolakis, one of the ideas was why don't you just bound the HRA analysis and spit out an answer? Well, that's pretty close to what Brunswick has done.

And the problem you get is you can't calculate a delta then or one that you truly know is the right margin. So Brunswick recalculated the -- basically it's really one operator action. It just has four conditions on it, it's power level control and there are a whole bunch of operator actions that we expected to see impacted that weren't and it's because they were all covered by the way they did a conservative timing for the operator action.

Therefore, when they did the MAAP runs to find out what the time was for those operator actions, they were already bounded. And the net result is you get a very small delta of one and a half percent delta risk increase when you know it's not. You know it's more than that.

MR. KRESS: You know it's something more that that.

MR. HARRISON: Right. Now, the reason that's not an adequate protecture question is because it's changing the delta but you know the base is bounded. So what this would really do, to do it correctly, you'd have to do the current plant condition, that would lower that number. The power uprate plant may actually come down just a little bit but that would give you the real delta, but I just wanted to put that up there just to make a point of what can happen.

The other thing I wanted to make a point of is, the NESC, we're included a statement to make it clearer. There was a question of we could be misleading the public and thinking that we're approving methodologies, HRS methodologies and we've added a statement to the SE to make it clear that these methodologies have not been formally reviewed and approved. That they're common used, widely used by the petitions and it's the current state of the art, but it's not something that we've actually officially recognize as the method to use?

But it can be used. It can give you a relative feel for the importance of actions and importance of changes and those actions.

MR. KRESS: Do you know if they had a risk informed submittal. Or the major changes were due to human errors, would you feel like you'd have to go and review these?

MR. HARRISON: Sadly, that's what Arkansas did and it's -- if it was risk informed, I would have sent them to look at what Arkansas had which is go back and recalculate your human error probabilities based on your current condition using your MAAP code. Make those runs, figure out what those should have been, then calculate what they will be and give me the delta.

But this is really not a slide necessarily for Brunswick as much as it is just to address the questions from before. And really, that's all I have.

MR. KRESS: Appreciate it, thank you.

MS. MOZAFARI: And now Richard Lobel from the plant systems branch to discuss the containment review.

MR. LOBEL: Good afternoon. My name is Richard Lobel. I'm with the plant systems branch and I would like to talk about the review we did of the Brunswick containment and other balance plant systems for power uprate. The -- we didn't find anything extraordinary in this review. There were no special issues raised and no tech spec changes for the plant and the trends were as we expected.

These are -- the next two slides are the systems that we looked at. You've seen these slides before, for plant systems. Main steam isolation valves are evaluated by a generic evaluation in the GE methods. The RHR suppression pool cooling and containment spray cooling I'll talk about a little later as well as the fuel pool cooling.

Containment system performance and NPSH I'll talk about a little later. Combustible gas control, the existing nitrogen suppose was found to still be adequate and the CAD system for uprated power. There was no significant change in the conditions for the main control room atmospheric control system. The standby gas treatment system, the draw-down time hasn't changed and the loading actually goes down with the alternate source term.

Spent fuel pool cooling, as we've discussed before, there wasn't a big effect from the power uprate. Service water, component cooling water and --

MR. LEITCH: Richard, could we just touch a minute on the standby gas treatment system.

MR. LOBEL: Sure.

MR. LEITCH: You said the loading goes down. I mean, I would picture that the loading on the standby gas treatment system would be -- the iodine level would be proportional to power and that the higher power level you would have more iodine production and would therefore, increase the loading in the standby gas treatment system.

MR. LOBEL: Maybe somebody else can address it in terms of the loading. We don't look at it in terms of how -- of the amount that's there. We look at it in terms of heating of the filters and the draw-down, the more mechanical parts of the system. I don't know if there's anybody -- is there anybody else here to address that?

MR. GRANTHAM: This is Mark Grantham, CP&L. I think the loading went down as a result of implementation of alternate source term which was a separate submittal from this. So we went from the -- to the new methodology and that's what drove the loading down. So it's actually a result of methodology change and not due to an increase in power.

MR. LEITCH: Okay, that would make sense, yeah, okay, thanks.

MR. LOBEL: And there were no significant changes to the power dependent HVAC systems, liquid and gaseous waste or the high energy line breaks since the pressure didn't change. Next slide, please.

Okay, the containment system performance was analyzed for the power uprate using General Electric Codes M3CPT for the short term response.

LAMB code was used for the blow-down analysis rather than the M3CPT code and Super Hex was used for the long term response. M2CPT and Super Hex were already in the Brunswick licensing basis. LAMB was added in order to give the licensee more flexibility in analyzing a wider range of conditions.

We did not perform an audit calculation for Brunswick since we had previously performed one for Mark I and had gotten good agreement with the GE methods. This table is just to provide some information about some of the changes that were made in conditions for the power uprate analysis. The service water temperature used was raised to the technical specification limit at 92 degrees.

The licensee assumed spent -- assumed RHR pool cooling rather than containment spray cooling for the suppression pool and that's conservative. It adds a little bit to the temperature. The decay heat value was upgraded from the nominal value to the nominal plus the two sigma for the same correlation and also some changes were made in terms of the longer burn-up was used in the calculation of the decay heat and some additional isotopes were considered.

DR. SCHROCK; Can I ask about this LAMB code. It was mentioned earlier that it was based on

Moody's --

MR. BOEHNERT: Virgil, do you want to get the microphone there. They can't hear you.

DR. SCHROCK: Are you familiar with --

MR. LOBEL: The LAMB code is in Appendix K, ACCS code but it's also used by GE for performing the blow-down in some cases for the mass and energy release in the containment. It provides them with a little more flexibility in the conditions that they can analyze since the M3CPT model for blow-down is fairly simple. And it does -- yeah, they said they used the Moody correlation because that's the Appendix K.

DR. SCHROCK: Which is generally considered to be conservative from the standpoint of analysis of the primary system which means what, it blows down more slowly. From the standpoint of containment, that's puts him to be non-conservative.

MR. LOBEL: No, I think it's the other way.

DR. SCHROCK: The other way?

MR. LOBEL: Yeah, the Moody correlation, in terms of ACCS, it gives you a faster depletion of the inventory vessel because it is a rapid discharge and that's conservative also for containment.

DR. SCHROCK: Okay, thank you.

MR. LOBEL: Okay. The next table I thought would just be interesting. Some of this was shown this morning by the licensee and the only point that I wanted to make by showing the table was the licensee did calculations using the same methods for the current rate of thermal power and for the extended power uprate. So it gives you a chance to look at a change due purely to the increase in power for the drywell peak pressure, drywell peak temperature, the bulk pool temperature and the wetwell pressure.

And also you can see the limits but there's still considerable margin to the design limits. The next slide. For the NPSH of the ECCS pumps, the licensee hadn't previously taken credit for containment over-pressure but with the power uprate, it became necessary to take some credit. This was discussed by the licensee this morning, too and maybe the only point to make now is I tried to show in this table a little bit of sensitivity studies that went into the calculation.

When the -- the two important parameters in terms of the containment are the wetwell temperature and the wetwell pressure for determining NPSH of the ECCS pumps and when the calculation was done with containment spray providing the cooling, the pressure was fairly high and the temperature was -- I'm sorry, let me start over.

Without containment spray, with just bulk cooling of the suppression pool water the pressure was fairly high and the bulk temperature was high. Assuming containment spray, which was done for the actual calculations for Brunswick, the pressure, calculated pressure is much lower, 11.3 psig, but there wasn't much of a change in the calculated temperature and, in fact, like the licensee said this morning, they actually increased the temperature up to the same value that they calculated without the spray.

So the point is just that the licensee selected a conservative set of conditions and for the case of NPSH conservatively low pressure and high temperature. For the spent fuel pool cooling, the spent fuel system consists of two independent spent fuel pooling trains, one pump and one heat exchanger each. The heat is transferred to the reactor building closed cooling water system. The RHS system can serve as a backup which may be needed for situations like -- abnormal situations like the full core off-load and Brunswick also has a supplement spent fuel pool cooling system as a backup to the RHR spent fuel cooling system.

The analysis was done with a surface water temperature of 95 degrees and in all cases the temperature was less than the limit of 150 degrees although it was fairly close. And in conclusion, the licensee in the area of the balance of plant and containment systems complied with the NRC regulations and the guidance on EPU conditions.

MR. BANERJEE: I'd just ask you a question. Are you going to talk at all about the fire protection --

MR. BOEHNERT: Sanjay, get close to the microphone.

MR. BANERJEE: -- because whoever is the right person, I want to ask the question.

MR. LOBEL: It definitely isn't me. I don't know if we have anybody here.

MR. BANERJEE: Because there is an aspect which I'd like to find something out about. It's part of your --

MR. SIEBER: It's SER and if you look on page 73, Section 6.

MR. LOBEL: We can try to get somebody over here to answer your questions but I had nothing to do with the fire protection side.

MR. BANERJEE: Well, it's part of the systems and facilities or whatever.

MR. LOBEL: Yeah.

A VOICE: A big increase in PCT then.

MR. BANERJEE: Yeah, what happens there is the PCT goes very close to the limit.

MR. CARUSO: Mr. Chairman, why don't we try to get the right fire protection engineer over for you. John Hanon is the branch chief and he's just going to give him a call and see if we can do this either in this session or whatever you'd like to do.

MR. BANERJEE: Well, the issue really is related to what happens to peak clad temperature.

MR. CARUSO: Okay, fire protection, peak clad temperature.

MR. SIEBER: The Appendix R, peak clad temperature maximum is 1500 compared to the LOCA maximum which is 2200. That's the issue. I think the numbers come out for safe shutdown the same as the LOCA response. As far as containment performance, peak clad temperature --

MR. LOBEL: I can speak to that a little.

MR. SIEBER: Okay.

MR. LOBEL: The 1500 degrees is usually a temperature that's used for the cladding when you don't want any damage or excessive oxidation to the cladding. It's typically thought of as the temperature at which the cladding reaction starts to increase significantly expedentially. The 2200 degree temperature in the ECCS, the basis of that is maintaining a coolable geometry, so you can have failure of the cladding and in fact, the dose calculations that are done for a LOCA assume that the fuel has all failed.

But I think that's the basic difference between the numbers.

MR. BANERJEE: Yes, but I mean, the current RTP has a peal clad temperature of less than 1200 and with the EPU it was close to 1500. So there's a big difference there. And --

MR. LOBEL: Yeah, I can't explain why the increase.

MR. BANERJEE: Yeah, first why and then the SCR or whatever it is --

MR. CARUSO: Okay.

MR. BANERJEE: It's below the design limit but it's very close and you know, I'd like to --

MR. CARUSO: Okay, the gentleman's name who is the fire protection reviewer is Ed Connell and he is not here today but we will get the question to him and get an answer to you. It will be whatever you'd like it, in writing or phone call, whatever you'd like.

MR. BANERJEE: Okay, it's on page 73 of your SER and it's on page 617 of the NEDC 33039P.

MR. CARUSO: Well, all right, that's fine. Is there any GE persons who can address the question directly? We can also have the staff confirm the answer. Okay.

CHAIRMAN WALLIS: I'd like to know the result of this --

MR. BOEHNERT: Will do, the staff, will do.

CHAIRMAN WALLIS: -- response as well.

MR. PAPPOANE: This is Dan Pappoane. With regards to the change in PCT for the Appendix R, the Appendix R is similar to a small break LOCA. So we do see -- we do see an increase in the PCT because we are dealing with more decay heat and more steam that we have to vent to depressurize the vessel.

The thing that I don't know right off the top of my head, when we do an Appendix R analysis, there is a certain number of relief valves that we can take credit for in that analysis. Usually we're not using the full -- okay, we use three relief valves instead of the full ADS complement or six or seven. And with the smaller number of relief valves, that accentuates the effect of the power because we're using a smaller area to depressurize the vessel.

So we'll see a bigger change in the PCT bit of the power change.

MR. SIEBER: Why do you use a smaller number of valves? Is that --

MR. PAPPOANE: That's the number of valves that they'll protect for the remote shutdown.

MR. SIEBER: So an Appendix R issue.

MR. PAPPOANE: Right.

MR. SIEBER: Okay.

MR. PAPPOANE: Right, it's an Appendix R issue but we are seeing that power and the effect of that power increase.

MR. BANERJEE: Right, it's just that the number changes very lot, almost 300 degrees.

MR. PAPPOANE: Yeah, and that's in line with what we've seen in some of the previous uprates. When we have less relief valve capacity, one way or another, either smaller valves or smaller number of valves, the effect of the uprate goes up. The PCT delta goes up.

MR. FLADOS: Paul Flados again. Another

big impact on the Appendix R is this event that had the peak clad temperature is the one where we delay any operator actions until they can get staged out into the power block. There's a big impact on this calculation in that with the extra decay heat in the same amount of time, by the time he gets there ready to do it, vessel level is a lot lower than it used to be. As a matter of fact, top of core is already uncovered by the time he starts depressurization.

The EPU effect on Appendix R is very significant and it's one of the things that could cross over a threshold if a utility does have a delay that corresponds to boiling too far down on the vessel level before he can get out there his remote shut down pad.

MR. SIEBER: But the solution to that would be to protect another valve as far as Appendix R is concerned.

MR. FLADOS: If you uncover too much fuel before he gets out there, the number of valves isn't going to help you as much as doing something to otherwise get out there faster or protect the vessel level before he gets there.

MR. SIEBER: So it would be better to buy him roller skates.

MR. CARUSO: Yeah, these valves are normally divisionalized too, and you may have a train that's protected, a whole train that may be protected and to decide to protect another train is a major issue. You may have to put barriers and other sprinkler systems, et cetera, just to gain one or two more valves. So -- and the whole alternate shutdown technique is because of how many trains you can protect.

But let me get the staff's answer to the question, too, just to make sure we're on the same wave length as GE. Okay.

MR. SIEBER: I'd like to have a copy of whatever --

MR. BOEHNERT: Yeah, why don't you have him send it to --

CHAIRMAN WALLIS: Okay, I'll send it to Paul.

MR. BOEHNERT: Send it to me, yeah.

CHAIRMAN WALLIS: And it better be quick because we're going to receive -- I think this is going to the full committee next week.

MR. BOEHNERT: That's correct.

MR. CARUSO: Okay, John, can you support that?

MR. ULSES: Yeah. Yes, the reviewer is actually working at home today, so we should be able to get it by close of business today.

MR. CARUSO: Great, thank you. Super, John.

CHAIRMAN WALLIS: I had a question earlier about this SRV discharge being ingested into the ECCS suction and I was told I'd get my answer this afternoon. Are you the one who's going to give me the answer?

MR. LOBEL: Well, I can -- we did ask the question and we have an answer. It was a response to a question 1-4 on an October 17th, 2001 letter.

CHAIRMAN WALLIS: Yeah, I remember that.

MR. SIEBER: It basically --

CHAIRMAN WALLIS: I read that in the SEC.

MR. LOBEL: Okay, it was pretty much repeated in the SEC and we did not do any further review of that.

CHAIRMAN WALLIS: You asked a question and the licensee indicated that they had performed an evaluation.

MR. LOBEL: Yes.

CHAIRMAN WALLIS: And they said something about bubbles and so on and so on and so on. And then you concluded it was all right. Well, how do we know that that evaluation was any good?

MR. LOBEL: We did not review the --

CHAIRMAN WALLIS: So we're just taking the word for the licensee that they did a proper technical evaluation and --

MR. LOBEL: In this case, yes. I don't have any more to add.

MR. CARUSO: Okay, Brenda, do you want to summarize for us, please?

MS. MOZAFARI: So just our last slide summarizes that the analyses are based on NRC approved analytical methods and codes. Onsite audits confirmed the compliance to staff approved methodology. The EPU SAR is consistent with NRC accepted guidelines and generic evaluations. Thermal limits and applicable safety analyses would be re-analyzed or re-confirmed using NRC approved core reload analyses methodology.

Now, you did have on your agenda that you had some issues in some other areas. Are there any other areas that you want the staff to elaborate on? We have the staff members available if there are any other particular issues.

MR. LEITCH: I just harken back to the Maine Yankee situation where there was evidently a controversy about the peak cladding temperature and the code that was used to determine that and the first bullet on your slide there, I guess, what you're saying is you're confirming that for the whole spectrum of LOCAs, the peak cladding temperature has been calculated using NRS approved codes and found to be less than 2200 degrees.

MS. MOZAFARI: That's correct.

MR. LEITCH: Okay.

MS. MOZAFARI: Were there any other issues?

CHAIRMAN WALLIS: Any other issues?

MR. CARUSO: We do have the take-away on fire protection. We're going to get an answer on that.

MS. MOZAFARI: Right, we're going to get back.

MR. CARUSO: And we heard some discussions, too, about the number of RAIs in general, and what I'd like to do for the subcommittee, the full committee, whatever you'd like is fill you in, in terms of the plan for the standard review plan and the plan for improving the efficiency, including looking at the RAIs, whether there's duplicate RAIs, how we can improve our efficiency in terms of that. So that's a take-away that I'll bring back to you.

We're due to go back to the Commission for the Commission paper the end of June, June 26th, okay, so we'll probably be talking back with you before that time.

CHAIRMAN WALLIS: So it looks as though we are through with the staff presentation.

MS. MOZAFARI: Right, and Herb Berkow would like to give some closing remarks for our staff.

MR. BERKOW: I want to thank you for your time and for the opportunity for us to present the results of our Brunswick extended power uprate review. The results of the staff's review, as Brenda pointed out, show that the proposed power increase meets the regulatory requirements and therefore, it's acceptable and we recommend approval of this power uprate.

This concludes our presentation and I guess there are no other questions and if there are, we'd be happy to answer them.

CHAIRMAN WALLIS: Well, the question we have to address is whether or not this is a mature enough situation for it to go to the full committee next week. I think that's what's on the schedule.

MR. SIEBER: That's right.

CHAIRMAN WALLIS: Is that your

understanding.

MR. BOEHNERT: The morning of May 2nd.

CHAIRMAN WALLIS: Yes, May 2nd. And does the committee disagree with me that this is ready for next week's presentation?

MR. KRESS: I think it's ready.

MR. SIEBER: I think it is.

MR. LEITCH: I agree.

CHAIRMAN WALLIS: So it is okay to go ahead next week. Then maybe we should talk a bit about what's to be said next week. The licensee has less time next week?

MR. BOEHNERT: We have a total time of two hours for everything.

CHAIRMAN WALLIS: A lot less time next week to put across your case.

MR. KITCHEN: Certainly, we can arrange that.

CHAIRMAN WALLIS: Again, just speaking for myself, I think we need your overview. That's important. The core considerations are important. There are some important issues covered there and my impression is the reactor vessel cracking and embrittlement could be covered fairly rapidly and also the containment response. We probably don't need to spend a lot of time on electrical system and piping stress limits.

There isn't much about operation -- operator actions and training. It just sounded as if there's nothing much new there, not much of a testing program. So you should be able to do it in the time available, I think if you hit the main points. It's very much like what we've heard from other plants, so the full committee should be familiar with that, this sort of a power uprate.

MR. KITCHEN: Yes, sir, the areas that you don't want as much discussion do we eliminate those or do we need to cover all the areas that we covered today?

CHAIRMAN WALLIS: Well, you might put them on -- have a least a bullet saying, this has been covered. I don't think you need to go into the details unless asked. You never know what the full committee is going to ask you.

MR. BOEHNERT: Do you want them to talk about PRA at all?

MR. KRESS: I think you'd better talk about the PRA but it went pretty fast. You can make it pretty fast, you know, just almost bottom line type.

CHAIRMAN WALLIS: I think the bottom line is important and the fact that the only thing that really seemed to matter were changes in time operators had to make decisions.

MR. KRESS: I think it's very important that you cover the SLC changes.

CHAIRMAN WALLIS: Yes.

MR. LEITCH: I think it might also be appropriate to discuss the justification for not doing the large scale tests.

MR. KRESS: The large transient testing because that will come up.

CHAIRMAN WALLIS: It will be the same argument that we had before.

MR. KRESS: It will be the same, but it will come up, so you ought to be prepared.

CHAIRMAN WALLIS: Anything else from the committee members?

MR. BOEHNERT: What about the staff?

CHAIRMAN WALLIS: We're going to get to the staff.

MR. LEITCH: I'm still a little -- not a little confused but I think it bears some discussion about the operation what I guess we're calling Phase 1, that is what is going to be the status during the first cycle when only certain physical changes have been made, yet the license is approved up to 120 percent but the plant is not physically capable of doing that.

MR. KITCHEN: So you would want an expanded description of the plant controls and mechanisms in place to operate the plant with a reactor limit above our balance plant capability.

MR. LEITCH: Yeah, I don't think we need anything expanded from what we heard today but I think that is an area that initially was somewhat confusing and I think we could just sharpen that area up a little bit.

MR. KITCHEN: Okay.

MR. SIEBER: Well, the thing that's limiting there I think is the turbine. If you're wide open, that's all you're going to get, right?

MR. LEITCH: Well, I don't think so. You've put in the new turbine, right. The new turbine is part of Phase 1.

MR. KITCHEN: Yes, that's correct. That's been installed but we could --

MR. SIEBER: You need pumping, feedwater.

MR. LEITCH: I think you're more limited by the transformer capability and by the ability of the condensate feedwater system to pump enough water.

MR. KITCHEN: We can make that portion of the presentation clearer as far as how we're controlling the plant and what actions were put in place to do that.

MR. LEITCH: I think that would be helpful, yes, thank you.

MR. KRESS: One of your slides had referred to a 70 megawatt base per metric ton burn-up. That's going to raise the eyebrows of at least one of the members and I'd be prepared to discuss it in further detail in case a question comes up and the detail would be how much of the core is actually at what level.

MR. BANERJEE: There was very little discussion, I don't know if this is the forum for it, of fuel performance and fuel behavior because of this high burnout and also you know --

MR. KRESS: Yeah, that would be the nature of it.

MR. BANERJEE: So that would be something that is missing here and I don't know if there's enough of a experience base here to talk about it.

MR. SIEBER: Well, the average discharge burn-up is 50 --

MR. BANERJEE: This is like 40 or 50 or something.

MR. SIEBER: 40 to 50.

MR. KRESS: So, you know, if they could -- that didn't come out until we asked the question.

MR. SIEBER: Yeah, well, that's where they should start, starting at 70 and saying --

MR. KRESS: Yeah, they should clarify what does 70 -- they should clarify what does 70 mean.

MR. SIEBER: Yeah.

CHAIRMAN WALLIS: Are we ready to move onto the staff presentation? My impression was that the written report gives the impression that a great deal was done and that the bases were all covered, although in some cases we have to take something on trust that, yes, indeed, the licensee did do good work.

I think in your oral presentation, it has to come across better than it did today that you folks really are on top of things and you don't have to turn to the licensee to get answers to questions and there's more certainty somehow in your presentation. Any colleagues want to wade in on this matter?

MR. BOEHNERT: Do you want to give them direction on what topics?

CHAIRMAN WALLIS: Well, we had asked in the past and you responded a bit this time to which parts of the review gave you some trouble or did you really have to think about and that didn't really go very far it seemed to me. Maybe there weren't any. I got the impression there really weren't any. Maybe that's the way it is. Maybe that's all you need to say, unless there was something really interesting that you had to pursue and resolve. That would be a good story to tell there. The SLC you need to be a bit more clear about.

MR. SIEBER: Well, I was wondering about that. Is the licensee committed to the changes and if they aren't, you know, even though it's been discussed in the SER, they aren't committed to, you know, super Boron and all of that, then I'm not sure we ought to give credit for it because they may not do it.

MR. POST: This is Jason Post with GE. I talked to Dr. Kress in the restroom a little while ago about this. When we did that ATWS analysis -- that doesn't have to be on the record, I guess. When we did the ATWS analysis, we used 86 gpm equivalent, okay. And so when the reload requires them to make a change to increase the boron so they have more shutdown margin. It will be made such that they maintain a minimum of the 86 gpm equivalent.

So the ATWS analysis remains applicable as long as whatever change meets the ATWS rule requirements, which, of course, it will.

MR. CARUSO: We'll talk about SLC and ATWS and challenges that we had in those reviews. Are there any other areas that were challenging that you want to bring up? Okay, we'll present those two. We'll highlight the challenges that we had and how we resolved them.

CHAIRMAN WALLIS: And maybe we'll be able to write a short letter.

MR. CARUSO: Great, short and sweet.

CHAIRMAN WALLIS: So is there anything else we need to do today? Am I ready to adjourn is the right word?

MR. KITCHEN: This is Bob Kitchen. I have two things. The targeted time for the presentations next week should be about an hour?

MR. BOEHNERT: Yeah, I'll get with you, Bob, but yeah, basically there's a total of two hours. I think with introductions and that, you guys will have close to -- well, yeah, close to an hour and give the staff the remaining time, maybe 45 minutes or something like that. That's just off the top of my head, but I'll sit down and think about it. I'll get back to both of you guys and let you know, but on that order.

And you should plan on -- we try to keep it 50 percent presentation time and 50 percent time for questions but that's going to be tough, given what we're handing you. But anyway, I'll get back with you on this, give you the details.

MR. KITCHEN: Okay.

MR. BANERJEE: There's one thing. They will provide some information about the feedwater line.

CHAIRMAN WALLIS: That's right, you'd asked for that. Yeah.

MR. KITCHEN: We can discuss that a little bit right now if you'd like.

CHAIRMAN WALLIS: You're ready for that now?

MR. KITCHEN: Yeah.

CHAIRMAN WALLIS: Okay.

MR. PAPPOANE: This is Dan Pappoane again. I just went through a crash course in annulus pressurization and the like that I guess what you're after, the bad news is we don't have a direct one-to-one comparison for feedwater line break. The original analysis or the current power analysis was done with a fairly high feedwater pressure that was assumed of 1475 and what we did for the extended uprate was that creativity that Ralph was talking about, we're using the actual feedwater system pressure at the uprate conditions, as the extended uprate conditions.

And that's 1210, so for the piping outside of the containment, that's primarily driven by that pumping pressure and that's what gives us the relief to get fit under the current design loads for the forces.

MR. BANERJEE: And what was done originally? Did you look at the --

MR. BOEHNERT: Talk into the mike.

CHAIRMAN WALLIS: Speak into the mike.

MR. BOEHNERT: They can't hear you.

MR. BANERJEE: What did you do originally when you did the calculations at higher pressure?

MR. PAPPOANE: Well, when they're doing those calculations outside the containment, they're looking at the room pressurization and flooding and they're also looking at pipe width and jet impingement and make sure the forces don't take out any safety systems. So those were all based on the -- on that higher pressure.

We've got an enveloping analysis and did pencil sharpening with this extended uprate to fit in that envelope by using the actual system pressure instead of very high bounding pressure and then --

MR. BANERJEE: Did you look at the force imbalances on the reactor internals?

MR. PAPPOANE: Yeah, that's the next part. We can go inside the containment. Inside the containment we look at what happens to the reactor vessel, what happens to the internals, also look at what happens to the reactor shield wall, because when we're looking at the pipe break inside the containment, we're assuming the break is at the safe end which is usually just inside the wall or actually within the wall itself, in the shield wall itself.

So we're looking at pressurized in that space and again, we're looking at the pipe width and the jet impingement loads. The reactor side of that is driven by the vessel pressure and for this uprate this hasn't changed. So that side of the forcing function is staying the same.

Now, for the pumping side, the feedwater pumping side, again, we're looking at the high pressure for the current -- or for the original analysis and using the actual pressure for the lower -

- for the extended uprate analysis and also did a little bit of fine tuning on calculating what the two phase flow out of the pump side of the pipe would be because we're doing to be seeing some depressurization in there and some flashing of pipe, so that's going to restrict the flow. And so that contribution -- the vessel site, what's coming into that annulus, the vessel side is staying the same. What's coming in with the fine tune calculation, is just fitting under the original design value.

So the overall design envelope for the loads has stayed the same. And then look at the energy content in there, we are getting a little bit higher flow initially. We have lower feedwater temperature but a higher flow rate so the initial energy that's being deposited in that annulus goes up but about three percent. And we looked at that as far as the -- as far as the forces on the shield wall and there's a lot of margin on the shield wall. I didn't fine it off-hand here but ones that I've looked at in the past, the forces have been -- the pressure forces have been down in the 25 to 50 percent range of what the shield wall design forces were.

So there was a lot of margin to the allowables.

MR. BANERJEE: Did you take the pressure wave going into account bouncing off the breaks? Is it a sudden guillotine break you're looking at?

MR. PAPPOANE: Yes, it's a sudden guillotine break. I don't have the analysis for the annulus pressure calculation but there they are looking at that pressure wave going out around the vessel.

MR. BANERJEE: Do you have this available, could be available?

MR. PAPPOANE: We have to see what they have, what they can bring next week for that when we get into that kind of detail.

MR. BANERJEE: Well, I'd just be interested to know more about this problem so that I understand what implication it may have. Were it be ready for the ACRS meeting, I don't know because I have encountered this problem with another BWR in some other country, that problem.

MR. PAPPOANE: Yeah, we do look at that acoustic loading for the circulation line break, which is a bigger break.

CHAIRMAN WALLIS: Okay. I'll ask the consultants to get --

DR. SCHROCK: Send a report.

CHAIRMAN WALLIS: -- a report to me right away because I have to write a letter.

DR. SCHROCK: Very promptly as usual.

CHAIRMAN WALLIS: And I'm ready to adjourn the meeting and will do so.

(Whereupon, at 3:38 p.m. the meeting of the subcommittee was concluded.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: ACRS Thermal-Hydraulic Phenomena Subcommittee (Open Sessions)

Docket Number: N/A

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

/s/ Debra Wilensky

Debra Wilensky
Official Reporter
Neal R. Gross & Co., Inc.

BRUNSWICK STEAM ELECTRIC PLANT Units 1 & 2

Extended Power Uprate

Brenda Mozafari

NRR Senior Project Manager
Division of Licensing Project Management

April 23, 2002

Overview

- BWR4/Mark I
- 20 percent power uprate from OLRTP
- Constant reactor dome operating pressure
- 5 percent stretch uprate approved Nov 1996
- 2 part additional implementation (7% and 8%)
- BOP modifications
- GE14 fuel

Application

- Mostly follows ELTR1 and 2
- Some exceptions to ELTR1 and 2
- Non-risk-infomed submittal
- Experience from Hatch, Monticello,Duane Arnold, Dresden/Quad Cities, and Clinton

BRUNSWICK UNITS 1 & 2
EXTENDED POWER UPRATE

ACRS Thermal- Hydraulic Phenomena
Subcommittee Meeting
April 23, 2002

Reactor Systems Branch
BWRs and Fuel Performance Section

Zena Abdullahi: Lead Reviewer

AGENDA

- Review Scope
- Review Approach
- Background on the Brunswick Units
- Challenging Areas of Review
- Conclusion

REVIEW SCOPE

- Reactor Core and Fuel Performance
- Reactor Coolant System and Connected Systems
- Engineered Safety Features
- Standby Liquid Control System
- Reactor Safety Performance Evaluation

Review Approach

- Reviewed the BSEP Units 1 and 2 EPU safety analysis report (NEDC-33039P)
- Used applicable SRP sections
- On-site technical review /audit
- RAI process

BSEP Units 1 and 2 Background

- **BWR/4 -Mark I**

- **Implement EPU in 2 phases**
  - 2nd batch of GE 14 fuel
  - MELLLA rod line.
  - implement EPU 2003 and 2004.

- **BSEP Units**
  - similarity
  - differences

- **Bounding analysis**
  - ▸ Consider differences
    - Analyze limiting unit

Challenging Review Areas

- Deviations
  - SLMCPR evaluation
  - the limiting transient analyses and the OLMCPR evaluation
  - the stability Option III setpoints calculations
  - the ECCS-LOCA performance evaluation approach

- Audited Deviations

- Reviewed Unit 1 Cycle 14 reload analyses

- Concluded deviations acceptable

Challenging Review Areas

ATWS

- PUSAR peak vessel pressure of 1492 psig (1500 psig allowable).

- Due to low margin, staff performed more in-depth review

- Staff questioned
  - limiting unit, with full bypass capacity analyzed for PRFO event
    - Unit 2 with larger bypass capacity (80.6 % v.s. 20.26% EPU steam flow)

- CP&L confirmed
  - ATWS analysis based on Unit 1 (limiting for LOOP and MSIVC)

Challenging Review Areas

ATWS

- CP&L reanalyzed
  - PRFO ATWS event based on Unit 2.
  - Reanalyzed PRFO event based on plant-specific data
  - Yielded lower peak vessel pressure of 1487 psig

Staff finds BSEP Unit 1 and 2 meet the requirements in 10 CFR 50.62 and the ATWS acceptance criteria

Challenging Review Areas

Standby Liquid Control

- No SLC relief valve margin evaluation in PUSAR
- Staff requested evaluation
- ATWS analysis assumed
  - SLC start to inject, later of
    - BIIT
    - ATWS-RPT occurs + 120 seconds
- Initial BSEP SLC relief valve evaluation resulted with negative margin.
  - Evaluation based on GE data.

Challenging Review Areas

Standby Liquid Control

- **CP&L re-evaluated the SLC relief valve margin based on**
  - Predicted dome pressure
  - Two pump system losses based on plant-specific tests
    - Original system losses based on 1984 GE evaluation
  - Plant-specific elevation head calculation

- **Resulted in a low SLC relief valve margin**
- **Staff concluded**
  - **margin positive but low.**

- **CP&L**
  - acknowledges low margin
  - plans to make some margin improvement modifications in the future

SLC License Condition

- **SE approves 20 percent uprate**
  - SLC shutdown capability
    - Increase boron (660 ppm to 720 ppm)
    - Loading of 2nd batch of GE 14 fuel
  - BSEP achieve EPU with 2nd batch of GE14 fuel.
  - Amendment not submitted.

- **License Condition**
  - Requires amendment request
    - Changes to TS 3.1.7,"Standby Liquid Control (SLC) System."
  - 6 months before implementation

SRXB CONCLUSIONS

- Licensing analyses are based on NRC-approved methods, codes and acceptance criteria
- BSEP EPU SAR is consistent with NRC-accepted guidelines and generic analysis for evaluating the impact of the extended power uprate on safe operation of the plant, except for the discussed deviations
- Deviations were presented to the Committee during the Clinton and the CPPU topical report meetings. (NEDC-32989P and NEDC-33004P)
- The staff finds that CP&L provided sufficient bases to support operation of BSEP Units 1 and 2 at the proposed power level of 2923 MWt.

BRUNSWICK STEAM ELECTRIC PLANT UNITS 1 AND 2 EXTENDED POWER UPRATE

STAFF RISK ASSESSMENT REVIEW

Donald Harrison, NRR

APRIL 23, 2002

STAFF RISK ASSESSMENT REVIEW

- Licensee Submitted Risk Information for Insights and to Ensure No New Vulnerabilities Created
  - Internal Events
  - External Events
  - Shutdown Operations
  - PRA Quality
- Staff SEs on IPEs and IPEEEs

OVERALL EPU RISK CONCLUSIONS

- **OVERALL RESULTS (Based on Sensitivity #5 - Worst Case)**
  - Internal Events — CDF ~2.7E-5/yr — LERF ~4.8E-6/yr
  - External Events — Fire CDF ~3.6E-5/yr — Winds CDF ~4.0E-6/yr
  - Shutdown Operations — Negligibly Small Impact
- **LICENSE APPLICATION ACCEPTABLE**
  - Meets Deterministic Requirements
  - No Changes Identified in Management of Risks
  - No New Vulnerabilities Identified
  - No Issues Identified That Would Question Adequate Protection and Base Risk Values Do Not Warrant Denial of the License Application

EPU HRA Evaluation

- The Only HEPs Re-Calculated for EPU Involve RPV Power/Level Control During an ATWS
  - The Operator Response Times used in the Current PSA are Shorter than the Time Available Under EPU for Most of the Typically Affected HEPs
    - Manual Scram, Initiating SLC, Inhibiting ADS, Initiating RPV Injection Sources, Initiating Emergency Depressurization, Initiating SPC
- SER Includes Statement that these HRA Methodologies Have Not Been Formally Reviewed/Approved by NRC
  - Commonly Used and Accepted Methods
  - Can Help Focus Reviews and Provide Comparative Insights into Relative Importance and Change in Importance of HEPs

BRUNSWICK UNITS 1 AND 2 POWER UPRATE

ACRS

APRIL 23, 2002

PLANT AND CONTAINMENT SYSTEMS, NRR

Richard Lobel

SPECIFIC AREAS OF REVIEW

- MAIN STEAM ISOLATION VALVES
- RHR SUPPRESSION POOL COOLING, CONTAINMENT SPRAY COOLING AND FUEL POOL COOLING
- CONTAINMENT SYSTEM PERFORMANCE NET POSITIVE SUCTION HEAD
- POST-LOCA COMBUSTIBLE GAS CONTROL SYSTEM
- MAIN CONTROL ROOM ATMOSPHERIC CONTROL SYSTEM
- STANDBY GAS TREATMENT SYSTEM

SPECIFIC AREAS OF REVIEW (CONT.)

- SPENT FUEL POOL COOLING SYSTEM
- SERVICE WATER, COMPONENT COOLING WATER AND TBCC WATER SYSTEMS
- ULTIMATE HEAT SINK
- POWER DEPENDENT HVAC SYSTEMS
- LIQUID WASTE, GASEOUS WASTE, AND OFF-GAS SYSTEMS
- HIGH AND MODERATE ENERGY LINE BREAKS

CONTAINMENT SYSTEM PERFORMANCE

- ANALYSIS METHODS CONFORM WITH ELTR1, APPENDIX G
  - M3CPT CODE FOR SHORT TERM RESPONSE
  - LAMB CODE FOR BLOWDOWN
  - SHEX CODE FOR LONG TERM RESPONSE
- NRC CALCULATIONS FOR ANOTHER MARK I CONTAINMENT PROVIDE AN INDEPENDENT ASSURANCE OF THE ADEQUACY OF THE METHODS USED FOR BRUNSWICK UNITS 1 AND 2
- NEW ASSUMPTIONS FOR CONTAINMENT ANALYSES:

PARAMETER	CURRENT	EPU
SWS TEMPERATURE	90°F	92°F
POOL COOLING	CONTAINMENT SPRAY	RHR POOL COOLING
DECAY HEAT (ANSI/ANS 5.1 1979)	NOMINAL	NOMINAL + 2σ

DBA LOCA CONTAINMENT ANALYSIS RESULTS

CHANGE WITH INCREASE IN POWER FROM CURRENT RTP TO EPU SAME ANALYSIS METHODS

PARAMETER	AT CURRENT RTP	AT EPU	Δ	LIMIT
Peak Drywell Pressure (psig)	44.2	46.4	2.2	62
Peak Drywell Temperature (°F)	290.4	293.0	2.6	340 (ATM) 300 (WALL)
Peak Bulk Pool Temperature (°F)	197.9	207.7	9.8	220
Peak Wetwell Pressure (psig)	30.5	31.1	0.6	62

NPSH OF ECCS PUMPS

- 3.1 PSI CONTAINMENT PRESSURE IS REQUIRED TO MEET REQUIRED NPSH FOR RHR PUMP
- 2.6 PSI IS REQUIRED FOR CONTAINMENT SPRAY PUMP
- 5.0 PSI CONTAINMENT OVERPRESSURE USED
- 11.3 PSIG IS CALCULATED MINIMUM WETWELL PRESSURE

PARAMETER	W/O CONTAINMENT SPRAY	W/CONTAINMENT SPRAY
Wetwell Pressure (Psig)	25.5	11.3
Wetwell Temperature (°F)	207.7	206.9 (207.7 used in analysis)

SPENT FUEL POOL COOLING

- CONSISTS OF TWO INDEPENDENT SFP COOLING TRAINS: ONE PUMP AND ONE HEAT EXCHANGER EACH.

- MAINTAINS SFP TEMPERATURE < 150 F

- HEAT TRANSFERRED TO RBCCW SYSTEM

- RHR SYSTEM BACKUP (E.G., FULL CORE OFFLOAD)

- ALSO, SUPPLEMENTAL SFP COOLING SYSTEM.

  BACKUP TO RHR SFP COOLING

- WITH SWS TEMPERATURE = 95 F, SFP WATER TEMPERATURE REMAINS BELOW 150 F FOR NORMAL AND FULL CORE OFFLOAD

SPLB CONCLUSION

- ALL BALANCE OF PLANT AND CONTAINMENT SYSTEMS COMPLY WITH NRC REGULATIONS AND GUIDANCE AT EPU CONDITIONS

OVERALL CONCLUSIONS

- Analyses are based on NRC-approved analytical methods and codes
- On-site audit confirmed compliance to staff approved methodology
- EPU SAR is consistent with NRC-accepted guidelines and generic evaluations
- Thermal limits and the applicable safety analyses would be reanalyzed or reconfirmed using NRC approved core reload analyses methodology