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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF THE SUBCOMMITTEE ON POWER UPRATES

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SUSQUEHANNA STEAM ELECTRIC STATION EXTENDED POWER UPRATE

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OPEN SESSIONS

TUESDAY,

OCTOBER 9, 2007

VOLUME I

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The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 8:30 a.m., Dr. Sanjoy Banerjee, Chairman, presiding.

MEMBERS PRESENT:

SANJOY BANERJEE Chair

OTTO MAYNARD

WILLIAM J. SHACK   SAID ABDEL-KHALIK

OTTO L. MAYNARD

JOHN D. SIEBER

NRC STAFF PRESENT:

JOHN LUBINSKI

RICH GUZMAN

BENJAMIN PARKS

DIANE JACKSON

GREG CRANSTON

JOSE MARCH-LEUBA , Oak Ridge National Laboratory

RICHARD LOBELL

MARK RUBIN

DONNIE HARRISON

GARRY ARMSTRONG

GREGORY MAKAR

ALSO PRESENT:

RICK PAGODIN

JOHN BARTOS, II

CHRISTOPHER HOFFMAN

JOHN GIOSITTS

JAMES WILLIAMS

JOHN SCHLEIKER

ROBERT BOESCH

DOUG PRUITT

KEVIN BROWNING

MIKE HERR

MIKE GARRETT

ALSO PRESENT: (CONT.)

CHETT LEHMANN

YOUSEF FARAWILA

JERRY INGRAM

KEVIN MCNULTY

RICK PASTOLLIS

FRANK CHISH

JOHN VANOVER

MARK HANOVER

PAT HAUBER

BRUCE SWOYER

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

8:31 a.m.

CHAIR BANERJEE: The meeting will now come to order. We have lots of people.

This is a meeting of the Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates. I'm Sanjoy Banerjee, Chairman of the Susquehanna Steam Electric Station Extended Power Uprate Subcommittee.

Subcommittee members in attendance are William Shack to my left who is the Chairman of the ACRS, Said Abdel-Khalik also of the ACRS, Jack Sieber and Otto Maynard of the ACRS.

We would also like to welcome two long term ACRS members who have now retired. But today they will join us as consultants. That's Graham Wallis on my left and Tom Kress. Thank you, Graham and Tom for joining us today. I'm sure we will use your experience and expertise.

All right. Oh, sorry. And our consultant Dr. David Diamond from Brookhaven, who will be joining us today as well. And yes, David, we will also look forward to your expertise.

DR. DIAMOND: I'm glad.

CHAIR BANERJEE: There'll be another consultant who will join us tomorrow, I think, Dr. Pierce.

In any case, the purpose of today's and tomorrow's meetings it to discuss PPL's extended power uprate application that was approved by the NRC Staff.

I see at various points in the documentation it's called EPU or CPPU, which confuses me no end because I thought this was an EPU and not a CPPU. We discussed that.

The Subcommittee will hear presentations by and hold discussions with the PPL, the license of Susquehanna Units 1 and 2, their consultants, the NRC Staff and other interested persons regarding these matters.

The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full Committee. Zena Abdullahi is the designated federal official 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 September 9, 2007.

As announced in the *Federal Register*, portions of this meeting will be closed to the public in order to discuss information considered as proprietary by the different industry representatives, including AREVA, General Electric and Continuing Dynamics. The closed sessions are identified in the agenda.

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

It is requested that speakers first identify themselves and speak with sufficient clarity and volume so that they can be readily heard.

I would also like to remind the Members that the Committee has determined that speakers should be allowed the first ten minutes of their presentation time without questions.

MR. WALLIS: How did that get in again?

CHAIR BANERJEE: I think this is the --

MR. WALLIS: That is something we always say and never do.

CHAIR BANERJEE: Well, let's attempt.

MR. WALLIS: But then if every speaker does that, we'll never have any questions at all. They're just relieve each other every ten minutes.

CHAIR BANERJEE: Well, we won't allow that.

We received a request for a teleconference from one individual. A bridge number was made available for Mr. Ferrante. Please be advised that the bridge connection is only for listening in.

And before I end this, I'd like to turn this over to Otto Maynard to thank PPL for a very interesting site visit that Otto and Graham and a few others went on.

MEMBER MAYNARD: Yes. In September Dr. Wallis and myself along with some members of the ACRS staff and the NRC Staff visited the Susquehanna Power Plant. Had a good tour, a good presentation. That also included some time in the simulator observing several scenarios. And one of which the crew did not know what was going to be coming at them, and so we had a chance to observe operator performance as well as watching the plant response to to various transients and stuff.

Dr. Wallis and I also helped prepare them for the meeting. Because apparently they were told to take the EPU stuff out, it was just a kind of familiarization visit. And, of course, Dr. Wallis and I wanted to talk a little bit about the extended power uprate. So they got to change some of their presentation on the fly, which I'm sure they'll get the opportunity during the next two days to do some of that. And they did a very good job.

So, I do appreciate their hospitality and giving us an opportunity to see the plant, especially the scenario at the simulator time.

Turn it back to you.

CHAIR BANERJEE: Thank you.

So I think we can proceed with the meeting. And I call upon Mr. Lubinski of the NRR to begin.

MR. LUBINSKI: Thank you.

Good morning. I'm John Lubinski. I'm the Deputy Director, Division of Operating Reactor Licensing in the Office of Nuclear Reactor Regulation.

I'm going to keep my opening remarks

brief, so following Dr. Wallis' recommendation to stay within ten minutes so that we don't get questioned.

I appreciate the briefing this morning, especially in light of the fact that there were multiple times that we had to reschedule this briefing. I appreciate the adjustments made.

I believe over the next days you will hear the results of a very thorough NRC review of the application submitted by PPL. The thoroughness of the review is supported by the fact that we had preapplication meetings with the licensee starting as early as November of 2005 in which the schedule for the application and the application review as well as the approach was discussed with the NRC.

We also performed an extensive acceptance review before initiating our complete review of the application. Again, we believe this helped with the efficiency and the effectiveness of our review.

We also had very frequent communications with the licensee; telecons, writing, meetings. And we believe that definitely helped with the effectiveness of our review.

Finally, there were several rounds of RAIs issued to the licensees. Request for additional information. The RAIs were submitted as they were developed allowing the license as much time as possible to review and respond to the RAIs in the different technical areas.

Some of the more challenging review areas that you'll hear about the next two days include:

The steam dryer stress analysis on which PPL submitted a finite stress analyses for a new dryer design;

The fuel and core design analyses;

The thermal hydraulic stability analyses;

As well as the emergency core cooling system performance and response to the loss of coolant accident. This also included confirmatory calculations by the NRC Staff in addition to the review performed by PPL.

As presented in the draft safety evaluation, which was provided to ACRS in August of 2007, there are currently no open technical issues in the NRC Staff's review PPL's extended power uprate application.

I am very pleased with both the thoroughness and the timeliness of the review conducted by the NRC. The Staff had extensive interactions with PPL on diverse technical issues and completed its review within ten months of submittal of the application.

At this point I'd like to turn over the discussion to our NRR Project Manager Rich Guzman who will introduce the discussions.

MR. GUZMAN: Good morning.

My name is Rich Guzman. I am the Project Manager in the Office of Nuclear Regulatory Regulations. I'm assigned as the Project Manager in the Division of Operating Regulatory Licensing assigned to the Susquehanna Steam Electric Station, Units 1 and 2.

Before I go over the agenda, I'd like to present some background information related to the NRC's review of the proposed Susquehanna EPU. The proposed EPU would increase the maximum authorized thermal level from 3,489 to 3,952 megawatts thermal. This represents an approximate 13 percent increase current licensed thermal power and --

MR. WALLIS: Can I ask a question? Is this true that this is the highest power for a BWR in the world?

MR. GUZMAN: 3952, I don't know the answer.

MR. WALLIS: I think so. I think that's been stated in the application.

Thank you.

MR. GUZMAN: It also represents a 20 percent increase above the original licensed thermal power.

The NRC licenses Susquehanna Units 1 and 2 on November 12, 1982 and June 27, 1984 for full power operation at 3,293 megawatts thermal respectively. The NRC also approved two previous power uprates, the first of which was an uprate stretch 4.5 percent increase. This was approved in Unit 2 on April 11, 1994 and for Unit 1 in February 22, 1995.

The second uprate was 1.4 percent increased that resulted in a measurement uncertainty recapture, which was approved on July 6, 2001.

As far as the method of NRC Staff review, the Staff's review for PPL's application was based on NRC's Review Standard For Extended Power Uprates RS-001. The Review Standard includes a safety evaluation template as well as matrices that corresponds to maintenance areas that are to be reviewed by the Staff as well as the specific guidance and the acceptance criteria that apply to those review ares.

CHAIR BANERJEE: NRC approved MELLLA?

MR. GUZMAN: Yes.

CHAIR BANERJEE: And what the status of that?

MR. GUZMAN: There were three amendments actually prior to this amendment, one of which was ARTS/MELLLA. That has been approved earlier in 2007. The other two was the standby liquid control system for sync pump operation and enriched boron. And then third was a full scope AST. So all three of those were approved prior to this being submitted early January to March 2007.

MR. WALLIS: Are we going to look at the boron mixing at all in these couple of days?

MR. GUZMAN: Yes. The licensee does have a presentation on --

MR. WALLIS: On boron mixing?

MR. GUZMAN: -- well, specifically it'll cover the three amendments. Actually, the next presentation will cover the three pre-EPU applications that support the extended power uprate.

MEMBER SIEBER: I take it all these uprates were constant pressure uprates?

MR. GUZMAN: Yes.

MEMBER SIEBER: I guess the first one was before the topical was issued, right, or was it?

MR. GUZMAN: Basically PPL's application followed the guidelines of the constant pressure power uprate --

MEMBER SIEBER: Right.

MR. GUZMAN: -- GE's topical report.

MEMBER SIEBER: And the current one?

MR. GUZMAN: The current, that's right.

MEMBER SIEBER: Yes. I have some questions later on about that.

MR. GUZMAN: Okay. I'll take note of that.

MEMBER SHACK: Well, I think the stretch was a constant power uprate?

CHAIR BANERJEE: The stretch was not.

MEMBER SIEBER: Yes, the stretch.

MR. GUZMAN: The stretch --

MEMBER SIEBER: one and one half percent or thereabouts. Or four and a half.

MR. GUZMAN: Yes, four or five percent.

MEMBER SIEBER: Yes.

MR. GUZMAN: After I include my remarks, the licensee will provide detailed presentation on their CPPU licensing approach, which will include their implementation schedule. There was some major engineering changes made associated with the CPPU as well as including the -- basically aware of the 13 percent, how the 13 percent is going to be achieved.

CHAIR BANERJEE: When you approved MELLLA it didn't come to us for comments, if I do recall, right? That was with ATRIUM-10 fuel?

MR. GUZMAN: That was HM-10 fuel, yes.

We'll move on to the last bullet for schedule and implementation. PPL's EPU application was submitted on October 11, 2006. There were three supplements that followed which were necessary for the Staff to consider the application as complete. The Staff completed its acceptance review January of 2007 and indicated then that there was sufficient information to proceed with the detailed technical review.

The Staff plans to issue the final safety evaluation and amendment by the end of December 2007 or early January 2008. The licensee plans to implement the EPU in two steps for Unit 1, an approximate 7 percent increase upon startup following the spring 2008 refueling outage, and then the remaining step upon startup of the spring 2010 refueling outage. And then implementation for Unit 2 would be a 13 percent increase one step on startup from the spring 2009 refueling outage.

Everyone can take out the agenda. I'd like to go over some of the agenda items for both days.

As you can see, on both days there are closed and open sessions due to the proprietary information that will be discussed in the material.

This morning's presentation will be provided by the licensee and will start with an overview of the proposed EPU. Much of the discussion will be focused on PPL's CPPU analyses and associated safety analysis, including presentations on startup power ascension and power maneuvering.

In the afternoon we will go to closed session for PPL to continue with the proprietary discussion related to the analytical methods used by their fuel vendor AREVA/MPP. These analytical methods are used to analyze minimum critical power ratio safety limits, shutdown margins, limiting transients and LOCA, including a presentation on the CPPU impact on stability.

Following PPL's presentation on AREVA methods, we will go to open session for the NRC to provide discussion of the review performed by the Reactor Systems Branch as discussed in the safety evaluation section 2.8.

Toward the end of that presentation we will switch again to closed session as a portion of the material does contain AREVA proprietary information.

The remainder of the meeting will be open session in the afternoon where the licensee will begin the discussion on containment analysis methodology and response.

Then the final presentations by the licensee will cover three review areas, each will be followed by NRC's Staff's presentations on related topics.

PPL's first presentation will cover their probabilistic safety assessment. The NRC Staff will then discuss its review of its risk evaluation related to the EPU.

PPL's next presentation will be on operations training, emergency operating procedures, operator actions and operator timelines. The Staff will then provide a discussion on the review related to the human performance as discussed in safety evaluation 2.11.

And then the last presentation for the day will be the licensee presenting the discussion on flow-accelerated corrosion and pressure temperature limit curves. And this will be followed by the NRR's Material and Chemical Engineering Branch review.

Tomorrow's first presentation will be a discussion by PPL pertaining to the analyses of the steam dryer and reactive vessel internals, review and analysis. We will then go to closed session in order for PPL to continue its discussion on steam dryer analyses, which will contain General Electric Hitachi proprietary information.

Upon completion of this presentation open session will resume and the licensee will provide a detailed discussion on its power ascension and testing plans.

In the afternoon the NRR Staff will provide a discussion of the review performed by the Mechanical and Civil Engineering Branch as discussed in the draft safety evaluation section 202. We will then go to closed session to discuss steam dryer loading, CL model testing and validation of the finite element model.

The NRR Staff will then provide the discussion of their review related to the EPU: Test programs, balance of plant systems, source terms and radiological consequences and then close with public comments and conclusion.

So that, this concludes my presentation as far as the introduction. And unless there are any questions, I'd like to turn it over to Mr. Rick Pagodin, the General Manager of --

CHAIR BANERJEE: Let me ask a point for clarification. When you refer to CPPU, my understanding, which may be wrong, it's an operate that we had looked at and previously approved for

GE-14 fuel. When you have HM-10 fuel is it still called a CPPU or is it another thing? Can you clarify thing? Because I remember the words that were attached to it, it was specifically for GE-14 fuel.

MR. GUZMAN: Yes. It is for HM-10 fuel and it's probably a good lead in for Rick, because he's going to give you the analyses.

CHAIR BANERJEE: But who has -- what's that wording for HM-10 fuel?

MR. GUZMAN: Well, we have with the --

CHAIR BANERJEE: With whose approval? You've approved it?

MR. PAGODIN: Let me just try and address this a little bit.

First of all, the terminology between the extended power uprate and the CPPU, the extended power uprate really applies to the fact that we are increasing our power to 120 percent of the original license.

CHAIR BANERJEE: I understand that.

MR. PAGODIN: The CPPU is just one method of achieving that 120 percents So our extended power uprate is a CPPU.

CHAIR BANERJEE: In a broad sense, but it's in the specific sense it has been used previously, which was for a specific type of fueling.

MR. PAGODIN: Yes.

CHAIR BANERJEE: You have completely the change the fuel in this core.

MR. BARTOS: Yes. I can answer your question. In general, we use the GE-LTR1 CPPU with the exception of the fuel area. The CPPU LTR doesn't apply, it only applies to the fuel. So for the fuel portion of this uprate we had to use the general EPU LTR.

CHAIR BANERJEE: Right. It's just confusing terminology.

MR. BARTOS: Right.

CHAIR BANERJEE: I mean, if you'd just call it EPU, I think that would have been straightforward. Here what you're doing is sort of a dog's breakfast using some methodology for this,methodology for that; it's not the same thing as just using the same GE methodology for everything.

MR. BARTOS: Right.

CHAIR BANERJEE: So in my view it's not a CPPU in that sense.

MEMBER SIEBER: I think that's true. But it is constant pressure.

CHAIR BANERJEE: It's constant pressure, but not a CPPU.

MEMBER SIEBER: And in the basic outline that the topical is being followed where it can be followed. Where it can't be, I'm sure you'll give us a further explanation.

CHAIR BANERJEE: With deviations.

MR. PAGODIN: We have a specific presentation on the AREVA methods a little later on.

Okay. Good morning.

I'm Rick Pagodin. I'm the General Manager for Nuclear Engineer for PPL Susquehanna. I have responsibility for all of the engineering functions at Susquehanna for the regulatory affairs and the license renewal and extended power uprate projects.

MEMBER SIEBER: Do you also have fuel regards?

MR. PAGODIN: Yes, I do.

MEMBER SIEBER: Okay.

MR. PAGODIN: Fuel and plant analyses, which is our PRA group.

MEMBER SIEBER: Do you do your own accident analysis for core -- or do you farm that out?

MR. PAGODIN: We do some analyses in conjunction with AREVA.

MR. HOFFMAN: Could you repeat the question, please, sir?

MEMBER SIEBER: Do you do your own in-house in core analyses and design analysis for the fuel and the safety analysis or do you farm that out?

MR. HOFFMAN: Okay. I'm Mr. Chris Hoffman. I'm the Manager of Nuclear Fuels and Analyses.

We perform some of our own in-house analyses. But our analyses of record are performed by AREVA using AREVA's methods.

MEMBER SIEBER: Okay.

MR. HOFFMAN: We oversee AREVA.

MEMBER SIEBER: And so the work you do is sort of a quality check on the vendor?

MR. HOFFMAN: That is correct.

MEMBER SIEBER: Okay.

MR. PAGODIN: Okay. Susquehanna is a two unit boiling water reactor located in northeast Pennsylvania currently rated at 3489 megawatts thermal, as Rich described earlier.

We began commercial operation of Unit 1 in 1983 and Unit 2 was commercial operation in 1985.

Also as mentioned earlier, we have implemented a stretch uprate of 4½ percent, and a measurement uncertainty uprate of 1.4 percent.

We used the lessons learned from both of those uprates in implementing this current project on EPI. We have also put together a team, as you can see here. A lot of our folks are full time PPL employees that we have reassigned from within engineering organizations, operations, maintenance and many other groups that are dedicated to our extended power uprate project. So that we were doing as much of the work ourselves as we could in providing oversight of contractors where appropriate.

We've also partnered with the appropriate level of contractors, both for doing technical work and analyses. And we have hired several other contractors to do independent assessments for us. We've had assessments done through our Independent Offsite Safety Review Committee over the last couple of years and they continue to provide oversight and monitoring our implementation of the EPU.

What I'd like to do this morning is give you brief overview of our CPPU and talk about the licensing approach. I'm going to go through basically our BWR steam cycle and briefly point out some of the changes and impacts that will occur with our extended power uprate.

A general overview of the Susquehanna plant. We'll talk about what major parameters are changing with our CPPU, describe the major engineering changes and modifications that we're making. We'll talk again about the implementation schedule.

We'll start with again the licensing approach. As Rich was mentioning earlier, we have implemented three major changes at the plant. The first one is ARTS/MELLLA. The ARTS also includes a change to our power range neutron monitoring system to install a digital monitoring system, which is the

General Electric NUMAC system. And the implementation of ARTS and MELLLA; ARTS is -- there will be a change to the APRM, rod block and tech specs and MELLLA gives us additional operating domain and changes some of our power-dependent rod blocks.

We implemented the alternative source term. Actually, that was fully implemented on site in September of this year. So we've recently fully implemented the alternative source term.

And we've implemented the standby liquid control enriched boron solution, that modification is installed in one unit and will be installed in the second unit in the upcoming outage.

Our extended power uprate application is requesting a change from 3489 to 3952 megawatts thermal. And we'll talk a little later about the 3952. Susquehanna, when we implement our extended power uprate, will be generator limited. So that might be a little different to you. We won't go to 3952 and stay full thermal power. We will be limited to 1300 megawatts electric on our generator and we will generally operate below 3952 megawatts thermals.

MR. WALLIS: It depends on the temperature of the cooling water or --

MR. PAGODIN: That's correct. It's basically environmental conditions that will drive the ability of the generator.

MEMBER SIEBER: Is that a financial constraint or a permit constraint or what?

MR. PAGODIN: No. Actually, it's a physical constraint on the generator and the size of the generator. We have done a rewind on our generator. We've got the most capacity out of it that we can.

MEMBER SIEBER: For the size of --

MR. PAGODIN: For the size of the generator.

MEMBER SIEBER: Okay.

MR. PAGODIN: Okay. Additionally we are asking for some decay heat methods changed and our containment methods changed. And we'll talk a little bit more about that later on in the afternoon when we talk about our containment analyses. And we're asking for several technical specification changes. For example, several of the changes relate to a percentage of rated power, that percent number changes throughout the tech specs.

We're also changing setpoints. As an example, the main steam line flow isolation setpoint will change.

And we are also changing our containment test pressure from 45 psig to 48.6 based on our revised containment analyses.

MEMBER SIEBER: Are the decay heat methods and containment methods lie outside the scope of the topical CPPU?

MR. BARTOS: I'll have to check into that. I'm going to do the containment presentation.

MEMBER SIEBER: Okay.

MR. BARTOS: And I'll have an answer to you by then.

MEMBER SIEBER: Okay. I don't recall that the CPPU topical had that amount of detail in it on containment, but you can let me know.

MR. BARTOS: Okay.

CHAIR BANERJEE: If it is outside it, it would be a nonfuel issue that were outside, right?

MR. BARTOS: Yes.

MR. PAGODIN: Okay. Let me briefly go through our BWR steam cycle. As depicted on this picture here, from the condenser we have the suction path with the condensate pumps and the feedwater pumps. And as part of our implementation we will be increasing flow in condensate and feedwater systems.

Inside the reactor we do have the increased power that will be generating and producing additional steam flow. And that's in the feed flow which will be going out to the generator. It is a constant pressure power uprate. One of the ways that's achieved is by replacing the high pressure turbine and opening the flow area to that high pressure turbine, and actually lowering the throttle pressure at that high pressure turbine.

So the steam flow path through the moisture separators through the three low pressure turbines is the same as current operation.

We are not making any changes to our circulating water system.

MR. WALLIS: Is your steam dryness the same with the uprate as it was before, or is it wetter steam?

MR. PAGODIN: Actually, our testing on the dryer, we'll get into that a lot more when we talk about the dryer. Shows that the new dryer should be as good or better than the existing.

MR. WALLIS: So the dryness fraction is the same then with EPU?

MR. PAGODIN: That's correct.

MEMBER SIEBER: Well, you got to take that with a grain of salt. The steam going to the turbine has essentially the same conditions as they had before the uprate. On the other hand, extraction steam, steam at the last few rows of blades in the turbine and going into the condenser, it's got to be wetter.

CHAIR BANERJEE: You've changed out the dryer.

MEMBER SIEBER: Temperature hasn't changed, pressure hasn't changed. So the steam has to be wetter.

MR. PAGODIN: That's true.

CHAIR BANERJEE: You've changed your dryers, right?

MR. PAGODIN: We are replacing the steam dryers.

CHAIR BANERJEE: Yes.

MR. PAGODIN: We have not done that yet. We are replacing them --

CHAIR BANERJEE: Trying to improve the performance from the dryers. But the steam is wetter, obviously.

MEMBER SIEBER: Well, I gathered that the modifications to the dryers is to make them stay together.

MR. PAGODIN: That's correct. It's a structural change more than it is to the steam.

MEMBER SIEBER: They may achieve a little bit of additional moisture reduction, but the changes in design to me did not look like that was the intent. It looked to me like the intent of all the modifications was to provide additional strength, change the frequency nodes. And so I wouldn't expect the change in the dryer inside the reactor to make any difference on the wetness of the stream. It's still a quarter of a percent, right?

MR. BARTOS: My name is John Bartos.

In addition to the structural modifications to the dryer, there is a new vein design.

MEMBER SIEBER: Yes, okay.

MR. BARTOS: And the direction for GE, which it tried to maintain, we had very good performance of our steam dryers and the direction for GE was to try to maintain that performance. And they required a different vein design.

MEMBER SIEBER: Yes.

MR. BARTOS: And they have begun testing. And their testing shows that we should see the same performance.

MEMBER SIEBER: You're going to be the same as you were before?

MR. BARTOS: Right.

MEMBER SIEBER: Okay.

MR. PAGODIN: And we'll go into more detail on that when we talk about the dryer later on.

Okay. The only other thing I'll point out here is that we do have two external reactor recirculation pumps. And in order to accommodate the CPPU the flow through those loops would be increased very slightly. About two percent increase in flow through the recirc system.

CHAIR BANERJEE: Have you done anything about moisture removal on the turbines?

MR. PAGODIN: In the turbines themselves?

CHAIR BANERJEE: Or between the high pressure and the low pressure stages?

MR. PAGODIN: No. Not directly related to our EPU application. We have implemented changes to our moisture separators in the past for obliviscence and maintenance reasons, which was also a goal to improve the moisture removal. But there was no changes directly tied to our EPU application.

CHAIR BANERJEE: Will you have the same moisture levels post-EPU as pre-EPU in these turbines or will they change?

MEMBER SIEBER: Okay. Yes.

CHAIR BANERJEE: I think that was Jack's question.

MEMBER SIEBER: Yes. I don't see how you can, but maybe you'll tell us differently.

CHAIR BANERJEE: Unless you put two moisture separators.

MEMBER SIEBER: And if you do, you'll explain how it comes about.

You didn't change the turbines at all, right?

MR. PAGODIN: Well, we did change all of the turbines out previously.

MEMBER SIEBER: Okay. And how did you change them?

MR. PAGODIN: But your question is really when we implement CPPU.

MEMBER SIEBER: Right.

MR. PAGODIN: So, I mean, those turbines have already changed. It's not another change we're making.

MEMBER SIEBER: Okay.

MR. PAGODIN: So pre and post there should be a change.

MR. BARTOS: Yes. This is John Bartos.

In 2003 and '04, I believe, we changed our turbines to Siemens' turbines.

MEMBER SIEBER: Oh, okay.

MR. BARTOS: And when we did that changeout we had in the back of our minds we were going to potentially do an uprate. So the low pressure turbines were actually designed for the uprated conditions.

MEMBER SIEBER: Okay.

MR. BARTOS: The hyper strip wasn't because we would take a big performance hit. So the new hyper -- we're going to put in is designed for the operating conditions.

MEMBER SIEBER: Okay. But it all goes into the same casing, right?

MR. BARTOS: Yes, sir.

MEMBER SIEBER: And so all you really change the diaphragms and the plate, and perhaps controls?

MR. BARTOS: Well, on the low pressure turbines the actual diameter of the stages are actually much greater.

MEMBER SIEBER: Okay. Okay.

MR. PAGODIN: Okay. Thanks, John.

MEMBER SHACK: Just a question there. You're going to get less cleanup of your water now in the new system, and so your conductivity is going to go up a little bit. Do you have any idea where that puts you relative to other BWRs? Are you now in the top quartile and you'll be in the top half or it's just an insignificant change?

MR. PAGODIN: In water chemistry? You're talking within the reactor vessel itself?

MEMBER SHACK: In the reactor vessel, right.

MR. PAGODIN: We haven't valuated our

reactor water cleanup system as far as it's ability to maintain within all of the water chemistry guidelines. And we can do that.

MEMBER SHACK: Yes, you're within the guidelines, but you're going to go up?

MR. PAGODIN: Yes. And we are making some modifications to approve the efficiency of the vessels themselves. We are not changing the flow, but we're making enhancements to the vessels.

John, is there anything else that you want to add on that?

MR. BARTOS: No. The changes that we're going to make to the direct water cleanup changes were intended to address that issue. But there's still the same flow. But we do generally have very good chemistry.

MEMBER SHACK: Right. I think it's something .1 and you're going to go to .13. I just don't know what BWRs run these days. I'm just -- you know, based on my previous experience, that's pretty darn good.

MR. BARTOS: We'll take that question and at a break we'll come back and see if we can give you better answer.

MEMBER SIEBER: It's a fresh water plant, so it gives you an advantage right there.

MR. PAGODIN: Okay. This next slide is a picture of our containment design. We are a GE Mark II containment with a suppression pool. So is the location of the reactor vessel within the containment, the suppression pool below it.

A couple of things I'd like to just point out. The drywell sprays and headers are at the very top here, at top of containment. And the suppression pool sprays are here located at the top of the suppression pool airspace.

In an accident the steam energy would be released into the drywell where it is then transferred into the wetwell under the water through the downcomers. They're located over here, which quenches the steam.

The containment and wetwell in normal operation are maintained inerted to keep the environment with less than 4 percent of oxygen. And we do have hydrogen recombiners located in the suppression pool area and the drywell.

CHAIR BANERJEE: The pumps are deeper in than other -- the recirculation pumps than in other plants? Isn't it you've got more in MPSH? Where are the pumps going to be?

MR. PAGODIN: Well, we're going to talk about MPSH a little later in terms of RHR and core spray pumps.

CHAIR BANERJEE: Right.

MR. PAGODIN: They are actually located in the floor in this location here. So they're basically at the bottom of this floor outside of the suppression pool.

CHAIR BANERJEE: Okay. So they're as low as you can get them?

MR. PAGODIN: That's correct. And you'll the design, the pump bowls themselves are actually below the floor.

CHAIR BANERJEE: Okay.

MR. WALLIS: There's a big hole the pump goes in, isn't it? As I remember, there's a long tube or something, the pumps --

MR. PAGODIN: Yes. And we have a slide on that later, Graham. We'll show that, the same slide that you're talking about.

Okay. This is an overview of the reactor vessel itself. The core is located in this region right here.

Talked a little bit before about the steam quality. Right above the core is our steam separator and on top of that here is the steam dryer. The steam leaving the separator is about 95 percent dry. And the steam leaving the dryer is about 99.99 percent dry.

MEMBER ABDEL-KHALIK: What's the quality of the top core with the power uprate versus the current quality?

MR. PAGODIN: The top of the core? Are we talking about the void fraction at the --

MEMBER ABDEL-KHALIK: No. Quality.

MR. KRESS: No. Mass fraction.

MR. PAGODIN: I'll have to get an answer for you on that.

MR. WALLIS: It would be the average quality?

MEMBER ABDEL-KHALIK: Right.

CHAIR BANERJEE: Average and maximum.

MEMBER SIEBER: Yes, it's going to very as you go up.

CHAIR BANERJEE: You may as well give average and max, have both.

MEMBER SIEBER: For the separator.

MR. PAGODIN: John, do you know? Would you come up to the mic and answer that question then?

MR. GIOSITTS: I'm John Giositts.

The steam fraction varies with core flow, but a typical core flow like 100 million pounds per hour we're going to have a steam flow if you're at 3952 megawatts thermal, it'd be about 16.5 million pounds per hour steam flow. So at that condition that would relate to about a 16½ percent exit quality versus today we have about 14½ percent.

MR. PAGODIN: Thank you, John.

MEMBER ABDEL-KHALIK: Thank you.

MR. WALLIS: That's the average. But the maximum is about the same, isn't it? Is the average -- the maximum about the same and it's just been redistributed?

CHAIR BANERJEE: The core is radially flatter and --

MR. GIOSITTS: Yes. The core would be radically flatter so that the maximum bundle exit quality would be nearly the same. I was talking about on the average.

CHAIR BANERJEE: What is the maximum, comparisons of the maximum?

MR. GIOSITTS: We'll actually get into that in the AREVA presentation. We have some presentations of void quality for that.

CHAIR BANERJEE: Exit quality?

MR. GIOSITTS: Yes, exit quality.

CHAIR BANERJEE: Okay.

MR. GIOSITTS: Versus the exit void fraction.

MEMBER SHACK: What's the condition of your reactor internals, the core shroud, top guide? Are they cracked?

MR. PAGODIN: There are cracks in the core shroud that we have been monitoring and continue to monitor. The top guide we continue to do inspections but there are no cracks that we have identified in the top guide.

MEMBER SHACK: Do you have any repairs on the core shroud or it's just you're just monitoring the cracks?

MR. PAGODIN: We have not implemented any repairs at this time. We continue to do the measurements and do the analysis and determine that there is sufficient structural support in the core shroud to not require repair at this time.

Our next inspections will be done in 2009 and '10.

CHAIR BANERJEE: Are these horizontal or vertical cracks? What sort of cracks are these?

MR. PAGODIN: The cracks are located in the horizontal, the circumferential welds. We also monitor the vertical welds. I'm not aware of any cracks in the verticals.

CHAIR BANERJEE: You had an answer to one of the RAIs I remember. Apparently this wasn't in the -- the issue came up in the RAI and you answered. And I think you mainly discussed the horizontal cracks. I was just wondering.

MR. PAGODIN: Okay. Getting back to the reactor vessel, I guess just something to point out the normal water reactor level would be about this level right here. It's 35 inches above the bottom of the dryer skirt.

The recirculation system that I mentioned, I do have the two loops of recirculation flow. This is the pump suction here. It goes through the pump and back out into the output here into the header that goes into the jet pumps. We have 20 jet pumps in the reactor.

MR. WALLIS: Where is normal -- where is the level zero? You talk about minus 60 inches and so on. What's the level zero of the water in the vessel?

MR. WILLIAMS: My name is James Williams.

The normal water level is plus 35 inches.

MR. WALLIS: Well, what does --

MR. WILLIAMS: Vessel zero is the bottom of the dryer skirt.

MR. WALLIS: The bottom of the dryers.

MR. PAGODIN: So that's located right here below the steam separator line.

MR. WALLIS: Okay. So the bottom of the dryers is level zero. Okay.

MR. WILLIAMS: And top of active fuel is minus 161.

MR. WALLIS: Okay. Thank you.

MR. PAGODIN: Thanks Jim.

Okay. Again, a couple of --

CHAIR BANERJEE: Is that just above the feedwater inlet or what? Oh, dryer. Dryer or the separator?

MR. PAGODIN: The zero is here at the bottom of the dryer.

CHAIR BANERJEE: Separator.

MEMBER SIEBER: Separator.

MR. WALLIS: I'm confused because of the dryer. But minus 60 is the normal level, which is in the separator.

MR. PAGODIN: No, the top of -- what he said was that the instrument zero is the bottom of the dryer skirt.

MR. WALLIS: Right. That's right. That's what he said.

MR. PAGODIN: And he said that's the zero.

Normal level less 35 inches, so --

CHAIR BANERJEE: The dryer is the one on top, right?

MR. PAGODIN: Right. The one on top is the dryer, up here, the green.

CHAIR BANERJEE: Okay.

MR. PAGODIN: And if you look over on

the right hand side, you can see the skirt here comes down over that --

MR. WALLIS: Down there. Okay. That's what it is.

CHAIR BANERJEE: Right. Right. Thank you.

MR. PAGODIN: So the bottom of the skirt is right below the arrow that's pointing at the steam separator.

CHAIR BANERJEE: Okay.

MR. PAGODIN: This blue structure in here is the steam separator.

MR. WALLIS: That's where it is. Okay.

CHAIR BANERJEE: Thank you.

And the core is minus 161?

MR. PAGODIN: The top of the active fuel is minus 161 inches from the zero point. So--

CHAIR BANERJEE: Well, this includes the blanket on -- it's not just the actual blanket. It includes the reflector blanket?

MR. PAGODIN: Chris?

MR. HOFFMAN: I'm Chris Hoffman.

That's correct.

CHAIR BANERJEE: So it's just the top of the fuel itself?

MR. HOFFMAN: Top of the active fuel to include the blanket.

CHAIR BANERJEE: Include the blanket? Okay.

MR. PAGODIN: Okay. Just a couple of other facts.

Located in the bottom here are the control rods. At Susquehanna we have 185 control rods in each unit. And our core consists of 764 fuel assemblies.

DR. DIAMOND: Rick, is somebody going to provide an overview of the fuel design at a later point? Because your overview seems to stop at the core here.

MR. PAGODIN: We certainly will do that.

CHAIR BANERJEE: If you wish, you can do that in closed session. It's okay.

MR. PAGODIN: Okay. We'll review what we need to present there.

MR. WALLIS: When you talk about level, does that mean level in the downcomer?

MR. PAGODIN: Yes.

CHAIR BANERJEE: So can we flag that as an item then for the full session?

MR. PAGODIN: Fuel design?

CHAIR BANERJEE: Yes.

MR. PAGODIN: Certainly. Okay.

On this slide, it certainly isn't every parameter, but we wanted to just give you a general sense of what is changing. As we mentioned before, the first slide there on the core thermal power, we are increasing our licensed thermal power from 3489 which we operate as a constant base loaded thermal power currently to a 3952. You see it says "variable" there. As I mentioned before, we will be generator limited and we will adjust the reactor power as needed to account for the environmental conditions. And most likely only in the hottest of the season would we be able to get to a 3952 megawatts thermal level.

Feed flow and steam flow both increased from 14.4. million pounds per hour to 16.5 million pounds per hour.

Our recirc flow, as I indicated earlier, is as small, approximately a 2 percent increase in the total recirc flow.

I should say our total core flow is not changing. That's 109 million pounds per hour and we'll stay with the maximum 108 million pounds per hour.

Final feedwater temperature, we get a slight increase there.

And the generator output, which I mentioned, at 1300 constant on the generator versus our current load of operation where we would vary anywhere from approximately 1150 to 1210 megawatts depending on the weather.

MEMBER ABDEL-KHALIK: Now if you go back to that slide, the recirc flow has gone up in volumetric flow. What is the core inlet temperature? How has the mass flow rate through the core changed?

MR. PAGODIN: John?

MR. GIOSITTS: I'm John Giositts.

The mass flow rate has not changed. It's still 100 million pounds per hour would be the nominal. And maximum, like Rick said, is 108 million pounds per hour. And the minimum flow would be constrained by the MELLLA boundary.

MEMBER ABDEL-KHALIK: So even though the

pressure dropped has increased in the core you expect the mass flow rate through the core to remain unchanged?

MR. GIOSITTS: The mass flow rate through the core will remain unchanged, however the driving flow required to maintain that core flow would increase slightly.

MEMBER ABDEL-KHALIK: Okay. Thank you.

MR. PAGODIN: This is a simplified view of our power flow map. We'll get into more detail of the power flow map in a later presentation. But what I wanted to show here is the net impact of our CPPU operation is that we would basically operate higher up the existing red line. So this is the current MELLLA red line that we've already implemented.

CHAIR BANERJEE: Are you currently at 108 percent flow capability?

MR. PAGODIN: Yes. Yes. The 108 million pounds per hour was implemented the same time we implemented our stretch power uprate.

MR. WALLIS: So you have changed the MELLLA line? All you've changed is your ability to maneuver at high power, really?

MR. PAGODIN: That's correct.

MR. WALLIS: Just squashed into that little corner at the top?

MR. PAGODIN: That's correct. This black area up in here is the region we would be allowed to operate in.

MR. WALLIS: Does that require then a lot more rod adjustments to stay that power level?

MR. PAGODIN: Chris?

MR. HOFFMAN: This is Chris Hoffman.

It will require more rod adjustments.

MR. WALLIS: So you've got to be more careful about damaging the fuel by doing it too quickly and that kind of stuff?

CHAIR BANERJEE: They're very brave. They do this with a nonbarrier flow, right?

MR. PAGODIN: Actually, we should point out our fuel history has been excellent. We have over 34 reactor years with no fuel failures. So I think our operation has demonstrated that we can maintain fuel integrity.

CHAIR BANERJEE: When did you put non-barrier fuel in?

MR. PAGODIN: We've always had nonbarrier fuel.

CHAIR BANERJEE: All this time?

MR. HOFFMAN: Chris Hoffman.

To the best of my knowledge we've never had barrier fuel.

MR. WALLIS: Does AREVA make barrier fuel?

CHAIR BANERJEE: Yes.

MR. PAGODIN: Yes, they do.

CHAIR BANERJEE: They offer both, right? Non-barrier and barrier?

MR. PAGODIN: I believe so.

MEMBER MAYNARD: We might get more into in the fuel discussion. However, we did talk about this at the site. And they do have their opinions of barrier fuel versus non-barrier fuel that --

CHAIR BANERJEE: We can do this in closed session.

MEMBER MAYNARD: Yes. Yes.

MR. PAGODIN: Okay. The next slide just go through some of the major engineering changes that we've implemented or will be implementing as part of our standard power uprate.

The first one is the introduction of

vibration and acoustic monitoring equipment both inside and outside of containment. We've installed accelerometers and strain gauges on our piping.

We have also implemented the power range neutron monitoring system in ARTS/MELLLA that I mentioned earlier.

We've made some changes to our ultimate heat sink. Primarily the changes involve plugging of some of the spray nozzles.

Our heat sink is a spray pond which uses larger sprayer rays to spray the water into the air and cool the water.

And we've plugged some of those nozzles to get more efficiency out of those sprays.

We've also installed --

CHAIR BANERJEE: Let me ask you sort of a question regarding this ARTS/MELLLA. You're going to use what they call, I guess, Option 3, right, for this?

MR. PAGODIN: Yes.

CHAIR BANERJEE: Do you have a manual backup system planned or is just going to be you rely on that?

MR. PAGODIN: We have a presentation

we're going to talk specifically about our stability methods a little later on today.

CHAIR BANERJEE: But where is that showing up in this? Because the schedule doesn't have a discussion explicitly on stability. Is it going to be in the closed session in the afternoon or after the break? Will it be in open session.

MR. PAGODIN: Mike?

MS. ABDULLAHI: It's before the closed session.

CHAIR BANERJEE: So it'll be before lunch under item 5?

MS. ABDULLAHI: Item 5. Yes.

CHAIR BANERJEE: Okay. Fine. Thank you.

MR. PAGODIN: The short answer to your question is, yes, we also have manual operator actions that we'll talk about.

Okay. The other modification listed there is the enriched standby liquid control boron solution. The modification to that other than changing out the solution itself was to change the controls to use single pump operation versus two pump operation. This is a modification that was needed for EPU but also gives us substantial additional margin in our plant design.

MR. WALLIS: Well, let's go over this. The enriched boron means enriched in boron in an isotope of boron? It doesn't mean -- I mean is the enrichment chemically about the same as before as it's just the isotope that's changed?

MR. HOFFMAN: Chris Hoffman.

The enriched boron we're going from a natural concentration up to an enriched concentration of at least 88 atom per boron-10.

MR. WALLIS: Yes. But the chemical composition is the same. Is it about the same?

MR. HOFFMAN: Mr. Jim Williams can --

MR. WALLIS: I'm talking about solubility issues and things; it's the same, isn't it?

MR. HOFFMAN: I'll let Mr. Jim Williams answer that.

MR. WILLIAMS: James Williams.

The concentration is actually less.

MR. WALLIS: Okay. So less?

MR. WILLIAMS: Yes. So the precipitation temperatures are lower.

MR. WALLIS: So it's less? Okay.

MR. WILLIAMS: Correct.

MR. PAGODIN: Okay. Thanks, Jim.

We have already replaced our condensate pumps on one unit. And we'll be replacing the second unit here in the spring. This is to the first step of increasing our condensate and feedwater flow that we mentioned before.

We did replace our number 4 feedwater heaters on one unit. No, one unit.

MR. WALLIS: Did you find evidence of FAC or anything in there?

MR. PAGODIN: There are some areas where we have been monitoring FAC. And we'll have a presentation specifically on FAC later. We'll talk about the feedwater heaters.

This replacement was geared more to the designed additional flow that would be going through those heaters and vibration concerns.

MR. WALLIS: Now you've got a chance to examine them. You take them out.

MR. PAGODIN: That's correct.

Our number 5 heaters we are able to do a rerate on those, so we're doing it.

MR. WALLIS: Change the materials at all?

MR. PAGODIN: On the numbers 4s, yes. We're putting in FAC resistent material.

CHAIR BANERJEE: How are you monitoring the flow?

MR. PAGODIN: How do we monitor the flow? Jim,you want to talk about how we monitor the flow on the feedwater heaters.

CHAIR BANERJEE: The feedwater flow, yes.

MR. WILLIAMS: On our feedwater flow we have venturis and leading edge flow monitors for feedwater. The feedwater heaters themselves, we do have indications on our computer for drain flows. Also have temperature and delta-T instrumentation on the feedwater heaters.

CHAIR BANERJEE: And you'll have the same venturis as you've had? You're not changing those out?

MR. WILLIAMS: No, we are not changing the venturis out.

CHAIR BANERJEE: And the throats are smooth still and everything?

MR. PAGODIN: Okay. The last modification we have up here is to install switchyard capacitor banks. This is done to accommodate operating generators at a higher power factor and to maintain the bar loading on the transmission system.

MEMBER MAYNARD: Back up to the vibration acoustic monitoring. I don't know if you're going to cover anymore later, but if I recall you're going to end up with quite a few monitoring points and vibration analyses equipment, is that correct.

MR. BARTOS: Yes. This is John Bartos.

Yes, yes we are. We've done piping analyses and we've looked for-- there is a piping that would be susceptible to flow in just vibration. And so we've installed monitoring for selective locations.

MR. PAGODIN: The first one on here is the implementation, the physical limitation of some of the setpoint changes we talked about before, like the main steam line isolations. There are a number of instrumentation that need to have their ranges exchanged for the higher flows that we'll be operating in, things like that.

We're also going to replace our generator output breaker on Unit 1. This is simply the design that was there to not have sufficient capacity for as to implement the full power uprate on that breaker.

It's on Unit 1 only in this case. Our Unit 1 and Unit 2 output voltages are different. We operate at 500,000 volts on Unit 2, 230,000 volts on Unit 1. So the equipment is different between the units. So it's not a change that we had to make in both.

MEMBER SIEBER: Are they SS-6 breakers?

MR. BARTOS: This is John Bartos.

Yes, sir, they are.

MEMBER SIEBER: Three tanks.

MR. PAGODIN: The Unit 1 transformers are three phase transformers and there are two of them.

MEMBER SIEBER: Okay.

MR. PAGODIN: Two 50 percent.

The Unit 2 transformers are single phase.

MEMBER SIEBER: Okay.

MR. BARTOS: The new circuit breakers are SS-6s, sir.

MEMBER SIEBER: Right. Okay. Actually they'll work, but only at one time.

CHAIR BANERJEE: When you say "implement setpoint changes," what were the main setpoint changes that you did?

MR. PAGODIN: They would be things like the change in the main steam line flow isolation setpoints. So this is where we physically installed that change into the plant as a modification package that we put together for all of the setpoints that we change. Any flow control valve adjustments that we would make, changes to the indication on the instrumentation, things like that.

MEMBER SIEBER: You will end up doing a lot of fine tuning in your power ascension --

MR. PAGODIN: That's true.

MEMBER SIEBER: -- of all that stuff.

MEMBER MAYNARD: But the setpoints come out of the safety analyses for the new power at primarily the trip setpoints and the action setpoints to maintain within the safety analyses limits.

MEMBER ABDEL-KHALIK: Is there going to be another presentation on the setpoint changes, or this is the only place?

MR. PAGODIN: This was the only place we have.

MEMBER ABDEL-KHALIK: If that's the case, could you explain to me the logic for the reactor recirculation runback limiter?

MR. PAGODIN: Sure. Jim, you want to take that?

MR. WILLIAMS: Our recirc runback had a 30 inch reactor water level confirmatory action signal. If we had a trip of a feed pump or a condensate pump, we previously waited until water level got to under 30 inches and then the recirc runback would start.

We took that 30 inch confirmatory out so that as soon as we trip a condensate pump or we lose a feed pump, we'll start running back recirc immediately.

MEMBER ABDEL-KHALIK: And the reason for that is?

MR. WILLIAMS: To avoid a scram on the level.

MEMBER ABDEL-KHALIK: Thank you.

CHAIR BANERJEE: You had also some changes for the RHR pumps, didn't you? I'm trying to recall vaguely.

MR. PAGODIN: Yes. The changes on the RHR -- John Schleiker, do you want to talk about that?

MR. SCHLEIKER: My name is John Schleiker.

We changed the way the logic is wired on the RHR pumps to avoid a vulnerability to fire induced cable damage. Logically it performs the same way.

CHAIR BANERJEE: Can you explain what you did there? This is an Appendix R --

MR. SCHLEIKER: Yes.

CHAIR BANERJEE: -- concern I think.

MR. SCHLEIKER: Yes, I can.

CHAIR BANERJEE: Just briefly. You're not going to treat this somewhere else, are you, Appendix R.

MR. PAGODIN: No.

CHAIR BANERJEE: So you may as well.

MR. SCHLEIKER: One component of the RHR

logic is that initiation signals from both divisions of the sensing produce initiation signals for all of the RHR pumps. And that in Appendix R analyses space, that creates some problems where the cabling that crosses the divisional lines physically goes into spaces that are protected against fires that for where the other division's equipment is being relied on.

So what we did in this modification was install bypass switches and sub-fused circuits so that in the event that there was damage to those parts of the circuit, you could cut them loose by hitting the bypass switches and then operate your RHR pumps like they're from the control room as desired to cope with the Appendix R fire.

CHAIR BANERJEE: So what does that guarantee? You have at least one train available.

MR. SCHLEIKER: Before EPU our Appendix R analyses was able to show that we were able to keep suppression pool temperatures under the limits with only RHR pump available and alternating between the two units. For a EPU with the higher decay heat loads we needed to have additional suppressionable cooling capability so we protected the function of additional RHR pumps with this engineering change. So now the suppression pool temperatures are quite a bit lower because we can keep cooling in service continuously on both units at the same time.

CHAIR BANERJEE: So what is the maximum bct temperature you come to in Appendix R calculations then?

MR. PAGODIN: We have on a future slide.

CHAIR BANERJEE: Oh, you're going to show us that?

MR. PAGODIN: Yes. Suppression for water temperatures.

MR. SCHLEIKER: Right. Did you mean suppression for water temperature or --

CHAIR BANERJEE: No, no. The BCT.

MR. SCHLEIKER: For Appendix R. I don't know the answer to that.

MEMBER MAYNARD: Well, actually, I would think this results in very positive enhancement. Because before for Appendix R requirements you had to be able to rely on one pump for each unit and switching back and forth. And now you can have one in each unit. I would think that would save operator action and a number of other things in having to switch back and forth.

CHAIR BANERJEE: The only reason I'm asking this question is that even with the modifications made in another plant, Vermont Yankee, the BCT temperature came very close to the limits.

MR. PAGODIN: We can get that.

CHAIR BANERJEE: Yes, I'm sure it's p-cokay. Otherwise it would have been flagged by somebody.

MR. PAGODIN: Yes. I know we have it. It wasn't part of the presentation, but we'll pull up that number.

MEMBER MAYNARD: Yes. I would think that if one was able to do it at the little bit power have sharing it half time, that one continuously should be able to. But you can get that number, yes.

CHAIR BANERJEE: Okay. Sorry.

MR. PAGODIN: As far as p-clad temperatures, I'm not aware of any numbers that are close to the limits.

CHAIR BANERJEE: The limits are low for Appendix R, remember. It's not 2200 Fahrenheit.

MR. PAGODIN: But we will get that number.

CHAIR BANERJEE: Yes.

MR. PAGODIN: Okay. The next two modifications that are listed on here relate to our steam dryers and steam dryers instrumentation. And we have a specific presentation on the dryers and the instrumentation. We'll cover it all a little later.

The high pressure turbines that I mentioned earlier we will be replacing those to increase the flow area and reduce the throttle pressure to accommodate the power uprate.

The last two that are on here are, and I'll talk about our implementation schedule on the next slide, but the reactor feed pump turbines we will be replacing in order to be able to get the higher feed flow that we need for the second phase of our power uprate where we go to the 113 percent. The first phase for 107 percent we would not need that change.

And additionally, as we get to the higher feed flow and condensate flow we've determined that we need to add an additional condensate flow and demineralizer to our existing equipment to accommodate the higher flows and provide additional cleanup.

CHAIR BANERJEE: Going back to the steam dryer instrumentation, the Unit 1 dryer has instrumentation installed right on it, but Unit 2 doesn't, correct?

MR. PAGODIN: Yes, that's correct.

CHAIR BANERJEE: Now if you look at your CPPU implementation schedule, I guess we call it the CPPU, you go up 7 percent with Unit 1 but then you do the full 13 percent with Unit 2. And then you implement later on the full 13 percent. So it seems that while you'll get information about the first 7 percent coming directly from these strain gauges or whatever, the way you've got it scheduled you're going to take Unit 2 up to 13 percent without a fully instrumented -- you just have instrumentation in the steam lines, right? So what was the logic for doing that instead of the other way around?

MR. PAGODIN: John is specifically going to address that in our steam dryer presentation.

CHAIR BANERJEE: Okay.

MR. PAGODIN: Just hold that question and we'll get to that.

CHAIR BANERJEE: Okay.

MR. PAGODIN: Okay?

CHAIR BANERJEE: One final question on this slide. I assume that you have lots of things to do with your ultimate heat sink. You're going up actually 13 or 14 percent. So you show nothing there that you're doing.

MR. PAGODIN: That's the next slide.

CHAIR BANERJEE: Oh, is it the next slide or something?

MR. PAGODIN: Right. It was on the third one on the first slide. The one before that.

CHAIR BANERJEE: Oh, okay.

MR. PAGODIN: That's where I mentioned that we plugged some of the nozzles into our sprays.

CHAIR BANERJEE: Okay. So you change the logic and got highest sprays, or whatever.

MR. PAGODIN: Yes. The other part of that modification was that we had a single failure in our existing design where we had a motorized valve, a motor operated valve in the bypass line to the spray rays. And a single failure of that valve where it failed in the open position would preclude us from using one loop in operation to remove that heat.

So what we've done is we added an additional manual valve that in bypass line to allow us to go out. And we've analyzed it for a three hour operator action to go out and close that manual valve. That restores the second division of flow out into the spray pond and gives us the additional capacities.

CHAIR BANERJEE: You've modified the sprays themselves so that you get the highest sprays or something?

MR. PAGODIN: By plugging some of the nozzles, yes.

CHAIR BANERJEE: And that gives you enough heat transfer?

MR. PAGODIN: That's correct. That, and the use of the two divisions.

CHAIR BANERJEE: And even under very humid conditions it works?

MR. PAGODIN: That's correct.

CHAIR BANERJEE: There's that calculation. You've tested it, I presume?

MR. BARTOS: We have done spray pump tests, yes.

CHAIR BANERJEE: Okay. Okay. Not just

a calculation? These are hard things to calculate.

MR. PAGODIN: Okay. I think we have covered this particular information. This is our implementation stepping.

MR. WALLIS: Will it not make snow in the winter?

MR. PAGODIN: I'm sorry?

MR. WALLIS: When it's 20 or 30 below and it's windy, do you make a snow storm or do you make spray?

MR. PAGODIN: Well, in the 20 below scenario we wouldn't need to spray because the water is cold enough, we can --

MR. WALLIS: The ultimate heat sink-- I mean the ultimate heat sink?

MR. PAGODIN: I understand.

MR. WALLIS: But you still wouldn't need to --

MR. PAGODIN: But we wouldn't need to use the sprays because initially the water would be cold enough.

MR. WALLIS: Then you'd melt the ice?

MR. PAGODIN: That's right.

MR. WALLIS: But eventually you'd be spraying, wouldn't you?

MR. PAGODIN: Eventually we would need the sprays.

MR. WALLIS: I was just wondering if you make snow or -- I'm sort of curious. I suspect that you would make it. You know, the winds blowing and you've got this spray and there's some fine particles, you would.

MEMBER SIEBER: It'll never get that cold again.

CHAIR BANERJEE: This is not Vermont.

MR. WALLIS: Well, it's pretty cold there, too.

MEMBER SHACK: Twenty below is pretty unusual.

MR. PAGODIN: Yes. Graham, the thing I would say about things like that is that they really become self-correcting. Because even if you got freezing --

MR. WALLIS: It melts later on.

MR. PAGODIN: -- then you get more heat and more flow in the line.

MR. WALLIS: I think so, yes.

MR. PAGODIN: And we've seen that in our cooling towers as well where we get ice build up in the cooling towers it gets to the point where it adds so much heat --

MR. WALLIS: What you don't want is plugging of the sprays somehow by freezing. That's what you want to avoid.

MR. PAGODIN: That's correct. And we have pretty much --

MR. WALLIS: Bringing them back and so on.

MR. PAGODIN: -- actions we take to prevent freezing in those sprays.

MR. WILLIAMS: In the wintertime we bypass the water flow to the pond. We don't put any water through the sprays at all. We have limitations. If air temperature is below 35 degrees or the water temperature is below 60, we will not spray. We will just bypass the water back to the pond.

Generally we don't spray until we get up above 70 degrees in the pond. So I don't know if we're getting ice or snow made out of that.

CHAIR BANERJEE: And these are all

seismic qualified?

MR. WILLIAMS: Yes.

CHAIR BANERJEE: I always worry about the ultimate heat sink. Yes.

MR. PAGODIN: The schedule shows our first 7 percent increase following the outage in 2008, the spring of 2008 and then the full power uprate, as you mentioned, in 2009 on Unit 2.

The primary driver for this schedule as far as the 9 and 10 implementation of the second 7 percent increase or the full increase was really the availability of the feedwater pump turbines and the time it takes to get those. It also allows us the option of monitoring the plant at a lower power level for an extended period of time and operating it the first 7 percent. So there's an advantage there with the first uprate.

The original schedule had us put the 7 percent on both units. Unit 2 was supposed to be the lead unit. However, when we made the decision to replace the steam dryers, we also deferred installation of our high pressure turbines and deferred the initial installation to 2008 time frame.

CHAIR BANERJEE: Have you taken delivery of the dryers?

MR. PAGODIN: No. The dryers will be delivered at the beginning of December.

CHAIR BANERJEE: Okay. And they'll be installed in your 2008 --

MR. PAGODIN: Spring 2008 outage, that's correct. It actually gets delivered in two halves. So after it's delivered, we'll get it up on the refuel floor. There's an assembly that's required to be done and installation of the instrumentation and testing, obviously. And we'll talk about that.

MEMBER SIEBER: Do you have to cut the old one apart to get it out?

MR. PAGODIN: Yes, we do. The new dryers will be shipped to us in boxes that we will also use as disposal containers for the old ones.

MEMBER SIEBER: To get rid of the old ones.

MR. PAGODIN: So the old ones will be cut in half to fit in those boxes, and then we have a storage facility, basically a large concrete structure that we have on site that will be used to store until decommission.

CHAIR BANERJEE: Your old dryers were instrumented, too, weren't they?

MR. PAGODIN: Yes. And John will talk about that.

Okay. So some of our conclusions here. The analyses that we've done has demonstrated that all safety aspects of our power uprate increase in thermal power were thoroughly evaluated.

Our evaluations were performed with NRC approved and industry accepted methods.

There were no new design functions that required modifications necessary for safety related systems.

And our CPPU impact on systems and components were reviewed to ensure that there were no significant safety system challenges.

We've done a thorough analyses of operator actions.

Our plant design equipment performance.

We've involved our system engineers throughout the initial phasing, the scoping of our assessment and as well, they're doing a final impact analyses before implementation.

MR. WALLIS: This review you refer to,

is that entirely an internal review or did you bring in people from other BWR plants with experience with uprates to look at what you've done, see if you've missed anything, that sort of thing?

MR. PAGODIN: Yes. We have had several self-assessments and independent assessments. John, do you --

MR. WALLIS: You have external reviews as well?

MR. BARTOS: This is John Bartos.

Yes, we have. We have had two external reviews. We've gone into different contractors to look at the--

MR. WALLIS: Did they find things that you didn't find yourselves?

MR. BARTOS: There were no major findings, but they did give us some good suggestions which we evaluated and implemented a number.

CHAIR BANERJEE: Some of your analysis was presumably done by AREVA, right? And with their own methods and stuff. So that will arise later on?

MR. BARTOS: Yes, that's a specific presentation. Yes.

MEMBER SIEBER: That's related to the

fuel. Everything else is done by GE or yourselves.

CHAIR BANERJEE: But your ATWS, was that done by GE methods or AREVA did that was I seem to remember.

MR. BARTOS: This is John Bartos again.

Yes, GE did that.

CHAIR BANERJEE: Why did they use MICROBURN then? That's a steady state code? It'll come up, I'm sure.

MR. PAGODIN: John Giositts?

MR. GIOSITTS: I am John Giositts.

Since our stretch uprate we've used GE for performing the ATWS analyses. And the AREVA methods of code you mentioned, MICROBURN is a steady state code. And there aren't specific approved applications for AREVA methods for ATWS. And that's why we used the GE ATWS analyses, the ODIN code for ATWS.

CHAIR BANERJEE: Okay. I'm sorry. I was under the impression that you had used MICROBURN. But maybe I read that.

MR. GIOSITTS: We used MICROBURN for the other fuel related analyses other than ATWS.

CHAIR BANERJEE: But not ATWS?

MR. GIOSITTS: No.

CHAIR BANERJEE: We'll get to it when we talk about ATWS.

When will we talk about ATWS? Will it be under -- is it under 5 and 6 or what?

MR. PAGODIN: Yes. Five and six. Yes.

CHAIR BANERJEE: And we'll also talk about ATWS and stability?

MR. GIOSITTS: Yes.

CHAIR BANERJEE: Okay. And mitigation actions at that point?

MR. GIOSITTS: Yes.

MR. PAGODIN: Okay. In closing, I'd just like to point out two other significant margins that we have in our analysis. One I've already mentioned where we will very seldom actually operate at the 3952 megawatts thermal. So we will have margin to operating at that level.

Additionally, when we did our safety analysis, all of our safety analysis was done using 2 percent instrument inaccuracy. So although we have the leading edge flow meters will have the .6 percent accuracy, our safety analysis was done assuming the full two percent.

MEMBER ABDEL-KHALIK: So based on historical weather data, what would be the maximum thermal power that you would operate at in the summer to get 1300 megawatts electric?

MR. PAGODIN: The maximum that we would operate at is 3952 megawatts thermal.

MEMBER ABDEL-KHALIK: And you said you'll have margin to it, but --

MR. PAGODIN: What I said was that most -- like in the wintertime, we would not operate anywhere near the 3952.

MEMBER ABDEL-KHALIK: But in the summertime you expect to operate at 3952?

MR. PAGODIN: We would unless we became condenser limited by vacuum.

MEMBER SHACK: Right.

MR. PAGODIN: So we have to make sure that we have adequate margin, you know, the condenser parameters.

So, again, even in the hottest part of the summer we may not be able to operate at 3952.

And John, do you have a better way to quantify that?

MR. BARTOS: This is John Bartos.

We would probably get close to our operate at 3952, but it would only be for a matter of probably two or three hours a day during the peak temperature periods of the day. And once the temperature started to fall and cool off, we would then fall back down below 3952. Matters of hours.

MEMBER MAYNARD: I understand and appreciate your margin here for now. But reality is if approved, you're allowed to operate there. And if you ever change your generator, that's not something you'd have to come back for approval. So while it is real margin, it's not margin I don't think that we can really take into account.

MR. PAGODIN: That's correct. Right.

MR. WALLIS: How accurately can you measure thermal power?

CHAIR BANERJEE: As accurately as you can measure flow.

MR. WALLIS: Because you said 3952. I just wonder how accurate that two is.

MR. PAGODIN: Well, we measure power through a heat balance, which is --

MR. WALLIS: Yes, but can you really get that as close -- try to get that as close as one point in 3900, can they?

MR. PAGODIN: And, again, we have instrument uncertainty that's involved in that analysis.

MR. WALLIS: Which is bigger than that.

MR. PAGODIN: We actually did the analysis for 4032 megawatts thermal.

MR. WALLIS: So do you have some allowance for that uncertainty, don't you? You have a margin or something? Or when you say 3952 is this the average measured or without including the uncertainty or what? How do you take account of that heat balance uncertainty?

MR. PAGODIN: The safety analysis is done assuming that there's a 2 percent inaccuracy here.

MR. WALLIS: Right.

MR. PAGODIN: So we actually analyze at the 4,032 megawatts thermal.

MR. WALLIS: That's quite a lot. It's another 80 megawatts.

MR. PAGODIN: About that. That's correct.

MR. WALLIS: When you say you're

operating at 3952, what do you mean? Do you mean it's somewhere between 3930 and 3960 something or what? I mean, what's the uncertainty on that figure?

MR. PAGODIN: By the instrument inaccuracy it could be as much as .6 percent.

MR. WALLIS: Point six percent? Okay.

MR. PAGODIN: By the existing instrumentation.

MR. WALLIS: But taking account of the temperature and flow uncertainties.

MR. PAGODIN: That's correct.

MR. WALLIS: You do very well.

MR. PAGODIN: That's what our current license would be. The leading edge flow meter is an instrument in accuracy of 0.6 percent.

MR. WALLIS: And most of that's in flow?

MR. PAGODIN: That's correct.

CHAIR BANERJEE: Actually, the flow if things go wrong could cause venturis eruption and it would actually give you a lower flow for the -- so you'd end up actually under predicting the flow based on that.

MR. WALLIS: So you don't rely on the

venturis for the high accuracy? You're using a scanning method or something, or you using --

MR. PAGODIN: The venturis are at two percent instrumentation, and that's what our analysis based on.

MR. WALLIS: Two percent is quite a bit in terms of error.

MR. PAGODIN: And that's why we previously implemented that instrument uncertainty change that we made --

CHAIR BANERJEE: Couldn't you reduce that by some time-of-flight method? Anyway, this is accepted.

MR. WALLIS: I think it is reduced. You have an improved instrument, it gives you the point set.

CHAIR BANERJEE: You have that for calibration purposes?

MR. PAGODIN: Yes.

CHAIR BANERJEE: All right. Shall we move on?

MR. PAGODIN: Okay.

MR. WALLIS: I was just wondering what we were approving when we approve 3952. Maybe that can be absolutely clarified somehow. This is that you're not going to exceed 3952 or that this is some nominal value we're giving you and it might go to 3980 sometimes, or what are we really approving?

MR. PAGODIN: Jim, do you want to talk about how that's concluded in our license?

MR. WILLIAMS: Yes. 3952 is what we're going to be licensed to operate at.

MR. WALLIS: You mean absolute maximum including uncertainty or --

MR. WILLIAMS: No. That's indicated power that we have.

MR. WALLIS: Indicated power?

MR. WILLIAMS: Yes. Thermal indicated power.

MR. WALLIS: So the real power could be bigger than that by .6 percent?

MR. PAGODIN: By 2 percent.

MR. WILLIAMS: By 2 percent.

MR. WALLIS: Two percent? That's a significant amount.

MR. PAGODIN: Our analysis assumes instrumentation there could be as high as 2 percent.

MEMBER SHACK: But you'll actually

operate with a .6 percent error?

MR. PAGODIN: Right. That's correct. As long as the leading edge --

MEMBER SHACK: As long as the leading edge is working.

MR. PAGODIN: -- instrumentation is operable, it would be at .6 percent.

MR. WALLIS: And if the leading edge stops working, then you back off?

MR. PAGODIN: It stops working, then we have the venturis, which are 2 percent which is also within our license.I don't think it's a big issue. I think when you have these sort of numbers that are correct to such great accuracy, I'd like to know what I'm approving. I'm still not quite clear.

MR. PAGODIN: Our operating license will allow us to operate at an indicated power of --

MR. WALLIS: Indicated power?

MR. PAGODIN: -- of 3952, as indicated on our power --

CHAIR BANERJEE: Plus or minus two percent, that's what we're --

MR. PAGODIN: Plus or minus two percent.

MR. WALLIS: And the power indication

actually gives you that accuracy? There's a digital power thing that says 3951 or something, is there? It's not one of these dials, is it?

MR. PAGODIN: It actually goes to decimal points and --

MR. WALLIS: It says 3951.693 or something?

MR. PAGODIN: I don't think there's that many digits.

MR. WILLIAMS: The heat balance does go out one decimal point on the indications.

MR. WALLIS: Well, that's enough then.

CHAIR BANERJEE: Okay. Are we done with this then?

MR. WALLIS: I didn't see this in the simulator.

CHAIR BANERJEE: Thank you. You're in fact ahead of time, which is wonderful. It never happened before.

MR. WALLIS: That's because you allowed him ten minutes with no questions.

MR. PAGODIN: I think the record would show I didn't make ten minutes.

CHAIR BANERJEE: Then we move on to the

next. Is that going to be Chris Hoffman? Great.

MR. WALLIS: Well, this gets interesting, the next one.

CHAIR BANERJEE: Now you have only 15 minutes, but I'm sure we can stretch it out, even to the break.

MR. HOFFMAN: Good morning. I'm Chris Hoffman. I'm the Manager of Nuclear Fuels Analysis for PPL Susquehanna. There are four groups of nuclear fuels and analyses. The functions that they perform are:

Nuclear fuel procurement, which is uranium conversion and enrichment service procurement;

Plant analysis to include probabilistic risk assessment. And you'll be hearing from Mr. Chett Lehmann later today on that;

Nuclear Fuels Engineering which performs fuel and core design. Also interfaces with AREVA for licensing, and;

Reactor Engineering, which is an engineering technical arm that supports for operation to include augmented staffing in the control room when the reactor is being reheated.

There are going to be two types of graphs that I'm going to be showing today. The first one is a time-based power versus time and the second one will be power-flow map, which you've seen a little bit of in earlier in Rick Pagodin's presentation.

The power versus flow map is better at showing when we're actually moving control rods and when we are adjusting reactor power with flow or balancing fission product build-ins with flow. So if you have specific questions on when we are using rods, when we are using flow to maneuver power, it's probably best to save those for a power-flow map.

The slides that I'm going to show you are at current licensed power. There will be some minor differences with EPU. The primary differences will be the number of iterations that we will need to take in order to finally set the control rod pattern. And Mr. James Williams is going to be assisting me in certain points here.

MR. WALLIS: Now you said at current rated power? So a 100 percent on this plot is how many megawatts?

CHAIR BANERJEE: Thirteen percent less

than 1350.

MR. HOFFMAN: 3489.

MR. WALLIS: So on all these figures that power level is based on current power on this?

MR. HOFFMAN: That is correct.

MR. WALLIS: So how do you ever get to higher power?

MR. HOFFMAN: When we get to the power-flow may I'll discuss how we get to --

MR. WALLIS: You're going to tell us that.

MR. HOFFMAN: -- higher power.

A typical reactor startup. We start the reactor out in what is known as bank position withdrawal sequence or BPWS. BPWS is designed to minimize the work of control rods on startup as part of the mitigation process for control rod drop accident, which is one of our analyzed accidents.

We take the reactor critical on BPWS. We increase reactor power by following the BPWS sequence until we reach about 15 percent reactor power, at which point after we have warmed the turbine, we place the generator on line.

We then increase reactor power to 20

percent, we'll replace feedwater heating and service. The reason why we are doing this at 20 percent is to have all of our feedwater heating and service before we go above 25 percent. Twenty-five percent is the point where the technical specifications require us to monitor fuel thermal limits.

Between the 20 percent power level that you see and the next plateau, we're going to come off of the BPWS sequence and start pulling toward the targeted control rod pattern. This control rod pattern has been developed by Reactor Engineering based upon the design work that was performed by Nuclear Fuels Engineering. It is approved by Operations management and Work Management before it is executed.

At 30 percent reactor power we place the second feed pump in service, the third condensate pump in service. And then we increase reactor power to 38 percent power.

At 38 percent power, which is prior to exceeding 40 percent power, we scram time test our rods. We have 185 control rods, each one is tested to make sure that its scram time response is less than the tech spec values so that we're ensured that all of our thermal limit monitoring, particularly MCPR is correct. And it takes us about 26 hours to perform this testing.

After the testing is complete we go up to 50 percent reactor power where we place our third feed pump in service, and our fourth, which is our final condensate pump in service.

And, again, mostly pulling control rod with some flow. And you'll see this on the power to flow map the slide, we increase reactor power to 75 percent where we perform a calibration of our in-core detectors. The detectors or local power range monitors commonly referred to the LPRMs.

To calibrate the LPRMs, and there are 43 strings of LPRMs, four detectors in axial locations for a total of 172 in-core detectors in fixed positions, we use the traversing incore probe or TIPs. TIPs is a very sensitive system. It is a moveable detector that can go up through each one of the LPRM strings. It is not left in the core because of its sensitivity and is only placed in the core when necessary to calibrate the LPRMs or to check out another reactor physics parameter such as if we wanted to look at where the tip of a control blade is.

We calibrate the LPRMs with TIPs. We perform some final feedwater tuning. And then we increase reactor power to about -- we're in this 75 not 80 percent reactor power range --

MR. WALLIS: This TIP, there's a long rod that goes up through the core with the TIP on it?

MR. HOFFMAN: It's a cable.

MR. WALLIS: A cable.

MR. HOFFMAN: It's a cable. It's a flexible cable, there are five --

MEMBER SIEBER: With a detector on the end.

MR. HOFFMAN: Flexible cable, we can select the LPRM strings.

MR. WALLIS: Well, is it driven from the top or the bottom?

MR. HOFFMAN: Driven from the bottom.

MR. WALLIS: From the bottom. And there's a penetration for the vessel then?

MR. HOFFMAN: Yes.

MR. WALLIS: For the TIP? Okay.

MEMBER SIEBER: You should go under there sometime. There's penetrations for everything. There's hundreds of them.

MR. HOFFMAN: It's interesting to see all of the TIP tubing and --

MEMBER SIEBER: Yes, right.

MR. HOFFMAN: We increase reactor power until we reach about 95 percent power, or until we reach the top end of our power to flow map. We're authorized --

MEMBER ABDEL-KHALIK: What's involved in the feedwater tuneups? What does that mean?

MR. HOFFMAN: Jim?

MR. WILLIAMS: My name is James Williams.

In the feedwater tuneups we get to about 75 percent reactor power and we give the feedwater level control systems perturbations, three to five percent up and down, and then we do individual reactor feed pumps three to five percent up and down in order to --

MEMBER SIEBER: To tune the instruments.

MR. WILLIAMS: -- tune the instruments.

MEMBER ABDEL-KHALIK: Thank you.

MR. WALLIS: So "tune" means calibrate or check, or what?

MEMBER SIEBER: You're tuning the controllers really.

MR. HOFFMAN: Tuning the controllers. Finding the optimal --

MEMBER SIEBER: So they don't hot --

MR. HOFFMAN: -- control ban for the controllers.

MEMBER SIEBER: Yes.

MR. HOFFMAN: So we increase reactor power to 95 percent or the upper end of our flow range and 107, just short of 108 million pounds per hour. Because this is a beginning of cycle startup, there are not a fission product poisons when we start. Throughout the time fission product poisons are building in, primarily xenon-135. And when we reach the limits of our flow we then take a reduction in reactor power to 75 percent so that we can reset, pull some additional rods.

This gets to Mr. Wallace's question earlier about more rod pulls with extended power uprate conditions. The answer is we will still be pulling our control rods at the reduced power levels. Primarily the maneuvers that we will use at the upper power levels will be on flow, which is a more global change in the reactor.

CHAIR BANERJEE: But you have a very small flow window, right, at the extended power?

MR. HOFFMAN: That's correct.

CHAIR BANERJEE: So will you still have enough room to maneuver?

MR. HOFFMAN: We will still have enough room to maneuver. What it will take, is it will take more of these resets. And I'll show you a reset on the power to flow map.

After setting control rods, we then flow up towards 100 percent power. We may adjust a few deep rods at 95 percent power. A deep rod is a rod that is more than two-thirds of the way in core. Deep rods give global power changes rather than local power changes.

We then reach 100 percent power for the first time. And as fission product poisons, primarily xenon, builds in we compensate by increasing reactor coolant flow, recirc flow.

If we reach the point where, again, we're at the upper end of the power flow map, 107/108 million pounds per hour, we will take another reduction in reactor power to pull some control rods. But, again, these will be deep rods.

CHAIR BANERJEE: How much reduction do you need to take to pull those rods?

MR. WALLIS: Five percent.

MR. HOFFMAN: What we're showing right here on the graph is the deep rod would be five percent. If we were going to be pulling intermediate rods, which are toward the middle of the core, or a shallow rod which is in the bottom third of the core, we would have to take a much larger reduction down to about 75 percent reactor power.

CHAIR BANERJEE: And what determines how much of a reduction you have to take?

MR. HOFFMAN: The fuel is monitored by a core monitoring system. The kilowatts per foot or linear generation of heat in the fuel determines how much of a reduction we need to take. That combined with preconditioning.

CHAIR BANERJEE: So give us sort of a concrete example. Take that rod there, what were you shooting for in kilowatts per foot or whatever to keep it at? Is there some licensed limit or something that you have to stay at?

MR. HOFFMAN: We have vendor guidance, which is known as REMACCS. Basically it's rules that are guidance for ramping the fuel.

CHAIR BANERJEE: Yes.

MR. HOFFMAN: What we would be shooting for is about 1½ kilowatts per foot below its precondition state.

CHAIR BANERJEE: We can get into it later.

MR. HOFFMAN: Okay. So this is timeline. Let's take a look at the power to flow --

MEMBER SIEBER: Well, before you switch, you do hand calormetrics from time-to-time through that process, correct?

MR. HOFFMAN: No, we do not.

MEMBER SIEBER: You do not? Okay. How do you know then that your power ranges come in as accurate? What do you compare that to?

MR. HOFFMAN: The power ranges permit that you're talking about is the average power range monitor, the APRM.

MEMBER SIEBER: Right.

MR. HOFFMAN: Okay. The APRM is

routinely calibrated to the heat balance.

MEMBER SIEBER: Okay. That's calormetrics.

MR. HOFFMAN: But it--

MEMBER SIEBER: Calormetric power of calculation. Okay. When do you do that. You must calibrate a couple of times through that increase. When do you do it?

MR. HOFFMAN: Jim?

MR. WILLIAMS: Yes. We do that at least once a day. And every time we do a rod pattern change, we'll do another one.

MEMBER SIEBER: Okay.

MR. WILLIAMS: Because when you move control rods --

MEMBER SIEBER: You change your flux?

MR. WILLIAMS: -- it changes your flux distribution in the core.

MEMBER SIEBER: Right.

MR. WILLIAMS: And it changes your indications on the APRMs.

MEMBER SIEBER: Okay. And what is the accuracy of the calormetric? It depends on every instrument that has input to that calculation, right?

MR. WILLIAMS: Yes.

MEMBER SIEBER: Do you know what that overall accuracy is?

MR. WILLIAMS: I do not.

MEMBER SIEBER: Does anybody?

MR. BOESCH: Yes. I do. This is Bob Boesch. I'm Ops Training Manager at Susquehanna.

Yes, it falls within the uncertainty of the safety analysis. So that would be two percent on venturis, .6 percent on --

MEMBER SIEBER: Okay. So you have not only instrument error, but the error associated with feedwater temperatures, flow meters and everything that go into that calculation, right?

MR. BOESCH: That's correct.

MEMBER SIEBER: Because you set your power range meters in accordance with what that calculation tells you the power is?

MR. BOESCH: That's correct.

MEMBER SIEBER: Okay. Just so that's clear. There's more factors in the accuracy of the power ranges instrument and to adjust the accuracy of the instrument itself.

MR. HOFFMAN: And let's take a look at this in power to flow space. Again, this is the same startup that you saw in the time-based profile, only now it's in power to flow phase.

CHAIR BANERJEE: Does everybody have a copy of this so that you can read it?

MEMBER SIEBER: That you can read?

MR. WALLIS: Now we've got to be sure, and you told us, this is based on current power level?

MR. HOFFMAN: That's correct, current power level.

MR. WALLIS: So you're going to go into the restricted region when you get into the power uprate?

MEMBER SIEBER: Yes, I can read it.

MR. HOFFMAN: Yes. The MELLLA line will continue.

MR. WALLIS: Right. So it would sort of help if you could have a little red region or something that shows. That's the difference between what you do now and what you're going to do.

CHAIR BANERJEE: See, if we extrapolate that line, it's at a 100 percent flow, you'd hit a

120, I presume?

MEMBER SIEBER: Or later, yes.

CHAIR BANERJEE: Sooner or later.

MR. WALLIS: I think it's cut off at about the right -- it's 113 we're talking about, isn't it?

MEMBER SIEBER: You'd run out of flow after a while.

CHAIR BANERJEE: No. Well, first of all, what is this power here? Is it 100 percent OLTP, originally licensed power?

MR. HOFFMAN: No. This is 100 percent current thermal licensed power.

MR. WALLIS: This is current.

CHAIR BANERJEE: That's current? So 100 percent here is our current.

MR. WALLIS: So 113 is the --

MEMBER SIEBER: A 100 is current.

CHAIR BANERJEE: I'm confused on this.

MR. WILLIAMS: James Williams.

The power to flow map, today we operate at 100 percent power at 3489. When we go to operate at extended power, we're still going to operate at 100 percent. But a 100 percent then will be 3952.

So from my --

CHAIR BANERJEE: Gut on this map it will be where? That 13 percent --

MR. WALLIS: 113.

CHAIR BANERJEE: 113.

MEMBER SIEBER: Well, the map will change when they change the --

MR. WALLIS: On this map the new licensed limit will be 113, won't it?

MR. WILLIAMS: No. The new map, 100 percent power will be 3952.

MR. WALLIS: Yes. But on this map if you wanted to show the new power on this map, it would be over 113?

MR. WILLIAMS: That's correct, Graham. It would be 113 percent. The MELLLA line that's drawn on there, that would just continue to extend up and the flow window would get narrower. The right hand side would stay at the 108 million pounds per hour as seen on the bottom. The left hand flow window at the 100 percent power would be --

MR. WALLIS: Presumable these scram trip setpoints will be extrapolated in some way as well?

Are you ever going to show us what it looks like with the power uprate in detail?

MEMBER SIEBER: Well, you set the power level from the calormetric calculation and then --

CHAIR BANERJEE: So this is just based on what it is today, right?

MR. HOFFMAN: That is correct, this is just based on what it is today.

CHAIR BANERJEE: Would you show us this at some point as to what it would look like if we did the uprate?

MR. HOFFMAN: We will do that.

CHAIR BANERJEE: So that we have a comparison.

MR. HOFFMAN: We will do that. It will not be to this detail.

CHAIR BANERJEE: That's all right.

MR. HOFFMAN: We do have other power to flow maps in other presentations. We will show those to you. It will not be in this detail.

MEMBER SIEBER: I take it you probably haven't mapped out as far as what escalation will be in that kind of detail, right, at this point?

MR. HOFFMAN: There are some variations

from cycle-to-cycle --

MEMBER SIEBER: Right.

MR. HOFFMAN: -- based upon the actual licensed core design.

MEMBER SIEBER: Right.

MR. HOFFMAN: Since we have performed numerous scoping studies for extended power uprate, we have a good picture of what it will be. But as far as --

MEMBER SIEBER: You don't have the final core design yet there, right?

MR. HOFFMAN: That is correct.

MEMBER SIEBER: Okay.

CHAIR BANERJEE: But if you went into the uprate case, you would just extrapolate the MELLLA boundary up to 113, I presume?

MR. HOFFMAN: That is correct.

MR. PAGODIN: If you look at slide 9 that was in my presentation.

CHAIR BANERJEE: Yes.

MR. PAGODIN: You'll see that that black region at the top is the additional area that gets added to the power to flow map.

CHAIR BANERJEE: Right. And that part of

it will not be restricted then, right, after you extrapolate that up to 113? So it'll give you at 100 percent roughly 113?

MR. HOFFMAN: That's correct.

CHAIR BANERJEE: Yes. When you have an operating range of maybe 8 percent or something in terms of flow maneuvering --

MR. HOFFMAN: Core flow, that's correct.

CHAIR BANERJEE: Yes. Okay.

MR. HOFFMAN: Okay. Walking through the startup. Again, we take the reactor critical on bank position withdrawal sequence. We get some increase in flow as we get buoyancy effects prior to significant two phrase. We continue to fall on bank position withdrawal sequence until we're somewhere around 20 percent power. There we start heading toward our target rod pattern.

This horizontal line that you see at 38 percent power is again the 26 hour hold that we have for scram time testing. And the reason why it's horizontal; we're increasing flow but not increasing power is because that's a long duration hold and we're just balancing fission product building.

We increase with rods flow, rods until

we get up to the 75 percent hold point where we perform our LPRM Cal and feedwater tuning.

Increase with rods. And then you'll notice that from just short of 80 percent reactor power up to the 95 percent max flow point, we're doing it primarily on flow. Lines that go up and to the left are indicative of slow increases.

At that point we have ---

MR. PAGODIN: And to the right. Up and to the right. Right.

MR. HOFFMAN: Up into the right.

CHAIR BANERJEE: So this is between the two red lines, right?

MR. HOFFMAN: Yes. The blue line that is going up and to the right between the two red lines.

CHAIR BANERJEE: Right.

MR. WALLIS: When the operators do this, they plot this with a pencil or something or with a pen?

MR. HOFFMAN: They do plot it. They manually plot it.

MR. WALLIS: Okay. They manually plot each point. They follow on a graph like this?

MR. HOFFMAN: That's correct. The

reactor engineer also follows this graph.

MR. WALLIS: Well, it comes out on your data system, too, right? The equivalent of that chart?

MR. HOFFMAN: Jim?

MR. WILLIAMS: James Williams.

The chart is not printed out, but the digital values are.

MR. WALLIS: Right.

MR. WILLIAMS: And then the operators will take the digital values and actually plot them on a power flow.

MR. WALLIS: And put them in? Right. Okay.

MR. HOFFMAN: And the red line that you see working its way back from 95 percent reactor power is indicative of a flow decrease. Because now we have enough fission products built in that we can pull additional control rods, we bring the unit back down from 95 percent power to 75 percent power. Increase reactor power with rods, which is that vertical line that you see moving upward. And then we flow back up to the 100 --

MR. WALLIS: And the reason you don't

just go up vertically directly is what?

MR. HOFFMAN: Again, resetting the control rods at lower power, we're making global power changes with reactor recirculation core flow at the higher power distributes the power more broadly throughout the core rather than a localized power increase that you would get from rods.

CHAIR BANERJEE: So you've lost me.

Now you're on that blue line at the end of it. Now where do you go?

MEMBER SIEBER: Going down the red track.

MR. HOFFMAN: You're on the blue line.

CHAIR BANERJEE: Yes.

MR. HOFFMAN: And you take the red track back.

CHAIR BANERJEE: Yes. And then you go up and you take the red track.

MR. HOFFMAN: Then you increase with rods.

CHAIR BANERJEE: All right. So you switch.

MR. HOFFMAN: And then you take the red track back.

MR. WALLIS: And that's how far back down you go before you go up again?

MEMBER SIEBER: Yep.

MR. WALLIS: I mean you could set the rods at any point on that red track, you could pull the rods, right?

MEMBER SIEBER: That's true.

MR. HOFFMAN: What sets how far back down we go is the REMACCS preconditioning rules.

CHAIR BANERJEE: What does that mean, reconditioning? Is that the fuel has to be treated in a certain way? All right. We talk about that later.

MR. WALLIS: Plotting core interaction business so that --

MR. HOFFMAN: That's correct. It's the interaction between the fuel pellet and the cladding.

CHAIR BANERJEE: It's somewhat mechanical --

MR. WALLIS: It's PPI.

MR. HOFFMAN: It's the mechanical interaction between the pellet and the cladding. When you heat the pellet, the pellet swells, it swells into the cladding. And maybe give the cladding the opportunity to relax and accommodate the pellet swell.

MEMBER SIEBER: Yes. Many years ago it was called power shock. Before they knew this was the phenomenon, they had a lot of fuel failures due to axial cracks.

DR. DIAMOND: Are there also tech specs that limit the operations so that you have to follow a particular down power route, or is it operational constraints from REMACCS which determines?

MR. HOFFMAN: Primarily operational constraints from fuel preconditioning.

MR. WALLIS: You would think it would go up slowly without going all the way back down in flow. Maybe just go up slowly and adjust the rod slowly.

MEMBER SIEBER: It's the rate of increase that causes the damages rather than the rate of decrease.

MR. WALLIS: Is it step-wise rather than continuous? Is this from one set position to another, it's not a continuous range?

CHAIR BANERJEE: I guess this, what

you're showing us, would ge very useful to see for the uprated condition. I mean, even if it's a cartoon --

MEMBER SIEBER: Well, it's the same.

MR. HOFFMAN: But it is essentially the same. What we would do, again in an uprated condition, is the red line where we were increasing reactor power or flow --

MEMBER SIEBER: You would go further.

MR. HOFFMAN: -- we would simply go further and then we would do a second iterative loop of the red box.

CHAIR BANERJEE: Oh, okay.

MEMBER SIEBER: Right.

CHAIR BANERJEE: So you would come back down and then go up and then go --

MR. HOFFMAN: That is correct.

MEMBER MAYNARD: You have a repositioned rod. It's not just a matter of continually moving rods in the same direction. At times you're having to reposition some rods to get it realigned to where you want to end up. And you need to get the linear heat rate down to below your preconditioned level when you're making your adjustments there before you then start increasing power again. That's why you come down in power; get your linear heat rate down around the areas where you're going to be making some rod adjustments.

MR. HOFFMAN: That is correct.

MEMBER SIEBER: Well, you got to do this sort of slowly and pretty deep because if you were just to control power with adjacent rods, you would never solve the so-called power shock problem. Because some of them the cladding would be strained throughout the maneuver. And so that's one of the reasons why they go through a pretty good maneuver to release the strain on the cladding.

MR. HOFFMAN: That's correct.

Next slide.

MR. WALLIS: Well, this is very interesting. What really concerns us is does the EPU change this in some way so that the PCI becomes more difficult --

CHAIR BANERJEE: No, because of the green line, right?

MR. WALLIS: -- More difficult to manage

or something?

MR. HOFFMAN: That's correct. The only thing that it is really changing with the EPU is the number of resets that we would have to do.

MEMBER SIEBER: And how far you go.

CHAIR BANERJEE: Except that now you'll get boxed into a little corner there. And then if you have some anticipated transient or something which suddenly changes the power level, your fuel is stuck in one little corner there, right? Because you're not in MELLLA+.

MEMBER SIEBER: Well, that's a good thing.

MR. HOFFMAN: Well, again, we would just--

CHAIR BANERJEE: It's a good thing, but--

MR. HOFFMAN: I mean, we would just simply be coming down on the rod line within the existing MELLLA boundary.

CHAIR BANERJEE: Yes, you'd come down the MELLLA boundary.

MR. WALLIS: So the comparison: This is what you do now and this is what you'll have to do with the power uprate. These are the number of maneuvering you need with rods with the present system, these are what you need with the uprate. And what's changed, is the question?

MR. HOFFMAN: Perhaps I could--

MR. WALLIS: Has something changed that really matters or is it just a bit more troublesome to you, or what? Now what has really changed is the point?

MR. HOFFMAN: What has changed is the number of iterative loops that we will have to do.

MR. WALLIS: Presumably eventually you can't keep up with the number of loops. You're changing it every day or something. But that doesn't happen with this power level.

MR. HOFFMAN: It will not happen. We can put one --

MR. WALLIS: Something like that.

MR. HOFFMAN: We could put one slide showing the effect into the fuel presentation.

MR. WALLIS: That would be useful.

CHAIR BANERJEE: Well, you need two iterative loops, perhaps, to go up right?

MR. HOFFMAN: That's correct.

CHAIR BANERJEE: Showing that. And that we can imagine fairly clearly what it looked like.

I guess then we need to address the issue of what happens to the situation if you suddenly have to change power when you're up there or suddenly the power change. But I think we can come back to that later.

This is the startup plan.

MR. HOFFMAN: Next slide.

The control rods in our reactor are divided into four sequences. We operate with one sequence of control rods in the reactor at a time. Basically one quarter of each set of rods is assigned to one sequence.

What I'm showing you here is a typical sequence exchange. We operate in a sequence between eight and 12 weeks. Every 8 to 12 weeks we exchange one set of that one-quarter of the control rods with another set. We do this so that we get an even burn on the core and we don't have corner pin build-in of plutonium in the corner pins of control bundles.

What's important here is we decrease reactor power to about 88 percent power. We then perform our scram time testing of a representative sample of control rods. It's 10 percent, that's 19 rods. That's performed by tech specs at least every 120 days.

After performing the scram time testing, we then reduce reactor power to whatever power level we need to to reach our preconditioning guidelines.

We performance the sequence exchange taking the one set of rods that are controlling and exchanging them for another set of rods that we're bringing into the core that were already fully out.

And then once the rods are set, we increase reactor power with flow.

The green line that you see there or the solid line is indicative of the low profile that was submitted, the plan that was approved by Operations, Work Management, Power Marketing. And the red line that you see there is the actual performance.

You will notice the stairstep effect on the red line. And that simply indicates where we take an increase with flow, and then we wait a while, and we take another increase with flow to give us the ramp rate that we need on the fuel.

Next slide.

The last power to flow map is indicative of how we would do a shutdown. Again, we start off in this example 100 percent power, 100 percent flow. We reduce reactor power with recirc flow to about 65 million pounds mass per hour, just short of 80 percent reactor power.

We then systematically in a preapproved manner insert control rods until we get down below the 70 percent rod line, which takes us down to about just under 50 percent reactor power, take a final decrease with flow by reducing speed of the reactor recirculation pumps. And then insert control rods until we go subcritical. And then we continue inserting control rods until we reach all rods in.

MR. WALLIS: What you do, but of course there are infinite number of ways to do it because you could step differently and still get the same end.

MEMBER SIEBER: But you can trip.

MR. WALLIS: So why do you do it this way?

MR. HOFFMAN: We do it this way because it's the most efficient way of doing it where we also clearly stay away from these stability region.

MR. WALLIS: But you could go down to whatever. You could go down to 70 and then take a step and so on?

So it's to stay away from instability?

MR. HOFFMAN: We stay away from the predesignated stability regions. And Mr. Chett Lehmann will have a presentation on stability later.

CHAIR BANERJEE: And what's above where you say it's restricted region? What bounds it there? On one side you have stability and then on top what is that? Let's say above the blue line to the left where you've got the hatching.

MR. HOFFMAN: Right here?

MR. WALLIS: The MELLLA line.

CHAIR BANERJEE: Yes. Yes. On the other side of the MELLLA line, what are the restrictions on that?

MEMBER SIEBER: Up above.

MR. HOFFMAN: Well, that is the MELLLA line. And the MELLLA line is our limit of authorization.

CHAIR BANERJEE: Right. I agree. But what is the physical limitation? Is it critical heat flux, is it LOCA? What limits that MELLLA line to where it is? There's always a reason.

MR. WALLIS: NRC approval.

MR. HOFFMAN: John?

MR. GIOSITTS: John Giositts.

The physical limitation -- well, I wouldn't call it physical. It's an analytical limitation. The analyses for all licensing analyses are only performed within the MELLLA domain which is bounded by that line. So if you were to operate in the restricted region, you'd be in an unanalyzed condition. And therefore --

CHAIR BANERJEE: Right. And what would be the physical reason it's restrictive? Is it critical heat flux, is it LOCA?

MR. GIOSITTS: The reason is we haven't analyzed there. I mean, the limits that are set that you need to meet for operation do not cover operating in that area. So therefore, your limits are invalid if you're operating there. But you really have nothing to compare to because you haven't analyzed that region of the map to operate at for normal conditions.

MR. KRESS: You can get there by further pulling the rods out?

MR. GIOSITTS: You can get there.

MR. KRESS: You can get there.

MR. GIOSITTS: But once you get there you're in the restricted region and need to get out.

MR. KRESS: You're in the region -- yes.

MR. GIOSITTS: Because you're outside your analyses bounds.

CHAIR BANERJEE: So if you were, after operating you were at 100 percent power and you wanted to shutdown after the uprate, you would run along the MELLLA line or would you do something else?

MR. GIOSITTS: Yes. If you run back in flow, if you'd reduce flow, you would run down that line.

CHAIR BANERJEE: So the analogy to do to this is that you would run along the MELLLA line and then you would drop at some point, right?

MR. GIOSITTS: Yes. Just like the blow line we've shown there that's decrease, and that's a slightly lower rod line than the MELLLA line. But if you were up on a higher rod line, like you said, if you came back in flow you would run down along that line. The MELLLA boundary is a rod --

CHAIR BANERJEE: Now you'd be not having any margin to the so-called unanalyzed condition, but you'd be right on the border of it?

MR. GIOSITTS: Right. And if you were coming down along that line during normal operation, it would be controlled evolution to come down and make sure you're plotting where you're going in power, make sure you're within the analyzed domain.

If you were to take a runback with an automatic runback, if you do end up in the restricted regions operating procedures would tell you what to do to get out of that transient condition if you were to go above the MELLLA boundary.

So either way the plant is operated in such a way such that you stay out of that region.

CHAIR BANERJEE: So what is the logic then for you to use that blue line rather than just walk along the MELLLA boundary? You know, go horizontal and then go around the MELLLA boundary and then drop it?

MR. GIOSITTS: It would be a function of where we wound up in final flow at the given rod pattern that determines how far to the right we would start. We could be anywhere between --

MR. WALLIS: There and there.

MR. GIOSITTS: We could be anywhere between the MELLLA boundary and the 108 million pounds mass per hour depending on what we needed to exactly balance the reactor at 100 percent power.

CHAIR BANERJEE: You could just hug that boundary, right, currently? The hatched. If you wished, you could just go along that boundary and then drop it?

MR. HOFFMAN: John?

MEMBER SIEBER: If you ran with all rods out, that would take you to the MELLLA line. Running with all rods out is not a good way to run because you don't have control over the reactor. You don't have rod work as a control parameter. So that's why they run the way they do. You have embedded rods.

CHAIR BANERJEE: I'm trying to understand the implications of this for the uprate. So at some point you show us the same thing --

MR. WALLIS: But for a lookover, because you've got so much room to maneuver and all kinds of blue lines you can do to get from --

MEMBER SIEBER: But what you're trying

to do is use the control rods to balance the power dissipation, you know the amount of fissioning that's going on in various sectors of the core. Anyway you can do that is to favor flow to withdrawn rods, which brings that line down.

MR. BOESCH: Right.

This is Bob Boesch.

From a practical standpoint what we're talking about here is shutting down the reactor from a given starting condition, in this case starting at a 100 million pounds square flow and 100 percent power. If we were to consciously try to ride the MELLLA line, from a practical standpoint that would require us to reduce flow and withdraw control rods at the same time. When we're trying to shutdown the reactor, that's not really what we're trying to do.

MEMBER SIEBER: Backwards.

MR. BOESCH: We're trying to drive power down. So we start at the starting point, whatever that happens to be, reduce power with flow first. Get down below our preconditioning guidelines and then insert control rods.

Again, you want to move control rods at the lowest power levels that you can to improve your margins of preconditioning.

CHAIR BANERJEE: And that's why you don't insert them right away?

MR. BOESCH: Right. The rule of thumb is flow first, get down to a lower power state and then move control rods.

CHAIR BANERJEE: That's based on your fuel?

MR. BOESCH: That's one of the reasons that we believe we've had such great fuel performance.

MR. WALLIS: This is very interesting, but there's nothing that's relevant to EPU because you're going to do exactly the same thing --

MR. BOESCH: Exactly.

MR. WALLIS: -- with a slightly restricted space.

MR. BOESCH: Yes, sir. That's correct.

MR. WALLIS: There's nothing really critical that happens with EPU that prevents you from doing this?

MR. BOESCH: Yes. That's correct.

MR. WALLIS: So this is --

CHAIR BANERJEE: So that the blue line

is along the MELLLA line, right, in EPU?

MR. KRESS: I think during the fuel cycle --

MR. WALLIS: The line moves.

MR. KRESS: -- you move a lot of that horizontal line by moving the rods, right? As you burn up, you have to move along that line. And you just have less flexibility to do that.

MEMBER SIEBER: That whole chart changes as you burn up.

MR. KRESS: Yes. And so -- well you're probably as you go through the cycle you're probably approaching the MELLLA line towards the end of the cycle.

MR. HOFFMAN: No. Actually we are moving away from the MELLLA line.

MR. KRESS: You're moving the other direction?

MR. HOFFMAN: So we will reach a point where we are all rods out, we are maximum flow to maintain 100 percent power. We will go up to the upper right hand power.

I will put one slide into the fuel presentation --

CHAIR BANERJEE: So let's -- yes. We'll follow this up. So for now I suggest that we call it a day for this presentation and take a break. And then we revisit this when we talk about the fuel and things, if that's all right.

Okay. So we'll take a break now. Do I need to bang this. And until quarter to 11:00. A ten minutes break.

(Whereupon, at 10:35 p.m. a recess until 10:47 p.m.)

CHAIR BANERJEE: Back in session.

We are going to have a presentation now on fuel dependent responses and applicability of AREVA methods. And I guess Chris Hoffman -- or who is going to kick this off?

MR. GIOSITTS: No. I am John Giositts.

CHAIR BANERJEE: Okay. John Giositts. Go ahead.

MR. GIOSITTS: Can everybody hear him?

CHAIR BANERJEE: Can everybody hear him?

MR. GIOSITTS: I'm John Giositts. I'm the Senior Nuclear Fuels Engineer. And I'm going to present results for fuel dependent analyses the CPPU.

I'm going to go over basically a background or where Susquehanna is today with fuel. And also I'm going to talk about the approach, how we approached the analysis having AREVA fuel. And also I'm going to go through safety analysis result comparisons to current operating cycle information.

Basically, we've had AREVA fuel at Susquehanna since the second cycle of operation on each unit.

We --

MEMBER SHACK: Is it true that you haven't had a fuel failure?

MR. GIOSITTS: Well, we haven't had a fuel failure since, I believe, the early '90s if I'm correct in that. I believe in reactor years, I think we've operated I think Rick said for 34 reactor years without a fuel failure.

MEMBER SHACK: A failure?

MR. GIOSITTS: That's, I'm assuming, both units operation.

Basically the second bullet I've got there just shows that where we are in cycles for each unit. Unit 1 is currently operating in cycle 15, Unit 2 is operating in cycle 14.

And both reactors have full core of ATRIUM-10 fuel. We've had ATRIUM-10 for probably the last 10 to 12 years, I believe.

And also I just wanted to note that AREVA methods are used to analyze the fuel for the current cycles.

MEMBER SIEBER: I need a little education here. AREVA is nonbarrier fuel and GE is barrier fuel?

MR. GIOSITTS: That is correct.

CHAIR BANERJEE: AREVA or both?

MEMBER SIEBER: What's the difference? What's the difference between them?

MR. GIOSITTS: My understanding of barrier fuel is that there is a soft layer of zirconium inside --

MEMBER SIEBER: Spun?

MR. GIOSITTS: -- inside the cladding. Yes, right, spun zirconium. And basically that helps to reduce the stresses if the pellet contacts the inside of the cladding.

MEMBER SIEBER: Well, this started at Perry, as I understood it. These long axial cracks. And I think it was related to power shock, which we were talking about before, which is manipulating control rod patterns. So it could be that you're better at manipulating control rod patterns and fuel doesn't make a difference or it could be the fuel is everything and --

MR. GIOSITTS: Well, I think it gets towards the preconditioning limits that you use.

MEMBER SIEBER: Right. Okay.

MR. GIOSITTS: And how close you go to those limits.

MEMBER SIEBER: Okay.

MR. GIOSITTS: Ignoring control manipulation.

CHAIR BANERJEE: Well, just for clarification, Jack, AREVA has both barrier and nonbarrier.

MEMBER SIEBER: Okay.

MEMBER MAYNARD: I think the main thing, the barrier fuel allows you to start up a little bit faster. I think there are some disadvantages it to it, too. But if you're willing to get on a slower startup it'll balance out.

CHAIR BANERJEE: One disadvantage is cost, I imagine.

MEMBER SIEBER: It seems to me that --

MEMBER MAYNARD: Well, yes. But a slower startup is cost, too.

CHAIR BANERJEE: Right. Right.

MEMBER SIEBER: It seems to me, though, that you're trading fuel resilience for startup time which means that if you get it right, you have eliminated whatever margin you have as far as startup rate is concerned or control rod movement rate is concerned.

But anyway, if you haven't had fuel failure, I guess that's a good thing.

MR. GIOSITTS: Yes.

Okay. This one I'm going to touch briefly on the analyses approach. For CPPU we've had AREVA analyze, assess shutdown margin and safety event along with the limiting transient and LOCA. Like I explained before, we have GE for ATWS analysis with their approved methodology using ATRIUM-10 fuel in their model.

Next slide.

I'm going to talk about some thermal limits. The main thermal limits would be for protecting critical power ratio, which I'll get to after this. The other limits protect local area and also rod-based power peaks. And those will be MAPLHGR and LHGR, layer heat generation limits. And MAPLHGR is an excellent average.

MR. WALLIS: MAPLHGR is a GE term?

MR. GIOSITTS: Right.

MR. WALLIS: And AREVA uses a different term, but you're using the AREVA methods.

MR. GIOSITTS: We still use that. And if you want to look for a unique term, when we look at the ratio of the actual power to the limit, we call that MAPRAT.

MR. WALLIS: MAPRAT. Yes, that's right.

MR. GIOSITTS: Right.

Basically MAPLHGR and LHGR elements are unchanged for CPPU. The LOCA analyses or the results of the LOCA analysis have shown that we can still support the current MAPLHGR limits. And also the LHGR limits are basically tied to the mechanical design. And we've determined that we don't have to change the mechanical design for it to support the CPPU core designs.

MR. WALLIS: Do you have any evidence for this being a true statement?

MR. GIOSITTS: Well, we've performed the core design to make sure we could meet the same thermal margin limit requirements that we have today. So we have not run into any thermal limits restrictions so that --

MR. WALLIS: Well, how much margin has been reduced?

MR. GIOSITTS: Well, basically the way that the core is designed up front you set how much margin you want to have to your limits. So the margin really gets designed into the core design.

So we typically like to keep maybe 9 percent margin on LHGR MAPLHGR and we like to keep, I believe, 7 percent on LHGR limits. So AREVA has been able to design a core to operate at CPPU conditions that maintains those margins.

MR. WALLIS: The same margin?

MR. GIOSITTS: Yes.

MR. WALLIS: So there's no reduction in safety if you're going to higher power?

MR. GIOSITTS: We are able to maintain the same amount of margin, so we don't have -- if we were not able to maintain those margins I just mentioned, we would have to look into raising the limits to be able to maintain that type of margin. And we haven't found that we've needed to do that. We've been able to maintain the margins that we live with today.

MR. WALLIS: And this achieved by manipulating the fueling on the power distribution across the core --

MR. GIOSITTS: Basically, where you place the assemblies in the core, and also you control peaking with control rod patterns. So you make control rod pattern adjustments to compensate for that also throughout the cycle.

MEMBER SIEBER: Your peak clad temperature changes, but it's probably really low in this plant anyway, right.

MR. GIOSITTS: I have a slide on that, I believe, to explain that.

MR. WALLIS: The difficulty I have is if somebody asks me who is not familiar with this, like someone who doesn't know anything about nuclear power, how can these plants keep increasing power without effecting safety? Try to explain it to a student or someone, it gets pretty difficult.

You can talk about Maple Hydro, but then you know, that's still the same limit. How do they manage to do that. And you finally --

MR. GIOSITTS: I'll try to provide a simple explanation.

The peak bundle powers are basically constrained by having to meet limits like MAPLHGR, LHGR and MCPR, right, which I'll go into. And basically because of that you really can't push those bundle powers any higher than they are today. Okay. You just don't have the available margin. But what you need to do is generate more power, obviously, is to have the average bundle come up in power.

MR. WALLIS: Right.

MR. GIOSITTS: So those bundles are -- they have more enlarging then the limiting bundle obviously, but they will now have a little less margin than they had before because we're going to push the plant in power. But they still have margins in the limits.

MEMBER SIEBER: It seems to me that since margin is comparing to an absolute number and if you make it, you make it; if you don't, you don't. And you really can't compare one core design to another as far as how much margin there is. You either make it or you don't make it.

MR. GIOSITTS: Right. I mean we have to operate through a set of thermal limits for each cycle.

MEMBER MAYNARD: When you're talking in terms of margin, too, your most limiting fuel element, not to the total margin of the core.

MEMBER SIEBER: Right.The core, right.

MEMBER MAYNARD: It may be the same for one, but you know overall you have more of them that are coming closer to that.

MR. WALLIS: So the ultimate core is the sort of one close shave when they all reach the limit together and the whole thing -- it's the ultimate core, is it? Every bundle reaches the limit at the same time?

MR. GIOSITTS: For one moment in time--

MEMBER SIEBER: I'd like to meet the fuel designer for that one.

MEMBER MAYNARD: They could maybe build that core but not necessarily was it really desirable.

MR. GIOSITTS: It's not one we'd want to

operate, no.

Okay. This is results summary for one of the items I initially reported AREVA has performed. And this is based on -- before I get into that.

The MCPR safety element basically, let's say, local power uncertainties. And also the uncertainties are based on things like gamma scans and analytic benchmarks.

MR. WALLIS: So this is DNB based, isn't it? It's departure for nuclear boiler?

MR. GIOSITTS: Well, critical power.

MR. WALLIS: Yes. It's based on going into a boiling transition?

MR. GIOSITTS: Yes.

MR. WALLIS: Now I haven't looked at the correlation for boiling transition, but what's in it? Is it power flow rate and quality or is there void fraction in the correlation? Or what goes into the correlation that predicts this critical power?

MR. GIOSITTS: I'll have to defer to AREVA.

MR. WALLIS: But does it depend on whether you're using Finley-Dix or O'Connor-Leahy, or whatever? Does it depend on those other correlations or does it stand on its own and is it based entirely on ATRIUM-10 data?

MR. GIOSITTS: I will let --

MR. WALLIS: I have a lot of questions about what the correlation is based on.

MR. McDUFF: My name is Bob McDuff,

The critical power correlation that we use is an empirical correlation based on flow pressure, enthalpy, local peak --

MR. WALLIS: It doesn't depend on any other correlation?

MR. McDUFF: Well, it uses a nonuniform axial correction term --

MR. WALLIS: But it doesn't use Finley-Dix's or --

MR. McDUFF: It does not depend on void fraction or Finley-Dix.

MR. WALLIS: It's based on fuel with ATRIUM-10 fuel?

MR. McDUFF: We've got full scale data for about a thousand data points.

MR. WALLIS: Okay. Are you going to show us how well it does on that data or something?

MR. McDUFF: I believe that the --

MR. WALLIS: It does remarkably well, doesn't it?

MR. McDUFF: It does quite well.

MR. WALLIS: What's the uncertainty?

MR. McDUFF: The uncertainty is about 2.2 percent.

MR. WALLIS: That is remarkably good.

MR. McDUFF: Yes, sir.

MR. WALLIS: It doesn't depend on any of these other correlations?

MR. McDUFF: It has no dependency on those.

MR. WALLIS: That's reassuring. Thank you.

MEMBER ABDEL-KHALIK: And it covers the entire parameter range expected?

MR. McDUFF: Well, the application will only be valid within the range of which it was tested.

MR. WALLIS: Go up to 98-- how high does it go in void fraction then?

MR. McDUFF: Exit void fractions of the database are close to 99 percent.

MR. WALLIS: Because if you look a the void fraction correlations, like this Finley-Dix, you find that there's a fairly big error in prediction of how much liquid is there at the high void fractions. And how much liquid is there is what determines dryout?

MR. McDUFF: Well, that's correct. But this doesn't have that physical mechanism in it.

MR. WALLIS: So the correlation goes all the way up to 100 percent quality?

MR. McDUFF: Very nearly 100 percent quality at the exit quality in the critical power data.

MR. WALLIS: Thank you.

We can find it. If we need to look at it, we can find this correlation somewhere? The Staff has it somewhere?

MR. PARKS: This is Benjamin Parks with the Reactor Systems Branch.

Yes, we have the SPCV correlation. There's a topical report. It's been reviewed and approved by the NRC.

MR. WALLIS: When you make your representation, you going to reassure us that it's roughly valid for EPU conditions and that the uncertainties aren't greater and so on?

MR. PARKS: Yes.

MR. WALLIS: You're going to do that? Okay. Thank you.

MR. GIOSITTS: Okay. Now I'll get into the comparisons for current cycle operation for the safety limits and the-- also I have a data point in here for Unit 1 cycle 16, which is a design that has been completed for -- which if we get this approved, will be started up in 2008, spring of 2008. And also I have the CPPU core design that was done by AREVA for CPPU.

And basically what I wanted to say is that for cycles those safety limits are in place right now on Unit 1 and Unit 2 as they're listed there. And so these are the numbers that appear in our technical specifications.

The Unit 1 number is a 1.09 and you can compare that to this CPPU of 1.07 and you kind of wonder one is going down. The 1.09 has, the analyses that was done for that has additional uncertainty included in it for channel bow. We had some channel bow issues at Susquehanna. And so to accommodate that increased bow, we have increased the uncertainties for channel bow that are in the MCPR safety in the calculation. That adds approximately a .02 for the safety limit.

MR. KRESS: How do you make these gamma scans? You run something down the core or from --

MR. GIOSITTS: When we're actually in the closed session, we'll discuss more about gamma scans.

MR. KRESS: Okay. We'll wait until then.

DR. DIAMOND: And maybe I should wait until the closed session. But one question regarding these uncertainties. First of all -- there are two questions.

First of all, they're based both on comparisons with measurement and comparisons with code-to-code comparisons, is that true?

MR. GIOSITTS: Well, I believe they also -- they have code comparisons, but they're based on the gamma scan information of actual ATRIUM-10 data.

DR. DIAMOND: Okay.

MR. GIOSITTS: And we'll get into that further in the closed session.

DR. DIAMOND: Well, let me just ask a general question.

MR. GIOSITTS: All right.

DR. DIAMOND: The ATRIUM-10, the 10 power distribution at EPU is expected to be the same as it is for the current cores for which gamma scans were done or do you see the possibility of a pin-by-pin power distribution change in going to EPU?

MR. GIOSITTS: The fuel bundles?

MEMBER ABDEL-KHALIK: In particular, not for the core.

MR. WALLIS: In one bundle?

MR. GIOSITTS: There's basically a minor change in the fuel bundle design for CPPU. Where we go from our current bundle design to the design for CPPU, really what we've done is we've increased the enrichment at the top of the bundle. We've reduced the reflector region. So that the lattices actually haven't had any major modification to them.

DR. DIAMOND: But now you have enrichment at the top of the fuel where you have the higher void fractions in EPU operation?

MR. GIOSITTS: Yes.

DR. DIAMOND: So I'm just wondering

whether that can change the pin power distribution and whether that changes the use of these uncertainty numbers which are based on ATRIUM-10 designs that didn't go to EPU conditions. For example, slightly lower void fractions at the top of the core?

MR. GIOSITTS: So I guess your question is you're wondering about the impact of the void change on those lattices?

DR. DIAMOND: Yes, on using these uncertainty numbers, which are based on ATRIUM-10 fuel which had different conditions, in particular at the top of the core.

MR. GIOSITTS: Okay. I think what I'm going to do is defer that to the closed session to talk more about the gamma scan data and how it's relevant.

DR. DIAMOND: That's fine.

MR. GIOSITTS: Okay. Basically what I wanted to say with the 1.09 that we have for Unit 1 currently there's approximately .02 is due to the increased uncertainty for channel bow. So if you take that off, that'd be a 1.07 and that'd be comparable to this CPPU numbers that we have also to

Unit 1 cycle 16 values.

Unit 1 cycle 16 does not have the uncertainty, traditional uncertainty for channel bow because we will by that time have replaced the channels in all these sub-cells at that point with new channels.

Also, Unit 2 cycle 14, U2 C-14 that's listed there, that also has the .02 in it. There was an also an additional .01 added in there because we've had to take mid-cycle rechannel outages. And we were concerned that any effects from that could possibly effect that result. So we increased that by .01.

Also, that essentially takes you to a 1.08 for Unit 2 cycle 14. We've seen cycle specific variations on the order of .01 for safety limits which is just due to the design changes, differences between the units.

DR. DIAMOND: But what design changes in particular would cause the uncertainty to change here?

MR. GIOSITTS: Well basically it's hard to nail down specific one, but what happens is the units do not operate identically because, you know, depending on outages and things that happen to the units. You know, when you have to design the next cycle there'd be some variation in how many fresh bundles you need and then where you actually place them for each unique design. So those minor changes can have an impact.

DR. DIAMOND: Have an impact on the --

MR. GIOSITTS: Can cause variability in the MCPR safety units between units.

DR. DIAMOND: Okay.

MR. GIOSITTS: Okay. Then the next item is the shutdown margin and that's basically as it relates to the control core activity. And our design practice for meeting the tech spec limit of .38 percent delta-k over k is to design for one percent delta-k over k margin. And we will continue to use this and the core design that we have designed by AREVA for CPPU is also able to meet this constraint. So basically we see no significant changes in the shutdown margin requirement that we have today for the core design.

The next thing I want to get into is the limiting transients. Basically the limiting transients, the measure of severity is the change in critical power ratio for the event that you're looking at.

As you go through a transient you basically lose critical power margin. So if there's a decrease in the critical power ratio that occurs for an event that is limiting from a thermal limit standpoint. And limiting events like generator low reject, turbine trip without bypass capability or feedwater control at failure max demand provide essentially -- not essentially, they do. They provide the limiting results for delta-CPR.

I have comparisons for Unit 1 and Unit 2. And the values are comparable. I would expect the values to be similar between CPPU and the current operating cycles.

Unit 2 cycle 14 we show slightly higher numbers there. And Unit 2 cycle 14 we had added some additional margin in the analysis because we wanted to cover a possible mid-cycle uprate on that unit, which did not occur, but it left us with slightly higher delta-CPRs for those events.

Also, control rod withdrawal error is also listed as a possible limiting event. And you can see the values there are similar. There is a little bit more variability with those cycle-to-cycle because it is a local event versus a core-wide event like the pressurization I just talked to.

MEMBER ABDEL-KHALIK: Can you intuitively explain how the delta-CPR goes down at the higher power level for the same transients?

MR. GIOSITTS: What I was trying to get is Unit 2 cycle 2, just for a comparison, you're seeing this goes down. Because of the way the analysis was done those are higher than --

MEMBER ABDEL-KHALIK: I'm asking for a physical explanation of how delta-CPR would actually go down analyzing the same kind of transient when you increase power.

MR. GIOSITTS: Basically at least for the transients we've had analyzed we don't see much of an impact on the delta-CPR for events. I mean I know you're saying you have increased steam flows and things like that for the events.

MR. WALLIS: I think your explanation is that --

MEMBER MAYNARD: Because you were bringing the peak down and spreading it out more across the --

MR. WALLIS: It's a different reactor, that's why. Yes.

MR. KRESS: You must be on a different slope for the power versus temperature curve.

DR. DIAMOND: But it's interesting that it goes down both for the over pressurization events and also for the reactivity withdrawal event.

MR. GIOSITTS: Well, like I said, the reactivity withdrawal events are more susceptible to cycle-to-cycle. Not even cycle-to-cycle, it's local. I mean, you're pulling a rod locally.

MEMBER MAYNARD: Yes. But the only way this can really be is by the redesign of your core. You know, typically what you're talking about is to your most limiting element there. I thought you guys were bringing your peaks down and spreading it out over more of the core.

MR. GIOSITTS: Right.

MEMBER MAYNARD: So that the highest one would be -- you could have more margin in your highest one, it's just that you're going to have more of them in the core that are coming closer. That's what I thought was what was going on here.

MR. GIOSITTS: Well, for transients I

mean you get into the -- in the first two transients, the low reject or core failure are core-wide events which would be -- I mean, basically both of these events result in either a turbine trip or low rejection which results in closing a valve at the end of the steam line which causes pressurization. So that ends up being a core-wide effect.

Now, things that can compensate for increased severity of the transient would be when you look at cap conductances on the fuel, you have to look at a core-wide gap conductance. How much energy can get out of the fuel into the coolant that caused the void feedback. Also you have to look at hot bundle impacts. Because you're going to higher exposures, you're generating more power, you have higher energy out, you would tend to increase the gap conductance on a core-wide basis. That would be a beneficial effect for these type of events. Because that would create more void feedback for you to keep the power piece down.

So from a transient perspective that would help you to limit the power increase due to the increased severity from the higher steam flows that you're going to see in these events. So the fact that the delta-CPR is not changing significantly, I think partly is attributed to that.

DR. DIAMOND: But couldn't you also argue with a longer boiling length you'll have more of a decrease in void in the over pressurization and that might lead to higher powers and therefore a larger delta-CPR? I mean, it's kind of speculation. You can pick any physical effect.

MR. GIOSITTS: Well, I'm not sure. I mean, basically I was trying to look for things that could possibly mitigate the change in delta-CPRs.

CHAIR BANERJEE: What code was used for this, the calculations?

MR. GIOSITTS: The analyses for the pressurization transients used the AREVA code Otransient 2.

CHAIR BANERJEE: Which one?

MR. GIOSITTS: Otransient 2. That's their transient code, one dimensional.

CHAIR BANERJEE: And they used their steady state CPR correlations for the ATRIUM fuel?

MR. GIOSITTS: Yes. The SPCV correlation was used.

MR. PRUITT: This is Doug Pruitt. Doug Pruitt from AREVA.

And several factors, obviously, go into the transient delta-CPR. One of the factors that goes into this for a pressurization event is that because of the increased steam flow at the higher power levels, your control valves are opened wider and they're on a relatively flat responsive flow versus valve position. So that gives you a little bit more lead time before you get into the rapid pressurization portion of the valve closure between the initiation of valve movement and the actual scram. So that's one of the factors.

In addition to that you have axial power distribution effect your scram worth. And just as you increase the power in the bundles, typically you get a smaller delta-CPR associated with it. And basically you can apply delta-CPR versus power. And as you approach higher powers, typically your delta-CPR goes smaller, becomes smaller.

MR. WALLIS: What's the effect of different times in the cycle? I mean the actual power distribution is a variable, isn't it?

MR. PRUITT: Yes, it is. And so for

pressurization events they are limiting at end of cycle where you have all rods out and you have a relatively --

MR. WALLIS: At least -- values at the end --

MR. PRUITT: Yes.

MR. WALLIS: Okay.

MR. PRUITT: Because a pressurization event is dominated then anywhere else in the cycle by the partially inserted control blades that provide a lot of scram worth and shut the event down very rapidly.

And these are end of cycle all rod out type of transients.

DR. DIAMOND: But you're not saying that if you went to, say, 95 percent power that delta-CPR would be even larger?

MR. PRUITT: Yes.

DR. DIAMOND: It would be? So these are the limiting delta-CPRs?

MR. PRUITT: Those are the full power limiting delta-CPRs. And they have.

MR. GIOSITTS: And basically they're the delta-CPRs that we would operate, have to operate to for 99.9 percent of the cycle.

DR. DIAMOND: Okay. Because at 95 percent then you're operating at a higher CPR?

MR. PRUITT: Correct.

CHAIR BANERJEE: You're going to make a presentation in the closed session of both the various methods?

MR. PRUITT: Correct.

CHAIR BANERJEE: And there you will discuss also this gamma scans and things like that?

MR. PRUITT: Correct.

CHAIR BANERJEE: The pin and bundle. So we'll get into the details of how reliable these numbers are at that point.

MR. PRUITT: Okay. Good.

MR. GIOSITTS: The next event that analyzed by AREVA is reactor vessel over pressure. This is basically a limiting over pressure event as main steam isolation valve closure with a scram on high flux. This is a normal position scram on any value closure was disabled for this.

We have to analyze to an ASME limit, which ends up 1375 psig. I have current cycles information listed here. The peak pressure, which occurs at the bottom of the vessel for Unit 1 is 1308 psig. And that was analyzed at the lowest power of 339. And that assumed four safety unit valves were out of service, and that's for the technical specifications.

We have 16 safety relief valves. We're required by tech specs to have 12 of the 16 operable. So therefore this event is analyzed with four SRVs out of service.

For Unit 2, as I mentioned before, we wanted to cover operation at increased power levels for normal power levels so that it's less conservative for this event because it depends on steam flow was to analyze the proposed 7 percent increased from CLPP that was talked about earlier. That would be 3733 megawatts thermal. So this was analyzed at a higher power level, and thus higher steam flow which this creates a higher peak pressure.

So that effect adds about 20 psi to the result for this. And it still assumes four SRVs out of service.

Then for CPPU we also analyzed at the full 3952 megawatts thermal and we still get 1328 psig, just like Unit 2 currently has, but the difference is we only assume that two SRVs are allowed to be out of service. There is a technical specification change with the application to require now 14 SRVs to be operating.

MR. WALLIS: You get these psigs and you have to assume some sort of atmospheric pressure? Because all your steam calculations are absolute pressure. You have to assume something about the environmental pressure?

MR. GIOSITTS: Yes. The --

MEMBER SIEBER: But not much.

MR. WALLIS: Which can vary by ten percent.

MEMBER SIEBER: Not ten percent of 1328.

MR. WALLIS: No, it's not of that. But it might move it by one unit.

MEMBER SIEBER: Yes, it might.

MR. GIOSITTS: You know, the margin to this is about 60 pounds at current operating. And that'll go down by about 20 psi.

MR. WALLIS: Well when you do the calculation you just have a standard atmosphere outside so it makes it easy?

MEMBER SIEBER: Yes.

MEMBER MAYNARD: Typically that is what would be quasi the worst case expected for that area.

MR. WALLIS: You have to pick some number.

MEMBER MAYNARD: I mean you have to pick a number.

MR. WALLIS: You pick the lowest pressure in a hurricane or something, would you do that?

DR. DIAMOND: You don't do that, surely.

MEMBER MAYNARD: You'd probably want the highest pressure, right?

MR. GIOSITTS: Well, the codes are initialized at the highest pressure and the highest power level and then --

MR. WALLIS: External pressure in the world outside? That's what all I'm getting. You have to assume something about atmospheric pressure. It's a trivial matter, but you have to assume something.

MR. GIOSITTS: Right.

MR. WALLIS: I'm just wondering what you

assure? You assume 48.7 psi or do you assume 14.4 or --

MEMBER SIEBER: If it comes from ASME, it's the standard atmosphere, right?

MR. GIOSITTS: But based on the heat balances that we have, we assumed the pressure. And the design pressure in the vessel in the dome which would be measured during operation --

MR. WALLIS: Then you subtract an external pressure?

MR. GIOSITTS: Well, it comes from an absolute.

MR. WALLIS: That's right.

MR. GIOSITTS: So we would use 1,050 --

MR. WALLIS: Then you subtract something to get this number, right? And you subtract 14.7.

MR. GIOSITTS: Yes. You subtract 14.7 to get this number.

MR. WALLIS: Okay. Thank you. You have to subtract something.

MR. GIOSITTS: Yes.

MEMBER ABDEL-KHALIK: Historically what is the maximum number of SRVs that were ruled to be inoperable during the entire life of your plant and how long tech spec allow you before you have to fix those SRVs?

MR. GIOSITTS: I would have to defer that to Jim Williams, and I'm not sure if Kevin Browning.

MR. WILLIAMS: James Williams.

We have never had any inoperable SRVs in either unit.

MEMBER SHACK: But how long does tech spec allow you if you have an SRV inoperable?

MEMBER SIEBER: Unless you shut the valve, you don't know.

MEMBER SHACK: How long does it take that you had to fix it?

MR. WILLIAMS: I'm trying to remember what tech spec says. I'll have to get that information for you. But we can operate for extended periods of time with one or two inoperable. The same amount-- the number of them that are in inoperable that would cause you to have to shut down.

MEMBER SHACK: But I think the question he's asking is, you know, when you hit the fourth do you have to shut down immediately or do you have some time?

MEMBER MAYNARD: I don't know about for this plant, typically on your safety relief valve you don't know until you shut down. There are some things that can happen sometimes that you would know that you had a failed. Typically it's the testings--

MEMBER SHACK: That reveals it.

MEMBER MAYNARD: -- that you do during refueling to see if it really does lift at its setpoint there.

MEMBER SIEBER: It could leak like a sieve and --

MEMBER MAYNARD: Right. There are some things.

MEMBER SIEBER: That would be a detectable thing.

MEMBER MAYNARD: Be physical damage or you could have something. But typically as far as the operability you only test those -- you take them off --

MEMBER SIEBER: Or refueling.

MEMBER MAYNARD: Yes.

MEMBER ABDEL-KHALIK: So during operation you have no way of knowing?

MR. WILLIAMS: That is correct. When we're operating, we can look at the tailpipe temperatures to see if any are leaking. But we cannot tell if any will not lift unless we shut down and test them.

MEMBER SHACK: How would you enclose this criterion on your safety analysis? How would you verify that this condition is actually met?

MR. GIOSITTS: I mean the analysis covers -- I'll have to defer to what our history is for safety relief valves, unless Kevin can provide--

MR. BROWNING: This is Kevin Browning, PPL.

We've had excellent ASME pop test results from our the history of the plant. I'd have to get the exact numbers for you. But only approximately a half percent have ever failed beyond the plus three percent, I guess, tolerance. But as Jim pointed out, during normal operation we really don't have anyway of doing online testing of any of the valves.

MEMBER MAYNARD: But what the question really isn't Susquehanna specific or EPU related.

And the way it's typically handled, again you tested it when you shutdown. And it depends on what your history has been and what's being found. There are times when you may have to take some other compensatory measures or do some other things if you've ended up with a history or whatever. But typically you don't find that many issues and you typically don't find a failure. You may find one that's slightly outside of its setpoint or something. But as far as just a failure to -- but this is not really a Susquehanna --

MR. GIOSITTS: Well, let's just stick with the --

MEMBER SIEBER: Well, unless your failures are obvious. Because what can you have? A leaking seat, which you can tell, a bent stem which comes from operating at too big a pressure differential and they leak, or a broken spring which means that it's wide open all the time.

MEMBER MAYNARD: Right.

MEMBER SIEBER: And otherwise the only thing that you can't pick up is galling or rust, and that's why they make them out of good material. Relief valves are highly reliable.

CHAIR BANERJEE: Perhaps we should move on and carry on.

MEMBER SIEBER: Yes. Let me ask without trying to stall this: When you get your EPU permission, this analyses is not based on any specific core. Each core that you install in the plant has to go through a reload core design analysis.

MR. GIOSITTS: Yes, we analyze in some cycles specifically.

MEMBER SIEBER: And all you're doing here is to try and set the limits on the box which that analysis has to fit, right?

MR. GIOSITTS: Yes.

MEMBER SIEBER: Okay. Just so that's clear. We're talking about a fictional core. And describing the limits as opposed to looking at the performance of an actual core.

CHAIR BANERJEE: Okay. This slide presents the result of the LOCA analysis results.

Before I get into this slide I just wanted to mention, I had some information for the Appendix R analysis. The peak Appendix R PCP from the analyses was 1191 degrees Fahrenheit for the

Appendix R analyzed limited case.

CHAIR BANERJEE: Thank you.

MR. GIOSITTS: Okay. Basically the three parameters I have up here are peak cladding temperature, cladding oxidation and core-wide metal water reaction. I have the results for current licensed minimal power and also for CPPU.

MR. WALLIS: Which LOCA is --

MR. GIOSITTS: I'll get it. Basically the first line shows that the CPPU analysis meets the 10 CFR 54.86 limit of 2200 degrees. We have a peak clad temperature of 1844 degrees.

The second line that I have shown there is because we have an analyses assumption change between the CLTP analysis and the CPPU analysis.

CHAIR BANERJEE: What was that change?

MR. GIOSITTS: The analysis assumption was, it was a conservative assumption in that the recirculation discharge valve would not close on a suction line break. We had assumed that in older analyses and when we implemented ATRIUM-10 and we didn't do that. The crediting of that value, we're able to credit that valve because the valve's qualified to close under those conditions. So for the CPPU analysis we wanted to bring that back into the analysis.

Now to assess what the difference is between the CPPU analysis and the CLTP analysis which has an additional conservatism in it, what we did was the limiting break condition for the break characteristic for the CPPU analysis which produced the 1844 was also run with the assumption that the discharge valve would not close under a suction line break. That resulted in a 1914 degree PCT. That is compared back to the CLTP analysis, a value of 1945 degrees.

Now this still shows that the CPPU PCT is slightly lower than the CLTP analysis.

MR. WALLIS: This assumption is completely independent from a single failure criteria, is it?

MR. GIOSITTS: Yes.

MR. WALLIS: It's probably is on top of that?

MR. GIOSITTS: Yes. Yes.

The further difference, the 30 degree difference that we see there can be explained by the fact that the CLTP analysis used slightly more conservative initial hot bundle conditions. The analysis for CLTP was done based on the requirement that the initial MCPF be 1.3. Okay. Which is a very low MCPF operating limit. We set it low such that it raises the bundle power. We also set it low such that the LOCA analysis is not the limiting event.

So when the hot bundles were initialized, though, some of the hot bundle conditions were initialized at even lower MCPFs than we required. So that caused that to be conservative and have slightly higher bundle powers than we would have needed to meet the 1.3 initial MCPR requirement. So the difference in the initial bundle powers between CLTP -- initial hot bundle powers between CLTP and CPPU was 6.5 megawatts versus 6.1 megawatts. So that difference would contribute to making them be --

MR. WALLIS: It looks like some bundle were up in the 7. something megawatts.

MR. GIOSITTS: Let's see.

MR. WALLIS: Did I misread something or is that --

MR. GIOSITTS: No. No. The way the

analysis is done, and I think I'm going to have to defer this to a closed session. Because this gets into how radial factors are set and how things are put on MAPLHGR limits for axiom power distribution.

CHAIR BANERJEE: Well why don't we just defer it.

MR. WALLIS: Just defer it?

MR. GIOSITTS: Yes, we'll have to defer it to the closed session.

MR. WALLIS: Which LOCA is limiting, can you tell me that? Which break size and where?

MR. GIOSITTS: The limiting break size is a double ended guillotine break on the suction side assuming failure of the low pressure coolant injection valve. That's the limiting single failure.

MR. WALLIS: And this is the same as the limiting break that the NRC found?

MS. JACKSON: After much discussion, yes.

MR. WALLIS: Well, they convinced you, did they?

MS. JACKSON: They convinced us and we convinced ourselves with additional questioning and analysis.

MR. WALLIS: And you're going to tell us about that, basically?

MS. JACKSON: Yes.

MR. WALLIS: Okay.

CHAIR BANERJEE: When are you going to tell us about that?

MS. JACKSON: In our session, which is I believe at 2:00. Peter Lien of the Staff performed those analysis. He'll be here with us.

CHAIR BANERJEE: Today?

MS. JACKSON: Yes.

MR. WALLIS: Okay.

CHAIR BANERJEE: And you'll also tell us about this on and off of counter current flow limitations at that point?

MS. JACKSON: We're prepared to discuss that.

CHAIR BANERJEE: Right. Now, did you disable your counter current flow thing in this or what?

MR. GIOSITTS: Not for the analysis. The disabling of the counter current flow is --

CHAIR BANERJEE: Did you allow counter current flow in this case?

MR. GIOSITTS: The counter current flow limitation model is imposed in this. I mean, it is working, it is not turned off. I mean, there was a sensitivity performed to compare AREVA's analyses and NRC's analyses. That was just a sensitivity.

CHAIR BANERJEE: So in the hot bundle here with all this steam rising you're going to allow counter current flow in these calculations?

MR. GIOSITTS: Well, there's a correlation to the term in how much flow you have.

CHAIR BANERJEE: So you're using this correlation?

MR. GIOSITTS: You're using the correlation.

CHAIR BANERJEE: Somebody will explain to us this correlation later on today?

MR. GIOSITTS: Yes. AREVA will be touching on this in their presentation in closed session.

MR. WALLIS: Is that a --

CHAIR BANERJEE: It can't be. The surface extension length scale won't work for a bundle.

MR. WALLIS: We'll get into that.

CHAIR BANERJEE: So we'll get into that in detail I'm sure.

If you did not use the counter current flow, what would happen? Imagine you didn't take credit for counter current flow, what would happen? Would it go over 2200?

MR. GIOSITTS: I can't say whether it would go over 2200 without actually running the analysis. My understanding would be you would not be getting the cooling from the top.

CHAIR BANERJEE: Right.

MR. GIOSITTS: So you would have to wait for that coolant that was diverted from going in the top to go down around the bypass and come back up the quench.

CHAIR BANERJEE: So that's an issue that at least from a bounding point of view you didn't see even if you believed there could be counter current flow. What would happen if there wasn't? You don't have that --

MR. GIOSITTS: What I can't verify is how much counter current flow there is in this that's presented here. I do not know that information.

CHAIR BANERJEE: Can somebody enlighten us? Who did this calculations?

MR. GIOSITTS: AREVA did the calculations. And AREVA will talk.

MR. HERR: This is Mike Herr from AREVA.

The counter current flow models for the big breaks are limiting and really don't matter much. We at the end of blow-down have to switch to the Appendix K spray heat transfer coefficients. So we're really not calculating any heat transfer at that point. We're using the Appendix K values, which are very low values, 1½ to 3 to 5 BUTs per hour per foot square depending on where you're at in the bundle.

So for the big breaks the counter current flow model is not a big player.

We did this --

CHAIR BANERJEE: You have the core spray coming, right?

MR. HERR: Right. The core spray is coming, but at that point we're doing a calculation with our Appendix K model which doesn't even see that water coming down. It's used in the spray heat transfer coefficients until we reflood the core.

CHAIR BANERJEE: So where is that spray coming? Through the top?

MR. HERR: Yes, it's from the top of the core.

Now where it does matter and came into play in some of the discussions with NRC were on the small breaks. There the break is long enough in period of time so the lake -- the puddle of water is building up on top of the core. Our model was allowing water to penetrate based on what the model would allow it to. We did turn that off and for the small breaks we did a calculation where we instead of injecting the water on the top of the core we actually put it into the bypass region. So no water accumulated on top of the core. And we saw about a 200 degree increase. Our small break went from like 1290 to 14 something. It's still not the limiting break. Our limiting break was 1844.

So the big break where the 1844 is coming from has, you know, virtually no sensitivity to the CCFL coefficients. And, again, it's --

CHAIR BANERJEE: Has it got sensitivity to the spray heat transfer coefficient?

MR. HERR: Yes. The NRC Staff asked us

to come up with some way of quantifying that effect as part of an RAI. We were looking for a quick way to do that. To do it more rigorously, we'd have had to do a code change, so we were trying to do it through the input to the code. So what we did is the core spray actually injects into the upper plenum over the top of the fuel. We actually just physically moved the location.

Normally the core spray goes in the upper plenum, it drains into the bypass region into the lower plenum. And some of it goes down the hit channel, some of it goes to the bypass. What we did in our simulation we just directed all the flow into the bypass region so none of it accumulated on top of the core. And we checked that in the runs. There was no liquid --

MR. WALLIS: So there was no liquid coming down from above at all?

MR. HERR: No.

CHAIR BANERJEE: Could you turn off the core spray in your calculations?

MR. HERR: Yes.

CHAIR BANERJEE: And what happened if you just turned it off?

MR. HERR: Well, then you have your reflood, because that's the source of water that's going down and filling up the lower plenum and filling the core back up. So you have to have it. That's why we put it in the bypass so we would still reflood, but we wouldn't get any penetration from above to cool the top of the --

CHAIR BANERJEE: And what code were you using?

MR. WALLIS: And you used Appendix K you say?

CHAIR BANERJEE: Sorry. Go ahead.

MR. WALLIS: You said you used Appendix K values. What are they based on?

MR. HERR: Appendix K values are defined in the --

MR. WALLIS: Just a heat transfer coefficient or something?

MR. HERR: Yes. Just defines you have to use this value for these rod locations.

MR. WALLIS: Does that assume that it's dry steam or what? It's just some value that--

MR. HERR: It's values that have came out of, I don't know, testing in the '70s or whatever.

MR. WALLIS: Come out of somewhere.

MR. HERR: But we do have a test facility for each new bundle design. We'll go out and confirm that the Appendix K values are still conservative for that design.

MR. WALLIS: Ah, so you've tested?

MR. HERR: Yes, we have.

MR. WALLIS: Are you going to get into that this afternoon?

MR. HERR: Yes, we'll talk some more about that.

CHAIR BANERJEE: What is the code that you're using for these calculations?

MR. HERR: It's a code called RELAX. And it's a RELAP derivative.

CHAIR BANERJEE: Is it prehistoric?

MR. HERR: Yes.

CHAIR BANERJEE: So it is homogeneous with STAIF or something?

MR. HERR: Yes. So we'll talk some more about that this afternoon.

CHAIR BANERJEE: And how do you get counter current flow in a homogeneous with STAIF code? That must be quite a trick, right?

MR. WALLIS: I guess Leahy managed to fix it up, didn't he, somehow?

MR. HERR: Yes. It's a Leahy correlation and the extreme goes to the Courvoisier correlation.

CHAIR BANERJEE: But we'll get into that. So let's move on.

MR. GIOSITTS: Okay. Where I left off was I was talking about bundle power differences. And basically if you were to take this bundle power, which is lower than what was used here, this would decrease and become comparable, even closer than the 30 degrees.

The other items here. CLTP's higher because we have a much higher PCT for this because of the difference in the assumption with the discharge valve closure. And also the core-wide water reaction, metal water reaction is essentially unchanged since it's a core-wide parameter.

MEMBER SHACK: Do these oxidation values include the pre-event oxidation?

MR. GIOSITTS: I do not believe that they do.

MEMBER ABDEL-KHALIK: Isn't the limit based on both the cladding oxidation during and prior to the event?

MR. GIOSITTS: I would have to let AREVA talk to that. But I believe the industry does not include the initial oxidation for LOCA analyses. Mike Garrett may speak to that.

MR. GARRETT: Yes. Mike Garrett.

Our LOCA, the numbers we calculate assume zero pre-event oxidation. That maximizes the delta metal water reaction we get during the event so we get the most heat addition from the oxidation. So that's the basis for the assumption. We're trying to maximize the PCT, which is the limiting criteria.

For boilers the metal water reaction is really not that serious of a criteria. It's more of a situation in the PWRs.

There's an industry issue going on about whether you have to consider the initial oxidation or not in that criteria. That's still being debated.

We have looked at it and we could do it either way for the boilers to meet the criteria because there's so much room to the metal water reaction.

MR. WALLIS: So the real criterion is embrittlement, isn't it?

MR. GARRETT: Right. And that came up, and you can go back and look, it's really a combination of high temperatures and the embrittlement is --

MR. WALLIS: The cladding observations are a very simplified way of doing it with embrittlement.

CHAIR BANERJEE: I think we should move on because we have to discuss stability still before lunch. And whatever time it takes, we will. So if necessary, we'd cut the lunch break short if that's an incentive to move on.

MR. GIOSITTS: Okay. The last result I have is from the ATWS analysis that was performed by GE. And basically it shows these are very comparable PCTs between CLTP and the CPPU, which is what I would expect similar to the LOCA.

Also the peak pressure and suppression pool temperatures will be presented in another presentation.

Basically just a summary. We have used

NRC approved methods and AREVA methods for these analysis, and also the GE analysis for ATWS.

We have learned that from the design we've had done for CPPU we can still meet our shutdown margin requirements. And also these are acceptable safety analysis results that we can go to CPPU with.

CHAIR BANERJEE: Thank you.

CHAIR BANERJEE: You're going to talk about stability now?

MR. LEHMANN: My name is Chett Lehmann. I'm supervisor of the Plant Analysis Group at PPL Susquehanna. In addition to the PRA, which I will be discussing later today, I'm going to be talking a little bit about the impact of CPPU on core stability.

I've been a member and sometimes Chairman of the BWR Owners' Group since 1990 in the detect and suppress methodology.

In discussing stability there's two main considerations that need to be taken into account, the first of which is the size of a region in which an instability may be possible. This is basically determined by decay ratio calculations. I'll talk a little bit more about those later.

The second of which is the core response to those oscillations given that one might occur. If one were to occur, a good measure of that that we look at every cycle is the fractional change in CPR as a function of the oscillation magnitude. In other words, what is the change in CPR. In other words, how much does CPR decrease as a result of a certain size oscillation.

Two things to keep in mind as we discuss this, and it's been discussed before and it'll probably be discussed ad infinitum throughout the rest of these presentations, but the rod line that we're talking about has not changed between our current licensed thermal power and what we're attempting to license for CPPU. That's very important for stability because one of the main things that drives stability is the power flow ratio that you might get after a flow runback.

And that we also have full cores of ATRIUM-10 fuel, there's no mixed core effects that need to be considered for this. We've been using ATRIUM-10 fuel for some time now. We're going to continue to use ATRIUM-10 on into the power uprate.

First, to talk about the regions that we refer to as stability regions where one might expect an instability. We have AREVA perform calculations using their STAIF code. They'll talk a little bit more about the STAIF code later. It's NRC approved and it captures cycle-specific variation. Both regional and core-wide decay ratios are analyzed as part of a standard reload analyses.

And I'll get to the next slide in just a second. But a comparison of CPPU to current cycles really shows only minor impacts similar to those which you'd see on a cycle-to-cycle basis.

You can go to the next one, please.

From what I understand if you're reading along in your books, this area up here is colored. So that really is not part of what we're trying to license here. If you have any Wite-Out, that would be useful.

CHAIR BANERJEE: That's what you come back to try and license.

MR. LEHMANN: I think it's a Microsoft artifact when you print right now.

CHAIR BANERJEE: A premonition.

MR. LEHMANN: As has been mentioned

before, this is the CPPU region. What I've done is I've plotted the power flow map as a function of absolute megawatts. So our current operating domain is from here and on down. When we go to CPPU we're adding this small piece at the top.

One of the important things is that one way to enter a region or an instability may occur is a two pump recirc pump trip, which would run you all the way back to this point on the power flow map. Notice that whether you start here or you start here, since it's the same rod line, you'll basically end up at the same power flow point when you do that. And that's an important feature.

Next. Oh, sorry. Not done yet.

What I wanted to point out was on here I plotted a .85 global decay ratio using STAIF calculations. And that is including the uncertainty, and the NRC licensed uncertainty, to the STAIF decay ratio calculations.

So if one compares the last two cycle of Unit 2, this is the Unit 2 cycle 13/cycle 14, and this is the CPPU core that was designed and analyzed by AREVA as part of this project. And if you'll notice that the CPPU lies pretty much between these other two. And that's why I said before that it's comparable to the cycle-to-cycle variations.

Another thing that's worthy of note is the required by the licensing requirement for arming the OPRM stability trip is this box over here. And as you can see, that with the CPPU code core as well as our current core, it's well within the region where the OPRM will be armed and able to terminate an instability event.

So those are the main points I wanted to make there.

So what I just discussed was the region where you might expect an instability and demonstrated that it's not that different from cycle-to-cycle variations when you go to CPPU.

Now I'd like to talk about the MCPR response. And again, this analyzed every cycle by AREVA using their methodology, which was RAMONA5-FA, which is a version of ROMONA which was developed by AREVA for this specific purpose. And, again, it captures the cycle-specific variations.

CHAIR BANERJEE: Now this is still under review, right, the code?

MR. LEHMANN: Do you want to talk to

that?

CHAIR BANERJEE: Its use is being allowed on a plant-specific basis here?

MR. LEHMANN: Yes. Yes. It's been allowed on a plant-specific basis.

Doug, do you want to clarify that?

MR. PRUITT: This is Doug Pruitt.

Yes. The initial analysis was audited by the NRC in the first application and has been approved based on for that plant-specific analysis. We've also submitted in support of our long term solution for MELLLA+ or extended flow domain windows. And it's under NRC review. And I think we have an ACRS meeting next month on that.

CHAIR BANERJEE: So why didn't you use it for ATWS?

MR. PRUITT: We haven't qualified it for ATWS. We've qualified it for CPR response.

CHAIR BANERJEE: So you'll tell us what you did for ATWS, right, later on? You used the MICROBURN or what?

MR. LEHMANN: The ATWS analysis was done by General Electric.

CHAIR BANERJEE: Ooops.

MR. PARKS: This is Benjamin Parks with Reactor Systems Branch.

CHAIR BANERJEE: By the stuff that I got to read in the -- yes, please.

MR. PARKS: In early drafts of the safety evaluation I gathered information from other sources and did so erroneously, and never went back and updated. I had extensive interactions with the licensee and with AREVA and with General Electric about the ATWS analysis. And it was, in fact, performed by ODIN. And I never corrected it in the draft safety evaluation report. It will be corrected.

CHAIR BANERJEE: Okay. That's what confused me. Thank you.

MR. PARKS: Yes. I apologize for the confusion.

MEMBER SIEBER: He's actually read it.

MR. LEHMANN: This is an input which is an input to the OPRM setpoint calculation. And if you compare, again, the CPPU to the recent cycles it really shows only minor impacts.

I'd like to go to the next slide, if I might.

What we have here is a calculation. This is referred to in OPRM-talk as the DIVOM, which stands for delta over initial MCPR as a function of -- versus oscillation magnitude.

So the Y axis is the fractional change in MCPR caused by a certain size oscillation. And the X axis is the oscillation size determined as eight minus minimum over average.

Okay. Again, notice the diamonds here are the CPPU calculations. And these are our two current cycles. This is Unit 1 cycle 15, this is Unit 2 cycle 14.

Again, notice that the CPPU is inside the--

MEMBER ABDEL-KHALIK: Again, could you explain to me intuitively why this LOCA as a DIVOM curve goes down in this case?

MR. LEHMANN: I guess what I'm trying to say is it's lower than this one and higher than that one.

MEMBER ABDEL-KHALIK: Right. Right. I mean intuitively, why is it lower than the case prior to power uprate? Wouldn't you intuitively expect it to be higher?

MR. LEHMANN: I'd like Doug to answer that question.

MR. PRUITT: This is Doug Pruitt.

Its primary function and these type of variations are due to the core void reactivity coefficient. And that varies from cycle-to-cycle a bit based on the particular fuel design, the core loading.

MEMBER ABDEL-KHALIK: But doesn't that also depend on the ration between the two phase pressure drop and a single phase pressure drop in a channel?

MR. PRUITT: Not particularly. The growth rate is dependent upon the two phase to single phase pressure drop ratio. This is the ratio of the CPR response to the neutron detected power oscillation. So if I have a faster growth rate, those points are spaced further apart as the oscillation grows. If I have a lower growth rate, they are spaced closer together. But the slope is not particular in function of the oscillation. You do need an unstable oscillation in order to generate the curve.

MEMBER ABDEL-KHALIK: So what's the

difference between Unit 1 cycle 15 and Unit 2 cycle 14 that caused that change in the DIVOM slope?

MR. LEHMANN: I cannot answer that. I don't know the specifics of it.

MR. PRUITT: Since the CPR response for the oscillation magnitude is the same, it's primarily the neutronic response. So that would be generated primarily from the void reactivity.

MEMBER ABDEL-KHALIK: And these two cores are so different it caused that much change in the DIVOM slope?

MR. PRUITT: Yes.

CHAIR BANERJEE: Are they at different points in the reload cycle or something?

MR. PRUITT: We picked the limiting point based on the -- we look at basically three different exposure points before. I don't know. And we take the limiting condition from the cases we calculate.

So void reactivity is going to be dependent upon: (1) Your fuel loading and what is your actual power distribution for that particular point in the cycle. Okay. So your void reactivity varies with exposure throughout the cycle depending upon the control rod inventory and both exposure and --

MR. WALLIS: Well, the CPR is a steady state correlation.

MR. PRUITT: Correct.

MR. WALLIS: And your oscillation is quite big. So why do you justify using a steady state correlation?

MR. PRUITT: We'll get into that in the meeting. But we have it compared to -- we have test data on the ATRIUM-10 -- that we've benchmarked.

MR. KRESS: What value of this delta or the initial would lead you into film boiling?

MR. LEHMANN: The methodology used to set the setpoints for the OPRM used this as an input and set the setpoints when an oscillation is terminated such that you do not violate the MCPR safety limits so you do not go into film boiling. And that's part of the point, that this is a real specific --

MR. KRESS: So these are just to set the setpoints then?

MR. LEHMANN: Well, what --

MR. KRESS: If you happened to achieve

that delta, would that put you in the film boiling?

MR. LEHMANN: Again, I can only say what's done on a cycle-specific basis. Maybe I don't understand the question. Let ne try this, and still haven't had your question answered, then come back at me.

Typically we're in the range in here in terms of the size of the oscillation when it's terminated.

MR. KRESS: Yes.

MR. LEHMANN: So from that we can determine, let's say, Unit 1 cycle 15 that would represent a 15 percent decrease in MCPR as a result of that size oscillation. Given you would then determine if that would violate the safety limit and, hence, potentially go into film boiling. If it would, you would have to lower your setpoint which would in turn lower the value down here, lower the fractional change in MCPR until it was a successful outcome.

MR. KRESS: That answers my question.

MR. LEHMANN: Does that help? Okay. Thank you.

DR. DIAMOND: How do you generate the

different oscillation sizes?

MR. LEHMANN: That's Doug.

MR. PRUITT: Basically the state points we were analyzing are unstable and so they grow as a function of time. And so these are just successive oscillation point in that growing oscillation.

CHAIR BANERJEE: So do you actually the follow the oscillation with RAMONA? I mean, this is not a linearized analysis.

MR. PRUITT: Yes, this is ROMONA calculations to time domain analysis. And this is just a -- each one of those series of points would be probably from a single ROMONA calculation as a broad oscillation.

CHAIR BANERJEE: So you have --

MR. PRUITT: Yes.

CHAIR BANERJEE: Yes. All right. So it's not like it's a linearized analysis.

MR. WALLIS: When we were in the simulator at your plant we saw some pretty big oscillations for the ATWS cases. I haven't got the case with me.

CHAIR BANERJEE: Yes, but that's ATWS instability.

MR. WALLIS: But it's still in effect the same way. Presumably the same average effects the CPR the same way, doesn't it?

CHAIR BANERJEE: I think Said's question is a very good question that we need a more clear answer to. But I don't want to take the time right now.

MR. WALLIS: The big question is will we ever get to lunch, I think.

CHAIR BANERJEE: Yes. So what I think we should do is table that question.

MR. LEHMANN: Okay. And what is exactly the question?

CHAIR BANERJEE: Well, he asked a question why the CPPU came out lower than Unit 1 cycle 15. And I don't think he got a clear answer to it.

MEMBER ABDEL-KHALIK: Without having, you know, access to the details of the methods, without reviewing the methods it's hard to tell how this was -- operationally, of course, he'd want the slope of his DIVOM curve to be as low as possible. It makes your life easier.

MR. LEHMANN: That's true.

MEMBER ABDEL-KHALIK: And that's why when I see a slope of a DIVOM curve that's lower than what I would intuitively expect, I try to find out why is it where it's at.

MR. FARAWILA: Okay. Yousef Farawila consulting for AREVA.

There is a qualitative difference in the power upgrade core in that the core radial distribution is flatter. For a flat radial distribution you have the -- value separation between the first azimuthum mode and the fundamental mode is smaller. And with that the neutronic response of the regional mode oscillation will be larger. So what you really see here is the x-axis expanding for the same hydraulic response.

CHAIR BANERJEE: Does that make sense to you? It's a more hair-triggered code. So why doesn't -- it doesn't make -- so we can talk about this later. Because I really want to keep this roughly on time, which is that we only want to be half an hour late for lunch and have only a half an hour lunch.

We'll come back to this. All right.

MR. LEHMANN: Just to put it in

perspective, those type of differences that you're seeing on that chart would only change the trip setpoint by a .01. In other words, instead of a 1.11, it would change it to a 1.12. I just thought I'd put that in the context of how it's used.

Okay. Conclusion from this is that the MCPR response to oscillations is really not significantly different and it's typical of cycle-to-cycle variations.

In summary, assume the aspects that I mentioned before, the stability characteristics are not significantly different. And the magnitude of the difference is both in the MCPR response to a instability and the regions in which an instability might be expected are similar to the cycle-to-cycle variations we've seen in the past. Just simply as account for core design.

One thing to point out is there are no methods changes that were used to CPPU. We're using the same methodology that we've been using.

As I pointed out before, the rod line is the same. And basically you would probably expect the stability characteristics to be somewhat similar given the same power flow regions of concern.

And as I said before, both of these items are captured by cycle-specific analyses and are directly incorporated into how we set our setpoints and run the core.

CHAIR BANERJEE: There's somebody coming in a bridge line I think, right, or something?

MR. LEHMANN: Any further questions on that?

CHAIR BANERJEE: You can revisit some of this later in the closed session.

MR. LEHMANN: This is a brief presentation on ATWS instability, at least on my part. An ATWS instability event, as you're aware, occurs from a flow run back to natural circulation from the highest rod line. Since we're on the same rod line, we'll end up at about the same power flow point that we did before going to CPPU. So there's really no increase in that.

As I pointed out before, there's not a huge difference in stability characteristics as a result of going to CPPU.

CHAIR BANERJEE: But now you've got a lot more power, 13 percent more heat being generated, right with this instability?

MR. LEHMANN: There is more power, yes.

CHAIR BANERJEE: That's what we want to see what happens.

MR. LEHMANN: Now, I'm sorry. Let me rephrase that.

Can you go back to the power flow map one?

CHAIR BANERJEE: You're coming along the rod line, but the fuel --

MR. WALLIS: The same rod line as before.

MR. LEHMANN: This is a power-flow map in the absolute megawatts. If I'm operating here or here and I trip both coolant pumps, I'm still going to end up here. So when we talk about an absolute stability, it generally runs down to this point here. So in answer to your question, you are pretty close to the same power level.

CHAIR BANERJEE: Right.

MR. LEHMANN: And that's the crux of the argument essentially. That there really is no significant change between current license thermal power and the CPPU.

MR. WALLIS: Well, how fast do you come

that rod line. It has some memory for where it's been, doesn't it, in that the fuel is hotter?

MR. LEHMANN: Very quickly.

MEMBER SIEBER: Seconds.

MR. LEHMANN: Yes.

MR. WALLIS: -- from quickly down a rod line.

MR. LEHMANN: In point of fact, what happens is it comes down and it comes slightly below the rod line.

MR. WALLIS: Right.

MR. LEHMANN: And then as the feedwater temperature calibrates and cools down to support the function of the lower power, it comes back up to that rod.

CHAIR BANERJEE: Is it a few seconds or how long is it?

MR. LEHMANN: Well, the trip of the reactor coolant pumps is very quickly. It's a matter of seconds.

MEMBER SIEBER: Thermal response is like 10 seconds or 15 seconds.

CHAIR BANERJEE: Ten seconds, roughly

MEMBER SIEBER: Yes, it's pretty quick.

MR. LEHMANN: Yes, it takes longer. It takes maybe a minute for the feedwater to --

MEMBER SIEBER: The decay or flow decay in the response through the whole system has to -- coming back up is a lot slower than coming down.

CHAIR BANERJEE: So you are saying you have the same problem?

MR. LEHMANN: Yes. If there is a problem, we have the same situation.

I just wanted to point out that the NRC approved topical for CPPU concluded that an analysis instability -- or instability analysis is not needed for these reasons here.

The basis for our ATWS instability, the licensing, is that --

CHAIR BANERJEE: I guess there's the point as to whether the fuel makes any difference at this point, right?

MR. LEHMANN: And the answer to your question it would make some difference, but not a large amount of difference.

I would like to point out that this NEDO-32047-A was done for the ATWS rule. And the concern in that report was core coolability and maintaining its geometry. There will be some small number of pins that go into boiling transition and perhaps fail the cladding.

CHAIR BANERJEE: But if you look at those oscillations during an ATWS instability, it's hard to imagine that that is true. But I suppose that's been approved, right?

MR. LEHMANN: One thing that's important about those oscillations, and again I'm basing this on the GE report, the deposited enthalpy from those large spikes, essentially, is less than calories per -- for each of those spikes. So you're not going to have dislocation in a rapid --

CHAIR BANERJEE: Well, it depends on where you go into critical heat flux or whether you rewet it. And there's a whole lot of issues.

MR. LEHMANN: Yes.

CHAIR BANERJEE: You're in a region which almost impossible to validate or calculate once that happens. So clearly what's required is, and that's I suppose what the idea is, that you mitigate it before you get into that region in some way.

MR. LEHMANN: That's true. One of the

most effective mitigators of the large oscillations in ATWS is to run back the feedwater to approximately five feet below the feedwater spargers. When you do that, the cold feedwater will fall through a steam environment and heat up, and thus the subcooling of the core would be reduced. And you may still have some minor oscillations, but they won't be such that they would fail the --

CHAIR BANERJEE: Right. It has to be done quite quickly. In other words, we encountered this in a much more problematic form with MELLLA+.

Anyway, that's--

MEMBER ABDEL-KHALIK: Did GE actually do calculations that are Susquehanna specific?

MR. LEHMANN: For this? No, they did not.

MEMBER ABDEL-KHALIK: So how can you use GE methodology to justify something for which they haven't done the analysis?

MEMBER SIEBER: The topical report says you don't need to do this, right?

MR. LEHMANN: Yes.

MEMBER SIEBER: That's the way it was approved.

CHAIR BANERJEE: The next point is --

MR. LEHMANN: That's the way it was approved. This is essentially a generic analysis to demonstrate that the core is going to -- geometry is going to maintain intact. And also the suggestion was made that you need to reduce your feedwater.

MEMBER ABDEL-KHALIK: Whatever conclusion --

MR. LEHMANN: That is the way to mitigate this particular event.

MEMBER ABDEL-KHALIK: I'm sorry to interrupt. But whatever conclusions there are or may be in the GE topical is fuel dependent, isn't it?

MR. LEHMANN: Well, one might argue that everything is fuel dependent. But my understanding is this GE topical has been used by virtually everyone in the industry to represent different cores, different fuel types, et cetera. It's a generic topical which came to certain conclusions which virtually everyone uses.

MEMBER SIEBER: Yes, but the conclusion--

MR. LEHMANN: Beyond that I really can't

speak to the report.

CHAIR BANERJEE: Is it for GE-14 fuel or is it broadly for every type of fuel? These GE topicals.

MR. LEHMANN: This one? I am not sure. It was done in 1995.

CHAIR BANERJEE: I guess that's what I--

MR. LEHMANN: So it would not be GE-14, I would suspect. But again --

CHAIR BANERJEE: But what approval was given to it at that point? Then it was extended to GE-14 or what sort of understanding the history of what happened there?

MEMBER SIEBER: The topical was approved after that. Its method was approved maybe in the '90s. But we heard the discussion on the topical report.

MEMBER MAYNARD: This may be a question more appropriate for the Staff when it's their turn to talk.

CHAIR BANERJEE: Anyway, I think we'll defer that question. And your argument here is that ATRIUM-10 is within the range of the sort of fuels that have --

MR. LEHMANN: I'm sorry. I can't hear you.

CHAIR BANERJEE: Your last point maybe you wanted to say something about that?

MR. LEHMANN: Well, what I was trying to make a point, and this is something that's mentioned in the PUSAR that we submitted as part of our submittal, that the difference between the ATRIUM-10 fuel and the fuel that was used in the original calculations is within the range or actually smaller than the different core, different cycles, different fuel types that was enveloped essentially by using this topical.

MEMBER ABDEL-KHALIK: But we don't know that for sure, do we?

CHAIR BANERJEE: Well, the Staff will respond to that, especially the number of -- and all sorts of things, you know, ATRIUM fuel presumably is different from GE fuel. But we come under that in the closed session because you don't want to give details.

MR. LEHMANN: I would like to hear from AREVA as well.

CHAIR BANERJEE: Say something,

somebody.

MR. LEHMANN: But we can save that for the closed session.

CHAIR BANERJEE: Yes, you can save it.

MR. PRUITT: That is what I would prefer, yes.

MR. LEHMANN: Yes. Okay. Thank you.

CHAIR BANERJEE: So are we done? Anymore questions? Shall we take a lunch break now? We'll reassemble at 1:00.

(Whereupon, at 12:13 p.m. the meeting was adjourned, to reconvene at 1:03 in closed session.)

(Whereupon, the open session began at 3:20 p.m.)

CHAIR BANERJEE: Back in session. Open session. And we'll hear from NRC, Diane Jackson. Okay.

MS. JACKSON: Good afternoon. I'm Diane Jackson. I'm a reactor systems engineer. I have the lead for coordinating the technical review for the reactor systems areas. Together with Ben Parks and Peter Lien we performed the technical review for the Susquehanna extended power uprate for the

Reactor Systems Branch and the Nuclear Performance and Code Review Branch.

Because this is an open session, our slides are nonproprietary. Counter current flow will be --

CHAIR BANERJEE: You can close it after.

MS. JACKSON: Okay. So just so you know we get to the end of this and you say, hey, you said you were going to address this --

CHAIR BANERJEE: Address it in closed session.

MS. JACKSON: Okay. Our review method for Susquehanna utilized the typical tools for an EPU. The licensee followed, to the extent that they could, the GE licensing topical reports. They gave the generic guidelines and the generic evaluations that are typically referred to as the ELTR-1 and the ELTR-2.

They also followed the approach for the GE licensing topical report for the constant pressure power uprate, which is typically referred as the CLTR.

Now we say to "the extent possible," because we talked this morning anything that is fuel dependent could not rely on that, and the licensee had to supply plant-specific evaluations or justification.

The analyses and the evaluations that they did use were based on NRC approved methodologies, analytical methods and codes.

For our review we followed our Review Standard RS-001.

Next slide.

For this presentation we're not going to cover all areas of the review scope for reactor systems. In particular we're not going to really discuss the areas that we reviewed typical results and we found acceptable. Rather, we're going to discuss the areas of our major conclusions and the areas that generated additional discussion between us and the licensee.

To this end, the slide list topics that we're going to cover today, we'll cover briefly: Fuel system and nuclear design; transient analyses; and Ben will cover stability, ATWS and the GE and AREVA methods; and Peter Lien will cover the LOCA analysis.

Susquehanna does have the AREVA ATRIUM-

10 fuel design. It is 100 percent core. And there's two main things that are noteworthy of this for our review, in that one that I mentioned: They couldn't use the typical GE topical reports so there was a more complex review on our part to make sure that all the areas were covered and they couldn't use the generic resolution that was already approved.

The second thing is because they were already a full core, it simplified the review or didn't make it quite as complex as they didn't uprate or change -- excuse. They're not changing their fuel and there was no nixed core. So it's a 100 percent fuel for the EPU and going to EPU conditions.

With the amendment they are increasing their assembly average enrichment level. And as we expect, the thermal limits will be determined with cycle-specific analysis.

To talk about the accident and transient analysis, they did use the NRC approved generic methodologies of the ELTR-1 and ELTR-2.

For their fuel thermal limits events, the most limiting was the generator load reject or the turbine trip with a bypass failure.

Excuse me. I'm a little bit nervous.

They found this most limiting. And this established their operating limits in a multicritical power ratio.

For their over pressure events they did find their main steam line isolation valve failure with a flux scram was their most limiting event. And they found, and we agreed, that their peak pressure of 1328 psig remained below the ASME limit of 1375 which is 110 percent of their design pressure.

For their loss of water events to establish their minimum level, they did find that the most limiting event was the loss of feedwater. And the result was that the core remained covered well above the top of active fuel.

And again, as expected, they will perform cycle-specific reload analyses using NRC approved methods.

CHAIR BANERJEE: What will these NRC approved methods be? Can you just give --

MS. JACKSON: Peter, do you want to go over that?

CHAIR BANERJEE: Just a brief list, that's all I need.

MR. LIEN: Like, you know, for example, the transient code is called -- I think PPL can probably give me more answers because there's a complete list of codes, you know, for different transients.

CHAIR BANERJEE: Well, that would be useful to have.

MS. JACKSON: Would you like us to get you one of those?

CHAIR BANERJEE: Yes.

MS. JACKSON: Certainly. They did review --

CHAIR BANERJEE: They're all approved or accepted, the reload analyses.

MR. WALLIS: So you believe the number because they used the approved code?

MS. JACKSON: And they applied it in the manner that is acceptable or any limitations that were there were --

CHAIR BANERJEE: You don't know that yet. The reload analysis has not been submitted yet, right?

MEMBER SIEBER: It is close.

MS. JACKSON: For what they have supplied to us, yes. When they get to their cycle-specific we'll have to reconfirm that. If it's something beyond or out of bounds from what we've already approved, then they'll have to come back.

MEMBER SIEBER: The Staff doesn't always reanalyze the licensee reload analysis submittal, right?

MS. JACKSON: No. But all their limiting events were also the ones that were reviewed and approved through the GE licensing topical report, which apply to Susquehanna.

MEMBER SIEBER: Yes. But do you intend to thoroughly review all aspects of this one or just pick out certain areas?

MS. JACKSON: For their reload analyses? Would we do that? I don't know that we would.

MR. CRANSTON: This is Greg Cranston, NRC.

When the submittal comes in we'll look at what the package looks that, and then we do confirmatory analysis where we think it's appropriate is typically what we do.

MEMBER SIEBER: So it won't necessarily be a full reanalysis?

MR. CRANSTON: Correct.

MEMBER SIEBER: Just where you think the emphasis should be placed?

MR. CRANSTON: That's right.

MEMBER SIEBER: Okay.

MS. JACKSON: Okay.

MR. PARKS: My name is Benjamin Parks. And I had review responsibility in the areas of the thermal hydraulic and fuel system design. And I also analyzed the anticipated transient without scram response as a part of the thermal hydraulic design. I reviewed the stability. And I also did a methods evaluations to ensure that several of the methods that are rather important to the core design were applied consistently with NRC approval of those methods. And that, I guess, the validation database supported the use of those methods at the uprated conditions.

And the first thing that I'll talk about is the stability aspects of the thermal and hydraulic design. As stated earlier, the licensee uses the detect and suppress option 3 system which uses an oscillation power range monitor to detect oscillation of the scram reactor. when the system is unavailable, there are interim corrective actions in place at the plant.

The licensee has recently installed the GE NUMACS power range neutron monitoring system. Cycle specific DIVOM calculations are performed using ROMONA5-FA. ROMONA5 has been approved for use at Susquehanna. It was approved in 2004 based on the site-specific audit. It has not received generic NRC approval. It is under Staff review at this point for generic approval.

There was no significant change in the DIVOM curve for the constant pressure power uprate.

During my review and since ROMONA5 is currently under review at the NRC, I was assisted in my review of the stability performance aspects by Dr. Tong of the Reactor Systems Branch and by Dr. Jose March-Leuba from Oak Ridge National Laboratory.

MEMBER SHACK: Now, there have been several Part 21s issued with regard to the option 3 since Nine Mile Point. How has Susquehanna responded to those Part 21s?

MR. PRUITT: I'll defer to Jose?

DR. MARCH-LEUBA: Yes, is Jose March-Leuba from Oak Ridge National Laboratory.

We have performed, actually, two audits. The Staff has performed two audits of Susquehanna of the stability analysis. And that's the number one question was how you handle the DIVOM. And they have handled -- they are perfectly aware of the situation and they have handled, in our opinion, constantly.

In the issue of the ROMONA5-FA code came out of the second DIVOM correlation, when the second Part 21 for the DIVOM correlation was found to be nonbounding, the generic DIVOM. And we were struck with having to do cycle-specific DIVOM calculations. And nobody had any methodology approved to do it. That's when we did one of the audits and we allowed ROMONA5-FA code to be used and with a promise that they would submit an LTR, which they did in early 2006, and it's in the review now. And you will be seeing it in November 16th.

MEMBER ABDEL-KHALIK: But there have been other Part 21s.

DR. MARCH-LEUBA: The other Part 21s are related with the -- they are the members, they are the lead members of their group. So in a sense Susquehanna is kind of doing the recommendations for everybody. So they're quite aware of all those recommendations and they have implemented them.

MEMBER ABDEL-KHALIK: Thank you.

MR. PARKS: The next area of my review is anticipated transients without scram. I reviewed the anticipated transients without scram response to ensure that the accredited operator actions were acceptable. In fact, in the process of transitioning from the current license thermal power analysis to the constant pressure power uprate analysis the licensee increased operator response times which resulted in a conservative effect on the results of the analysis. In other words, the results would become severe and the operators would have more response time.

The predicted peak reactor pressure vessel was 1366 pounds per square inch. And this is within the ASME design limit.

And I also verified that the operator actions are consistent with the emergency procedure guidelines and severe accident management guidelines for stability protection.

CHAIR BANERJEE: So all this was done with GE codes, right?

MR. PARKS: Yes. The ATWS analysis was done using ODIN.

CHAIR BANERJEE: ODIN. Okay.

Now, it made no difference in your view that the fuel was different or were there any aspects related to that?

MR. PARKS: I interacted with the license and asked questions about the fuel dependence and the qualification and ODIN. And I believe that the response was that when you consider the power level and the plant reactions to the ATWS, by in large, I guess the plant response doesn't become that sensitive to the fuel geometry, which would be the effect of using a GE code to do an analysis.

CHAIR BANERJEE: So what's needed? You need some void coefficients and all this sort of stuff that gets fed in, or how does it --

MR. PARKS: I would defer that to Jose.

DR. MARCH-LEUBA: All this is a ID -- so you do need collapsed cross sections.

CHAIR BANERJEE: Right.

DR. MARCH-LEUBA: But there are two limiting criteria that you're trying to satisfy. One is earlier in the first 10/20 seconds on pressurization, what you don't want to go over the vessel, you don't want to go over 1500 psig. And that's a global effect of how much steam is going through the steam line.

So the local geometry of the fuel has no significant effect on the over pressurization transient.

The other limiting criteria is the suppression cool temperature, and that happens like 10/20 minutes later. And it's low effect, that this is a global effect that again the fuel geometry has no effect on it.

You would be worried about fuel geometry if you were having to do a CPR correlation or looking at the effect of -- things like that. And those are hardly ever -- to my knowledge, they're never dominant criterion in ATWS.

CHAIR BANERJEE: You would be only if you were worried about CPR during ATWS instability.

DR. MARCH-LEUBA: You do violate CPR on every --

CHAIR BANERJEE: Yes, but under what conditions, for how long and how much operator time you have to take your corrective actions or mitigative actions.

DR. MARCH-LEUBA: Same doing a pressurization analysis when you close the MSIV and you have a very fast rise of the pressure, you have a very rise of the power and you do get CPR on dryout. And it lasts for a few seconds. But that turns out never to be the limiting case. So the limiting criteria is always how close you get to the pressure where you would have the level ASME pressure limits.

CHAIR BANERJEE: I guess from my point of view it would be nice a rationale presented, and it could well be the way Jose is saying that the fact that we have different fuel here doesn't make any difference. I mean, this is the first time I've heard the arguments why it doesn't.

DR. MARCH-LEUBA: For ATWS.

CHAIR BANERJEE: Yes. For ATWS.

DR. MARCH-LEUBA: Yes.

CHAIR BANERJEE: I mean, it may be that you are right, Jose. I'm pretty sure you are. But it's a point that certainly needs to be discussed.

DR. DIAMOND: Jose, could you just clarify. I thought you said that the initial over pressurization or the initial power spike was important. And that, of course, is a function of the void feedback in the core.

DR. MARCH-LEUBA: What's important is the pressure, how much pressure you build up inside the vessel. So your criteria is are you going to reach a level CS ASME criteria, which is 1500 psi. And the boil feedback makes a difference, yes.

DR. DIAMOND: Which is fuel dependent?

DR. MARCH-LEUBA: Sure. Yes, that's well for a GE-8 than for a GE-14, then probably for ATRIUM-10. And they are using the correct cross sections.

CHAIR BANERJEE: But the cross sections are calculated elsewhere, right? I mean ODIN doesn't do that calculation, does it?

DR. MARCH-LEUBA: No. No. ODIN takes --

CHAIR BANERJEE: So ODIN is just a --

DR. MARCH-LEUBA: Correct.

CHAIR BANERJEE: -- thermal hydraulics code.

DR. MARCH-LEUBA: That is correct. And one in neutronics.

CHAIR BANERJEE: But how are the neutronics done then with using what? CASMO, MICROBURN is not going --

DR. MARCH-LEUBA: No, no. It will just simulate. It will simulate the cross sections.

CHAIR BANERJEE: So how are they doing that?

DR. MARCH-LEUBA: I don't know.

DR. DIAMOND: I mean, obviously, they generate cross sections as a function of the particular fuel type and then put them into the 1D model in ODIN.

DR. MARCH-LEUBA: One option will be to burnup the --

DR. DIAMOND: Because the question is do they try to do anything to make their calculations bounding so that it would encompass all fuel types including non-GE types?

DR. MARCH-LEUBA: Let's get the real answer.

MR. GIOSITTS: John Giositts.

We provided all design information for

ATRIUM-10 including the core design to General Electric so that they could model it with their codes so that they could actually burn the core out using their PANACEA code and feed their cross sections, which would be specific to our core design into their models. And also we gave them all the geometry information that they would need to model the ATRIUM-10 fuel assembly.

CHAIR BANERJEE: It was done with PANACEA?

MR. GIOSITTS: Yes, PANACEA and ODIN was done for the transient calculation. But PANACEA would be used to generate the cross sections and burn the core.

DR. DIAMOND: So the GE calculations were specific to Susquehanna then?

MR. GIOSITTS: Yes, they were specific to Susquehanna and to the ATRIUM-10 fuel.

DR. MARCH-LEUBA: And this is no different then when you have a mixed core where GE code picks up an AREVA plant and they put a third of GE and you have two-thirds of ATRIUM.

CHAIR BANERJEE: Thanks.

MR. PARKS: The next significant area of

my review was of the application of the nuclear design, which was is CASMO4 MICROBURN-B2. The start for this review is documentation and NRC approved licensed topical report EMF-2158(P)(A), which was submitted, I believe, in 1998. Subsequently reviewed and approved by the NRC Staff.

The database that appears in EMF-2158 is supported by pin-by-pin gamma scans and TIP comparisons. And the gamma scan database covers the 10 by 10 fuel geometry in use as Susquehanna.

I also looked at the void quality correlation validation, and it is validated in fact against the ATRIUM-10 geometry by experimental testing. The maximum predicted exit voiding is enveloped by the database and the conditions at constant pressure power uprate are bounded by AREVA observed recent operating experience.

MR. WALLIS: How accurate is the void quality correlation have to be?

MR. PARKS: The void quality correlation would need to be accurate enough to produce results that fall within the constraints of the neutronic code validation. In other words, there's a power distribution uncertainty associated with CASMO and

MICOBURN. The void quality correlation would need to be accurate enough so that those uncertainties are supported.

MR. WALLIS: So it's then validated by these TIP measurements and that sort of says that the void quality correlation is good enough in some way?

MR. PARKS: The void quality correlation, yes, ultimately becomes a component of the uncertainty in the total power distribution which is then validated by the gamma scans.

MR. WALLIS: So could we say that the TIP measurements tell us that the void quality correlation is good enough? Do you regard that as being a confirmation of the adequacy of the void quality correlation?

MR. PARKS: When we confirm that the power distribution uncertainty is within the uncertainty when it's established in the topical report, and we say that's good enough. And when we see that those results are in fact good enough, then yes we confirm that the void quality correlation is good enough.

The next area of review is the safety

limit minimum critical power ratio. There is a statistical methodology that factors in uncertainties associated with the fuel cycle design. The safety limit minimum critical power ratio is set so that there is assurance with 95 percent confidence that 99.9 percent of the rods would not undergo boiling transition during normal operation.

The uncertainties included a special channel bow uncertainty at Susquehanna that could be reduced due to rechanneling because some of the fuel channels at Susquehanna are susceptible to bowing, and that would change. The effect would be a slight reduction in the safety limit minimum critical power ratio.

CHAIR BANERJEE: Is there any effect of bypass voiding?

MR. PARKS: In the safety limit minimum critical power ratio no, because that's bypass voiding. It doesn't correspond to rods and dryout.

CHAIR BANERJEE: No. I mean what effect does that have on the uncertainties?

MR. PARKS: On the parameter uncertainties in the safety limit minimum critical power ratio none.

CHAIR BANERJEE: And when you talk about the gamma scans and things like this and you add up all these uncertainties, bypass voiding doesn't enter anywhere or does it enter somewhere? Where does it enter?

MR. PARKS: Bypass voiding does not --

CHAIR BANERJEE: Enter anywhere?

MR. PARKS: No uncertainty that I observed with the bypass voiding associated with it.

MEMBER ABDEL-KHALIK: Does it effect the cross sections?

MR. PARKS: Not that I have seen. And again, the cross sections are validated as a part of the neutronic calculations, which are validated against operational and gamma scan data.

DR. MARCH-LEUBA: This is Jose March-Leuba.

Bypass voiding effects mostly the measurement of the power at which you are in the real plant. Because RPM now becomes uncalibrated because you have some voids around it and you're not measuring the same power than you really have. Okay.

Now, with that said, bypass voiding

should occur according to calculations where you have a very off power -- very -- low high power conditions. Under normal conditions we don't expect any bypass voiding. And there is a limit, a typical specification on LPRMs that LPRMs have to operate with a bypass voiding of less than 5 percent.

CHAIR BANERJEE: That condition is never obtained in this MELLLA?

DR. MARCH-LEUBA: With MELLLA+ --

CHAIR BANERJEE: No, with MELLLA. MELLLA+ is a separate issue. We know it operates there. Yes.

DR. MARCH-LEUBA: With MELLLA, at low flows I wouldn't be surprised that you do get a little bit more five. But it is understood that that five percent bypass void in tech spec applies to steady state operations for long periods of time. And offload, you don't operate for long periods of time.

So the effect of bypass voiding is that you are measuring a lower power or higher power -- I think it's lower. Lower power is bypass voiding then you only have in the upper nodes. So you have miscalibration in those nodes.

CHAIR BANERJEE: But does this add to the uncertainties?

DR. MARCH-LEUBA: Most of our limiting conditions occur at high power steady state where you by tech spec you don't have bypass voiding. So you would in effect-- there is one specific case which is the OPRM scam which it's only active when you're at low flows. And for that we have a penalty on bypass voiding. And there's additional uncertainty on the measurement of the OPRM oscillation and ARPM for MELLLA.

CHAIR BANERJEE: But that penalty is now a part of the record, or what's happening?

DR. MARCH-LEUBA: It's part of the record for GE methods. This body reviewed it last year and it's part of the method for GE record.

CHAIR BANERJEE: But how does it come into this?

DR. MARCH-LEUBA: You add a 3 percent error to the setpoint on the OPRM setpoint.

CHAIR BANERJEE: So this is part of what SSES is --

PARTICIPANT: May I make a statement?

CHAIR BANERJEE: Please, yes.

PARTICIPANT: Values, it becomes proprietary. AREVA would have to come out with the exact numbers.

CHAIR BANERJEE: Okay. We can defer this to the closed session.

DR. MARCH-LEUBA: It would have to be a GE closed session.

PARTICIPANT: The amount of how much the calibration error would be.

CHAIR BANERJEE: Maybe it will be a closed session without AREVA.

DR. MARCH-LEUBA: You have to get the result.

So there is an uncertainty because you have a measurement uncertainty on the OPRM when there is void. There is an uncertainty in the OPRM that you have to --

CHAIR BANERJEE: So has the Staff put a limitation on this?

MR. PARKS: The Staff did not put a limitation on the safety limit minimum critical power ratio because the domain at which the OPRM is--

CHAIR BANERJEE: Oh, no. I'm talking

about this. We are talking about the bypass void effect.

MR. PARKS: Right.

DR. MARCH-LEUBA: It will be on the OPRMs.

MR. PARKS: I see.

CHAIR BANERJEE: There's no limitation by the Staff.

MR. PARKS: No.

DR. MARCH-LEUBA: Not to my knowledge.

CHAIR BANERJEE: So this is an item we need to discuss then.

MS. JACKSON: Does Susquehanna want to add something?

MR. PRUITT: This is Doug Pruitt.

With respect to the discussion here, the safety limit, we did look at the potential for localized boiling around the hot bundles. And the bypass flow is sized at that -- any bypass flowing that occurs in there is very, very small. It doesn't effect the transient analysis or the steady state power distributions.

Of course, with a two pump trip down to the instability regions, you do have significant boiling. And that's included in our stability methodology with respect to modeling the boiling in the bypass, and it's included in the reactor benchmarks.

And the amount of boiling that we see under those conditions and their effect on decay ratios it's certainly much more severe the German plants that have the internal recirc pumps. They're going to about 15 percent flow instead of 30 percent flow. And the code marks that -- you know, there's no difference in the quality of the benchmarks for those extremely low flow and bypass conditions.

CHAIR BANERJEE: But for this plant is there any effect? Does it have any significant effect on the uncertainties?

MR. PRUITT: No.

CHAIR BANERJEE: So --

MR. PARKS: From the Staff's viewpoint this was not an issue that we addressed because we didn't review any expansion of the operating domain with it. And we found that the expansion of an operating domain would make this more severe.

CHAIR BANERJEE: Well, clearly for MELLLA+ situation we understand that. But within this current operating domain, which is MELLLA, there's no issue there?

MR. PARKS: In the Staff's opinion, no.

CHAIR BANERJEE: But I thought, Jose, you said something different. So I need to understand what is the issue here.

DR. MARCH-LEUBA: I don't know.

CHAIR BANERJEE: Is there an issue?

DR. MARCH-LEUBA: There is an issue with measurement of local powers if you have bypass voiding around OPRM. And that uncertainty should be accounted for.

CHAIR BANERJEE: So are we going to have bypass voiding under any conditions around the LPRMs?

MR. PRUITT: This is Doug Pruitt.

Down in the low flow stability region, yes, you have boiling in that situation. And as Jose mentioned, that effects the OPRM ability as far as magnitude of the oscillations and its impact there. But with respect to the code's calculation of DIVOM and slopes and the decay ratios, that is accounted for, the bypass boiling and its reactivity parameters.

DR. MARCH-LEUBA: The point of view of the review and the reason we didn't include this as part of the review is that we don't see any difference between pre-EPU and post-EPU in Susquehanna. That bypass voiding issue exists today before the EPU. It has not changed. And solution 3 has been approved --

CHAIR BANERJEE: It can be issue but it's not taken into account right now?

DR. MARCH-LEUBA: It may be a generic issue.

CHAIR BANERJEE: And certainly for MELLLA+ it's an issue.

DR. MARCH-LEUBA: For MELLLA+ it's a change and we definitely can take it.

CHAIR BANERJEE: So the fact that there may be an issue here, it's simply because it's MELLLA it's grandfather?

DR. MARCH-LEUBA: That was our review of it.

MR. PARKS: That was the scope of our review, yes.

PARTICIPANT: It is applied to the GE, though.

CHAIR BANERJEE: It is applied --

PARTICIPANT: For EPU.

CHAIR BANERJEE: We need to clarify this. We can take it up. Let's move on.

If it's applied to GE, we have validate that it is and then follow up on this.

MR. PARKS: There is no change in the maximum average planner linearage heat generation rate limits from the current licensed thermal power to CPPU. The limitation on the MAPLHGR limits is based on burnup and the NRC approved burnup limits will be observed for the operation. The limit curve is confirmed by the licensee's plant specific LOCA analysis and is supported by Staff's audit calculations.

In conclusion, with respect to the methods the neutronics calculations are supported by geometry specific gamma scans, TIP comparisons, experimental data and code-to-code comparisons. The safety limit minimum critical power ratio is determined using acceptable parameter uncertainties. The MAPLHGR limits were confirmed to be acceptable and we accepted the CASMO4 MICROBURN-B2, the SAFLIM2, which is the safety limit minimum critical power ratio method and the MAPLHGR limits for the proposed CPPU operation.

And with that, I'll turn it over to ECCS performance and LOCA to Peter Lien.

MR. LIEN: Good afternoon, everyone. My name is Peter Lien.

Now I want to summarize the LOCA review and the conformity calculations of Susquehanna at EPU condition.

I believe everybody agrees that the best way to determine if ECCS cooling capability is adequate for EPU condition is through the performance evaluation. Because LOCA is a complex process.

In the LOCA review the Staff finds the NRC EXEM BWR-2000 methodology is used in the licensee's LOCA evaluation. This methodology was approved in 2001.

So to confirm --

CHAIR BANERJEE: What does EXEM stand for? I mean, this is a suite a stuff or what?

MR. LIEN: That's a good question.

CHAIR BANERJEE: We have all these fancy names.

MR. LIEN: I think PPL will answer it.

MR. PRUITT: Doug Pruitt, AREVA.

EXEM comes from our legacy. The EX stands for Exxon, we were Exxon Nuclear at one time. Evaluation Methodology.

CHAIR BANERJEE: So this includes the historical RELAX, right?

MR. PRUITT: Right. That's why the X is in RELAX.

CHAIR BANERJEE: Well, I'm very happy that the Staff used RELAP5 here. I'm sure all of us are.

MR. LIEN: To confirm the proper application of the methodology the Staff does compare the modelization of Susquehanna in the model to the generic model in the topical reports. And the Staff finds there are minimum changes. Those changes include bottom drain lines model and also the reactor water clean up models. Those are tiny flows so it won't effect the PCT results.

And also one significant change is the core actual nodes. It has one more nodes compare to the generic model. And I defer to the topical report and it says the actual node has to be like seven or more nodes. In the Susquehanna model it has like nine nodes compared to the eight nodes in the generic modelization. So I think that this modelization is acceptable.

And also the Staff checked the brake size in the break spectrum. The spectrum start from .05 square foot all the way to double ended break of the recirc pipe at 3.5 square foot. Compared to the validation cases in the topical reports, it's within the range. So I think the break size is also acceptable.

And also a step to compare the codes that are used in the application, and also the sequence of execution. I checked the flow chart and compared to the topical reports, they are all identical. So I believe they used the codes in the proper way.

So based on these facts, I conclude that methodology is acceptable for the evaluation.

Talking about this and methodology, imperial to the review the Staff also performed confirmatory calculations using RELAP5 3.3 to make sure the initial condition and bundling conditions are identical or as close as possible the Staff incorporated the same ATRIUM-10 fuel geometry into the RELAP deck. This included the fuel rods, the geometries in those so those are heating diameter, hydraulic diameter size and recalculate that into the RELAP deck. Because I noticed that those hydraulic diameters and heating diameters are crucial and they did effect the final results.

And also I incorporated the ECCS pump curves exactly the same licensee's data.

And I also used the same single failure assumption. That means after the single failure assumption all the remaining ADS systems should be the same. And also the injection points should be the same.

And I put the axial power shape into deck also. And based on the radial peaking factor and the local peaking factors provided by the licensee to distribute the power in my average channel and also the hot channel in the RELAP input deck. And make sure the initial power/flow conditions are exactly the same as licensee. So I readjusted the steady state calculation. Make sure the loop flow and also the core flows are identical.

Now let's move on to the review.

MR. WALLIS: Did they provide input decks or something or do you have to build this whole thing yourself?

CHAIR BANERJEE: This is RELAP5.

MR. LIEN: Yes. This is a RELAP5. You know, it's a different code from licensee. But they didn't provide us, and so we had to rebuild it. So the Staff basically used an existing BWR-4 --

MR. WALLIS: You adjusted it?

MR. LIEN: -- and made some modifications.

CHAIR BANERJEE: Did you have a Browns Ferry deck?

MR. LIEN: Yes.

CHAIR BANERJEE: Let me ask you a leading question.

MR. LIEN: Yes.

CHAIR BANERJEE: Why didn't you use TRACE?

MR. LIEN: Because the Staff has some backgrounds with RELAP and it's easier. Even I didn't have extensive experience in running the code, but I have a lot of experience because basically in my previous experience I did recode the other -- the RELAP models. So it's natural choice that, you know it's a short learning curve to use RELAP.

And right now RELAP is very mature, you know. You can put in the -- you know they start running the LOCA case for --

CHAIR BANERJEE: It was just easier to run than TRACE?

MR. LIEN: Yes, so far I feel that far.

CHAIR BANERJEE: And TRACE, You did the detail the Browns Ferry that for TRACE?

MR. LIEN: I've heard there is one TRACE deck. But I don't have the experience with TRACE, so I naturally I don't use TRACE.

So one one check of when you're in the LOCA is the limiting break characteristics. Based on Staff previous EPU review experiences for constant pressure power operate with power increase less than 20 percent, which Susquehanna is, the step would conclude -- it would expect the limiting break characteristics would remain similar or the same. Because, the PCT remain close. I will elaborate that in the next slide.

And also, the pressure transient in a

LOCA for EPU conditions very similar to pre-EPU because it's constant pressure in a power uprate. So the pressure to pressurization history are similar to the pre-EPU case.

And also the ECCS setpoints and also those are operating requirements, they all remain the same. So based on this in our questionaires, I would expect the limiting break characteristics will not change or will remain closed.

So according to the licensee's evaluation this is confirmed. So the limiting break characteristics remain the same as the pre-EPU situation. And the characteristics are large break LOCA with double-ended guillotine break and occur at the recirculation pump suction. And the single failure assumption is LPCI valve failure and using the top-peak power shape.

So another checkpoint in our LOCA review is the PCT value. The step would expect PCT remain closed for the pre-EPU condition because basically the PCT is closely related to the hot bundle power. And the hot bundle power is controlled by the method hardware limit and also being a heat generation rate limits. So in EPU condition the hot bundle power will not change much. The only change will be on the average bundles the power will be increased. And also because the majority of power increases from the average bundle so the void in the average bundle will increase. And that will cause more two phased resistance. So the hot bundle actually gets more cooling. This is my understanding. So it will help the PCT. So --

CHAIR BANERJEE: Your code has parallel channels? In this description for RELAP is the code modeled by just a set of axial code or are there radical code --

MR. LIEN: In the RELAP model I have average bundle paired it to the hot bundle, you know all connected to the upper plenum and lower plenum. In licensee's model they have cross -- I don't see the cross flow, you know, modeled between the actual -- the average channel and the hot channel. Because licensee's model actually they are not parallel calculated. They calculate the average channel with the bypass channel and use the bundle condition of the upper plenum and lower plenum to recalculate the hot channel results. And using the hot channel result and fit into the heat up code. But in RELAP calculation we have a parallel connect to the upper plenum and the lower plenum.

CHAIR BANERJEE: But no cross flow?

MR. LIEN: No cross flow.

CHAIR BANERJEE: Okay.

MR. LIEN: Yes. Because I notice in always cross flow sometimes it varies on reverse flow, you know it become difficult to get it right for the cross channel. And, actually, this flow is minor, you know.

CHAIR BANERJEE: Yes. In this case anyway for GE fuel.

DR. DIAMOND: Okay. So you have no bypass channel, is that correct?

MR. LIEN: Yes, yes, I do. I do have bypass channel but no cross channel between the average channel and the hot channel I don't have.

So the Staff would expect that the PCT to remain very closed, but however when I reviewed the application it says the PCT calculation at EPU is 1844 compared to 1945 or pre-EPU. The licensee come back with the explanation for this. The licensee said because for EPU calculation it use a conservative assumption. That conservative assumption is no LPCI flow goes through the flow -- because the work is in the recirc pipe. So they put an assumption there that there is no LPCI flow going to the -- so if they used the same assumption in the EPU condition, the PCT will go up to 1914, so which is about 30 degree lower than the pre-EPU case. And also they mentioned that in the pre-EPU calculation they operating them at -- they follow is slightly slower. So that happened at power is slightly higher. That explain that 30 degree difference.

So I think all these explanations acceptable to me for the PCT results.

So in the conformity calculations --

MEMBER ABDEL-KHALIK: So it's not surprising to you that --

MR. LIEN: Initially it surprised me that the pre-EPU is higher. But after their explanation I think it's acceptable.

So basically, you know, it's pretty close the pre-EPU case and the EPU case.

MEMBER ABDEL-KHALIK: Just because the peak bundle power is roughly the same?

MR. LIEN: Yes. Even if bundle power equally is a little power, but like I said, the void distribution will help the hot bundle will get more cooling. Because the average bundle gets more void---

CHAIR BANERJEE: But the hot bundle is closer to the average bundle now.

MEMBER SIEBER: Right.

MR. LIEN: But that effect may be minor. But, you know -- in these hot bundle very close to an EPU standard.

Let me move on. In the conformity calculation the Staff tried to perform as many as possible cases to confirm the break spectrum, not just one point. Because I think the ECCS systems sometimes they play different roles in different LOCA. For example APS flow plays important role in the small break LOCA, but doesn't play much role in the large break LOCA. So I actual covered as much as possible the break spectrum that I can have --

CHAIR BANERJEE: How did the PCT vary? I mean, typically there are always two peaks in the PCT, one for large break and one for sort of a small break. So how different were these two peaks?

MR. LIEN: Actually two peaks and based on my calculation they all showed up in small break

LOCA and the large break LOCA. I will show you the graphs that I have.

Usually for large break LOCA the stress peak, which is around like a 1,000 degree F. But, you know, the second peak which is the focus of our evaluation, the second peak usually go up to like 1800 or 1900, so it's in that range.

CHAIR BANERJEE: And is it a small break?

MR. LIEN: Small break LOCA, my experience those two peaks are closer --

CHAIR BANERJEE: But how high was it for the SBLOCA, how large was the --

MR. WALLIS: Could you give us a table of results? I don't see anything here.

MR. LIEN: Yes. I will go to that table and I'll give close -- because it was --

MR. WALLIS: You will compare it with what the licensee predicted, you would compare the two?

MR. LIEN: Yes. And also --

MEMBER SHACK: Will you show us how they had oxidations, too?

MR. LIEN: Pardon?

MEMBER SHACK: You show whether it had oxidations, too?

MR. LIEN: No. In my calculations I don't calculate that. I only confirmed the PCTs.

That table and also the past might disclose some licensee proprietary information.

CHAIR BANERJEE: Well, we can take it later.

Carry on then.

MEMBER ABDEL-KHALIK: So let me just make sure. The numbers you're showing in the first bullet, these are your numbers or the licensee's number?

MR. LIEN: No. The licensee's number.

MEMBER ABDEL-KHALIK: So what your numbers corresponding to this?

MR. WALLIS: Well, wait. He's just keeping us in suspense.

MR. LIEN: My number, you know actually for EPU condition is 1816.

MR. WALLIS: Are you going to show us those quickly or are you going to keep us waiting?

MR. LIEN: I would rather go to the latest action.

MR. WALLIS: The latest action?

MR. LIEN: Yes. Because we thought we want --

CHAIR BANERJEE: He wants to keep us waiting.

MR. WALLIS: Waiting.

CHAIR BANERJEE: Carry on.

MR. LIEN: Okay. So like I said, I want to cover the entire spectrum as much as I can. So I've done quite a few calculations and the representatives ones are the following.

The first one is limiting PCT case with large break LOCA of discharge coefficient 1.0. And also another large point LOCA with the discharge coefficient .6.

And I also did the small break LOCA of size and .7 square foot. This is the limiting case in the small break LOCA range.

And I also did a small break LOCA at the very end of the spectrum, which is .05 square foot.

And I also changed the initial core flow to 108 percent flow which will cover the main flow domain.

So these five representative cases well

covered the change coefficient and break size and also single failure. Because in the small break LOCA the single failure assumption is battery failure. The large LOCA cases, you know, the single failure LPCI valve fails.

So the summary of the comparison is, you know, the Staff believes the comparison shows PCTs are reasonably close. And the trends are the same. Because we are comparing two results, one is from best estimate code and the other one is Appendix K calculation. So I don't expect they are to be exactly the same, but the trend should be the same.

MR. WALLIS: They're very different. Appendix K and best estimate are very different.

MR. LIEN: Yes. So that's why I would say the trend should be there, the trend. For example the PCT versus break size or PCT versus the change coefficient, you know things like that. I would see that trend to be seen in the comparisons.

So based on the review and our two independent calculations the Staff conclude that Susquehanna LOCA at EPU condition will meet 10 CFR--

MR. WALLIS: Where's the evidence for this conclusion?

CHAIR BANERJEE: I guess he can show it to you in the next session.

MR. LIEN: Yes, I will talk about --

MR. WALLIS: Is that after the break or something or is he going to --

DR. DIAMOND: During the break.

CHAIR BANERJEE: We already had a break.

MR. WALLIS: So what is this next section we keep hearing about?

CHAIR BANERJEE: We will close the session as soon as he's finished.

MR. WALLIS: On the closed session?

CHAIR BANERJEE: Yes.

MR. WALLIS: It has to be a closed session? Oh, now I understand. Okay. Thank you.

MR. LIEN: Okay. So the requirements, the five requirements are listed here.

I found the licensee's calculations show the PCT 1844 and oxidation there was .8 percent. Hydrogen generation is .2 percent. So with these three and the conditions are met the coolable geometry requirement is assured.

And those are based on both calculation results shows the core is flooded with the -- LPCI cooling capabilities. So the Staff concluded the capacity is adequate. So as long as they are remaining available in long term cooling, so the core remain flooded.

DR. DIAMOND: Is there an issue wit decay heat, the decay heat model? I seem to recall this morning somebody brought that up and said that this has got to be discussed later.

MEMBER SIEBER: They later changed to it, yet.

CHAIR BANERJEE: They used the less conservative decay heat model from what I remember.

DR. DIAMOND: The licensee?

CHAIR BANERJEE: Yes. From the PUSAR.

DR. DIAMOND: Okay.

CHAIR BANERJEE: But you can validate that. What sort of decay model would the licensee and you use? You used the same decay heat model?

MR. LIEN: No. In RELAP in our model I didn't use the Appendix K requirements, which is 1971 ANS model plus 20 percent. I didn't use that. I just used the 1979 -- you know, the model in the RELAP. But I did compare the power history. I think the power is pretty close to the -- because like in other project, I compared to the GE result. They have Appendix K power distributions. And from history, and then I compare --

CHAIR BANERJEE: And the licensee used Appendix K?

MR. LIEN: Yes. Yes, that's the requirement.

MEMBER SIEBER: Yes.

MR. LIEN: It's a requirement.

CHAIR BANERJEE: All right. Thank you.

Do you want us now to close the session so that you can talk about things that we're all dying to hear.

MS. JACKSON: Zena, is there anything that you need to say?

CHAIR BANERJEE: So, Zena, we would like to close the session. We would like to close the session.

So anybody who is here should not be here.

(Whereupon, at 4:16 p.m. moved to closed session, to come back in open session at 4:53 p.m.)

CHAIR BANERJEE: So we're back in session. An open session again. Open transcripts.

And we're going to start with containment analysis.

We're running about an hour behind time, or a little bit more. But I do want to finish everything that's on the agenda today. So if necessary, we'll run to 6:15. I hope that's okay with everybody.

MEMBER SHACK: We've got to be prepared to run longer than that.

CHAIR BANERJEE: Well, I'm trying to hurry it on. All we have to do is to keep these Committee members quiet, and then it'll be fine. I have no authority over them, you can see.

MR. BARTOS: Hello. My name is John Bartos. I'm the lead engineer for the CPPU project of PPL. My responsibilities are oversight of all the analysis and design activities.

And I'm here to give you an overview of the containment analysis and talk a little bit about why we don't need to take credit for containment over pressure for NPSH suction or ECCS pumps.

Let's go to the next slide.

I'd like to talk a little bit about the codes that were used for the analysis. LAMB was used for vessel mass and energy release.

M3CPT, the thing that was used for containment pressure and temperature response.

PICSM was used for swell.

And SuperHEX was used for maximum temperatures.

These codes were all the codes that were used in our present analysis. There is no change. They actually were the codes that were used, but our application did request a licensing basis change for two issues associated with the containment analysis. And we talked about these a little bit earlier this morning.

We requested permission to use a prolonged term decay heat model to go from an ANS5 with a 20 percent uncertainty for the first thousand seconds and a 10 percent for the remaining of the events. Two ANSI/ANS 5.1-1979 with a two sigma uncertainty.

We also requested permission to use passive heat sinks in the calculations. This would take credit for heating of the structural steel inside containment, including the liner, that there was no heat transfer beyond the liner.

A question was asked this morning to the LTRs address this. They do by reference. There's a GLTER on the use of SuperHEX for containment analysis. And in that they address these two issues. And both the ELTR and the CLTR reference that LTR.

In addition to that there's some additional correspondence between GE and the Commission on the use of those two changes.

So we elected to for the containment analysis to use the ANSE 5.1-1979 and take credit for passive heat sinks inside containment.

CHAIR BANERJEE: So all these codes and things, they are either accepted or approved?

MR. BARTOS: Right. Actually, the codes are the codes of record for the present OLTP analysis.

CHAIR BANERJEE: And the decay heat model is also accepted right now?

MR. BARTOS: Yes.

MR. GIOSITTS: By the Staff or by the --

MR. BARTOS: Yes.

CHAIR BANERJEE: Okay.

MR. BARTOS: Okay. Let's go to the next

slide.

MEMBER SHACK: Wait. When you say accepted, that licensing basis change has been made?

MR. BARTOS: Oh, no. It's been accepted in that it's been used by other licensees. For us it's part of our request. So they haven't formally accepted our request yet.

MEMBER SHACK: Thank you.

MR. BARTOS: All right. This table shows you a quick summary of the results for the parameter peaks for drywell pressure, wetwell pressure, drywell temperature and suppression pool temperature.

Now, for the LOCA break, the LOCAs, steam pressure -- this is a constant pressure power uprate. Steam pressure doesn't change. And the water, feedwater going into the vessel, those are very small changes. A couple of degree increase in final feedwater temperature.

So one wouldn't expect to see peak drywell pressure, wetwell pressure and drywell pressure change much. But we do see that there is a fairly significant change.

The thing that does change, though, is

that there is more heat from the vessel. And that heat has to get out of the containment. The more it gets out of the containment is through the suppression pool. So we would expect to see a significant increase in suppression pool temperature.

CHAIR BANERJEE: When do those peaks occur?

MR. BARTOS: Well, I'm going to go through it. I have charts which will go through each one of these transients and I will point that out.

CHAIR BANERJEE: I see.

MR. BARTOS: The reason we do see these changes from CLTP to CPPU is that when we redid the containment analysis, we went over the design inputs from our analysis of record. And in talking with GE, we found that there were two assumptions that we thought we needed to change. And these were inputs into the codes that I talked about.

One assumption was in our analysis of record presently for the containment it was originally assumed when we licensed the plant that the containment pressure was at a nominal pressure, which was .5 psig in containment. In talking to GE in the analysis that they have done recently they generally assume -- they look at what the normal band would be and they assume that you're either at one end of the band or other, whichever would result in a more conservative result to the analysis, i.e., you end up with less margin to the limit.

So in that case we agreed that we would when GE did the reanalysis, that they would use either one or the other end of the band of the normal containment pressure. And I'll talk about that specifically for each one of these cases.

The other assumption that we looked at was in the large break LOCA our analysis of record right now assumes as soon as the break occurs, that feedwater starts to coast down. Okay. In looking at what actually happens, we think that it's probably not going to be immediate. And so there's an assumption, at least for the first ten seconds, that we have full feedwater flow. And that's a more conservative assumption and that it results in less margin to the limit, but it's also probably closer to what really happens in real life.

So let's go to the curve, and we can

look from the curves.

This is the short term LOCA DBA pressure response. The black lines are the drywell responses. And the red lines are the wetwell responses. The dotted lines are the current licensed double power values. And the solid lines are the CPPU values.

MR. GIOSITTS: So physically why does the drywell go up so much?

MR. BARTOS: I'll tell you. This peak right here. What's happening is when you get the break, you have a lot of noncondensables.

MR. WALLIS: Right.

MR. BARTOS: You have nitrogen and the drywell. Those get driven into the wetwell through the downcomers. And that's actually what you see right here.

You'll notice when the wetwell pressure exceeds the drywell pressures, we have vacuum breakers on the downcomers, they open up and let the noncondensibles return to the drywell. And what you see here, that's what's happening in this case. And the vacuum breakers close and the wetwell begins to repressurize.

MR. WALLIS: The vacuum breakers are a big range of opening and closing?

MR. BARTOS: Excuse me?

MR. WALLIS: You said they close at ten. They close up way up when the pressure differences --

MR. BARTOS: What I said happened at ten is there was an assumption in the original analysis that the feed pumps coast down. Okay. What we assumed in the new CPPU analysis is that the feed pumps pump full flow to the vessel --

MR. WALLIS: No, we're talking about the vacuum breakers opening. There is only a very short time when the pressure in the drywell exceeds the wetwell.

MR. BARTOS: That's right.

MR. WALLIS: Or the wetwell exceeds the drywell.

MR. BARTOS: Right.

MR. WALLIS: And so you'd think the vacuum breakers would then close.

MR. BARTOS: No. There's a dead band on the opening and closing.

MR. WALLIS: Yes. That's what I was

getting at.

MR. BARTOS: Yes.

MR. WALLIS: So there's --

MR. BARTOS: And they do close rather quickly. You can see they close --

MR. WALLIS: While they're still open there's back flow through them?

MR. BARTOS: Yes. There's flow from the wetwell to the drywell, yes.

MR. WALLIS: But then it must be the other way around because the pressure is less again before they close.

MR. McNULTY: This is Kevin McNulty.

We assumed that our five vacuum breakers opened at their max opening capability. And that is what allows us to see the higher pressure in the wetwell. So they would normally crack at about a quarter pound of differential pressure. In this analysis we assume that it takes to 2½ pounds before they --

MR. WALLIS: When do they close?

MR. McNULTY: Pardon me?

MR. WALLIS: When do they close? At what point do they close?

MR. McNULTY: Once they open, they'll then close again and the pressure drops back down.

MR. WALLIS: At what point do they close? When the pressures cross?

MR. McNULTY: When the full open. In other words, when the wetwell pressure exceeds the drywell pressure by 2½ pounds --

MR. WALLIS: They open.

MR. McNULTY: They open. And then they relieve themselves. The minute when it drops down below a quarter --

MR. WALLIS: They'll close again?

MR. McNULTY: They'll close again.

MR. WALLIS: It's only open for a very short time?

MR. BARTOS: Correct.

CHAIR BANERJEE: They'll open much later, right? Or they won't

MR. WALLIS: But then why does the pressure keep dropping?

MR. McNULTY: The dynamic is when you get the noncondensibles blowing down, you clear our your vents. You then get a slug of water coming up as the noncondensibles are being into the suppression pool. You get a compression of the wetwell air space as the swell of the bubble comes up. And that's what you're seeing there is the increase pressure as the pool swell bubble is created until the differential pressure is hit, the vacuum breakers open. And then you see fall back loads coming in. So that's why the pressure goes back down because the swell that occurred now is falling back down. That's why you're seeing the drop in the wetwell pressure.

MR. BROWNING: And this Kevin Browning.

You can see that happens at about two seconds, at which point they close and then the wetwell begins to slowly pressurize due to the further ingestion of steam.

MR. WALLIS: I just don't understand why it goes down from 35 to 10. That's what I don't understand.

CHAIR BANERJEE: A lot of stuff goes out, probably, in that short period.

MR. WALLIS: But it doesn't. It can't go out if the pressure drop is negative.

MR. McNULTY: Again, this is Kevin McNulty.

Because there's going to be still pressure up in the wetwell, you're not going to see the wetwell relieving itself back down to zero.

CHAIR BANERJEE: No. He's asking how does that brief period when it's open, relieves so much pressure.

MR. WALLIS: All the way down to 10 psi.

MR. BROWNING: This is Kevin Browning.

Two things are happening at that point. First of all, we do have five sets of vacuum breaker, so there is a fairly significant flow area. So they burp the noncondensibles back to the wetwell.

We're also seeing during that sharp decline is the pool level falling back down.

MR. WALLIS: Well, doesn't that change the pressure? It's the gas space in there that sets the pressure, isn't it?

MR. McNULTY: Right. But as the fall back goes back down, your volume increases in size. So it was compressed when you had the pool swell coming out --

MR. WALLIS: So there's condensation in the bubble that's pulling back down. Okay. That could perhaps do it.

MR. McNULTY: So you're having the swell falling back down, so the wetwell pressure will drop.

MR. WALLIS: With condensation.

MR. LOBELL: This is Richard Lobell from the Staff.

It's not really condensation. They're talking about noncondensibles. You're compressing the noncondensibles.

MR. WALLIS: But does it relieve the pressure? You got to have something --

MR. LOBELL: The influx of air is forcing the suppression pool level up.

MR. WALLIS: Okay.

MR. LOBELL: When that air breaks the surface -- or nitrogen I mean breaks the surface, the water level collapses again.

MR. WALLIS: But they've still got the same amount of gas in there, so the pressure should still be the same. It doesn't make any sense.

MR. LOBELL: You've compressed it. You've compressed it.

CHAIR BANERJEE: It's 2½ pounds --

MR. LOBELL: You've compressed it to a high pressure and now it's going back towards more the nominal pressure.

MR. McNULTY: The analysis assumes all noncondensibles in the drywell are forced down into the wetwell.

MR. WALLIS: Well, that seems strange. That little tiny burst of --

CHAIR BANERJEE: The only thing that can explain it is, as you were saying, if there is condensation.

MR. WALLIS: Yes. What's in the bubble after that it will burp is steam, and then it condenses. You've got to remove some gas somehow.

CHAIR BANERJEE: You can't.

MR. BROWNING: This is Kevin Browning.

The gas is being vented back to the drywell through the vacuum break.

CHAIR BANERJEE: Well, he's worried because very little time is open, you see.

MR. WALLIS: Because there's no -- pressure.

CHAIR BANERJEE: Eventually there has to be conservation of mass. So --

MR. WALLIS: Conservation of volume, in a way.

MR. GIOSITTS: And the pressure in the system will equalize very rapidly. I mean, between a bubble which is under water and the free space on top, pressure except for the gravity head and some momentum head is going to equalize at the speed of bound, basically. So that doesn't explain it. There either has to be some condensation going on. So what's probably happening at that point if you look at your calculations is some of the steam is starting to come in as well and collapse.

MR. BROWNING: Correct.

MR. WALLIS: A lot of steam. If you drop the pressure from 35 to 10, you've got to remove 70 percent the vapor. Seventy percent of the gas.

CHAIR BANERJEE: Yes. So that has to do with the dynamics of the condensation.

But let's --

MR. WALLIS: Pass over it.

CHAIR BANERJEE: -- pass over it and Graham can follow this up if he wanted.

MR. BARTOS: I wanted to point out the

peak pressure occurs at this point. And this is the point where the water level drops below the break. So before this point we're getting both steam and water coming out the breaker. And after this point it's just steam coming out.

All right. Now for these cases there were the two assumptions changes that I mentioned. The first current analysis. This assumes a starting drywell pressure of .5 psig. The CPPU analysis assumes a 2 psi initial pressure in the drywell. And also the exception on the feed pump factors into these two cases where the current analysis assumes that the feed pumps start to coast down at the beginning of the event. And the CPPU analysis assumes that you have full feedwater flow up to 10 seconds into the event.

Let's go to the next slide.

This is short term temperature response. We do see an initial increase at 2 seconds into the event. This, again, is due to the assumption. In this case for temperature response the current analysis assumes an initial containment pressure, again half of psi. For the CPPU analysis it's assumed that the initial containment pressure is minus 1 psig. The normal range that we could operate the containment at is minus 1 psig to 2 psig.

Other than this 2 second initial temperature occurrence, which this peak occurs when the events start to clear initial. We have the break, the containment's pressurized. It's pushing water down the downcomers. You get to a point when all the water is pushed out of the downcomers and you start to vent steam to the containment. And that's actually this point right there. Okay.

Let's go to the next slide.

The one is our monitor suppress temperature response. Our current analysis assumes a LOCA and our single failure is we lose one diesel. What that does is you lose an RHR, residual heat removal heat exchanger. And you also lose a number of ECCS pumps.

And so now this is the SuperHEX code and it involves the two changes, the one decay heat and also taking credit for passive heat sinks. So what we did was we ran a case at CLTP one diesel failure without the new decay heat curve and without the passive heat sinks. And that is the red curve.

And then we wanted to see what the method changes would do. So we essentially reran that with the passive heat sink and the new decay heat. And that's the blue curve. And that did give us more margin because those are less conservative assumptions.

Then we ran the CPPU with the one diesel failure, and essentially we came right back with the--

MR. WALLIS: With the methods change or not?

MR. BARTOS: With the method changes. So essentially the methods changes mitigated the CPPU change.

MR. WALLIS: Yes.

MR. BARTOS: Now in doing this we asked GE to run some sensitivity cases. And we looked at some of the analysis that were done at another plant. And what we found was is that the one diesel failure is probably not the worst case single failure. Well, it isn't the worst case single failure. There were other single failures which will result in a loss of a RHR heat exchanger. For instance, the failure of a discharge valve to the heat exchanger or the failure of RHR service water pump.

In that scenario, though, all of your ECCS pumps are running and are all adding heat to the containment. And what we found is is that a single failure where you're losing RHR heat exchanger but yet you have all pumps running which is the directions that the emergency procedure guidelines give the operators, actually resulted in a higher long term suppression pool temperature.

And so we ran a CPPU case with passive heat sinks, with the new decay heat curve, but all pumps running and loss of a RHR heat exchanger. And that is the black line.

And for the CPPU case, that is our limiting long term suppression pool temperature response.

MR. WALLIS: That temperature looks higher than the one on the next slide, though.

MR. BARTOS: The one on the next slide, I believe --

MR. WALLIS: Oh, that's ATWS.

MR. BARTOS: That's ATWS.

MR. BROWNING: That's a special case.

MR. BARTOS: So this was a bit of a revelation to us. We put this into our corrective action system, this event, and we talked to GE and we asked them to look at it for a Part 21 type issue.

So for the CPPU analysis, this would be our analysis of record.

Let's go to the next slide.

Okay. This is the ATWS containment analysis. Peak vessel pressure at CLTP is 1288, it goes up to 1336. It's still within the 1500 psig limit.

Peak containment pressure actually goes down. And peak suppression pool temperature goes down. And there's a reason for that. That is because we choose to elect to adopt enriched boron for our standby liquid control system. The reason that we did that was specifically for these transients.

We knew that if we didn't do something, that the suppression pool temperature limit would probably be challenged at 220 degrees.

So let's go down the next couple of slides. This shows the CLTP is the red and the black is the CPPU. And it shows the slight reduction.

Now this isn't a coincidence. When we had GE do this we requested that GE look at what born concentration would essentially mitigate this transient and give us the same results. And they came back and they told us -- Kevin, what was the concentration?

MR. BROWNING: 88 weight percent.

MR. BARTOS: And that's what was used in the analysis.

I'd just like to note that the actual weight percent that we used is higher than that, and that's what --

MR. McNULTY: Ninety-six, enriched we used 96.

MR. BARTOS: Yes, we used 96. What we found was that when we went out to try to buy 88, that was a nonstandard value.

MR. McNULTY: You can't. No.

MR. BARTOS: And that the 96 was actually cheaper. But that in fact does give us some extra margin.

MR. WALLIS: Now this boron is all squared in on one side of the lower plenum?

MR. BARTOS: It's injected --

MR. WALLIS: How does it get to the other side? How does it get to the fuel elements on the other side of the --

MR. BARTOS: It's injected into the bottom of the vessel. It's --

MR. WALLIS: But it's only injected on one side, isn't it?

MR. BARTOS: Yes. But the record water level is lowered. So it's injected into the bottom of the vessel. And basically the analysis assumes it sets there. And then once reactor water level is raised, the water is then flushed into the core.

MR. WALLIS: And then it just spreads over the whole plenum?

MR. BARTOS: Yes.

MR. BROWNING: That's what the model showed.

MR. BARTOS: Yes. The mixing model is a version of ODIN of GE developed. And the mixing part of ODIN was based on tests that were done at -- there is a GE topical on this.

CHAIR BANERJEE: There was an issue about this some time ago. And I don't know how it was resolved.

MR. WALLIS: But the injection system is the same as it was before the power uprate?

MR. BARTOS: Yes.

MR. WALLIS: It's just that you're injecting much less stuff?

MR. BARTOS: Yes.

MR. WALLIS: So I guess the mixing -- and it's denser is it now or is it --

MEMBER SIEBER: Yes.

MR. WALLIS: Does it stratify the whole plenum?

MEMBER SIEBER: No. You can't tell the difference. It's less dense.

MR. BARTOS: Yes, it's less dense.

MR. WALLIS: But does it tend to stratify because of its boron or not?

MR. McNULTY: This is Kevin McNulty.

We've applied to use new mixing model based on the values of this testing. In our ARTS/MELLLA analysis we saw the increase in heat pool temperature. So the issue of stratification that was occurring and the longer time it takes for the boron once you flood up to mix to shut down the reaction is what gave us the increase in suppression pool temperature. So that was incorporated into the GE part of their LTR that was approved in September or February of 2000 to incorporate that new mixing model. And it was part of our ARTS/MELLLA analysis and also our EPU analysis.

MR. BARTOS: Yes. And the results that we saw in ARTS/MELLLA is what drove us to the enriched boron.

MR. McNULTY: We saw about a 20 degree increase in suppression pool temperature from our current license to the ARTS/MELLLA analysis.

MR. KRESS: When you inject the boron you basically scram the reactor. And you're now dealing with decay heat, which to me CPPU is a higher level. I would have expected even with an enriched boron to see some higher temperatures here. Can you tell me why not?

MR. BARTOS: The enriched boron shuts the reactor down faster in a shorter period of time. By doing that there's less energy put to the suppression pool.

MR. KRESS: Okay. So the decay heat's not really driving that --

MEMBER SIEBER: In the long run it would be the same, I think.

MR. KRESS: What?

MEMBER SIEBER: In the long run the temperatures would come together.

MR. KRESS: Because the CPPU is a higher decay heat level?

MEMBER SIEBER: Yes. Right.

MR. KRESS: But I understand what you're saying.

MR. BARTOS: Yes. This is actual operating power.

MR. KRESS: Yes. I'm with you on that.

MR. BARTOS: Okay.

MR. KRESS: Okay.

MR. BARTOS: Go to the next slide.

The other one was ATWS contained pressure. This is suppression pool temperature. And the results are very much similar.

Okay. This is a comparison on suppression pool temperature response. This is our DBA LOCA. This is the Appendix R analysis. And this is the ATWS, again for long term DBA LOCA gives you the peak suppression pool temperature. In the short term the ATWS does give you the higher peak, but it is bounded by the DBA LOCA.

I want to talk a little bit now about net positive suction head available for the RHR core spray and the RHR and core spray pumps.

Our containment analysis did not take credit for containment over pressure. Our NPSH available is based on the suppression pool design temperature of 220 degrees, which we never reach. And it's also based on a max -- it's based -- the strainer fouling is based on the maximum strainer clogging or fouling that we calculate plus additional margin.

CHAIR BANERJEE: Do you have stack strainers or what sort of strainers?

MR. BARTOS: We have the stack strainer design.

CHAIR BANERJEE: Disk or is it like the rectangular stack strainers?

MR. BARTOS: They're disks.

MR. McNULTY: Stacked disks.

CHAIR BANERJEE: Stacked disks. And they're how far below the surface of the suppression pool? You have vortex breakers or anything?

MR. BROWNING: No, we don't. But we've got vortex calculations which assume that the entire flow enters the strainer from the top and we still have enough margin -- we still have enough level.

CHAIR BANERJEE: How many inches or feet below the surface are you? Because I've seen some calculations based on numbers and all which we let go in the past, but we have to be sure that you've got enough head there above them. How many? Is it a couple of feet or is it --

MR. BROWNING: I don't know the exact number off the top of my head. However, I do know that our vortex calculations do assume the lowest postulated suppression pool level during a DBA LOCA. And I'll also point out that those calculations are applicable for CPPU because we're not changing any required flow rates.

MR. BARTOS: Rick Pastollis.

MR. PASTOLLIS: I'm Rick Pastollis.

We also did testing with an actual RHR stacked disk strainer at the EPRI training facility in Concord, North Carolina to demonstrate that we will not get vortex problems with our strainers.

CHAIR BANERJEE: So you had a sort of a

scaled model or something?

MR. PASTOLLIS: This was a full scaled actual core spray -- I'm sorry. RHR strainer that we used in the facility.

CHAIR BANERJEE: All right.

MR. BARTOS: It was one of the strainers you actually installed in the plant.

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MR. PASTOLLIS: That is correct.

CHAIR BANERJEE: Okay.

MR. BARTOS: Our RHR core spray pump required is actually fairly low. And let's go to the next slide.

This gives you a table. For the RHR pump the MPSH required is bulk heat and the MPSH available is 8.17.

The other thing I'd like to note is that the MPSH required is -- we used the runout flow required, not the normal flow. And in the core spray the MPSH required is four feet and the MPSH available is five and three-quarters feet.

MR. WALLIS: Does it take account of the fact that the intake to the first stage is way below the flow?

MR. BARTOS: No, it doesn't.

MR. WALLIS: It doesn't?

MR. BARTOS: Those are calculated to the center line of the flange on the pump. And I'll show you that. It doesn't take credit for the vertical--

MR. WALLIS: That's many feet.

MR. BARTOS: Yes.

MR. WALLIS: Yes.

CHAIR BANERJEE: Do you have a diagram or something?

MR. WALLIS: Yes, it's the next figure.

MR. BARTOS: Sure.

MEMBER SIEBER: That also means the pump manufacturers --

MR. BARTOS: These are outline drawings of the RHR pup, the core spray pump and I've also included one of the condensate pumps, and there's a reason for that. The design of the pumps are all the same. They're stack stage vertical pumps. The MPSH suction calculation is done to the centerline.

MR. WALLIS: So assuming that the pump is horizontal instead of vertical?

MR. BARTOS: No, it is vertical.

MR. WALLIS: No. But I'm saying they're saying seems to be based on being horizontal. Does it give you any credit for that height?

MR. BARTOS: That's the --

MR. BROWNING: Excuse me. This is Kevin Browning.

The pump vendor or the MPSHR specified by the pump vendor is based upon on the inlet where John just showed you there. It is the suction flange inlet. And that's why it's appropriate to use that.

You do get additional static head as the fluid flows down into the suction can.

MR. KRESS: But you lose it coming back up?

MR. WALLIS: No. But that's what the first --

MEMBER SIEBER: You've already pumped it.

MR. BARTOS: It comes up through the stages. You know, the first stage is at the bottom. The final stage is at the top.

MR. KRESS: So you could make --

MEMBER ABDEL-KHALIK: So it just depends on what the manufacturer specifies as the required MPSH?

MR. KRESS: And they take credit for that already.

MEMBER ABDEL-KHALIK: Yes.

MEMBER SIEBER: Also you have to make sure that the manufacturer did not specify the center line of the pump suction above the floor here.

MR. BROWNING: We have confirmed that.

MEMBER SIEBER: Okay. Because they sometimes do that in an open can pump.

MR. BARTOS: These pumps were designed to pump saturated fluid. And the reason I included the condensate pump, which is the same design, same vendor, is that the condensate pump pumps liquid out of the condenser hot well. And if you think about it--

MEMBER SIEBER: Which is a couple of inches.

MR. BARTOS: -- the condenser operates with dump pressure, which is a vacuum. And that pump operates every day 24 hours a day, and it does the job quite nicely.

The other --

MEMBER SIEBER: These aren't to scale, though, right?

MR. BROWNING: No, they're not. No. That's a good point. The condensate pumps you can see -- this is Kevin Browning, by the way, are 10 stage whereas the RHR and core spray pump are six stage and four stage respectively. Condensate pumps are much bigger.

MR. BARTOS: Yes. This is a very big one.

MEMBER SIEBER: Well, the stage isn't

necessarily the same height in each pump. I would suspect the condensate pumps get pretty deep compared to the --

MR. BARTOS: Yes.

MR. BROWNING: Yes.

MEMBER SIEBER: -- core spray and RHR.

MR. BROWNING: This diagram is just provided to illustrate the similarities in the pump design.

MEMBER SIEBER: Yes. I don't want anybody to get misled.

MR. BARTOS: Right.

Let's go to the next.

The other thing that we take advantage of is that the ECCS pumps are installed at the lowest point in the plant. And the cans with the stages actually extend into the foundation base of the reactor building.

And, as Kevin mentioned before, our MPSH calculations assumed that we started our minimum allowable water level by technical specifications. And we do have a large amount of actual -- one thing I want to point out is that the bottom of the suppression pool is actually three feet higher than the bottom floor level of the reactor building.

MR. McNULTY: Kevin McNulty.

We assume 18 feet of -- the suppression pool to the bottom of the base in our analysis. So that's what you're looking at in terms of static head.

MR. KRESS: And who gets a different level if you actually went into one of the severe accidents?

MR. BARTOS: Excuse ne?

MR. KRESS: Is this modeled in the PRA? I presume that 18 feet has to do with design basis?

MR. BARTOS: Yes.

MR. KRESS: You know, severe accidents you can drop that level.

MR. McNULTY: Eighteen feet accounts for -- and during a DBA LOCA some of the suppression pool volume being held off in the drywell, on the floor of the drywell. So that is calculated on that that volume be retained.

MR. BROWNING: This is Kevin Browning.

The static head does assume containment main integrity is maintained.

MR. KRESS: Yes. Okay.

MR. BARTOS: What's what I wanted to get across with regards to the containment, the pressure issues.

Okay.

CHAIR BANERJEE: When you say like MPSH required five feet, is that at a particular temperature that you say that in the previous slide?

MR. BROWNING: This is Kevin Browning.

The definition of MPSH are == you know, you're comparing absolute terms. And it's the suction head that you have available at the center line of the pump suction less the saturation temperature of the fluid.

CHAIR BANERJEE: Okay. So whatever is the saturation temperature or pressure you take it away?

MR. BROWNING: That's correct.

CHAIR BANERJEE: Okay.

MEMBER SIEBER: So you need five feet above the inlet.

MR. BARTOS: Yes.

MEMBER SIEBER: And how far does that -- well, okay. Never mind.

MEMBER MAYNARD: Five feet actually will

get a pressure than an actual --

MEMBER SIEBER: Yes, if it were still ought to be five feet.

MR. BARTOS: Okay. Thank you.

MEMBER SHACK: Before you leave, I've got some questions that aren't particularly directly relevant to this that one of our absent members, John Stetkar has asked. And before we start off in PRA land, let me just come back to a couple.

I had a question about the RCSI system where it says there's no required change in the RCSI flow rate. And he's sort of wondering because you have a higher decay heat level how this can be.

MR. McNULTY: This is Kevin McNulty.

Our accident analysis we don't take credit for RCSI performing any function.

MEMBER SHACK: Okay. So that's strictly--

MEMBER SIEBER: Yes, that would do it.

MEMBER SHACK: And you had another case here where the radiation dose, you got an air operated valve limit switch, conduit seals decreased from 39.8 years to 13 years. What are the functions performed by that valve? Is that a significant difference? Is that something that you maintain?

MR. BARTOS: John Schleiker.

MR. SCHLEIKER: Yes. I'm John Schleiker.

Well, a couple of things. We're going to be putting qualified seals in those limits just before we go to EPU. Do you still have the question.

MEMBER SHACK: That solves that question, yes.

MR. BARTOS: Okay.

CHAIR BANERJEE: Okay. Thank you. Thank you very much.

So we now move on to the probabilistic safety analysis. And I guess it would be Mr. Lehmann

MR. LEHMANN: My name is Chett Lehmann of PPL. And with me is Frank Chish, who has over ten years experience in PRA. He's also PPL. And John Vanover, who is been our PRA consultant on power uprate.

First slide, please.

This is a summary of the results of our internal events including flooding PRA. The two figures would mirror our core damage frequency and large early release frequency, also known as CDF and LERF.

We have two nearly identical units. There's only some small electrical supply symmetries between the two.

The results shows a 6 percent increase in CDF and a half of percent increase in LERF as a result of CPPU compared to the current licensed power.

MR. KRESS: How did you calculate LERF?

MR. LEHMANN: What's that?

MR. KRESS: Did you use the Brookhaven method for calculating LERF or did you use --

MR. LEHMANN: I'm not familiar with the Brookhaven method.

MR. KRESS: Well, all they look at is whether or not a sequence has core melt within a fraction of time before you have containment failure. And just add up those sequences, frequencies. They'll really do a level 2.

MR. LEHMANN: No. No.

MR. KRESS: I just wondered did you do a level 2.

MR. CHISH: We did a detailed level 2 analysis. We had 12 release bins and large early, obviously one of them. And we looked at --

MR. KRESS: Excuse me. What characterized the large early event?

MR. CHISH: What characterized what, sir?

MR. KRESS: The large early. Was it an amount of fission products --

MR. CHISH: It's ten percent fission product was used.

MR. KRESS: Ten percent. Okay.

MR. CHISH: Ten percent. And within less than six hours from us declaring a general emergency.

MR. KRESS: So 9 percent wouldn't fall in that then?

MR. CHISH: So that would be an intermediate release.

MR. KRESS: Yes. And did you by any chance add those LERFs together?

MR. CHISH: Did I add the LERFs together?

MR. KRESS: For two plants?

MR. CHISH: No, we didn't. No.

MR. LEHMANN: We'd have to have a common--

MR. KRESS: Of course, they're low enough it doesn't -- It's not much. You know, jus wondering. You're well within guidelines-

MR. LEHMANN: We model the common systems, but we do quantify them separately.

MR. KRESS: Sure. That's the answer.

MR. LEHMANN: The CPU effect is largely due to three things. First of all, it's a decrease in the required loop recovery times, a slight decrease in the available or the allowable operator action times. And these are directly attributable to the increased decay heat as resulting from CPPU.

The third thing is there's a slight increase in the SRV probability of being stuck open. Because with the increase in energy, they cycle more frequently essentially. There's a slight increase in the probability of failing and having a stuck open SRV.

MEMBER SIEBER: What's the change in operator response time in minutes? And what is it?

MR. LEHMANN: I'm going to talk about

that a little bit later.

MEMBER SIEBER: Okay.

MR. LEHMANN: I have a couple of examples. Per unit we have approximately 80 operator actions in our model. And we've looked at those and determined failure rates.

MEMBER MAYNARD: You made some changes that actually increased allowed time for operator actions. Did you also take those into account in the other direction, or did you only take hits for decreased operator action time?

MR. VANOVER: We only took hits for decrease at the time that we did the PRA analysis.

MR. LEHMANN: Correct.

MR. KRESS: Did you use the EPRI model for the effect of that on human error probability?

MR. LEHMANN: Which is that?

MR. CHISH: The --

MR. KRESS: Yes.

MR. CHISH: The ASAP model for less than one hour.

MR. KRESS: Okay. That's what I was getting at, for less than one hour --

MR. CHISH: ASAP.

MR. LEHMANN: We used the adjustment.

MR. KRESS: All right.

MR. LEHMANN: Okay. So to put this in perspective compared to Reg. Guide 1.174 both the change in CDF and the change in work would be characterized as a very small change in risk according to Reg. Guide 1.174. The star on the chart represents where we are in terms of our baseline CDF, and our change in CDF as a result of power uprate.

MR. WALLIS: That should be a gold star.

MEMBER SIEBER: Just so I understand the key there.

MR. LEHMANN: Certainly.

MEMBER SIEBER: Region I no changes allowed. Region II small changes. Is that allowed.

MR. LEHMANN: Yes.

MEMBER SIEBER: Region III very small changes. It should be backwards, right? Region II should be very small and Region II should be small?

MR. CHISH: I think the "very small" refers to the core damage frequency change.

MR. RUBIN: This is Mark Rubin from the Staff.

Perhaps I can answer that question. You were correct in your interpretation. The regions are to show that where we have confidence in what the baseline plant risk is, we're willing to accept a somewhat higher delta risk due to the licensing change request. While if we don't have a complete model or if all the modeling attributes and initiators suggests that you may be somewhat above ten to the minus four, then we would start to question whether you should have any significant increases at all. And, in fact, search for ways to reduce risk.

But in any case, very, very small changes are allowed by this process. And that would be the ones that you see in the very small region called III.

MR. KRESS: These baseline values --

MR. LEHMANN: Yes.

MR. KRESS: -- are internal events?

MR. LEHMANN: Internal events plus --

MR. KRESS: What would you expect the seismic to do?

MR. LEHMANN: As part of CPPU we did effectively a quantitative evaluation of seismic.

MEMBER SHACK: But the 1.174 guidelines, that's a total CDF. You've plotted the internal. Your star is in the wrong place.

MR. HARRISON: This is Donnie Harrison from the Staff as well.

If you were to look at what Reg. Guide 1.174, if you were in Region II there's words in that Reg. Guide that talk about the need to know total CDF. If you were coming out in Region III what you need to know is that there is no vulnerabilities that have been identified with the seismic or the external events that would make you think that you're going to be unfavorable.

MR. KRESS: But the uprate doesn't the delta CDF.

MR. HARRISON: For like a seismic event, and the Staff did a qualitative approximation of seismic risk would be for the plant given its seismic hazard curve to get a ballpark. And I think we were saying it was somewhere around 2E to minus five.

MR. KRESS: So it just moves that thing away.

MR. HARRISON: It moves it to the right

but not up.

MR. KRESS: Still in Region III?

MR. HARRISON: Right. Right. And it doesn't move far enough to raise a question.

CHAIR BANERJEE: Can we carry on?

MR. LEHMANN: Thank you.

CHAIR BANERJEE: I think we need to finish this at most in five minutes or less.

MR. LEHMANN: I'll do my best.

MR. KRESS: Have you ever done a level III at this plant, site?

MR. CHISH: No. For the license renewal yes.

MR. KRESS: You did a level III?

MR. CHISH: Yes.

MR. LEHMANN: Yes.

MR. KRESS: And you came out of that with total deaths and total injuries as well as whether or not you meet the QHOs?

MR. CHISH: We wound up with evaluating the severe accident mitigational terms that we could employ and be economical given the baseline dollars per man rem that the NRC has given us in the regulation.

MR. KRESS: 2000.

MR. CHISH: Yes, 2000. Exactly. And we had more SAMAs that we were looking at a potential. I don't know if that answers your question.

MR. KRESS: It didn't exactly.

MR. VANOVER: This is Don Vanover.

A level III analysis was done in support of the SAMA, but the figure of merit in the license renewal is a different thing --

MR. KRESS: Is a different thing.

MR. VANOVER: -- than the fatalities and death.

MR. KRESS: Yes. I was just wondering how your plant status was with respect to the QHOs and with respect to the majors that I might dream up. But, you know, if you haven't done those--

MEMBER SIEBER: QHOs aren't a limit, though.

MR. KRESS: Pardon?

MEMBER SIEBER: QHOs aren't a limit.

MR. KRESS: I don't know. There's no requirement that they ever be met. I was just curious.

MEMBER SHACK: Gentlemen, can we go on?

MR. WALLIS: There is no issue with this, is there?

MR. LEHMANN: I'm not aware of any.

MR. WALLIS: So why do we need to talk about it anymore.

MEMBER SHACK: We can try to move on.

MR. LEHMANN: Okay. This is -- we're way below.

As I said before, we have the level I and the level II in LEFR.

External events were originally done as part of the IPEEE study and internal fires revisited as a result of some RAIs. What we did is we used a current cable database and the current PSA models to capture fire effects. This is not a fire PRA, but it represents a sensitivity study. And this showed the same basic results. In other words, very, very small changes from current licensed thermal power to CPPU.

And as I said before, we did other external events and seismic --

CHAIR BANERJEE: You do it the same way.

MR. LEHMANN: Okay. I'll try to go as

rapidly as I can.

Our PSA reflects the CPPU plant configuration. We made specific model changes prior to the submittal. Re-evaluated using thermal hydraulic methodology to re-evaluate the success criteria, the required operator action times.

And configuration control in our PRA is maintained by keeping it consistent with our emergency procedures. And all the modifications were looked at for impact on the PSA and included if applicable.

As a result of the modifications there were no new initiating events, no increases in challenges, no additional major sequences were brought about by changes, modifications.

There were two minor impacts, one was we've talked about before was the one pump standby liquid control operation with enriched boron. And the other one, we have an extra spray pond bypass valve.

MEMBER SHACK: John Stetkar had another question, which was your assumption that your base probability for a stuck open relief valve just was conservatively bounded by the 13.3 percent increases. And his question is why is that a conservative bound on the failure probability for an increase?

MR. CHISH: We pro-rated it based on the increase in power. We didn't expectedly cycle it. But it's been cycled several times just from the initial transient -- with our current power level, and absent thermal hydraulic work, we just -- so we just bound that by a --

MEMBER SHACK: Well, we know how you scaled it. The question is why is it a bound?

MR. LEHMANN: Did you say that was a bound?

MR. VANOVER: I don't recall we had used the word "bound." If we did, it's best estimate. We go three options out --

MEMBER SHACK: It's called a conservative upper bound is what it's called. But that's John's question, is why, you know. So you just scaled it and that's your first order estimate of the change?

MR. CHISH: That's correct. Yes.

MR. VANOVER: And it's there's never been a stuck open relief value at the site. So it's based on a non -- a prior and we may have been --

MEMBER SHACK: No calculation was done of the number of cycles that you're going to go through before and after the CPPU or the EPU?

MR. LEHMANN: Okay. These are two sample operator actions. These are ATWS operator actions, which the two members of the ACRS Subcommittee were able to observe at Susquehanna. And these are the allowable operator action times for these two specific. One is to inhibit the automatic depressurization system and the other is to initiate the standby -- control system.

As you can see these changes from five minutes -- I'm sorry. From current license thermal power from six minutes to five minutes. And you can see below there the increased failure probability that results from the decrease in time. Because the less time he has, the more likely he is to make an error according to the methodology.

And that's what those are. As I said before, there are small increases in the failure probability, and particularly for the short term actions. And those were included into the model.

MEMBER SIEBER: You've listed two. Do

you have any guess as to how many you would have in 30 minutes? How many operator actions would be required within the first 30 minutes?

MR. CHISH: It depends on transient.

MR. LEHMANN: Well, it depends on the scenario and the transient.

MEMBER SIEBER: Well, your worst one,

MR. LEHMANN: Jim, do you have a clue?

MR. WILLIAMS: Within 30 minutes?

MEMBER SIEBER: Yes.

MR. WILLIAMS: For ATWS you're talking a few dozen operator actions, easily.

MR. KRESS: But you include all those in the PRA at the same time.

MR. WILLIAMS: Yes.

MEMBER MAYNARD: But didn't you actually increase the time allowed for some? I don't know if that's for the ATWS or not?

MR. WILLIAMS: James Williams.

For the ATWS the time the inject liquid doesn't change, we have a two minute limit today that's a two minute limit at CPPU. The times that we extended were the times to place suppression pool cooling in service. And the original time was about the second step -- in service. We extended that to 1100 seconds and 1600 seconds for the second thing just to give the operators more time.

When we finished the analysis we found that the suppression pool temperature was still within the design basis of the containment. So even by giving the operators more time, we didn't effect containment design analysis.

CHAIR BANERJEE: Can we wrap this up now?

MR. LEHMANN: Yes.

CHAIR BANERJEE: I think that's --

MR. LEHMANN: That's essentially all I have.

CHAIR BANERJEE: If there's no more comment, which I think we'll keep to NRR next up. Let's move on to the next. Mr. Harrison, right?

So again, please try to keep to 15 minutes.

And if anybody asks you any questions, refuse to answer them.

MR. HARRISON: Actually, I think we'll go faster than 15 minutes.

CHAIR BANERJEE: Oh, great. You can

make up time then.

MR. HARRISON: Yes, well I can't make up an hour and a half. I was only given 15 minutes. I'll try to make up five.

CHAIR BANERJEE: All right.

MR. HARRISON: My name is Donnie Harrison. I'm with the -- or I was with the PRA staff within NRR. I'm the lead reviewer on this application for the risk part.

And what I thought today what I'd do is given that there's a number of fairly new ACRS members, is walk through the risk review that we do. Because it's unique in the sense of these are not risk-informed applications and you need to understand that coming in. Because that sets the ground rules by which we can perform our review.

So with that, I'll jump to the conclusion first so you know where we're going.

In doing the review the Staff did not identify any "special circumstances." And that's in quotes. We'll define what special circumstances are. But basically that would rebut the presumption of as were protection provided by the licensee meeting the currently specified regulatory requirements. That's a legalistic term, but that's the scope of our review and we'd have to play within that context.

Again, the Susquehanna power uprate is not risk-informed, therefore it's not evaluated per Reg. Guide 1.174 directly. There's five principles in Reg. Guide 1.174. We do not use those five principles in this review.

The applicant makes their submittal in accordance with their GE topical report for constant power uprates. We review it in accordance with review standard 001 Matrix 13. The Staff review is driven by this SRP Section 19.2 Appendix D. It's the use of risk information or reviews of non-risk-informed license amendment requests.

The scope of that review is to determine a special circumstance exists, and then there's that whole legalistic following. In doing that, we confirm that the risk associated with the power uprate are acceptable.

CHAIR BANERJEE: By risk, you mean CDF and LERF?

MR. HARRISON: CDF and LERF, yes. That's the shorthand for -- and I understand the issues, Dr. Kress, with that definition.

MR. KRESS: I know everybody does.

MR. HARRISON: Yes. Okay. Yes, it's a shorthand review.

MEMBER SHACK: Even the licensee is careful to specify these things are always in terms of a percentage.

MR. KRESS: Oh, yes.

MEMBER SHACK: So that he can avoid your problem.

MR. HARRISON: Okay. Now in trying to determine if we have special circumstances, this is what the Staff has to look at.

Issues that could reflect of the presumption of adequate protection. You get that by meeting your regulations, meeting your licensing basis. So if the licensee does that, what we have to look for are situations that were not identified in the development of the regulations. That if you saw this issue as being important enough, you'd write a new rule. Or, we know something about this plant and the risk associated with this power uprate and if this was risk-informed, we'd deny it. Those are the two conditions by which we have to look at the application to see if we want to essentially reject it. We're not looking for approval necessarily as much as we're looking to see if there's something here that would cause us to reject the application.

You can't read this drawing, but what we're going to do is start at the type diamond and work down the process. This is the Appendix E process flow object. The next couple of drawings are going to go through this.

The next diamond is we get a non-risk-informed submittal. It meets the deterministic requirements for its licensing basis. We take a look at it. We see if could rebut the presumption of adequate protection and it has those special circumstances. If it doesn't, we stop our review. If it does, we then inform the licensee that we have some issues. At that point we also have to inform our management that we have a risk concern. And by the way, there's going to be some schedule impacts from this.

There's also a commitment that we tell the Commission if we ever go past this box.

So with that, the next process assuming

our management -- because the next block talks about the management can determine that they disagree with the Staff technically, and they can actually close the issue. If they agree that special circumstances exist, we can request and evaluate risk information. If the licensee does not provide it, then they are at risk -- if I use that word -- that we will reject their application.

Okay. If they provide the information, then we will conduct a review. We will formally look at Reg. Guide 1.174 safety principles. If they are not met, you go down. If they meet those, then we stop our review. If they aren't met, then we raise those questions regarding adequate protection and we can use other factors in making determination if it's an acceptable application anyway.

Okay. So we've reviewed 15 or so power uprates. We've never gone past the first diamond. Okay. We've always bounced out of never having found something that would challenge adequate protection. That's especially true for BWRs that have risk numbers as a base case so low that you'd have to have some phenomenal event get discovered that would put them up so high that you'd start to worry from a risk perspective.

So, we looked at their model, we asked them some questions. They addressed our questions.

By the way, on the SRV they had three different conditions they looked at. The SRV that they called their upper bound is the one where they just scaled it up to 13 percent.

I mean, you could also look at that and say given it's opened the first time, you have a decreasing probability of it sticking closed because it's already proved itself in the last half a second. So there's different ways of looking at cycling SRVs, but it's a reasonable approach to scale it up.

So we looked at those types of things. We looked at the HRA, the human error probabilities primarily because that's where most of the impacts is.

MEMBER SHACK: In the original IPE, I mean Susquehanna was famous for its low baseline error probabilities. Are those now more reasonable?

MR. HARRISON: Yes. Well, what's happened is they've integrated into their PRA the actual HEPs that are using the EPRI methodology, the cost-base methods they're using more of those traditional methods.

If you go back to the late '80s, early '90s I think there was a -- and the original IPE was the argument that their operators did not make those errors. They followed procedures and you have incredibly low error probabilities. Now you will see on the ATWS failure to initiate slick. t's going to be where everyone else, you know, .1. If you get down to five minutes, it's going to be .2 or approaching that area.

So you're going to see that they've become more normalized, if you will.

So looking at this from a risk perspective, the numbers they meet, as you saw. They're well within -- like I said, the Staff did a ballpark seismic guesstimate. That was around 2E to minus five. The fire estimate is around 10 to the minus seven. Six if you take credit for suppression. If you don't give them any credit for suppression, it comes into the two minus five range, I believe. But that still puts you far away from where you would start to question adequate protection.

So because we couldn't find anything in this review that would cause to raise that question, we concluded that there were no special circumstances with this application.

MR. KRESS: So you've never looked at level 3 results when you're thinking about special circumstances?

MR. HARRISON: We've looked into that five or six years ago. If you remember, I gave a presentation on LEAPSTOP, if that's how you pronounce it, about the fact that if you do a 20 percent uprate, your fission product inventory is going to be 20 percent higher, the accidents are going to occur 20 percent faster --

MR. KRESS: Forty percent.

MR. HARRISON: Well, 20 percent faster with 20 percent more stuff.

MR. KRESS: Yes. You got twice as much.

MR. HARRISON: And what they did was they added those two numbers together. You can't really add because you're dealing with two different things. But they argued that --yes. And if you got two plants, you could say -- again, you have to be careful there because of wind directions and how things fall out, but yes you could argue for doubling the facts.

That being said, our metrics have always been CDF and LERF. And that's what we look at as a ballpark, even though if you look at a plant like Susquehanna given their numbers are so low, it would be hard to imagine that you would have a problem.

MR. KRESS: How far away is New York City?

MR. HARRISON: You know, I don't know. 150/120 miles.

MR. KRESS: Well, there's a lot of population there.

MR. HARRISON: Yes, it's a long ways away.

MR. KRESS: A pretty populated city?

CHAIR BANERJEE: Well, we're not operating Indian Point.

MR. KRESS: That's for sure. That's for sure.

MR. HARRISON: But anyway, that's the Staff conclusion on this review.

Any other questions.

CHAIR BANERJEE: All right. Donnie,

that's very nice for you to finish on time. Thank you. And we've picked up three minutes.

So I think now we move on to the PPL. Maybe we can make up 15 minutes here. Is it possible?

MR. WILLIAMS: It's possible.

CHAIR BANERJEE: If only you would be faster.

MR. WILLIAMS: I'm an operator. I'm always hungry.

CHAIR BANERJEE: Good. All right. Go for it.

MR. WILLIAMS: Okay. My name is James Williams. I'm a unit supervisor in the Operations at Susquehanna. I'm also the Operations representative for the power uprate and license renewal programs.

I'm going to be discussing the effects of the uprate on mostly operating procedures, operator actions, timelines and operator training.

Currently Susquehanna uses the EOPs developed by the BWR Owner's Group Ref. 4. For most of the operating procedures, the uprate does not require any new procedural actions. There are, however, some minor changes for setpoints, flow rates and pressures.

Next slide.

All right. For example, we have an awareness step in a couple of the EOPs that remind operators to prevent uncontrolled condensate injection. We've uprated our condensate pumps and placed a little more emphasis on controlling the reactor pressure.

For the first couple of minutes following a scram or a transient we have to make sure that we maintain reactor pressure above 700 pounds. It used to be 600 pounds.

Another minor change, our heat capacity temperature element is going to change a little bit. Heat capacity temperature limit plus RPV pressure against two suppression pool parameters, temperature and level. With power decay heat associated with CPPU the temperature limit curves are adjusted downward a few degrees.

Next slide.

The graph on the left is pre-CPPU. The graph on the right is post-CPPU. It's a little bit hard to read, so I have a table that gives you an example.

Next slide.

All right. So I gave you some examples to look at. For a case where you have low suppression pool level of 22 feet, our normal level is 22 to 24, and we have a thousand pounds of reactor pressure our capacity temperature has changed from 189 down to 186 degrees Fahrenheit. Not a big amount, but it is noticeable.

Now our heat capacity temperature limit is used in the primary containment control EOP and in the emergency time. And the primary containment control EOP exceeding the heat capacity temperature limit in a non-ATWS situation requires us to rapidly depressurize. So a couple of degrees earlier we will rapidly depressurize now due to CPPU.

In the emergency plan for at ATWS situation it's a general emergency declaration. For a non-ATWS, it would be a site area emergency.

All right. Next slide.

CPPU is not significantly effecting the operator response times. For example, for an ATWS situation we still have a limit of 120 seconds to inject standby liquid. I've observed crews in the simulator and we consistently did it at 90 seconds.

MEMBER SHACK: Now what does that mean you require these times?

MR. WILLIAMS: All right. That is the time assumed in the analysis.

MEMBER SHACK: Okay. Even though the action time --

MR. WILLIAMS: The PRA is like five and six minutes.

MEMBER SHACK: Right.

MR. WILLIAMS: But when you do the analysis for ATWS to the baseline --

MEMBER SHACK: To the baseline. Okay.

MR. WILLIAMS: Correct.

MEMBER SIEBER: What it means is if the operator takes longer, you're on the anayzler.

MR. WILLIAMS: And you're going to put more heat in the containment.

MEMBER SIEBER: Yes. Well, you're on the analyzer, you don't --

MR. WILLIAMS: Now for suppression pool cooling, this is one of the places where we took advantage of the analysis. And we performed the analysis with increased operator response times.

The current licensed thermal power we were looking at thousand seconds to have both loops -- in service. And we increased that analysis to 1100 seconds for the first loop, 1600 seconds for the second loop. And we still met our containment temperature that was required under the design analysis.

For Appendix R --

MEMBER MAYNARD: Now that's an additional 1600 seconds or is that --

MR. WILLIAMS: The first loop 1100 seconds, and the second loop at 1600 seconds.

MEMBER MAYNARD: Okay.

MR. WILLIAMS: And 1600 seconds, roughly 27½ minutes.

And then Appendix R we have no changes in the time to get to the shutdown panel to perform duties.

And for the LOCA on one unit and a loss of offsite power which shuts down the other unit at the same time, the new modification that we installed, we installed a manual isolation valve--

MEMBER ABDEL-KHALIK: Who is keeping track of time in the first two minutes?

MR. WILLIAMS: Who is keeping track of time?

MEMBER ABDEL-KHALIK: Right.

MR. WILLIAMS: As far as simulator scenarios or in the --

MEMBER ABDEL-KHALIK: No, as far as real world.

MR. WILLIAMS: In real world the way we train our operators on the emergency operating procedures, we methodically step through the flow charts. And by the time the unit supervisor reads the step to the plant control operator and he performs the actions, by the time we get down to injecting standby liquid control and inhibiting ADS, it's about 90 seconds. And we pretty much do that routinely.

MEMBER SIEBER: But there's no record of individual actions?

MR. WILLIAMS: No.

MEMBER SIEBER: Okay. Which is probably your question.

You can retrieve it later from your operating stuff.

MR. WILLIAMS: Yes.

MEMBER ABDEL-KHALIK: Right.

MEMBER SHACK: No, he's talking about the real world.

MEMBER ABDEL-KHALIK: But then does the procedure then say that you have to complete this or initiate this within 120 seconds?

MR. WILLIAMS: No.

MEMBER ABDEL-KHALIK: It doesn't? It does not?

MR. WILLIAMS: Neither does the emergency operating procedure.

All right. One of the modifications we installed --

MEMBER SHACK: Just come back.

MR. WILLIAMS: All right.

MEMBER SHACK: I mean, I assume that injecting this slick is something you really don't want to do unless you have to do it. So, I mean recognize this situation is unambiguous from the operator's point of view. I mean, how much time is he -- you know, hitting the button, I can understand, that doesn't take much time.

MR. WILLIAMS: Well, when do we practice it?

MEMBER SHACK: Well, you know, recognizing the symptoms, I guess. He's got two minutes to think about this before he hits that button.

MR. WILLIAMS: Within five seconds he's recognized he's in a ATWS.

MR. WALLIS: Yes. When we were there--

MEMBER MAYNARD: Yes, you had mentioned that they had an ATWS.

MEMBER SIEBER: So if you had an ATWS you know this didn't work, you know that. Your only choice is to do that.

MR. WALLIS: Hit that button.

MR. WILLIAMS: And we do practice those scenarios quite frequently. If the training we go by was not at ATWS in the scenario, we're kind of disappointed.

MR. BOESCH: This is Bob Boesch.

Just to give you further evidence, we also structure the EOP flow charts so that we give the order to inject standby liquid as early as possible in the sequence. So after you ascertain all the pertinent information, what's the power level, you know what's the status of all the systems, that's the very first action you take.

MEMBER SIEBER: It's the most important thing you'll do.

MR. BOESCH: That's correct.

MR. WILLIAMS: And that's after we've given a couple of other tries to get the rods fully inserted. You know, what should have given you an automatic scram replace most -- which in shutdown, which is a manual scam. And we mainly hit push buttons to try to scram the reactor. We also have alternate route injection.

MEMBER SIEBER: Yes, it's not such tragedy anyway. You can recover from an inadvertent slick injection. It just takes some time.

MEMBER ABDEL-KHALIK: And all those prior actions take 90 second when you go through the procedures.

MR. WILLIAMS: Yes. Yes.

All right. Getting back to the ultimate heat sink. We installed a new manual valve to back up a single failure situation where with the motor operator the valve failing for whatever reason. It wouldn't allow us to dissipate heat in the spray pond. And we gave the operators 80 hours within which to perform that action. We didn't want anything within one hour because there's just too much to do during the initial part of the transient. Give an hour for the TSC to have a briefing, get the crew together and then go out and dispose it manually.

MEMBER SIEBER: Is that outside the control room?

MR. WILLIAMS: Yes.

MEMBER SIEBER: No NICs required?

MR. WILLIAMS: No. Actually, the valve itself is located out in the yard out by the spray pump.

CHAIR BANERJEE: In a blizzard in an earthquake, right?

MR. WILLIAMS: I didn't hear that.

CHAIR BANERJEE: That's what will happen, in a blizzard and in an earthquake.

MR. WILLIAMS: Well, in a blizzard we don't need to use it.

CHAIR BANERJEE: Right.

MEMBER SIEBER: You got to open that valve and then go home.

MR. WILLIAMS: All right. Next slide.

For operator training. In 2006 we started doing the operator formal presentation on the CPPU. Wanted to let them know what the plant conditions were going to be.

We asked for their comments, answered their questions and we wanted to make sure that they were engaged in the project.

Also in 2006 we developed a software package for the simulator to support operator training for the CPPU. And a couple of weeks ago when the Committee members went to the plant they got to see that software package in action.

MEMBER SIEBER: Do you have to change on the simulator the meter faces and so for?

MR. WILLIAMS: Some of them, yes.

MEMBER SIEBER: When will that be done?

MR. WILLIAMS: That will be done this spring when Unit 1 has its modifications installed. Our simulator mimics Unit 1 so we have to wait until Unit 1 --

MEMBER SIEBER: Okay. How many differences are there between the Unit 1 control room and the Unit 2 control room? That's why we had two simulators. Two many differences.

MR. WILLIAMS: Basically there's no differences at all between Unit 1 and Unit 2. The plants are almost identical in their control room.

As far as the gauges go with what we're having to change out, it's only half a dozen or so gauges that we have to change the scales on.

We have 29 annunciator windows that we're either installing or removing to make it easier for the operators to diagnose events.

And we're installing four new keylock switch and changing the one keylock switch for standby liquid.

So there's not a whole lot of control room panel changes.

MEMBER SIEBER: Do the units have any different operating characteristics? One's faster, one's slower?

MR. WILLIAMS: No.

MEMBER SIEBER: Okay. So you only need one software package?

MR. WILLIAMS: Correct.

MEMBER SIEBER: Okay.

MR. WILLIAMS: All right.

MEMBER SIEBER: And your operators have

dual licenses?

MR. WILLIAMS: Our operators do have dual licenses.

MEMBER SIEBER: And your electrical system is unique to each plant? Because there's --

MR. WILLIAMS: We do share diesels.

MEMBER SIEBER: Yes, right.

MR. WILLIAMS: We share diesels and offsite power supplies.

MEMBER SIEBER: So there's some extra things there that you have to deal with.

MR. WILLIAMS: Correct. But the operators are trained on that.

MEMBER SIEBER: All right.

MR. WILLIAMS: All right. Next slide.

In 2007 the operators began training with the new CPPU software. And the reason for that was because we had most of the modifications we were installing for CPPU installed last outage, and we needed to have the operators trained with the new pump parameters, the new reactor recirc, that type of stuff.

The significant changes for the control room crews. The enriched boron for standby liquid, the new condensate system parameters, reactor recirc runback logic changes and the changes to the emergency operating procedures.

Prior to the startup coming out of the 2007 outage for Unit 2 we performed just in time training on the simulator. And that gave the operators a chance to practice the plant startup with the new condensate pump parameters. And we also gave them an idea of what the testing was going to be coming out of the outage.

And it's important to note that the operators have been operating Unit 2 with the equivalent that we're going to be needing for CPPU.

MEMBER SIEBER: So the units right now are different?

MR. WILLIAMS: The units are slightly different right now.

MEMBER SIEBER: In their operating characteristics.

MR. WILLIAMS: That is correct.

Now after the 2007 outage the units will essentially be identical with the exception of the high pressure turbine on Unit 2 will now have been changed out. 2008. Excuse me.

All right. Next slide. All right. 2008 coming up here this spring we're going to give the operators similar training to what they had in 2007 for Unit 2 modifications. The simulator is going to be updated during the outage with all the new hardware changes. So when we're getting ready to come out of the refuel outage, we're going to give the operators just in time training again. They'll have all of the new hardware installed in the simulator. And we'll also be giving them startup training and we'll be putting them through the startup testing procedures that we're going to be performing coming out of the outage.

MEMBER ABDEL-KHALIK: Is the core model simulating any change every cycle.

MR. WILLIAMS: Bob?

MR. BOESCH: Yes. Yes. It's modeled after every cycle. Every time we upgrade a cycle, we mimic --

MEMBER ABDEL-KHALIK: So the model that you have now responds to what?

MR. BOESCH: The current core of record, then the training model which Jim is talking about for Unit 2 is the current Unit 1 cycle. We're a

Unit 1 reference simulator. So by law we are required to mimic Unit 1.

Now to demonstrate the uprate load -- the difference condensate pumps on Unit 2 have the uprate right now, we install a training load just so that the operators would be able to experience it. But it was not our load of record. Our load of record with the NRC is Unit 1's load.

MR. WILLIAMS: All right. Next slide.

And in 2009 when we go to implement full sequence EPU on Unit 2, the operators are going to receive some more training on a couple of other modifications we're installing for the reactor feed pump turbines and condensate filters. And they'll be having instruction in the new operating procedures for the new equipment we'll be installing. Startup training coming out of the outage because we'll be going up to full CPPU. And the startup testing activities associated with CPPU.

MEMBER ABDEL-KHALIK: Thank you.

MR. WILLIAMS: Any questions?

MEMBER MAYNARD: Just real briefly. The is an area we did get an opportunity to observe while we were there. Got to see the control room as well as the simulator and watch the operators in action, timed some actions and everything. And I didn't really see anything that concerned me.

I think the biggest challenge they had was not so much related to EPU but any other change they'd make in that for a while you're going to have differences in Unit 2 than you do to Unit 1. There's some different setpoints that the operators are going to have to know. But that happens when you make other plant modifications anyway that you have to deal with those types of things.

MR. WILLIAMS: Correct. We had the situation when we replaced the main turbines a few years ago; one unit had the new turbines, the other unit had the old turbines.

MEMBER ABDEL-KHALIK: The crews are dedicated, though? You don't share the crews?

MR. WILLIAMS: No, they're not. The crews can operate either unit and they are rotated through the positions.

MEMBER SIEBER: Yes, dual licenses.

MEMBER MAYNARD: But while they're on shift, you generally have one that's the reactor operator assigned to Unit 1 and to Unit 2.

MEMBER SIEBER: Per unit, right.

MR. WILLIAMS: Correct.

MEMBER MAYNARD: But the next day they could be swapped.

MEMBER SHACK: Okay. And it could be that frequent?

MR. WILLIAMS: And it does at times. We don't intentionally move people around that quick. Usually they're on a given unit for a week at a time. But to cover absences or vacations, there are times where they have to change everyday.

MEMBER SIEBER: One of the interesting things is if you have two plants that are just slightly different and you ask any operator I've ever talked to whether he could operate this one or that one without making a mistake, he'll say I don't make mistakes. So that means that we no longer have to care about human factors, right, since they don't make mistakes.

MEMBER MAYNARD: Well, usually they're so aware of those, that that's usually not where the mistake is made. It's usually on the routine or something that's unassociated with that.

CHAIR BANERJEE: It's like skiing.

MEMBER SIEBER: Well, we ended up with two simulators.

CHAIR BANERJEE: On the flats you break your legs.

Thank you very much.

Let's move on to NRR.

MEMBER SIEBER: You could just read us the conclusion.

Garry Armstrong is going to make the presentation.

Garry, again, I appeal to you not to answer any questions. I know that it's hard, but do your best.

MR. ARMSTRONG: I'm going to do my best to stay about five minutes. Like I said, mainly a lot of this is just confirmatory to what he just presented. So I'll do my best.

MR. WALLIS: Go for it.

MR. ARMSTRONG: All right. Again, my name is Garry Armstrong. I'm a human factors engineer for the Operator Licensing and Human Performance Branch.

And for our evaluation that's required by the Review Standard 001-Matrix 11 we look at five areas for the licensee CPPU related to human performance. And those include the emergency operating and at normal operating procedures, operator actions, changes to control room alarms displays and control, the safety parameter display system and operator training in control room simulator.

And the purpose of the review is to assure that the CPPU does not adversely affect operator performance.

For the EOPs and AOPs after the reviewing the licensee's submittal and supplementary information to our RAIs, the Staff concluded that the CPPU does not introduce new manual actions or revised existing operator actions in the EOPs and AOPs, which in turn provides no changes in the current operating and accident mitigation philosophies.

And as discussed earlier, the modifications that are being made to the EOPs and AOPs are just mainly to revise the plant parameter thresholds and curves due to the increase of power level and decay heat levels. And also the associated setpoints.

For operator actions, as discussed, the only new operator action that's being introduced is not associated with the EOPs but it's in the RHR operating procedure which adds the action for the operator to go out and manually close these isolation bypass valves associated with the ultimate heat sink during LOCA conditions.

This is not necessarily an additional action, but this is a change in the control that the operators will do for Appendix R related events. To run one RHR loop for each of the units for the -- oh, sorry. To RHR loops for the suppression pool cool in suppression pool cooling mode for each unit, previously they had one loop being shared between both units. And overall the CPPU does not affect any of the operator action times they have in place by a gross measure. Some actions may take place a few seconds faster than they've done before or, you know.

And moving on to the control room. A listing of all the control room setpoints displays and alarms was provided to the Staff by the licensee, which will not effect operator's ability to read, interpret or visually identify information required for operation.

Some of the control room changes that they provide specific for Unit 2 prior to what they will do for Unit 1 is the pump switch modification for the slick system, the new keylock switches in the upper relay room to bypass reactor feed pump low flow signal when an RFP is out of service, and to increase the minimal flow setpoints for the condensate pump discharge pressure.

Moving on to the SPDS. The following parameter based displays are going to be revised due to CPPU based on the increased decay heat, which includes the heat capacity temperature limit and the maximal acceptable core recovery time. And no other changes were identified to the SPDS with the exception of the revised EOP curves and limits.

Finally, for operator training and plant simulator, my slide probably varies a little bit from what the licensee just provided. But mainly the software package that they developed for the CPPU modifications, they've already, or at the time when we reviewed it, they were planning on training the operator on a software package on a Unit 1-based simulator. And when they make the modifications to the actual Unit 1, they'll make those modifications to the simulator as well. But during that they will have this package already created for the operators to be familiar with the CPPU modifications as well as the associated EOP changes.

MEMBER SHACK: Does the NRC review these software packages?

MR. ARMSTRONG: At least we don't.

MR. BOESCH: This is Bob Boesch.

Yes, the NRC does review on a biannual basis. They have an NRC inspection 71111.11 where they review the license operator requal training programs as well as the simulator.

MR. ARMSTRONG: Yes. We don't look at that. That's a regional review.

MEMBER MAYNARD: There's also can't take credit for it, but INPO that's also part of the training and accreditation is simulator fidelity. And that gets a real hard look during the accreditation.

MEMBER ABDEL-KHALIK: It's an ANSI standard. Yes.

MEMBER SIEBER: Well, it's how well it replicates the actual plant, right? And my experience is pretty old, but it seemed to me that unless something really stuck out during EOPs or ERGs, you didn't get a complaint about your simulators or your operators.

MEMBER MAYNARD: In the last five to seven years it's taken on a whole different role, Jack. It really gets looked at hard now.

MEMBER SIEBER: Well, the operators are the ones that complained first. Because they say the plant works a little different than this.

MEMBER ABDEL-KHALIK: It is an issue.

CHAIR BANERJEE: Okay.

MR. ARMSTRONG: For our conclusion, just to wrap it up, the Staff has reviewed all the submittal and the supplemental information from the licensee and we have concluded that Susquehanna has identified that there are no adverse effects on the proposed CPPU on current operator actions. They committed to take appropriate actions to ensure that the CPPU does not adversely effect operator performance and indicated that the operators will have approximately one year of CPPU related experience prior to the actual CPPU implementation on Unit 1 next year.

And with respect to human performance the Staff finds the proposed EPU acceptable for Susquehanna.

CHAIR BANERJEE: Any questions?

Thanks a lot, Garry.

MR. ARMSTRONG: Thank you.

CHAIR BANERJEE: Now we move on to, I guess, PPL telling us about flow accelerate corrosion. So this will make Bill Shack very happy.

Now this, I guess, even if you tried you're not going to be able to hurry. So give it a shot.

Maybe it's not that bad.

MR. HANOVER: My name is Mark Hanover. I'm the flow accelerator program engineer for PPL Susquehanna.

I'm going to talk a little bit about -- I'll give a basic review of the program and what we've done to evaluate and address flow accelerated corrosion.

For a brief program overview, talk about the CPPU events and how we've evaluated and how we'll address it through the program.

Our program is based on a programmatic

approach. It's being implemented and maintained through the requirements of commitments we've made per Generic Letter 8908. And we followed the guidance of industry standard EPRI NSAC-202L.

We've had a tight monitoring system in place since 1983, which is before the Generic Letter. It was to monitor erosion, corrosion --

MR. WALLIS: Is this a ChecWorks approach?

MR. HANOVER: That was prior to ChecWorks.

MR. WALLIS: It was prior to ChecWorks.

MR. HANOVER: That was prior to ChecWorks.

MEMBER SHACK: But you needed ChecWorks. It took you a long time to get there.

MR. HANOVER: We'll get there.

So we have a program in place, and it's developed over the years. In 2003 we implemented a large scale program uprate, and that involved creating basically all new program basis documents, procedures and adopting the EPRI ChecWork software for a predictive analysis.

So our current program incorporates

predictive analyses, which is based on ChecWorks. We continue to reinspect the flows we're inspected over the years based on trending of that data.

We incorporate operating experience. What we've seen in our plant, the opposite unit and throughout the industry and also incorporate trainings we've received through the industry.

MEMBER SHACK: Just over the years, what fraction of your piping is now FAC-resistent piping? A lot of it or --

MR. HANOVER: As far as total -- the highest wear piping is FAC-resistant, do you know?

MR. HAUBER: Pat Hauber, PPL Susquehanna, prior FAC engineer before Mark.

Extraction piping, both units, 80 percent of it was changed from carbon steel to a clad stainless.

On small drain lines when I turned it over to Mark, there was at least 15 different lines on each unit that we replaced with a P22 material instead of the carbon steel. The A-1 and six grade B.

MEMBER SIEBER: Is that because of leaks or because they measured it to be thin?

MR. HANOVER: We have a proactive approach. If we detect where, and we see that it's actually wearing, we're approaching minimal, we'll replace it. I mean, the intent is to detect wear, replace prior to leaks. That's not to say --

MEMBER SIEBER: You aren't answering my question. How many of these actually develop leaks?

MR. HANOVER: We have had several that develop leaks.

MEMBER SIEBER: Okay.

MR. HANOVER: Our ChecWorks model is periodically updated. Typically every cycle to incorporate changes in process conditions, water chemistry conditions, any changes in plant modifications due to maintenance and modifications. And also to incorporate plant inspection data in an effort to calibrate that ChecWorks model.

Since we adopted ChecWorks, and this would be for the last outage in each unit, we've inspected 150 to 160 components. Prior to that we inspected on the average about 100. So what we've done is increase the number of inspections in highly ranked components throughout the ChecWorks models to try to achieve calibration.

CHAIR BANERJEE: You only had one point. They're sort of component then.

MEMBER SIEBER: No.

CHAIR BANERJEE: It's since the last outage that's only the inspection is done? You adopted ChecWorks --

MR. HANOVER: Correct.

CHAIR BANERJEE: -- for how many years?

MR. HANOVER: Since 2005 is when we had the models completed. We've got a wealth of historical data leading up to that. For cycles prior to that we incorporated as much as UT data as we could. But for temperance to accept it, your UT data has to be consistent. The griding has to be consistent from outage-to-outage. So a lot of our older data we couldn't incorporate into ChecWorks. So that's why we don't consider our models to be calibrated at this point. All that previous data is used more for trending and determining really when something needs to be inspected.

ChecWorks right now is being used to determine which components are most likely to see the most wear, and we'll inspect those in addition to those we see by trending.

MEMBER SIEBER: So this is just two years that you've been doing this?

MR. HANOVER: Yes.

MEMBER SIEBER: Not a long time?

MR. HANOVER: Not with ChecWorks, no.

MEMBER SIEBER: Yes.

CHAIR BANERJEE: So when do you expect to have enough data to have reasonably well calibrated models in ChecWorks? Does it take ten years?

MR. HANOVER: This may have increased the number of inspections we're doing. I'm hoping to start achieving calibration within the next two to three cycles, so I think four to six years.

MEMBER SIEBER: See, the issue now is they made no fault to thickness, but they don't know the rate of thickness reduction. Not enough time has passed.

CHAIR BANERJEE: They have some historical data.

MEMBER SIEBER: If you haven't used consistent grids and consistent points, it's pretty hard to use that data for anything.

MR. HANOVER: Yes. I would say that the

previous data does work well for trending.

MEMBER SIEBER: Yes.

MR. HANOVER: Which is what we've done.

MEMBER ABDEL-KHALIK: This 20 percent of the extraction steam lines have not been replaced, are those on the high pressure end?

MR. HANOVER: We'll get into that. The 20 percent that has not been replaced is the extraction piping associated with the high pressure turbine. We monitor that on a regular basis, but it's not wearing as much as the others did because it operates at a much higher temperature.

MR. WALLIS: It's dry. It's dry.

MEMBER SIEBER: Has lots of moisture.

MEMBER SHACK: Well dry helps, high temperature helps.

MR. HANOVER: It quality similar to some of the LP extractions. But it is a much higher temperature.

MEMBER ABDEL-KHALIK: Yes, a lower velocity.

MR. HANOVER: Yes. With our main steam condensate and feedwater systems we haven't seen any real downward trend in wall thicknesses. And what I mean by that is when we inspect individual components, we see wall thickness variations that our calculational methods will give us a calculated wear rate. We'll reinspect. But for components where we have three or four inspections since plant operation, we don't see any trended wear in them.

CHAIR BANERJEE: If you were looking at the models in ChecWorks --

MR. HANOVER: Yes.

CHAIR BANERJEE: -- what's the exponent on flow velocity related to corrosion rate? Is it linear, is it to the point eight power? Is it squared?

MR. HANOVER: That is well published. There are curves that show velocity versus flow, or velocity versus wear for the ChecWorks correlation. And it's interesting. Wear rate does increase with an increase in flow, but it is not necessary linear.

CHAIR BANERJEE: Then what is it roughly.

MEMBER SIEBER: Exponential.

CHAIR BANERJEE: What's the exponent point?

MR. HANOVER: That I don't know. We

actually in training they'll tell you that wear rate varies in proportion to flow.

MR. WALLIS: Not to reveal the secret?

MR. HANOVER: It's not published. But the point is, actually the exercise we did for CPPU we found that with a 15 percent increase in flow, increase in temperature we found that we were getting increases in wear rate less than 15 percent. So what we did is go back, take out all of their changes and just change flow. That change in flow, 165 percent increase in flow did not result in 15 percent increase in predicted wear. So we know that it is fairly close to linear, but it does drop off as you go out. So it does increase with flow, but it is not linear.

CHAIR BANERJEE: So maybe Bill has an idea about this as I know nothing about ChecWorks. Is it sort of reaction kinetics mass transfer coupled model or what's it?

MEMBER SHACK: I think it's more empirical than that. I mean it really is -- there's a lot of data and they've accumulated it.

MEMBER SIEBER: And it's mostly trended.

MR. HANOVER: What's published in the

EPRI works is that it's a function of mass transfer. So you have Reynolds numbers and that type of thing in, so it is not directly proportional.

CHAIR BANERJEE: Does it roughly to the .8 then, if it's mass transfer?

MR. HANOVER: I couldn't tell you what the exponent is. All I know is it is not quite linear.

CHAIR BANERJEE: And erosion is not by little thingies coming in wearing things out on it?

MR. HANOVER: It's a corrosion process. You will not see the erosion until it gets to very high velocities to where it's actually stripping the corrosion layer from the inner surface of the pipe.

MEMBER SIEBER: Well one thing to watch out for is when you go up in power with the CPPU that the attraction lines will have more moisture in them and they'll wear faster because of that.

MR. HANOVER: Exactly. And we'll talk about this. We talked about our significant replacements. We've replaced over extraction piping from the low pressure turbine. The high pressure we have not replaced yet. We've replaced it with a stainless steel clad carbon steel pipe. Given that, the higher or increases in wear rate associated with CPPU off the LP turbines we've already taken care of that with our extraction replacements. On the HP turbine we actually predict a decrease in wear rate. Plus, we continue to monitor those on a regular basis.

CHAIR BANERJEE: You predict a decrease in wear rate?

MR. HANOVER: Correct.

MR. WALLIS: Yes.

CHAIR BANERJEE: Due to what? What's the physics there?

MR. HANOVER: We have a new HP turbine. The extraction is different.

MR. GIOSITTS: Oh, it's a new? I see. All right.

MEMBER SIEBER: Yes, you probably shifted the operating point between HP and LP?

MR. HANOVER: Exactly. I believe, again, it is a temperature effect.

MEMBER SIEBER: No, it's a moisture effect.

MR. HANOVER: Our program, we will programmatically replace components with FAC-resistent material. Once we've identified that a component or a line is wearing, so we have at least two inspections that show we're trending downward, we will plan to replace the piping. Typically with chro-moly. That is our mitigation effort.

For CPPU the first thing we did is go through our systems acceptability evaluation which looks at all cast systems for susceptibility defect. And we found that with the changes in operating conditions associated with CPPU that there are no additional pipelines or systems that need to be added to the program.

We also incorporated the operating conditions associated with CPPU into the ChecWorks models to get an idea of the changes that will occur once we implement that. And, again, that involves a 15 percent increase in feedwater flow and a maximum temperature increase of 8.8 degrees Fahrenheit in the final feedwater.

Our systems include both single and two-phase piping system. And what we found is the largest average wear increase -- well, in that feed water system.

CHAIR BANERJEE: And that's still in

what? The ChecWorks calculations?

MR. HANOVER: That was based on ChecWorks. And this is what threw us into how can we have 15 percent increase in flow temperature change and yet we're still less than 15 percent increase -- less than 15 percent increase in predicted wear. That's why we went back and checked to see what that velocity correlation was.

These are examples of the specific components that we looked at for the current thermal power and CPPU. The thing that we need to keep in mind with this is that the actual wear rate values there are noncalibrated. And what we're really looking at there is the percent change. This is what we predict will change when we do implement the full CPPU. And we'll find in feedwater that the largest -- well, for this specific component we had, say, an 11.4 percent increase in predicted wear.

The biggest thing for me with this is that at least in the short term even with that percentage increase in wear, we're only looking at 1 to 2 mils over an operating cycle. So we'll be able to get that and then better -- get a better correlation of the actual increase versus what

ChecWorks is predicting.

We'll conclude with the FAC program, and that program's based on the EPRI guidance, they're dynamic in nature and they're designed to capture changes -- capture and accommodate changes in plant configuration and operating conditions. Typically, we're dealing with a modification, changes here and there, CPPU being a large one. But the program is set up to accommodate these types of things.

Secondly, since we did just adopt ChecWorks we're already taking increased population samples, looking at the highest ranked components and in so doing we're going to be checking any points that would be of concern for CPPU. So that any near term pressure boundary issues should not arise because of this.

And the one thing I did want to mention is going from current thermal power to the CPPU no changes in relative rankings of components occurred. So components ranking with respect to wear rate are the same, it's just the magnitude of that wear rate change. So highest ranking components we're inspecting will remain the highest ranked components.

MEMBER SIEBER: It had increased for the most part, right. Your expectation of wear rates increased?

MR. HANOVER: There were increases and decreases all across the board. What we'll find is condensate feedwater, systems less than 300 degrees increased. Going beyond 300 the temperature to wear rate, the curve drops off. They start to drop down.

So we had predicted changes all over the map.

MEMBER ABDEL-KHALIK: You have a line here with a wear rate of 40 mils or 41 mils per year. How thick is that line?

MEMBER SIEBER: The start value is--

MR. HANOVER: And that would be RWC.

MEMBER SIEBER: That's like the blowdown line. In PWRs blowdown lines --

MR. HANOVER: Yes. And that's what I wanted to emphasized. This is noncalibrated data. That's a four inch by four thirty-eight line.

MEMBER MAYNARD: Like PWR --

MR. HANOVER: Our predicted wear rates on that are far beyond what we've measured. And since given this, given water chemistry, we're doing a lot of inspections in reactor water cleanup now. And we're not seeing wear rates of this magnitude. And that's why I tried to stress these are noncalibrated numbers. And --

CHAIR BANERJEE: Just for me, where I do notice things, where are you injecting the hydrogen into the --

MR. HANOVER: Hydrogen is injected just right near the feed pumps.

MR. GIOSITTS: Oh, okay. So they come and they come through the spargers and down.

MEMBER SIEBER: If I were to give advice, since you've only been in the ChecWorks program for two years, whereas a lot of operators have been in it for many years, is that you got a late start on that and you need to really press that program so you understand your plant better than this two points. Because you only make these measurements during outages, right?

MR. HANOVER: That's correct.

MEMBER SIEBER: So you only have two sets of data. That doesn't show a trend, that just gives you a straight line.

MR. HANOVER: For the ChecWorks' data,

yes.

CHAIR BANERJEE: Okay. The last slide.

MR. SWOYER: I'm presenting the last slide.

MR. SWOYER: I'm presenting the last slide.

My name is Bruce Swoyer. I'm in PPL Susquehanna Design Engineering Materials. And I'm going to talk about the pressure temperature limit curves.

The PT curves are used to assure that the RPV materials, reactor pressure vessel materials behave ductily whenever we change the pressures and temperatures. And the present PT curves reflect the CPPU. And the component of the CPPU that they were changed to is -- changed for were the fluence. We redid the fluence calculations in 2005 using the RAMA code. That's the three dimensional transfer code. And we used a bounding EPU load with 100 percent capacity. And that was input into the new PT curves and approved and put into our tech specs.

The next section here I just wanted to reflect that what our fluence rates were previously before the RAMA code and address the impact of CPPU.

Really, the impact of the RAMA code as opposed to the previous two dimensional code, that methodology that was used.

As you can see there, that taking the current CLPP fluences for Unit 1 and Unit 2, they're very much different. And when we get to CPPU both are pretty much identical. And that's because the RAMA code is definitely much more accurate.

As a matter of fact, Susquehanna was one of the plants that the RAMA code was benchmarked against.

MEMBER SHACK: Yes, we've heard a lot about the RAMA code lately. But since you have a benchmarked version of it --

CHAIR BANERJEE: Thanks a lot.

MR. SWOYER: All right. You're welcome.

CHAIR BANERJEE: And I think you have a last presentation by NRR.

MR. MAKAR: Nine slides away.

CHAIR BANERJEE: Take your time.

MR. MAKAR: Go make dinner.

CHAIR BANERJEE: Yes. Okay. As long as you finish by 7:00, you're fine.

MR. MAKAR: All right. Good evening.

I'm Grey Makar. And I'm going to discuss three areas of review in materials and chemical engineering. That is the coatings in containment and other organic materials, flow accelerate corrosion and the reactor water cleanup system.

Starting with protective coatings. You can see our regulatory basis. And I just want to highlight on this one that these ANSI and ASTM standards, the older version of Reg. Guide 1.54 referred to ANSI standards and it now refers to AST standards. These standards cover the qualification of the coatings themselves, qualification of personnel involved with the coatings and monitoring of the coatings.

At Susquehanna their qualified coatings, they have coatings that were qualified to the reg. guide. And they were on equipment ordered before the reg. guide existed, so it was qualified to the ANSI standard that the reg. guide referred to. And they have coatings that are unqualified.

Now, part of their coatings in containment were what they call in situ-qualified after the fact by creating some samples taken out of containment and then subjected to the same qualification tests that the original coatings were subjected to.

CHAIR BANERJEE: Do you know how much of this would form debris? I mean, the unqualified coating is obviously --

MR. MAKAR: The amount of debris attributed to the failure coatings in a postulated LOCA is consistent with the industry guidelines. That was reviewed as part of the generic letter process in 1998. So we are focusing here mainly on what may be changing as a result of EPU.

With respect to the amount of coatings degradation that could come, debris, because of the assumptions used in that original analysis, that's not changing. The temperature, pressure and dose are increasing by small amount which are not expected to expect the coatings. And in addition their inspection and maintenance procedures on the coatings are consistent with one of the ASTM standards that our reg. guide refers to. So, again, it's not because of these small changes in the environmental conditions in containment we don't expect any change in that original evaluation.

CHAIR BANERJEE: Okay.

MR. MAKAR: And I don't think I've mentioned this specifically, but we did look at these changes in temperature pressure and radiological dose are within the original qualification testing parameters.

CHAIR BANERJEE: Some of the temperatures seem to go up quite a bit, especially the drywell temperature compared to --

MR. MAKAR: The coatings qualifications tests were at 340 degrees Fahrenheit.

CHAIR BANERJEE: Okay.

MR. MAKAR: I think the maximum temperature they're showing is 337. So you could probably argue with variations and location and things, that they're about the same. But nominally they are bounded.

CHAIR BANERJEE: They're staying with the same assumption regarding debris loading on the sump screens -- rather on the strainers or whatever they're called for PWRs.

MR. MAKAR: Yes. And in some cases it doesn't matter because, for example, with the unqualified coating the assumption is they will all become debris anyway.

CHAIR BANERJEE: Yes. Right. Okay.

MR. MAKAR: There's one other area of organic materials that we considered and that's due to these changes in the environmental conditions in containment that there could be some effect on hydrogen or organic gas generation. But, again, because these are small contributors to something like hydrogen in containment and because there are only small changes that these would be insignificant. And in related matter, the effect of the additional dose on generating acids from the organic table insulation, that's already been evaluated as part of the ultimate source term amendments.

So based on all those factors we concluded that they all were satisfactory and that the EPU would not change that evaluation.

All right. Flow rate corrosion. I'm sorry. I'm not keeping up.

I'd like to just give some background material on FAC and our review. Flow accelerated corrosion, as Mr. Hanover said, is a corrosion process. It requires a liquid environment. It is sensitive to a large number of parameters;

temperature, alloy, composition, the water chemistry composition, the flow rate and others.

The approach that industry is using is to have a mathematical model that can handle these parameters, look at the interactions of them and then on the basis and direct you to inspect the right things, a limited number of them, so that you can then qualify the uninspected things for continued service.

The interactions of these variables are complex. Some have simple affects like more chromium means less FAC. But other are more complicated, like temperature. There is a peak in the temperature, 300 to 350 degrees I think, depending on the environment.

So we look at it the same way that Mr. Hanover described. And I would agree that what I've been able to find out is that the effect of velocity alone is approximately linear, but it's not directly linear and you can't find out really exactly what it is used in the program. And I discussed with EPRI some.

So what I just mentioned about the temperature, if you look at, say, a 15 percent increase in velocity, if you were in a system that's already at the high end above the 300/350 degree peak, you're already on the decline if you increase temperature. You're going downhill. So an X increase in velocity coupled with an increase in temperature drives the corrosion rate down in this system.

If it were a system below 300 degrees, it's going to go the other way. You're going to see a combined -- increases due to both the flow and the temperature.

So in our review guidance we do not have SRP sections or reg. guides that address FAC exclusively. We use the EPRI documents that gives guidance on how to set up a FAC program, what elements are needed in a FAC program, how to do measurements, how to analyze those measurements, what systems could be excluded, and many other things.

We also have the generic letter that asked all the licensees to explain how they were managing this. And it occurs in all single phase and two phase carbon steel high energy piping.

MEMBER SIEBER: That was in 1989?

MR. MAKAR: That's 1989. At that time one thing I would point out is it was called erosion corrosion. This really is not erosion corrosion. We are not physically wearing things away. The effect of flow is mainly on mass transport and chemistry changes and things like that on the protected film or the corrosion product film that should be protecting the alloy.

MEMBER SIEBER: So that was 18 years ago, the generic came out.

MR. MAKAR: The generic letter asked for how it was being managed.

MEMBER SIEBER: How you're going to manage it. Correct.

CHAIR BANERJEE: You probably covered this slide already.

MEMBER SIEBER: Right.

CHAIR BANERJEE: Is there something more to say on that?

MR. MAKAR: No, other than now that I've told you how we would -- you know, what we came up with, we looked that they were identifying the changes that were resulting.

The ChecWorks model can do two things, I think. I'm not used ChecWorks. But my understanding is: (1) You can put in the values of these parameters and it will predict the corrosion rate for you.

MEMBER SIEBER: Yes.

MR. MAKAR: You can also, once you have -- and you can do that without inspection data. Once you have inspection data, then you can use that to improve your model and make more accurate predictions. And when they say that it's not calibrated, I think that's what is missing and that is what is going to take some time. In the meantime, you don't want to start decreasing the inspection, the number of inspection locations until you have some good data. So that's probably the main conclusion of our -- and point of our -- reactor water cleanup system.

We do have regulatory guidance based on the general design criteria, which are based on protecting the reactor cooling pressure boundary and preventing releases of radioactive materials and handling the waste.

The applicant provided us with their evaluation of pumps, valves, piping, heat exchangers, demineralizers. Concluded that the changes were negligible. We asked for some additional. They provided some of the details. We asked for some additional details to codify the changes and compare them to the design margins.

Essentially, we found that all of these changes; slight decrease in temperature, slight increase in pressure are insignificant with respect to the design of the equipment.

Move on to the next one.

There will be an increase in some impurities including iron in the system, which can be handled by deminerializers, although they will need to be backwashed and the resin replaced a little more often. And this is not a constraint on their ability to handle waste.

And we also looked at containment isolation valves to see that the effect on them was negligible either because of the functional requirements aren't changing or the environmental effects are so small, or they are manually operated valves or check valves that aren't effected by the power uprate.

MEMBER SIEBER: I have a question.

Getting a look at technical BWR RWC connections, it's a pipe that goes up to the bottom of the middle of the reactor vessel surrounded by all these control rod mechanisms and in-core probes. Has there ever been a failure or a leak in that pipe in that area or is that so strong that that's not a worry? Because it looks like it would really be a tough job to --

MR. MAKAR: Inspect it.

MEMBER SIEBER: Inspect it and repair it. Inspect even, you know, would take you probably a couple of weeks because you have to remove all the stuff.

MR. HANOVER: This is Mark Hanover. This past March we inspected our bottom head drain in Unit 2. We had a semi-automatic device that we were able to slide down the line and then remotely manipulate and then get data on that --

MEMBER SIEBER: In the inside?

MR. HANOVER: It was external to the pipe, but --

MEMBER SIEBER: Pardon?

MR. HANOVER: It was external to the pipe. We did UT of the elbow directly off the drain nozzle.

MEMBER SIEBER: Yes.

MR. HANOVER: So we were able to see what type of wear we had. We were one of the top rated units in terms of predicted wear in that line because we have a very high flow rate.

MEMBER SIEBER: Would that be low wear or high wear?

MR. HANOVER: High. We run the high end of the fleet. And we found that --

MEMBER SIEBER: It could be either one.

MR. HANOVER: -- based on that single outage data that the wear was much less than we had predicted by the empirical analysis. So we know we don't have to revisit that for at least ten to 12 years.

MEMBER SIEBER: How did you come to that conclusion based on one measurement? You assumed that when it was brand new it was the same thickness that it was in the catalogue.

MR. HANOVER: What we do is -- the methodology for that is you look at all variations in the fitting. So you're looking at either the maximum measured thickness or nominal. Typically you'll have measurements that are much greater than the nominal. Versus the minimum. You assume all the variations are due to wall loss as opposed to manufacturing variations.

MEMBER SIEBER: Right.

MR. HANOVER: And then we throw a safety factor on top of that. But we were well above what our code minimum allowable was.

MEMBER SIEBER: You were able to get the full circumference of it?

MR. HANOVER: Yes, we were. We were able to get the --

MEMBER SIEBER: Over the weld, too?

MR. HANOVER: We were able to get the entire elbow, just above the weld the entire elbow and six inches downstream.

MEMBER SIEBER: I thought it was impossible. It's just difficult, right? Okay. Thank you.

CHAIR BANERJEE: You can ask them how they did it.

MEMBER SIEBER: I don't want to do it.

CHAIR BANERJEE: Okay. Thank you.

I'd like to thank all of you for staying so long and bearing with us.

MEMBER SIEBER: Wait until tomorrow.

CHAIR BANERJEE: We're only one hour over, by the way. Entirely due to a flaky Chairman.

So, we're done.

(Whereupon, at 7:04 p.m. the meeting was adjourned, to reconvene tomorrow at 8:30 p.m.)