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NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

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POWER UPRATES SUBCOMMITTEE

OPEN SESSION

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THURSDAY

JULY 25, 2013

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ROCKVILLE, MARYLAND

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The Subcommittee met at the Nuclear Regulatory Commission, Two White Flint North, Room T2B3, 11545 Rockville Pike, at 8:30 a.m., Joy Rempe, Chairman, presiding.

SUBCOMMITTEE MEMBERS:

JOY REMPE, Chairman

J. SAM ARMIJO, Member

SANJOY BANERJEE, Member

CHARLES H. BROWN, JR. Member

MICHAEL CORRADINI, Member

HAROLD B. RAY, Member

STEPHEN P. SCHULTZ, Member

WILLIAM J. SHACK, Member

GORDON R. SKILLMAN, Member

ACRS CONSULTANTS PRESENT:

KORD SMITH

NRC STAFF PRESENT:

PETER WEN, Designated Federal Official

TERRY BELTZ, NRR/DORL

ROBERT DENNIG, NRR/DSA

TAI HUANG, NRR

CHRIS JACKSON, NRR

JOHN MONNINGER, NRR/DORL

BENJAMIN PARKS, NRR

AHSAN SALLMAN, NRR/DSS

ALSO PRESENT:

KENNETH AINGER, Exelon

WILLIAM M. BENTLEY, TVA/Browns Ferry

JOHN BJORSETH, NSPM

KEVIN BURTON, Exelon

PETER DILLER, GE-Hitachi

GENE ECKHOLT, NSPM

JOHN FIELDS, NSPM

STEVE HAMMER, NSPM

JOHN HANNAH, GE-Hitachi

NATHAN HASKELL, NSPM

ATUL KARVE, GE-HITACHI

LARRY KING, NSPM

GUHNGJUN LI, GE-HITACHI

JOSE A. MARCH-LEUBA, ORNL

TIM MOORE, Exelon

DAVID NEFF, Exelon

JOHN OSBORNE, TVA/Browns Ferry

HAROLD PAUSTIAN, NSPM

SCOTT PFEFFER, GE-Hitachi

JEFF RICHARDSON, Entergy

JOHN ROMMEL, Exelon

MARK SCHIMMEL, NSPM

MICHAEL SCOTT, NSPM

RICK STADTLANDER, NSPM

ALSO PRESENT (CONTINUED):

THOMAS STODDARD, GE-Hitachi

DAVID VREELAND, NSPM

C-O-N-T-E-N-T-S

C-O-N-T-E-N-T-S (CONTINUED)

P R O C E E D I N G S

8:29 a.m.

CHAIR REMPE: (presiding) This meeting will now come to order.

This is a meeting of the ACRS Power Uprates Subcommittee. I'm Joy Rempe. I'm Chairman of the Subcommittee.

ACRS members in attendance include Charlie Brown, Mike Corradini, Bill Shack, Sam Armijo, Harold Ray, Dick Skillman, Stephen Schultz, and Sanjoy Banerjee.

In addition, we have our ACRS consultant, Dr. Kord Smith, present. Peter Wen of the ACRS staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the Monticello Extended Power Update License Amendment Request and the associated Draft Staff Safety Evaluation. We will hear presentations from the NRC staff and the licensee, Northern States Power Company, Minnesota. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions as appropriate for deliberation by the full Committee.

As shown in the agenda, some presentations will be closed in order to discuss information that is proprietary that to the licensee and its contractors, pursuant to 5 USC 552b(C)(3) and (4). Attendance at this portion of the meeting dealing with such information will be limited to the NRC staff, licensee representatives and its consultants, and those individuals and organizations who have entered into an appropriate confidentiality agreement with them. So, consequently, we will need to confirm that we only have eligible observers and participants in the room and the closure of the public line for the closed portion.

And I would like to request that the licensee and the staff help us by noting that there is a time when some of our questions are going to need to be deferred to the closed sessions of the meeting, so that we don't go beyond the bonds of what we are supposed to be discussing.

The rules for participation in today's meeting have been announced as a part of the notice of this meeting previously published in The Federal Register. We have received no written comments or requests for time to make oral statements for members of the public regarding today's meeting.

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

Register Notice. Therefore we request that participants in this meeting use the microphones located throughout the meeting room when addressing the Subcommittee. Participants should first identify themselves and speak with sufficient clarity and volume, so that they can be readily heard.

So, now we are going to proceed with the meeting. And I call upon John Monninger of the NRC staff to begin.

MR. MONNINGER: Good morning, Dr. Rempe, fellow ACRS members.

I'm John Monninger. I'm the Deputy Director of the Division of Operating Reactor Licensing within NRR.

On behalf of the staff, I want to thank the ACRS very much for engaging us today on this review of the Monticello application and, in particular, on the staff's safety review, the staff's independent safety review. We take that responsibility very, very seriously, and we do appreciate the insights and the discussions with the Advisory Committee.

Maybe one item of note. Last month the staff prepared to the Commission an Annual Commission Paper on the status of Power Uprate Program. It is a high-priority program for the agency, as directed by the Commission. Of course, it is of interest to the nuclear industry also.

With that said, it has been a very successful program for the staff. Over the years, 28 extended power uprates have been approved by the staff.

Currently, in-house we have three, one of them being Monticello. In addition to that, we are in the process of the review of the Peach Bottom and Browns Ferry EPU application, which we also look forward to engaging the ACRS on those applications in the future.

You know, from my understanding, the most recent EPUs that have been approved for the boilers are Grand Gulf back in July 2012 and Nine Mile Point in December of 2011. So, we do believe it a successful regulatory program focused on safety. We have the independent guidance out that we do use, and we are looking forward to discussing that with you today.

Maybe one thing to note upfront, the review is essentially complete. There is one area with steam dryers that we appreciate the Committee's consideration as we proceed through the review on that. We will be discussing the details of the status of the staff review, and we do believe we are prepared for today's meeting and ultimately prepared for a full Committee meeting, recognizing, of course, we would have preferred to have had that review 100 percent complete prior to this meeting. But we do believe we are in good shape to continue to --

CHAIR REMPE: John?

MR. MONNINGER: Yes?

CHAIR REMPE: Let me interrupt you here because this is, I think, something that we need to understand.

MR. MONNINGER: Yes.

CHAIR REMPE: Because, as you know, we have to have a federal notice appearing a month before the meeting.

MR. MONNINGER: Right.

CHAIR REMPE: And we thought that you would have received RAIs by now and you would have had time to finish the steam dryer issue.

MR. MONNINGER: Right.

CHAIR REMPE: And that has not occurred. So, if it does not occur here a month before the September meeting, we need to pull it off the agenda. And so, we need to have some sort of resolution I think by this meeting to understand when the drop-dead date is and what is going to happen on that.

MR. MONNINGER: Okay. And I think between today's discussion and tomorrow's discussion, we can fully commit to providing the path forward, the issues, et cetera, and provide you with that level of confidence.

CHAIR REMPE: All right.

MR. MONNINGER: Okay. So, with that, that pretty much concludes my brief remarks. I am going to turn it over to Terry. Terry is our Senior Project Manager on this.

Also, maybe one of the things I would like to say with regard to the licensee, we have had very productive discussions. They have been very forthcoming to the staff. I just want to thank the licensee for their focus on safety and their focus on completing this project, too. It has been a good working relationship with the licensee, recognizing, of course, our independence. But they have fully responsive to any concerns that the staff has raised.

With that, I will turn it over to Terry.

MR. BELTZ: All right. Thank you, John.

Good morning.

As John said, my name is Terry Beltz. I

am the Senior Project Manager in the Division of Operating Reactor Licensing, Project Manager for Monticello and Point Beach.

On behalf of the NRC staff, I would like to take this opportunity to thank the ACRS members for accommodating us in the schedule, again, with the understanding that we still have some work to do to complete the steam dryer review. So, thank you for that.

Over the course of the next two days, you are going to hear presentations from Xcel Energy and the NRC staff. The objective is to provide sufficient information related to the details of the Monticello extended power uprate application and to discuss the evaluation supporting the staff's reasonable assurance determination that the health and safety of the public will not be endangered by operation of the proposed EPU.

Before continuing with the discussion of the agenda for this morning, I wanted to present just a timeline and some background information related to the staff's EPU review. The application that is currently under review was submitted to the NRC in November of 2008. So, it is going on its fifth year anniversary come this November.

On December 18th, that application was accepted for review. In October 2009, the review of the Monticello EPU was placed on hold, and it was to resolve issues regarding the use of containment accident pressure for use in analyzing ECCS and containment heat removal system pump performance during postulated accidents. The review was formally reactivated back in March of 2011.

Finally, there was a public meeting last November, and it was held at NRC headquarters. It was used to capture any changes that may have occurred over the past two to three, four years since the original application was submitted and the staff's Safety Evaluation Reports were completed, which was for the most part in 2009-2010. So, we held a meeting to find out if there are any changes that need to be captured to update the staff's Safety Evaluation Reports.

During the course --

MEMBER CORRADINI: Can I ask a question there?

MR. BELTZ: Certainly.

MEMBER CORRADINI: So, for the gap analysis, this was a public meeting, but staff had already done the equivalent within the staff itself?

I'm trying to understand.

MR. BELTZ: In discussion with the licensee, we decided that because so many of the reviews were completed two or three years ago, we need to capture things that had changed in the interim.

MEMBER CORRADINI: Sure.

MR. BELTZ: So, the licensee proposed and they had some changes that they identified. The staff also had questions that they had of possible things that may have changed. And we came to an agreement at that public meeting, and then, the licensee submitted those changes on the docket, so the staff could complete the reviews.

MEMBER CORRADINI: Okay. So, this is not the right time, but just to alert, my biggest question with this is, how did the ongoing potential changes for BWR Owners' Group for Fukushima-related issues affect this? And I have some very particular things about CAP. But my question is, does that fit into the November thing or where does that roll in, downstream somewhere?

MR. MONNINGER: It would have to roll in downstream.

MEMBER CORRADINI: Okay.

MR. MONNINGER: I assume you are probably talking about early venting --

MEMBER CORRADINI: Right.

MR. MONNINGER: -- is probably the issue.

MEMBER CORRADINI: Right.

MR. MONNINGER: So, that is a very interesting issue amongst the staff also, but it doesn't play into today.

MEMBER CORRADINI: And so, from a regulatory standpoint, this would, all things being okay, this would proceed forward, and then there might be changes downstream of that with the EPU because of Fukushima-related issues?

MR. MONNINGER: Yes, right, there could be.

MEMBER CORRADINI: Is the staff, at the appropriate time today or tomorrow, is the staff ready to at least chat about that? Because I think it is good to bring it up now, so there is no confusion later.

MR. MONNINGER: To chat about early venting issues?

MEMBER CORRADINI: Yes.

MR. MONNINGER: No.

MEMBER CORRADINI: And change in procedures that might affect CAP credit?

MR. MONNINGER: Yes. You know, the staff, the particular staff working on this application wouldn't have been involved in that. We could see if towards the end of the meeting if the staff --

MEMBER CORRADINI: Just at an appropriate moment, but I just wanted to make sure, because, to me, that was the connection point that, at least qualitatively, has to be covered eventually. And I'm just curious what's the appropriate time.

Okay. Thank you.

MEMBER BANERJEE: What is your timescale on possibly -- this early venting issue, of course, is something that has been in our minds.

MR. MONNINGER: Yes.

MEMBER BANERJEE: What do you think is the timescale on some sort of resolution here?

MR. MONNINGER: So, at risk of getting in trouble, because I am no longer within that organization, the JLD --

MEMBER CORRADINI: Feel free.

(Laughter.)

MR. MONNINGER: To get in trouble?

MEMBER BANERJEE: We will cover for you. We'll try.

(Laughter.)

MR. MONNINGER: Yes. So, it is intimately integrated into the mitigating strategies/responses that licensees have submitted earlier this year. The staff is proceeding with those reviews. We have five different bins, five different groups of plants, and we are proposing to have all the draft SE's with open items issued by this February.

So, you know, the staff is currently, we have completed the initial review of the two pilot plants and have sent out sets out RAIs. But the issue of early venting would be addressed as part of the ongoing mitigating strategies reviews, the RAIs ongoing and the draft staff evaluations to be issued in February.

MEMBER BANERJEE: Okay.

MR. MONNINGER: Did that help or hurt?

MEMBER BANERJEE: Yes, I think it gives us an idea of the timescale. Right, right.

MR. MONNINGER: But the final implementation of all the stuff would be by the end of 2016. So, there will be issues between the Draft Safety Assessment with Open Items next year and the eventual closure of that and subsequent submittals from licensees. They provided an initial submittal, and then, every six months as they continue to do procurement, develop procedures, do analysis, they will be supplementing those applications.

To be honest, there are a lot of questions that the staff has with the interrelationship between their early venting and the staff's subsequent order that was issued this year on the vent for severe accidents. So, all these issues are intertwined.

MEMBER CORRADINI: Well, I mean, as you said, this is a bit early, but I think at least the question I had -- I don't know if it is a concern; it is a question -- is that if the strategy is for early venting at some pressure, what is that pressure or temperature set compared to what the analysis is for CAP credit? Or is the answer --

MEMBER BANERJEE: Or the timescale for when it comes on.

MEMBER CORRADINI: Well, that's another. Or it is an apples-and-oranges issue that you are going to tell me that we are in regulatory space right now for DBAs, so that's all deterministic, and we are over here now in the real world of accident and accident management.

But I guess, having recently visited a Mark I, I am a bit interested in the connection point and how it is logically connected and what the staff is thinking about. So, if we wait, we wait; that's fine. Yes, okay.

MEMBER SCHULTZ: However, John, you mentioned how intertwined these issues are.

MR. MONNINGER: Right.

MEMBER SCHULTZ: And it would be nice in the context of what we are discussing today and tomorrow if we could get some perspective from the staff as to how that will be unraveled over time.

We do have a Subcommittee meeting coming up related to the venting procedures in September. But that, again, we need to focus on the relevant timing associated with the issue. As you say, it is not being wrapped up in that first round, but has a ways to go.

MEMBER CORRADINI: Yes, and I think where Steve is coming from, at least my understanding is that some owner-operators will choose to use early venting as a strategy for satisfying the SBO rule in terms of RCIC operation. So, that means they may change the setpoint for a different reason than just simply early venting.

So, all this stuff in my mind is intermixed. So, I look forward to the staff helping us.

MR. MONNINGER: So, I think we can come back between today and tomorrow, and we will have, of course, during breaks, lunch, et cetera, to engage with the staff and come back and discuss our plans at the appropriate level.

With that said, we do fully believe we can proceed with --

MEMBER CORRADINI: Sure. I understand.

MR. MONNINGER: -- approval, assuming Monticello meets all the NRC's technical safety requirements.

MEMBER CORRADINI: Okay. Thank you.

MR. MONNINGER: We believe we can proceed.

MEMBER CORRADINI: Thank you very much.

MEMBER SCHULTZ: Thank you.

CHAIR REMPE: I think you have one more slide, Terry?

MR. BELTZ: Yes. I will go through it real quick.

Really quick, just to go through some background again as far as the scope of the review. There were approximately 40 to 50 letters/correspondence from Xcel Energy to the NRC during the EPU review. And there were about 40 responses to requests for additional information.

There were 15 supplements to the application, and two supplements were directly associated with the staff's gap review.

As we mentioned before, there were some challenging review areas during the review. That was review of the replacement steam dryer and the use of containment accident pressure.

To go over the topics for today, Xcel Energy is going to give a presentation. They are going to do an overview of the EPU. Both the staff and Xcel will give presentations on nuclear design and safety analysis, and safety analysis, including ATWS instability. And then, in the afternoon the staff and the licensee will be going over containment analysis and containment accident pressure.

Unless there are any additional questions, what I will do is I will turn over the presentation to Mr. Mark Schimmel. Mark is the Site Vice President of the Monticello Nuclear Generating Plant.

Thank you.

MR. SCHIMMEL: All right. Good morning.

(Chorus of "Good morning" from those present.)

Getting off to a good start.

I'm Mark Schimmel. I'm the Site Vice

President at Monticello. To my right is Nate Haskell. He is the Engineering Director at Monticello. John Bjorseth is the Director of the EPU Projects, and Rick Stadtlander is actually one of our Shift Managers, but he has been assigned to be in the middle of all the development, as we went through EPU and the testing and some other things. And we have Mr. Hammer sitting against the back wall over here, who will also get a chance to speak when we get to the nuclear design and safety analysis section of the presentation.

And this has been quite a journey for everybody involved here. We are pleased that we have got an opportunity to actually sit here before you and discuss this and support the NRC as required. A lot of work has gone into a project of this size. As you can see, the timeline was quite extensive, maybe longer than other plants, for various reasons, for things that developed along the way.

But we have engaged industry on numerous occasions and our primary vendors throughout to ensure that we have the best approach and that we have incorporated all the lessons learned from industry the best we can as they apply to Monticello.

Now the design changes and operating parameters I believe are well-understood. I think we will be able to discuss those over the next couple of days.

We work closely with the NRC staff, and we are aligned on the issues. As John said, I think the relationship has been pretty healthy. We have worked pretty close to make sure that, if there are any questions raised or the RAIs come up, that we get an answer to them as quickly as possible, and through numerous phone calls, try to work out the specific details as we move forward here. So, I think that has been very helpful.

The overview is the next slide. What we have here is we are going to talk about, I will cover the background, and the plant modifications Mr. Bjorseth will cover. The reconstitution of the programs Mr. Haskell will cover power. Power ascension Rick will discuss. And then, when we get down to the nuclear design and safety analysis, we will turn it over to Mr. Hammer, and he will walk us through the transient analysis, the long-term stability solutions, the ATWS stability, and the hydraulic questions everybody has, as we move forward here.

On the next slide, the safety analysis, again, this will be, pretty much for us, a Closed

Session. There will be some times in here where we will be able to talk about the transient analysis.

Containment accident pressure is obviously on everybody's mind, and Steve is the expert from our side of the house to talk about that. So, I would be happy to get him up here and let him answer any questions you might have.

Materials and the mechanical civil engineering, B.J., you're going to discuss that when we get to that point. So, we should be able to walk through what that is.

And we have a Closed Session, which we talked about earlier this morning. So, that will be coming up here. And again, we will have members of our staff available to discuss that. We have some preparation for that.

Then, in the Open Session, we have the electrical engineering, which Rick will talk about that. And he will also cover the engineering aspect. Rick, not only is he a Shift Manager, he was a previous engineer; came up through the ranks. So, he is the right guy to have on that conversation on that side as well.

We will talk about blackout capability and a little bit grid stability, if there are any questions there.

The next slide on page 6 is simply the staff that I just discussed that is here with us today. So, if you are interested in any spellings, that's what that is.

Seven has basically just a table of contents and the slides that it covers and where we are going to be for reference as we go through, if you need to jump back and forth a few times to go through it.

And for opening remarks, that is pretty much -- now we are going to get into the background and overview, if you guys are okay.

All right. So, we got our initial operating license in 1970, and commercial operation was in June of 1971. And then, we got our full-term operating license about 10 years later, which was about January 9th of 1981. As somebody stated, it is a Mark I containment.

Initially, the original licensed thermal power as 1670, and we operated like that for a while. And then, in 1998, we did a rerate and basically took the plant from 1670 megawatts thermal to 1775 megawatts thermal.

MEMBER BANERJEE: What was that primarily?

Was it the flow metering or what is the reason for that?

MR. SCHIMMEL: Go ahead and answer that, Steve.

Steve was actually there during the evaluation, right?

MR. HAMMER: Steve Hammer, Monticello.

At any rate, the first rerate is what we were calling it. We were actually the lead plant of GE's extended power uprate program. So, it was classified -- people might call it a stretch-out rate, but it was the lead plant in the EPU process. We helped develop the ELTRs.

The goal of that project for NSP at least was to do an uprate that would allow us to achieve the maximum power available while minimizing the amount of capital modifications. So, that is pretty much what we did. So, we used the margin that was available in the equipment that existed.

MEMBER ARMIJO: Before you leave --

MEMBER BANERJEE: It was a 5-percent stretch.

MR. HAMMER: It was 6.3 percent.

MR. SCHIMMEL: It was 6.3, and we did do some turbine work, right, Steve?

MR. HAMMER: Yes, part of this, the turbine was reaching end of life for a lot of -- we had problems with inner casing erosion. So, we did do some turbine work. We replaced the turbine. We sized it for this power level.

MEMBER BANERJEE: Were there any flow meter changes or --

MR. HAMMER: No, no meter changes.

MEMBER BANERJEE: Okay. So, you stayed with your Venturi?

MR. HAMMER: We are still using the original 2-percent uncertainty.

MEMBER ARMIJO: Just to refresh my memory, this is a very low-power density core. If you could give m -- I looked in the SE for the numbers, but the original core power density was in the order of 30 kilowatts per liter, something like that. If you could just give me what the original was and where you wind up after this 20-percent total.

MR. SCHIMMEL: Harold has got that. My guess is probably less than 50.

MEMBER ARMIJO: You know, compared to the fours, it is going to be pretty low, but I just want to know --

MR. SCHIMMEL: Harold Paustian is our

reactor engineer.

MEMBER ARMIJO: Okay.

MR. PAUSTIAN: Hi. Harold Paustian.

MEMBER ARMIJO: Oh, I know Harold, yes.

(Laughter.)

Well, then, it is really good information.

MR. PAUSTIAN: I looked at a listing of power densities expressed in kilowatts per foot, and it was a few years old. But, at that point in time prior to our rerate to 1775, we were in the bottom five of approximately 45 BWRs. After our rerate to 2004 megawatts thermal, we will be basically in the middle of the lower one-third of that distribution.

MEMBER ARMIJO: So, you will be less than the 45 kilowatts per liter that was going in for BWR IVs? That was the original.

MR. PAUSTIAN: Correct. That's right.

MEMBER ARMIJO: So, you will be lower than 45. Okay.

MEMBER BANERJEE: What will be the number after the 2004 operation?

MR. PAUSTIAN: Pardon me?

MEMBER BANERJEE: What will be the number?

MR. PAUSTIAN: I don't have the kilowatts-per-liter number off the top of my head.

MEMBER ARMIJO: Yes, if you can look that up?

MEMBER CORRADINI: The volume here changed. So, 20 percent of what they --

MEMBER ARMIJO: Yes, but if we knew the starting number, I could have calculated that myself, but I forgot. But, anyway, the point is it is really going to stay a low-power density?

MR. PAUSTIAN: Yes, sir, that is correct.

MR. SCHIMMEL: And the last number on that page is where we are headed, which is the 2004 megawatts thermal, based on the power uprate that we just put all the equipment into the plant for and why we are sitting here today.

CHAIR REMPE: Before you leave that slide, it does say you are planning to implement this in 2013, which there is not a lot of time after September. And frankly, there is the MELLLA+ LAR coming up. And so, what is the planned schedule? Are you going to try to implement it before you get the MELLLA+?

MR. SCHIMMEL: Yes, we would. Now there would be some power level we could go to without MELLLA+. We would take the plant to some point, and that is where we would have to stop.

CHAIR REMPE: What is that "some point"? Do you know?

MR. SCHIMMEL: Right now, we are looking 1880 megawatts thermal as being a stable operating point. We do have the capability to go above that, but it is not a sustained power operation. It would be more of --

CHAIR REMPE: 1180, is what you said?

MR. SCHIMMEL: Correct.

MR. PAUSTIAN: Less than 30 megawatts.

CHAIR REMPE: Okay. So, if you didn't get the MELLLA+, what would you plan on doing? Would you never go to the full EPUs that you are requesting or would you --

MR. SCHIMMEL: No, we would never go to the 2004 megawatts thermal. Of course, my boss and I can have that conversation. But what you end up doing is you drive the operators into region that it is too high; it is too tight.

CHAIR REMPE: Uh-hum.

MR. SCHIMMEL: And you can't ask them to operate the plant like that.

MEMBER CORRADINI: So, if I understand the logic, if you were to do that, you are at the point -- so you would always have to be mucking around with power to do any sort of maneuvering.

MR. SCHIMMEL: Well, part of what I told the controlman Rick is I'm not interested in rod maintenance on a routine basis. So, I would prefer that we would just stay further down on a powered-flow curve.

MEMBER CORRADINI: Okay. Thank you.

CHAIR REMPE: So, I'm not sure if you should answer this or the staff. But is this a good way to proceed legally? And what should the staff be doing? This seems like we are giving them an EPU for a higher rating than what they will really be doing to at this time. Is that typically done?

MR. MONNINGER: We understand your question. We are going to talk about it. Can we get back to you?

CHAIR REMPE: Absolutely. I just am kind of curious about that.

The other issue is, of course, what I brought up with the staff earlier today, that we have this requirement that we have to have the agenda for the full Committee meeting in The Federal Register. And as you know, there are some open items. What is your plan, time to respond to those open items to the staff?

MR. SCHIMMEL: Well, the open items, we intend to have them cleaned up, I think, by -- I don't --

CHAIR REMPE: You could answer later in the meeting, but we really need to know by the end of this meeting.

MR. SCHIMMEL: We can give you an exact date, because we have still got a few open items that we have not sent back in yet.

CHAIR REMPE: Right.

MR. SCHIMMEL: And we have dates for those. I will make sure we give you the right dates for that before we just speak off the top of our head.

MEMBER CORRADINI: But, just to say it again, technically, I want to make sure I get the technical discussion correct at least. Is it your feeling that, given everything else stays the same, you have an expected value that gives you appropriate technical maneuvering, so that you feel comfortable?

MR. SCHIMMEL: That's correct.

MEMBER CORRADINI: And it is approximately 18? Okay.

MR. BJORSETH: And we've got the capability going above 1880, but it means the power would die down over time.

MEMBER CORRADINI: Sure.

MR. BJORSETH: Because, as Mark said, we don't want to manipulate rods to maintain it.

MEMBER CORRADINI: Understood. Understood.

Thank you.

MEMBER BANERJEE: Are there any other limitations, other than having to maneuver with rods if you're going over 1880? Your pumps are all fine and everything?

MR. BJORSETH: With the modifications that we have done this last outage, that completed the modifications needed for the power ascension with the exception of setpoint changes and tech spec changes.

MR. SCHIMMEL: I think when you see the presentation John is going to cover on the modifications that went through, you will see the extent of what we did on the secondary side.

MEMBER BANERJEE: So, we have, of course, dealt with many EPUs that didn't have MELLLA+, and we just have to satisfy ourselves that the plant could deal safety with that.

MR. BJORSETH: I came from a plant that did have the same situation, that they could achieve full power, but not sustain it because of a narrow operating margin at a point in the operating flow map. And they ended up moving power up and down, but did not maintain that maximum power all the time.

CHAIR REMPE: We just need to understand.

MR. JACKSON: Good morning.

My name is Chris Jackson. I'm Chief of the Reactor Systems Branch.

So, I think you posed a question to the staff. Would you like me to address it now or do you want me to --

CHAIR REMPE: Sure. Go ahead, uh-hum.

MR. JACKSON: So, obviously, MELLLA+ is something they have also applied for, but it is a distinct amendment and it has got its own issues. So, you're right, typically, we wouldn't or, traditionally, we wouldn't issue an amendment, recognizing they couldn't achieve full power. But in the past we have issued amendments where physical plant modifications would need to be made over the next subsequent outages to achieve full power. So, we are still working on MELLLA+.

If we don't get MELLLA+, the EPU is still safe and it meets the regulations, but they would have to make another decision in terms of augmenting MELLLA+, making physical changes to the jet pumps or something. But we would see that as an economic decision at that point.

So, your question was, is it typical to issue an EPU when they couldn't achieve that? The answer is no, but it is not unheard of and it is not outside of our regulatory process. So, we continue to work MELLLA+. We will know in the fall, we will have a better idea in the fall of how we are going to proceed with that or how they can proceed with that. So, I think at that point, then we would have to make a decision, do we keep the full power what it is?

But at this moment we have reviewed the EPU. It is safe. Although they physically can't get there in a stable condition, it is safe to operate the plant the way they have it, the way they are proposing to. And we will deal with the MELLLA+ and the flow regime, and they will have to --

MEMBER BANERJEE: So, you just made a comment about modifications to the jet pumps. What did you mean by that?

MR. JACKSON: I think that there would be physical modifications possible that could bring them up to full power if they could change the --

MEMBER CORRADINI: If you remember, we had another applicant way back where their thought was to essentially take what is flow this way.

MEMBER BANERJEE: But is that what you meant? We understand what other applicants did, but is that you meant, that if they didn't get the MELLLA+, they have the option to modify the jet pumps so they can operate into that range?

MR. JACKSON: Right. I believe -- and I am not a plant operator -- but I believe in discussions we have had with them that there are other physical plant changes that could be made to bring them up to full power. Now that would be up to an applicant and based on economics, whatever they choose.

MEMBER BANERJEE: Absolutely.

MR. JACKSON: But issuing the EPU prior to being able to physically get there has been done in the past. You know, people had to make changes to turbines, and so forth, in subsequent outages. So, people have implemented EPUs over subsequent outages in the past.

CHAIR REMPE: Right.

MR. JACKSON: That's legal and safe. So, the EPU we feel will stand alone at this point. Obviously, we want to get the MELLLA+ issues resolved, and we are going to do that. But at this moment the

EPU was good. They will not be able to achieve full power the way they wanted to with MELLLA+, but their decision, I guess going forward, is more economic than safe, from my perspective.

MEMBER BANERJEE: So, let me just ask a question for information. We have approved many EPUs without MELLLA+. Are any of those plants operating at full EPU power and, if so, how?

MR. JACKSON: Yes, many of the plants are operating at full EPU power. But I think their pumps are capable of producing the flows. They can achieve that. It requires more rod movement than it would be with MELLLA+.

MEMBER BANERJEE: So, they go over 100-percent flow? To get that flexibility, they have to go over 100-percent flow, right? Or how do they do it? That is what I am asking. Well, rods up, obviously, but they don't want to use rods. Fine. We sympathize with that. But are there other plants using rods or are they just going up in flow.

MR. JACKSON: My understanding is the other plants are using rods.

MEMBER BANERJEE: Only rods?

MR. JACKSON: That they have greater flexibility in their recirculation flow, and they can get to a higher flow and get to a higher power. Now it requires more rod movement, which isn't contrary to safety, but we support their desire. We support the concept of MELLLA+ and reducing that. Now we are not in a position to approve MELLLA+ now.

MEMBER BANERJEE: Just to pursue the question for a little more information, because I don't have it, just remind me if any of those plants are going over 100-percent flow to get that flexibility because they have that capability in their pumps.

MR. JACKSON: I believe so. I didn't review the prior EPU. So, I would have to get back to you to get a --

MEMBER BANERJEE: Yes, that would be interesting just to know, informational purposes. It doesn't necessarily impact this consideration, but --

MR. JACKSON: Okay.

MEMBER BANERJEE: Yes.

MEMBER SCHULTZ: But just to drive to the point here for this application, there are no conditions on the license being proposed associated with any either operational modification that is being considered separately or any plant modifications, also considered separately?

MR. JACKSON: No. We are issuing, we are proposing to issue this license without conditions in this regard. And I'm sorry, in terms of dryers, and so forth, I don't know if we have conditions associated with that. But in terms of flow, no conditions.

MEMBER SCHULTZ: Thank you.

MR. SCHIMMEL: The next slide, our EPI application was based on Topical Reports, and you can see them listed here. Our uprate was based on constant reactor pressure uprate. The EPU that we have been talking about here is the 12.9 percent. It is considered for us the optimal design with fuel cycle capabilities and the operating margins. We will talk more about that as we get into the presentations.

The last real slide I will talk to you about is on page 11. This basically is an overview of the major parameter changes since our current licensed thermal power versus the EPU power, and you can go down here and sees how we jump up in megawatts: thermal, about 229. Full power core flow rates, you can see we lost the bottom end a little bit on that, but the top end remained the same. The same is true of the full power core flow range, and percent rated. Steam dome pressure did not change. Vessel steam flow went up a little bit, 1.17. Feed flow rate went up a little bit to 1.07. And our final feedwater temperatures run a little hotter. It is 402 versus the 383.

MEMBER BANERJEE: So, excuse me. You can get 105-percent flow, even at EPU, with the additional steam in there?

MR. SCHIMMEL: Your question is can we still achieve greater than 100-percent flow? Do you want to answer that, Steve?

MEMBER BANERJEE: But your pumps are capable?

MR. SCHIMMEL: Our pumps are capable, right.

MR. HAMMER: Steve Hammer from Monticello.

We are licensed for 105-percent core flow, but we don't have the capability or the capacity in our jet pumps to achieve that. So, our normal 100-percent rated flow was 57.6 times 10 to the 6th pounds per hour. We can get to on a range of about 56 right now.

MEMBER CORRADINI: Kind of the same thing with power as is flow; they are licensed above, but they don't have the capability.

MEMBER ARMIJO: They can't get there.

MEMBER BANERJEE: I think that is helpful, yes. Thanks.

MEMBER RAY: Mark, be careful with your folder on that microphone.

MR. SCHIMMEL: I'm sorry.

MEMBER BANERJEE: So, you said it is about 56? Is that the right number?

MR. HAMMER: Yes. I will provide a little bit more details on that later on.

MEMBER BANERJEE: Okay.

MR. HAMMER: I've got a slide.

MEMBER BANERJEE: That is 56 under EPU conditions? Is that it?

MR. HAMMER: Fifty-six is today, is CLTP.

MEMBER BANERJEE: Okay. CLTP. And what would it be under EPU conditions then with additional --

MR. HAMMER: I don't remember off the top of my head. You lose about 1.7 percent, something like that.

MEMBER BANERJEE: Okay. Thank you.

MR. SCHIMMEL: All right. That is all I wanted to cover. I am ready to turn the presentation over to John Bjorseth here.

Can you walk us through the modifications?

MR. BJORSETH: Okay. I will do a high-level review of the modifications. But just as a preamble here, as an engineer and a former licensed operator, one of the things that I hold very dear to me is operating in safety margins of the plant. One of the things that we have tried to do across the board is try to maintain or improve on those operating safety margins. So, you will see that as a theme as we go through these. This is the third EPU I have been involved with and probably the most modifications of any of the three EPUs just because of that aspect.

MEMBER SKILLMAN: John --

MEMBER BANERJEE: Which were the other two? Sorry.

MEMBER SKILLMAN: John, with respect to your comment on margins, where is your margin limiting? Where is your weak link, if you will, for all that you are presenting us here?

MR. BJORSETH: What is your thought on it, Steve, as we went through the design process? What is the most limiting item?

MR. HAMMER: I haven't really probably thought about it in those terms.

MEMBER SKILLMAN: The recommend comment regarding margin, I understand what he said. So, you have done millions of dollars of upgrades, but there is a pinch point in here somewhere. And my question is, where is that? Is it on your rewind? Is it on your amps? Is it your isophase flux cooling? Is it your LP condenser back pressure?

MR. HAMMER: The tightest spot is probably the generator capacity.

MEMBER SKILLMAN: Generator, electrical?

MR. HAMMER: Electrical.

MR. BJORSETH: The other pinch point that we would have up there, on a hot summer day, our isophase duct cooling gets higher in temperature. At 2004 on a 100-degree day, it probably would be most limiting.

MEMBER SKILLMAN: So, it is not nuclear?

MR. BJORSETH: No.

MEMBER SKILLMAN: It is not fuel? It is not in the reactor vessel, the reactor compartment? It is exterior?

MR. BJORSETH: Correct.

MEMBER SKILLMAN: Thank you.

MR. BJORSETH: Okay. The first group of modifications we will go through is the ones for the --

CHAIR REMPE: Okay.

MR. BJORSETH: Yes?

CHAIR REMPE: Are you on the next slide then? Or are you still on --

MR. BJORSETH: Yes, on page 13.

CHAIR REMPE: Okay. Let's go back to that slide because I had some questions --

MR. BJORSETH: Okay.

CHAIR REMPE: -- if you don't mind.

There are a lot of things that are discussed here, but I didn't see some things that sometimes we see at other plants. And I just was curious, because perhaps it was the life extension or something or the license extension and I missed it. But there is no Boraflex in the spent-fuel pool? There was never any issues about that discussed in the submittal. And I just was curious about that. So, there is no degradation?

MR. BJORSETH: No, we have no issues at all with Boraflex in spent fuel. We don't have Boraflex.

CHAIR REMPE: You don't have Boraflex, right? What about your torus? What is the coating on the interior of the torus?

MR. BJORSETH: We have got an epoxy coating on the interior of our torus, and it has been coated once before, recoated.

CHAIR REMPE: Okay. So, is it like zinc or what?

MR. BJORSETH: It is an epoxy.

CHAIR REMPE: An epoxy? Okay.

MR. BJORSETH: There are two options you can choose out there. One is a zinc and one is an epoxy.

CHAIR REMPE: Okay.

MR. BJORSETH: And the plant has chosen epoxy.

CHAIR REMPE: Okey-doke. And let's see, there was also something in the news recently, and I meant to bring this up earlier and I missed it, but there was a yellow finding about flood protection. Has that been resolved.

MR. SCHIMMEL: Yes. The finding was associated with the bin wall and the design or change that we made to our A6 flooding procedure. We revised that procedure to incorporate an earthen berm and the issue has been resolved --

CHAIR REMPE: Okay.

MR. SCHIMMEL: -- and corrected.

CHAIR REMPE: And I think that's it. So, go ahead. Thanks.

MEMBER BANERJEE: Let me ask a question. So, going back to the torus -- why are you laughing? He knows these questions. They have come up before.

(Laughter.)

You are still with the same filter systems in the torus or did you change that out at all?

MR. HASKELL: As a result of EPU?

MEMBER BANERJEE: Yes. Yes, the strainers.

MEMBER SCHULTZ: You need a chair near a microphone.

MR. HAMMER: The question was -- let me repeat it. I'm not sure I heard it very well.

MEMBER BANERJEE: Yes, are they the same strainers?

MR. HAMMER: Yes, we put in new strainers with significantly increased surface area prior to rerate actually, back in the mid-1990s.

MEMBER BANERJEE: Oh, okay.

MR. SCHIMMEL: But we didn't change anything as a result of the power uprate.

MEMBER BANERJEE: The EPU, yes. Right. That was the question.

And the second question, how much has the temperature or how much would the temperature of the liquid in the torus go up -- I'm sure you will come to that -- as a result, just to get an idea?

MR. BJORSETH: We have that as part of our CAP discussion later on with Steve.

MEMBER BANERJEE: Yes, but just give me a rough number. How much will it go up? We will revisit it surely.

MEMBER CORRADINI: It's on the SER, page 86.

MEMBER BANERJEE: So, you know the answer. Tell me.

MEMBER CORRADINI: I think one of their maxes is 207. It is up about 10 degrees, 8 degrees, 9 degrees.

MEMBER BANERJEE: Okay. It went up 9 degrees?

MEMBER CORRADINI: Approximately.

MEMBER BANERJEE: And there were no modifications done to try to keep that temperature lower?

MR. BJORSETH: No, not that I know of.

MEMBER BANERJEE: Okay. Are those modifications very difficult to do?

MR. BJORSETH: They would be sizable. I mean changing our heat exchangers.

MR. HAMMER: We can talk about that.

MEMBER BANERJEE: Sure.

MR. HAMMER: I will talk about that when we get there.

MEMBER BANERJEE: Yes. Okay. Thanks.

MR. BJORSETH: The overview of the modifications, I'm on page 13 here. First of all, the steam dryer replacement, we've had some discussion on that already, but that has improved our operating margin and our moisture carryover. We are now running at less than .01 percent steam, which is about a tenfold increase over our previous dryer. So, not only are we getting a more robust design in our dryer, which we have had in service now for one cycle, but we have seen improved performance on the steam quality.

MEMBER ARMIJO: John, I know we are going to get into the dryer in more detail later, but were there any other problems related to that dryer on that? Let's say cracking or whether it is fatigue or stress corrosion, or anything like that, that was the reason for the replacement or was it really moisture carryover?

MR. BJORSETH: The reason was because we did not feel for EPU conditions that it had the robustness required. So, that was a conscious decision made to improve our operating margin again or our safety margin in this case.

MEMBER ARMIJO: But you weren't having any mechanical problems with it, cracking or anything like that?

MR. BJORSETH: No.

MEMBER ARMIJO: Okay.

MR. HAMMER: Well, there were some IGSCC cracks, but nothing significant.

MEMBER ARMIJO: Okay.

MR. SCHIMMEL: Another question over here?

MEMBER CORRADINI: No. I didn't write it down. I was very curious. So, what was the improvement, just for your margin decision, but you had an improvement in dryness of the steam. And I didn't catch what you said. I'm sorry.

MR. BJORSETH: It is about a tenfold improvement in steam quality.

MEMBER CORRADINI: Okay.

MR. BJORSETH: It went from 99.9 to 99.99 percent.

MEMBER CORRADINI: Okay.

MEMBER BANERJEE: Yes, that is fantastic.

MEMBER CORRADINI: Is that needed or just good, given the fact that you added another, if I remember correctly, you added another lower pressure stage to the turbine? In other words, would you have needed that for that turbine performance on that final stage? I thought somebody said that early on in the improvements. Or maybe I read it.

MEMBER BANERJEE: No, they modified the HP state, didn't you?

MR. SCHIMMEL: Correct.

MEMBER BANERJEE: You need that.

MEMBER CORRADINI: Oh, I thought you modified, also, the LP stage?

MR. SCHIMMEL: Just casing is all we did in the LP.

MR. HAMMER: For the original? Yes, back in the nineties, we replaced the LP turbine completely and we replaced the HP rotating assembly.

MEMBER CORRADINI: Okay. Then, I'm confused. I'm sorry.

MEMBER BANERJEE: But I think your question is still relevant in the sense that that is going to give you an advantage with the HP stage, right?

MR. BJORSETH: Absolutely.

MEMBER BANERJEE: Yes.

MR. BJORSETH: And if we stated at CLTP,

it is strictly an economic decision of do we invest all that improve the steam quality? No. Why did we do it? It is really for the robustness of the steam dryer. It is a much more robust dryer. It has 100-plus years of reactor years operation over in a Nordic country, and they have not had issues at all. So, that is why we selected that design.

MEMBER CORRADINI: Well, you are kind of a Nordic country.

(Laughter.)

MR. BJORSETH: Absolutely. Kind of?

MEMBER CORRADINI: Kind of. Kind of, maybe.

(Laughter.)

MEMBER SCHULTZ: Could you put that on an average unit basis? In other words, how long has the new dryer been in service?

MR. BJORSETH: It has been in service for two years, and we just --

MEMBER SCHULTZ: No, I meant that experience, the 100 years. If you break that down, that is over how many plants?

MR. BJORSETH: How many plants is that? Six.

MEMBER SCHULTZ: What is the longest

experience time track?

MR. BJORSETH: Almost like eight.

MEMBER SCHULTZ: Okay.

MR. BJORSETH: Eight or 10. I don't remember the entire list. There is a list in --

MEMBER SCHULTZ: And the longest is about in that range, eight years?

MEMBER ARMIJO: Oh, more than that. In the eighties --

MR. BJORSETH: Probably longer.

MEMBER ARMIJO: Yes, the original --

MEMBER SCHULTZ: Okay.

MEMBER ARMIJO: I think they did the original, say dryers or some modification of those.

MR. BJORSETH: Correct.

MEMBER BANERJEE: So, these were originally in what, Forsmark and things like that?

MR. SCHIMMEL: That is correct, Scandinavian BWRs.

MEMBER BANERJEE: But they are still there, even after the uprates on Forsmark?

MR. SCHIMMEL: Correct.

MR. BJORSETH: And we have had our new one in service now for two years. We just got done with an inspection and came out clean. No indications.

MEMBER BANERJEE: Also, let me ask you, instrumented this, right?

MR. BJORSETH: Correct. We instrumented it for the last cycle.

MEMBER BANERJEE: And you had, also, the steamline instrumentation at that time?

MR. BJORSETH: Correct.

MEMBER BANERJEE: So, you have got the correlation between what is happening on the dryer and the steamline?

MR. BJORSETH: That's correct.

MEMBER BANERJEE: But we can come back to that.

MR. BJORSETH: Okay.

Okay. Our next item here is our PRA risk. We did have an increase in PRA both for core damage frequency and LERF of about 8 percent on both of those. However, we were able to offset those to modifications outside of the EPU process to bring the core damage frequency back down.

And some of those included our HELB barrier changes that are upgrades. We did change a failure mode on our condensate demin valves. We added additional offsite power source and improved our two offsite transformers.

CHAIR REMPE: There was something I read somewhere about the water level in torus, the indicator being replaced because of radiation damage. What type of indicator? Was it a DP cell? Or what was it that was replaced?

MR. BJORSETH: It was a DP cell. Just from an EQ standpoint, we can extend the life, so we went with an upgraded model, so we could extend out the life of it.

CHAIR REMPE: So, it was an end-of-life thing because radiation damage didn't --

MR. BJORSETH: It wasn't radiation damage. It was EQ.

CHAIR REMPE: Yes, that is what I would have -- it made more sense. I couldn't understand that comment. I don't know if I read it in the SE or in your documentation.

Go ahead.

MR. BJORSETH: Okay. That leads us into the next line item there.

MEMBER SKILLMAN: John, before you change, on EQ modifications, this is an old plant. EQ was kind of an exploratory exercise back in 1970 and 1975. And then was the rule or change in regulation.

The question is, in the Safety Evaluation you read that the EQ program has been reconstituted, and here you present you have improved qualified life on replaced components. What about the not-replaced components? What assurance is there that those original components can withstand the EQ conditions presented by the mass energy releases, the power uprate?

MR. BJORSETH: Do you want to talk about EQ now, Nate?

MR. HASKELL: Yes.

MR. BJORSETH: Do you want to talk to it later?

MR. HASKELL: We will get into a slide here after John gets done.

MEMBER SKILLMAN: Okay.

MR. HASKELL: And we will cover that. But the short answer to your question is we did go back and reconstitute the profiles for equipment qualification, and we validated that all the equipment would continue to be operable with those new profiles. So, that work was done, and that has caused us, through the application of our lives, to change the, we call it the equipment changeout lives for some of the components.

MR. SCHIMMEL: We have changed some of

them out, Dick.

MR. HASKELL: Yes.

MR. SCHIMMEL: This last outage we changed actually quite a few.

MR. HASKELL: Yes, components.

MEMBER SKILLMAN: Okay. Thank you, Mark. Thank you, Nate.

MEMBER SHACK: Just on the plant mods, in some connection with your Appendix R, there was a statement that you performed some valve modifications and fuse configuration changes to prevent MSOs. Can you tell me a little bit more about that?

MR. SCHIMMEL: Yes. The multiple spurious operation evaluation was completed. As part of that, we identified some valves, containment vent purge valves that needed to be modified to accommodate that multiple spurious operation, and those design changes were made.

MEMBER SHACK: Okay, and those have actually been implemented then?

MR. SCHIMMEL: That is correct. That is complete.

MEMBER BANERJEE: There was no additional protection needed of the trains in compliance in Appendix R? You got through it with no problems?

MR. SCHIMMEL: That is correct.

MEMBER BANERJEE: Okay.

MR. SCHIMMEL: Monticello elected to stay with Appendix R, primarily because we do have good divisional separation, and we have done a series of modifications to deal with MSO. And those mods are all complete.

MEMBER ARMIJO: Just a quick question on the feedwater heater replacements. Were all the feedwater heaters replaced or just some of them? And then, what was the main reason you did that?

MR. BJORSETH: Six out of the 10 were replaced. And the reason for those six is twofold. One is end of life, life cycle management on some of the feedwater heaters. And the other is for EPU. It was really twofold.

MEMBER ARMIJO: Okay. Was there any controls or strategies for dealing with them in the case of transient, things like that? Were there any changes there? Or it is pretty much the same control setup?

MR. BJORSETH: Pretty much the same control setup.

MEMBER ARMIJO: Okay.

MR. BJORSETH: The only real difference is we had a slight, small change in the final feedwater temperature based on the feedwater heaters.

MEMBER ARMIJO: Okay.

MR. SCHIMMEL: Even though it looks the same, there are some different valves in our feed system that were replaced as a result of the power uprate.

MEMBER ARMIJO: Yes.

MR. SCHIMMEL: So, the feed reg valves, some internals on some condensate min flow valves. We did do some of that stuff.

MEMBER ARMIJO: Okay.

MEMBER SHACK: In the IPEEE, you guys are sort of notorious for being susceptible to internal floods. Were you able to improve that at all with anything, changes in the feedwater system?

MR. SCHIMMEL: I think John mentioned the addition of the HELB barrier and the change in the configuration of the conden min outlet valves. We did create a new barrier around our lower 4kV switchgear room, such that it no longer is susceptible to flooding from pipe breaks.

MR. HASKELL: New watertight doors.

MEMBER SHACK: Say it again?

MR. HASKELL: New watertight doors.

MEMBER SHACK: Oh, yes.

MEMBER SKILLMAN: The question that Sam asked was about the feedwater heaters. Let me pile onto that question. You picked up 19 degrees from 3 to 4 for the uprate. Your reactor conditions haven't changed and you are saturated. So, did the 19 degrees in feedwater temperature increase come from the area and the fluorite conditions resulting from all of the heater changes?

MR. BJORSETH: Correct, from the feedwater heater changes themselves. They are much more efficient, larger.

MEMBER SKILLMAN: Okay. Thank you. Thank you.

MR. BJORSETH: Okay. The next bullet there is training and simulator upgrades. I have got to say that EPU, there's a lot of things that happen with EPU and upgrading the simulator, and the training aspect was one of them because I would say we are probably one of the leading simulators out in the industry right now with our BOP, our Balance-of-Plant Model improvements, our electrical distribution, and core modeling.

And the operators have gone through the training on that. They will continue to go through the training and through the license approval and power ascension.

And the next one is the tech spec set point changes. We will be making those after license approval.

I will go through some of the pictures here. I am on page 14, the picture of the new steam dryer.

Page 15 is the simulator panel trainer that we have installed now. This is not the simulator, but this is something that the instructors can use, the engineers can use to model some of the potential transients and things like that without having to use an entire simulator, which is very busy with operator training.

Page 16 we get into the balance-of-plant modifications, where a major part of our effort was. We talked about the feedwater heater replacements already, but those are in place now and operating very well.

Our feedwater pumps and motors were replaced. We went from a 4 kV power system. We upgraded to a 13.8 kV system, and this is just for the feedwater pumps, the condensate pumps, and the reactor MG sets. And those are in place and running now.

Our condensate pump and motor replacements are also 13.8 with the new pumps. The condensate mineralizer replacement was done two years ago during the prior refueling outage. And that has really been a boon for operations because not only does it give operations the ability to have much less likelihood of an error, but from a maintenance standpoint we used to have the old cams and 40-50-year-old technology; replaced with PLCs. Programmable Logic Controllers are beautiful for the operators to use, and it has improved the water quality.

MG set motor replacements, I talked about. The high-pressure turbine replacement, we have talked about already.

MEMBER BANERJEE: Did you have to add more stages to this or what happened to get more power out of the --

MR. BJORSETH: On the high-pressure turbine?

MEMBER BANERJEE: Yes.

MR. BJORSETH: The same number of stages as prior. Turbine design has come a long ways in the last 40-50 years.

MEMBER BANERJEE: But blade designs were changed or something?

MR. BJORSETH: Yes.

MEMBER BANERJEE: It is primarily the blades?

MR. BJORSETH: Right.

MEMBER BANERJEE: Are these blades more erosion-resistant as well? Oh, I guess you have cleaned up your steam, so you have much less --

MR. BJORSETH: Right.

MEMBER BANERJEE: -- potential for erosion.

MR. BJORSETH: Just keeping up with the technology as it improved over 40 years was a main part of that. A lot of plants have been going through turbine replacement, getting 30-40 extra megawatts on their turbines just because of the efficiencies. So, we took advantage of that, plus the additional steam flow. We had to increase the area of steam.

MEMBER BANERJEE: Who did that?

MR. BJORSETH: General Electric did that.

MEMBER BANERJEE: Okay.

MEMBER SKILLMAN: I note that you did not replace or change your LP or your condenser. At least there is no mention of that. Why? Is the efficiency or the discharge pressure of the HP great enough to not require any changes to the LP or the back-pressure rating on the condenser?

MR. BJORSETH: Yes, the LPs were replaced with a monoblock design back in the nineties.

MEMBER SKILLMAN: Okay.

MR. BJORSETH: So, we did not have to upgrade those. Those had already taken advantage of some of the improvements in the turbine design and theory. The condenser had capability. We did the analysis on the condenser, and with our circ water flows, it could handle the steam flows. It had margin in it.

MEMBER SKILLMAN: So, the condenser is really covered by a margin of the original design?

MR. BJORSETH: Correct.

MEMBER SKILLMAN: Okay. Thank you.

MEMBER ARMIJO: Is that the original condenser in the plant? Or was that changed to titanium in the eighties?

MR. HAMMER: The original condenser tubes were Admiralty brass, and they were changed out back in the eighties to stainless steel.

Just one clarification. Currently, Monticello does have the potential to reduce power during very high river conditions if a condenser vacuum is reduced. And we did evaluate that with EPU, and there is some increased potential for more days where we might have to reduce power to meet our vacuum limits. But, you know, that is the design that we are --

MEMBER ARMIJO: Okay, but you retubed to stainless steel, not titanium?

MR. HAMMER: Stainless steel, correct.

MEMBER ARMIJO: Okay.

MEMBER RAY: Should you identify yourself?

MR. HAMMER: Oh, Steve Hammer, Monticello.

MEMBER BANERJEE: Just going back to the LP stage now, you would get increased wetness, right, due to the steamline coming down? And that is not likely to cause you any problems with the LP stage?

MR. BJORSETH: With our moisture separators that we have, we can remove most of that wetness and really not have a chance in performance on the LP turbine side.

MEMBER BANERJEE: Okay.

MR. BJORSETH: We also did a rewind on a generator field and stator. We did that two years ago during the prior refueling outage. And that was both a life-cycle management, end of life on fuel needed to rewind, as well as an EPU. So, we were able to improve the performance of that.

And our transmission system upgrades, we went through 1AR, which is a third safety-related essentially transformer for offsite power supplies, replaced that.

Our main transformer was replaced a well as our 13.8 kV bus was a brand-new addition to the plant, a new bus system, and the associated transformers.

Some of the items that you will see on the next few pages, I have pictures of these. Page 17 is a picture of one of the feedwater heaters being replaced. Also, along with the feedwater heaters being replaced, we increased the drain size on some of the lines going from the feedwater heaters back to the condenser. We have to accept the higher flow rates.

On page 18, a picture of our new feedwater pumps and the motor associated with it. We have gone from a 6,000-horsepower motor to an 8,000-horsepower motor, and that gave us some extra margin on our feedwater. We were running at about 8-percent margin on feedwater prior to the uprate. We have improved that now to a 14-percent margin under EPU conditions.

MEMBER BANERJEE: You are still with the same diesels and everything?

MR. BJORSETH: Correct.

MEMBER BANERJEE: And these have gone up, you said, to 13 kV or something?

MR. BJORSETH: On the feedwater pumps and the condensate pumps and the reactor MG set. That has really been a help to us from a margin standpoint, too, because what we have done is, by adding these 13.8 buses that are separate from our previous 4-kV buses, we stripped that extra load off our safety-related 4-kV buses, so that there is a lot more margin on those now.

Page 19 is the new condensate pump and motor picture.

And page 20, the condensate demin replacement I talked about. That was a significant job to replace those. It wasn't just some septa or some valves. The entire system was replaced, putting vessels, piping, valves, controls, wiring. We brought that up to basically a new plant standard.

MEMBER SKILLMAN: So, is that 100-percent condensate policy? Is that what you have?

MR. BJORSETH: A hundred percent condensate demineralizers.

MEMBER SKILLMAN: Yes.

MR. BJORSETH: Four out of the five can handle 100-percent flow.

MEMBER SKILLMAN: Thank you.

MR. BJORSETH: We have got two out of the five septum have iron filtration in them. So, a portion of the feedwater flow does get filtered out for iron.

MEMBER SKILLMAN: Okay. Thank you.

MEMBER BANERJEE: Do you do any zinc addition in these pumps?

MR. BJORSETH: Yes, we have got zinc injection, and we are planning in three months to go to a noble metal, online nobel metal addition, all part of chemistry improvements.

Page 21 is the control panel that I talked about earlier. It is a much simpler panel than what we used to have with all of the switches. Now we are going to go ahead and go through the changeout of demin.

Page 22 is a picture of the new MG set motor, 13.8 kV MG set motor.

And page 23 is the new high-pressure turbine that went in. And our target increase for this is a 71-megawatt electric increase as part of EPU from CLPT conditions.

And page 24 is a good shot of our generator rewind. We are able to improve the limitations on our generator from a 66-MVA limitation to a 718-MVA.

Page 25 is just a shot of our switchyard. But, again, it is very important from an offsite power source to have diversity in our supplies. And Xcel, as a corporation, ha put in a new line that ran through our switchyard. And that is our sixth power supply. It goes from North Dakota, and it will be ending up down at the Prairie Island Red Wing Station.

Page 26 --

MEMBER CORRADINI: Is this just for the dramatic effect or what?

(Laughter.)

You could have shown a wind turbine burning up.

(Laughter.)

MR. BJORSETH: But, actually, that is the new power supply going in where they do explosive welding, and that is where they did the tie-in right here.

CHAIR REMPE: You said explosive what?

MR. BJORSETH: Welding.

CHAIR REMPE: Welding? Okay.

MEMBER SKILLMAN: Let's go back a slide, please.

MR. BJORSETH: Yes.

MEMBER SKILLMAN: I read about your power fracture corrections and other detail relative to transmission system and your output. The question is, what obligations do you have for importing or exporting bars and is that factored into your new transformer design, particularly the copper in that machine?

MR. STADTLANDER: Yes, we do have an inter-tie-in agreement with MISO, and we are working within Xcel network ourselves. We are pretty much right in the middle of the Xcel network. So, we have worked with the sister plants about working with the capicitator banks that we put in to meet the power factor requirements that we need. And we have also got an inter-tie-in agreement with MISO as well that lays that out. We will get a little bit more about that in the electrical engineering side, you know, the section towards the end of tomorrow.

MR. SCHIMMEL: Are we carrying more bars as a result of the upgrade?

MR. STADTLANDER: I don't know the answer to that off the top of my head, if that is the plan right at the moment. I don't know if you know, Steve, but I think they are planned to be comparable to where we were previously.

MR. SCHIMMEL: I think they were, too. That is the point that we had, was more reactive loading, more challenges. I don't think it is a significant reactive loading question. We designed it for increased reactive loading. I don't know exactly how much. But that was all the size we talked about with the company and distribution, to see what all that is. Of course, I would like to have less reactive loading, but we carry the same, I think it is roughly the same percentage.

MEMBER CORRADINI: For the non-electrical engineer in the audience, you would rather have less reactive loading, can you explain?

MR. SCHIMMEL: It is hard to get paid for the vars.

(Laughter.)

MEMBER SKILLMAN: But you could attach your windmills and they could pay you, right? Xcel can pay Xcel.

(Laughter.)

MEMBER SKILLMAN: When you are out on the end of the wire, the vars become an issue in terms of operating the plant, and you may have to back up because of the amount of copper you transform. And so, it doesn't sound like a safety issue unless you are in a real pinch and you need the power, in which case it becomes an operating issue, a real operating issue.

MR. STADTLANDER: Yes, and like you said, it is more of an issue if you are kind of at the end of the fire. Right now, where Monticello is located, we are actually right in the middle of a pretty very stable grid. We are kind of in a unique area, it seems like, for a lot of the nuclear power plants, where we have got a major inter-tie for the Xcel grid network as part of our subyard.

So, we have actually got three 345-kV lines coming in. We have got 315-kV lines coming in, and we actually have two 230-kV lines that are going out. So, as far as Monticello goes, we are pretty unique in the industry, I believe, based on the subyard and the distribution network that we have got access to.

MEMBER SKILLMAN: Okay. Thank you.

MR. BJORSETH: And that takes us up to page 27. It is a picture of our new transformer.

MEMBER ARMIJO: Before you go there --

MR. BJORSETH: Yes?

MEMBER ARMIJO: -- could you go back to 25 or your previous slide? Now I am sure there is something that is significant here, but I am not a transmission or an electrical guy. So, what are we trying to point out with this explosive welding? Is this a new thing, a good thing? Or is it sort of -- what am I supposed to get out of this slide other than it's interesting?

MR. BJORSETH: No, that's about it.

(Laughter.)

MEMBER ARMIJO: I got it, I guess.

(Laughter.)

This is routine kind of way of --

MR. BJORSETH: It is something that Xcel has been using the last couple of years that we thought was pretty interesting. When it actually happened, we had a crowd outside of the plant watching it happen, and everyone walked away pretty awed that this was occurring, that you do explosive welding on wires and make a connection like that that is more secure than any other method that they have.

MEMBER ARMIJO: Okay, but there are other techniques for --

MR. BJORSETH: Yes, there are.

MEMBER ARMIJO: -- making the connections? This is a significant improvement? Is that the point?

MR. BJORSETH: This is a significant improvement.

MR. SCHIMMEL: I think that is what you were trying to display, was this was something that is out of the ordinary. It is not typically how we have done this.

MR. BJORSETH: Right.

MR. SCHIMMEL: This is fairly --

MEMBER CORRADINI: It's an improvement, Sam.

MEMBER ARMIJO: Well, I agree. Explosive welding is an okay thing. I just wanted to see what I was supposed to get out of that.

Thank you.

MR. BJORSETH: The new transformer has gone from 650 MVA on the old one up to 800 MVA for the new one. So, again, margin improvement.

MR. SCHIMMEL: Notice the colors we had to paint them.

MR. BJORSETH: Page 28 is the colors. From a human factors perspective, when you have got two transformers identical next to each other, it is great to have them different colors. It helps the operator be aware.

The fact that they are painted University of Illinois and Iowa State University colors might be just coincidence. We will just leave it at that.

(Laughter.)

MEMBER CORRADINI: The engineers in charge don't fight, do they?

(Laughter.)

MR. BJORSETH: Not at all.

MEMBER CORRADINI: Okay. On page 29 is the picture of our new breakers and buses for our 1308 system. This is one of two new buses that we have added.

And at this point, barring any of the other questions you may have on the modifications, we are going to turn it over to Nate Haskell, who is our Engineering Director, and he will talk about the engineering programs and how those have changed.

MR. HASKELL: Yes, specifically, I am going to cover our high-energy line break, environmental qualification, and motor-operated valve programs. Those are a few programs that benefitted greatly and were reconstituted associated with the EPU upgrade.

If you go to the next slide, under the high-energy line break, we updated our existing analysis to reflect the EPU conditions. We had an enhanced HELB model using the latest version of GOTHIC. And the results indicated acceptable levels of temperature, pressure, and submergence for all reactor building and turbine building volumes. So, we redid our reactor building and our turbine building analyses. There were 46 calculations that were revised and 12 new analyses that were created as a consequence of updating that analysis. We also looked at pipe whip and jet impingement, and those evaluations showed acceptable results.

So, some of the changes that we had in the modeling were double-ended break flow to include flow from both ends of postulated breaks. System depletion included mass and energy and piping systems and vessels.

We also changed the stroke time from our ASME-measured strokes to the maximum stroke times associated with the values in our updated Safety Analysis Report. That gave us some conservative mass and energies out of the break locations.

We also assumed that the flow through the break was 100 percent up until the valve went full closed, as opposed to previously our analysis assumed a linear closure of the valve and a linear flow rate out of the break location.

MEMBER SKILLMAN: Did you have margin when you did the calculation that way?

MR. HASKELL: Yes. When we did the calculations, we did get good margin still.

MEMBER SKILLMAN: Even though you did not use a linear reduction in mass and energy --

MR. HASKELL: Right.

MEMBER SKILLMAN: So, you took full stroke time and continued 100-percent mass and energy release until the valve was closed?

MR. HASKELL: Until the valve was closed, that is correct.

MEMBER SKILLMAN: Thank you. Okay.

MR. HASKELL: Okay. And the Environmental Qualification Program, we did update, as I mentioned earlier, all the environmental profiles to reflect the revised HELB input. We converted all our qualification files to EPRI's EQMS format, and all of the equipment within the scope of the EQ program is qualified still, as we previously mentioned.

Okay. Let's go to the MOV program. We reconstituted the MOV functional analyses for the differential pressures, temperatures, and flows associated with EPU. We updated the valve coefficient-of-friction analyses, and we had 12 MOVs that we had to make switch adjustments to satisfy the EPU conditions. So, on those 10 MOVs, we modified the torque switch settings to facilitate the new EPU values.

MEMBER SKILLMAN: Nate, before you finish your presentation here, let me ask you a question. Again, you're an old plant. This is an old plant.

MR. HASKELL: Uh-hum.

MEMBER SKILLMAN: So, you have updated HELB, EQ, found a couple of warts and wrinkles in your MOV program.

MR. HASKELL: Uh-hum.

MEMBER SKILLMAN: Now the real question is the robustness of the configuration you control in part with high-energy line break in the queue. But, as importantly, in your cycle counting from the beginning of plant operation, in the analyses that are driven by the cycle counting, cumulative usage factor, particularly on feedwater nozzles.

MR. HASKELL: Uh-hum.

MEMBER SKILLMAN: So, as I hear the licensee talk about program reconstitution -- and these are a couple of the big programs --

MR. HASKELL: Right.

MEMBER SKILLMAN: -- among these big

programs is cycle counting.

MR. HASKELL: Uh-hum.

MEMBER SKILLMAN: And so, either now or later, I would like you to please talk with us about how we can be confident that you really have accounted for the cycles on this machine.

MR. HASKELL: Yes, we will be presenting that information and talking specifically about the cumulative usage factors that we have and that we have determined. So, that will be coming.

MEMBER SKILLMAN: Yes, sir. Thank you.

MR. HASKELL: Uh-hum.

MEMBER SKILLMAN: Okay.

MR. HASKELL: Okay. With that, that brings us to the power ascension plan. And Rick Stadtlander has that.

Rick?

MR. STADTLANDER: All right. Thanks, Nate.

All right. As Mark introduced me, I am a Shift Manager by training right now. A couple of years ago, I got asked to be the Test Director for the EPU. So, that is why I am talking about this particular item.

And then, previous positions I have held in the plant was as an electrical engineer as well. So, that brought me into the Test Director role, since a lot of the upgrades we made were electrical in nature.

As part of the presentation here, we will discuss Monticello's power ascension testing approach, give a quick summary of the major testing that is being performed, and talk about the acceptance criteria, make sure our testing is evaluated correctly.

CHAIR REMPE: I believe you are on the microphone, and that makes the recorder very angry.

(Laughter.)

MR. STADTLANDER: All right. Sorry about that. As I flip pages, I will be cautious.

All right. As we came up with the power ascension testing here, we used an approach that is similar to our initial uprate, part of our initial uprate that took us to the current 1775-megawatts thermal that we are at now.

We have an issue of passive and dynamic testing being performed, as we raise power up to the 2004-megawatts thermal. So, a majority of the testing is passive in nature, but at various points they will be performing dynamic testing, consisting of reactor-level changes, feedwater flow changes, and reactor pressure changes. But we are not doing any large transient testing.

During our initial startup, our large transient testing was performed, such as the MSIV closure, the generator load rejection testing, the recirculation pump trip test, the recirc flow testing, along with feedwater pump trips.

So, these tests have all been evaluated, determined not to be required for the EPU testing. Between the plant OE and industry OE, the transient response is predictable following the EPU implementation.

So, a couple of items that were specific to the Monticello OE here is we experienced an MSIV closure event, approximately 98-percent CLTP when a technician bumped an instrument rack while roping off a contaminated area. So, the scram was within 15-percent of EPU power.

In 2002, we experienced a generator load reject.

MEMBER BROWN: Did you say he just bumped -- excuse me --

MR. STADTLANDER: Yes.

MEMBER BROWN: -- he just bumped the rack and it created this difficulty?

MR. STADTLANDER: Correct. Yes. Actually, the rack that he was working around, I had actually just joined the plant at about this timeframe. He was working around it, not realizing the sensitivity of it, and I believe he actually kicked it with his foot as he was going through and roping this off.

MEMBER BROWN: And so, that caused the plant transient?

MR. STADTLANDER: Yes. Yes. It caused a Group 1 isolation, is what it caused, so causing the MSIVs to close and causing the plant scram at that point.

MR. SCHIMMEL: The plant has got a lot of barriers to prevent that from happening.

MR. STADTLANDER: Yes. We learned a lot from that.

MEMBER ARMIJO: The question is, why is so sensitive?

MEMBER BROWN: What is the response under a seismic situation? Just everything goes berserk because the panel shakes a little bit? That seems to be a little bit sensitive to me. I mean, you ought to be able to blow up 500 pounds of C4 a couple of feet away from it, and it ought to be just fine.

(Laughter.)

I am being a little bit facetious, but --

MR. STADTLANDER: Right.

MEMBER BROWN: Just somebody kicking something accidentally seems, from a spurious plant response standpoint, seems to be a little bit tentative to me.

MR. STADTLANDER: Okay. I know that, since that timeframe, I know we have done a lot of work in this area to make sure we have made it more robust.

MR. SCHIMMEL: The same with single-point vulnerabilities. We have identified all those. We added redundancy to some of the stuff. We have put barriers on the floors to keep people, to make sure they are sensitive, that if they lean against the racks or hit an instrument, then it could cause an unwanted condition.

MEMBER BROWN: But why don't you want to have instrumentation that is not sensitive to perturbations and people bumping up against it? That is just it seems to me your seismic capability is significantly impacted because of the lack of robustness mechanically and electrically. It has got to be connection-wise or your cards shifting, or whatever that is, pins not coming open, or what have you. That is pretty sensitive. You are putting barriers around it. It is nice, but it doesn't help you if you have an earthquake somewhere.

MR. BJORSETH: From my perspective, if I was in the control room operating and I had an earthquake, I would want the plant to shut down.

MEMBER BROWN: I would like it to shut down in a somewhat more controlled manner than what you apparently said happened in this circumstance. You don't have an answer for that, is what you are telling me?

MR. BJORSETH: Yes, right.

MEMBER BROWN: So, that is the way I walk away from this question.

MEMBER CORRADINI: The C4, though, I don't think they can --

MEMBER BROWN: Oh, well, that is my style. I'm sorry about that.

MEMBER SKILLMAN: They have a custom remedy for ATWS.

(Laughter.)

MEMBER BROWN: Pardon?

MEMBER SKILLMAN: A custom remedy for

ATWS, kick the panel.

(Laughter.)

MEMBER BROWN: Yes.

MR. STADTLANDER: All right. Fair enough.

In 2002, we experienced a generator low reject, but 100-percent current license power. And that scram was within 13 percent of the EPU power.

So, the data from both of these events was available and evaluated and determined that further large transient testing wasn't required as part of the EPU testing.

So, we have also had no new design functions in the safety-related systems that are required or that would require any large transient testing validation for the EPU. And based on plant historical data, EPU analytical results, large transient results in conditions that are within the design limits.

Our EPU plan was developed in accordance with the NRC Standard Review Plan 14.2.1. Our actual post modification testings performed satisfactorily with the pre-operational testing completed. And we are in the process of completing our operational test as the plant comes back up to 100 percent CLTP.

So, on the next slide you can see we have

10 individual tests that are being completed at various points during this testing. There is one document that actually controls the overall power ascension testing.

The majority of the testing is passive in nature, like I said, monitoring that the plant is responding to new power levels as we expect. Some of the monitoring includes the radiation levels and vibration levels within various points.

Once the testing is complete at a particular power level, the results are going to be rolled into a report. And then, this data will be used along with the previous results to predict where we expect the next test data to be as well.

So, all this will be rolled into one report, then, the actual test that we have gotten and the predicted results for the next step. That will be reviewed by a technical team who will go through and make sure it meets all the test data that we have taken, meets all the acceptance criteria that we have laid out, and that's been laid out.

At that point, it will go to our Management Operating Review Committee, and they will review it, take the recommendation from the technical team, create their own recommendation to the Plant

Manager, and determine if we are safe to or if we are ready to proceed to the next power level.

MR. HASKELL: We are actually going to leverage our safety -- when you talk about safety, you know, your process onsite here, your Safety Review Oversight Committee? That is the intent. The intent is you hit a level and you stop, and you review the data. The data gets technically-reviewed and, then, goes to the Safety Review Board which says: is it the right thing to do? Do we understand the safety impacts of it?

MEMBER ARMIJO: I know the focus of this is on safety, not on operations, but are you also going to be monitoring your water chemistry as you go, particularly because you can have crud transients, because less so because you are replacing all those feedwater heaters? But, if you weren't, you could have a big crud trench. It would mess up your fuel. So, you will be?

MR. STADTLANDER: Yes.

MEMBER ARMIJO: Okay.

MR. STADTLANDER: Yes, that is chemical and radiochemical.

MEMBER ARMIJO: Okay.

MR. STADTLANDER: What we will be doing.

So, yes, we will be monitoring that throughout the whole process.

MEMBER ARMIJO: Right.

MEMBER BANERJEE: So, you will go through the process for the steam dryer in detail when we consider the steam dryer?

MR. STADTLANDER: Yes. Yes, those details will be dealt with a little bit later.

MEMBER BANERJEE: Okay.

CHAIR REMPE: But, as we discussed earlier, EPU is really like you are going to stop at the 1880 or so, right?

MR. STADTLANDER: Correct.

CHAIR REMPE: And so, you are not going much above 110, where you are going to stop on this process? If I did my math right, it is like 13 percent or something?

MR. STADTLANDER: Yes, we have got a 13-percent power uprate, roughly, 12.9. So, we do have provisions in the test plan that we have got where, if we don't have MELLLA+ at that point, that it tells us to stop I believe roughly at the 105-percent level.

CHAIR REMPE: Oh, okay, so you will stop even -- okay.

MR. STADTLANDER: Yes. So, we will be

stopping and holding the testing, then, at that point until we can proceed on.

MEMBER CORRADINI: 1770, not 105 of 1675?

MR. STADTLANDER: Yes.

MR. SCHIMMEL: Don't leave her the impression -- that is not the final destination, right?

MR. STADTLANDER: No, no.

CHAIR REMPE: Okay.

MR. STADTLANDER: The final destination is to get all the way up to the 2004 thermal.

CHAIR REMPE: But, again, if you hit the MELLLA+ --

MEMBER ARMIJO: You need to hit MELLLA+ before you do that.

CHAIR REMPE: -- or something else. Okay.

MR. SCHIMMEL: Correct.

MEMBER SCHULTZ: Rick, could you describe in a little more detail for information the evaluation program that occurs after each of these hold points, these test conditions?

MR. STADTLANDER: Yes.

MEMBER SCHULTZ: What the timing is of the testing and the power ascension.

MR. STADTLANDER: As you can see, we are

going up, once we get to 100 percent of our current license power and we get the new license, we will be going up at 2.5 percent increments. At the end, when we get up to the 102.5 percent of current license power, we will be stopping and holding at that point, gathering all the data, you know, that is based off of the testing that we are doing here, rolling that all into one big report, sitting down with the technical team and reviewing that.

We will review it against our Level 1 and Level 2 criteria, which I will get into in a moment here. Make sure it meets all those criteria. If it doesn't, we have got an evaluation to be performed to look at. Once it meets all the criteria, that technical review team will, then, turn that over to our Safety Operating Committee, our PORC, our Plant Operating Review Committee. We will turn that over to that.

And at that point, the Safety Review Committee will look at it, not only at the current data, but at where we expect to be on the next step. So, when we do the testing at the 102.5 percent, we will also do it based on the testing that we did at 90 and 100 percent. We will do a prediction of the 105-percent testing.

So, we will roll that all into one big report, have that reviewed by our Safety Committee, and then, they will make a recommendation to the Plant Manager as far as their confidence for proceeding up to the next step. In this case, it would be the 105 percent.

MEMBER SCHULTZ: Thank you.

MR. STADTLANDER: Yes.

MEMBER BROWN: So, does the plant come back down to 100 while they are doing all this? And how much time does it take to do that?

MR. STADTLANDER: No. The expectation is that we will stay at 102.5 percent unless we find something glaring, some issue, right.

MEMBER BROWN: How long does it take all these committees and the report to be generated? Do you sit there for a week or three days or --

MR. STADTLANDER: It could be as long as a week. Right now, we are going through that process to determine the report format. We have got a lot of the test data that we are taking is actually automated through our plant process computer system. So, we will be able to pull that data actually fairly quickly.

MR. SCHIMMEL: We have criteria that we

will be able to bounce it against and we expect to see this. If we see that, it gets logged against it, and there is zero deviation from that, as long as there is no deviation in the data. And when it is telling us what we expect to see, then I think it wouldn't take too long.

MEMBER BROWN: Right.

MR. SCHIMMEL: It is when you start to see anomalies or a rate change that you didn't expect to see, that is when you are going to slow down and see --

MEMBER CORRADINI: So, you will have pre-predictions on all the key parameters to get an estimate or an expectation of what you expect to see?

MR. SCHIMMEL: Absolutely.

MEMBER BROWN: Which will allow you to stay at the 102.5 percent, for instance?

MR. SCHIMMEL: Right.

MR. BJORSETH: Any deviation would enter for a corrective action program and do a formal assessment. This includes any pressure or temperature for balance of plant, feedwater heater temperatures, generator temperatures, turbine pressures.

MEMBER SCHULTZ: What is the reason why you have decided or elected not to review the entire suite in the matrix at 105- and 110-percent power?

MR. STADTLANDER: Some of that was due to the actual testing. For example, the pressure regulator and the feedwater system, that is some of the dynamic testing that we are doing. So, to perturbate the system, more often than we had to, rather than putting the plant in that condition, it seemed to make more sense to have a good prediction as far as where we are going, understand what we expect to see, and then, proceed up 5 percent in that case instead of the 2.5 percent.

MEMBER SCHULTZ: Thank you.

MR. STADTLANDER: All right. All right. Just to take a look at the acceptance criteria that we have got, we do have two levels of acceptance criteria. The Level 1 acceptance is associated with plant safety. So, if for some reason we don't have a Level 1 test criteria met, we will place that in a safe hold condition, judged to be satisfactory and safe. We will, like John said, issue that or we will document that in the corrective action program with resolution that we have to pursue immediately.

Following that resolution, the failed test will be repeated to verify the Level 1 criteria actually is met or justification for not reperforming that would have to be documented. And then, a description of the problems included in the report, documenting the actual successful test. So, making sure that we look at it, we go back, review it, reperform the test if we have to, and then, document all the issues or any issues.

On the next slide we have got the Level 2 acceptance criteria, and that is associated with the design performance.

Limits stated in this category are usually associated with the expectations of system transient performance. The issue, again, if we have a issue, it will be documented in the corrective action program, evaluated to see if any equipment adjustments are required. An evaluation will be initiated to investigate the performance parameters and the control adjustments related to the criteria not met. The evaluation will include alternative corrective actions and concluding recommendations. And all that would be included in the report as well.

That is the end of the power ascension plan.

CHAIR REMPE: Okay. So, if there aren't any questions, I think we ought to have our break a bit early and then come back, if that sounds good to everybody else.

So, at this point, we will go off the record. Oh, yes, 15 minutes, by the way, too. So, let's try to get back here at 10:20. We will give you a little extra time. Okay?

(Whereupon, the foregoing matter went off the record at 10:01 a.m. and went back on the record at 10:19 a.m.)

CHAIR REMPE: So, who is up next?

MR. HAMMER: Okay. My name is Steve Hammer. I am the Licensing Project Manager for EPU. I guess I was involved in the last power uprate at Monticello for rerate also.

Before we get started, the ACRS did have a question on our power density, and we do have an answer.

CHAIR REMPE: Great.

MR. PAUSTIAN: All right. My name is Harold Paustian. After that question was asked, there was some information that was found on that.

The after-EPU power increase, the power density for Monticello will be 48.3 kilowatts per liter.

MEMBER ARMIJO: Okay.

MR. PAUSTIAN: Which is pretty much in the middle of the pack. It is not a challenging-type number in terms of the spectrum.

All right?

MEMBER ARMIJO: Okay. Thanks. Thanks, Harold.

MR. HAMMER: Okay. Today I am going to talk a little bit about what we did for design and safety analysis of the EPU project. The subjects that we are going to cover here are shown.

Next slide.

This is kind of a list of the general transients and accidents that were evaluated as part of the scope for the EPU project at Monticello. We will go through these very briefly. And just if anybody has any questions --

Next slide.

One of the issues that is typically evaluated is excessive heat removal. For Monticello, for this event, the evaluation did show that it met the CLTR requirements or the constant pressure power uprate licensing Topical Report requirements. We confirmed the fuel and design limits and reactor coolant pressure boundary limits are not exceeded under EPU conditions.

And this category of events is in the

typical reload evaluation scope for the non-bounded events. Some of these events are considered bounded events. So, not all of them are covered in the reload analysis.

Any questions there?

MEMBER ARMIJO: In the case of your loss of feedwater heater event, do you reach the same kind of peak powers during that transient? I recall numbers in other plants, something on the order of 16 kilowatts per foot or until you can terminate the transient.

MR. HAMMER: I guess that one I don't know the response to. We can check it and look for the answer.

MEMBER ARMIJO: Yes.

MR. HAMMER: Okay. Next slide.

Decrease in heat removal events. This is another class of events that is typically covered. These also meet the CLTR requirements and don't challenge limits for the fuel or the pressure boundary. And again, these are events for non-bounded events that are typically reevaluated as part of the reload scope.

Loss of non-emergency AC, another classification. Again, very similar disposition.

They meet the CLTR requirements. These events are typically determined to be non-limiting and at Monticello that remains the case. And so, these are not part of the normal reload evaluation scope.

Loss of feedwater flow. This is a situation where we assume loss of the feedwater pumps and a loss of offsite flow or some malfunction that results in the loss of the feedwater system. We also include HPCI inoperable, and we verify that RCIC has the capability to maintain a sufficient water level in the core to ensure that we don't have to do an ADS blowdown. And in this case, we had substantial margins to those values.

Decrease of feedwater flow. These events also met the CLTR requirements. They are typically determined to be non-limiting events. And these events are not in the EPU or the reload analysis scope.

Instantaneous loss of reactor coolant system flow. Again, these events met the CLTR requirements. They are typically non-limiting except for single-LOOP operation. Single-LOOP operation at Monticello has a separate MCPR limit. And that really is not changed with the EPU. So, those limits remain.

And we confirm the field design limits and reactor coolant pressure boundary limits are not exceeded under EPU conditions.

On control rod assembly withdrawal at low power, this is an event where it was evaluated, and the peak fuel enthalpy is at 72 calories per gram, which remains below the limit of the 170 calories per gram. This one is verified by EPU as being acceptable, and it is in the reload analysis scope.

On a control rod assembly withdrawal at power, again, it also meets the CLTR requirements and the reload analysis verifies.

Startup of an inactive reactor coolant system LOOP, again, we met the CLTR requirements. It is typically a non-limiting event, but the reload analysis does verify that.

Control rod drop accidents, these can occur for a number of different reasons, but they were evaluated. They meet the CLTR requirements. At Monticello, we do follow rod sequencing similar to what we do now while using the bank position withdrawal-system-type patterns.

Peak fuel enthalpy at EPU is 162 calories per gram. That remains below the acceptance criteria of 282 calories per gram for this event. And this is an event that the reload analysis does verify.

Increase in reactor coolant system inventory. Again, these events meet the CLTR requirements. And again, the reload analysis does verify these events.

Inadvertent opening of a pressure relief valve. At Monticello, those are the safety relief valves, but they are all of similar design. They all can be operated remotely. These meet CLTR requirements, and the reload analysis does verify that they are properly accounted for.

So, those are the transient events that we have looked at. We just covered very briefly that the assessment and EPU was done based on a representative core design. Since we have taken a little while to get this approved, we have gone through several cycles where we have done core design and reload analysis considering these events. And we haven't run into any problems.

Following this, we have loss-of-coolant accidents.

MEMBER SCHULTZ: Steve, just one question there. Where are you in cycle? If you implement this mid-cycle, how are you able to do that? How are you planning to do that with regard to remaining core lifetime?

MR. HAMMER: Well, what has happened for the last few cycles, we have actually, depending on how the licensing effort was going, we made predictions about where we thought EPU might be approved.

(Laughter.)

MEMBER SCHULTZ: Right.

MR. HAMMER: The last couple of cycles we have had, we have planned the core design based on the expected energy that we were going to use based on that prediction of it being approved at those times.

MEMBER SCHULTZ: Okay.

MR. HAMMER: And we actually have, for example, servers that were done based on that cycle running at CLTP and based on implementation of EPU at that point, and now, recently, MELLLA+ also.

MEMBER SCHULTZ: You are essentially pre-loaded.

MR. HAMMER: We are pre-loaded.

MEMBER SCHULTZ: When is your next outage?

MR. HASKELL: 2015.

MEMBER SCHULTZ: 2015? You just came out of an outage?

MEMBER SCHULTZ: That is correct.

MEMBER SCHULTZ: Okay. Thank you.

MR. HAMMER: Yes, we are in the process of starting up now. As Rick pointed out, we are still in operational testing for the mods that were installed.

MEMBER SCHULTZ: All right. So, the core is ready to go?

MR. HAMMER: The core is ready to go.

MEMBER SCHULTZ: Got you. Thank you.

CONSULTANT SMITH: So, you mentioned you did generic safety analysis for this. Which fuel design did you assume for that?

MR. HAMMER: Well, Monticello is currently using GE-14, and that is what the analysis was based on. So, we have all GE-14.

MEMBER BANERJEE: And you have done things like turbine trip analysis, and so on?

MR. HAMMER: Uh-hum.

MEMBER BANERJEE: And I guess that is what sets the OLMCPR, right?

MR. HAMMER: The question is, what is our limiting event for operating limit CPR?

CHAIR REMPE: Identify yourself, please.

MR. PAUSTIAN: Harold Paustian.

It is typically --

CHAIR REMPE: Go to the microphone. Sorry.

MEMBER BANERJEE: Are you going to discuss this separately or --

MR. HAMMER: No, I don't think so. Now would be the time.

MEMBER BANERJEE: Okay.

MR. PAUSTIAN: Yes, Harold Paustian.

Typically, I think our limiting transient has been an inadvertent HPCI start. I believe that is still true for other servers, but I would have to double-check to be absolutely sure.

MR. HAMMER: I think, you know, we check for the limiting event every time, and like Harold says, that is typical for the last few cycles probably.

MR. PAUSTIAN: There are frequently two or three events very close to each other.

MEMBER BANERJEE: Will the staff be addressing this at some point?

MR. PARKS: Yes, we will address some of these results and the EPU effects in our presentation.

MEMBER BANERJEE: Okay. Is it that, the events that you are talking about, is that the limiting event?

MR. PARKS: The staff agrees, yes. Based on their supplemental reload licensing reports, which we have reviewed, yes.

CHAIR REMPE: And you need to identify yourself, too.

MR. PARKS: Sorry. I'm Benjamin Parks, Reactor Systems Branch in NRR.

MEMBER ARMIJO: Yes, when you talk about these limiting events, I would appreciate it if you would also provide the peak powers that the fuel rods see, the kilowatts per foot, durations. Things like that help me understand what is actually happening.

MR. SCHIMMEL: Okay. Any other questions for Harold?

MEMBER BANERJEE: No, I think for the moment -- you might need to get to it.

MEMBER ARMIJO: But your peak LHGR for normal operation, you are still at 13.4 kilowatts per foot?

MR. PAUSTIAN: It is a bit higher than that.

MR. SCHIMMEL: We can get back to you on that.

MEMBER ARMIJO: Okay.

MR. HAMMER: Okay. For loss-of-coolant accident at Monticello, these are pipe breaks from the reactor coolant pressure boundary at a rate in excess of the capability of the normal reactor coolant makeup system. We did look at the capability of the ECCS system. At Monticello, HPCI is typically used for small-break accidents. Core spray and low-pressure cooling injection are used for all LOCAs after the unit is depressurized.

We use an automatic depressurization system with three SRVs, or Safety Relief Valves, to depressurize the primary system for small-break accidents if you assume a HPCI failure.

And one of the issues that resulted as a part of EPU was that EPU, because we have a slightly higher power level and a higher decay heat, it does take a little bit longer for ADS to blow down. And you end up with a higher peak clad temperature for small-break accidents under LOCA conditions. And in order to address that, we eliminated a tech spec that we had that allowed an ADS valve to be out of service. So, now we require all three ADS valves to be operable for Monticello from this point going forward with EPU. And assuming that all three ADS valves are operable, we have sufficient capacity under EPU conditions to maintain the small-break accident as a non-limiting event.

MEMBER BANERJEE: Did you exceed the peak clad temperature otherwise?

MR. HAMMER: Well, otherwise, there was a potential that we would have had -- if you would have kept the old tech spec and allowed an ADS valve to be inoperable, we would have had to adjust our linear heat generation rate setdown values, and it was an operating condition or it was an operating evaluation that we had that would have made it a little bit more difficult for the nuclear engineers to come up with an appropriate rod pattern, et cetera, and operate the unit. So, we wanted to avoid that. So, we, by going to 380S belts, we can maintain the same LHGR setdown that we have part of it.

MEMBER BANERJEE: What was the thermal hydraulic code and things that you used for this --

MR. HAMMER: For the SRV capacity? Larry, the question is, what code did we use for SRV capacity for the blowdown.

CHAIR REMPE: You have to come to the microphone and introduce yourself, please.

MR. KING: The transient analysis was based on using ODYN code.

MEMBER BANERJEE: Sorry? I couldn't hear.

CHAIR REMPE: Introduce yourself.

MR. HAMMER: You have to speak louder.

MR. KING: I'm sorry. My name is Larry King.

The code that is used in transient analysis for overpressure is ODYN.

MEMBER BANERJEE: ODYN? Okay.

MR. KING: Yes.

MR. HAMMER: One of the things that was evaluated was the break spectrum. With this change in ADS valve operability, you know, the break spectrum at Monticello was not impacted by EPU. 10 CFR 50, Appendix K analysis results confirm that the limiting break remains the recirc suction line design-basis accent, and our limiting single failure remains the LPCI injection valve failure.

For single-LOOP operation, I mentioned before that single-LOOP operation is based on a multiplier applied to the two-LOOP linear heat generation and maximum average planar linear heat generation rates or limits. And the operating conditions for single-LOOP operation are not really changed with EPU, and we will show you that in a little bit more easily when we look over the power flow map a little bit later.

So, the single-LOOP or the current CLTP analysis of single-LOOP operation remains acceptable for EPU, and the ARTS limits are not affected by EPU.

MEMBER BANERJEE: When you did this Appendix K analysis, I tried to -- I haven't spent a lot of time reading it, but there was some treatment of uncertainties that you did that seemed a little different. Can you explain that?

MR. HAMMER: Well, maybe I will ask Larry to --

MR. KING: I didn't hear the question.

MEMBER BANERJEE: How did you treat uncertainties?

MR. HAMMER: The question came up as the changes in uncertainty treatment for the Appendix K analysis.

MR. KING: Larry King.

I'm told there is no change.

MR. HAMMER: Yes. Okay.

MEMBER BANERJEE: I thought there was, but I will look at the writeup and see.

MR. HAMMER: Anything further there? Okay.

All right. This slide shows the general results of the ECCS analysis. Our licensing basis peak clad temperature, the 10 CFR 50.46 limit is less than or equal to 2200 degrees Fahrenheit.

Our EPU analysis was based on a target value of 2140 degrees Fahrenheit. And as part of the ongoing assessment of thermal conductivity degradation, there was an issue that was identified where generically Monticello was assessed at having an impact from thermal conductivity degradation or the use of PRIME as 45 degrees Fahrenheit. We have done a plant-specific analysis to lower that value to 10 degrees Fahrenheit. So, EPU, we expect to have a licensing basis peak clad temperature for our analysis of 2150 coming out of this.

The other limits are really unchanged between EPU and CLTP. The local cladding oxidation limit remains at less than 9 percent. The hydrogen generation core-wide metal reaction remains at less than .2 percent, and coolable geometry is maintained. And long-term cooling remains acceptable based on the same methods that were used at CLTP.

MEMBER BANERJEE: What were the pre-EPU values, say the peak clad temperature?

MR. HAMMER: The peak clad temperature? As I said, there are a number of different analyses that have been done for that. The EPU analysis, based on the use of the representative core, actually showed both EPU and CLPT having a calculated value of 2123.

So, there wasn't really much change there. The Appendix K value for PCT was 2119 at EPU and 2080 at CLTP. So, they are relatively-small changes, and I believe right now some of these are being verified by the server, and they continue to show very small changes between the EPU analysis and --

MEMBER CORRADINI: They will be verified by what? I'm sorry.

MR. HAMMER: The reload analysis.

MEMBER CORRADINI: Oh, okay.

CONSULTANT SMITH: And that 2140 really is a 95/95 number. That is not a best estimate.

MEMBER BANERJEE: It is in Appendix K, right?

MEMBER CORRADINI: It is in Appendix K. So, I think all the conservatisms are lumped into a number, if I understand how you did it.

MR. HAMMER: Well, the licensing basis PCT numbers, it is based on the most limiting Appendix K case, plus some plant variable uncertainty values that account statistically for the uncertainty, and parameters are not specifically addressed in Appendix K.

MEMBER BANERJEE: That is what I was trying to -- I thought there was some change in doing that, but I will go back and read it.

MR. PARKS: I have something I can show you --

CHAIR REMPE: Identify yourself.

MR. PARKS: -- during the proprietary session.

MEMBER BANERJEE: Okay.

MR. PARKS: And I also have a statement that is within double brackets in my SE I would like to clarify.

MEMBER BANERJEE: Okay.

CHAIR REMPE: And you need to identify yourself, too.

MR. PARKS: Benjamin Parks.

CHAIR REMPE: Yes.

MEMBER BANERJEE: We will wait for that until we get into it. Okay.

MEMBER CORRADINI: In the red zone.

MEMBER SCHULTZ: Are we also going to hear more about the Monticello-specific adder, the evaluation that was done to move from 40 degrees to 10 degrees?

MR. HAMMER: Yes, that also shows up. There is a discussion that we have on interim methods, and we will discuss a little bit further on that.

MEMBER SCHULTZ: Okay. And in the earlier presentation, the summary description of the changes, it was indicated that, with regard to the tech spec setpoint changes, there were changes to meet the safety analysis margins. So far, we haven't talked about any tech spec changes related to the analyses that have been done. Are those coming up or can you describe that in some detail?

MR. HAMMER: Well, we don't have a discussion specifically about all of the tech spec changes. I guess what you can say generically is, you know, there is analysis that has been done. They have all been submitted to the staff. We have had very few questions on those.

MEMBER SCHULTZ: Right. But, so far, in the presentation, as you have discussion the evaluations, it is within analyses that have been done previously. So, we haven't really talked about those. But am I missing something in terms of what has been submitted as changes --

MR. HAMMER: No. All the tech specs --

MEMBER SCHULTZ: -- with respect to the analysis you have discussed so far?

MR. HAMMER: Well, we didn't really include in part of the discussion, I guess, a discussion of the tech spec changes and what they are based on. So, I guess we could provide some --

MR. SCHIMMEL: We can pull that together if you want to review it.

MEMBER SCHULTZ: That would be good. Thank you. I appreciate that. Thank you.

MR. HAMMER: Next, one of the other things that were evaluated by EPU was special events. We did look at ATWS station blackout, Appendix R. If you go on to ATWS -- I guess we have a slide issue there -- but the current licensee bases for ATWS is based on 10 CFR 50.62, and at Monticello that requires the use of an alternate rod injection system, the ability to inject the equivalent of 86 gpm of 13-weight-percent sodium pentaborate, and an automatic reactor recirculation pump trip logic.

Now, at Monticello, the ARI and the trip logic are installed. They are operational. They are not changed by EPU.

At Monticello, standby liquid control capacity is 24 gpm, and we meet the sodium pentaborate requirement by using 55-weight-percent-enriched boron-10.

MEMBER BANERJEE: Do you do anything to the feedwater during ATWS?

MR. HAMMER: During an ATWS? Yes, during an ATWS, there is a number of time-critical operator actions that happen. The staff actually did come out and do an audit of the simulator. They wanted the operators perform. So, what we do is we have to inject standby liquid control in, I think it is 121 seconds under EPU, and we have to reduce feedwater. You do level power control, so you reduce level in the reactor within 90 seconds.

MEMBER BANERJEE: Does that change with the EPU, that time?

MR. HAMMER: There is a small change. There is like a 1-second change in the standby liquid control.

MEMBER BANERJEE: Oh, is that all?

MR. HAMMER: And actually, for feedwater level reduction, our time-critical operator reaction there is 78 seconds. So, we actually increased that time a little bit.

MEMBER CORRADINI: That is intriguing. I was expecting it to decrease a little. So, why did it increase?

MR. HAMMER: Well, it is an input to the analysis. The operators wanted a little bit more margin on their times there. So, they requested that we do the analysis.

MEMBER CORRADINI: That is an engineering judgment call? Is that what you are telling me?

MR. HAMMER: When you are trying to enhance the ability of the operators to successfully perform the event, they requested a little bit more time. So, we ran the analysis with a little bit more time than we had previously, and it still works. You know, we met the requirements.

MEMBER CORRADINI: Okay. I see. I understand. Thank you.

MR. HAMMER: We are just giving the operators a little bit more time to respond.

MEMBER CORRADINI: Understand.

MEMBER SKILLMAN: What controls are in place to make sure that your pentaborate solution has the required B-10 concentration?

MR. HAMMER: There is a tech spec surveillance on that. I don't know the periodicity, but there is a tech spec surveillance that looks at it periodically.

MEMBER BANERJEE: This is, of course, not the MELLLA+ line?

MR. HAMMER: Well, MELLLA+ really doesn't impact this, either. But, yes, there is no change to

SDLC.

MEMBER BANERJEE: But all these calculations were done for the --

MR. HAMMER: Yes, these were all done for EPU. There is not covering MELLLA+.

MEMBER ARMIJO: I'm sorry, did you or didn't you change the boron-10 concentration?

MR. HAMMER: We did not. So, it stays the same.

MEMBER ARMIJO: Yes. Okay.

MR. HAMMER: At the bottom of the page, you see some of the results of the ATWS evaluation. It is CLTP peak vessel bottom pressure is 1385 psig for EPU. That did increase to 1489. The limit is 1500 psig. The suppression pool temperature limit is 281 degrees Fahrenheit. And there is a small change going from CLTP to EPU, 2 degrees Fahrenheit, and containment pressure, the limit there is 56 psig. And again, there is a small change going from CLTP to EPU.

MR. SCHIMMEL: That suppression pool temperature I think was a question from somewhere on this side of the room.

MEMBER ARMIJO: Yes, earlier.

MEMBER BANERJEE: Right.

MEMBER CORRADINI: But my count, this is

not the limiting transient.

MEMBER BANERJEE: No.

MEMBER CORRADINI: Yes.

MR. HAMMER: Any questions here?

(No response.)

Okay. Station blackout.

CHAIR REMPE: Again, please watch the microphone.

MR. HAMMER: Oh, me? I will work on that.

Station blackout. Our current licensing basis for station blackout is based on NUMARC 87-00 and Reg Guide 1.155. All appropriate 10 CFR 50.63 criteria are met and continue to be met.

And one of the things that we did here is we did change the model that was used. The CLTP model was based on the use of MAAP code. And for EPU, we had switched to using Super HEX on this one. Super HEX is a little bit more of a limiting code. It is a conservative code; whereas, MAAP was more of a best estimate code. So, there are some changes there from --

MEMBER CORRADINI: Super HEX is something from the vendor or something you guys have in-house?

MR. HAMMER: No, that is a GE code. So, GE did the containment response here versus in the past we did it in-house.

MEMBER CORRADINI: With MAAP?

MR. HAMMER: With MAAP.

MEMBER CORRADINI: I see.

MEMBER SKILLMAN: What is the pedigree of Super HEX, please?

MR. HAMMER: Super HEX, Larry, maybe you --

MR. LI: This is Guhngjun Li from GE-Hitachi.

Super HEX code basically is a simple code. You have a different node actually come out of the whole BWR. So, while the suppression pool kind of wets the system, and all the RHR system and ECCS injection system and high-pressure co-injection are core spray, and the RCIC system. Basically, it is a simple code. It is a mass-energy release, mass-energy conservation, basically.

MEMBER SKILLMAN: And is there a Topical Report? Is there a Topical Report or --

MR. LI: We have it as a report, but the NRC staff did a review. That was approved for use in 1993, and it is also stated in the CLTR CPPU methodology.

MEMBER CORRADINI: So, it is approved for use on the unit?

MR. LI: That's righ6t.

MEMBER CORRADINI: Okay. That's what I thought. Thank you.

So, I know it is there somewhere, but maybe I can't remember where it is. So, did you do a comparison, since you said it is conservative, as to what MAAP predicts versus what Super HEX predicts for this?

MR. HAMMER: We did just a comparison of CLTP versus EPU.

MEMBER CORRADINI: Okay. With Super HEX? I'm looking at the comparison, because when you made the point that Super HEX has conservative flavor to it, I was trying to get a feeling for how --

MR. SCHIMMEL: We looked at it under MAAP. And did you look under --

MR. HAMMER: Yes, that is a question I don't remember. Larry, do you remember if we did a benchmark with Super HEX? We will check and we will get --

MEMBER CORRADINI: It doesn't have to be right away. That is fine. Thank you.

MR. HAMMER: Okay. Oh, do you have it now?

MR. LI: Yes. Actually, I did that analysis. So, we literally baselined MAAP. So, basically, as I said, Super HEX is a mass-energy conservation. So, the comparison is very similar.

MEMBER CORRADINI: Oh, so you got a very similar answer?

MR. LI: Yes.

MEMBER CORRADINI: Okay.

MR. LI: It is their scenario.

MEMBER CORRADINI: Okay.

CHAIR REMPE: For EPU as well as the --

MR. LI: No, we didn't do the EPU. We only baselined the CLPT case. Whatever, then, MAAP used, we used for the Super HEX.

CHAIR REMPE: Okay.

MR. HAMMER: Okay. The impacts from EPU are increased initial power level and decay heat. We do have an increased drawdown of CST inventory. At Monticello, we have a minimum required CST inventory of 75,000 gallons, and under EPU conditions we require a CST inventory to address this event of 44,329 gallons. So, we are within our existing CST inventory requirements that are controlled by procedures.

There are more SRV cycles and higher air usage on the SRVs to operate those valves. At

Monticello, we have our baseline calculation for SRV is always assumed 40 cycles, and for the difference between CLTP and EPU, at CLTP we predicted less than 25 cycles of SRVs for this event, and GE now predicts 31 cycles for EPU. So, while there is some increase in cycles there, it is well within the existing analysis basis.

Increased temperature on the drywell in containment, actually, we will show some of those on slide 66 for the suppression pool. For the drywell, peak drywell conditions change from -- the CLTP analysis showed 34 psia and, with EPU, it goes to 41.3 psia. CLTP with MAAP, you had 293.6 degrees Fahrenheit, and for EPU it was 268.4 degrees Fahrenheit.

So, the analysis showed that we still continue to meet our CST water requirements. We are within the current tank inventory. The additional cycles, while they do increase, were within the analysis limits of the existing analysis. And peak drywell containment temperatures remain within design limits.

And the other thing we note here is we don't exceed the heat capacity temperature limit at the end of the event. What we did is we did look at that to verify that we are a four-hour coping plant. So, we just verified that at the end of four hours we are still below the heat capacity temperature.

Appendix R, the current licensing basis for Appendix R is 10 CFR 50.48 and 10 CFR 50, Appendix R. At Monticello, we have typically evaluated two events, two cases: one where we have a relief valve that is stuck open and one with no stuck-open relief valves.

The results here show that we don't have any new operator actions. There is no equipment required for safe shutdown for Appendix R or no new equipment required. And we have one train of systems available to achieve and maintain safe shutdown from the main control room or the alternate shutdown panel.

MEMBER SHACK: Now this one confused me a little bit because you went through the analysis for the SECY where you have these 13 cases with the different MSOs. And you have actually got a more limiting case. Your 2C1 has like half the margin that you have for either one of those. I assume that somehow these are your current licensing basis events and the others are somehow some exploratory thing to look at the effect of MSOs? Is that why we are treating them differently?

MR. HAMMER: Well, we are licensed for the use of containment accident pressure for Appendix R, both under CLTP, and now with EPU we did redo that analysis. One of the things that came out of the new NRC staff guideline requirements for consideration of the impact of containment pressure on the Appendix R event was to look at some possible spurious operations like that. So, we did do that assessment. That is not part of the current licensing basis. So, it is not part of the CLTP licensing basis. And right now, we don't believe that it is really part of our licensing basis for EPU. However, it was assessed and was looked at, and we do have those results.

So, what we did with Appendix R is what was mentioned. There were a few modifications that were done to eliminate some flow pass that would not have allowed us to meet the containment accident pressure limits. So, that was like a purge event where it modified, so that they would not spuriously operate.

We did some work on drywell spray valves and I believe main steamline drains to eliminate spurious operations there. And for the remaining possible spurious operations that are out there, we tried to identify the limiting conditions for four sets of spurious operations combined. And we looked at the impact on containment accident pressure for Appendix R for those various cases. And that was the 13 cases you are talking about.

MEMBER SHACK: But you don't consider those part of your licensing basis?

MR. HAMMER: Yes, at this point in time that is true.

MEMBER SHACK: Okay, then, just required for the demonstration to acceptance for the SECY, or however it is going to be phrased. Okay.

MR. HAMMER: Go to the next slide.

This shows the impact on the analysis from Appendix R. Peak cladding temperature went from 596 at EPU to 980 -- or excuse me -- 596 at CLTP to 984 under EPU. Part of that change was due to the fact that the time-critical operator action for the operators here is 17 minutes to get from the control room, to get out to the alternate shutdown cooling panel, and to take control of plant operation. At 17 minutes under CLTP, the analysis showed that we were at top of active fuel. So, we started an ADS blowdown essentially on top of active fuel.

With EPU, again, it was a deal where we wanted to make sure that the operators had sufficient time to withstand this event. So, we kept that time delay the same, and we did uncover a little bit of the top of the core. So, there is some increase in peak clad temperature, but we are well within the 1500-degree Fahrenheit limit.

MEMBER CORRADINI: That is the main reason for what would appear to be a pretty non-linear change?

MR. HAMMER: Yes, that is the main reason.

Primary system pressure changes slightly, as shown there from 1273 to 1335 with a 1375 psig limit. Primary containment limit is 56 psig, and you can see the changes there from --

MEMBER CORRADINI: I didn't understand that one. Everything else is going in what I expected direction. So, why did it go down 3 psi?

MR. HAMMER: Somebody help me here. I'm lost.

MR. LI: Yes, this is Guhngjun Li.

So, basically, there is a little bit of model input change for these two cases. For the CLTP case, contain the pool and that airspace uses thermal equilibrium. So, for the CLTP, we use a little bit more realistic -- we use a mechanistic. Basically, for the CLTP case, you have more heat transferred from the pool to the airspace. That is why you have higher pressure.

MEMBER CORRADINI: So, you changed the model?

MR. LI: The input. The model did not change. It is the input.

MEMBER CORRADINI: I'm listening to you, but you changed something more than the input. So, that means some calculation was changed.

MR. LI: That is a model input, not a model change.

MEMBER CORRADINI: So, tell me more.

MR. LI: There is an input control, controls the heat transfer, which one you want to use.

MEMBER CORRADINI: So, you changed from what to what?

MR. LI: From thermal equilibrium to the mechanistic.

MEMBER CORRADINI: So, tell me more about the mechanistic.

MR. LI: The mechanistic, actually, this is a flat surface of the pool, hot pool.

MEMBER CORRADINI: Yes.

MR. LI: Depending on that, depending on temperature difference, you calculated the heat transfer coefficient.

MEMBER CORRADINI: Okay.

MR. LI: Yes. So, less heat into the --

MEMBER CORRADINI: So, what heat transfer coefficient did you use?

MR. LI: This is just calculated based on the textbook as a natural conversion.

MEMBER CORRADINI: Oh, so you just had a natural circulation heat transfer coefficient?

MR. LI: Right.

MEMBER CORRADINI: Okay.

MR. LI: Yes. So, that is the reason for the difference.

MEMBER CORRADINI: So, you have a hot pool and a cold atmosphere, colder?

MR. HAMMER: Colder, yes.

MR. LI: That's right.

MR. HAMMER: It is probably the EPU analysis was more realistic of the real physics of the situation than the CLTP analysis.

MEMBER CORRADINI: It is different.

(Laughter.)

MR. SCHIMMEL: See, that is why he is having trouble. It is not a one-to-one --

MEMBER ARMIJO: Got it. It's not apples-and-apples.

MR. SCHIMMEL: Yes, that's right.

MEMBER CORRADINI: Thank you.

MR. HAMMER: Suppression pool temperature, then, increased slightly, as shown here, 4 degrees Fahrenheit, and net positive suction head was evaluated and remains adequate for both CLTP and EPU.

Okay. Radiological events. Monticello is an alternative source-term plant. We were licensed for the use of alternate source-term before we started the EPU process. So, all of the assessments here were done based on changes to the alternate source-term evaluation.

Radiological events, the events were analyzed, as I said, based on AST, 10 CFR 50.67 and GDC-19 requirements. Previous analysis was performed at 1880. So, while Monticello was licensed for 1775, our source-term analysis since the rerate days was always done at 1880. The 1998 change in our license from 1775, or from 1670 to 1775 megawatts thermal, essentially, all of the analysis that was associated with it, with that work, was done based on 1880 megawatts thermal. So, there was some margin that existed for most of those analyses. This is an example of that.

The review was performed using AST in accordance with the guidance shown. And EPU doses remain within regulatory limits.

This shows for the different events that we looked at what the results were for the EPU doses and the regulatory limits associated with those events. So, for example, for LOCA, the exclusionary boundary is 1.46 rem with a regulatory limit of 25. The closest limit we have got is for the control room operators there, which is a predicted dose of 3.8 rem with the control room operator regulatory limit of 5. And that same approach follows through on the rest of this table.

MEMBER SCHULTZ: Steve, the limiting dose for the control room operators is the fuel-handling accident. Have there been any input changes related to the fuel-handling accident as a result of the uprate in terms of source-term?

MR. HAMMER: No, there was no significant changes between the AST analysis and --

MEMBER SCHULTZ: You are not doing different analysis with regard to peak burnup or anything like that? This is the dose limit that you had?

MR. HAMMER: Yes.

MEMBER SCHULTZ: And you have got an ongoing program associated with control room in-leakage testing?

MR. SCHIMMEL: Yes. Yes, we monitor that.

MEMBER SCHULTZ: Okay. Thank you.

MR. HAMMER: Any other questions there?

(No response.)

Okay. Limiting events. For transient accident analysis, we did look at some of the limiting events. On our next slide, it shows some of the changes that did result.

Suppression pool temperature for Appendix R, that changed from just a couple of degree Fahrenheit as shown. The limit for suppression pool temperature is listed there as 197.6 for CLPT and 212 degrees Fahrenheit for EPU. And that value there, while containment is designed for a temperature of 281 degrees Fahrenheit, the limiting value that we have is torus-attached piping. So, the torus-attached piping provides that temperature limit in those cases.

ATWS, loss of offsite power. The ATWS event we will talk about shortly. There is the loss-of-offsite-power event provides a limiting response for the suppression pool temperature. And there is a small change there associated with EPU.

Station blackout, we have talked about also some of the changes there. That is a little bit larger change that reflects the increased decay heat that you have for the four-hour coping period associated with station blackout.

Temperature for the design-basis accident goes from 194.2 under CLTP to 207.1 degrees Fahrenheit. We will talk here shortly about some of the assumptions that went into the EPU analysis, but the 207.1 degrees Fahrenheit is actually based on the use of a constant K value for the RHR heat exchanger.

And one of the things that was done with EPU is we did look at the use of a variable K value for the RHR heat exchangers. So, we allowed it to vary slightly based on process temperatures. So, if you use a variable K value, the actual suppression pool temperature is slightly lower than that. It is about 203 degrees Fahrenheit. So, that is a more representative value of what I would expect to see in real life.

MEMBER SHACK: But there is also a difference, too. You took more credit for the heat sinks in the EPU calculation.

MR. HAMMER: Well, there is a number of different changes.

MEMBER SHACK: Changes, yes.

MR. HAMMER: So, we did credit -- and those are all listed and we will talk about it.

MEMBER SHACK: Yes, but, I mean, the changes are a little harder to compare when you have made some assumption differences.

MR. HAMMER: What we did between CLTP and EPU, there was a slight change to the K value, as I pointed out here. And that probably dominates the amount of change that you see.

MEMBER CORRADINI: Can you repeat that again? I'm sorry.

MR. HAMMER: We took more credit for our RHR heat exchanger capacity.

MEMBER CORRADINI: Okay.

MR. HAMMER: And that probably drives it the most.

There is a small change in pressure for design-basis accident, loss-of-coolant accidents there in the suppression pool area.

For the drywell, the main steamline break accident for a small-break accident, the values listed there are based on airspace temperature from a steamline break. So, you ended up with some super heat going on. So, under CLTP, it was 335; whereas, EPU gets it up 3 degrees Fahrenheit to 338.

There was an assessment done of actual wall temperatures based on those time periods. What we do is at 10 minutes we spray the drywell to try to eliminate those high temperatures. And so, the impact on wall temperatures is showing there. It goes from 273 to 278 with a limit of 281.

Pressure for the drywell for DBA LOCA, CLTP shows 39.5 to 43.4. We can explain that here in just a second. For EPU, the value goes to 44.1. The limit is 56.

One of the changes that did occur in the containment response for Monticello, at CLTP, when the original CLTP analysis was done, we did not have a lot of setpoint calcs. So, there weren't many analytical limits that existed. So, the original CLTP analysis for containment used an initiating event assumption of initial drywell pressure of 2 psig, which was a high drywell pressure trip nominal value.

With EPU, what we did is we used the analytical limit for that setpoint. So, the initial pressure for containment went from 2 psig to 3 psig. And that is the basic difference in the range there. The higher initial pressure results in the vast majority of net change.

Core parameters.

MEMBER CORRADINI: So, the delta change from EPU is small --

MR. HAMMER: Yes.

MEMBER CORRADINI: -- with the same set of assumptions?

MR. HAMMER: Yes.

MEMBER CORRADINI: And is that because of core spraying -- or I'm sorry -- drywell spraying?

MR. HAMMER: No.

MEMBER CORRADINI: I'm trying to understand, I guess.

MR. HAMMER: I mean, it is a very --

MEMBER CORRADINI: Or was there another change in the model that --

MR. HAMMER: This transient happens very quickly. It is within the first few seconds after the break, you know, and then, it promptly drops off.

MEMBER CORRADINI: And there is no comeback? That's it?

MR. HAMMER: Yes.

MEMBER CORRADINI: There is essentially just a mass-energy discharge?

MR. HAMMER: Yes. Decay heat doesn't really factor very much into that first peak.

MEMBER CORRADINI: Sure. Okay.

MR. HAMMER: Core parameters. We did talk about fuel temperature here. The peak vessel pressure is defined by the MSIV closure event with failure of the position indication scram off the MSIVs. And that changed from 1296 to 1335 psig with a limit of 1375.

MEMBER SCHULTZ: So, a general question, Steve. As you have gone through the analysis evaluations, you indicated that some of the analyses earlier in the evaluation were done with a generic core design, and that would be updated when you did the reload core design evaluation.

So, now you have a reloaded core that is set to go for EPU conditions. So, I presume, then, that the evaluation has been done. What you have been showing here, though, is the generic analysis, is that correct?

MR. HAMMER: This is the generic. This is the stuff that was submitted for the review.

MEMBER SCHULTZ: And can you comment on that, the evaluation that was done for the current core? Any changes of significance? Is it all bounded by the generic analysis or what has been done?

MR. HAMMER: It is going to be similar. We can get back to you on that. I don't know, Larry, do you have any? We will have to get back to you on that. We don't have that right now.

MEMBER SCHULTZ: Okay. Thank you.

MR. HAMMER: Okay. The next thing I was going to talk about was thermal hydraulic stability. Monticello has Power Range Neutron Monitoring System installed. We use Option 3 as part of or to define our stability solution for Monticello. And we have had this installed for the last, well, two cycles, I guess. And it has worked very well for us. We haven't had any significant problems.

Our requirement --

MEMBER SKILLMAN: Excuse me. I am reflecting on Steve's question. And you have just restarted in this new run. You are on a 24-month fuel cycle?

MR. HAMMER: Uh-hum.

MEMBER SKILLMAN: So, you load 660-670 days of energy, approximately, in your core design? So, you have added enough 235 to cover the higher power level? Is that accurate?

MR. HAMMER: Yes. I believe the energy plan for this cycle was based on that we would implement EPU in November or December.

MR. SCHIMMEL: It was based on a fourth

quarter start.

MEMBER SKILLMAN: I am building on Steve's question because of an issue I dealt with some time ago. So, you have got enough 235 in there for your projected power consumption for this next 24 months. When you did your reload analysis for the third that you loaded for this cycle, does your accident analysis reflect that greater amount of potential energy for this cycle?

MR. BJORSETH: I don't think having more energy in the core necessarily affects that.

MEMBER SKILLMAN: Really?

MR. BJORSETH: You know, they do look at the decay heat that is predicted at the begin of cycle, end of cycle, and we use the --

MR. SCHIMMEL: The new fuel, if you are asking, was part of the consideration. It had to be, right, from the reload --

MEMBER SKILLMAN: I'm thinking the answer is yes because I am really wondering operability for your present --

MR. SCHIMMEL: Because when I signed it and sent it out, I guarantee that it did. So, the question is -- well, what is your question again, Dick?

MEMBER SKILLMAN: My real question is, as you have loaded this new one-third with a higher potential energy that it contains with the 235, are you covered by your accident analysis for this cycle? That is what I am asking.

MR. SCHIMMEL: The answer is yes.

MR. SCOTT: Yes, of course.

MEMBER SKILLMAN: You say, "Yes, of course."

(Laughter.)

Could you identify yourself, who says, "Yes, of course."?

(Laughter.)

MR. SCOTT: Mike Scott.

MEMBER SKILLMAN: Why don't you step up to the microphone?

MR. SCOTT: Sorry. Michael Scott.

MEMBER CORRADINI: You have to speak louder. I'm sorry.

MR. SCOTT: Yes, of course, the analysis shows acceptable results.

MEMBER SKILLMAN: Thank you, Michael. Thank you, Mark. Okay.

MR. HAMMER: Okay. For Monticello, if the Option 3 hardware becomes inoperable, the OPRM system becomes inoperable, we have a backup stability protection that is utilized per the current tech specs. And when BSP is inoperable, we expect a reduced power to less than 20 percent of rated.

The design basis for Option 3 combines closely-spaced OPRM detectors defined as cells to detect either core-wide or regional/local modes of reactor instability. The open-arm cells are configured to provide local area coverage with multiple channels, and the hardware combines signals and evaluates the cell signals with instability detection algorithms.

The period-based detection algorithm is the only algorithm credited in the Option 3 licensing basis. However, there are two other algorithms that exist and run in the background. We have the amplitude-based algorithm and the growth-rate-based algorithm. They offer a high degree of assurance that fuel failure will not occur as a result of the consequence of instability-related oscillations. And as I noted before, BSP is used when Option 3 is inoperable.

This is a picture of the OPRM. You will see an OPRM trip-enabled region. So, it is the area of the power flow map where we expect to have the

OPRMs that are required to be operable.

There is also a Region 1 scram region, which is this small area in the upper left around point A. And Region 2 is a controlled-entry region, which is the next line out from point A.

Actions for the scram region are based on the OPRM system being operable or inoperable. So, if the OPRM system is operable, entry into Stability Region 1 requires immediate actions to be taken until the reactor is operating outside of Stability Region 1 and Stability Region 2. If the OPRM system is inoperable, entry into Stability Region 1 requires insertion of a manual scram.

Region 2 is a controlled-entry region. Entry into Stability Region 2 requires immediate actions to be taken until the reactor is operating outside of Stability Region 2. Approved Option 3 stability solution methodology would allow unrestricted entry into this region when the OPRM system is operable and would allow limited entry when the OPRM is inoperable. However, Stability Region 2 is conservatively treated as an immediate exist region under all conditions to ensure consistent operation and conservative margin for thermal hydraulic stability by Monticello plant procedures.

Since we are on this slide, it is not a bad thing to talk a little bit about, if you look in the upper righthand corner, points D and E. They are defined in the chart on the lefthand side there.

So, for Monticello to get to full EPU power under EPU conditions, we have to be able to achieve point D there, which is 100-percent power and 99-percent core flow.

Now we do have some limited -- we can't quite achieve that flow, and we won't achieve quite that flow under EPU conditions. We will provide a little bit more detail on that later also. But we are licensed to 105-percent core flow. So, that shows point K out there as 105-percent core flow.

MEMBER CORRADINI: If you had a jet pump that would to it.

MR. HAMMER: If we had a jet pump that could do it.

(Laughter.)

MEMBER CORRADINI: I wanted to make sure we are clear.

MR. SCHIMMEL: I think what he is asking is, is the jet pump a restriction in the flow or is it the jet pump? Is that anything else rather?

MR. HAMMER: Yes, right now, our belief,

the original jet pumps have fouled, some since the original operation, and they continue to foul. They will be fouling slowly with time. And so, the performance of those jet pumps has fouled.

MEMBER CORRADINI: Okay. That's fine. Thank you.

MR. HAMMER: Thermal hydraulic stability.

CHAIR REMPE: I think I will ask it. I have been curious. Are you thinking at some point in the future of replacing the jet pumps? I am curious, and I will ask it.

MEMBER CORRADINI: They are looking for donations. Have you got some money?

(Laughter.)

CHAIR REMPE: I don't make as much as you, Mike.

(Laughter.)

MR. SCHIMMEL: It is on the table as an option.

MEMBER ARMIJO: I have got to ask the question. What is the mechanism for fouling of the jet pumps?

MR. HAMMER: What you have is, the way it has been explained to me is there is an electronic charge that does build up on the metal surfaces and has a tendency to attract crud and it sticks to the metal surfaces.

MEMBER ARMIJO: Okay. Now, with your new feedwater heaters, which are cleaner, would you expect the normal process that these things would change in any positive way or are they just going to stay fouled and get worse?

MR. HAMMER: I would say, you know, the fact that we have got a new condensate demin system, that we have increased rack water cleanup capacity slightly to maintain the original reactor water cleanup system capacity, although that should help to improve water quality. I would think better water quality would help to reduce crud buildup. But I wouldn't expect to see a significant change.

MEMBER ARMIJO: But your expectation is that fouling is kind of a permanent thing? Unless you do something --

MR. HAMMER: Yes.

MEMBER ARMIJO: -- to really clean it up --

MR. HAMMER: Yes.

MEMBER ARMIJO: -- nothing will improve?

MR. SCHIMMEL: You can do things to better that situation versus buying brand-new jet pumps.

MR. HAMMER: Yes, well, we did hydrolyze them once quite a number of years back, but they refouled fairly quickly.

MEMBER ARMIJO: Okay.

MR. HAMMER: For hydraulic stability, EPU's effect on thermal hydraulic design for the core and the reactor cooling system is acceptable. The GDC-12 requirements are met at EPU conditions and instabilities continue to be effectively detected and expressed. And the plant-specific reload analysis will confirm the fuel design limits will not be exceeded under EPU conditions.

CONSULTANT SMITH: So, what tools do you use for your stability analysis?

MR. HAMMER: I am going to default to --

MR. VREELAND: The name is David Vreeland with GE-Hitachi.

For the setpoints, we used TRACG and, then, some other, PANACEA, and then, kind of a little tool, OPRM code, to calculate the hot oscillation channel magnitude. BSP is calculated by ODYSSEY.

CONSULTANT SMITH: Thank you.

MR. HAMMER: Okay. One of the things that we did evaluate was the impact of EPU at ATWS stability. At Monticello, our solution for ATWS stability is based on the CPTU LTR requirements, and those are based on some previous work that was done in 1995 and 1992 that was provided to the NRC. And the impact of EPU does not impact our acceptability based on those rules.

The NRC staff did perform an operational audit of Monticello's operator actions used to mitigate an ATWS event. That was done at our Training Center, actually, in May 2009. And it went very well.

Okay. Interim methods. As part of GE's use of, their continued use of a SAFER/GESTR, there was a number of interim methods that were defined for NRC approval of applications based on that method.

And what we did is we didn't do a confirmatory analysis to evaluate the 24 limitations and the conditions for application of these GNF methods to the expanded operating domain or EPU. In our case, the expanded operating domain discussion is basically related to the MELLLA+ thing. It is still pending.

The limitation and conditions were evaluated for the EPU submittal, and we will go through those briefly. The limitation conditions were updated recently based on NRC approval of later codes. So, there is some impact from later work that will impact that, and we will go through some of those.

The first limitation or condition there has to do with use of a couple of codes that GE has shown there. And those particular codes were used in our analysis. And therefore, we met that requirement.

The second limitation or condition has to do with the use of 3D MONICORE. If you are using 3D MONICORE, a couple of, again, codes that are related to the use of that program.

At Monticello we don't actually use 3D MONICORE. We use --

MR. SCHIMMEL: GARDEL.

MR. HAMMER: -- GARDEL, yes.

MEMBER CORRADINI: I didn't hear you guys.

MR. HAMMER: We use GARDEL.

MEMBER CORRADINI: GARDEL?

MR. HAMMER: And so, we don't have any reliance on the codes of concern here.

The power-to-flow map, our power-to-flow ratio, the thermal power-to-core-flow ratio will not exceed 50 megawatts thermal per million pounds per mass per hour at any ay statepoint in the operating domain. And we did confirm that we met that limitation. And so, that one is satisfied.

Going to the next page, the Safety Limit

Critical Power Ratio 1 for EPU operation and single-LOOP operation requires the use of an adder, and that adder was applied for single-LOOP operation. So, we do meet that requirement.

Limitation Condition No. 5 is another adder that would apply to MELLLA+. And since this isn't really MELLLA+, it is not applicable for EPU. So, it is not an issue for this application.

Limitation Condition No. 6 was an R-factor value, and we did verify that the R-factor is consistent with the hot channel axial void conditions for EPU. And therefore, that limitation is met.

CONSULTANT SMITH: So, how do you do that verification of R-factors?

MR. HAMMER: I think I am going to need some -- Larry, you guys got a --

MR. KARVE: Atul Karve, GE.

We actually took the generic core and we checked the void fractions and confirmed that the void fractions are consistent with the void fraction that is used, the RFGen methodology. So, there is a void fraction that is used with the RFGen methodology. There is a number, and we confirmed that that is consistent with the EPU core.

CONSULTANT SMITH: So, how high a void

fraction do you go to for that analysis?

MR. KARVE: I'm sorry, I didn't hear.

CONSULTANT SMITH: How high a void fraction do you go to for that analysis?

MR. KARVE: That, maybe we can talk in the proprietary session.

MEMBER SCHULTZ: That evaluation, the R-factor verification, would also be done at the reload analysis, is that right?

MR. KARVE: I believe so.

MEMBER SCHULTZ: Reload analysis, that is reevaluated; a comparison is done.

MR. KARVE: So, the number that we used, the RFGen methodology ensures that we calculated the R-factors at that higher void fraction. So, we always use the higher void fraction for calculating the R-factors.

I'm not sure if we confirmed that again at the station. I can check on that.

MEMBER SCHULTZ: Thank you. I appreciate that.

MR. HAMMER: Okay. No. 7. No. 7 has to do with consideration of top and mid-peak power shapes. And that limitation and condition is met. We did include top or mid-peak power shapes for determining MAPLHGR and PCT limits.

No. 8 is really not applicable to EPU. That is another MELLLA+ consideration.

No. 9 has been satisfied for EPU. We did an analysis that showed a substantial margin in the fuel centerline melt and clad strain.

MEMBER BROWN: Can I ask, it is not applicable to EPU? Maybe I missed something, but I thought you needed the MELLLA+ to get to 204.

MR. HAMMER: Yes, well --

MEMBER BROWN: Isn't that the EPU? Or are you now redefining EPU as being 1880 without the MELLLA+? Is that --

MR. HAMMER: Well, this has to do with expanded operating domains, and the EPU submittal doesn't have any expanded operating domains.

MEMBER BROWN: Oh, okay. All right.

MR. HAMMER: So, the expanded operating domains come under the MELLLA+ license application.

MEMBER BROWN: Okay. Thank you.

MR. HAMMER: No. 10, what we are asking for here is that each reload demonstrate compliance with the transient thermal mechanical acceptance criteria. And that is demonstrated in each server as it is completed as part of the reload analysis. So, that one is met.

Condition No. 11 has to do with ensuring that you have a void history bias for use in the evaluation when using TRACG or ODYN. The reloads being done now for Monticello are crediting the use of TRACG-04, and the void history bias is incorporated into the TRACG-04 analysis. Therefore, no additional acceptance criteria are required there.

No. 12 has to do with LHGR and exposure qualification. This requires some additional limits be applied.

The time sensitivity analysis used for the limiting LOCA case, what we did there, I discussed earlier that Monticello had a generic impact from PRIME of 45 degrees Fahrenheit. What we did is we did to a Monticello-specific PRIME analysis to limit that value to 10 degrees Fahrenheit.

And what is being done here is compliance with this parameter is covered by compliance with Condition 14. So, we will show that in a second.

Limitation Condition 13 has to do with the use of gadolinium. Monticello bundled design stays less than the 10-percent gadolinium limit that is defined here.

Condition 14 is what we were talking about briefly before on Condition 12. The GE-14 thermal mechanical operating limit applied to Monticello Cycle 27 incorporated the 250 psi penalty for the fuel rod critical pressure to comply with NRC conclusions. So, this limit is satisfied by incorporation of that penalty.

Fifteen has to do with void reactivity coefficient bias and uncertainties in TRACG. And the void reactivity condition was included in Cycle 27 server. And so, the issues associated here were addressed under that server.

No. 16, let's see. Okay. Condition 16 is associated with TRACG methodology. Again, that is related to the void history bias. The TRACG Topical Report has been approved and is used in the Cycle 27 server. So, that has been incorporated in the approval of that report.

MEMBER SCHULTZ: Is that a generic approval? The TRACG Topical Report is now approved generically?

MR. HAMMER: Larry, have you got some discussion? The question is, is the TRACG Topical Report approval generic? I believe it is.

MR. KING: Actually, let me get back with you on that to make sure.

MR. HAMMER: All right.

MR. KING: This is Larry King.

MR. HAMMER: Seventeen, steady-state 5-percent bypass voiding. Limit bypass voiding to 5 percent. GE will provide the highest-calculated bypass voiding of any LPRM level. As part of the reload analysis, the Cycle 27 server indicated that we are less than 5 percent bypass voiding at the D level, which is the limiting level for that reload.

Eighteen.

CONSULTANT SMITH: A question on 17?

MR. KING: Steve, we got back with that real quick. Yes, that is approved.

CHAIR REMPE: You need to restate your name.

MR. KING: Larry King.

CONSULTANT SMITH: The issue on 17, the 5-percent bypass limit, under what conditions -- sorry -- 17.

MR. KING: Yes, 17, okay.

CONSULTANT SMITH: That 5-percent bypass void, under what conditions do you reach or do you predict your maximum bypass voiding?

MR. HAMMER: Larry, that might be another one for you guys. The question is, under what conditions do we predict maximum bypass voiding? How is that evaluated?

MR. KARVE: Yes, Atul Karve, GE.

We use the ISCOR methodology, and it has been a while since I did that. But, if I remember correctly, we used the hot channel bypass void and we confirmed that it, indeed, is less than 5 percent.

CONSULTANT SMITH: Okay. Thank you.

MR. HAMMER: Okay. The next slide.

MEMBER BANERJEE: Let me just ask a question. These sort of conditions, they are relatively common. We have done this with the other EPUs, these limits, right? So, it has passed through before? I am just asking the staff just to confirm that.

MR. PARKS: Yes, the disposition here is going to be slightly different than it was for the immediately-previous EPU that we presented because that was based on, the application as submitted was based on the latest approved methods, which included PRIME. This one came in in 2008. So, it was based on GESTR and thermal mechanical analyses, for instance.

So, the disposition is a little bit different, but, yes, there is a disposition for each of these conditions and limitations. And then, there is an extra layer here because they have since transitioned in their AOO analyses to TRACG.

So, the short answer to your question is, yes, this is common for current EPUs.

CHAIR REMPE: And you have to state your name for the record.

MR. PARKS: I apologize again. My name is Ben Parks with the staff.

MR. HAMMER: Okay. For Limitation Condition No. 19, this is another example where TRACG-04 is used. So, the penalty that is requested is not really applicable for TRACG-04.

Condition No. 20 requires --

MEMBER BANERJEE: We have gone fast on that. Is that what we have done? Has that been done before, Ben? Using TRACG, we haven't put a penalty? If we used TRACG, we have not put a penalty in the past because of that?

MR. PARKS: That is correct. I don't know that that specifically has been applied. I would expect that it was applied to Grand Gulf, but I am not sure. I would have to go check.

I did review briefly the Safety Evaluation. I think it was a Supplemental Safety Evaluation for NEDC 33173PA. A supplement to the

Interim Methods Licensing Topical Report concluded that that penalty could be removed, proved that TRACG was used, because the particular correlation that was causing us issue -- I will be vague here because my knowledge is a little shallow -- is approached differently in TRACG.

MEMBER BANERJEE: Which supplement was this? It will come back to me in memory because there are so many of these things.

(Laughter.)

Was it 2 or 1 or which one was it?

MR. PARKS: I can give you an appendix to the latest.

MEMBER BANERJEE: Okay.

MR. PARKS: I will go find it over lunch and get back to you with it.

MEMBER BANERJEE: Okay.

MR. PARKS: The question is, which supplement approved or --

MEMBER BANERJEE: Right.

MR. PARKS: -- drew conclusions about TRACG-04 in 33173P?

MEMBER BANERJEE: Uh-hum.

MR. PARKS: Yes, I will find that for you.

MEMBER BANERJEE: Fine.

MR. HAMMER: Okay. Limitation Condition No. 20, again, this is one where the TRACG Topical Report has been approved and used in Cycle 27 servers. So, the issues associated with this limitation are addressed by that disposition.

Limitation Condition 21, as we mentioned, Monticello has a homogenous core of GE-14 fuel only. So, we don't have a mixed core concern.

Limitation Condition 22, again, this is one where we don't have a mixed core concern. So, it is not applicable.

Twenty-three is Eigenvalues, and this is not applicable for EPU.

And 24 is provide a prediction of key parameters for cycle exposures for operation at EPU, and that information has been provided in the PUSAR. So, that one is in.

And that's it. I guess at this point we turn it over to NRR or something.

CHAIR REMPE: I would guess your presentation will take at least an hour. Is that a true statement?

So, I think I'm going to decide this. Go ahead and take an earlier lunch and come back here at 12:30. And then, we will restart with NRR. Does that sound okay with everybody's schedule?

MR. PARKS: That sounds fine.

CHAIR REMPE: Okay. Let's go off the record.

(Whereupon, the foregoing matter went off the record for lunch at 11:34 a.m. and went back on the record at 12:34 p.m.)

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

12:34 p.m.

CHAIR REMPE: We are going to go back on the record again.

And I hear we are going to have another guest presentation by Mr. Monninger.

MR. MONNINGER: Good afternoon.

This is John Monniger from the staff. We are pleased to be back to discuss the Monticello EPU.

From this morning's opening session, the staff did take an action item to provide the ACRS with additional information on our plans for evaluating the proposal from industry on early venting under extended loss-of-offsite power scenarios and any implications on early venting on utilization of containment accident pressure.

So, what we did is I consulted with our organization, the Japan Lessons Learned Project Directorate, Rob Taylor in particular, as to what their plans were for reviewing the industry proposal and potential future engagement of the ACRS.

Prior to that, I think given that today's focus is on the Monticello EPU amendment request, I did just want to mention a couple of things to put a couple of caveats in upfront.

The first consideration is that in the development of the NTTF recommendations and the staff's endorsement of that and the Commission's decision to go forward on those recommendations, which resulted in mitigating strategies in early venting and the orders for severe-accident-capable events, both the staff and the Commission concluded that existing plants are safe and the current set of requirements provides adequate protection of public health and safety.

So, when we look at these recommendations, mitigating strategies, potential for early venting, et cetera, the whole notion is to potentially improve safety, but it is not trying to address what we believe to be any type of vulnerability with the current set of plants.

With that said, we are continuing with our licensing program, which would include such things as EPUs and reviewing EPUs against our current set of requirements. If in the future implications for early venting or implications on the mitigating strategies, or anything else, if it impacts the existing plant analysis, it would be addressed within those realms. So, we are proceeding with current licensing. Separately, the staff is evaluating the order responses, et cetera. And if new technical issues come up, they would be addressed within that realm. If technical questions come up that question previous decisions or question the design of the plant, margins, et cetera, it would be addressed within that spectrum. So, that would be one thought.

The second thought would be the notion to recognize the difference within regulatory space of design-basis accidents and beyond-design-basis accidents. So, here we have the EPU, and we are looking at design-basis accidents and associated with deterministic and prescriptive requirements. And within that, you come into the consideration of CAP. It is within our deterministic space.

And separately, when we look at things such as beyond-design-basis accidents or severe accidents, it is more best estimate, realistic, et cetera. So, you know, we believe there should be a distinction between the two sort of regulatory regimes. And CAP we believe is within the regulatory regime of design-basis accidents.

So, with that said, you know, we have just started engaging with licensees on the review of the mitigating strategy submittals. We have had several public meetings, and we are continuing those meetings.

We are issuing a request for additional information.

But, right now, we are at the really early engagement time period on this topic, in addition to a dozen or so more. So, at this time we don't actually have a plan laid out to discuss with you. But what we would like to propose is to come back in September, and maybe through one of your P&P, your planning and -- I forget what the second "P" stands for --

MEMBER ARMIJO: Procedures.

MR. MONNINGER: -- planning and procedures meeting, more thoroughly discuss with you what our potential plans are and where is the more appropriate engagement and timing for the ACRS. We would propose to either do it through that or do it through Ed Hackett or something like that. We would not be in a position to provide any type of presentation to the ACRS in September, but, rather, we would like to discuss our plans.

Does that make sense?

MEMBER ARMIJO: Yes. Whether it is a P&P or through some informal administrative meeting, yes.

MR. MONNINGER: Yes, whatever is the most appropriate.

MEMBER ARMIJO: Yes.

MEMBER SHACK: But even under the current guidance, under 6.3.8, they are supposed to address possible losses of containment integrity, including containment venting required by procedures.

MR. MONNINGER: Right.

MEMBER SHACK: Then, I note in the IPEEE submittal, the success of venting is assumed to have no negative effect on NPSH for injection pumps taking suction from the suppression pool.

MR. MONNINGER: Right.

MEMBER SHACK: So, those all seem fair game in this context.

MR. MONNINGER: If the procedures currently had early venting, and if early venting was approved.

MEMBER SHACK: Well, at least we should ask them what their plans are for venting --

MR. MONNINGER: Yes.

MEMBER SHACK: -- in this context.

MR. MONNINGER: Yes. Now, actually, within the current set of EOPs, the first step is, if you are below the trip setpoint for your containment isolation, there are provisions in there to currently vent, but it is not meant to be to the extent for early venting. It is more for a temperature-type control if you were to lose your chillers, that kind of stuff.

But this early venting notion is substantially different. So, our proposal would be September.

MEMBER CORRADINI: So, stayed tuned.

MR. MONNINGER: Stay tuned.

CHAIR REMPE: If there are no additional questions, it is time for Benjamin Parks to start off, right?

MR. PARKS: Thank you.

My name is Benjamin Parks. I'm with the Reactor Systems Branch. I am enjoyed to my right by Tai Huang, also from the Reactor Systems Branch, and our consultant from Oak Ridge National Laboratory, Dr. Jose March-Leuba.

We will be talking to you about the reactor systems review. That is my end of that. Tai and Jose will discuss the EPU stability considerations with you, once I conclude.

As we have been discussing, we will carry on some of our discussion in a Closed Session. So, these slides are very "texty" and a lot of words. So, we will get to more specifics once we are in the Closed Session to avoid disseminating proprietary information.

So, today we are going to describe the staff's review of the Monticello transient and accident analyses for EPU, and we will also provide a brief overview of the licensee's efforts to address nuclear fuel thermal conductivity degradation. And we will also discuss long-term stability Option 3 and thermal hydraulic stability. We will also discuss the Interim Methods Licensing Topical Report as well.

Just the framework within which we are working, the licensee references the CLTR's Constant Pressure Power Uprate Licensing Topical Report. That document provides a framework for the evaluations and the analyses that are necessary to justify a requested power uprate, and its use is based largely on using the GE fuel product. And Monticello is using GE-14 fuel. They have a full core of it at this point in time.

For our review of the fuel design, there is not much to do on a plant-specific basis when the generic Topical Report says this is for fuel of a certain design, and they say, "We use exactly that design."

So, we requested that the licensee provide some core design parameters, so that we could verify the assertions in the LTR. What we observed was there are no significant changes in the fuel discharge burnup. There is a limited increase in the EPU fresh fuel batch fraction. I think the reference core was based on a batch fraction of .34, and in the Supplemental Reload Licensing Reports for the recent EPU analyzed cycles, the loading was .31.

The key parameters remain within GE-14 limits, the peak enrichments, the discharge burnup, that stuff.

So, we concluded that the fuel design was acceptable for operation at EPU conditions. I believe, Dr. Armijo, you asked a question about power density. You asked about kilowatts per liter.

MEMBER ARMIJO: Yes.

MR. PARKS: I have the same observation, and I will show a little graphic that was in the application toward the end of the presentation.

MEMBER ARMIJO: Okay. Good.

MR. PARKS: Relatively low was my observation.

The disposition for thermal limits fits with what is in the Constant Pressure Power Uprate Licensing Topical Report. They have applied an adder for the safety limit minimum critical power ratio.

So, that is increased by .02.

A recent amendment, I'm just noting, you know, because we did our review in 2008-2009, they have recently requested and gotten approval for an increase in both the two-LOOP and single-LOOP operation values to 1.15. That brings the TS limit for the safety limit minimum critical power ratio into compliance with EPU and MELLLA+ interim methods requirements.

Note that a higher tech spec limit on the safety limit minimum critical power ratio is conservative. So, if you add what is necessary for EPU and you have still got margin between the 1.15, it is okay to have a value that limits you at 1.15.

Okay. So, this is an area where we will discuss more in the Closed Session.

The operating limit minimum critical power ratio, just generically you observe that there is little EPU-related variation in that value. When the application was submitted -- and I am going to guess the SE revision that you have at this point in time, it observes that there is an adder based on the use of ODYN, PANAC, ISCOR, and LAMB. Okay, so that is the disposition there.

It has only been recently that the

licensee has addressed differences between those legacy models and the new TRACG-04 for anticipated operational occurrence and overpressure evaluation. The assertion is that TRACG-04 migration obviates the need for that .01 penalty. I have some additional information to share. Just because it teeters on proprietary, I am going to push that into the Closed Session.

The linear heat generation rate disposition is listed here. They are established by the fuel design. It is not affected by EPU, and the MAPLHGR limits are determined by the ECCS evaluation.

Okay. Again, I do my best to make this slide, you know, due to the nature of proprietary information, sufficiently descriptive yet vacuous, and I am afraid it might be a little bit more the latter and less of the former here.

But, basically, the limiting AOOs are analyzed on a cycle-specific basis. We have talked about that a little bit already. There is a disposition in the suite of power uprate licensing Topical Reports, and the licensee justified and applied that disposition.

So, having said everything I said about this slide, let's talk a little bit about what the EPU does to the AOOs and how I verified that this was okay.

The licensee began submitting supplemental reload licensing reports soon after our May 2009 audit. We got the first one for Cycle 25. The reason we don't do this typically as a part of an EPU review is because these reports are not available when we are reviewing the EPU. So, we are looking at generic cores and this is the cycle-specific analysis.

So, Cycle 25 was a non-EPU fuel cycle. And then, Cycles 26 and 27 were subsequently submitted. And those are both EPU cycles. Cycle 27 is the one that I believe is currently resuming right now or beginning.

My observation was, based on reviewing those reports, that the disposition for AOOs was confirmed by looking at the analyses. The results of the analyses were consistent with what is asserted in the CLTR. There is little variation in the predicted CPR performance pre- and post-EPU. And it was my observation that the most significant differences appear to arise due to changes in the SLMCPR. So, that tech spec went up to 1.15, and you saw an increase in the OLMCPR as a result.

MEMBER BANERJEE: Ben, this is, of course, for GE fuel. What would happen if at some point they went to a transition, to a mixed core, and then --

CHAIR REMPE: Actually, they have a licensing amendment request --

MR. PARKS: Actually, they already have plans to do that.

CHAIR REMPE: --to go to AREVA fuel, yes.

MEMBER BANERJEE: They would have to?

CHAIR REMPE: They have request. It is already --

MEMBER BANERJEE: They have a request?

CHAIR REMPE: Yes.

MEMBER BANERJEE: Okay.

MR. PARKS: So, what we do is, you know, we are considering the plant the way it is licensed to operate today. And we don't, as a matter of routine practice, accept any license amendment that is linked to another one. However, we have made some exceptions in this case because we have had good reasons to do so.

Now, with a transition to a different fuel vendor on the table, obviously, we will do a separate review for that, but we do a pretty thorough review for fuel transitions as well. And so, there will be no exception there.

So, these dispositions apply to the EPU based on the way GE analyzes its fuel. Okay? The fuel transition is going to be justified based on the way any other fuel vendor would analyze its product, and that would include EPU operation, any potentially expanded operating domain, and the effects of using fuel from two different vendors in a mixed core configuration. So, all of those would get rolled into that review.

MEMBER BANERJEE: The different vendors have different methodologies as well.

MR. PARKS: Absolutely.

MEMBER BANERJEE: So, you would have to go through all that all over again?

MR. PARKS: Yes. And I think probably the staff's review practice in the past three or four years has shown that a fuel transition review is a fairly substantial effort, at least on the part of the Division of Safety Systems. The number of hours that we spend on those reviews has gone up considerably. So, it is a source of significant staff effort. It is not something that we think is a wash.

MEMBER BANERJEE: Okay.

MR. MONNINGER: That submittal just came in, and we have assigned it, but we haven't begun that review in any tangible way. So, we are not in a position to answer any real questions. But we will do a full-blown review to make sure.

MEMBER CORRADINI: You have another bite at that apple.

MEMBER SKILLMAN: Has it been accepted? Has it been accepted?

MR. JACKSON: No, it has not been accepted.

CHAIR REMPE: I'm sorry, but you have to state your name.

MR. JACKSON: Oh, I'm sorry. My name is Chris Jackson. I'm the Chief of the Reactor Systems Branch.

MEMBER ARMIJO: Is this all you are going to say about the AOOs? Because I want to ask --

MEMBER BANERJEE: In the Closed Session, they are going to say more.

MR. PARKS: Yes. Yes.

MEMBER CORRADINI: We have a Closed Session for it.

MEMBER ARMIJO: Maybe I will just wait until the Closed Session. Because, guys, I saw something -- well, it is in the SE. So, it is not proprietary.

I found that it was curious in that it was related to an RAI-2.8.3-10. Staff was requesting an evaluation of a fuel temperature oscillation against a pellet-clad interaction PCI limit. And I found that puzzling because there is no PCI limit that we have in the regulations. We have a PCMI limit, and we have a fuel melting limit in these centerline melting.

So, I was wondering. So, I went on to read a little bit further, just to see what we are talking about. And the response to the RAI went back to the PCMI and the fuel centerline melting. But, then, there was a further discussion on -- okay, the PCI limits are not a design criterion. Therefore, the licensee only addressed the issue in qualitative terms, and they talked about their fuel, their barrier fuel, and it has got good performance.

And the question I would ask is, why is the staff asking them about PCI limits if it is not a regulatory requirement in this RAI? And that triggered another question. But, as soon as you answer that one --

MEMBER CORRADINI: He is ready with a second one.

(Laughter.)

MR. PARKS: I am going to have to reach.

So, I might have to bring you an answer in September.

MEMBER ARMIJO: Well, I think it is a good question.

MR. PARKS: Well, I am just recalling how I did my review and how I tried to limit my review scope to what is appropriate, given all of the constraints that apply to me.

MEMBER ARMIJO: Yes.

MR. PARKS: And I probably sensed some recent interest in the topic. So, I inquired about that.

MEMBER ARMIJO: I am certainly interested, but I am not sure anybody else is. I thought it was a good question because it triggers something a little more basic for me.

They have a fuel design that has got certain advantages related to PCI, but the database that demonstrated that they had these PCI-resistance advantages was in the 1980s, and the cladding material that was used, the liner material, was a high-purity zirconium liner. And since then, the manufacturers have alloyed this stuff.

And my question really gets down to, is it really the same kind of cladding that you can count on to have the same kind of resistance? And maybe the vendors or Monticello can tell us that, you know, they have tested it, and it has got the advantages that they claim they have.

But, again, we are out of regulatory space. We are in a space where at least some of us believe there should be some sort of regulatory concern about a fuel failure mechanism that could occur, if you had a whole core transient.

MEMBER BANERJEE: In some letter, Ben, we have added comments from people on this.

MEMBER ARMIJO: We have raised this issue before. But, you know, even if it isn't a regulatory issue, I think the concern I have is the mechanical design is changing in very subtle ways, and the things that you are counting on for performance may not be there anymore, or may be. Maybe there has been some testing and everything is okay.

CHAIR REMPE: There is actually a person who wants to respond.

MEMBER ARMIJO: Yes. Yes, go ahead.

MR. DILLER: My name is Peter Diller with GE-Hitachi.

So, I guess the question mainly is about the changes to the cladding material that have occurred since the most recent ramp test? I think we probably need to get back with -- I am not immediately familiar with the most recent ramp test that has been performed.

MEMBER ARMIJO: Okay.

MR. DILLER: But I think we certainly would argue that the zirconium liner has not changed to any significant degree since those ramp tests have been performed, to the extent that they would affect the PCI resistance offered by the zirconium.

MEMBER ARMIJO: Well, I don't want to debate it too much, but you know the chemistry of the liner has changed. It has been alloyed with iron, and as opposed to being just pure zirconium.

And if GE-Hitachi has done some ramp tests that are equivalent to the original database and shown it is the same, you know, the problem is solved. But if there has been no ramp testing, it is just an assertion, I think that is kind of weak.

So, that is basically the question. And it is broader in that subtle changes in the mechanical, in the cladding property and things like that can be happening as people start fooling around with the materials, and the properties you expect may not be there --

MR. PARKS: Sure.

MEMBER ARMIJO: -- unless it is demonstrated by tests.

MR. DILLER: Okay. So, you are not referring to Ziron, are you?

MEMBER ARMIJO: No. No, I'm talking about the liner itself, the barrier liners, zirconium liner. The ramp test data on that was made on pure zirconium. Okay? And once you alloy it, well, you have a duty, I think, to do some more tests to show that it has equivalent properties.

And you may have that data. I haven't seen it.

MR. PARKS: Right.

MEMBER ARMIJO: And I don't know if the staff has seen it.

MR. PARKS: What I will offer to do, given the caveats we have put on the discussion, I have made a note in regards to 283-10, the RAI, and noting that the database for the PCI limits or the PCMI limits was generated in the eighties and noting that there may be some changes to the clad lining chemistry --

MEMBER ARMIJO: Yes.

MR. PARKS: -- what is a staff assessment of the currency or relevancy of that data, those data?

MEMBER ARMIJO: The validity of the data.

And the PCMI being purely mechanical failure, I wouldn't expect much. I wouldn't be worried about that. But if there is an interest in the PCI, the stress corrosion cracking limit, if there is a concern, then you really have to know what has happened to the liner chemistry itself and whether it has been tested to show it is equivalent in performance.

MR. PARKS: Okay. So, we will --

MR. JACKSON: Just as a note, I mean, Ben isn't our expert on fuel. We didn't bring our experts on fuel. So, we may know the answer to that. I personally don't.

MEMBER ARMIJO: Yes.

MR. JACKSON: For this meeting, we didn't, and putting it in the SER, recognizing that it is not regulatory or safety limit, their ability to operate within the operational limits is still something that we have interest in.

MEMBER ARMIJO: Yes. Well, you know, I am not challenging the PCMI. You know, it meets PCMI criterion, because pretty much any zirconium alloy is going to behave pretty much the same. It is purely mechanical. But when you get into chemistry, it is a different game. Okay.

MR. PARKS: Yes. So, we have got a note of the question.

MEMBER ARMIJO: Sure. Thank you.

MR. PARKS: And we will either shoot for a short answer tomorrow or we will talk about it a little bit more in September.

MEMBER ARMIJO: Yes.

MR. PARKS: Okay?

MEMBER ARMIJO: And the GE people may have a good answer.

MR. PARKS: Okay. So, based on the CLTR and Monticello's use of that document and the dispositions contained therein, and based on, also, our confirmation by reviewing these recent supplemental reload licensing reports, we determined that the EPU is acceptable for Monticello.

Okay. So, for overpressure events, based on the reference core design, there is an analysis for, I believe it is referred to as the MSIVF event, main steamline isolation valve, with either a failure of the direct scram or a scram on flux. That is the "F" -- there we go -- instead of the position indication on the valve.

They also analyzed an ATWS event. Or, actually, they analyzed three, to confirm that the pressure relief system is acceptable for EPU and that the standby liquid control system operates acceptably to provide the required protection.

I will note, also, that the physics capability of the SLC injection system is assessed on a cycle-specific basis as well. So, they confirmed that they reached shutdown margin requirements there on a cycle-specific basis.

Okay. Emergency core cooling system performance. Here, I will clarify a little bit in general terms some of the discussions happening this morning, and then, we will talk about it a little bit more in the proprietary session.

The specific model is SAFER/GESTR-LOCA that is used to evaluate ECCS performance. The regulatory framework that it is based on is SECY 83-472. It basically permits a more realistic approach while still conforming to the required and acceptable features of Appendix K evaluation models.

The effect of this on me, as the reviewer, is I have to look at a variety of different calculated peak cladding temperatures, and it is not necessarily from like the current, I guess in a regulatory context, the current state-of-the-art, best-estimate methods. It is not quite like that. It is a slightly different assessment of uncertainty. And it still involves the use of Appendix K models, too.

The bottom line here, and one thing I will point out about this licensing report, is there was an assessment, sort of apples-to-apples, so to speak, of EPU versus current license thermal power performance. And the analyses confirmed that the EPU itself has little effect on the limiting PCT.

This plant is large-break-limited. Here is the licensing-basis PCT. That is 21.50. That includes the sort of TCD penalty.

The estimated effect is based on what has been called a single-effect sensitivity study. So, that is swapping out the GESTR-based mechanical models with PRIME and re-executing. And so, the end result is a 10-degree increase in the predicted PCT.

MEMBER ARMIJO: And PRIME has the PCT built into it?

MR. PARKS: Right.

MEMBER ARMIJO: Okay.

MR. PARKS: It has been very recently approved by the NRC staff.

MEMBER CORRADINI: But all the rest of the stuff just follows Appendix K's assumptions?

MR. PARKS: That is largely true, yes.

MEMBER CORRADINI: So, "largely" means what?

(Laughter.)

MR. PARKS: I talk about that in about 45 minutes.

MEMBER CORRADINI: That we would welcome.

MR. PARKS: Okay.

(Laughter.)

MEMBER BANERJEE: But he is going to clarify. I mean, this question is on the table.

MEMBER CORRADINI: That's fine, yes.

MEMBER BANERJEE: I mean, what the uncertainties are.

MEMBER CORRADINI: We might as well just stipulate and go right to Closed Session.

CHAIR REMPE: Patience.

Go ahead.

MR. PARKS: Okay. So, there's a couple of other things I want to note.

MEMBER BANERJEE: What is the date of that SECY, '83?

MEMBER CORRADINI: Yes.

MR. PARKS: 1983.

(Laughter.)

Well, this is prior to 1988.

MEMBER CORRADINI: That is when people really did work.

(Laughter.)

MEMBER BANERJEE: Well, nothing has changed since then.

MEMBER SHACK: I tried to find it. It is off in the depths of the legacy ADAMS.

MEMBER BANERJEE: Has that been applied this --

MR. PARKS: To my knowledge, this is the only one in use today that applies this framework. The other boiler evaluation models are based on Appendix K methods. There may have been a P evaluation model in the past, but it has been replaced. And this one, General Electric has something that is under staff review that should come in replacing this in due time.

MEMBER BANERJEE: Well, that was the unusual feature that I noticed. So, we will come back to this. Okay.

MR. PARKS: Okay. I was going to get to this, and then, I realized I had a slide for it. So, a little bit about Monticello's emergency core cooling system. The ECCS performance is a function of what pumps you have and how much liquid you can reinject into the vessel after you have had an accident. So, for Monticello, that is a LPCI system, low-pressure coolant injection; a LPCS, low-pressure core spray; high-pressure coolant injection, and an automatic depressurization system which comprises three of the safety relief valves at the plant.

There were some changes. And so, that is why I was glad to see an apples-to-apples comparison of the PCT effects due to the EPU.

One of the things that happened was an upper-bound PCT limitation was removed, and that permitted the use of increased MAPLHGR limits in the ECCS evaluation.

The licensee also increased the number of safety relief valves because, as you increase your core decay heat, you increase the blowdown requirements. And so, in order to keep the break spectrum performance relatively the same pre- and post-EPU, they increased their relief capacity, so that they could still say their break spectrum performs the same as it did beforehand.

And so, you know, when you account for all of those changes, the pre- and post-EPU peak cladding temperatures were consistent, and they are within 2200. That is our regulatory acceptance criterion.

MEMBER BANERJEE: So, the depressurization came out to be essentially the same? Is that it?

MR. PARKS: I can't say that it was essentially the same --

MEMBER BANERJEE: Fairly close?

MR. PARKS: -- because I didn't review the entire break spectrum. But, presumably, what would happen is you would see the limiting small break or something close to it come way up in predicted peak cladding temperature because of the increased decay heat load. And then, when you increase the relief capacity, it enables you to get your low-pressure coolant injection in sooner. So, that brings the PCT back down.

MEMBER BANERJEE: But my question was, with the increased relief capacity, the depressurization transient must look fairly close to what it was with two developing fuels. Is that sort of the case? Otherwise, your various ECCS systems would have trouble getting in.

MR. PARKS: Right.

MEMBER BANERJEE: The pressure would hang out, right?

MR. PARKS: In terms of the specific small-break transients, you know, I didn't look at a plot of vessel pressure versus time. So, I can't say with certainty that that is the case. But that is what I expect.

MEMBER BANERJEE: What you saw was that the PCTs, so the peak is similar, which means the ECCS got in at least.

MR. PARKS: Yes. That's correct.

MEMBER BANERJEE: This was a reflood peak, clearly, right?

MR. PARKS: Yes, that's right. It is late in the transient.

MEMBER BANERJEE: It is late in the transient, though.

MEMBER SKILLMAN: Ben, did the crediting of the third SRV degrade critical margin from the perspective of now not having a backup SRV? Was that third valve credited as a redundant component, such that by taking credit for the third valve, some margin has been forfeited?

MR. PARKS: Okay. So, prior to EPU, the analyses assumed that there was up to one ADS valve, the lingo is, "out of service". Okay? And so, the analysis had at that point, I guess you would say, two-thirds margin to the actual configuration at the plant.

But licensees take those equipment out of service, flexibilities, you know, when they do operability assessments. So, if there is an issue with that particular ADS valve, they will assert that analytical margin.

With the EPU, Monticello loses that flexibility because they have taken that out of their analysis suite. And so, I don't know exactly what their tech specs say at this point off the top of my head, but if the tech specs previously said that you need to have two ADS valves, they now say you have to have three. I believe that my SE has some RAIs to that effect in it.

MEMBER SKILLMAN: I would like to follow up on that, if we could, please.

MR. JACKSON: I'm sorry, in what sense? What was the question, just so we get it right?

MEMBER SKILLMAN: Yes. You were using two before. Now you need three in order to maintain your pressure to where you want it to be.

MR. JACKSON: That's correct. Yes.

MEMBER SKILLMAN: That is not such a bad idea unless you were counting on that third valve either as a backup or one that was credited to be out of service. You may now have taken credit for what might have been a redundant component back in the original design criteria days. I mean, this is probably pre-GDC-70. Okay?

So, it could be that that valve was once called a spare or it was used for analytical margin. Now it is required. So, has something been forfeited? That is my real question.

MR. JACKSON: And I think the answer is yes. I think they forfeited operational flexibility because now, if something happens to one valve, they would have to --

MEMBER SKILLMAN: As long as they have got that clarified, I'm good to go. I mean, that is their decision on how to operate the plant.

But, you know, say you had three diesels and you normally count on two, and you say, "Now I'm counting on three," then what were the requirements for that third engine and have you forfeited something? That is the question I am asking myself.

MR. JACKSON: Good. Thank you.

MEMBER SKILLMAN: And it is not intended to be pejorative. They are certainly allowed to do that, but I would just like to understand it.

MR. JACKSON: No, I just wanted to make sure we hit the mark when we respond.

MEMBER SKILLMAN: Good.

MEMBER BROWN: That wasn't the way I understood it from reading the thing. So, I correct me if I am wrong because I have got a totally different perspective.

The way I read it was that they previously allowed one to be out of service. Then, they did their analysis. I mean, they could operate with two. And then, they had a single-failure criteria where they could either have another ADS valve fail or something else fail. And now, the way I read it is they are going to a single-failure criteria where now that first ADS valve becomes that single failure for those transients in order to be able to pass. They can't stand something else failing as well.

So, that is the way I read this. I think that is a little bit different than what you --

MEMBER SKILLMAN: Yes, I read it as, where before they required two, now they are require three. And if there is no redundancy after that third, then they are full in with three, and there is no further --

MEMBER BROWN: No, I think they can still stand the single failure of one, if I read that right, of one of the ADS valves. But they can't handle a failure of anything else in combination with that one ADS valve.

Did I read this, did I state that correctly? That is what I read in their papers and in the SE.

MR. HAMMER: Yes, Steve Hammer, Monticello.

Yes, we are required to assume a single failure, the most limiting single failure. So, one of the single failures that is considered is an ADS valve. But, then, they don't have another single failure in addition to that. You don't see a HPCI available.

MEMBER BROWN: That's right, but before you could have a single valve out, and then, you would say something else would fail.

MR. HAMMER: That's correct.

MEMBER BROWN: Okay? And you can't pass that now.

MR. HAMMER: Right.

MEMBER BROWN: So, that's a change, but it is still a single failure. Their flexibility is what they are -- they can't assume something else fails if they have all three required. So, it is a single-failure issue to me, is the way it was. It changes --

MR. HAMMER: Right.

MEMBER BROWN: Obviously, they have got some less flexibility, but it is really based on single-failure analyses more than it is --

MR. HAMMER: We have removed the capability to have something out of service for maintenance or for --

MEMBER BROWN: Right.

MR. PARKS: They have changed Tech Spec 3.5.1. They now require all three. We are so confirmed.

MEMBER BROWN: Yes, they changed it. That was the reason for the tech spec change.

MR. JACKSON: There was an installed spare before in a sense; now there is not.

MEMBER BROWN: Got it. Okay.

MR. PARKS: And so, in single-failure space, I would actually look for some type of control failure that inhibits the single and causes all three to fail or maybe they have a hardware configuration that prevents that.

MEMBER BROWN: That is another issue.

MR. PARKS: But in their limiting single-failure evaluation, they concluded that the low-pressure coolant injection was the limiting single failure. And I would expect that, you know, provided they have increased their ADS capacity and they have evaluated the design of the ADS, so that they know how many the limiting single failure there would pull out, then they are large-break-limited. They need a high-capacity, low-pressure injection system. And so, if that is the case, then limiting failure is of that system.

MEMBER SKILLMAN: I'm good. Thank you.

MR. PARKS: Okay.

MEMBER SKILLMAN: Charlie, thanks. That's good.

MEMBER BROWN: Okay.

MEMBER SKILLMAN: Yes.

MR. PARKS: Okay. So, interim methods. I discussed the interim methods impact on the thermal limits. We performed a review of their evaluation of compliance with conditions and limitations. We discussed that in an appendix or an extra section to the Safety Evaluation.

The bottom line is the licensee provided the required information. They applied the necessary adders and penalties. You know, the staff's review documents in some cases there was a difference in interpretation. We made sure that we resolved that, and we concluded that the licensee satisfied the IMLTR conditions and limitations.

Now the case here is that they were using a suite of methods that are not necessarily the current generation. And so, those are the conditions and limitations and the way that they apply.

Okay. Thermal conductivity degradation is a topic that we have been discussing with great interest for the past couple of years at this point. The bottom line is this EPU request was submitted prior to the completion of the PRIME review, and PRIME is the new model that accounts for thermal conductivity degradation as a function of burnup.

At that time, I believe that addressing the effects of thermal conductivity degradation was a part of the Interim Methods Licensing Topical Report. So, there are thermal mechanical penalties applied to the legacy methods.

And there is also burnup-dependent limits on linear heat generation rates at boiling water reactors. And so, that is the type of disposition that was in this application, basically.

So, the EPU relied on GESTR-based analytic methods. Penalties applied. And now, we are seeing a transition, as we are supposed to, to PRIME-based analytic methods. And so, what we got for closing the loop on this review is the estimated effect of TCD on the LOCA analysis.

They were operating with what was previously a conservative adder that was reported to me, and I just briefed the Committee in February, I believe, about those conservative adders areas where the staff intended to perform further review.

We have gotten more information here, and that is this PRIME single-effect sensitivity study that assesses TCD at 10 degrees Fahrenheit.

MEMBER BANERJEE: Is that effect so small because the stored energy doesn't have much of an effect on the BWR?

MR. PARKS: It is a couple of things. The assertion is typically -- you can see this if you care to go searching for 50.46 reports from boiling water reactors that assess the effects of thermal conductivity degradation. You would see that most estimate something that is small, except for a small set, a certain vintage of boiling water reactors, of which Monticello is not a part.

There is a couple of reasons. One is, you know, this isn't a blowdown-peak-limiting transient. Okay? So, stored energy is less significant.

Another consideration is, again, the linear heat generation rate, and the MAPLHGR has to come down as a function of burnup. And so, that is an operating limit that is imposed on the plant. And so, that is an area, recall, that boiling water reactors are a little bit better with respect to TCD.

And so, all this stuff comes together and we get small estimates, and we don't --

MEMBER BANERJEE: I think it makes sense.

MR. PARKS: Yes. We don't find ourselves too surprised about it.

All right. I wanted to show a couple of other things. These say potentially proprietary, and I am going to add we did a verification. I wanted to be extra-cautious because this is showing a lot of specific data, but, indeed, these figures are in the publicly-available PUSAR. So, this is not proprietary information. Okay? Just so we are clear there.

This gray trace at the bottom shows Monticello's EPU maximum bundle power as a function of the cycle burnup. And what you can see is, admittedly, it is a selection of data. And the selection of data shown, they are kind of down at the bottom. And so, they have a comparatively-low bundle power.

And the other thing I am going to show, there is too much information here because it reflects too many different power and flow conditions that we are not really considering for the EPU application at this point.

But the 120 percent, so EPU 100-percent-rated flow reflects about the extent of their allowed operating domain at EPU conditions. And you can see that they are bundle void fractions. So, we are looking at the second row up from the bottom on this table. You can see that their bundle void fractions are less than 85 percent. Okay.

MEMBER CORRADINI: You're right, though with significant figures, I don't know if I believe any more than two,.

(Laughter.)

MEMBER BANERJEE: Or one.

(Laughter.)

MEMBER CORRADINI: Well, two. So, I guess what I was trying to understand is the 80 and the 100 line for the EPU and why the bundle void is higher.

MR. PARKS: Okay.

MEMBER CORRADINI: So, you are going the opposite direction than I would expect to.

MR. PARKS: So, at 80 percent --

MEMBER CORRADINI: I'm sorry, it was rate of flow. Never mind.

MEMBER BANERJEE: It is just the flow.

MEMBER CORRADINI: I was misreading. I misread it.

MEMBER BANERJEE: It is the flow.

MEMBER CORRADINI: Never mind.

MR. PARKS: Okay.

CONSULTANT SMITH: But, backing up one slide, when you compare the EPU maximum bundle powers to all these other plants, the Monticello was a generic design, right? And yet, you look at a maximum bundle power versus real plant. And the others are all real plant designs or site-specific, and Monticello was not. So, would you anticipate that that Monticello number might actually go when you have a real design on EPU?

MR. PARKS: In a real design, I would expect it could. I wouldn't expect it to go up significantly. Otherwise, we would see some other licensing changes, I would certainly expect.

CONSULTANT SMITH: So, are most of these just kilowatt-per-liter differences driving this?

MEMBER ARMIJO: Yes, that has got to be it.

CONSULTANT SMITH: I think so.

MEMBER ARMIJO: Uh-hum. The power density is low.

CONSULTANT SMITH: I guess the bottom line is Monticello has a huge advantage being a very low power density core.

DR. MARCH-LEUBA: Yes, these are megawatts per bundle.

MR. PARKS: Yes, I would like to be careful and not potentially overstate the advantage, but, yes, I think they are not in the area where we have been concerned about thermal limits before. Okay?

CONSULTANT SMITH: Thank you.

MR. PARKS: All right. So, I put these together as sort of some thoughts to leave you with. And having said that, I am about to turn it over to Tai and Jose. So, let me give my conclusions, and then, we will do that.

We reviewed the licensee's assessment of the EPU. It was based on the Constant Pressure Power Uprate Licensing Topical Report. So, Monticello is using the GE-14 fuel assembly entirely, and they analyzed their accidents and transients in accordance with NRC-approved reload licensing methods, cycle-specific basis.

We have verified the results of their assessment using their reload licensing documents, and we concluded that the EPU was acceptable.

So, if there are no further questions, I will turn it over to my colleagues here.

MEMBER BANERJEE: There will be, but they will be in the Closed Session. All right?

DR. HUANG: Yes, I'm Tai Huang from the Reactor Systems Branch.

So, we reviewed the stability issue by two aspects. First, we reviewed their submittal and, also, a second one, we made sure they incremented, and we started to do the audit to find out their system is very incrementive of what they said in the submittal. Also, their operator training is good, you know, respond to this transient.

So, now the NRC staff, you know, we complete here the SER with a positive finding based on the review of available documents and an audit. So, Monticello, they used Solution 1D for a while successfully, and the EPU upgrade, including the digital NUMAC-based Power Range Monitoring System, which is including the function of the Solution III. And, of course, it is then easy; they can change to the DSS-CD in the future.

Currently, the long-term stability solution implementation is Solution III, and it is adequate for EPU because they satisfy our GDC-10 and -12, and their protection in the EPU is similar to the current licensed thermal power and standard --

MEMBER BANERJEE: You know, please, I don't recall these details very well.

DR. HUANG: Yes, yes.

MEMBER BANERJEE: Solution III, Option 2, whatever these things are.

DR. HUANG: Oh, okay.

MEMBER BANERJEE: Could you remind me what they are, actually?

DR. HUANG: Oh, okay.

MEMBER BANERJEE: I mean, I know we have reviewed these 100 times.

DR. HUANG: Yes.

MR. HASKELL: He's older; he needs help.

(Laughter.)

MEMBER BANERJEE: I do not recall.

DR. HUANG: Yes, the stability long-term solution they have three options. Option 1 they call 1D. Today they are 1D and 1E -- 1A, yes, 1A. They have two Option 1s, and 1A and 1D is different, you know. It is an exclusion reason. You know, you cannot get into there. That is 1A solution by just one plant in the U.S. In 1D, they still have a few plants there. But when they go to the EPU to MELLA plus for us, they will change from 1D to Option 3 and DSS-CD.

And the Option 2, only two plants are using that, the average power, APIM control for the stability. You know, these are only two plants in the U.S. One is Hope Creek. The other one is Nine Mile Point 1. There are only two plants.

And then, the Option 3, most of them are Option 3 plants in the U.S. And that would be the EPU; we review many Option 3, many.

DR. MARCH-LEUBA: Yes, the Option 3, which is the one that they have implemented now, it is also known as the OPRNM, or Oscillation Power Range Monitor. It is the one in which every LPRM in the core is being monitored by a computer, and it is an algorithm called the PBDA that takes oscillations. When the oscillation is large enough, it scrams.

They are both supposed to satisfy GDC-10 and -12. GDC-12 says that your plant shall be demonstrated not to be unstable. Or, if it is unstable, you will suppress those oscillations. And that is what these solutions are called that they can suppress, because they go through the DNS part of the GDC. So, what they do is they detect oscillations while they are small enough and they scram.

MEMBER BANERJEE: They are just a threshold, right?

DR. MARCH-LEUBA: It is very small. It is about 10-percent oscillation, typically.

MEMBER BANERJEE: Okay.

DR. MARCH-LEUBA: So, you do have to calculate a setpoint.

MEMBER BANERJEE: And there is a number of these that have to happen.

DR. MARCH-LEUBA: Correct. It is called a period-based detection algorithm, and it is looking for seal crossings -- it is a very old technique, actually -- and looking for the period between oscillations, if it is coherent. So, all the periods are the same value and it confirms 10 oscillations or 12 or 15, depending on -- it scrams.

So, the trick with the suppression solution like Solution III is to use a lot of analysis to demonstrate that, after you have waited for 10 oscillations and it grows so much, you still haven't violated CPR. So, that is where the whole methodology comes along.

MEMBER BANERJEE: And this is for a bunch of channels. What happens with a single -- or am I mixing up different vendors? If I am --

DR. MARCH-LEUBA: No, you are not. Well, you are, but not yet.

(Laughter.)

MEMBER BANERJEE: You can draw the line because so many of these have happened that I can't keep track of which vendor does what.

MR. JACKSON: Jose -- I'm sorry, this is Chris Jackson -- should we discuss this in the proprietary session or should we --

DR. MARCH-LEUBA: I don't think we do.

MR. JACKSON: Excuse me?

DR. MARCH-LEUBA: I don't think we do.

MR. JACKSON: Okay. Go ahead, then. I apologize.

DR. MARCH-LEUBA: We need to.

MR. JACKSON: Okay.

DR. MARCH-LEUBA: I mean, what he was referring to is another vendor is not personally in the room that has a special methodology that is proprietary. So, we won't discuss that one.

MEMBER BANERJEE: Yes. Okay.

DR. MARCH-LEUBA: You know, the LPRMs are distributed along the core, and there are 31 strings in the large plants times four. So, it is a whole bunch of LPRMs. And they are typically arranged so that you see the average of the power. So, they get the LPRM from here, from here, from here, from here, and give you an average power range monitor, which is the average power of the core.

Now that doesn't work when you have an oscillation that is side-to-side -- those are the ones we call regional or out-of-phase -- or you have a single channel oscillating because this is a special channel.

So, the Solution III was a new power range one. It is called the oscillation power range. There is an LPRM, APRM, and OPRM. The LPRM bundles something like eight or ten LPRMs in a region. So, now each LPRM is a regional power.

MEMBER CORRADINI: So, you survey them differently?

DR. MARCH-LEUBA: Survey they locally.

MEMBER CORRADINI: Looking for something that is in a region versus in a global?

DR. MARCH-LEUBA: That is correct.

MEMBER CORRADINI: So, instead of doing

this, it is doing this or doing that?

DR. MARCH-LEUBA: Correct. And the idea was that they didn't want to monitor a single LPRM because there would be too many failures. I mean, you just look at one detector. You are going to have scrams all the time. So, they wanted to do eight of them, but just around the bundle. So, you are monitoring. And as I said, the methodology relies on how you calculate all these things and how you ensure that.

MEMBER BANERJEE: Thanks for the tutorial, Jose.

DR. HUANG: Okay. So, finally, the OPRM Option 3, the option you needed to count. So, it tripped the reactors.

Okay. Now the stop outage. You know, we made that in May 21st, 2009. And the staff, you know, we conclude that the Monticello operators understand.

Next slide.

The Monticello operators show a good understanding of stability and ATWS and the staff observation of operators option in the simulator support. You know, there is a 120-second delay, you know, assumed for the safety calculations, yes, because you need --

MEMBER BANERJEE: This is an annual scram or an automatic scram? There is an option, right?

DR. MARCH-LEUBA: It is a failure to scram. It is an ATWS.

MEMBER BANERJEE: No, ATWS I understand, but --

DR. MARCH-LEUBA: Oh, you mean the Solution III? It is automatic.

MEMBER BANERJEE: Automatic? But there was something that had a manual/automatic -- remind me again.

DR. MARCH-LEUBA: Those are the backup solutions.

MEMBER BANERJEE: Okay.

DR. MARCH-LEUBA: We are not taking too much time, right?

During the experience --

MEMBER BANERJEE: We can understand what we are doing, right?

DR. MARCH-LEUBA: Yes.

During the experience we have with the long-term solutions, we found what is now known in the industry as the Part 21 issue, in which we discover after every plant has implemented Solution III that the methodology they had used was not appropriate.

So, suddenly, the methodology was invalidated and you could not demonstrate that those scram setpoints were protecting you.

So, you still have the hardware working. You still have the scram. But it was not protecting you in the regulatory space.

So, everybody had to move out to what is called a backup, solution, which these are manual-based and some calculated regions. And this morning we saw some of those. There is Region 1. If you went to an automatic scram as manual, and there is a buffer area, as you know, as the control in the region where you are not supposed to obey it.

DR. HUANG: Okay. So, now the staff observation, you know, find out there is a 120-second delay, assuming the calculations is reasonably good, and that the Monticello EOP are adequate for the EPU. And we looked at these --

DR. MARCH-LEUBA: Oh, this is not supposed to be here. Yes, that slide was not supposed to be there.

DR. HUANG: Yes. Okay.

Now you look at what is the difference between occurring similar license, similar power, and EPU. You can see from that point extended out on the narrow line. So, you know that EPU, we are talking about that triangle there.

And then, you know, what we want to make a point is EPU for the current licensed thermal power, when you have a two pump trip, the endpoint would be the same as in the natural circulation in that narrow line and that red dot over there because they are on the same narrow line there. Yes, this is the stability characteristically endpoints are similar. So, this will start to show this.

And then, now turn over to the detail of this study. We already explained by Dr. Jose, and you can keep going for the rest of them. And then, there is also interest in all the Training Center on the ATWS situations.

MEMBER BANERJEE: But, at the moment, though, you have mainly verified the capability using a simulator?

DR. HUANG: Yes. Yes. Yes.

MEMBER BANERJEE: Once they get whatever condition they are, then it will still be primarily simulators?

DR. HUANG: Yes.

MEMBER BANERJEE: It will not be a pump trip?

DR. HUANG: Right.

MEMBER BANERJEE: Okay.

DR. HUANG: And a key issue is the operator knows how to control your reactor in shutdown situations.

DR. MARCH-LEUBA: So, basically, the conclusion from this slide, and what Dr. Huang was trying to say, is that from the stability point of view, EPU is really not a big concern because the transient we are worrying about is moving into the unstable region, which is this to the left of the rail line, following this line.

And if you see CLTP or an EPU --

MEMBER ARMIJO: You are going to wind up in the same spot.

DR. MARCH-LEUBA: -- you just follow the same line.

MEMBER BANERJEE: Well, as long as you are on the MELLLA line.

DR. MARCH-LEUBA: Correct. This is what we have proven today. Now, obviously, you keep in mind MELLLA+ is going to move you to the left of this point. And therefore, when you trip, you will end up much higher, and that will be a problem for stability. MELLLA+ is a concern for stability, in other words.

EPU, the first thing that happens during ATWS is you trip the pumps.

MEMBER CORRADINI: Say that again? I'm sorry?

DR. MARCH-LEUBA: The first thing that happens within an ATWS is to trip the suppression pumps. So, the first thing you do is move down to the red point. At this point, you don't know if you have a CLTP or EPU. And within a few seconds you are back at the same point where you have been.

So, the difference between EPU and CLTP, here there is 20 percent more decay heat. But, as long as you are in ATWS, you hope you are in decay heat because that means you shut down.

(Laughter.)

Okay. And that's about it. I mean, there are second-order effects which are never to be discounted, which is power distributions. So, in an EPU core, you have a different power distribution, and it may have a significant effect. So, you do have to analyze everything. But, in approximation, you are in the same area.

So, from the point of view of stability, the first slide here says that the plant at Monticello worked on Option 1 for years, and it worked very well.

You guys are not familiar with Option 1D, but Option 1D means that the plant is very, very, very stable. You are not allowed to go into this option unless you are very stable. So, Monticello is a very stable plant.

And as anecdotal, I can tell you that, when they were trying to calculate the setpoints for Option 3 the first time, GE, which is the one that was doing the analysis, by procedure is supposed to treat the pumps and establish an oscillation, which will then tell them how much the CPR is being degraded by the oscillation. They were unable to make the plant oscillate.

(Laughter.)

The plant just would not go unstable. And they had to use the standard, the default curve. So, it is a very stable plant.

So, they went into Solution III simply because they are planning to go to MELLLA+ and they needed DSS-CD eventually. And it does give them more flexibility in operation. It is a nicer solution.

The primary reason people didn't install Solution III at the beginning is because it required this digital protection system, the PRNM, which back in the early 1990s not everybody had. All the plants were built with analog protection systems, and very few had -- and it is a significant expense.

And you will say, "Why don't you upgrade to the PRNM?" Well, I think it is between $10 and $15 million, plus a whole bunch of reviews and uncertainties. So, not everybody -- you have a protection system that is working; why would you want to change it?

So, when they moved to EPU, and hopefully MELLLA+, they said, "Well, let's get Solution III because it is for free. So, they installed it, and they installed it actually while we were there doing an audit in May 2009. And they were testing it at the time, and we went through all the procedures of testing and we interviewed some operators. "How is it going?" "Everything is going well."

They followed a standard 90-day trial period where you install the hardware and you make sure it is not causing any problems before you arm it. So, there is a jumper that prevents those relays from closing during those 90 days. After those 90 days, they turned it on and it has been running for the last four years.

As we said, we don't expect the hardware to fail. What we have seen in the past is the licensing basis getting validated. So, you cannot demonstrate that your trip really prevents CPR from happening, simply because your analysis methodology has a step that is wrong in there.

And if that happens, there are backup solutions. These are manual, and they work very well. What we have insisted, though, is that these backup solutions operate only for 120 days, and that is revisited in the tech specs. So, we want the automatic solution to be in place, and you want the backup solution only if something fails. But they have to take positive actions to get out of there or at least communicate. What we don't want is that the plant turn off the automatic long-term solution and go into backup for years without anybody knowing it. So, those 120 days are in all the tech specs, all the modern tech specs.

And the plant has a good experience with Solution III. They haven't had any problems, and there is no impact expected for EPU because all the methodology is available.

The same thing with ATWS. For that period we were showing before, EPU was essentially ATWS at CLTP. It doesn't really change that much. But we did review all their procedures, and they have implemented the EPG SAG Revision 2, which is the latest solution, which requires the operator to have an early water level reduction and early boil injection. Before Revision 2 of the EPG was implemented, these states may happen later.

MEMBER BANERJEE: What do you mean by "early"?

DR. MARCH-LEUBA: Instantaneous, as fast as you can.

The first minute during an ATWS in this control room flies.

(Laughter.)

I mean, the first thing you do is every single light which was dark when you started, every single one of them lights, and all the alarms go on. So, the first thing they are supposed to do is go and acknowledge all the alarms, so that the noise will go down. And then, they will have to -- some operator will say, "Scram demanded. Wait. We still have power."

So, then, the senior operator will say, "Ah, we are in ATWS." He will have to go and pick up his big chart, put it on top of the table, and say, "Okay, where are we," and he will start marking orders.

There will be three guys in front following orders, and there will be one guy in the back following the chart, seeing what he is supposed to do now. It takes 60 seconds to do that, even for a good trained -- and they are very well-trained, but it does take time.

So, the reason --

MEMBER BANERJEE: That is why they increased it to 60 seconds? Is that it, the operator action?

MEMBER SHACK: No, it is 78.

MEMBER SKILLMAN: No, 90.

DR. MARCH-LEUBA: This morning they say that during our audit they accomplished to do it in 78 seconds. I mean, really time flies. Really time flies. And we have done this before. I have recommended that you guys need to see this because it really is eye-opening, how good these operators are.

MR. PARKS: It generally takes two NRC staff to follow Jose to see what he is doing.

(Laughter.)

He is very quick at this, too.

DR. MARCH-LEUBA: Yes, and take notes.

(Laughter.)

MEMBER CORRADINI: Speak slowly.

DR. MARCH-LEUBA: Yes. Well, see, the 78 seconds will go faster.

(Laughter.)

So, what we concluded from our analysis is that Monticello has an excellent ATWS response. I mean, it is a very low-power density plant, and it really has a high suppression pool capacity limit, and 180 degrees is pretty high.

Another characteristic that they have is they have 100 percent motor-driven electric pumps for feedwater, meaning that they have water available to flood the core. They can put 100-percent flow into the core, which most plants can't do that once you isolate. And if you have steam-driven turbines that are only 20-percent motor-driven, you can only put 20-percent water into the core, and then, you have to rely on other PCCS. All the ATWS management is now with feedwater pumps, just as you do it in operation.

So, we reviewed the EOPs, and the plant has a procedure to review the emergency operating procedures every cycle to make sure that all the variables that are in there, all the action points on those graphs still apply to your current cycle. So, when you move from 100-percent power to 120-percent power, all those action points are automatically updated by procedure.

So, we did an audit. Actually, we have done two audits in Monticello because we did one as simulations for the EPU request. But, at the time they operate, the simulator was not still updated for EPU. So, we came back when they submitted the MELLLA+ application and we ran the cases of true MELLLA+ conditions, 120-percent power and 80-percent flow.

So, we have run seven of these, and we concentrate on two transients, the turbine trip ATWS from full power, in which case the turbine bypass is still available and you are losing some steam to the condenser directly without having to run the condenser into the containment.

And then, you have an MSIV isolation ATWS, which puts as much heat as possible into the containment to see what the option is.

In many plants, the turbine trip ATWS is the one where we call ATWS instability. When you have a bypass open, that is when you can have the possibility of large power oscillations.

In the particular case of Monticello, their bypass valve is a baby bypass valve. It only handles 11-percent capacity. So, it is like a small SRV. So, really, the difference between an isolation and a turbine trip is minimal at the beginning.

CHAIR REMPE: Jose, it went by quick. So, just repeat it for me a minute. You went twice, once before they had upgraded the simulator and once after, but you had them go through the EPU with just the MELLLA or did you have them do it assuming MELLLA+? That is where I got confused on what you said.

DR. MARCH-LEUBA: The first one, we did it at 100-percent power, 100-percent flow. That is CLTP. So, that is all CLTP. Okay?

CHAIR REMPE: Okay.

DR. MARCH-LEUBA: And then, the second one, we did it from the MELLLA+ corner, 120-percent power, 80-percent flow.

CHAIR REMPE: Okay.

MEMBER CORRADINI: I'm sorry, I was just going to interject, though, but your point earlier, two or three slides ago, is going from the MELLLA-only EPU would be the equivalent of just starting it higher up in the same --

DR. MARCH-LEUBA: Correct. And again, the quality of the simulator is pretty good, but it is not a TRACG or TRACE fidelity. The models are not supposed to be. Okay?

But the beauty of the simulator is that

every single auxiliary system, every single valve, every single pump is modeled as it is in the plant. So that, whereas TRACE or TRACG model, they call it very accurately, and I can tell you each node exactly under which flow conditions they are; the simulator doesn't have that accuracy in the core, but it has all of the secondary systems; plus, it has the operator.

So, it is good to look at the two ends of the range because you can always forget something. Maybe there is not enough steam capacity to do what TRACG was thinking they could do.

And TRACG and TRACE don't typically model the secondary systems, they tend to make them too conservative. So, you just put a bounding curve for your feedwater temperatures instead of calculating it.

I remember it wasn't even a plant. It was a BWR 6, and we were running the ATWS. BWR 6s, they don't have any motor-driven feedwater. It is all steam-driven. So, two minutes into the transient, I am noting that the operator that is handling the water level is controlling with feedwater. I say, "How come you can be using the feedwater pump when you don't have any steam?" He says, "No, I still have 2 kilometers of steam at 600 psi." Sure, the extraction of steam had been closed, but he still had 2 kilometers of volume that the simulator had used and allowed him to run down his feedwater flow for another two minutes, which saved the plant, by the way.

So, when you look at a very accurate TRACG calculation, it will tell you melted the plant. When you go to the simulator, you say, "Ha, the feedwater was still available." Okay? So, it really pays to do both ends of the simulation.

So, here you have some eye candy, some plots of what happens in the plant. And this one actually is from MELLLA+, the MELLLA+ corner. One thing you have to know when you go to these plants is the operators go 100 percent whatever the NRC lets them run hot. Okay? So, it is 100 percent of my license power. So, if it says 100 in there, that means 120 percent of the power.

This plot shows the power, and this plot shows the pressure. What we have, this one is a turbine trip. So, you have a very large pressure peak that produces a large peak in power. At this point, all the lights come on on the simulator. And just about the time here, the operator realizes that there was a scram requested and we are still on power. Okay? So, they enter the procedures.

All these oscillations you see here, I

know they look like unstable oscillations. What it really is, if you look at the pressure, it is SRVs opening and closing. It took the operator about a couple of minutes to take control of the SRVs.

One of the things they are supposed to do, continue to open SRVs until they stop cycling. So, you have 12 SRVs or however many, in this case only three. And they are cycling. You just open them as one. They are still cycling. Open two. Open three until it stops cycling, in which case you are controlling the pressure. You don't want these oscillations to happen.

So, somewhere around here, the water level will start to go down, and it eventually went down, and the boron started coming in, and it took control of the transient.

The next one shows a realistic plot of the suppression pool temperature. This is what the containment happens. The HCTL, heat capacity temperature limit, for this plant is about 180 degrees.

MEMBER CORRADINI: Remind me, I know I should remember what that is, but remind me what that is.

DR. MARCH-LEUBA: If you have stored

energy in the vessel, and you have to have an emergency depressurization --

MEMBER CORRADINI: Oh, this is what it goes to?

DR. MARCH-LEUBA: Oh, this is the suppression pool. This is the torus.

MEMBER CORRADINI: I understand, but this is what it goes to if I put all the energy there in an instantaneous --

DR. MARCH-LEUBA: Right.

MEMBER CORRADINI: Okay. That's what I couldn't remember.

DR. MARCH-LEUBA: Right. So, what happened is, for the other guys that didn't realize what it is, you have stored energy in the vessel because you are still at 1,000 psi. And in the future, you will need to emergency depressurize. If that happens, you don't want to blow up the containment. So, you need to reserve temperature in your suppression pool to handle a possible future depressurization. So, there is a heat capacity temperature limit, which is all the pressure in the vessel. That reserves heat capacity in the suppression pools so you can depressurize.

If you heat that HCTL, you have to

depressurize now. Because if you wait longer, you will not be able to. Okay? And that is a bad thing. It happens in most ATWSes, but you prefer to keep the reactor pressure and still have it pressurized and put all the heat load in the containment.

While all this is going on, you have your I&C technicians in the back of the room trying to reopen those MSIVs and reopen a path to the condenser, so you don't have to dump all the heat in the containment. You want to dump it into the river.

So, the trick in ATWS is to stretch out the time you have for those I&C technicians to fix what caused the problem, and then, you take control of the plant, or take the power of the plant so low that RHR will be able to handle it forever. So, you stabilize the plant in two ways. Either you reach the RHR conditions for single-heat removal or you open your pathway to the condenser.

So, when we do a "realistic," quote/unquote, simulation in the simulator, we see that the temperature of the pool is probably less than 140 or so; whereas, I mean, we didn't even get close to challenging containment in this.

So, we get to the end of the presentation. In summary, the EPU operation is acceptable from the stability point of view and there is really no change from the normal conditions. And the OPRM, the design criteria 10 and 12. And ATWS stability are not affected significantly by EPU. It satisfies the ATWS acceptance criteria 50.62. And actually, Monticello has an excellent ATWS performance design because of the low-power density and the high HCTL.

MEMBER BANERJEE: You showed us all these nice graphs, but you didn't show us the flow and the fuel temperature.

DR. MARCH-LEUBA: They are on the earlier report, if you would like to see them.

MEMBER BANERJEE: No, it's okay. Did they go into significant periods of dryout?

DR. MARCH-LEUBA: Not during this. But in ATWS the rules change. You have three criterias with ATWS. You do not have a significant release of site containment; you maintain culpability, and you don't break your containment, your primary system. You satisfy the ASME. You satisfy Level C pressure limits. So, those are the three criteria.

CPR is violated; no problem. But --

MEMBER BANERJEE: But I want to know for what period it is going into dryout and rewet.

DR. MARCH-LEUBA: You will have to --

MEMBER BANERJEE: Go back and look?

DR. MARCH-LEUBA: I mean, the simulator is not good to answer that question. For that, you have to go TRACE or TRACG.

MEMBER BANERJEE: Yes. So, I was asking this because you must have had TRACE and TRACG calculations done, right?

DR. MARCH-LEUBA: Yes, yes. And during these oscillations, you violate CPR. Certain criteria, you have a 250-percent power peak, you are going to violate CPR. And then, it will dry out. It will dry out and then --

MEMBER BANERJEE: What does the fuel temperature get to? I mean, there are certain assumptions here about rewet and stuff like that. But what does that show?

DR. MARCH-LEUBA: It will depend on the particular transient.

MEMBER BANERJEE: Will there be massive fuel failures?

DR. MARCH-LEUBA: That means the fuel temperature hits 220 degrees Fahrenheit. That is failure under ATWS conditions. In these particular runs, it never got that hot.

MEMBER BANERJEE: Okay. Yes, yes.

DR. MARCH-LEUBA: So, if you heat only one or two pellets during an ATWS of 200, that will be still acceptable. I mean, all you are trying to satisfy here, remember, this is beyond, this is not --

MEMBER BANERJEE: Especially in that?

DR. MARCH-LEUBA: Especially when all you are trying to maintain is core coolability. So, if half of your core the zirconium is oxidized and producing hydrogen, and the pellets fall to the bottom of the vessel, that is not core coolability. Obviously, you failed. But if two pins do it, well, it's okay. So, it becomes core coolability is a little bit subjective. We know what it is definitely not. Half the core is not good, but two pins, yes, probably it is okay.

MEMBER BANERJEE: The reason I am asking is, when the original ATWS calculations were done, undoubtedly, there wasn't a capability to do it with TRACE or TRACG. And so, now you have that capability. And I know that TRACE had a lot of problems at one point with ATWS calculations, as you know. But now I think it is able to do these calculations --

DR. MARCH-LEUBA: It is.

MEMBER BANERJEE: -- in the recent past.

DR. MARCH-LEUBA: Uh-hum.

MEMBER CORRADINI: I seem to remember you were asking the same questions when TRACG was being --when we went through the Topical Report for MELLLA+ --

MEMBER BANERJEE: Right.

MEMBER CORRADINI: -- for ATWS.

MEMBER BANERJEE: Right.

MEMBER CORRADINI: Memory serves me.

MEMBER BANERJEE: Yes, you're right.

So, I am asking, now that you have these calculations, what does it show?

DR. MARCH-LEUBA: It depends. It depends on the conditions and what reactor you are going to assume and what are your transient assumptions.

MEMBER BANERJEE: But did you do any calculations for this plant? Did you have any confirmatory calculations done?

DR. MARCH-LEUBA: For EPU, no.

MEMBER BANERJEE: It is probably not needed, but for MELLLA+ you certainly get that pressure.

DR. MARCH-LEUBA: We will follow it up on MELLLA+.

MR. JACKSON: Yes, for EPU, we didn't do that. When we do the TRACG issues and TRACE, we have done a lot of work for MELLLA+ --

MEMBER BANERJEE: Yes.

MR. JACKSON: -- not directly relevant to this, but that has been ongoing. We could talk about that a little bit, I suppose, in the Closed Session.

MEMBER BANERJEE: You don't have to. I mean, you can defer it to September, or whenever.

MR. JACKSON: Yes, we are still working on that.

MEMBER BANERJEE: Yes.

DR. MARCH-LEUBA: The licensing bases for EPU are, for EPU, ATWS is still a rule basis. I mean, ATWS was resolved by a rule. For EPU, it still applies.

Back in the early 1990s, we did some evaluations for ATWS stability where there were some TRACG calculations performed. I don't remember the name of the report, but it is all there. And they showed that what we called ATWS mitigation actions, which is lower the water level as fast as you can, inject boron as fast as you can, were sufficient to satisfy the ATWS criteria. So, our licensing basis for EPU are the same as we have today for CLTP.

DR. HUANG: So, that is the Generic Topical Report 32164, 1464, 64, something like that.

We have two Topical. One is the ATWS rule; the other one is mitigation for the ATWS. So, there is no change today, the same position.

MR. JACKSON: And for MELLLA+, though, they do do plant-specific calculations, the applicant, and we will present those when we are satisfied or rewritten.

CHAIR REMPE: So, for the record, you do have to say your name every time you talk.

MR. JACKSON: I'm sorry. I'm really sorry.

CHAIR REMPE: Sorry. That's okay.

MR. JACKSON: Chris Jackson.

CHAIR REMPE: Thanks.

MR. PARKS: And I just verified in the Safety Evaluation Tai gave the right report number. It is 32164, and that is in the references for the Safety Evaluation.

CHAIR REMPE: Thank you.

DR. MARCH-LEUBA: I think we are ready to move to the Closed Session.

CHAIR REMPE: Okay. Are there no more questions?

MEMBER BANERJEE: But you didn't essentially do any new work? It was not necessary?

DR. MARCH-LEUBA: For EPU? No.

MEMBER BANERJEE: For the EPU?

DR. MARCH-LEUBA: Correct.

MEMBER BANERJEE: You just verified that the methods that had been used earlier to get the stability boundaries and everything were still defensible?

DR. MARCH-LEUBA: The, quote/unquote, "rules of the game" --

MEMBER BANERJEE: Yes.

DR. MARCH-LEUBA: -- and I apologize for using the word "game"; it is not a game, but you know what I mean --

MEMBER BANERJEE: Yes.

DR. MARCH-LEUBA: -- are, when you review an application for EPU from a licensee, it is, are they using methods that have already been reviewed and approved? And if they are, they pass. That is what --

MEMBER BANERJEE: So, the differences are fairly minor from the viewpoint of stability? The fact that you might have a flatter core, or something, it doesn't matter too much?

DR. MARCH-LEUBA: All we can do is increase the probability if we have a scram that the

Solution III will actually activate when it needs to. If the flatter core makes the core more unstable, what it is doing is increasing the probability that they will have an instability, and Solution III will, then, discount it.

MEMBER BANERJEE: So, the stability boundary may shift a little bit, right?

DR. MARCH-LEUBA: It will shift.

MEMBER BANERJEE: Yes.

DR. MARCH-LEUBA: It will shift.

MEMBER BANERJEE: Did you look at even a linear analysis of this?

DR. MARCH-LEUBA: Again, it is good to have these numbers. During one of the seven events in WMP2, which is now known as Columbia, the reactor tripped. There was a real instability. Okay? And we have our special team. We spent two weeks there. We worked with AREVA -- at the time it was called something else -- to analyze the event and design a new startup path that would be more stable to let them restart. Okay?

And we want to do it in the most stable possible path that we possibly could find and make sure that the ratio of the same power and flow in the same plant -- two weeks later, it was 0.2. So, the plant had been the ratio 1.0 and had actually tripped on a scram, by changing controller positions, you could make it 0.2. That is as stable as a rock. So, yes, power distributions have a big, big effect.

Our concern from the licensing basis is we assume you are going to have an instability. Are you going to limits before the scram? That is our concern from the license point of view.

MEMBER BANERJEE: Sure. I mean, I think what you are doing is fine, but did you evaluate or did the licensee evaluate the effect of the EPU on the stability boundary? Now in this plant, which is, as you say, extremely stable --

DR. MARCH-LEUBA: Uh-hum.

MEMBER BANERJEE: -- you may be in a position that you don't see anything, even if you come down the load line all the way down, your stability boundary, maybe even beyond it; I don't know.

DR. MARCH-LEUBA: The answer is yes.

MEMBER BANERJEE: But if you shift it into the load line region?

DR. MARCH-LEUBA: The answer is yes, and Monticello can provide you that information. They calculate what we call the backup stability solutions, those lines, and they calculated the BSPs for Cycle

24, 25, 26, 27. If you are curious, they can give you that.

MEMBER BANERJEE: I just wanted to know, does it actually go from being outside the line into the line?

DR. MARCH-LEUBA: It is never outside. It is always inside because --

MEMBER BANERJEE: It is always inside? All right.

DR. MARCH-LEUBA: Because we use very, very conservative assumptions for that line. Even for Monticello, it is inside the line.

DR. HUANG: Right. It is a cycle-specific calculation. You can look into that factor of stability in the report. Each cycle they have that. They show the boundary. You have to calculate based on their core design.

DR. MARCH-LEUBA: But if you are interested in evaluating --

MEMBER BANERJEE: But that is a linear calculation, I think.

DR. MARCH-LEUBA: It is a frequency domain linear calculation.

MEMBER BANERJEE: And the linear calculation worked, is reasonably in agreement with a

TRACG or a TRACE calculation?

DR. HUANG: Yes.

MEMBER BANERJEE: Oh, I know, but I am saying, do they agree?

DR. MARCH-LEUBA: They both agree on the benchmark cases. So, we benchmark against real plant stability, and both ODYSSEY and TRACG match the real plant for the five, six, seven cases we have analyzed. So, yes.

MEMBER BANERJEE: But in one case we have a finite amplitude oscillation.

DR. MARCH-LEUBA: Well, what I mean is I would do the comparison in the stable domain where the calculation is less than 1, and you don't have to worry about linear.

MEMBER BANERJEE: But did you try it with the non-linear region?

DR. MARCH-LEUBA: Can we talk off the record?

CHAIR REMPE: Why don't we hold this? And we need to close the Open Session to do the Closed Session for about an hour. And we may have some extra time later, but just to make sure we get through some of the important topics this afternoon, I would like to truncate here for a minute.

So, at this time, we need to go off of the open record, and we need to verify the room to make sure it is secure and all that.

(Whereupon, at 2:02 p.m., the meeting went off the record and went back on the record at 2:04 p.m. in Closed Session.)

(Whereupon, at 2:46 p.m., the meeting resumed in Open Session.)

CHAIR REMPE: Okay. We are going to go back on the record for the Open Session.

And are you in charge, Mark?

MR. SCHIMMEL: I can be.

(Laughter.)

(Pause.)

CHAIR REMPE: Okay. Great.

MR. SCHIMMEL: We are going to turn this part back over to Mr. Hammer here.

Do you want to cover our containment Accident?

MR. HAMMER: Yes. Right.

My name is Steve Hammer again. I'm from NSP, Licensing Project Manager.

The first thing I am going to do, let's go to the next slide here.

One of the things I am going to cover in

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MR. HAMMER: Yes. Right.

My name is Steve Hammer again. I'm from NSP, Licensing Project Manager.

The first thing I am going to do, let's go to the next slide here.

One of the things I am going to cover in brief is a little bit of the background/history on the containment analysis. We did use NRC-approved GE analysis methods. The NRC approval did request a couple of changes on what we have used on methods for containment analysis compared to the past. And that was based on use of passive heat sinks, the variable K value, so the variable capacity of the RHR heat exchanger, and one item that was discussed earlier, the use of a mechanistic heat and mass transfer between the suppression pool service and the suppression pool atmosphere. So, those are changes from what we have used in the past, and the NRC was asked to approve those methods/changes.

The primary analysis codes were, I think, familiar to you, LAMB, M3CPT, and Super HEX. The methodology has been updated from the original license analysis which occurred in the mid-1980s.

And for Monticello, let's go to the next slide. The EPU effects on the suppression pool temperature, we assume analysis or service water temperature for the heat sink of 90 degrees Fahrenheit, which is a pretty conservative number for the Mississippi River, where we happen to live.

MEMBER SKILLMAN: What do you mean "pretty conservative," Steve?

MR. HAMMER: The highest the river has ever gotten based on our records in Monticello was 86.5 degrees, I believe, on that order. So, we are not really challenged by that 90-degree limit. It has been a pretty good value.

The variable K value that we discussed --

MEMBER SKILLMAN: Excuse me. What is your ultimate heat sink license temperature?

MR. HAMMER: Ninety.

MEMBER SKILLMAN: Ninety? Okay. Thank you.

MR. HAMMER: Okay. The variable K value is allowed to vary based on the inlet temperature, which is on the suppression pool side of the heat exchanger. So, we have allowed it to vary over a range of 110 degrees to 195 degrees. The base value for K is 147 BTUs per second degrees Fahrenheit. If we allow it to vary, it does vary by about 3.5 percent over that temperature range.

If you have a constant K value, the maximum temperature in the suppression pool is 270 degrees Fahrenheit, and that is what we have used as our design basis or license basis value in the EPU analysis.

MEMBER CORRADINI: And that is regardless of what got you there? That is what you are starting with as your max temperature?

MR. HAMMER: Well, you mean for containment accident pressure?

MEMBER CORRADINI: Yes.

MR. HAMMER: Well, I will talk through that a little bit.

MEMBER CORRADINI: Okay.

MR. HAMMER: What we did is we actually looked at the entire time history from time zero out through the peak of the suppression pool temperature, and we didn't go very much past the peak, you know.

The EPU dynamic loads were also looked at. The Mark I long-term program method was verified, that the original assumptions that were used in the Mark I long-term program remain conservative. And so, those weren't really impacted or changed.

EPU containment isolation was looked at, which becomes one of the early impacts potentially on containment accident pressure. We did verify that all the isolation valves would work as expected. The assessment of multiple spurious operation did address or did result in changes to the purge and vent valve system design, drywell spray valves, and main steamline drain valves, to eliminate potential spurious operations for Appendix R fires for those particular sets of valves. And there were other MSOs that were analyzed as part of the CAP response, and we can go over some of those.

Okay. Next slide.

Some of this you have seen before, so I am not going to go over this too much. This is just a review of what the peak values were for some of the containment response.

From a net positive suction head standpoint, Monticello has always credited containment accident pressure for ECCS pump NPSH. Unfortunately, what we ended up with in the mid-1990s, when the NRC inspected us on their approval of the use of containment accident pressure, we couldn't show that it had ever been reviewed on the docket. So, we did make a license amendment, and it was formally approved for DBA LOCA with License Amendment No. 98 in July 25th of 1997.

MEMBER CORRADINI: I didn't understand what you just said.

MR. HAMMER: We have always in our analysis, all of the calcs for NPSH, we have always credited the CAP. The original GE approach is we took half of the containment pressure above the atmospheric and assumed that that was available for ECCS pump NPSH.

MEMBER CORRADINI: So, half of 60?

MR. HAMMER: No, half of, say, for whatever point in the time history you're at. So, the typical, the peak response for the suppression pool is --

MEMBER CORRADINI: Oh, oh, oh.

MR. HAMMER: -- 32 psi. So, we would allow 16 psi for ECCS pump NPSH. Now what happened --

MEMBER CORRADINI: That was just the analysis method?

MR. HAMMER: Yes, that was the analysis from day one type of stuff, early days.

Now what we did is, with the approval of CAP in 1997, I think we were the second plant that got drug through that wringer, and we have used that same method now up to today. Now the SECY-11-0014 requirements have augmented those requirements. And we will go through that.

The containment analysis was revised in 2004 under Amendment No. 139, where we again re-evaluated the containment response. And the change in 2004 was that we also included Appendix R as requiring a CAP credit and, in addition, the DBA LOCA.

So, as of today, for CLTP, we only are required for CAP analysis for DBA LOCA and Appendix R. The other events haven't --

MR. HASKELL: Well, you need them for both? Not just Appendix R, but also for the DBA LOCA?

MR. HAMMER: Yes. Yes. So, we are crediting CAP for those to events at this point in time.

The original EPU NPSH evaluation, we credited the use of CAP; we credited passive heat sinks, as discussed; thermal equilibrium suppression pool, as discussed. We evaluated all of the events that are potentially impacted by CAP. So, for the EPU analysis --

MEMBER BANERJEE: Credited passive heat sinks? What do you mean by that?

MR. HAMMER: Well --

MEMBER BANERJEE: It tends to reduce the pressure, right, which is what you don't what?

MR. HAMMER: What you end up with, yes. For NPSH, though, it does tend to reduce the pressure.

MEMBER BANERJEE: Yes, it does. So, that goes the opposite. How do you credit passive --

MR. HAMMER: Well, that is a conservative approach. What you end up -- and we will talk through some of that. But what you are doing is you are, by reducing the pressure in containment, you have less NPSH available theoretically for your pumps, right?

MEMBER BANERJEE: So, when you credit passive -- don't you use passive heat sinks for your --

MR. HAMMER: Oh, yes. Yes, that is what we are doing. We are using passive heat sinks for this analysis, right. But that was a change from our previous analysis. That is what we are talking about.

MEMBER BANERJEE: But it is there. I mean, what is the point of crediting it?

CONSULTANT SMITH: Why do you consider it a credit?

MEMBER BANERJEE: Yes.

MR. HAMMER: It wasn't in the previous analysis.

Go ahead.

MR. LI: It is Guhngjun Li from GEH.

Another two aspects by crediting heat sinks. Actually, heat sink can reduce your pool temperature and, also, can reduce your pressure. The pool temperature is more important since it increases the temperature, the pressure. So, there are two aspects. One part is temperature; one part is pressure. So, temperature is more important than pressure. So, that is why when you use the heat sinks, basically, we call it credit.

MEMBER BANERJEE: Well, I would have thought that -- I mean, maybe it is going against, the opposite to what I would think. Because what concerns you here is the minimum pressure that is available.

MEMBER SHACK: But your NPSH is so dependent on the pool temperature that, if you lower the pool temperature --

MEMBER CORRADINI: That dominates.

MEMBER SHACK: -- that dominates.

MR. HAMMER: That's right.

MEMBER BANERJEE: Well, which is, of course, what you want to -- a more conservative calculation would be one which gives you the maximum pool temperature --

MR. HAMMER: Right.

MEMBER SHACK: But it is a credit.

MEMBER CORRADINI: They are being consistent in the application of it. If they add heat sinks, it lowers the pressure in the wetwell, but simultaneously it also decreases the pool temperature, which gets you a lower vapor pressure and gives you more margin. Think of it this way: the delta is getting bigger, even though the top is going down.

MEMBER BANERJEE: I would have thought what was important is if you did not credit the heat sinks, you end up with the maximum pool temperature --

MEMBER CORRADINI: Correct.

MEMBER BANERJEE: -- which is the worse situation.

MR. HAMMER: Right.

MEMBER BANERJEE: So, why is it credited?

MEMBER CORRADINI: Because he doesn't want to take the worse situation.

MEMBER SHACK: They are following the SECY.

MEMBER BANERJEE: I wouldn't credit it.

MEMBER SHACK: They are just following the SECY.

MEMBER BANERJEE: No, no, I'm just saying I wouldn't --

MEMBER SHACK: He is doing it conservative, but not the most conservative calculation he can do.

MEMBER BANERJEE: All I'm saying is I wouldn't call it a credit.

MR. HAMMER: It is in the terminology that you are trying to understand.

MEMBER BANERJEE: That's all, yes. Trying to understand why you call it a credit.

MR. HAMMER: We are making use of it.

(Laughter.)

MEMBER BANERJEE: Yes, you are making use of it for your own benefit, correct.

(Laughter.)

MR. HAMMER: There is a slide a little bit later that will show you some of this. But, you know, GE has a -- for containment analysis, they do a deterministic analysis to define the maximum pressure response, and they use a different set of assumptions that defines the minimum pressure response and PSH response. And there is quite a difference between those two analyses, and this is just a factor.

MEMBER BANERJEE: So, whatever affects your NPSH in a way which makes the situation worse for you --

MR. HAMMER: Yes.

MEMBER BANERJEE: -- is going to be a debit; it is not going to be a credit.

MR. HAMMER: Yes, and the GE deterministic analysis provides all the debits at once.

(Laughter.)

Okay. For EPU, we did look at all the

events. So, as I pointed out, our current licensing basis is DBA LOCA and Appendix R. Now we have also analyzed station blackout, ATWS, and small-break accidents.

MEMBER BROWN: Let me make sure I understand. Before the EPU, it was just DBA LOCA and the Appendix R, but based on the 2004 --

MR. HAMMER: Yes.

MEMBER BROWN: -- extension or amendment?

MR. HAMMER: Amendment.

MEMBER BROWN: So, now the EPU now has decided we are going to use this to our benefit for every DBE, is that correct?

MR. HAMMER: Well, I don't know if I would say to our benefit, but --

MEMBER BROWN: Well, that's what your words said in your piece of paper that you submitted with this. You said it is now going to be used for all design basis.

MR. HAMMER: Yes, the SECY requirement or guidance requires you to analyze all events to make sure that you --

MEMBER BROWN: Well, I know, but you don't have to take credit for it for all events. You're just doing that.

MR. HAMMER: Yes, we are doing the evaluation, yes.

MEMBER SHACK: But the more scenarios he looks at, the worse it is for him because he might find one that doesn't work.

MR. HAMMER: Right. The limiting events --

MEMBER BROWN: I understand that, but if you have pumps that don't require it, then it doesn't matter anyway if all you need is atmospheric pressure. You haven't answered. There was nothing in your paper about evaluating plant modifications at all.

MEMBER CORRADINI: SECY doesn't require it.

MR. HAMMER: SECY doesn't require it.

MEMBER BROWN: I understand. I just --

MR. HAMMER: We can talk about that. I am prepared to talk about that, if you want to talk about it.

MEMBER BROWN: Good.

MEMBER CORRADINI: Well, actually, maybe this is the point to talk about it because, unless you do, you are going to still get these questions.

MR. HAMMER: Monticello is a little different than some other plants out there. And the largest difference between Monticello and other sister plants is that a lot of the other plants have one RHR heat exchanger per RHR pump, and Monticello has one RHR heat exchanger per RHR division.

In addition --

MEMBER BROWN: How many pumps per division?

MR. HAMMER: We have two RHR pumps and one core spray pump per division.

MEMBER BROWN: And how many divisions? I don't know. That's why I'm asking.

MR. HAMMER: Two divisions. Two divisions. So, there are two divisions. So, we have one diesel that supplies each division. And in order to get into the containment cooling mode with the loss of offsite power, what we would do is, initially, when you reflood the core, you start up a core spray in both RHR pumps and you reflood the core.

MEMBER BROWN: For both trains?

MR. HAMMER: For both trains. And for us, the limiting single failure for like containment response is typically a diesel failure because, then, you get down to just three pumps off of one diesel. Each diesel can supply three pumps.

MEMBER BROWN: Even though there's only

two per train?

MR. HAMMER: No, there's two RHR --

MEMBER BROWN: And core spray. I'm sorry. I got it.

MR. HAMMER: And so, what you end up with, then, is, after you reflood the core, which happens at about 250 seconds or so, then you can transition into the definition of long-term core cooling or you can start transitioning your pumps into containment cooling and the lower flow rate you would use for long-term core cooling at Monticello. And for that, what we credit is one core spray pump operating to cool the core.

So, what would happen, then, is at that point in time we would take one RHR pump out of service. We would transition one RHR pump into a containment cooling mode, and there's three equivalent modes for Monticello. You could have LPCI injection cooling. You could have drywell spray and containment spray or you could have suppression pool cooling.

Now, in order to provide the flow path, you have to have an RHR service water pump, right. But, again, because we have only one diesel that can do three pumps, when you drop that one RHR pump, that allows you to start one RHR service water pump. So, from a containment cooling standpoint, our limiting scenario is one diesel supplying three pumps, one of which is core spray, one of which is RHR, and one is an RHR service water pump. So, that gives you a fairly-limited complement of equipment.

MEMBER BANERJEE: And there is no suppression pool cooling?

MR. HAMMER: Well, suppression pool cooling is a mode that is possible. But, for Monticello, what happens is, for example, the EOPs require you to spray the drywell or spray the containment to mitigate Mark I loads if you have more than 12 psi in the drywell.

And so, what typically happens for all of these events, we typically do hit 12 psi for just about all of these events. So, the normal mode that GE used for cooling containment was drywell spray. But the other options do exist if you don't have that high pressure or if you have a more nominal assumption of conditions there.

So, the problem that you have got, there was an analysis that was done. There is NEDC-33347P. It was a BWR Owners' Group effort that looked at containment accident pressure concerns. And Monticello was the plant that was evaluated there.

And in Appendix B of that document, there was a study that was done to look at what it would take to eliminate containment accident pressure at Monticello. And what it boils down to is for us to be able to say under a DBA LOCA condition that we don't need any credit for containment accident pressure. You have to have no single failures. You have to have no loss of offsite power. You have to have all of your pumps running.

MEMBER BANERJEE: All of them?

MR. HAMMER: All of them, all RHR pumps, all RHR service water --

MEMBER BROWN: From both trains?

MR. HAMMER: From both trains. And I can't meet the 21-percent uncertainty requirement for the SECY guidelines. So, I can meet NPSHr3, not NPSHr3 effective, and

MEMBER CORRADINI: Effective meaning the uncertainty --

MR. HAMMER: Meaning the uncertainty.

MEMBER CORRADINI: And so, one plus the uncertainty?

MR. HAMMER: Yes, one plus the uncertainty.

MEMBER SHACK: But, even then, you had

about four minutes that you couldn't --

MR. HAMMER: Yes. Yes, even there, we were short a little bit upfront, yes. And we will talk about that first 10 minutes where we are short.

So, the problem that you have got, basically, is, as I mentioned, our base RHR heat exchanger capacity that we assume in this analysis is this 147 BTUs per second degree Fahrenheit. In order for us to eliminate the need for containment accident pressure, we basically need about 350 BTUs per second degree Fahrenheit capacity.

MEMBER CORRADINI: Versus the 147?

MR. HAMMER: Versus the 147.

MEMBER CORRADINI: So, you would need twice as big of a steam --

MR. HAMMER: More than twice, two and a half.

And what you end up with is, you know, we would have to have at least two more heat exchangers. You would have to have at least one more diesel. You know, there's a bunch of things that you would get into that just immediately make it a very cost-prohibitive thing for us to do. So, that is the story.

MEMBER BANERJEE: What would happen if,

instead of just three pumps running, you also had the suppression pool cooling pump running?

MR. HAMMER: Well, RHR is the suppression pool cooling pump. So, RHR in the containment cooling mode --

MEMBER BROWN: It is just the alignment.

MR. HAMMER: Yes. And what you have got is we have a study where GE has looked at the equivalency of the suppression pool cooling versus drywell spray or versus LPCI injection cooling, and they are essentially identical. You get the same amount of BTUs removed from containment with any of those modes. So, it doesn't really make a whole lot of difference what mode you are in. The use of drywell spray is fairly equivalent to the use of suppression pool cooling.

MEMBER BANERJEE: But you would actually leave the other train running?

MR. HAMMER: Well, the one positive way to look at it, in a realistic sense your chances are you are not going to have a loss of offsite power. Chances are a lot of that equipment is going to be available.

Now the other thing that you should keep in mind is the 90-degree Fahrenheit heat sink temperature is a pretty conservative assumption. You know, in Minnesota we end up having about two-thirds of the year where we are well below that value.

MEMBER SKILLMAN: And if you run your analyses with that more realistic temperature for two-thirds of the year, where do you end up in this analysis?

MR. HAMMER: Well, we didn't run that exact value, but I do have a slide that shows some of that data. So, a little bit later I will show you some of the impacts of some that.

MR. SCHIMMEL: He is talking about running the pumps -- you need to clarify that, because you asked, would you still run the train?

MR. HAMMER: Oh, would you still run the other train?

MR. SCHIMMEL: Yes. I don't think he answered that, right?

MR. HAMMER: Well, the operators could run the other train. I guess what we end up doing is, from a design-basis analysis standpoint, from a containment failure standpoint, the limiting containment failure, containment response failure is a diesel generator failure. So, we typically only analyze one. But, yes, realistically, the operators could run the other train and probably would run the other train.

MEMBER BANERJEE: And then, what would happen?

MR. HAMMER: Well, you are still going to need containment accident pressure. You are not going to be able to limit --

MEMBER BANERJEE: Much less.

MR. HAMMER: Much less, yes.

MEMBER BROWN: Well, yes, I think what you said, if I understood you, you said, even if you ran both trains --

MR. HAMMER: Uh-hum.

MEMBER BROWN: -- and all three pumps in both trains, and you had something else thrown in there also, that even then you still needed some credit for --

MR. HAMMER: Well, the thing to keep in mind, you know, one heat exchanger is about 150 BTUs per second.

MEMBER BROWN: Yes.

MR. HAMMER: So, two would be about 300. We need about 350 to eliminate CAP.

MEMBER BROWN: Oh, so they needed --

MR. HAMMER: So, we would be very close.

MEMBER BROWN: They still don't quite meet it, even with everything running?

MEMBER BANERJEE: But it could be very well within the conservatisms and uncertainties.

MR. HAMMER: Uh-hum.

MEMBER BANERJEE: But, in any case, we can visit that later.

MR. HAMMER: Sure.

MEMBER BANERJEE: But I think you have answered my question.

MR. HAMMER: Yes.

Okay. Now what happened, the last point here is the 2004 analysis was superseded under EPU by the requirements of SECY-11-0014.

So, next slide. Here we go. Oh, wait, maybe I was -- go back. I'm sorry.

The NRC Commission selected the use of Option 1 of SECY-11-0014, and that is the point where we started the reviews of the EPUs based on the NRC's revised guidance. So, we discussed earlier that our license amendment was put on hold for a fairly-long period of time.

And once that guidance was resolved, we again restarted the reviews and started working on the resolution of CAP. The guidance that we primarily followed was Enclosure 1, guidance on use of SECY-11-0014; Enclosure 1, guidance on use of CAP, and Section 6.6 of that enclosure provides the details on each of the requirements.

The NSPM did develop a response, and that was submitted to the NRC.

What we are going to go through real briefly here is each of the sections. There are about 10 sections that we had to meet.

Section 6.6.1 is NPSHr effective. One of the things that Monticello did, for example, the earlier analysis of NPSH at Monticello did not always consistently use NPSH 3-percent curves to define NPSH requirements. There were a few situations where we used NPSHr 1-percent curves for various portions of the analysis or various things. So, the SECY guidance does require a consistent use of NPSHr 3-percent curves.

It also requires in this Section 6.1 that, for design-basis accidents, you need to consider a number of different uncertainty values. And what we did in Section 6.6.1 is we verified that the appropriate amount of certainty for Monticello was 21 percent. And that's what we did in our analysis, and that's what was --

MEMBER BANERJEE: The 3-percent curve came from what, the manufacturer or --

MR. HAMMER: Yes, the 3-percent curves are provided by Sulzer in this case.

MEMBER BANERJEE: Okay. But Sulzer did that for the Owners' Group, or what was it? It was a generic thing, wasn't it?

MR. HAMMER: There's a couple of aspects there. For Monticello, our specific pump curves are from Sulzer reports from pump testing for RHR and core spray pumps. So, that was done quite a while before this effort.

As part of the uncertainty effort, that justification of why 21 percent is a good number, Sulzer was involved with the BWR Owners' Group on a very lengthy study to try to determine the requirements for the uncertainty requirements. So, it included looking at original instrument uncertainty for the original tests, piping geometry, dissolved gas. There were a number of different aspects. Impeller life. And Sulzer was involved with all of those things, in addition to a number of different people, some of which are here, that participated as part of the BWR Owners' Group.

MEMBER BANERJEE: So, your main thing was dissolved gas?

MR. HAMMER: No. No.

MEMBER BANERJEE: It is not vortexing or anything like that?

MR. HAMMER: Vortexing is not an issue because of the design of the suction strainers and level.

MEMBER BANERJEE: Yes.

MR. HAMMER: You know, dissolved gas has a potential impact on the uncertainty, and that is one of the factors that goes in here. Piping geometry ended up being a fairly-substantial factor. You know, in an ideal world, you would have straight pipe going right in your suction.

MEMBER BANERJEE: Well, just behind a band or something?

MR. HAMMER: Yes, we have got two short radius elbows.

MR. SCHIMMEL: We can take an action to make the call and find out a little more about the percentage, if you would like to know more about it.

MEMBER BANERJEE: Yes, I think it would be interesting to see how that got constituted.

MR. HAMMER: We can pull that together.

MEMBER BANERJEE: Okay.

MR. HAMMER: And then, one clarifying point, for the non-DBA events, the use of the standard NPSHr 3-percent curve was what was used. So, we didn't have any uncertainties for the non-DBA events.

MEMBER BROWN: So, an electrical guy like me -- and I went through this drill on the 3 percent and the 1 percent once before -- I mean, the 3 percent is just 3 percent, whatever the NPSH you need for the pump to operate, to meet its rated flow, is that just 3 percent of that NPSH added onto it to say that's what you really need? And then, the 21 percent uncertainty is another set of factors that are applied on top of that?

MR. HAMMER: Well, for Monticello, for example, an RHR pump operating at the 4,000 gpm that we normally assume for containment cooling requires the NPSHr 3-percent curve, requires I think it is 21.5 feet of head.

MEMBER BROWN: Without the 3 percent, what would it be, if it was just --

MR. HAMMER: Well, let me give you a definition of the 3 percent.

MEMBER BROWN: That's what I am looking for.

MR. HAMMER: What happens is, when they do pump testing, what they will do is they will reduce the suction pressure on the suction of the pump until the discharge head falls by 3 percent. And whatever that head is, that is the 3-percent curve.

MEMBER BROWN: I've got it.

MR. HAMMER: And so, they do that for all the different flow rates that the pump could operate at. So, the 3-percent curve is just the suction pressure that is required to give you that 3-percent head reduction on the discharge of the pump.

Now what they will typically do is they provide a family of curves. So, we have got for our pumps, we have 1-percent curves; we have 3-percent curves; we have 5-percent curves. And those are all situations where the pump can provide stable flow at those amounts of discharge head reduction with slight variations in suction pressure. So, a 1-percent curve is slightly more suction pressure than a 3-percent curve.

MR. SCHIMMEL: That is the answer to his question. His question was, what was the basis of the 3 percent. It is not 3 percent in net positive suction. It is a 3-percent drop in discharge --

MR. HAMMER: Yes, yes.

MR. SCHIMMEL: -- as it equates. And

based on that, that is where they stake the assumption at.

MEMBER BANERJEE: No, my question was --

MR. HAMMER: You want to know what the different uncertainties are?

MEMBER BANERJEE: Yes.

MR. HAMMER: Yes, we can provide that.

Okay. The maximum pump flow rate for NPSHa analysis, the requirement of Section 6.6.2 is just to have a flow rate chosen for the NPSHa analysis that is greater than or equal to the flow rate assumed in the safety analysis. So, for example, if you are assuming 4,000 gpm for containment cooling, we assume 4,000 gpm or higher for the NPSHa analysis, and we did that. The same thing for the ECCS analysis. It would seem to be pretty common sense.

But Section 6.6.3, conservative containment accident pressure for calculating NPSHa. What we did here is we used the GE Super HEX deterministic analysis, and that bounds the 95/95 lower tolerance limit for calculation of CAP to determine NPSHa. And I have a curve that shows that.

MEMBER CORRADINI: So, can I say that back to you, so I get it? What I interpret you are satisfying that 6.6.3 was is you took what you might say is a more conservative analysis that bounds the 95/95 versus computing the 95/95?

MR. HAMMER: We actually do have a 95/95 analysis.

MEMBER CORRADINI: But you didn't use Super HEX or SHEX?

MR. HAMMER: Well, the 95/95 analysis did use Super HEX also.

MEMBER CORRADINI: Oh, it did?

MR. HAMMER: Yes.

MEMBER CORRADINI: Oh, I thought you used the other things on your --

MR. HAMMER: Well, I will get into that.

MEMBER CORRADINI: Get into that.

MR. HAMMER: Yes.

MEMBER CORRADINI: Okay. I'm sorry. Excuse me.

MEMBER BANERJEE: You are going to expand on each of these as we go?

MR. HAMMER: As much as you guys want.

MEMBER BANERJEE: Okay.

MEMBER CORRADINI: They want us happy.

MR. HAMMER: Section 6.6.4 is assurance that containment integrity is not compromised. So, that is the multiple spurious operation thing that we talked about, and that primarily is aimed at the Appendix R event. However, you know, as I mentioned, we didn't review our containment isolation capability and verify that all the containment isolation valves are going to work as expected.

So, the typical analysis assumes for DBA LOCA a standard as the assumed containment leakage of 1L sub a. And what we did for the Appendix R event is, with the remaining pass that could still spuriously operate, we assumed the four limiting events could happen simultaneously, and we verified we could still meet our ECCS pump and PSH requirements with those failures.

MEMBER SHACK: You just didn't look at any scenarios that would require containment venting?

MR. HAMMER: Well, we haven't looked at containment venting at this point in time, no. The thing, remember, at Monticello is we don't have a design-basis accident that requires us to vent containment. And we are little bit unique compared to a lot of other people in that, for example, as was discussed, the EOPs can get you into venting containment, but Monticello does have a specific licensing action with the NRC where we asked for an exemption from that EOP requirement.

MEMBER SHACK: Say that again?

MR. HAMMER: We have a licensing action with the NRC where we asked for an exemption. So, we don't have to flood containment immediately if we can't raise water level above two-thirds core height, for example. You know, I think your standard EOPs would get you into trying to promptly flood containment.

Now what we have done is we have allowed, with the exemption that we've got, we have a certain amount of time to allow us to evaluate accident conditions and potential impact on offsite dose. Recognize that we do have adequate core cooling with the definition of adequate core cooling we have got, and we have some latitude as to when we would start flooding containment.

MEMBER BANERJEE: Well, there is no possibility of the seals to containment penetrations failing due to fires and things?

MR. HAMMER: I don't know if I can answer that question off the top of my head.

MR. SCHIMMEL: They are all qualified penetrations, right? They are tested.

MEMBER BANERJEE: Yes, you know, because in this Committee, that concern has been raised in different guises.

MR. HAMMER: In my mind, it would seem that you would have to, for example, have a valve where you burned the packing under the valve, and the valve seat was on that. I don't know that I can answer that off the top of my head.

MEMBER BANERJEE: Well, we will keep that in abeyance right now.

MR. HAMMER: Yes, 6.6.5, operator actions. We don't have any changes to operator actions to address and PSH concerns right now. We are using the same procedures that we use right now for mitigating these events in order to meet the NPSH requirements.

Section 6.6.6, NPSHa less than NPSHr or NPSHr effective. What this requires is that, if you do have a situation where you are negative on NPSH available compared to your requirements, that you need to have a test to verify that your pumps are going to remain reliable.

And what we used in this case is we used both a combination of the original testing done on our pumps plus a lot of testing that was done on other industry pumps to show that just the standard NPSH tests that are done to define the NPSHr curves typically get you down to values more challenging than what we expect to see in our particular event for durations that are at least four minutes or longer, and the pumps remain reliable. So, that is our way of addressing that.

Section 6.6.7, assurance of no preexisting leak. The issue here is that we need to determine what is the size of the leak that would result in a loss of containment accident pressure. So, we did an analysis there based on the use of GOTHIC. The leak size that would be required for us to lose containment accident pressure is on the order of 30 times L sub a. As I mentioned, you know, you have a tech spec requirement, and containment operability is based on 1L sub a.

We did develop an online leakage test that allows us to monitor for gross leakage of containment. And right now, we have we have a commitment that, if we haves leakage of about two-thirds of that limit, about 20 L sub a, that we would enter 303.

MEMBER SKILLMAN: Steve, could you explain to us what that procedure is or what the approach is for that quick determination of L sub a?

MR. HAMMER: Yes. The general approach that we have got, we do have a containment air monitoring system. Normally, the only leakage that goes into containment is the small amount of leakage that you would get from leakage from the nitrogen air supply to the drywell. So, you have got air being supplied to the SRVs and/or nitrogen being supplied to the SRVs and MSIVs, a number of components like that inside the drywell. And there is a small amount of leakage that does go into containment.

Historically, at Monticello, what we have done is we used the containment air monitor to monitor drywell nitrogen and oxygen concentration. And we can route the return from that system to either the reactor building plenum or the vent from the reactor building and run it to atmosphere or we can recycle it back to containment itself, and then, you will have a closed LOOP.

Now, historically, what has happened is we typically, if everything is tight, you know, we don't really run it to the plenum much. We typically recirculate it back to the containment.

And what we have done for this test, then, is what we are doing is we have a makeup meter on a supply to the drywell, and we have the known capacity of this drywell cam, and we have a ComputerPoint that calculates the non-condensable gas mass inside containment.

And so, if we set it up with a known air or nitrogen input, and we have this thing lined up so it is recirculating back to containment, not venting to the atmosphere, we can essentially watch this containment, the drywell non-condensable gas mass ComputerPoint, and you can predict over a period of time what your leakage rate is from containment based on that.

And it has been pretty reliable. We don't have a lot of operating experience with it. It is done based on using a number of instruments that don't have the accuracy to do this particular thing, but they are repeatable and we seem to be able to measure leakages down to a fraction of once a day, about .4 or .5, fairly routinely.

MEMBER SKILLMAN: Would you feel confident if the temperature was changing significantly inside containment?

MR. HAMMER: Well, the ComputerPoint that we use is temperature-compensated. So, some of the inputs -- we have about -- there's a number; I can't give you the exact number, but we have a number of thermocouples inside the drywell, for example, that monitor/provide a weighted average of the temperature inside the drywell.

MR. SCHIMMEL: Isn't there a table, also?

MR. HAMMER: Excuse me?

MR. SCHIMMEL: Isn't there a procedure with a table in it?

MR. HAMMER: Yes.

MR. SCHIMMEL: That has temperatures and the compensation?

MR. HAMMER: Yes. And the ComputerPoint takes credit for that drywell-weighted average temperature. And the ComputerPoint has been very good. We have been using that ComputerPoint since the rerate work back in 1998. And that ComputerPoint, for example, also, it calculates the amount of non-condensable gas that was assumed in the original NPSH analysis to make the ECCS pumps operable. So, if we fall below that non-condensable gas mass, since 1998, it would require us to shut the plant down.

MEMBER SKILLMAN: Okay. Thank you.

MEMBER SCHULTZ: What are the tech spec requirements associated with the availability of this leakage test?

MR. HAMMER: Well, right now, it is not in tech specs. And what we are proposing to do is put it in the Technical Requirements Manual, I believe, for performance.

MEMBER SCHULTZ: Okay. What has the experience been in terms of its availability?

MR. HAMMER: Well, it is an existing surveillance test. Right now, you know, it is available and we can run at any point in time. We are not crediting it at this point in time yet, until this licensing action is complete.

MEMBER SCHULTZ: I'm confused. It's an online leakage test, but it is something that you start up to implement and it takes some time to do that measurement?

MR. HAMMER: Yes. I don't remember the exact timeframe. We can get you that. But what you end up with is -- you typically wait a few days after you start it up because containment does change.

MEMBER SCHULTZ: Yes.

MR. HAMMER: It takes a while for it to reach equilibrium. But, after it has reached equilibrium, then we can run this test. And I think the test is -- I don't know. Do you remember? Eight hours? Sixteen hours? I can't remember the exact time period, but it can be done over a fairly-short period of time.

MEMBER SCHULTZ: Okay. And I missed, if you mentioned, I missed it. How frequently do you run it now?

MR. HAMMER: Well, we don't have a periodicity. That is what I say; right now, it is not in the schedule at this point in time because we are --

MR. SCHIMMEL: We are changing the monitor.

MEMBER SCHULTZ: So, it is something that has been developed --

MR. HAMMER: Right.

MEMBER SCHULTZ: -- and evaluated, but not implemented?

MR. HAMMER: It hasn't been implemented yet at this point in time.

MR. BJORSETH: Can I say something here, Steve, too?

John Bjorseth.

We figured that the most risk is coming out of refuel outage, when you have done all the work on containment. You want to start out knowing that you don't have a known leak somewhere. So, you do this test as an additional measure, even beyond an ILRT, as a part of your program, the ILRT program? They also make calculation --

MR. HAMMER: No. No, it's not. It

doesn't have the precision. You wouldn't want to use this test to verify the tech spec 1L sub a leakage rate.

MR. BJORSETH: This is more of a gross measure to make sure that from a CAP standpoint we are not challenging that at all.

MR. HAMMER: Yes, that we don't have, for example, a mispositioned valve on startup that we haven't found, that kind of thing.

MR. BJORSETH: Right.

MEMBER CORRADINI: So, can I go to the third bullet? So, if you are two-thirds of the limit, so if you are measuring 20L sub a, then what do you do?

MR. HAMMER: Well, what we would do, then, is we are going to enter Tech Spec 303 and that would require as shutdown.

MEMBER CORRADINI: Oh, okay.

MR. HAMMER: Any other questions here?

CHAIR REMPE: Did you say you were going to put this leakage monitor in a tech spec change? And is that part of the submittal right now?

MR. HAMMER: Yes, it is part of our submittal.

CHAIR REMPE: Because I am looking at the tech spec changes that the staff has.

MR. HAMMER: Oh, it is not a tech spec. We were going to do it in the Technical Requirements Manual.

CHAIR REMPE: Okay.

MEMBER BANERJEE: So, I don't know in detail the SECY, or whatever, but it would seem that prudence would dictate that assurance of no preexisting leak is one thing, but the second is that a leak would not occur during the accident. Is there some assessment needed of that? I mean, imagine that has Appendix R fire. You know, to me, that seems like a more realistic scenario, and some assessment needs to be done of that.

MR. BJORSETH: And that is why we did the four evaluations that were discussed earlier.

John Bjorseth again.

But, if I remember right, one of them is a fire would occur and main steamline drains would open and open up essentially containment. That is that type of situation --

MEMBER BANERJEE: Right.

MR. BJORSETH: -- that is more plausible that you are looking for.

MEMBER BANERJEE: Yes.

MR. BJORSETH: So, that is why we put it for that scenario, so that that event could not occur. We defeated that potential.

MEMBER BANERJEE: Okay. That certainly is in the right direction, yes.

MR. HAMMER: For example, we evaluated the four limiting spurious operations that could occur, and they assumed that they occurred at the same time. Now what we did is we did some sensitivity work to define what those four things were. So, we did, I think, 13 different scenarios. But it was things like failure of the drywell sump valves to open. It was a number of different things where our assessment showed that these flow paths potentially could fail open under an Appendix R fire.

MEMBER BANERJEE: Could you just give me the section that you discuss this, so I could quickly look at it?

MR. HAMMER: Yes, we can look that up.

MEMBER BANERJEE: Yes, just give it to me.

MR. HAMMER: Yes.

Okay, 6.6.8, one of the things, there is a zone called the maximum erosion zone. It is actually a suction pressure that is above the NPSH required value. So, an NPSHr 3-percent for

Monticello's RHR pump might be at 21.5 feet, and the maximum erosion zone would be a slightly-higher pressure than that. It might be 24 feet or something like that.

So, to evaluate the reliability of pump operation for the required mission time, we looked at the pump operating at that maximum worst-case erosion point continuously for an extended period of time. And at Monticello, that showed that we expected a pump life of 6,200 days if we operated continuously at that point. And that was really a factor of safety of at least two above the real impeller life, because Sulzer assumed a factor of safety of two over the minimum impeller vein thickness that they would normally use for that analysis.

Section 6.6.9 is an estimate of NPSH margin. We have got some slides here, 93 to 96, that will show that. We did that by a comparison of Super HEX, GOTHIC, and Monte Carlo work. And we can go through that in a second here.

MEMBER RAY: Can I ask a question at that point? To what extent does the margin consider underestimate as opposed to -- in other words, that you predicted pressure would be higher than actual, for reasons not considered in the analysis? Is that part of the --

MR. HAMMER: That the pressure would be higher than that?

MEMBER RAY: No, that the pressure would be lower than what you calculated it to be, for reasons that are associated with the analysis, as opposed to leakage, for example? But you don't have a leak, but you just overestimated the pressure in --

MR. HAMMER: The pressure?

MEMBER RAY: Yes.

MR. HAMMER: Well, the GE Super HEX analysis, the deterministic analysis, is biased to try to drive pressure as low as possible. And it is an approved methodology. That is the license basis that Monticello has had since 1998 or actually 1997, whenever it was, 1996.

MEMBER RAY: So, it is biased --

MR. HAMMER: It is biased low, and you will see that when we do the slides here.

Section 6.6.10 was assurance of pump operability for the total time required. Here what we did is our required mission time is 30 days, and we did the analysis to verify that the pumps would remain operable in that time period.

This curve shows NPH margin.

And I am going to stand up here a little bit.

The bottom curve here is actually the GE --

MEMBER SHACK: It is probably better if you do that with the mouse at a microphone. She can't here you, I don't think, up there (referring to the recorder).

MR. HAMMER: Oh, okay. Well, I'll tell you what. I will let John drive.

Okay. The bottom curve is the GE Super HEX analysis, and that is the deterministic analysis that I have talked to you about. It is biased to try to provide the lowest containment pressure that we would expect to see by a simultaneous combination of all the appropriate inputs to try to drive that pressure down as far as you can. And that has been our licensing basis for a number of years.

These curves here are all based on the use of NPSHr effective. So, they include the 21-percent uncertainty value.

MEMBER CORRADINI: Which drives it down further.

MR. HAMMER: That drives it down further, yes.

MEMBER CORRADINI: And then, if you were to apply the black squares for your current power level versus the EPU, where would they be, approximately? Double that? Triple that?

MR. HAMMER: No. The required pressure, right now, the NRC credits us for 6.1 psig of containment pressure at the worst-case point in the containment response for design-basis accidents under CLTP power levels.

MEMBER CORRADINI: So, that is the DBA LOCA?

MR. HAMMER: The DBA LOCA.

Now, if you do the EPU analysis without the 21-percent uncertainty, we can still meet that 6.1.

MEMBER CORRADINI: It is the 21 percent that drives you to --

MR. HAMMER: Yes.

MEMBER CORRADINI: -- a lower number here?

MR. HAMMER: Yes. Once you get to 21, you apply the 21 percent to it, and we require 8.6 psig, I believe.

MEMBER CORRADINI: So, can I say it back to you a different way? And there is a current way in which your CAP credit is allowed. You don't go through this additional 21-percent uncertainty because of geometry, other stuff, and you essentially with the EPU are at the same point you are now?

MR. HAMMER: Well, it does actually --

MEMBER CORRADINI: Without the uncertainty? With the uncertainty, it takes you to -- essentially, it erodes that margin. And you need, instead of 6.-something, 8.-something?

MR. HAMMER: Yes, right.

MEMBER CORRADINI: Okay.

MR. HAMMER: And the NRC-allowed value that we are allowed to credit for containment accident pressure, there is some margin between the actual peak that we would have. So, what we are basically doing is we are using up a little bit of that margin, but we are still able to stay below 6.1.

Does that make sense?

MEMBER CORRADINI: I thought I had it, but at that point you lost me.

MR. HAMMER: Well, see -- and I don't have the exact numbers in front of me --

MEMBER CORRADINI: That's okay. I just wanted to understand the process that you just said.

MR. HAMMER: Yes.

MEMBER CORRADINI: If you could repeat it, please?

MR. HAMMER: Well, for example, the NRC right now approves the use of 6.1 psig. But the actual required value is -- I don't remember what it is -- say 5.9. You know, what we are doing is with EPU we are going to 6.01 psig as required by the analysis, but that still remains below the 6.1. So, we do need a higher value, but we are still within the NRC's approved value for containment accident pressure.

MEMBER CORRADINI: Okay. I thought you had quoted another value higher. I apologize.

MR. HAMMER: We wouldn't need additional credit.

MR. BJORSETH: If we didn't have uncertainty.

MR. HAMMER: If we didn't have, if we didn't have uncertainty.

CHAIR REMPE: Without the 21 percent?

MEMBER CORRADINI: So, I did get that original thing right? Okay. Fine. I'm with you now.

MR. HAMMER: Yes, absolutely.

MEMBER CORRADINI: So, your point is the 6.1, you went in the second significant figure from 5.1-something-or-other to 6.-something-or-other, but still below your CAP?

MR. HAMMER: Yes.

MEMBER CORRADINI: With uncertainty, now you have to get --

MR. HAMMER: I will worry about that.

MEMBER CORRADINI: Okay. Thank you very much.

MR. HAMMER: Okay. To give you some idea of the sensitivity of this to changes in inputs, the diamonds, the second curve up there, that is the Monte Carlo analysis. So, that is a 95/95 or slightly better than 95/95 analysis of containment response that the BWR Owners' Group did a number of years back.

The next curve up there with the diamonds, I guess, that is what we call GOTHIC conservative. So, what we did is we did do a GOTHIC model of containment or, actually, the NRC did a GOTHIC model of containment, and they kindly let us use it to help assess some of this. And that is done using the same inputs as GE uses for their deterministic analysis on the bottom curve.

So, that gives you some comparison between a best-estimate code and what Super HEX, being a conservative code, would provide.

And then, the top curve there is GOTHIC

realistic. And GOTHIC realistic, in this case what we did is we varied the inputs of a few of the key assumptions by a fairly-small amount. What we did is we used values that would be met in Minnesota 98 percent of the time. And so, the key values ended up being river temperature, initial suppression pool temperature, things like that. And we allowed small changes just to show the impact of that. And you can see it does start having a fairly-prompt response.

MEMBER BANERJEE: And that is because of the temperature of the suppression pool primarily?

MR. HAMMER: Yes, it is because of the temperature. The pressure is related to the temperature, you know. So, there is a relationship there.

MEMBER BANERJEE: They can be non-equilibrium --

MR. HAMMER: Yes.

MEMBER BANERJEE: -- between the two.

MR. HAMMER: What happens is, depending on the event, depending on the flow rates that you have got at Monticello, if you can keep suppression pool temperature below about 175 degrees, you don't need CAP. That is kind of a general rule of thumb, but it varies depending -- like if you had a lot of pumps running for an event, and that was an event that runs all the pumps, it is going to need a little bit more, that kind of thing.

MEMBER BANERJEE: So, what is the temperature? Is it 190 or something you get?

MR. HAMMER: Well, as we pointed out earlier, for EPU DBA LOCA, we get to 203 to 207, depending on what you assume for RHR heat exchanger capacity.

MEMBER CORRADINI: The DBA LOCA -- I can't remember which one was limiting, but you had it in your stuff.

MR. HAMMER: Yes.

MEMBER CORRADINI: It was the DBA LOCA that was at 20-something?

MR. HAMMER: 207, yes. So, the NPHS analysis for Monticello is 207 degrees.

MR. BJORSETH: That is what the starting torus temperature, torus water temperature of --

MR. HAMMER: Of 90, yes.

MEMBER BANERJEE: Of 90?

MR. HAMMER: Yes, and that with a 90-degree river temperature, yes.

MR. BJORSETH: So, that last curve, if we assume a 75-degrees starting temperature, which it is almost always below that, then it is much better.

MEMBER SCHULTZ: Okay. So, the realistic river temperature is 75 degrees?

MR. HAMMER: Well, we do have a curve that we could put up that shows how the river temperature varies with time, too. We could provide that.

MEMBER BANERJEE: So, let me ask you a question.

MEMBER SCHULTZ: I would like to see that.

MEMBER BANERJEE: Yes, let's say if you did something equivalent to a best-estimate calculation, taking things into account, and you took your input parameters, which is the river temperature, and so on, and assumed some distribution, and you sampled it. And you arrived at the 95/95. You can do Monte Carlo, if you like. You can do non-parametric, if you like. It doesn't matter how you do it.

MEMBER SHACK: His Monte Carlo is 59 samples.

MR. HAMMER: Yes, it is 59 samples.

MEMBER BANERJEE: It is?

MEMBER SHACK: Yes. When he says Monte Carlo, he means what you mean.

MEMBER BANERJEE: Oh. And is it done in a non-parametric way, then?

MR. HAMMER: Yes.

MEMBER BANERJEE: Okay. So, it is essentially the non-parametric. So, that is the 95/95.

MR. HAMMER: Yes.

MEMBER BANERJEE: Based on best estimate.

MEMBER SHACK: Well, it is based on Super HEX, though, which is a conservative code.

MR. HAMMER: Yes.

MEMBER SHACK: I don't know why -- nobody has done the GOTHIC with a 95/95, for example.

MR. HAMMER: Yes. Right.

MEMBER BANERJEE: That would be more realistic.

MR. HAMMER: Yes, probably.

MEMBER SHACK: Probably.

MEMBER BANERJEE: But we don't know.

MR. HAMMER: We don't know. We haven't run that, no.

MEMBER CORRADINI: But if I could ask Sanjoy's question a little bit differently, I want to repeat the one thing you said that I guess I missed in your writeup, but it seems to me significant.

So, if you were required not to do the uncertainty analysis, but to do the same analysis as you are currently licensed, you go from 5.9 to 6.-and-change.

MR. HAMMER: We can give you those numbers, but --

MEMBER CORRADINI: And you all fit within the CAP. So, it is really the change in methodology that requires more credit than you already have?

MR. HAMMER: That's correct.

MEMBER CORRADINI: I guess I missed that totally.

MR. HAMMER: Well, what we are assuming, basically, is, you know, SECY-11-0014 is the law of the land.

MEMBER CORRADINI: Yes, yes, yes, yes. That's fine.

MR. HAMMER: So, yes, we didn't probably go into a whole lot of detail on that.

MEMBER CORRADINI: That's fine. I just missed that nuance. That is why I was --

MEMBER SHACK: But that change also includes the changes you made in the analysis method, too?

MR. HAMMER: Yes.

MEMBER SHACK: The previous one didn't have the heat sinks?

MR. HAMMER: Yes, that's true.

MEMBER SHACK: The new one does.

MR. HAMMER: That's true.

MEMBER SHACK: So, it is not quite an apple-apple.

MEMBER CORRADINI: It is a Macintosh-to-Red-Delicious.

(Laughter.)

MEMBER SHACK: You have got to just watch where the "P" is all the time.

(Laughter.)

MEMBER BANERJEE: But the GOTHIC, that is a GOTHIC conservative, right?

MR. HAMMER: Well, the GOTHIC conservative is using the same inputs as was used in the NPSH deterministic or the bottom curve.

MEMBER CORRADINI: But it is just a different set of --

MR. HAMMER: It is a different code.

MEMBER CORRADINI: Supposedly, more realistic? But they still don't get rid of CAP. They just change the value.

MR. HAMMER: Yes, we just change the value. We reduce it by 5 feet, 6 feet.

Okay. Next slide. This is the shortfall

issue that we have got. During the first 10 minutes of the event on a design-basis accident, as I have noted, all ECCS pumps initially start. The core is reflooded to about two-thirds core height within about 225 seconds. And by 300 seconds, the operator should have stable indication of two-thirds core height on the water level instrumentation.

So, as this points out, as we have substantial margins to the MPFD, the curves on the bottom, the bottom curve, whatever color that is -- I am colorblind, and, unfortunately, I can't tell you what color that is, the bottom curve.

MR. BJORSETH: Green.

MR. HAMMER: Green is an NPSHr 5-percent effective curve. So, the requirements for the SECY are the next curve up, which is the NPSH4 3 effective curve.

MEMBER BANERJEE: That is the brown?

MR. HAMMER: Is that brown? Was that brown? Yes.

MEMBER BROWN: It might be mauve.

(Laughter.)

MR. HAMMER: At any rate, that is the acceptance criteria. So, as you see, somewhere about 425 seconds, the curve crosses the NPSH available curve for core spraying. There is a slightly different curve between core spray alpha and bravo. We provide them both there. And the core spray pumps are more limiting than the RHR pumps. So, we are showing the core spray pumps here.

But what this shows is that, you know, if you leave the pumps at full runout, there will be a point about 425 seconds where you will no longer meet the NPSHr 3 effective curve. And we have a slight shortfall for a few seconds out to 600 seconds. And once you throttle the pumps to their normal long-term cooling requirements, what happens then with core spray for the SAFER/GESTR analysis, we assume -- say for GESTR analysis, it requires 3,915 gpm of flow from the pump, and our NPSH analysis for this period assumes 4,245 gpm. So, we are using a fairly bounding number there. But this shows that, until you throttle that pump down to the long-term cooling requirements, which are 3,388 gpm per pump, you are going to have shortfall. Once you throttle the pumps, then you are on the curve on the previous page that we just looked at, and you have a margin available.

MEMBER CORRADINI: So, you are essentially negative for a little bit under four minutes?

MR. HAMMER: Yes, a little bit under four minutes.

And at that point in time, the issue that you have got -- I mean, the primary goal here is to make sure that the core is cool. Once you have got the core reflooded to two-thirds core height, you can transition into this definition of long-term cooling. So, instead of needing the 3,915 gpm, you really can assume a larger amount of degradation on those pumps, down to the 3,388 gpm.

So, the way we show this is, while we are slightly below the 3-percent effective curve, we are well within the 5-percent effective curve. And an assessment of pump capacity shows that that doesn't challenge those flow rates. Like I say, realistically, once the operators see the stable indication of two-thirds core height, they can start adjusting flow on these pumps and we would expect them to meet NPSH requirements very shortly.

MEMBER SKILLMAN: Steve, if you go back one slide, please, that is titled "NPSH Margin Comparison". Is the Y-axis really NPSH available or is that a delta?

MR. HAMMER: It's delta. It's the delta between --

MEMBER SKILLMAN: What is required --

MR. HAMMER: -- available and required. So, if you look there, it says Figure 6.6.9-3. It is the long-term core spray and PSH margin.

MEMBER SHACK: But these are really two different accidents.

MR. HAMMER: No, it is the same accident, but it is the two different time periods, yes.

MEMBER SHACK: No, but isn't one a large-break LOCA with one of the diesels gone and the other one is the one with the LPCI injection logic?

MR. HAMMER: Well, yes.

MEMBER SHACK: Different single failures?

MR. HAMMER: Yes, you get into different single failures, right.

MEMBER SHACK: Well, okay.

MR. HAMMER: You're right.

MEMBER SHACK: Same initiating event?

MR. HAMMER: Yes.

MEMBER SHACK: Different single failures. I would call them different accidents.

MEMBER CORRADINI: Different configurations.

MR. HAMMER: Well, what we are doing is we are using conservative bounding flow rates for those time periods, yes, you're right. So, for example, if you go to the next slide --

MEMBER SHACK: But you don't really want to try to match the short-term from that next curve to the short-term in this curve because they are really different.

MR. HAMMER: Yes, true. That is true.

This curve is based on LPCI injection valve failure. Now what really means is that you are injecting in the wrong LOOP. So, you have got four RHR pumps running to the walls out the break, and you have got two core spray pumps running --

MEMBER SHACK: A lot of water.

MR. HAMMER: -- as much as they can to the reactor. Yes, it is a lot of water.

All right. Any more questions on this one?

CHAIR REMPE: The second one was done Super HEX, I assume, right?

MR. HAMMER: This curve right here?

CHAIR REMPE: Yes.

MR. HAMMER: Yes, this is Super HEX.

MEMBER CORRADINI: But that is the only one --

MR. HAMMER: Super HEX deterministic, yes.

MEMBER CORRADINI: Excuse me. I just want to make sure, though. Although you showed us all the previous curves for our edification, the only one that is licensed from approved analysis is Super HEX?

MR. HAMMER: Right, and our submittal is based on continued use of the Super HEX --

MEMBER CORRADINI: Okay.

MR. HAMMER: -- deterministic analysis.

MEMBER CORRADINI: Thank you.

MR. HAMMER: The others are there as a demonstration of margin. That's what it is.

MEMBER BANERJEE: So, let me just understand this. So, around 450 seconds or something, even with the available head based on Super HEX or something, you still go into a region which is between 5-percent and 3-percent --

MR. HAMMER: Yes.

MEMBER BANERJEE: -- degradation in the outlet flow?

MR. HAMMER: Yes.

MEMBER BANERJEE: And that continues for a few hundred seconds?

MR. HAMMER: The assumption is that the operators take action to throttle the pumps by 600 seconds. So, we assumed it went out through 600 seconds.

MEMBER BANERJEE: Okay. And then, it just moved back?

MR. HAMMER: Yes. Once the pumps are throttled, then you are well within the NPSH --

MEMBER BANERJEE: That is based on the Super HEX calculation?

MR. HAMMER: Yes, the Super HEX deterministic.

MEMBER BANERJEE: Which tends to give you the minimum possible margin, that calculation, right?

MR. HAMMER: Yes.

MEMBER BANERJEE: Okay.

MEMBER SKILLMAN: Are there plant conditions for which you need that copious flow from the RHR pumps? Do you really need all that flow rate? And if you don't, why don't you orifice, so that you are in a flow condition where you don't need CAP?

MR. HAMMER: Well, the problem that you have got is, what you are doing there is you are reducing ECCS flow rate.

MEMBER SKILLMAN: So?

MR. HAMMER: And ECCS flow rate is important for fuel temperature.

MEMBER SKILLMAN: I understand that. But do you really need that copious flow?

MR. HAMMER: I believe we do, yes. I don't think we can reduce that.

MEMBER RAY: Well, Dick, even if you didn't need it, isn't the loss of required overpressure going to have the same effect as long as it doesn't damage the pump?

MR. HAMMER: Yes, right. The point that we are trying to make with this analysis is that you are not going to challenge the reliability of the pumps. It is a very short-term thing. You know, the pumps can handle it.

MR. BJORSETH: Let me also provide some input here, Steve.

John Bjorseth.

If you orifice the discharge, you are also restricting flow for other situations of higher pressure where you may want that additional flow versus let the operator take control at the 10-minute mark. And then, if you have got the low reactor pressure or high-flow conditions, that gives the operator a chance to throttle that valve for those specific conditions.

MEMBER SKILLMAN: Well, that is why I asked early on, do you really need that copious flow? You're saying, yes, you do. And I agree with you, Harold. I have been involved in another activity where throttling was the right thing to do.

MR. BJORSETH: And that is reinforced through both training and procedures, and the operators, they will throttle.

MEMBER BANERJEE: But do you really want to throttle your ECCS?

MR. HAMMER: Absolutely. Well, the way to look at it there is, you know, we are meeting the ECCS flow requirements by throttling the pumps. The core is adequately cooled. We meet the 10 CFR 50.46 analysis, right? By not throttling the pumps, you are potentially challenging the reliability of the pumps at some point in time. How long will the pumps last if you operate at that shortfall --

MR. BJORSETH: You are going to run them out.

MR. HAMMER: -- for a long period of time.

MEMBER BANERJEE: Right, but, I mean, in some way, what you are doing is, because you have this -- imagine that you could cool your water somehow. You would never get into this situation. Therefore, you would never need to throttle your pumps. I mean, you would have to throttle eventually or realign them or something; I don't know. But, at least in the short-term, when all these things are happening, who knows what is happening?

MR. HAMMER: Well, remember, the suppression pool water temperature at that 600-second point is about 150ish degrees. It is in that range. So, it is quite a bit less than that.

And what happens is, when you depressurize the reactor and dump that heat from the reactor primary coolant system into the suppression pool, that raises suppression pool temperature on the order of about 60 degrees. And that happens very, very quickly. So, if you don't throttle the pumps at all, you are going to be having that shortfall for an extended period of time.

MEMBER BANERJEE: But that shortfall is based on some calculation, and throttling the pump is a real thing. Is there an indicator that there is anything happening which an operator can see and say, "Look, nothing is happening to these damned pumps. So, why should we throttle them?"

MR. HAMMER: Well, we have struggled with that. And one of the things you end up with is the classic indication of a pump NPSH is surging on the pump, right? But you have to have essentially flow collapse. And so, what Sulzer was able to show is --

and we have got some analysis that shows this, too -- is that the pump, if you enter flow collapse, the pump flow rate will drop off, the NPSH conditions will improve, and you will supply suction pressure, and then, you will reestablish flow. So, the pump flow rate is going to surge.

Now the problem is here, since we are above the NPSH 5-percent curve, you have stable flow. The pump is just going to have a little bit more degradation than you would normally have. So, instead of having a 3-percent degradation, they are going to have a 4-percent degradation, and the operators are just not going to be able to see that.

MEMBER BANERJEE: Well, then, why do you throttle the pump? I mean, you know, they are in some regulatory space which is a real sort of detriment to -- I love copious ECC flow.

MR. HAMMER: Yes, I know, it is a wonderful thing.

MEMBER BANERJEE: The more, the better.

(Laughter.)

MR. HAMMER: The problem you have is that people that build pumps like this say that it is just not a good idea to operate there forever. You know, they do have pump curves that show that, but they are not willing to warrant 30-day mission times if you are operating on that NPSHr 5-percent curve.

MEMBER BANERJEE: No, I am not saying that you shouldn't throttle them back later on.

MR. HAMMER: Yes.

MEMBER BANERJEE: But in this period when things are happening rapidly, I mean, we are only talking of a few hundred seconds, is it absolutely necessary to throttle your pumps? I mean, I would feel much more shakey about that than the containment.

MR. HAMMER: Well, that is why we were getting at it. You know, the containment or the core is reflooded, the two-thirds core height, by 225 seconds, and you have stable indication of two-thirds core height on the level indication by 300 seconds. So, the operators, what they are going to be looking for is they are going to be looking for the stable indication that the core is reflooded. And once they see that stable indication, what will happen in our case is you will have the water level, it will be flying around, and then, it gets to a point where it should become much more stable.

And the two-thirds core height, that indicates to the operators that they are at that two-thirds core height point, we are overflowing the jet flows, and the flow is going out the break. And at that point, then, it is okay to start throttling these pumps and start transitioning to the containment cooling.

There are a couple of things that have to happen here, you know. You have got to get into containment cooling also, you know. So, I agree it is a busy time. It is a challenging time. But there is time available to do what is required.

MEMBER BANERJEE: Well, okay. It just seems we are going an opposite way to what your intuition would tell you, put as much flow as you can.

MR. HAMMER: Well, one way to look at it, for example, is if you look at the core boiloff rate 10 minutes after the event, you only need about 500 gpm of water to keep the core at a stable level, right? So, the extra flow that we are providing is basically spray cooling for the upper portion of the core, and that is --

MEMBER BANERJEE: That is pretty good, too.

MR. HAMMER: That is pretty good. It is a requirement. But, you know, the GE generic solution is, as long as we can provide the design-basis core spray flow rate, which is the flow rate that we are assuming in the long-term analysis, the 3,388 gpm, that is adequate to cool the core. And that is a value of about on the order of about five times the required flow rate. So, it is still substantially above the required flow rate.

MEMBER BANERJEE: Okay.

CHAIR REMPE: So, you are really depending on the water height in the core, right, the indicators, the instrumentation, the DP cells, which --

MR. HAMMER: Yes.

CHAIR REMPE: -- you are going to have to use these operator aids because you are at a different pressure, and they are not going to be reading correctly? And you modify it?

MR. HAMMER: Well, I believe -- and maybe Rick can talk to that -- but, you know, what we are asking the operators to verify is not necessarily an absolute value of water level because we recognize some of those errors are going to be there, but, rather, that you have a stable response, that it more or less levels out, and you have a response.

MEMBER SCHULTZ: It would help us to hear what Rick has to say here.

MR. STADTLANDER: Right, this is Rick

Stadtlander.

In regards to how we have been talking about -- we are looking for the stable readings on our instruments. We also have those marked off with operator aids on them directly, you know, that kind of mark the levels that we expect to see, where the fuel range is.

We have also got temperature compensated, assuming the computers are still there. We have got those that are compensated for us.

And then, we do have charts available on the control panels as well.

I don't know if that answered the question you were looking for, but okay.

MR. HAMMER: Okay. Any other questions here?

(No response.)

Okay. Now this has got a lot of information. I am not necessarily going to go through this. But this shows the margins that you would have on a pump-by-pump basis for the short-term analysis.

So, for example, if you go across the top to the one, two, three, four, five, sixth column, it says, "Margin to NPSHr effective 3 percent," and that shows for the short-term analysis we have one pump that does have positive margins, but the rest of them are going to be slightly negative.

And then, if you look at the NPSHr 5-percent curve, "The Margin to NPSHr 5-percent" curve, a couple more over, John -- that one -- that shows the margin above the NPSHr 5-percent curve. So, it does show that we have a substantial margin to the next available curve.

Next slide, John.

This is the deterministic analysis NPSH margin for the long-term DBA LOCA. This for RHR and core spray. The flow rates shown include some of the expected flow out of the pump through things like minimum flow lines or leakage for core spray into the annulus area.

So, those are the flow rates that were assumed in the NPSH analysis.

MEMBER BANERJEE: What is the single failure in this case here?

MR. HAMMER: Well, for the containment, for the long-term analysis, the typical limiting single failure is loss of a diesel, because, then, that gets you down to that one RHR pump and one RHR service water pump cooling containment. If you have another diesel, then you have two RHR pumps, at least two RHR pumps, and two RHR service water pumps.

And again, this shows margin to NPSHr effective, as in the righthand line. So, we have got the minimum margin there is about 11.1 and 3 percent for core spray, which is probably one significant figure too many, maybe two.

MEMBER BANERJEE: It doesn't matter how you enter this DBA; it is pretty much it doesn't matter whether you had a different single failure to give you the worse condition for this.

MR. HAMMER: Well, when we looked at it, we were looking at trying -- like in the short-term analysis, the goal is to provide the maximum complement of pumps running because the system resistance on the suction piping becomes the dominant factor in defining your margin to NPSH. And with all of the pumps running that we had, I don't remember off the top of my head, but, you know, it is 28,000 gpm or something. It is a lot of flow.

And in the long-term analysis, then you are driven by your containment response primarily. So, we are looking at the minimum complement of pumps that would give you the most challenging containment response.

As we have said before, the flip side of that is if you have an accident and you don't have a loss of offsite power, we are probably not going to need much containment accident pressure. We should be able to avoid it.

Any other questions here?

(No response.)

Okay. So, the basis of acceptability for containment accident pressure is we have demonstrated adequate core cooling, meeting the requirements of SECY-11-0014, Enclosure 1, as described; the use of CAP results and a very small increase CDF, as defined by Reg Guide 1.174. The NSPM analysis of that shows an increase in risk on the order, increase of CDF on the order of 9 times 10 to the minus 9.

Online monitoring for containment integrity is available. We have a surveillance that has been approved. We provide training to increase operator awareness and sensitivity to NPSH concerns. That includes pump and NPSH monitoring, containment integrity monitoring, and the emergency operating procedures are going to be revised to recognize alternate methods -- well, they already exist to provide alternate methods. There is an EOP change that covers the change to pressure that is required to meet CAP limits, so based on the use of the uncertainty values.

Next slide, John.

MEMBER SHACK: Just let me make a comment there. It is the small increase in CDF. I mean, one of the things that we see at least in the staff's PRA is that, although the increase in CDF is small, the risk achievement work of having the containment pressure is pretty large. It is 750.

And that is what I like about your Appendix B and the BWR Owners' Group, is they get the 750 because they make the rather conservative assumption that every time they lose containment pressure and they need suction pumps, things fail. Well, what you show in Appendix B is that you can have a pretty bad accident and you don't really need very much. So, in most of the scenarios, I suspect that you are not really going to need it at all. It would be nice if somebody looked at more scenarios and showed me that, but I am willing to believe Appendix B.

What I would like to see, you know, Appendix B was done as a one-time shot, and it looks good for you guys. I would like to see Appendix B done for all plants because I am not sure all of them would look as good as Monticello does. And it is the one that sort of gives you, again, for my structuralist colleagues who want defense-in-depth, you know, you really like to see that risk achievement worth smaller than 750. In your case, the Appendix B calculations give me confidence that, although I don't know what that number is, I know it is not anywhere near that. It is not clear what it would be for other plants.

MR. HAMMER: Yes, and I'm not sure how the NRC did the study. I guess, like the last bullet here, one of the things I am trying to point out is the emergency operating procedures do provide alternative methods. For example, like we can use fire pumps to provide drywell spray or containment injection. There's a number of different options that are in the real world available to you that we don't credit.

MEMBER SHACK: Well, on PRA, I am assuming you are crediting that sort of thing.

MR. HAMMER: Yes. Anything else here?

(No response.)

Okay. Continued basis for acceptability, use of 21-percent uncertainty for NPSHr results in ability to deliver the required flow for the DBA low commission time. We did determine that we do have a shortfall to NPSHr 3-percent effective for the design-basis accident for about four minutes. And we verified that that does not impact performance or reliability for the 30-day mission time.

Testing of similar pumps demonstrated that operation below NPSHr 3-percent curve for periods longer than four minutes does not result in pump damage. That is the testing piece that is required.

And the core is reflooded with two-thirds core height within the first four minutes of an accident of a DBA LOCA, which is prior to any shortfall in NPSH margin. And after the core is reflooded, only 3,020 gpm of core spray is required to be delivered to cool the core. So, that is a point.

Experts in hydraulic analysis provide direction and review the results. So, the BWR Owners' Group analysis did include a number of industry experts that helped to provide input and results on that.

MEMBER SCHULTZ: Steve, can you back up one slide, please?

MR. HAMMER: Sure.

MEMBER SCHULTZ: Or I can read the point, the bullet, that I am -- okay, there it is. The bullet on providing training to increase operator awareness and sensitivity, could you elaborate on where you are today and what this really means in terms of augmenting the training program here? I don't quite understand what, in particular, is going to change from where you are today. If so, are we --

MR. HAMMER: Well, there is a mix of a couple of things.

MEMBER SCHULTZ: The way it is expressed, it sounds like there is a lot that needs to be done there. And I am not certain it is --

MR. HAMMER: A large piece of this has been completed. I mentioned, for example, that we have a procedure for monitoring non-condensable gas mass in containment. We also have procedures for venting containment and for adding nitrogen to containment.

And what we did is we did a little bit of an assessment of all those procedures and we tried to say, you know, if this happens on this procedure, it potentially could indicate that we may have a leak. You know, if you are venting containment too often, that might indicate a leak. Or if your oxygen concentration is increasing, that could indicate a leak.

So, what we have done is we have already revised those procedures and added some precautions to the operators to try to flag potential issues that could be indications of leakage.

MEMBER SCHULTZ: But that is on the containment integrity monitoring side.

MR. HAMMER: That is on the containment integrity piece.

The other thing that we are doing is we are going through, for example, the core spray ops manual procedures, the operating procedures for core spray. And we are providing some additional guidance for the operators on what the expectations are for operating the pumps, what they might see during an accident, and some of those kinds of things, some of the thins that we talked about today.

MEMBER SCHULTZ: Uh-hum.

MR. HAMMER: And those are still in progress.

MEMBER BANERJEE: This is mainly DBA-focused. What happens for Appendix R?

MR. HAMMER: Appendix R -- DBA ends up being the limiting event. Appendix R is not -- the other events aren't as limiting. We can provide you a table. I think that might be a backup slide.

MEMBER CORRADINI: The SER has a table,

but I think staff is going to --

MEMBER SCHULTZ: Yes, but they don't have the worst-case Appendix R in the staff's. The worst-case Appendix R, when you have the multiple spurious operations, gets you down to 1.7. So, it is still not the limiting case, but it is lower than your two cases that are in your licensing basis.

MEMBER BANERJEE: Do you have a backup slide?

MR. HAMMER: Yes. I don't know if they've got it.

(Pause.)

MEMBER SHACK: He is looking for, presumably, Table 6.6.4-1.

MR. HAMMER: You are ahead of us, I believe.

(Laughter.)

What we can do is we can look for it, and we can --

CHAIR REMPE: Maybe hand it out tomorrow? That would be good.

MEMBER SHACK: It is in the second submittal on CAP, the supplemental submittal.

MEMBER BANERJEE: Oh, okay. That we have, yes. I can probably pull it up as well. Okay.

CHAIR REMPE: If there are no more questions, I think we should switch to the staff, but I did let this go over a bit because I think it is time well-spent because we can't do this at the full Committee meeting.

So, are there any more questions?

(No response.)

Okay. So, staff time.

Thank you, by the way, for your presentation. It is helpful.

CHAIR REMPE: This is a bit different today because they have two computers, and we are trying to get it switched. So, just hold on for a second.

(Pause.)

MR. DENNIG: By way of introduction, I am Bob Dennig, the Branch Chief in the Containment and Ventilation Branch in NRR.

Ahsan is a Senior Reactor Engineer who has done the analysis, containment response, and the PSH margin for the Monticello EPU. Ahsan has been involved in the development of the improved guidance on NPSH margin from the beginning. He has also performed a great deal of GOTHIC analysis himself as part of the development of that guidance.

And I will turn it over to Ahsan. He is well-qualified to tell you how this is done and why we did what we did.

Ahsan?

MR. SALLMAN: Okay. My presentation is today based on the containment accident pressure for Monticello.

First of all, I will talk about some key definition that I used in CAP analysis. First of all, the definition of available NPSH is what we say is a suction in the pressure which is conservatively determined by maximizing or by biasing the inlet, biasing the initial conditions, and in order to maximize the transient wetwell pressure, maximize the suppression pool temperature and minimize the containment vessel pressure.

CAP is the transient absolute pressure that is developed above the pool during an accident, and CAP credit means the transient pressure in determining the relevancy as such.

Another definition which is used is that NPSHr 3 percent is the presence of NPSH for a pump which corresponds to degrees in 3 percent total dynamic head for a given flow. And then, NPSHr effective is equivalent to NPSHr 3 percent with the uncertainty factor included. And this accounts for the differences between the test setup and the free conditions.

The NPSH margin which we use is the difference between the NPSH available and the NPSHr 3 percent. Adequate NPSH margin means positive NPSH margin.

And the margin ratio is the ratio of the available NPSH and the 3 percent required.

The regulatory requirement, this is derived from GDC-38, that the RHR and the core spray pumps for Monticello should have adequate NPSH during an accident or abnormal events.

Next slide.

For Monticello, the licensee determined that CAP is needed for design-basis LOCA, small steamline break accident, ATWS event, Appendix R fire event, and the licensee determined that the CAP is not needed for the SBO, the station blackout event. And we issued the staff guidance in SECY-11-0014, Enclosure 1.

And I will go over these requirements or the guidance in the SECY document, Enclosure 1, that were also covered by the licensee. And there is 10 of them, numbered 6.6.1 through 6.6.10.

The first one in which the licensee implemented the staff guidance in which we wanted them to use NPSHr effective for the DBA LOCA analysis and NPSHr 3 percent for the non-DBAs. So, that was implemented by the licensee.

The second guidance stated that the licensee should conservatively use higher pump flow than that required for the ECCS analysis. So, that was implemented.

The third guidance, 6.6.3, the licensee was requested to perform the Monte Carlo 95/95 analysis to calculate NPSH margin.

MEMBER BANERJEE: Can I just interrupt you on this point? I was puzzled by what Bill said. So you mean Monte Carlo or non-parametric? If they were asked to do Monte Carlo, it is not the same thing. Can you explain what -- or somebody can explain this?

MR. SALLMAN: The analysis that was performed was randomly-selected. Fifty-nine runs were made using the Super HEX code.

MEMBER BANERJEE: So, to get 95/95, then you have to use Wilde's and Wall's theorem. It has nothing to do with Monte Carlo.

MEMBER SHACK: I think they are using Monte Carlo just to mean randomly-selected things.

MEMBER BANERJEE: But that's --

MEMBER SHACK: It is not Monte Carlo --

MEMBER BANERJEE: It has nothing to do with Monte Carlo.

MEMBER SHACK: Well, aside from the fact that you are making random selections in the sampling, but --

(Laughter.)

MEMBER BANERJEE: Never mind.

MEMBER SHACK: But if you look at the Owners' Group, the Owners' Group document, which is what this is really based on --

MEMBER BANERJEE: Yes.

MEMBER SHACK: -- is really the 59 non-parametric samples.

MEMBER BANERJEE: Yes. I think just the nomenclature is wrong; that's all.

MEMBER SHACK: Right.

MEMBER BANERJEE: Yes. It shouldn't be called -- it is misleading. So, okay.

MR. DENNIG: We will fix that.

MEMBER BANERJEE: What you did is okay. I mean, there is nothing wrong with it.

MR. DENNIG: Right, but we will straighten out the verbiage.

MEMBER BANERJEE: Yes, yes.

MR. SALLMAN: This 95/95 analysis was done to quantify the margin in the conservative or the deterministic analysis that is documented.

The guidance in Section 6.6.4 required that in an Appendix R fire scenario to demonstrate containment integrity is not lost due to venting or circuit issues. And the licensee met that guidance and considered MSOs, multiple spurious operations, due to circuit failures and performed necessary modification, as were discussed previously, that the MSOs that would adversely affect the safe shutdown.

6.6.5, there were no operator actions needed.

6.6.6, as was discussed by the licensee also, there was a short duration of four minutes in which the NPSH, available NPSH was less than NPSHr effective 3 percent, and the range was between NPSHr effective 3 percent and 5 percent.

And the Sulzer report indicated that there was no detectable pump degradation during factory testing when they operated the pump at NPSHr 5 percent. That report was submitted to NRC by the Owners' Group.

The No. 6.6.7, the guidance requested an online monitoring of the containment for leakage. The licensee proposed an online monitoring method that was discussed during the previous session, and we reviewed it and we found it acceptable.

The guidance in 6.6.8, the Sulzer report submitted by the Owners' Group also has 6,200 days of service life when the margin is between 1.2 and 1.6.

The guidance in 6.6.9 cites conservative and Monte Carlo analysis. The licensee performed a realistic analysis using nominal inputs and demonstrated that there is more margin.

The CAP required from realistic analysis is 50 percent of the CAP calculated by conservative analysis and 70 percent of the CAP required from the Monte Carlo inputs. So, the realistic analysis demonstrated that there is more margin from the conservative analysis performed by Super HEX.

The last guidance, 6.6.10, the pump mission time for DBA LOCA and non-DBA events until the CAP credit is not needed was evaluated and results were acceptable.

This last slide shows the NPSH for the most limiting pumps, the maximum CAP credit and the CAP available at that time for DBA LOCA events and Appendix R events.

That is the summary of the Monticello EPU containment and NPSH analysis credits CAP for CS, core spray, and RHR pumps, and the licensee has satisfied the staff guidance. We, as NRC staff, find the user CAP to be acceptable.

MEMBER BROWN: One question. I am trying to connect the dots between -- I like that last table where it showed for the long-term all the LOCAs; 126 hours, that is what, five days or something like that, five-plus days. And yet, when Monticello was talking, they commented that, once they got into the accident, there would be -- after some period of time, you would end with operator actions throttling back because you would no longer need the CAP credit. Did I misunderstand that? Shake your head up and down if I misunderstood it. Okay?

(Laughter.)

MR. HAMMER: Steve Hammer, Monticello.

What is provided here is a good assessment of the amount of time that is required for CAP, although this is basically the long-term analysis, which is after 600 seconds, after 10 minutes. And what we did is we did an assessment of at what point is atmospheric pressure sufficient to operate the pumps without any need for containment accident pressure, and these values were part of a submittal. I don't remember exactly which one, but --

MEMBER BROWN: Okay, but these also assume, when you do this, you have lost all offsite power and one of the trains is out of service, and whatever. There was something else you mentioned, and I don't remember what it was.

MR. HAMMER: It is done based on the limiting assumptions for that accident. You know, for example, ATWS might have, it probably does have offsite power available, or I don't remember for this particular event whether we assumed loss of offsite power.

MEMBER CORRADINI: But, for the LOCA one, can you just repeat for Charlie the assumptions that went into the LOCA attempt?

MR. HAMMER: Yes. Yes. The LOCA analysis is consistent with what you are saying. But some of the other events have different complements of equipment.

MEMBER BROWN: No, I understand that. I was just focusing on the LOCA specifically to make sure that --

MR. HAMMER: Yes, absolutely.

MEMBER BROWN: -- with all the loss of

offsite power, you had one train out, but you had, I guess, the three pumps being run.

MR. HAMMER: That is correct.

MEMBER BROWN: The single heat exchanger available at your measly 147 BTUs per whatever the rest of the --

MR. HAMMER: Yes, per second.

MEMBER BROWN: Per second?

MR. HAMMER: Per degree, yes.

MEMBER BROWN: Per degree? Yes, right. I had forgotten those details.

MR. HAMMER: Yes. No, that is correct. What you are saying is correct. It is the limiting assumption of the equipment.

MEMBER BROWN: Okay.

MEMBER BANERJEE: So, how would all this be affected if you had another diesel generator?

MR. HAMMER: It will get shorter. The duration of CAP requirement will get shorter, and the amount, the amplitude and magnitude of the CAP required will get less.

MEMBER BANERJEE: For all of them, all the events, or just some of them?

MR. HAMMER: Yes, for all of the events, that's true.

MEMBER BANERJEE: For all of them?

MEMBER BROWN: What if you had a bigger heat exchanger on the one train? Would that help? Two and a half times the size you've got, would that get the CAP credit needed?

MR. HAMMER: Yes, other than the fact that it would require a different building to put it in. We don't have the room to do that type of stuff.

A clarification on your last comment. For example, Appendix R, we do have a limited complement of equipment on the alternate shutdown panel. So, that really can't change. That is the limiting amount of equipment we have got.

MEMBER CORRADINI: Say that again louder, please.

MEMBER BANERJEE: Say that again? Yes, that is interesting.

MR. HAMMER: The Appendix R fire assumes the use of an alternate shutdown panel. And so, that panel only has a subset of all the ECCS equipment on it. It doesn't have all the equipment on it. And so, the containment cooling analysis is based on the subset of equipment that exists on the panel.

MEMBER CORRADINI: So, I have a large fire that essentially puts you to only being used in that alternate shutdown panel and whatever equipment is appropriate for that?

MR. HAMMER: Well, yes, the only way you get to the alternate shutdown panel is you have to have a cable spreading room fire or a control room fire. So, if you have a fire that doesn't impact manning the control room, you would have the equipment in the control room available.

MEMBER BANERJEE: But that scenario would be helped by an additional diesel generator or not helped by it? It would not be helped by it? Is that --

MR. HAMMER: If you are on the alternate shutdown panel, we would have to put more equipment on the alternate shutdown panel for an additional diesel to make a difference, right.

MEMBER SHACK: He could protect more equipment.

MR. HAMMER: You need to protect more equipment, absolutely.

MEMBER SHACK: Which is what we have suggested for some plants.

MEMBER BANERJEE: Yes, suggested it once, and it was done, right?

MEMBER SHACK: Yes. Others objected.

MEMBER BANERJEE: But it happened.

CHAIR REMPE: Any more questions?

MEMBER SHACK: I mean, these people chose to go with the deterministic one because they could sort of live with that. Other plants might well use the 95/95 to get a little bit more margin on the available --

MR. SALLMAN: Actually, you know, the guidance, the deterministic, or we call it conservative, would be the licensing basis.

MEMBER SHACK: Okay. I missed that. It is still the licensing basis.

MR. SALLMAN: For every plant that uses CAP, the conservative will be the licensing basis, but they are required to demonstrate there is margin using the statistical 95/95.

MEMBER BANERJEE: So, it is sort of a hybrid situation.

MEMBER CORRADINI: So, it really doesn't matter? They have to use the conservative, the deterministic, which essentially has conservatisms in it.

MR. SALLMAN: Yes, the question was, how much conservatism is in the conservative analysis?

(Laughter.)

MR. DENNIG: The task for the student is to show how much margin was in that calculation, not to not use that as the design basis.

MEMBER CORRADINI: So, that is what lead to the additional curves that showed where --

MR. DENNIG: Yes.

MEMBER CORRADINI: Okay.

MEMBER BANERJEE: So, I am still trying to understand that.

MEMBER CORRADINI: My interpretation is that the Super HEX, in their case, choosing Super HEX as their basis, and the additional calculations above it, just gives the staff information as to how much margin there is there from a best -- I won't say "best estimate" -- a better estimate than a conservative approach.

MEMBER BANERJEE: Let me give it back to you because I don't completely understand it. So, you do, let's say, a conservative Super HEX calculation. That is the calculation. Now, if you wish, you can do a more realistic --

MEMBER CORRADINI: Not if you wish; you must.

MEMBER BANERJEE: If you must, okay. A more realistic Super HEX, and then, you sample your input parameters, or whatever, in your non-parametric way, 59 runs. That gives you a 95/95. And then, you show that your conservative calculation is bounding, is that it?

MR. SALLMAN: Just bounding or there is margin.

MEMBER BANERJEE: Margin compared to the sort of best estimate?

MR. DENNIG: The concern was that we using NPSHa that was very close to what was going to be available with a conservative calculation. And that made people uncomfortable.

And so, in order to address largely your concerns, we went back and looked at different ways to show to the best of our ability that there was margin, how much margin there was, and try to quantify to give something you can get your hands on rather than say, "Well, gosh, it's only a 10th of a psi," or whatever.

Likewise, we added the uncertainty to the required, again to demonstrate that, for those uncertainties, treating every one of them in the wrong direction, that we would still have margin.

So, the objective wasn't to change the design basis. The objective was to show, to give a sense of comfort and understanding of how much margin was there. That was basically why we changed all of the procedures, all the guidance.

MEMBER BANERJEE: Say in this 95/95 calculation, you would sample, say, things like the Mississippi River temperature? Would you do that or is that sort of not done?

MR. SALLMAN: Yes, that is how 95/95 was done.

MEMBER BANERJEE: Okay.

MR. SALLMAN: Some of the parameters input were samples and some of them were conservative numbers used in the 95/95 analysis. So, the real Monte Carlo analysis was better than 95/95, yes.

MEMBER BANERJEE: But let's go back to the Mississippi River.

MR. SALLMAN: Okay.

MEMBER BANERJEE: So, if you sample that temperature, would you then sample a distribution which is based on the recorded distribution of temperatures in the river or is just a flat distribution or what sort of a distribution were you sampling or was sampled? It is just a question. If you did sample the Mississippi River?

MR. SALLMAN: Yes, they were sampled.

MEMBER BANERJEE: Yes.

MR. SALLMAN: I think there was data for -- as I remember, there was five-year data in the Topical Report --

MEMBER BANERJEE: At distribution?

MR. SALLMAN: At distribution.

MEMBER BANERJEE: It was randomly-sampled, 59 random samples.

MR. SALLMAN: Fifty-nine random samples from that.

MEMBER BANERJEE: I am trying to understand exactly what was that.

MR. SALLMAN: There was data. There is data for that.

MEMBER BANERJEE: Yes. And the distributions you did not have, you put a flat a distribution? Or what did you do?

MR. SALLMAN: Yes, that was a flat distribution.

MEMBER BANERJEE: Uniform?

MR. SALLMAN: Yes.

MEMBER BANERJEE: Do you have a table somewhere where it shows the parameters sampled and the distributions used?

MR. SALLMAN: The Topical Report has -- I think we --

MEMBER BANERJEE: Okay. So, if you didn't, did you take a triangular distribution? Did you take a flat one? I mean, I am just trying to understand this because these things have very important effects.

There is a table somewhere with this, right?

MR. LI: This is Guhngjun Li from GE-Hitachi.

Actually, yes, there is a five-year data of the river temperature. So, you can divide them into different things. Actually, in five years, you know how many days. And let's say you have a temperature of 85 degrees as your high of 200 days. And you do the same thing, 70 degrees, 65, until the minimum/maximum. From that data, we do the probability of the exceedance.

MEMBER BANERJEE: That was just randomly-sampled?

MEMBER SHACK: No, no, no. What they do is they really rank the data to get essentially a cumulative distribution.

MR. LI: That's right.

MEMBER SHACK: And then, they compute out a probability of exceedance, but it is really based on data by and large.

MR. LI: That's right.

MEMBER SHACK: You know, they just take whatever they have got, rank it up in a cumulative thing, and then, take it, and it is all in the BWR Owners' Group report. There is sort of table after table of it.

MEMBER BANERJEE: So, the river temperature you have data?

MR. LI: Yes.

MEMBER BANERJEE: How many parameters were sampled?

MR. LI: Totally, it is 10.

MEMBER BANERJEE: Oh, a very small number.

MEMBER SHACK: Again, they are not trying to do a real best estimate here. They just wanted to demonstrate.

MEMBER BANERJEE: And so, these were the 10 most significant parameters, I take it?

MR. LI: That's right.

MEMBER BANERJEE: And how did you determine this, with a PIRT or something, or what?

MR. LI: No. We did -- actually, there were three different groups, these 10 parameters, like, let's see, the summer power. Summer power is required at 2 percent, 2 percent uncertainty. We take the normal distribution and actually one standard deviation, 1 percent. You sample that. And another one, we did the same thing. So, all the other measured data, we did this probability of the exceedance.

MEMBER BANERJEE: So, you assumed the width of the distribution and you fitted it with a normal or with a triangular, which is approximation to a normal?

MR. LI: Let's say, I just said we can find the probability of the exceedance at each temperature.

MEMBER BANERJEE: I understand with the river what you did. What did you do with the --

MEMBER SHACK: Everywhere where he has data, he just does a ranking and, then, comes -- so, he has an approximation of the cumulative distribution and comes out and uses that rank table to estimate the probability of distribution.

MR. LI: Yes. The probability only can be from zero to 1. So, the minimum is 1; the maximum is zero. And then, we do the uniform draw actually from zero to 1, get 59 values. Take each value. Go there to find the --

MEMBER BANERJEE: You did uniform, not random for 59?

MR. LI: It is random.

MEMBER SHACK: The zero to 1 he picks from a uniform random distribution.

MR. LI: That is random, yes.

MEMBER SHACK: But then, he goes to a cumulative distribution to pick off a value.

MR. LI: That's right.

MEMBER BANERJEE: All right.

MEMBER SHACK: I mean, it is just what you think it is.

MR. LI: It is actually, yes, it is the method of the Monte Carlo sampling.

MEMBER BANERJEE: Yes, it is not quite.

MEMBER SHACK: He doesn't like that word.

(Laughter.)

MEMBER BANERJEE: Yes, and it is not quite -- never mind.

(Laughter.)

With the 10 variables, what does it matter?

MEMBER SHACK: Think of it as 59 Monte Carlo samples, but, then, he ranks the samples when he is all done instead of looking for a distribution.

MEMBER BANERJEE: Well, okay. Strange things.

Why didn't you just do a straightforward --

MEMBER CORRADINI: That's straightforward.

MEMBER BANERJEE: It's not very.

MEMBER CORRADINI: It's different straightforward.

MEMBER BANERJEE: Yes.

MEMBER SHACK: Now I could ask how they ranked the 59 when you have time-dependent things. Did you rank, at every time step, you ranked a variable, so that you actually have sort of pseudo-profile?

MR. LI: No, actually, this is a probability exactly, yes, let's say your minimum temperature is 30. That means the probability of exceedance is 1 at 30. So, from zero to 1, you randomly get 59. Let's say the first one is 1. If I take the 1, I will get 30 degrees, right? So, if you had .7 --

MEMBER SHACK: No, I'm thinking on the output.

MR. LI: Oh.

MEMBER SHACK: I now have 59 NPSH curves.

How do I combine those 59? How do I rank the curves? Do I slice them at points and do a ranking at each time step to sort of get the 95th at each time step?

MR. LI: You're right, actually, we do 59 cases. You have exactly the time; let's say 500 seconds. You have the 59 --

MEMBER SHACK: Samples.

MR. LI: The parameter, actually, we called it HWW. So, that is the parameter we used. At that time, you calculate HWW. From the 59, you will find the minimum. That one we call minimum, you saw it in the curve.

MEMBER SHACK: Right.

MR. LI: And use that to calculate the NPSH.

MEMBER CORRADINI: Oh, so, independent of the 59, you go find a minimum of the 59?

MEMBER BANERJEE: It is a very curious procedure.

MR. LI: That is the other step.

MEMBER CORRADINI: Okay. Okay. Then, I'm going to his side now.

(Laughter.)

MEMBER BANERJEE: It is a very curious -- they are not doing Monte Carlo, which is to establish the output distribution, you know.

MEMBER CORRADINI: Well, they could. When they are at 59, they could; they just chose to sample the 59 in a different way.

MEMBER BANERJEE: No, you need a million --

MEMBER SHACK: You would need am much larger sample.

MEMBER BANERJEE: Yes. That's why it is a strange way of doing everything because you don't have doubtful distribution. People do Monte Carlo to get doubtful distribution, right?

MR. LI: You do have this output. The output of the parameter is only -- the threshold pressure or the true temperature. We care about HWW. Basically, it has combined these two. So, the threshold pressure. So, the other statistical, basically, why we do 59? Because if you do 59, you will choose either maximum or minimum. In this case, we choose minimum. So, if you do that, yes, you can more, let's say 93. You only choose the second-largest or the second-lowest. So, yes, you can do more. So, that's 50, 59.

MEMBER BANERJEE: If you do 184, you take the third. But that is not a distribution. That is to actually give you some specific thing, like a peak clad temperature or whatever and compare it to some criteria. So, in the end, because I told you it comes out of Wilde's and Wall's, it is really something which is used for manufacturing to look at the effect of various manufacturing parameters on a tolerance limit. So, this is a very specific thing, and it has been used for the peak clad temperature or the amount of oxidation, which is a very specific requirement. There is one parameter you are looking for, right?

MR. LI: In that sense, actually --

MEMBER BANERJEE: You are not looking for the distribution. We are just going to say the peak clad temperature cannot exceed this with 95/95.

MEMBER SHACK: Well, that is all he is looking for, is the minimum head.

MEMBER BANERJEE: Yes, if you are only looking for one parameter, that 59, but it is not Monte Carlo because a Monte Carlo gives you an output distribution. And you don't know anything about the output distribution here.

MR. LI: In that sense, actually, my understanding --

MEMBER BANERJEE: Well, read the original paper.

MR. LI: Yes, they are saying, the only thing is --

MEMBER BANERJEE: I will send you copies.

MR. LI: -- we will use Super HEX, the only thing. The only thing, Super HEX is a conservative code. So, that is why we said probably our probability is more than 95 percent. So, we can get the distribution. You can get it actually. You can do the normal test to see whether it is normal distributed. You could use the mean value plus this 2.024 standard deviation. You can do it either way.

So, in this case, we used the minimum actually to demonstrate how much margin we have. So, the deterministic, the conservative one is still the --

CHAIR REMPE: Okay. I think we have got enough, right?

MEMBER BANERJEE: We know what they did.

CHAIR REMPE: Okay.

MEMBER SHACK: Just coming back, so, again, that is why you have the Appendix R with and without the safety relief valve rather than the minimum case from the table with the MSOs, is that you are not really changing your licensing basis. You are just having them explore, then, the effect of MSOs to make sure there is not a problem, even that gives you a much smaller available margin.

MR. HAMMER: Steve Hammer from Monticello.

For Monticello, the original Appendix R analysis did include both the stuck-open relief valve case and a case without a stuck-open relief valve. So, that analysis actually predates the CAP issues by quite a bit.

MEMBER SHACK: Yes.

MR. HAMMER: We are just repeating that analysis, but you're right; it is a potential spurious operation. You are correct.

CHAIR REMPE: Are there any more questions on this topic?

(No response.)

Okay. As I recall, we will go around to the Committee for final comments, and to the public. But did you have a question you wanted to bring up today that was earlier?

MEMBER SKILLMAN: I did. I have two questions that I would like to address to Nate Haskell, please, Engineering Manager.

MR. HASKELL: Yes, right here.

CHAIR REMPE: He's still here.

MEMBER SKILLMAN: Nate, in the Safety

Evaluation, are the words "the emergency heat load" -- this is for spent-fuel cooling -- it is 24.7 million BTUs an hour, and the USAR states, "The emergency heat load condition assuming the last core discharge that fills the last 484 spaces in the pool is required 30 days following the last refueling discharge, and the full core discharge is completed 150 hours after shutdown."

Would these parameters, then, change the heat load resulting from the emergency heat load case, would increase? And so, what you have done is changed that 150 hours to 192 hours that is reserved with 24.7 million BTU an hour heat load. And my question is, what has been forfeited or compromised by that change from 150 hours to 192 hours?

MR. HASKELL: What's compromised -- this is Nate Haskell -- what's comprised by going from the 150 to the 192 is the time to begin core offload. So, we would have to wait additional time to begin refueling.

MEMBER SKILLMAN: Okay. And that time is just under two days. I understand that, which is why I asked the question.

MR. HASKELL: Yes.

MEMBER SKILLMAN: Are there any drivers

which that almost two days is critical?

MR. HAMMER: We don't have any events that are defined in that fashion. So, it is just an option that is available.

Yes, Steve Hammer from Monticello.

We don't have events that are specifically defined that makes the time for instituting refueling operations a critical thing. There is no design-basis requirement to do any specific actions in that timeframe.

MEMBER SKILLMAN: So, let me repeat back.

MEMBER BROWN: What was the basis for the change?

MR. HAMMER: Well, the original requirement, the basis for the change is we have a capacity for -- again, this is another mode of RHR. So, RHR has a capacity for cooling the fuel pool system in that moment of operation. And rather than change the capacity of the system, we elected to delay the onset of refueling.

MEMBER SKILLMAN: I understood. I am just wanting to be certain that there isn't a tech spec item or a plant event item for which that 150 hours is critical.

MR. HAMMER: Yes, there is nothing.

MEMBER SKILLMAN: Okay. Let me ask one more, please.

This is on your turbine bypass system. You have increased your power level in this uprate by 13 percent, and it was prior 6.3 percent. Your turbine bypass system has not changed. Are there any events for which you are counting on the dump to the condenser with your turbine bypass valves?

MR. HAMMER: Yes, the key thing for the bypass valves ends up being the transition when you start shutting the unit down onto shutdown cooling. So, it takes a little bit longer for us with that bypass valve capacity to clear the head pressure interlock. There is a 75-psig interlock to protect low-pressure piping and RHR, and it takes a little bit longer to depressurize the reactor to reach that limit to allow us to put in shutdown cooling. So, again, it will take us a little bit longer to achieve cold shutdown.

MEMBER SKILLMAN: Okay. So, in both cases, instead of changing hardware, what you are doing is taking a longer time period to effect the same condition with a higher power level?

MR. HAMMER: Yes, that is correct.

(Someone speaks off-microphone.)

CHAIR REMPE: Is there something that needs to be put on the transcript? We can't hear you.

MEMBER SKILLMAN: We couldn't hear you.

MR. BJORSETH: That is another aspect that would be good to discuss. You are not taking credit for any bypass mode in that.

MR. HAMMER: Yes. Well, what he is pointing out is that there is a transient analysis for the turbine trip with bypass, turbine trip without bypass, where this is analyzed on a cycle-specific basis. But, you know, we are using the appropriate values in the transient analysis based on the existing capacity.

The other thing I was going to point out is there is a USAR requirement for the time required to achieve cold shutdown, achieve 125 degrees, I believe, with all RHR pumps available. And we do impact that value a little bit. It goes from 24 hours to a little bit beyond 24 hours. I don't remember the exact off the top of my head. We can get that for your. About 25 hours.

MEMBER SKILLMAN: So, how is that handled in license space?

MR. HAMMER: In that case, it becomes, I believe we discussed that in the PUSAR, and it will be a USAR change.

MEMBER SKILLMAN: Thank you. Thank you, Joy.

CHAIR REMPE: So, we should probably do public comments next. Is anyone out there on the phone line? Just acknowledge that you are there.

(No response.)

I don't think we have any public comment.

Usually, we wait until tomorrow to go around the table, but some of the members here today won't be here tomorrow. So, just briefly.

MEMBER BANERJEE: When are we ending tomorrow?

CHAIR REMPE: Oh, tomorrow we are ending about 5:00. So, that will be another reason that some people may want to go ahead and give some comments now. Well, 4:00. Excuse me.

But we are starting early tomorrow, by the way, just to remind everyone. Yes, at eight o'clock. There are certain members who need to leave a little early. But I did want to remind you about that.

But why don't we just go ahead and go around the table, if anyone does have any comments they want to put in.

Do you want to start, Charlie?

MEMBER BROWN: I have no more.

CHAIR REMPE: Mike?

MEMBER CORRADINI: I thought the presentations were very helpful. I am still struggling with CAP and its intersection with other soon-to-be-rolled-out procedures for containment venting. So, I think that is the open item. It doesn't, as Mr. Monninger, who is not here, said, it doesn't affect the EPU directly, but it will affect it eventually. So, I want to understand that eventually. So, that is really an open item, not for the licensee, but as much for the staff.

So, except for that, I think everything was very helpful.

I agree with what Bill pointed out to me that I missed. One, that it is not apples-to-apples, but I think it is interesting to note that their analysis for CAP credit is not that much different from what they are already licensed under, which is the other thing I was wanting to pay close attention.

Thank you.

CHAIR REMPE: You're welcome.

MEMBER SHACK: I think it was good to have the comparisons with the different models because we have always had some question as to how conservative the estimates of the available pressure are. So, I think the calculations with the weighted methods and the GOTHIC calculations are helpful from that point of view. The 59 samples, since I can't call them Monte Carlo or I am going to get stomped on.

(Laughter.)

And the other really positive thing I thought was the MSO examination, you know, searching out possible ways that you could lose the containment thing. I mean, if I had to pick something that I thought really made a real contribution to increase safety, that would be probably the part of the exercise that seemed to me most useful. So, I was happy with that.

And again, I will just get back to my thing. The Owners' Group had this Appendix B where they really came close to a realistic calculation. And I think that is a useful thing to have because, again, the notion that the risk is small has never been really an ACRS thing. We have always been worried about defense-in-depth.

And the way to quantify that defense-in-depth is to really understand the range of scenarios over which you might need CAP credit, and I would prefer to have a PRA that looked at many, many scenarios, but Appendix B and the Owners' Group is a helpful start to give you some idea of just how much conservatism you are really building into these calculations and how much you are really giving up by allowing CAP credit.

And I have to echo Mike's thing about the early venting might change a whole lot of things here. But that will be interesting.

CHAIR REMPE: Sam?

MEMBER ARMIJO: No, nothing.

CHAIR REMPE: Harold?

MEMBER RAY: Well, add me to the list of what lies in the future as being important. I think from the standpoint of what Bill says, I am a deterministic, independent person from the standpoint that the unlikely challenge of the pumps by an insufficient period of CAP insufficiency, the fact that the pumps will survive that and be available and able to continue to perform their functions, and that they aren't threatened by that relatively-brief period of insufficient containment overpressure is an important consideration.

So, I will just need to become comfortable with the idea that the loss in flow that may occur during that period of time is insignificant to the overall analysis. And it is my judgment at this point that that probably is the case.

CHAIR REMPE: Dick?

MEMBER SKILLMAN: I would give the Monticello high marks for throwing this in BOP, in the wait they treated CAP. There is more work to be done, but in my view this has been a very constructive use of time and it is beneficial. You have done a good job.

CHAIR REMPE: Steve?

MEMBER SCHULTZ: I appreciate very much the presentations today. And I would agree with Dick in terms of the overall thoroughness of the evaluations and the perspective that has been provided on the plant-specific basis associated with the challenges that the EPU presents, and the approaches that the plant could take to address those challenges. I think a good job has been done with respect to that.

With regard to CAP credit, I agree with everything that has been said. I learned a lot today. I will be here tomorrow. Based on what I have learned, I feel that I need to do some homework to get to the point where Harold is or wants to be with respect to this. Both of us will look at that very carefully.

I appreciate the presentations today both by the licensee as well as the staff.

CHAIR REMPE: Sanjoy?

MEMBER BANERJEE: So, I won't be here tomorrow.

CHAIR REMPE: At all?

MEMBER BANERJEE: I will be --

CHAIR REMPE: In the morning, right?

MEMBER BANERJEE: No, I will be here through the day, but I have a five o'clock plane to catch out at Dulles.

So, let me give a brief overview. I think the presentations by both the staff and the applicant were very good. They were very informative.

There are certain points; I will just go through them briefly.

Certainly, the LOCA analysis, which to me at some point is a bit puzzling. At least it satisfied me how they had calculated these uncertainties and all; it is not entirely clear, but, nonetheless, I have got a pretty good handle on that. So, I think understand part of what they did. I might need to again do a little homework to make sure that I fully get it.

With regard to the stability, which is

another area, I think the fact that they are still on the MELLLA line, and this is a very stable plant, you know, with regard to the EPU, I don't see any real issues there. And the systems that they have already deployed, the simulator, and all the tests and things that they have done, and the staff has audited, you know, it is reassuring. What will happen with MELLLA is a different matter, but I don't think right now we need to be too concerned about that. At least that is what I feel.

Going on to CAP, you know, we were always interested in practical alternatives to try to avoid CAP or at least minimize the need for it. And I think the analysis that was presented, it certainly conforms in many ways to the requirements of the SECY, to the extent I understand them. I am not quite sure what they mean by Monte Carlo, but, nonetheless --

MEMBER ARMIJO: We got that part.

(Laughter.)

MEMBER BANERJEE: -- I think it is sort of used loosely in some way.

But, other than that, as Bill said, we have always been concerned about the conservatisms in these calculations and the uncertainties. They did a great job in talking about that. The fact that they used 10 of these inputs, which were the most significant maybe in some way, is reassuring.

I need to also do a little bit more homework on the methodologies or the scenarios they considered for the containment to fail. That really, the 15 or whatever that number was, I haven't really looked through it. So, I must say that that would be interesting to look at.

And finally, it would be really interesting to understand if there was some minimal thing or maximal thing -- I don't know -- like putting another diesel generator or something, which could take care of this problem. Now we encountered something similar to this in the past with Appendix R. That was a more serious issue where the separation of trains was not sufficient, and we really requested that there be some barriers put between them, and it was done eventually. I think that was helpful in some way.

So, we need to look at if there are any practical things. Now we are not designers, but if it one thing or the other that could be done to help out and minimize the requirement for CAP, at least we should look at it. Maybe it doesn't conform to the letter of the law, but I think it would conform to the spirit probably of the law.

So, that is the only comment I have. Otherwise, it seemed like a pretty solid case because they have done something like this before, very close to it.

Anyway, that's my comments.

CHAIR REMPE: Actually, based upon what I am hearing today, it is a lot different than what I heard maybe a week ago informally from my colleagues. And so, I think the presentations by the staff as well as the licensee were very helpful and helping to increase our understanding. We appreciate it.

Again, I would like to emphasize that I am still concerned about what we are going to do about the remaining outstanding items because we do need to understand what we are going to do, if we are going to have this meeting in September. We don't want to waste the time. I want to put it on the agenda. So, I hope by tomorrow we will have a good answer from the licensee and the staff on that.

MEMBER SCHULTZ: Are we adding that to the agenda?

CHAIR REMPE: The steam dryer is already on the agenda. My concern is that we have to publish in The Federal Register what we are going to do at the full Committee meeting.

MEMBER SCHULTZ: The discussion related to the licensee's response and the schedule --

CHAIR REMPE: At the end of the day, you can bet that is what we are going to be discussing, if it is on the agenda or not. But, hopefully, we can even find out earlier.

Okay?

MEMBER SCHULTZ: Thank you.

CHAIR REMPE: So, with that, I would like to just close for the day.

Thank you.

(Whereupon, at 5:05 p.m., the meeting adjourned, to reconvene the following day, Friday, July 26, 2012.)

ACRS Subcommittee on Power Uprates

NRC Staff Review

Monticello Nuclear Generating Plant Extended Power Uprate

July 25, 2013

Opening Remarks

John Monninger

Deputy Director
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Introduction

Terry Beltz

Senior Project Manager
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Review Timeline

- November 5, 2008 – Application submitted to NRC
- December 18, 2008 – Application accepted for review
- October 2009 – Review placed on hold to resolve issues regarding application of CAP
- March 2011 – Review reactivated
- November 2012 – Gap analysis public meeting

Background

- NRC Staff Effort
  - Requests for additional information
  - Supplements to application
  - Gap analysis review

- Challenging Review Areas
  - Replacement Steam Dryer
  - Use of Containment Accident Pressure (CAP)

Topics for July 25th

- EPU Overview
- Nuclear Design and Safety Analyses
- Safety Analyses – ATWS & Stability
- Containment Analysis
- Containment Accident Pressure

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Monticello Nuclear Generating Plant Extended Power Uprate ACRS Subcommittee Meeting

Reactor Systems

Benjamin T. Parks
Reactor Systems Branch
Division of Safety Systems

Purpose/Objectives

- Describe staff review of MNGP transient and accident analyses for EPU

- Provide overview of licensee's efforts to address nuclear fuel thermal conductivity degradation

- Discuss Long-Term Stability Option III and thermal-hydraulic stability

Introduction

- Licensee references General Electric licensing topical report for Constant Pressure Power Uprate (CLTR)
- CLTR provides framework for evaluations and analyses required to justify the requested power uprate
- CLTR use is based on using GE fuel product
  - Monticello uses GE14 fuel

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Fuel Design - Staff Review

- **Monticello uses GE14 fuel product; entire core is currently comprised of GE14 fuel**
- **Staff requested that the licensee provide core design parameters to verify CLTR assertions**
  - **No significant changes in fuel discharge burnup**
  - **Limited increase in EPU fresh fuel batch fraction**
  - **Key parameters remain within GE14 limits**
- **Staff concluded that fuel design was acceptable for operation at EPU conditions**
  - **Note that, at uprated conditions, MNGP core power density remains comparatively low**

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Thermal Limits

- **Safety Limit Minimum Critical Power Ratio**
  - Previously limited to 1.10 for two recirculation loop operation; 1.12 for one recirculation loop operation
  - Recent amendment increased both values to 1.15
  - Includes interim penalties required per NEDC-33173P-A for EPU and MELLLA+

- **Operating Limit Minimum Critical Power Ratio**
  - Little EPU-related variation in OLMCPR
  - Included interim penalties for ODYN/PANAC/ISCOR/LAMB
  - TRACG04 migration obviates need for said penalty

- **Linear Heat Generation Rate**
  - Limits established by fuel design and unaffected by EPU
  - MAPLHGR limits are determined by the ECCS evaluation

Anticipated Operational Occurrences (AOOs)

- The limiting AOOs are analyzed on a cycle-specific basis
- The disposition for AOOs is contained in the General Electric suite of licensing topical reports (i.e., CLTR and predecessor reports ELTR1 and ELTR2)
- Licensee used the CLTR disposition for AOOs

EPU Effect on AOOs

- Licensee submitted Supplemental Reload Licensing Reports (SRLRs)
  - Cycle 25 (non-EPU)
  - Cycles 26 and 27 (EPU)
- Results of the cycle-specific analyses confirm licensee's disposition for AOOs
- Little variation in predicted CPR performance pre- and post-EPU
  - Most significant differences appear to arise due to changes in the SLMCPR
- Since information in SRLRs confirms the CLTR disposition, staff determined that EPU was acceptable for Monticello

Overpressure Events

- The plant was analyzed for an inadvertent MSIV closure with failure of direct scram and for an anticipated transient without scram (ATWS) event
- Results confirmed that pressure relief system was acceptable for EPU
- Standby liquid control system provides adequate protection for ATWS

ECCS LOCA

- ECCS performance evaluated for EPU using SAFER/GESTR-LOCA evaluation model

- SECY 83-472-based evaluation model
  - Permits a more realistic approach for evaluating ECCS performance while conforming to required and acceptable features of Appendix K

- EPU has little effect on limiting PCT
  - Plant is large break limited
  - Licensing basis PCT is 2150 °F
  - Includes 10 °F estimated effect of upgrading from GESTR to PRIME based on single effect sensitivity study (using PRIME)

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MNGP ECCS

- BWR/3 – ECCS “network” includes LPCI, LPCS, HPCI, and ADS (3 S/RVs)
- Licensee removed an “Upper Bound” PCT limitation, permitting the use of increased MAPLHGR limits in the ECCS evaluation
- Licensee increased number of S/RVs required, to improve SBLOCA performance
- Licensee compared pre-EPU to EPU PCTs, assuming the elimination of the UBPCT limitation
- Pre- and post-EPU PCTs were consistent

Interim Methods

- Staff reviewed licensee's evaluation of compliance with conditions and limitations contained in Interim Methods Licensing Topical Report (IMLTR, NEDC-33173P-A)
- Licensee provided required information and applied necessary adders/penalties
- Staff concluded that licensee satisfied IMLTR conditions and limitations

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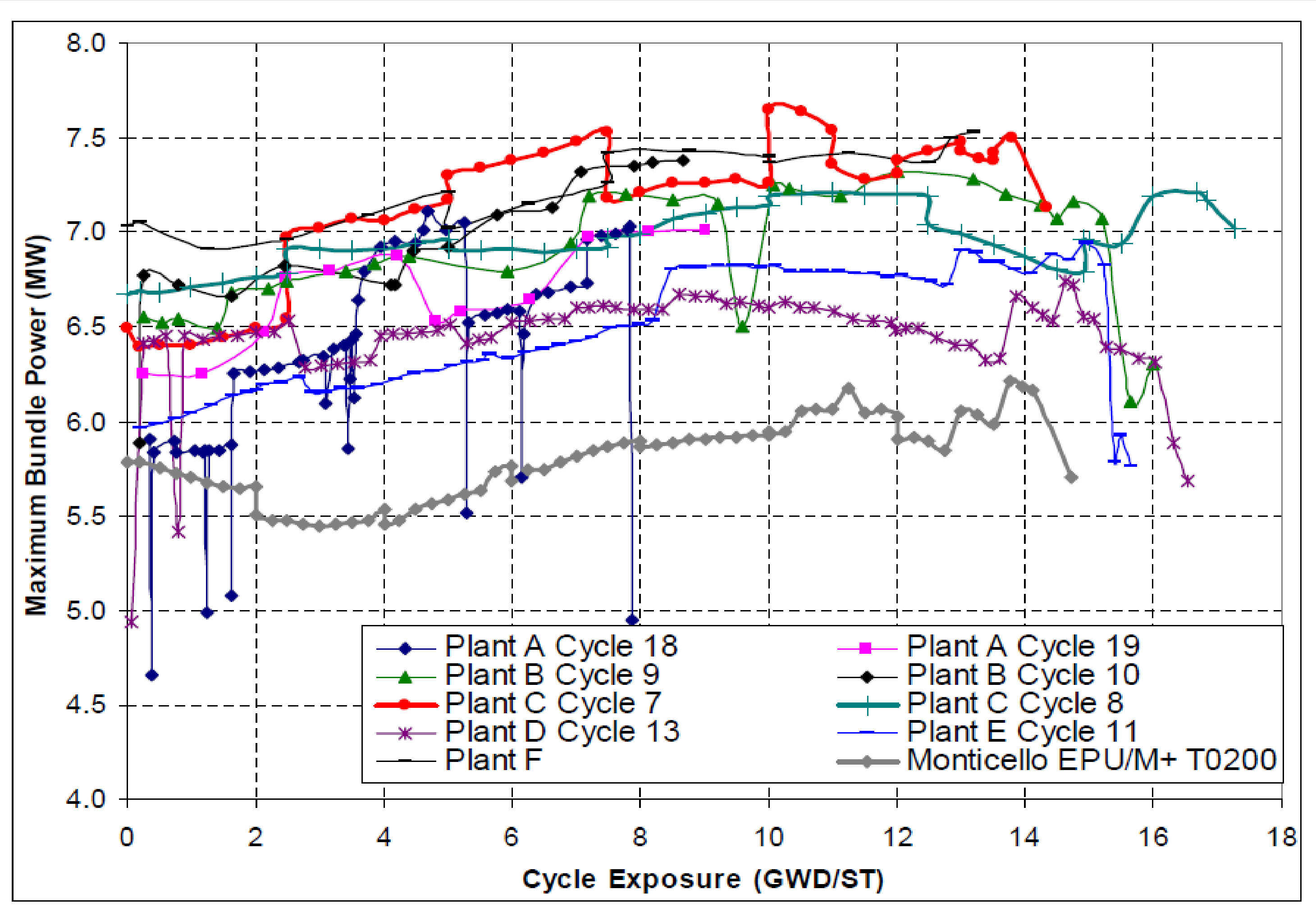
Thermal Conductivity Degradation

- Licensee submitted EPU request prior to completion of PRIME review
- EPU relied on GESTR-based analytic methods, and analytic penalties are applied to address legacy code issues including TCD
- Licensee is transitioning to PRIME-based analytic methods
  - Estimated effect of TCD in LOCA analysis
  - PRIME implemented in TRACG AOO analyses

Bundle Power Comparison



Bundle Exit Void Fractions

Table 2.8-1 Core Exit High Powered Bundle Void Fractions

Power (% OLTP)	Rated Flow	Bundle Void Fractions		
		BOC	MOC	EOC
96.8% (80.6275% EPU)	55%	0.859	0.896	0.885
120% (EPU)	80%	0.851	0.884	0.878
120% (EPU)	100%	0.820	0.821	0.838
106.29% (CLTP)	82.4%	0.838	0.844	0.845

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Conclusions

- Staff reviewed licensee's assessment of EPU for Monticello
- Assessment based on CLTR
  - Monticello uses GE14 fuel entirely
  - Accidents and transients will be analyzed in accordance with NRC-approved reload licensing methods
- Staff verified results by reviewing EPU cycle SRLRs; analysis results are acceptable
- Licensee has satisfied NEDC-33173P-A conditions and limitations
- Based on above, staff recommends approval of EPU

Questions

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Monticello Nuclear Generating Plant Extended Power Uprate ACRS Subcommittee Meeting

ATWS and Stability

Dr. Tai Huang
Reactor Systems Branch
Division of Safety Systems

Dr. Jose March-Leuba
Oak Ridge National Laboratory

Safety Evaluation Report

- The NRC staff completed its SER with positive findings based on review of available documents and audit
  - MNGP used Solution ID successfully
  - EPU upgrade included digital NUMAC-based PRNM neutron monitoring, which includes Solution III and an easy upgrade to DSS-CD for MELLLA+ implementation
  - Current LTS implementation (Sol III) is adequate for EPU
    - Satisfies GDC 10 & 12
    - Level of protection in EPU is similar to CLTP

Audit Results

- NRC staff audit concluded that
  - MNGP operators show good understanding of stability and ATWS issues for EPU
  - Staff observations of operators’ action in the simulator support the customary 120 s delay assumed for safety calculations
  - MNGP EOPs are adequate for EPU

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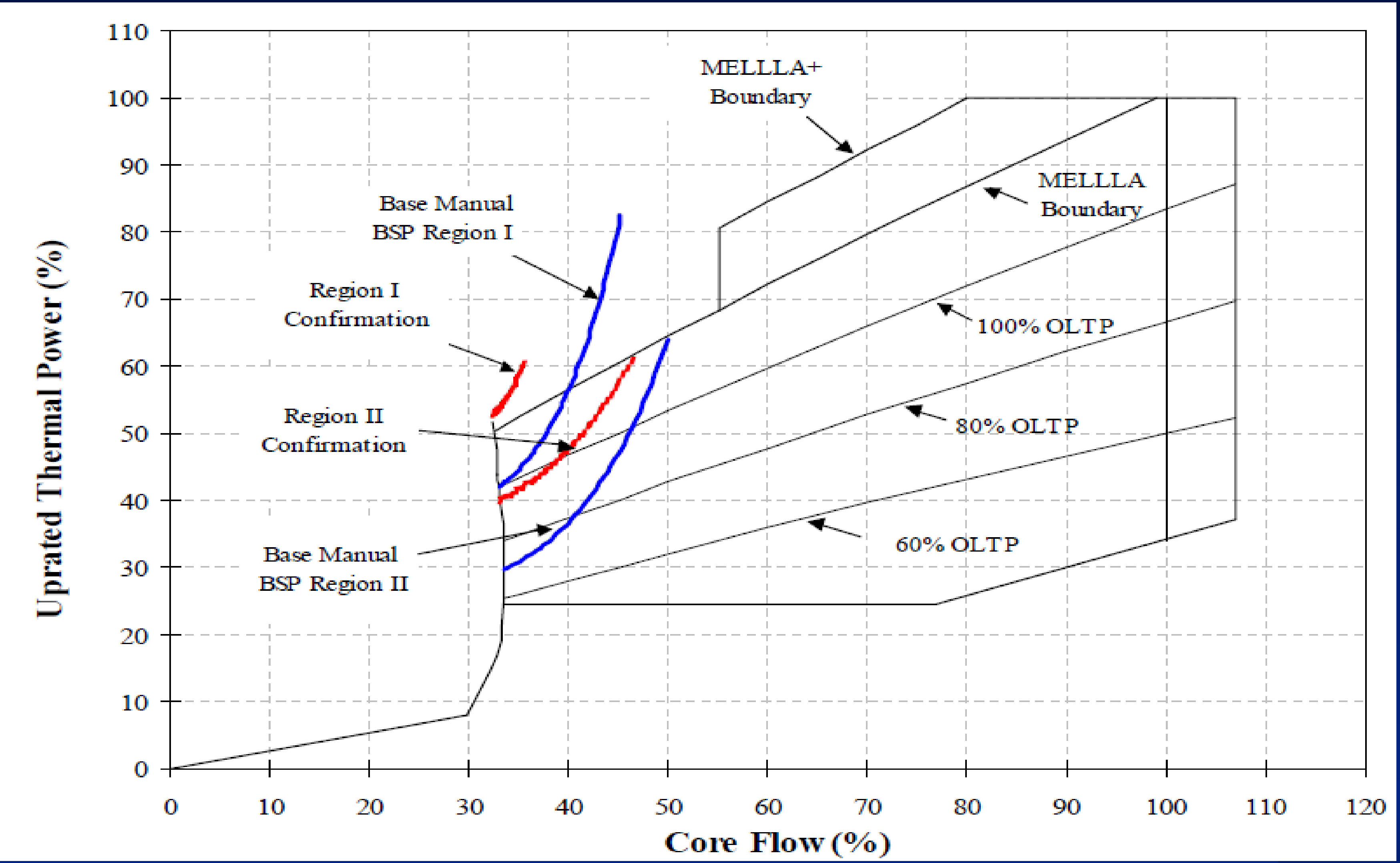
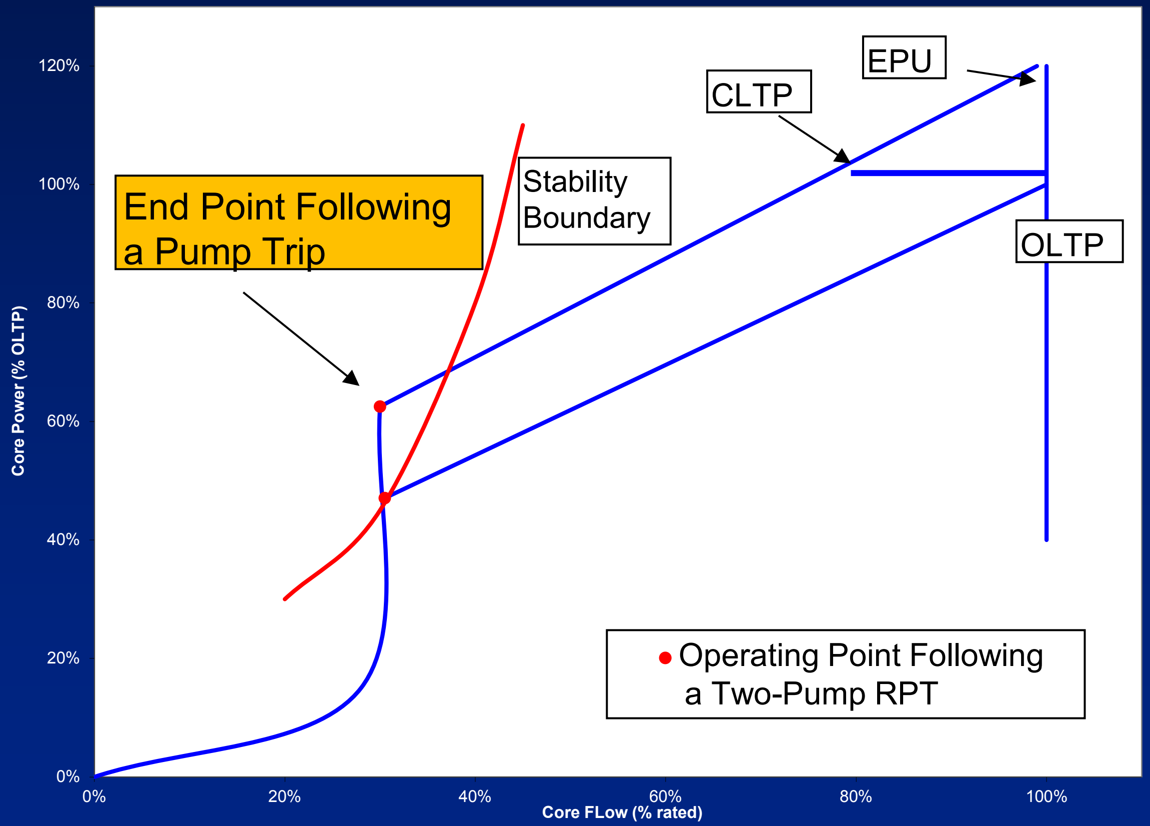
BWR Operating Map



EPU Does Not Change the End Point After the Recirculation Pump Trip



- End Point is the same for CLTP and EPU because it is defined by
  - Natural Circulation
  - Subcooling (lower pressure of FW heating-steam)
- Stability characteristics of end point are similar

Stability

- LTS Option ID installed for years with good experience
- Solution III installed and armed since 2009 as part of the EPU upgrade
  – Plant followed the standard 90-day trial period for setting adjustable parameters and familiarization
  – Backup solution is based on Interim Corrective Actions (ICA) with plant-specific regions and 120 day maximum
- Plant has good experience with Option III
- No impact expected for EPU
  – Option III and DIVOM methodology are applicable

ATWS - Instability

- MNGP has implemented latest EPG/SAGs
  - Early level reduction & boron injection

- MNGP has excellent ATWS response because
  - Low power density, and
  - High suppression pool Heat Capacity Temperature Limit (HCTL ~180F)
  - Not likely to need emergency depressurization

- EOPs are reviewed every cycle and are not affected significantly by EPU

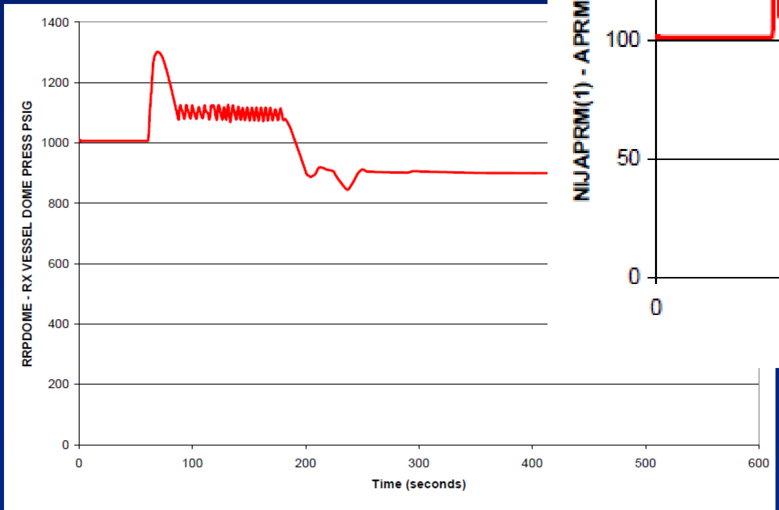
Staff Audit

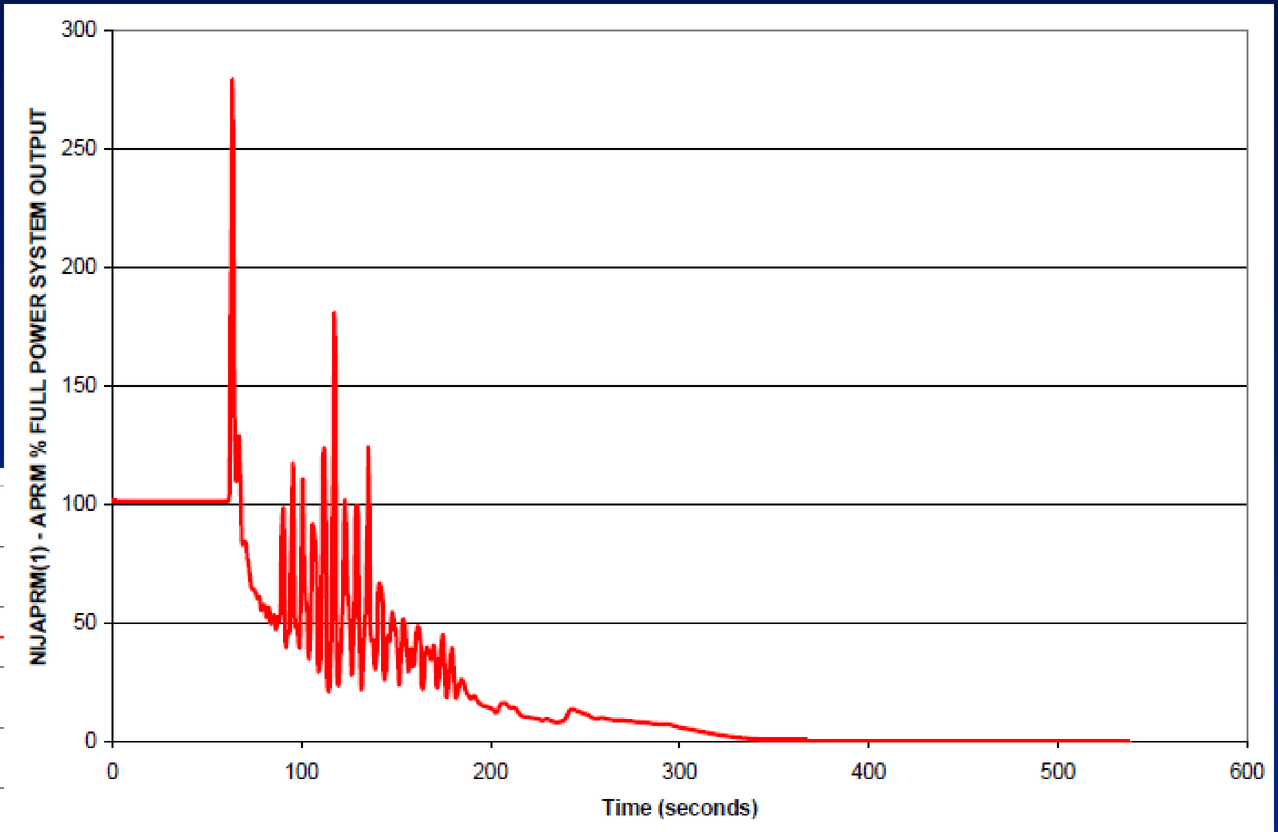
- Staff reviewed the performance of the OPRM Solution III system in the simulator

- For EPU, Staff reviewed ATWS performance in the simulator (2 different scenarios)
  – Turbine Trip ATWS from full power EPU conditions
  – MSIV Isolation ATWS from full power EPU conditions

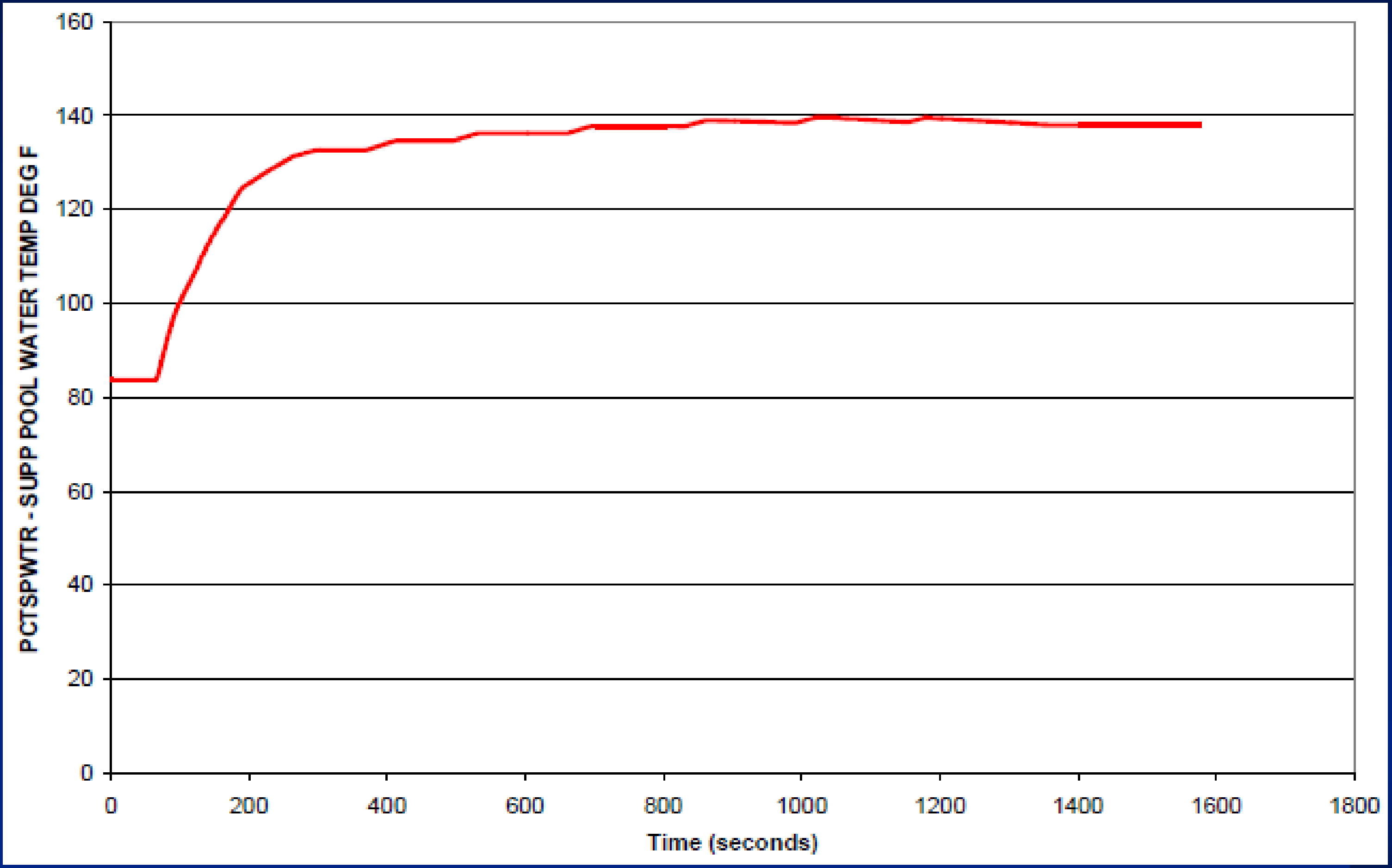
- MNGP provided the simulator ATWS result plots

Simulator Indicates that Mitigation Actions are Still Effective at EPU Conditions





Simulator Indicates Margin to Emergency Depressurization (HCTL ~180F at 1000psi)



Summary

- EPU operation is acceptable from stability point of view
  - Installed LTS (Sol III) provides similar level of protection under EPU and CLTP
  - OPRM scram satisfies GDC 10 and 12

- ATWS and ATWS-Stability not affected significantly by EPU
  - Satisfies ATWS Acceptance Criteria (10CFR 50.62)
  - MNGP has excellent ATWS performance design
    - Low power density
    - High HCTL (~180F)

Questions

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Monticello Nuclear Generating Plant
Extended Power Uprate
ACRS Subcommittee Meeting

Containment Accident Pressure

Ahsan Sallman

Containment and Ventilation Branch
Division of Safety Systems
Office of Nuclear Reactor Regulation

Contents

1. Key Definitions

2. Regulatory Requirement

3. Monticello EPU CAP Needs & Staff Guidance for Using CAP

4. Staff Evaluation of Licensee's Implementation of CAP Guidance in Enclosure 1 of SECY-11-0014

5. CAP Credits

6. Summary

Key Definitions

- NPSHa - The transient NPSH available at the suction inlet of the pump determined conservatively by using initial conditions and assumptions that minimize the transient wetwell pressure and maximize the transient suppression pool temperature

- CAP is the transient absolute pressure developed above pool surface during an accident or an abnormal event minus the minimum allowed technical specification absolute pressure above pool surface during normal operation.

- CAP Credit refers to the inclusion of the CAP in the calculation of NPSHa

Key Definitions (cont'd)

- NPSHr3%- Hydraulic Institute has defined NPSH required (NPSHr) as NPSH corresponding to a decrease in pump total dynamic head of 3% for a given flow.
- NPSHreff = (1 + Uncertainty) x NPSHr3%
- Uncertainty is a fraction that accounts for the differences between the pump vendor test value (NPSHr3%) and the as-installed at site value (NPSHreff)
- For DBA LOCA, NPSH margin = (NPSHa – NPSHreff)
- For non-DBAs, NPSH margin = (NPSHa – NPSHr3%)
- Adequate NPSHa means positive NPSH margin
- NPSH Margin Ratio = NPSHa/NPSHr3%

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Regulatory Requirement

To satisfy AEC proposed GDCs applicable to Monticello- equivalent to current GDC-38, "Containment Heat Removal", the Core Spray (CS) and Residual Heat Removal (RHR) pumps should have adequate NPSHa during the design basis accident and non design basis events.

Monticello EPU CAP Needs & Staff Guidance for Using CAP

- CAP Credit is needed CS and RHR pumps NPSHa analysis for:
  - Design Basis LOCA
  - Small Steam Line Break Accident
  - ATWS Event
  - Appendix R Fire Event
- CAP credit not needed for SBO event
- Staff guidance issued in SECY-11-0014

Staff Evaluation of Licensee's Implementation of CAP Guidance in Enclosure 1 of SECY-11-0014

6.6.1 - For calculating NPSH margin, NPSHreff should be used for DBA LOCA & NPSHr3% may be used for non-DBAs
Evaluation - implemented in licensee's NPSH analysis

6.6.2 - Pump flow rate assumed in NPSH analysis should be greater than the flow rate used in ECCS analysis
Evaluation - implemented in licensee's NPSH analysis

6.6.3 - Perform Monte Carlo statistical analysis to calculate the CAP used to determine NPSHa
Evaluation - Monte Carlo 95/95 analysis performed; the analysis quantified the margin in conservative analysis

Staff Evaluation of Licensee's Implementation of CAP Guidance in Enclosure 1 of SECY-11-0014 (cont'd)

6.6.4 - Demonstrate loss of containment integrity from containment venting, circuit issues due to an Appendix R Fire or other causes cannot occur as long as CAP is needed.

Evaluation

- ***Considered most limiting Appendix R Fire scenario,***
- ***Considered effect of multiple spurious operation (MSO) following guidance in NEI 00-01 Revision 2 (endorsed by NRC) and RG 1.189 Rev 2***
- ***Performed modification to preclude fire induced MSOs from adversely affecting safe shutdown.***
- ***Loss of containment integrity due to fire induced failures adequately addressed.***

Staff Evaluation of Licensee's Implementation of CAP Guidance in Enclosure 1 of SECY-11-0014 (cont'd)

6.6.5 - Operator action to control CAP is acceptable upon NRC staff approval and to be included in plant procedures

Evaluation - No new operator action

6.6.6 - NPSHa is less than NPSHreff or NPSHr3% is acceptable if tests are done to demonstrate the pump will perform its safety function.

Evaluation - Sulzer evaluation during factory test shows no detectable pump degradation for 4-minutes when NPSHa is between NPSHreff3% and NPSHreff5%

Staff Evaluation of Licensee's Implementation of CAP Guidance in Enclosure 1 of SECY-11-0014 (cont'd)

6.6.7 - Consideration of loss of CAP due to loss of containment integrity; determine minimum leakage that looses CAP needed; perform an on-line leakage monitoring

Evaluation ***- Calculated the minimum containment leakage rate that will loose the CAP needed and proposed an acceptable on-line monitoring procedure using the available control room data.***

6.6.8 - Consideration of zone of maximum erosion that lies between NPSH margin ratio of 1.2 to 1.6; limit the operating time in this zone unless justified.

Evaluation ***- RHR and CS pump manufacturer (Sulzer) report on impeller service life indicates at 6200 days service life while operating in the NPSH margin ratio between 1.2 to 1.6***

Staff Evaluation of Licensee's Implementation of CAP Guidance in Enclosure 1 of SECY-11-0014 (cont'd)

6.6.9 Perform a realistic calculation of NPSHa and compare with Monte Carlo 95/95 analysis results to demonstrate conservatism in Monte Carlo analysis.

<u>Evaluation</u>* - *Realistic inputs (met 98% of the time at Monticello) for DBA LOCA analysis, and a best-estimate code; demonstrated required CAP credit about 70% of the required CAP credit in Monte Carlo analysis and 50% of the required CAP credit in conservative analysis both using the SHEX code.

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Staff Evaluation of Licensee's Implementation of CAP Guidance in Enclosure 1 of SECY-11-0014 (cont'd)

6.6.10 Pump mission time using CAP should include the accident mitigation time when the NPSH margin is limited plus additional time (about 30 days) needed to maintain the reactor and containment in a stable cool condition

<u>Evaluation</u> - Pump mission time for DBA LOCA and non-DBA events until the CAP credit is not needed evaluated and results are acceptable

CAP Credits

Accident /Event	Most Limiting Pump	Maximum CAP Credit (psig)	CAP available when maximum CAP is needed (psig)	Duration of CAP need (hours)	Minimum NPSHa for the most limiting pump (feet)	NPSHreff (1) (feet) NPSHr3% (2) (feet)
DBA-LOCA (long term)	CS	9.1	10.0	126.4	30.2	28.2 (1)
ATWS	RHR	6.2	9.6	7.6	23.9	23.5 (2)
App R Fire with SORV	RHR	3.3	7.0	28.7	31.2	23.5 (2)
App R Fire, No SORV	RHR	3.1	6.8	28.8	31.0	23.5 (2)

Summary

- The Monticello EPU containment NPSHa analysis credits CAP for CS and RHR pumps for DBA and non-DBA events.

- The licensee has satisfied staff guidance in SECY-11-0014 for the use of CAP under EPU conditions.

- The NRC staff considers the use of CAP to be acceptable for the Monticello EPU.

U.S.NRC
UNITED STATES NUCLEAR REGULATORY COMMISSION
Protecting People and the Environment

Questions

Public Comments

Committee Comments

Adjourn

Monticello Nuclear Generating Plant
Extended Power Uprate

Advisory Committee on Reactor Safeguards

Meeting of the Subcommittee on Power Uprates

July 25 - 26, 2013

Monticello Nuclear Generating Plant

Extended Power Uprate

Introduction

Mark Schimmel

Site Vice President

ACRS Subcommittee Agenda

- EPU Overview (NSPM)
  - Background
  - Plant Modifications
  - Reconstitution of Programs
  - Power Ascension
- Nuclear Design and Safety Analyses (NSPM)
  - Transient and Accident Analyses
  - Long Term Stability Solution Option III
  - Impact of EPU on ATWS-Stability
  - Thermal-Hydraulic Stability
  - GE EPU Interim Methods Applicability

ACRS Subcommittee Agenda

- **Safety Analyses (NRR)**
  - **Transient and Accident Analyses**
  - **Long-Term Stability Solution Option III and Impact of EPU on ATWS-Stability Events**
  - **Thermal Conductivity Degradation**
- **Safety Analysis - *Closed Session (if necessary)***
- **Containment Analysis and Containment Accident Pressure (NSPM)**
- **Containment Accident Pressure (NRR)**

ACRS Subcommittee Agenda

- **Material and Mechanical/Civil Engineering (NSPM)**
- **Mechanical/Civil Engineering (NRR)**

Closed Session

- **Steam Dryer Overview (NSPM)**
- **Steam Dryer Review Status (NRR)**

Open Session

- **Electrical Engineering (NSPM)**
  - **Electric Plant Overview**
  - **Station Blackout Capability**
  - **Grid Stability**
- **Electrical Engineering (NRR)**

NSPM ACRS Subcommittee Presenters

- Mark Schimmel – Monticello Site Vice President
- Nate Haskell – Monticello Engineering Director
- John Bjorseth – Monticello EPU Project Director
- Steve Hammer – Monticello EPU Licensing Project Manager
- Rick Stadtlander – Monticello Operations Shift Manager

Table of Contents

EPU
Project Overview

Background

Plant Modifications

Reconstitution of Programs

Power Ascension Plan

Background

Monticello Nuclear Generating Plant Overview

Operating License issued on September 8, 1970

Commercial Operation commenced on June 30, 1971

Full Term Operating License was issued on January 9, 1981

GE BWR 3 - Mark I Containment

OLTP Limit	1670 MWt
Initial Plant Rerate Implemented in 1998 (CLTP)	1775 MWt
20% OLTP (12.9% CLTP) EPU Planned for 2013	2004 MWt

EPU Project Team Staffed with Personnel Having Extensive BWR Plant Experience

Background

Monticello Nuclear Generating Plant Overview

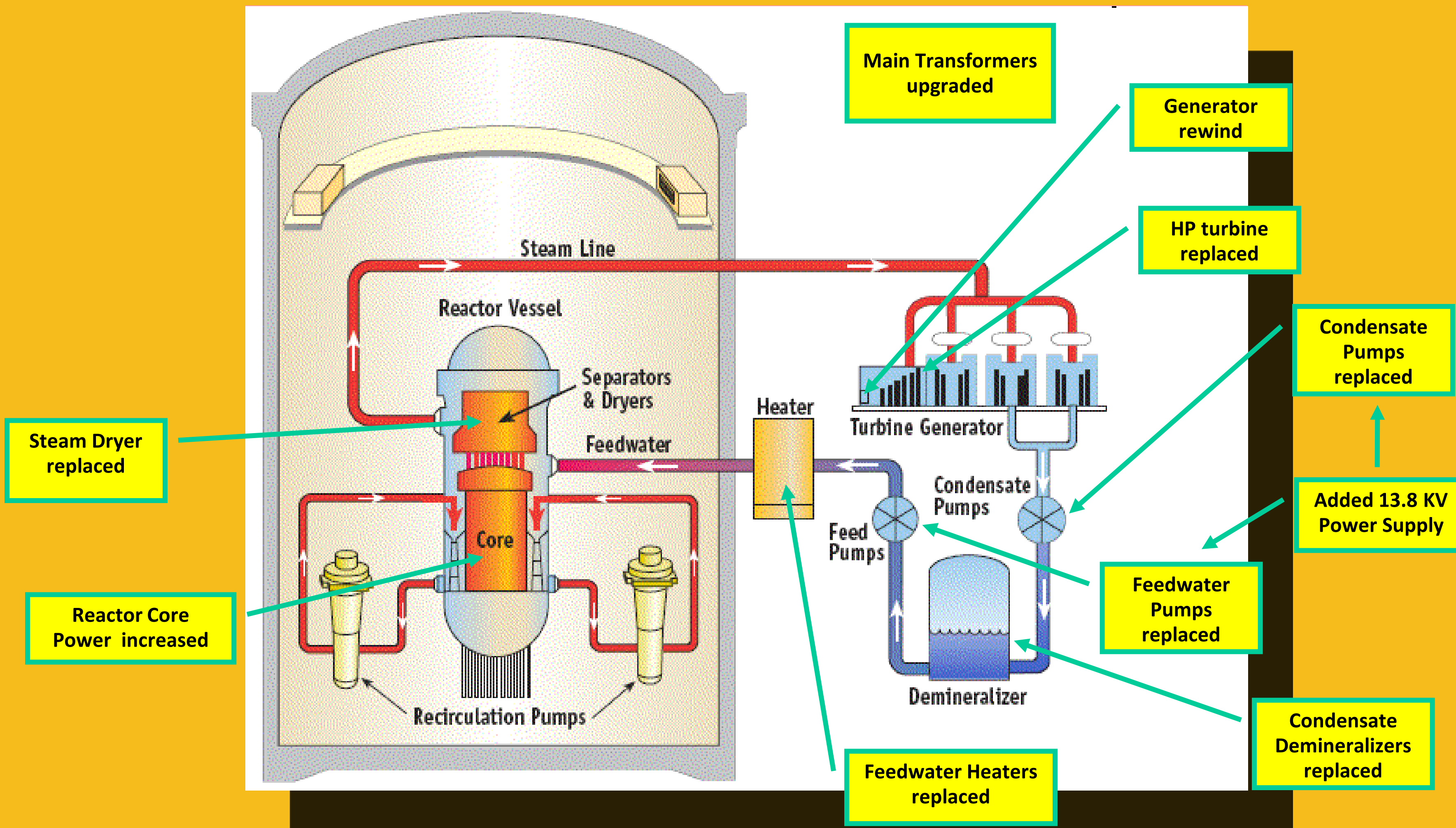
- EPU application based on GEH Extended Power Uprate Licensing Topical Reports
  - NEDC-32424 (ELTR-1)
  - NEDC-32523 (ELTR-2)
  - NEDC-33004 (CLTR)
  - NEDC-33173 (IMLTR)
- Constant reactor pressure uprate
- 12.9% CLTP EPU considered optimum for design, fuel cycle capabilities and operating margins

Background
Overview of Major Parameter Changes

Parameter	CLTP	EPU
Core Thermal Power (MWt)	1775	2004
Full Power Core Flow Range (Mlbm/hr)	47.5 - 60.5	57.0 - 60.5
Full Power Core Flow Range (% Rated)	82.4 - 105	99 - 105
Steam Dome Pressure Limit (psia)	1025	1025
Vessel Steam Flow (Mlbm/hr)	7.26	8.34
Feedwater Flow Rate (Mlbm/hr)	7.24	8.31
Final Feedwater Temperature (ºF)	383	402

Plant Modifications

Overview of Major Modifications



Plant Modifications

Major EPU Modifications to Improve Safety and Transient Risk Margins

Steam Dryer Replacement – Improved Operating Margins, Moisture Carryover

Very Small PRA Risk change – offset by modifications

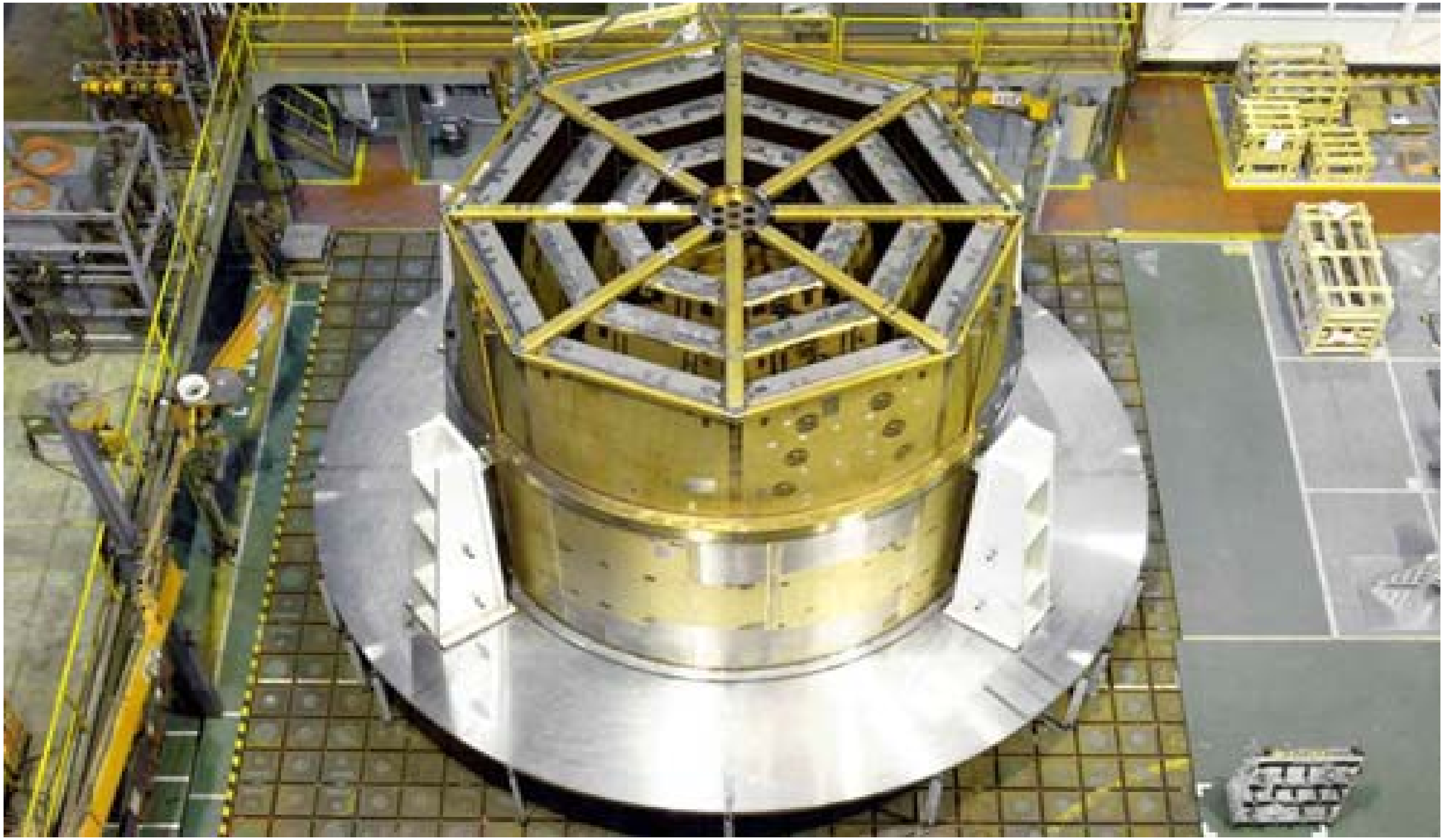
EQ modifications – Improved Qualified life on replaced components

Training and Simulator upgrades – Changed to assure fidelity with plant

TS Setpoint Changes – Changed to meet Safety Analysis Margins

Plant Modifications

Replaced Steam Dryer



Plant Modifications

Improved Training and Simulator Panels

Plant Modifications

Major EPU Modifications to Improve Reliability and Operating Margins

FW Heater Replacements

FW Pump and Motor Replacement

Condensate Pump and Motor Replacement

Condensate Demineralizer Replacement

MG Set Motor Replacement

High pressure turbine replacement

Generator Field and Stator Rewind

Transmission system upgrades (1AR Replacement)

Main Transformer

13.8KV Bus and transformers

Plant Modifications

New Feedwater Heaters

Plant Modifications

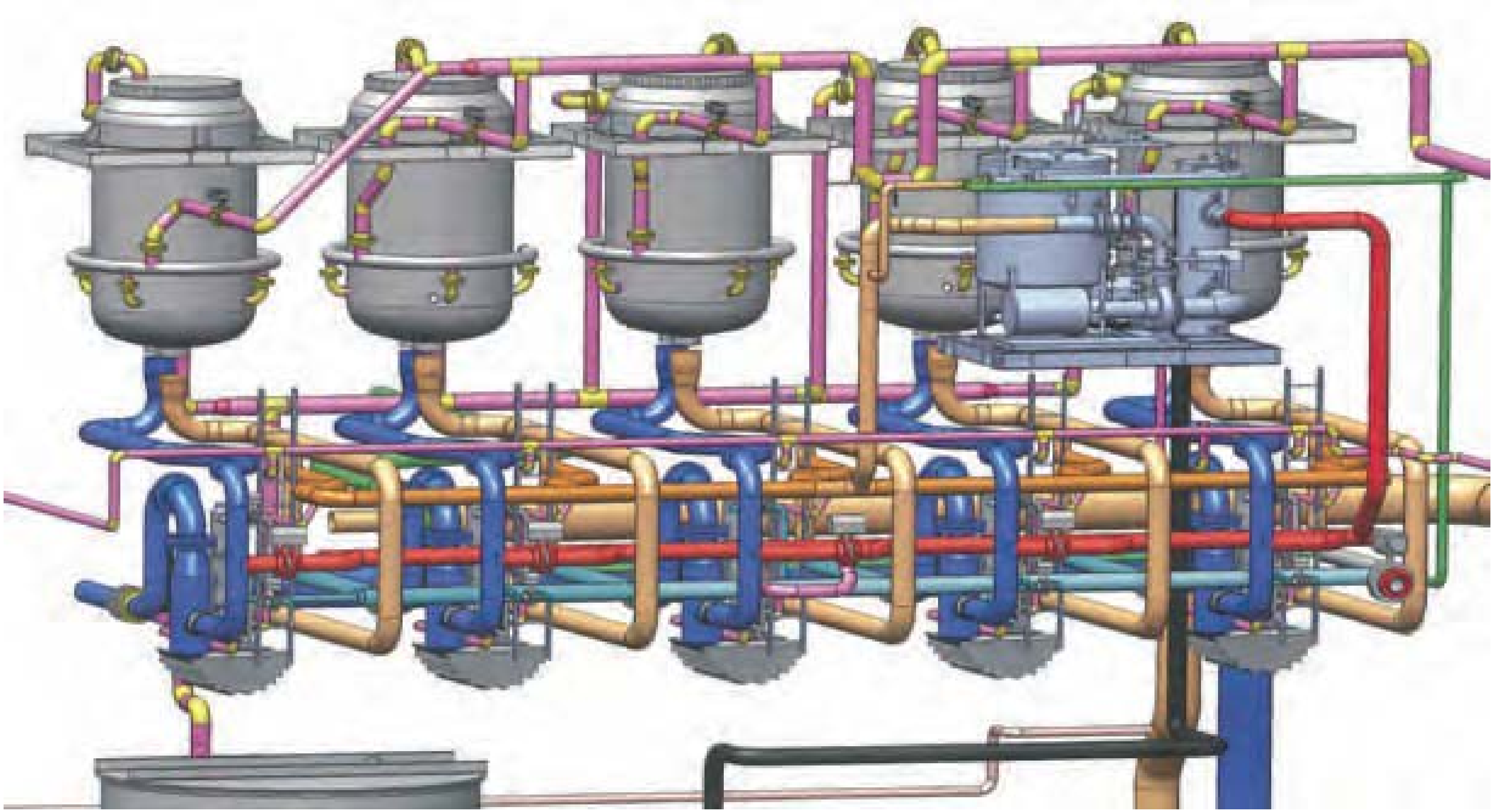
New Feedwater Pumps and Motors

Plant Modifications

New Condensate Pumps and Motors

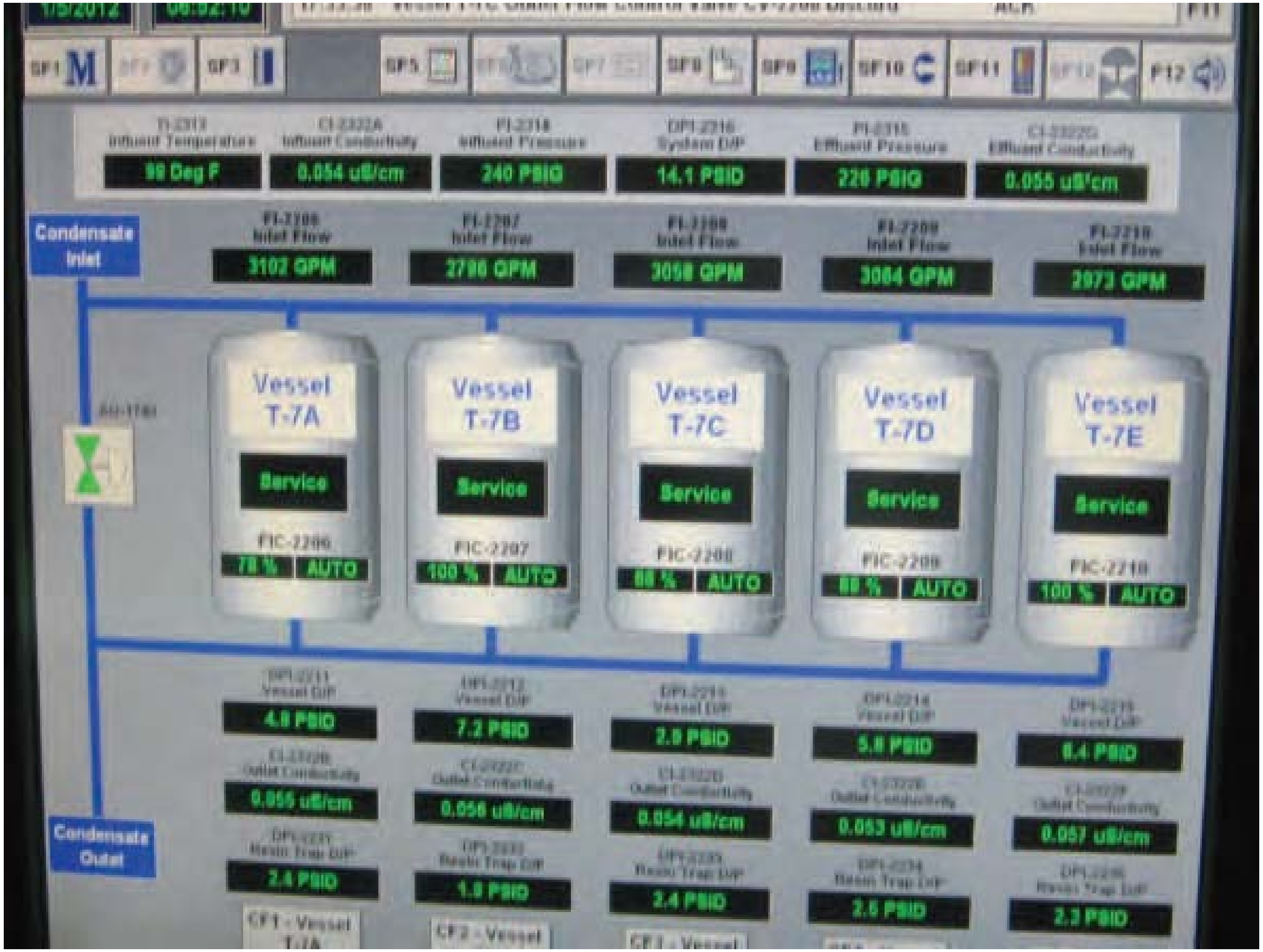
Plant Modifications

Condensate Demineralizer Replacement



Plant Modifications

Condensate Demineralizer Replacement

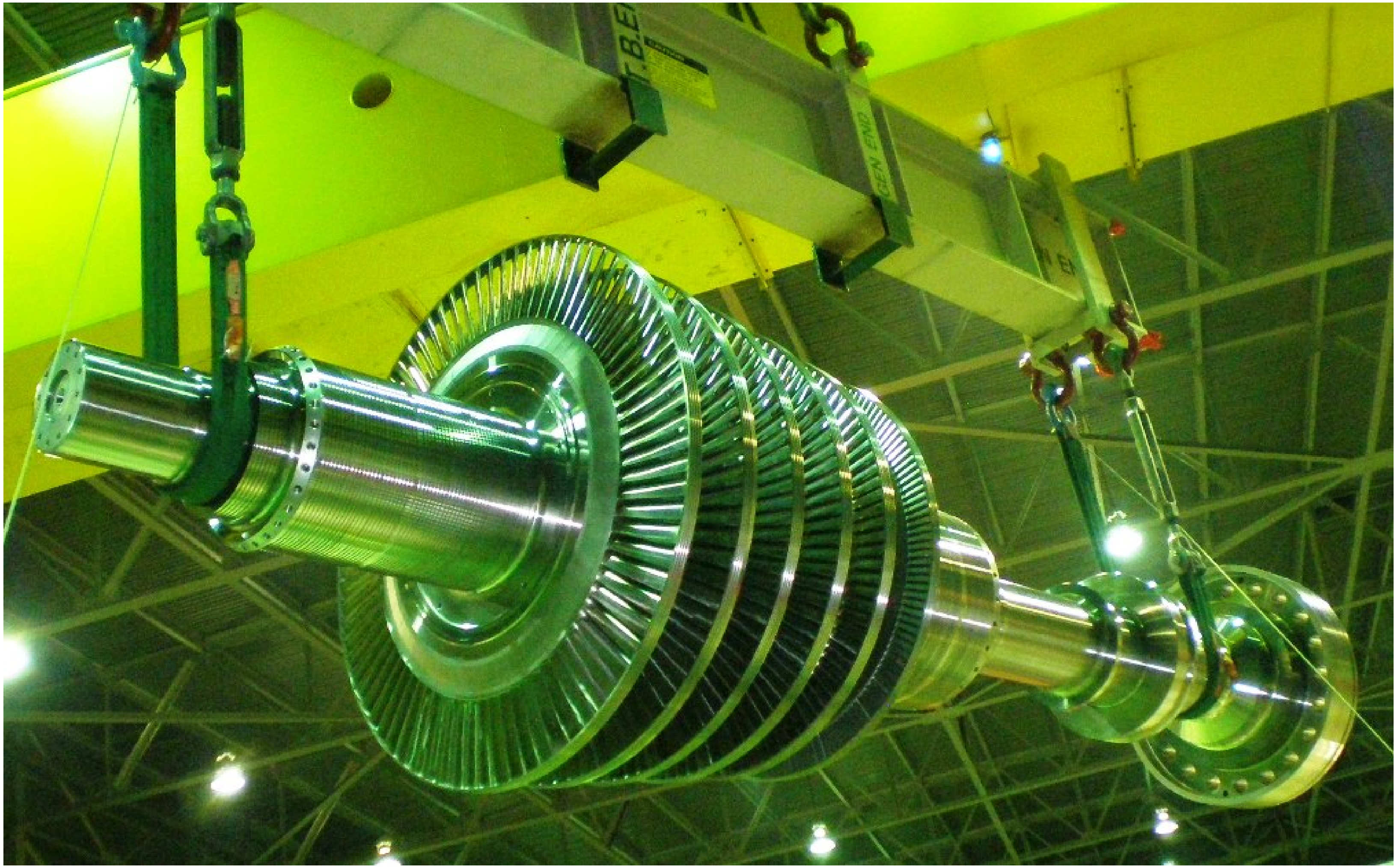


Plant Modifications

MG Set Motor Replacement

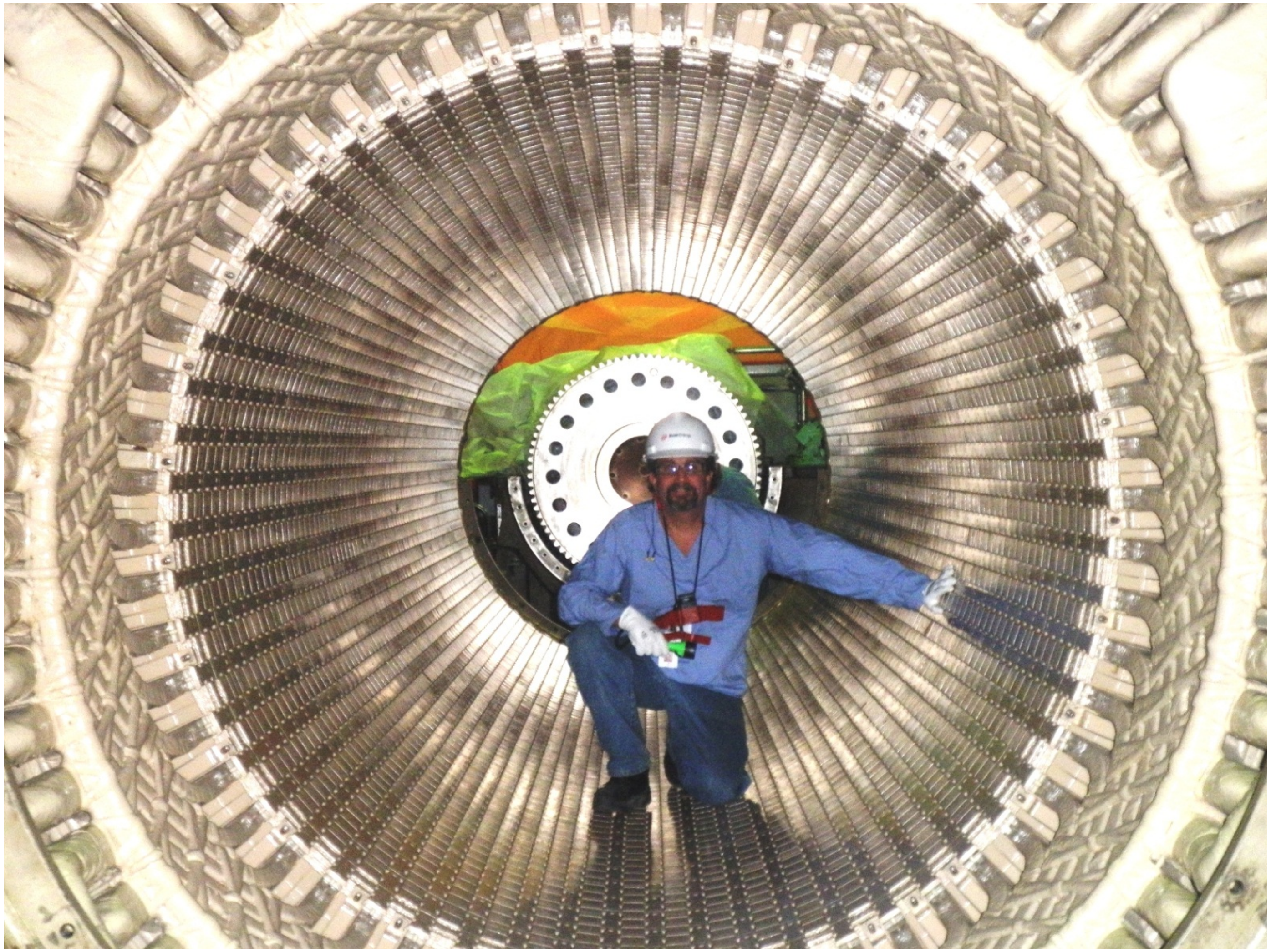
Plant Modifications

New High Pressure Turbine



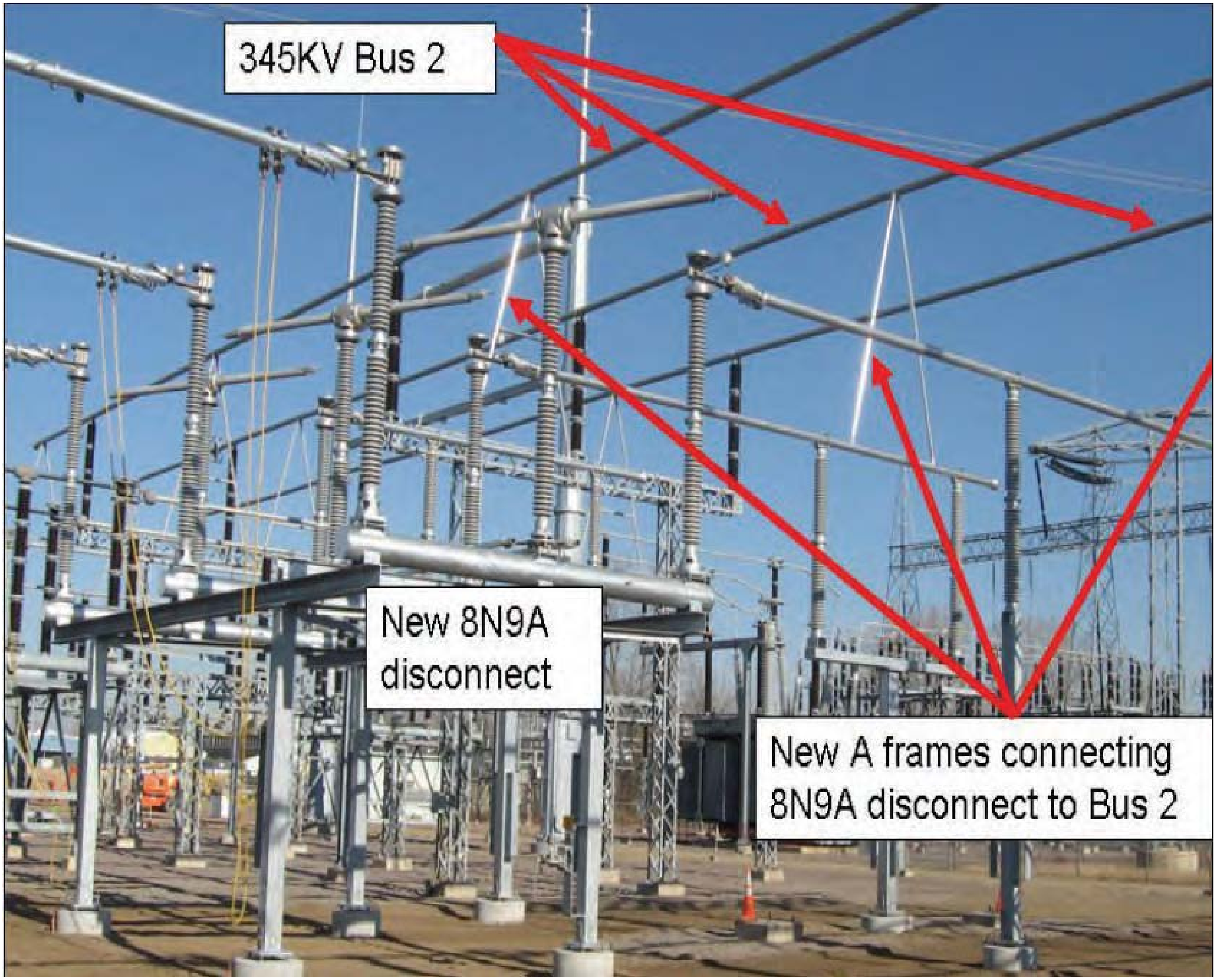
Plant Modifications

Generator Rewind



Plant Modifications

Transmission System Upgrades



Plant Modifications

Transmission System Upgrades

Plant Modifications

New Main Transformer

Plant Modifications

New Auxiliary Transformers for 13.8 KV

Plant Modifications

13.8 KV Busses

Reconstitution of Programs

High Energy Line Break

Environmental Qualification

Motor-Operated Valve

Program Reconstitution

High Energy Line Break

- Purpose – Update Existing Analyses to reflect EPU conditions
- Enhanced HELB model, latest version of GOTHIC
- Results indicated acceptable levels of temperature, pressure and submergence for all reactor building and turbine building volumes
- Pipe Whip and Jet Impingement evaluations showed acceptable results

Program Reconstitution

Environmental Qualification

- Updated the environmental profiles to reflect revised HELB inputs
- Qualification files converted into EPRI's EQMS format
- Conclusion: all equipment within the scope of the EQ Program remains qualified

Program Reconstitution

Motor-Operated Valve

Reconstitution consisted of:

- Developed revised MOV functional analyses (system calculations) for differential pressures, temperatures, and flows to account for system condition changes pursuant to the EPU

- Updated the valve COF analysis

- 10 MOVs required switch adjustments to satisfy EPU conditions

Power Ascension Plan

Power Ascension Test Approach

Major Testing

PAT Acceptance Criteria

Power Ascension Test Approach

No large transient testing

- Industry OE demonstrates predicted transient response following EPU implementation
- Performed large transient during initial startup (OLTP) testing
- Plant specific events bound initial startup testing
  - 2001 MSIV closure event at 98% CLTP
  - 2002 Generator Load Reject at 100% CLTP
- No new design functions in safety-related systems are required that would need large transient testing validation for EPU
- Based on plant historical data and EPU analytical results, the large transients result in conditions that are within design limits

Power Ascension Test Preparation

- **EPU test plan developed in accordance with SRP 14.2.1**
- **Post Modification testing performed satisfactorily**
- **Test plan consists of 10 individual tests**
  - 9 tests from original startup testing scope
  - Steam dryer power ascension test plan
- **Tests developed and will be performed by personnel experienced in MNGP testing**

Power Ascension Major Testing

Test Description	Test Condition (% CLTP)							
	≤ 90	100	102.5	105	107.5	110		EPU
Chemical/ Radiochemical		X	X	X	X	X		X
Steam Dryer	X	X	X	X	X	X		X
Radiation		X	X	X	X	X		X
Pressure Regulator	X	X	X		X			X
Feedwater System	X	X	X		X			X
IRM Performance	In accordance with Surveillance Program							
APRM Calibration		X						
Core Performance	X	X	X	X	X	X		X
MS and FW piping Vibration		X	X		X			X
Plant Monitoring	X	X	X		X			X

PAT Acceptance Criteria

- Level 1 Acceptance Criteria - Associated with plant safety
- If a Level 1 Test Criterion is not met:
  - The plant must be placed in a hold condition that is judged to be satisfactory and safe
  - Issue documented in the Corrective Action Program with resolution immediately pursued (Plant operating procedures, test procedures, or Technical Specifications, may guide the decision on the direction to be taken)
  - Following resolution, the failed test must be repeated to verify the Level 1 requirement is satisfied or justification for NOT re-performing is documented
  - A description of the problem must be included in the report documenting the successful test

PAT Acceptance Criteria

- Level 2 Acceptance Criteria - Associated with design performance.
- If a Level 2 Test Criterion is not met:
  - The limits stated in this category are usually associated with expectations of system transient performance, whose characteristics can be improved by equipment adjustments
  - Issue documented in the Corrective Action Program and evaluation of performance or equipment adjustments related to the criteria not met
  - An evaluation will be initiated to investigate the performance parameters and controller adjustments related to the criteria <u>NOT</u> met, as well as the measurement and analytical methods, if appropriate
  - This evaluation is to include alternative corrective actions and concluding recommendations.

Nuclear Design and Safety Analyses

Transient and Accident Analyses

Long-Term Stability Solution Option III

Thermal-Hydraulic Stability

EPU Interim Methods Applicability

Impact of EPU on ATWS-Stability

Transient & Accident Analyses

EPU Analyses

- Excessive Heat Removal
- Decrease in Heat Removal
- Loss of Non-Emergency AC
- Loss of Feedwater Flow
- Decrease in RCS Flow
- Instantaneous Loss of RCS Flow
- Uncontrolled CRA Withdraw – Low Power
- Uncontrolled CRA Withdraw – At Power
- Startup of Inactive RCS Loop
- Control Rod Drop Accidents
- Increase in RCS Inventory
- Inadvertent Opening of PRV
- LOCAs

Special Events

- ATWS
- Station Blackout
- Appendix R

Radiological Events

- LOCA
- Fuel Handling Accident
- Control Rod Drop Accident
- Main Steam Line Break

Limiting Events

- Results

Excessive Heat Removal

- Events:
  - Decrease in Feedwater Temperature
  - Increase in Feedwater Flow
  - Increase in Steam Flow
  - Inadvertent Opening of a Main Steam Relief or Safety Valve
- Evaluation:
  - Meets CLTR Requirements
  - Confirmed that fuel design limits and RCPB limits are not exceeded under EPU conditions
  - Reload evaluation scope for non-bounded events

Decrease in Heat Removal

- Events:
  - Loss of External Load
  - Turbine Trip
  - Loss of Condenser Vacuum
  - Closure of Main Steam Isolation Valve
  - Steam Pressure Regulator Failure (Closed)
- Evaluation:
  - Meets CLTR Requirements
  - Confirmed that fuel design limits and RCPB limits are not exceeded under EPU condition
  - Reload evaluation scope for non-bounded events

Loss of Non-Emergency AC

- Event:
  - Results in the loss of all power to the station auxiliaries and the simultaneous tripping of all RRPs
  - Causes a flow coast down as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip
- Evaluation:
  - Meets CLTR Requirements
  - Determined to be non-limiting event, Turbine Trip with steam bypass failure is more limiting
  - Not in reload evaluation scope

Loss of Feedwater Flow

- Event:
  - Results from FW pump failures, valve malfunctions, or a LOOP
  - Results in an increase in reactor coolant temperature and pressure which eventually requires a reactor trip to prevent fuel damage
- Evaluation:
  - Adequate core cooling is provided by maintaining reactor water level above TAF
  - Assumes failure of HPCI and uses only RCIC to restore reactor water level

Decrease in RCS Flow

- Events:
  - Trip of RRP Motor
  - RCS Flow Controller Malfunctions
- Evaluation:
  - Meets CLTR Requirements
  - Determined to be non-limiting event
  - Not in EPU or reload analysis scope

Instantaneous Loss of RCS Flow

- Event:
  - Instantaneous seizure of the rotor or break of the shaft of a reactor recirculation pump
  - Results in sudden decrease in core coolant flow leading to a reactor and turbine trip
- Evaluation:
  - Meets CLTR Requirements
  - Determined to be non-limiting event, except in SLO, which has a separate MCPR limit
  - Confirmed that fuel design limits and RCPB limits are not exceeded under EPU conditions

Uncontrolled CRA Withdrawal – Low Power

- Event:
  - Uncontrolled CRA withdrawal from subcritical or low power startup conditions caused by a malfunction of the reactor control or rod control systems
  - Results in uncontrolled addition of positive reactivity to the reactor core, resulting in a power excursion
- Evaluation:
  - Peak fuel enthalpy at EPU is 72 cal/gram, below acceptance criteria of 170 cal/gram
  - Verified by EPU and reload analysis

Uncontrolled CRA Withdrawal – At Power

- Event:
  - Uncontrolled CRA withdrawal at power caused by a malfunction of the reactor control or rod control systems
  - Results in uncontrolled addition of positive reactivity to the reactor core, resulting in a power excursion
- Evaluation:
  - Meets CLTR Requirements
  - Reload analysis verifies

Startup of Inactive RCS Loop

- Events:
  - Increased core flow
  - Introduction of cooler water into the core
  - Event causes an increase in core reactivity due to decreased moderator temperature and core void fraction
- Evaluation:
  - Meets CLTR Requirements
  - Determined to be non-limiting event
  - Reload analysis verifies

Control Rod Drop Accidents

- Event:
  - CRDA can occur due to collet finger failures in one CRDM, a CRD system pressure regulator malfunction, or a CRDM ball check valve failure
- Evaluation:
  - Meets CLTR Requirements
  - Control Rod Sequencing for EPU follows BPWS
  - Peak fuel enthalpy at EPU is 162 cal/gram, below acceptance criteria of 280 cal/gram
  - Reload analysis verifies

Increase in RCS Inventory

- Event:
  - Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory
  - Depending on RCS temperature, event may cause a:
    - Power level increase and, without adequate controls, could lead to fuel damage or overpressurization of the RCS, or
    - Power level decrease and depressurization
- Evaluation:
  - Meets CLTR Requirements
  - Reload analysis verifies

Inadvertent Opening of PRV

- Event:
  - Opening of a PRV results in a RCS inventory decrease and a decrease in RCS pressure
  - Pressure regulator senses the RCS pressure decrease and partially closes the TCVs to stabilize the reactor at a lower pressure
  - Reactor power settles out at nearly the initial power level
  - FW control system maintains RCS inventory using water from the CST
- Evaluation:
  - Meets CLTR Requirements
  - Reload analysis verifies

LOCAs

- Event:
  - Loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system
- Evaluation:
  - HPCI used for SBAs, CS/LPCI used for all LOCAs after depressurized
  - ADS uses SRVs to reduce reactor pressure following SBA (assumes HPCI fails)
    - EPU results in a longer ADS blowdown and a higher PCT for the small break LOCA
    - MNGP analyses demonstrate that there is sufficient ADS capacity at EPU conditions with all ADS valves available

LOCAs

- ECCS Performance
  - Break Spectrum not affected by EPU
  - 10 CFR 50 Appendix K analysis results confirm that the limiting break is the recirculation suction line DBA and that the LPCI Injection valve failure is the limiting single failure
  - SLO
    - A multiplier is applied to Two-Loop LHGR and MAPLHGR Operation limits
    - Operating conditions for SLO are not changed with EPU; the CLTP SLO analysis is acceptable for EPU
  - ARTS limits are unaffected by EPU

LOCAs

- ECCS 10 CFR 50.46 criteria

10 CFR 50.46 Criteria	10 CFR 50.46 limit	EPU value
Licensing Basis Peak Clad Temperature	≤ 2200^oF	< 2140^oF + 10^oF (TCD Adder)
Local cladding oxidation limit	≤ 17%	< 9.0%
Hydrogen generation (Core-wide metal-water reaction)	≤ 1.0%	< 0.2%
Coolable Geometry	Maintained	Maintained
Long-term cooling	decay heat removed for extended period of time	decay heat removed for extended period of time

Special Events

ATWS

Station Blackout

Appendix R

ATWS

- Current Licensing Basis - 10 CFR 50.62
  - ARI system
  - Equivalent 86 gpm of 13 weight-percent sodium pentaborate
  - Automatic Reactor Recirculation Pump trip logic
- EPU Assessment - Three limiting cases evaluated:
  - MSIV closure
  - Pressure Regulator Fail Open
  - LOOP
- EPU Results
  - Local fuel conditions are not changed with EPU

Acceptance Criteria	CLTP	EPU
Peak vessel bottom pressure (1500 psig)	1385	1489
Peak Suppression pool temperature (281 ^{o}F)	187	189
Peak Containment pressure (56 psig)	11.1	11.6

Station Blackout

- Current Licensing Basis
  - NUMARC 87-00 and RG 1.155
  - All appropriate 10 CFR 50.63 criteria are met
  - Analytical model changed from MAAP to SHEX-06A
- EPU Impacts - increase in the initial power level and decay heat:
  - Increased drawdown of CST Inventory
  - More SRV cycles - higher compressed air usage
  - Increased Temperature/Pressures in Drywell and Containment
- EPU Results
  - Increased CST water requirements within current tank inventory
  - Additional SRV cycles within current actuator supply capacity
  - Peak Drywell/Containment temperatures within design limits
  - HCTL not exceeded

Appendix R

- Current Licensing Basis
  - 10 CFR 50.48
  - 10 CFR 50, Appendix R
- EPU Impacts – Two cases
  - One Relief Valve Stuck Open
  - No Stuck Open Relief Valves
- EPU Results
  - No New Operator Actions
  - No new equipment required for safe shutdown for Appendix R events
  - One train of systems remains available to achieve and maintain safe shutdown from main control room or alternate shutdown panel

EPU Results

Appendix R

Acceptance Criteria	CLTP	EPU
Cladding Temperature (1500 ^oF)	596	984
Primary System Pressure (1375 psig)	1273	1335
Primary Containment (56 psig)	27.3 psia	24.5 psia
Suppression Pool Temperature (212 ^oF)	193	197
Net Positive Suction Head Adequate for ECCS performance	Yes	Yes

Radiological Events

Alternative Source Term

Consequences Results

Radiological Events

Radiological Events - Consequences

- Event analyses based on AST (10 CFR 50.67 and GDC-19)
- Previous analysis performed at 1880 MWt
- Review performed using AST in accordance with guidance provided by RG 1.183 (July 2000)
- All EPU doses within regulatory limits

Radiological Events

Radiological Events - Consequences

Event	EPU Doses – (Rem TEDE)	Regulatory Limit – (Rem TEDE)
Post-LOCA	EAB - 1.46 CR Op - 3.80 LPZ - 1.99 TSC Op - 0.92	EAB - 25 CR Op - 5 LPZ - 25 TSC Op - 5
FHA	EAB - 1.74 CR Op - 4.67 LPZ - 0.34	EAB - 6.3 CR Op - 5 LPZ - 6.3
CRDA	EAB – 2.00 CR Op - 1.89 LPZ - 0.91	EAB - 6.3 CR Op - 5 LPZ - 6.3
MSLB – Pre-incident Iodine	EAB - 1.05 CR Op - 3.25 LPZ - 0.20	EAB - 25 CR Op - 5 LPZ - 25
MSLB – Equilibrium Iodine	EAB - 0.11 CR Op - 0.33 LPZ - 0.02	EAB - 25 CR Op - 5 LPZ - 25

Limiting Events

Transients and Accident Results

Transient & Accident Analyses

Limiting Events

Criteria	Limiting Event	Result CLTP / EPU	Limit CLTP / EPU
Suppression Pool			
–Temperature (AOO events)	App R	193 / 195.4 ºF	197.6 / 212 ºF
	ATWS (LOOP)	186.7 / 188.8 ºF	
	SBO	151.2/ 175.5 ºF	
–Temperature (w/debris)	DBA (LOCA)	194.2 / 207.1 ºF	
– Pressure	DBA (LOCA)	31.2 / 32.7 psig	56 psig
Drywell			
– Temperature	MSLB (SBA)	335 / 338 ºF*	335 / 338 ºF (air)
		273 / 278 ºF	281 ºF (wall)
– Pressure	DBA (LOCA)	39.5 - 43.4 / 44.1 psig	56 psig
Core Parameters			
– Peak Clad Temperature	DBA (LOCA)	2140 / 2140 + 10 ºF	2200 ºF
– Peak Vessel Pressure	MSIVC	1296 / 1335 psig	1375 psig

*** Use of revised analysis inputs increased CLTP results as shown.**

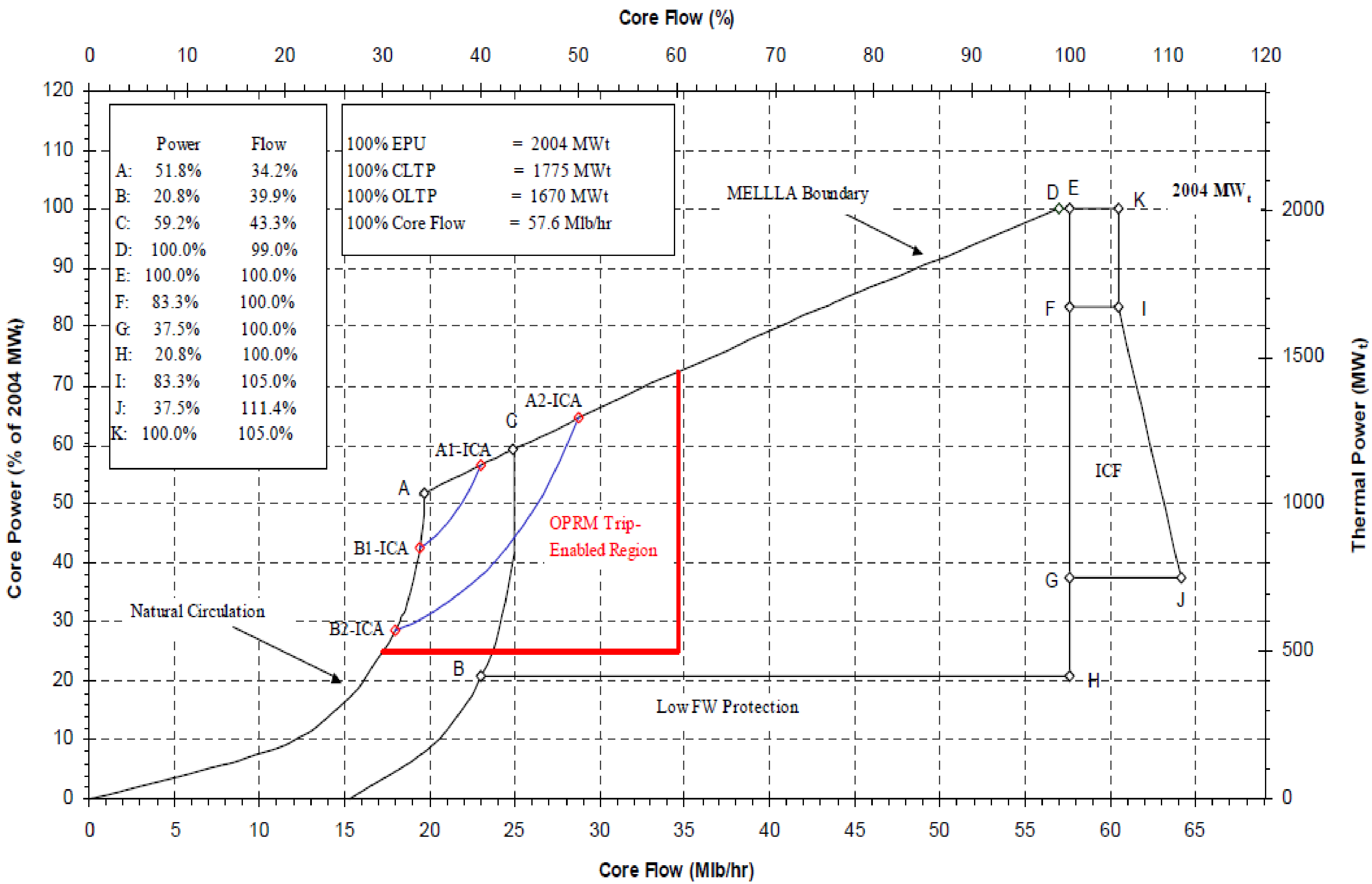
Long-Term Stability Solution
Option III
Thermal/Hydraulic Stability

Stability Solution

Stability Solution

- Licensing Basis
  - MNGP has installed Option III hardware – OPRM (TS Table 3.3.1.1-1 Function 2)
  - When OPRM system is inoperable BSP is utilized (TS 3.3.1.1.I)
  - When BSP is inoperable reduce power to < 20% RTP
- Design Basis Option III
  - Option III combines closely spaced LPRM detectors into "cells" to detect either core-wide or regional (local) modes of reactor instability (OPRM cells)
  - OPRM cells are configured to provide local area coverage with multiple channels
  - Hardware combines the LPRM signals and evaluates the cell signals with instability detection algorithms
  - PBDA is the only algorithm credited in the Option III licensing basis
  - Two defense-in-depth algorithms, (ABA and GRBA) offer a high degree of assurance that fuel failure will not occur as a consequence of instability related oscillations
- BSP used when Option III is inoperable

OPRM Trip Enabled Region



Thermal-Hydraulic Stability

- Conclusion
  - EPU effect on the thermal and hydraulic design of the core and the RCS is acceptable
  - GDC 12 is met at EPU conditions and instabilities continue to be effectively detected and suppressed
  - Plant specific reload analyses will confirm that fuel design limits will not be exceeded under EPU conditions

Impact of EPU on ATWS with Stability

ATWS with Stability for EPU

- Generically Addressed per CPPU LTR
  - "ATWS Rule Issues Relative to BWR Core Thermal-Hydraulics Stability", NEDO-32047-A, June 1995
  - "Mitigation of BWR Core Thermal-Hydraulic Instabilities in ATWS", NEDO-32164, December 1992
- NRC staff performed an operational audit of operator actions used to mitigate at MNGP Training Center on May 21, 2009.

EPU Interim Methods Applicability

IMLTR

EPU Interim Methods Applicability

Confirmatory Evaluations:

- **SER for NEDC-33173P-A Rev.1 imposes 24 limitations and conditions for application of GNF methods to expanded operating domains or EPUs**
- **Limitation conditions were evaluated for EPU submittal**
- **Limitation conditions were updated recently based on NRC approval of later codes and methods**

EPU Interim Methods Applicability

Limitation Condition	Disposition
1. TGBLA/PANAC Version – Must use TGBLA06 / PANAC11 or later NRC-approved codes	TGBLA06 / PANAC11 used to support MNGP EPU analysis
2. 3D Monicore – If using TGBLA04 / PANAC10 must bundle RMS Δ uncertainty from TGBLA04 / PANAC10	No reliance on TGBLA04 / PANAC10 in MNGP EPU analysis
3. Power to Flow Ratio - Thermal power to core flow ratio will not exceed 50 MWt/Mlbm/hr at any statepoint in the operating domain	Confirmed that the power to total core flow ratio does not exceed 50 MWt/Mlbm/hr in the EPU operating domain

EPU Interim Methods Applicability

Limitation Condition	Disposition
4. SLMCPR1 - For EPU operation in SLO a 0.02 adder is applied to SLMCPR value	0.02 adder to SLMCPR applied for SLO
5. SLMCPR2 – For MELLLA+ a 0.03 adder is applied to SLMCPR value	Not applicable for EPU
6. R-Factor – R-factor calculation at a bundle level must be consistent with lattice axial void conditions for hot channel operating state	Verified R-factor is consistent with hot channel axial void conditions for EPU

EPU Interim Methods Applicability

Limitation Condition	Disposition
7. ECCS-LOCA 1 – SBA and LBA ECCS-LOCA analyses will include top or mid-peaked power shape for determining MAPLHGR and PCT	MNGP EPU analyses for SBA and LBA ECCS-LOCA analyses include top or mid-peaked power shape for determining MAPLHGR and PCT
8. ECCS-LOCA 2 – ECCS-LOCA analysis will be performed at upper boundary of expanded operating domain	Not applicable to EPU
9. Transient LHGR 1 – For normal operation or core-wide AOOs, demonstrate: no loss of fuel rod integrity from fuel melt or pellet-cladding interaction	Analysis at EPU conditions showed margin to fuel centerline melt was 26% and margin to clad strain was 35%

EPU Interim Methods Applicability

Limitation Condition	Disposition
10. Transient LHGR 2 – Each reload demonstrate compliance with transient T-M acceptance criteria	Compliance demonstrated in SRLR
11. Transient LHGR 3 - Account for void history bias by demonstrating a 10% margin to fuel centerline melt and 1% cladding circumferential plastic strain when using TRACG or ODYN	Void history bias incorporated into TRACG04. Therefore, no additional acceptance criteria required.
12. LHGR and Exposure Qualification - Plenum fission gas and fuel exposure gamma scans included in T-M licensing	PRIME sensitivity analysis used for limiting LOCA case. Compliance with Condition 14 is adequate to satisfy this Condition.

EPU Interim Methods Applicability

Limitation Condition	Disposition
13. Application of 10 Weight Percent Gd – Use of 10 weight percent Gd must be reviewed and approved by NRC	MNGP EPU bundle design uses less than 10% Gd
14. Part 21 for GESTR-M fuel temperature calculation – Apply NRC conclusions to evaluation of Part 21 to GESTR-M T-M assessment	GE14 T-M Operating Limit applied to MNGP Cycle 27 incorporated 350 psi penalty for fuel rod critical pressure to comply with NRC conclusions
15. Void Reactivity 1 - Void reactivity coefficient bias and uncertainties in TRACG must be representative of installed fuel lattice designs	Void reactivity condition was included in cycle 27 SRLR

EPU Interim Methods Applicability

Limitation Condition	Disposition
16. Void Reactivity 2 - TRACG methodology must incorporate the void history bias	TRACG topical report approved and used in cycle 27 SRLR
17. Steady-State 5 Percent Bypass Voiding – Limit bypass voiding to <5%	GEH will provide highest calculated bypass voiding at any LPRM level. Cycle 27 SRLR indicates less than 5% bypass voiding at the D Level.
18. Stability Setpoints Adjustment – Account for calibration errors of 5% for OPRM or 2% for APRM	EPU analysis included 5% calibration error for OPRM

EPU Interim Methods Applicability

Limitation Condition	Disposition
19. Void-Quality Correlation 1 – If using PANCEA/ODYN/ ISCOR/TASC for operation at EPU an additional 0.01 will be added to OLMCPR	TRACG04 is used so no penalty for OLMCPR is required
20. Void-Quality Correlation 2 - Apply NRC conclusions in SE for NEDE-32906 to EPU analysis	TRACG topical report approved and used in cycle 27 SRLR
21. Mixed Core Method 1 - Provide plant-specific justification for extension of GE's analytical methods or codes	MNGP does not have a mixed core – only GE14 fuel is used

EPU Interim Methods Applicability

Limitation Condition	Disposition
22. Mixed Core Method 2 - Provide assessment data similar to that provided for the GE fuels if using TGBLA06	MNGP does not have a mixed core – only GE14 fuel is used
23. MELLLA+ Eigenvalue Tracking – Track cycle specific eigenvalues information.	Not applicable for EPU
24. Plant Specific Application – Provide prediction of key parameters for cycle exposures for operation at EPU	Information provided in PUSAR

Safety Analysis – NRR Session

Containment and Containment Accident Pressure

Containment Analysis

SECY 11-0014

BWROG Analyses

MNGP Implementation

Containment Analysis

Methods

- Used NRC Approved GE Analyses Methods
  - NRC Approval Requested for use of passive heat sinks, variable K-Value and mechanistic heat and mass transfer

- Primary Analysis Codes
  - LAMB -- Blow-Down Flow Rates
  - M3CPT -- Short Term Pressure & Temperature Response
  - SHEX -- Long Term Containment Response

- Methodology updated from original license analysis (mid 80s)

Containment Analysis

EPU affects on Suppression Pool Temperature

- Analysis assumes 90°F SW temp
- Variable K-value over range 110 °F to 195 °F
- Base value 147 BTU/sec °F varies by 3.5%
- Max temperature in Suppression Pool is 207°F

EPU Dynamic Loads

- Mark I Long Term Program method, no impact

EPU Containment Isolation

- Unaffected by EPU, MSO concerns addressed on purge & vent valves, drywell spray valves and main steam line drain valves

Containment Analysis

EPU Mass and Energy Release

- Maximum M&E based on DBA LOCA

Parameter	CLTP	EPU	Limit
Short-term air temperature	335°F	338°F	338°F
Short-term pressure	39.5 psig	44.1 psig	56 psig

ECCS Net Positive Suction Head

- **CLTP NPSH evaluation:**
  - Evaluated use of CAP for DBA LOCA and Appendix R only
- **Original EPU NPSH evaluation:**
  - Credited use of CAP
  - Credited passive heat sinks in containment
  - Thermal equilibrium in suppression pool and wetwell air space for first 30 seconds
  - Evaluated DBA LOCA, Appendix R, SBO, ATWS, SBA
  - NPSHr3% curve used for analysis
- **Original EPU NPSH evaluation superseded by revised NRC guidance in SECY 11-0014**

SECY 11-0014

- NRC Commission selected Option 1 of SECY 11-0014 – restart reviews of EPUs based on revised NRC guidance
- SECY 11-0014, Enclosure 1, Guidance on Use of CAP, section 6.6 provides technical guidance on the use of CAP in reactor safety analyses
- NSPM developed response to SECY 11-0014 guidance for MNGP EPU

SECY 11-0014

MNGP meets SECY 11-0014, Enclosure 1, by the following:

- **6.6.1 $NPSHr_{eff}$ –** For DBA, included uncertainty of 21% on top of the value of $NPSHr_{3\%}$. For non-DBAs, $NPSHr_{3\%}$ without uncertainties used.
- **6.6.2 Maximum Pump Flow Rate for the NPSHa Analysis -** maximum flow rate chosen for the NPSHa analysis is greater than or equal to the flow rate assumed in the safety analyses.
- **6.6.3 Conservative Containment Accident Pressure for Calculating NPSHa –** use of deterministic analysis bounds 95/95 lower tolerance limit for calculation of CAP to determine NPSHa.
- **6.6.4 Assurance that Containment Integrity is not Compromised -** Demonstrated that loss of containment integrity from containment venting, circuit issues associated with an Appendix R fire would not impair ability to safely shutdown plant.

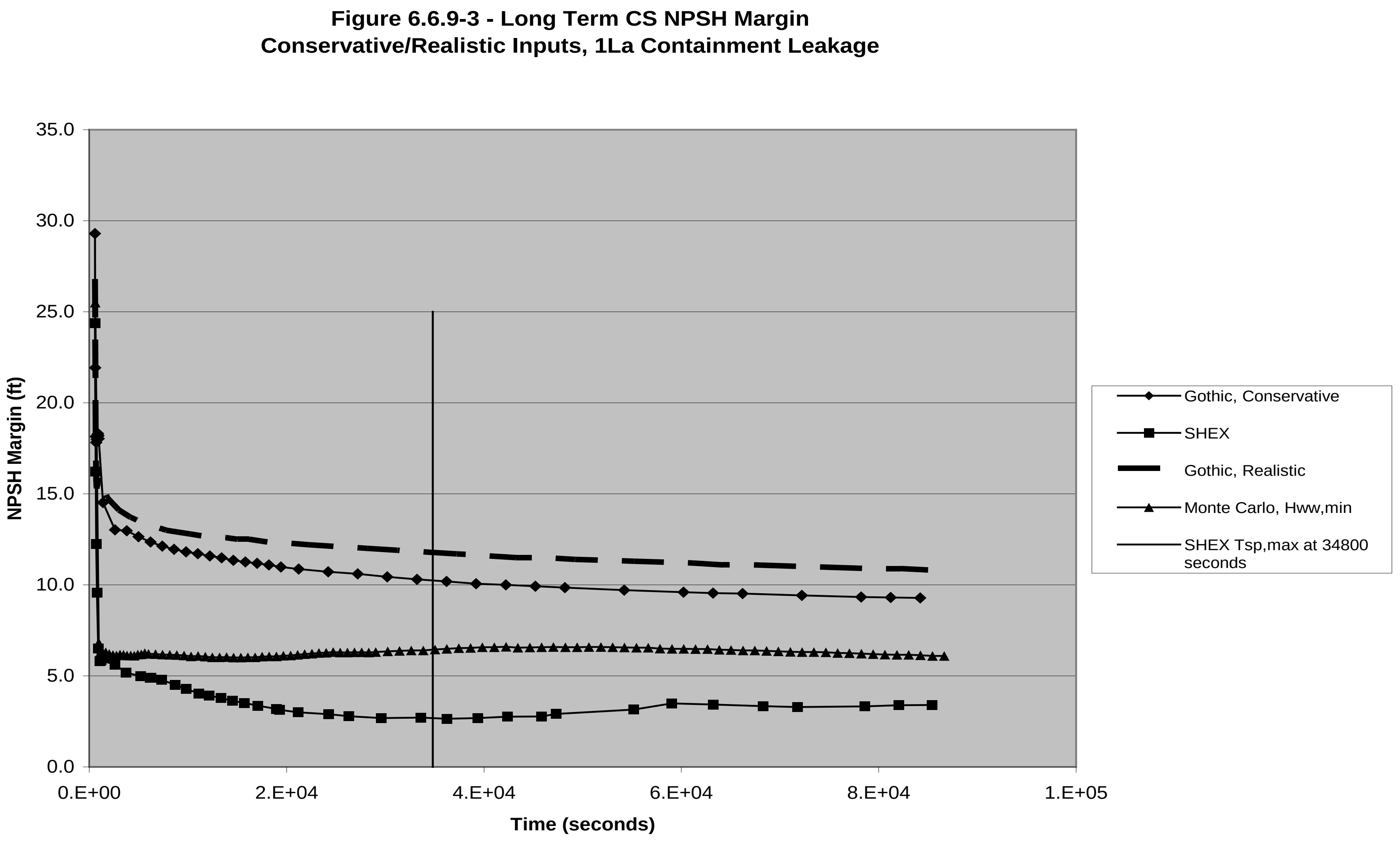
SECY 11-0014

- **6.6.5 Operator Actions –** No changes to operator actions were necessary
- **6.6.6 NPSHa less than NPSHr or $\mathbf{NPSHr_{eff}}$ –** Testing demonstrated acceptable results for short durations MNGP has less than 4 minutes duration
- **6.6.7 Assurance of no Pre-existing leak**
  - NSPM determined approximately 30 L_a leak would be needed to defeat CAP needs
  - Developed an on-line leakage test to monitor for gross leakage of containment
  - Enter TS 3.0.3 if 2/3 of limit is exceeded

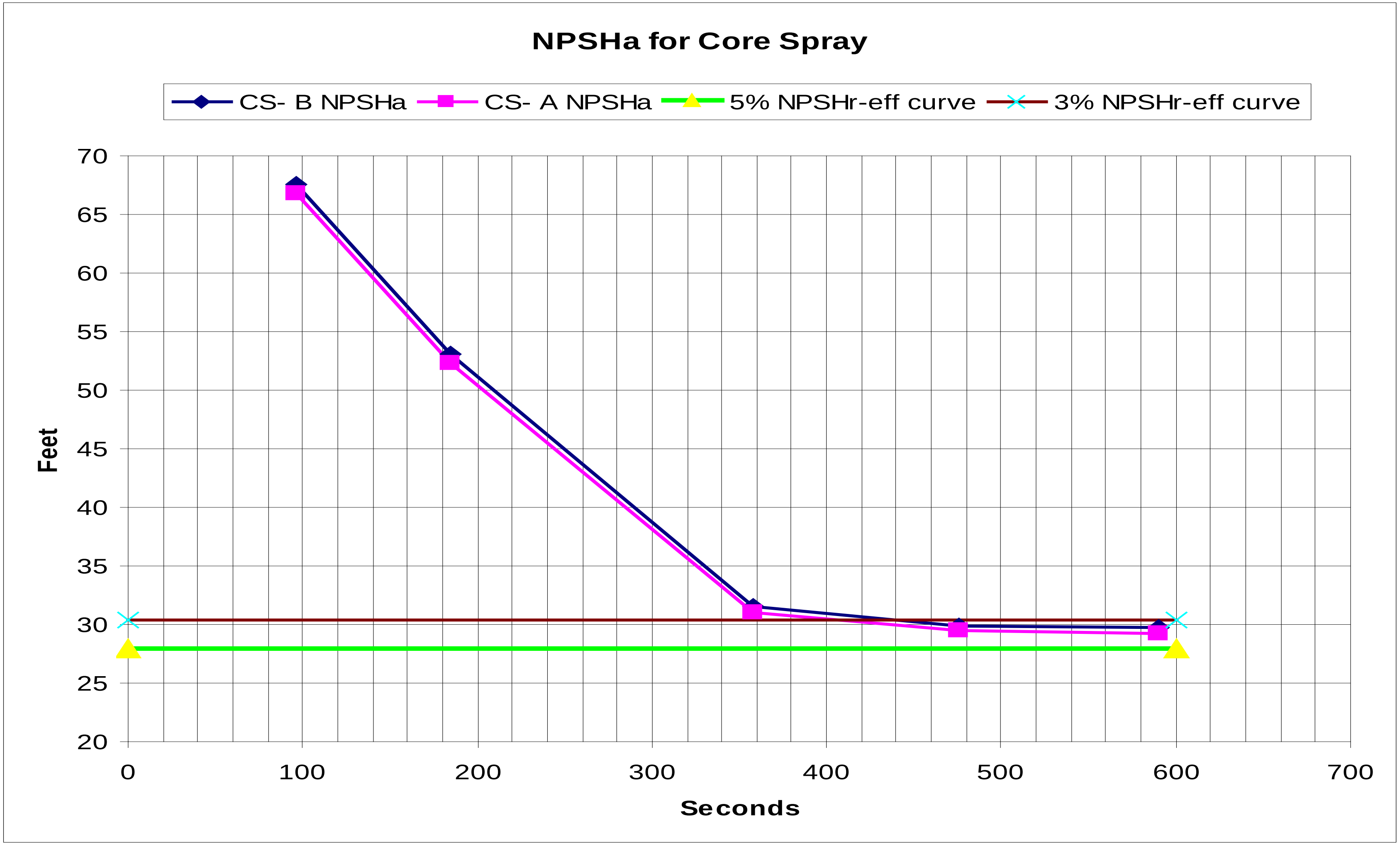
SECY 11-0014

- **6.6.8 Maximum Erosion Zone –** Determined impeller could operate for over 6200 days in max erosion zone
- **6.6.9 Estimate of NPSH Margin –** Performed SHEX, GOTHIC and Monte Carlo estimates of NPSH margin (Slides 93 - 96)
- **6.6.10 Assurance of Pump Operability for Total Time Required –** Analysis demonstrated 30 days of operation without failure of ECCS pump.

NPSH Margin Comparison



NPSH Margin – Short Term Deterministic



Deterministic Analysis

MNGP Results – NPSH Margin Short-Term DBA LOCA

DBA Short-term pump	Run-out Flow** (gpm)	NPSHr 3% (ft)	NPSHreff 3% (ft)	NPSHa [min] (ft)	Margin to NPSHr 3%	Margin to NPSHr eff 3%	NPSHr 5% (ft)	NPSHreff 5% (ft)	Margin to NPSHr 5%	Margin to NPSHreff 5%	5% degr Run-out Flow** (gpm)
P-202A (RHR A)	4278	25.50	31.37	31.59	23.90%	0.73%	23.8	29.27	32.75%	7.92%	N/A*
P-202B (RHR B)	4327	25.50	31.37	30.04	17.82%	-4.21%	24.1	29.64	24.66%	1.35%	4300
P-202C (RHR C)	4330	25.50	31.37	30.62	20.09%	-2.36%	24.1	29.64	27.07%	3.31%	4295
P-202D (RHR D)	4347	25.50	31.37	30.96	21.43%	-1.28%	24.3	29.89	27.42%	3.60%	4318
P-208A (CS A)	4129	25.11	30.88	29.37	16.98%	-4.89%	23.11	28.42	27.10%	3.34%	4065
P-208B (CS B)	4058	24.25	29.83	29.80	22.88%	-0.10%	22.25	27.37	33.93%	8.88%	3980

Deterministic Analysis

MNGP Results – NPSH Margin Long-Term DBA LOCA

DBA Long-term pump	Throttled Flow (gpm)	NPSHr 3% (ft)	NPSHreff 3% (ft)	NPSHa [minimum] (ft)	Margin to NPSHr 3%	Margin to NPSHreff 3%
P-202B (RHR B)	4178	23.5	28.435	32.53	38.43%	14.40%
P-202C RHR C)	4178	23.5	28.435	32.78	39.49%	15.28%
P-208A (CS A)	3388	23.3	28.193	31.33	34.46%	11.13%
P-208B (CS B)	3388	23.3	28.193	31.33	34.46%	11.13%

MNGP Implementation

Basis for Acceptability

- Adequate core cooling is demonstrated by meeting SECY 11-0014, Enclosure 1 criteria as described.
- Use of CAP results in a “very small” increase in CDF as defined by RG 1.174*
- Online monitoring for containment integrity.
- Provide training to increase Operator awareness and sensitivity to NPSH concerns, that includes pump NPSH monitoring and containment integrity monitoring.
- Emergency Operations Procedures provide alternate methods to cool the core.

*** NRC staff presentation to ACRS found in ML101830190**