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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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MEETING

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

(ACRS)

SUBCOMMITTEE ON THERMAL-HYDRAULIC PHENOMENA

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WEDNESDAY,

JANUARY 26, 2005

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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., Dr. Graham Wallis, Chairman, presiding.

COMMITTEE MEMBERS:

GRAHAM B. WALLIS, Chairman

F. PETER FORD, Member

THOMAS S. KRESS, Member

VICTOR H. RANSOM, Member

STEPHEN L. ROSEN, Member

JOHN D. SIEBER, Member

ACRS STAFF PRESENT:

RALPH CARUSO

NRC STAFF PRESENT:

HERBERT BERKOW

ROBERT DAVIS

MICHELLE HART

STEVE JONES

N. (KALY) KALYANAM

RICHARD LOBEL

LOUISE LUND

KAMAL MANOLY

L.B. (TAD) MARSH

JAMES MEDOFF

SAM MIRANDA

KRIS PARCZIEWSKI

PAUL PRESCOTT

WILLIAM H. RULAND

ANGELO STUBBS

MARTIN A. STUTZKE

JAMES TATUM

JOHN TSAO

LEN W. WARD

ALSO PRESENT:

ROB ALEKSICK, CSI Technologies
JEFF BROWN, Westinghouse
PRASANTA R. CHOWDHURY, Entergy
JOSEPH CLEARY, Westinghouse
DAVID CONSTANCE, Entergy
STEVEN CYBERT, Westinghouse
THOMAS FLEISCHER, Entergy
JAMIE GOBELL, Entergy
MARIA ROSA GUTIERREZ, Entergy
ALAN HARRIS, Entergy
JERRY HOLMAN, Entergy
THEODORE LEONARD, Entergy
G. SINGH MATHARU, Entergy
JOSEPH REESE, Entergy
RALPH K. SCHWARTZBECK, Enercon
PAUL SICARD, Entergy
DON SISKA, Westinghouse
DAVID VIENER, Entergy
ARTHUR (GENE) WEMETT, Entergy

A-G-E-N-D-A

A-G-E-N-D-A (con't)

STAFF'S PRESENTATION

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

8:31 a.m.

CHAIRMAN WALLIS: The meeting will now come to order. This is a meeting of the Advisory on Reactor Safeguards Subcommittee on Thermal-Hydraulic Phenomena. I am Graham Wallis, Chairman of the Subcommittee.

Subcommittee members in attendance are Tom Kress, Victor Ransom, Jack Sieber, Steve Rosen and Peter Ford.

The purpose of this meeting is to discuss the extended power upgrade application for the Waterford Steam Electric Station, Unit 3. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC staff and the Waterford licensee, Entergy Operations regarding these matters.

The Subcommittee will gather information, analyze relevant issues and facts and formulate proposed positions and actions as appropriate for deliberation by the full Committee.

Ralph Caruso is the designated federal official for this meeting.

The rules for participation in today's meeting have been announced as part of the notice of this meeting previously published in the *Federal Register* on December 21, 2004.

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

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

We have not received any requests from members of the public to make oral statements or written comments.

I have an opening comment. I read hundreds of pages of text, prepared both by the licensee and the staff, and I still don't have a good grasp of how this operate is achieved. I noticed some changes which were very small in the temperatures of the cold leg and hot leg, but they do not seem to be sufficient to account for an 8 percent uprate. And there's no mention whatever of what happens to the full rate through the core.

In some way the power in the core is increased and yet we're told that the linear heat generation rate, actual linear heat generation rate is reduced and the radiation to the core internals is reduced, so something has presumably happened with the fuel management, although we're told it's the same fuel. But there's a mystery there I'd like to have resolved.

So it will be very useful if someone could explain just how the operators achieved and what the consequences are for important parts of the system such as the fuel and the cooling system. And maybe this in the documents and I just couldn't find it, but I'm still mystified by just exactly how the uprate was achieved and what the consequences were. Otherwise, most of the documentation was very readable and explicit.

I'm sorry, Tad, to hold you up.

MR. MARSH: That's fine.

CHAIRMAN WALLIS: Please go ahead.

MR. MARSH: Thank you.

Good morning, Mr. Chairman. And I do hope we address those questions either from the licensee from the staff in terms of how this is actually taking place in the reactor.

Good morning. My name is Tad Marsh. I'm the Director of the Division of Licensing Project Management in the Office of Nuclear Reactor Regulation.

The purpose of our briefing today is to

present our review of Entergy's application for the extended power uprate for Waterford Unit 3. If the 8 percent uprate is approved, it will be the largest power uprate for pressurized water reactor in the U.S. And Waterford 3 will operate at a core power level of 3716 megawatts thermal.

Our review of the proposed EPU for Waterford is the first one to be completed using the Review Standard RS-001. Throughout the development of the Review Standard the staff was in communication with the ACRS. First in the July 2002 time frame the discussed an outline of the Review Standard with the Committee and then presented the draft Review Standard to the Committee in a meeting in December, 2002. At that time the Committee encouraged the staff to issue the draft review standard to the public for comment and report to the resolution of those comments to the Committee.

The staff presented the Review Standard including incorporation of the public comment to the ACRS Thermal Hydraulic Phenomena Subcommittee in August of 2003, and the Review Standard was finalized later that year.

The staff's review of the Waterford power uprate application was challenging and required a substantial amount of additional information from the licensee to complete its review. And this was the first review involving large transient testing for PWR, and the staff set the standard high and followed the new Standard Revenue Plan associated with large transient testing. And you'll hear more about that.

The staff completed a thorough review of the application for Waterford, but there are still a few items remaining resolution. Our Project Manager Kaly will describe those items to you as we go through the presentation.

Stepping back a little from Waterford, in particular, and going to power uprate in general this is, as I say, the first application of the Review Standard in a power uprate review. And we believe the review standard is a very thorough, very complete document which is guiding our technical staff in these reviews. But we did notice that there was a lot of RAIs associated with this application and with other applications associated with the Review Standard review. We believe that's because the staff is now guided with some specifics in terms of reviews, so it's an effort for complete and thorough documentation and complete and thorough review of an application which we believe is in part resulting in these RAIs.

We do intend on issuing a regulatory issues summary, a RIS, to clarify to the industry what we believe we need for a thorough and complete application associated with the Review Standard. And those lessons learned are coming from not only the Waterford review, but from other power uprate reviews which are ongoing.

We look forward to the dialogue with you. We would like to get a sense from you the level type of information that you would like in the context of some of these open items. Because you will hear today that we are not quite done with them. So we would like a sense from you what you would like in terms of follow on communications or a presentation at the full Committee. But we would like a sense of that, too, as you go through these presentations.

Well thank you very much. I'd like to turn it over to Kaly who will give an introduction for the presentation.

CHAIRMAN WALLIS: Just one moment. You mentioned the use of the new standard.

MR. MARSH: Right.

CHAIRMAN WALLIS: I think that's very evident in the SER.

MR. MARSH: Right.

CHAIRMAN WALLIS: The SER is very comprehensive and thorough in a way that some of the earlier ones didn't.

MR. MARSH: Right.

CHAIRMAN WALLIS: I think that the standard, obviously, is having an effect.

MR. MARSH: I recall conversations with you about thorough and completeness of the safety evaluations and making sure that the basis was apparent in the staff's review. And the Review Standard will help us in that regard. But it is causing more hours to be expended for these reviews than we had anticipated. And what we're trying to discern is this a level of completeness standard that we need to articulate to the industry more clearly, hence the RIS, or is this our staff you know being guided thoroughly in the Review Standard itself. But it is causing more review time, quite a bit more.

CHAIRMAN WALLIS: Well, it's the first time. You're learning, too.

MR. MARSH: It is.

CHAIRMAN WALLIS: And also I think it's appropriate with such a large power uprate for a PWR that you do cover all the bases.

MR. MARSH: Right.

CHAIRMAN WALLIS: Maybe next time you can do it a little quicker and more efficiently.

MR. MARSH: Maybe. But thorough and complete is important, making sure that the staff can make the right kind of safety findings.

CHAIRMAN WALLIS: Thank you.

MR. MARSH: Thank you.

Kaly?

MR. KALYANAM: Good morning. My name is Kalyanam and I'm known as Kaly here. I'm the Project Manager for Waterford 3, and I work in the DLPM.

Okay. Just to give you a little background for the Waterford uprate.

The plant was originally licensed in 1985 for operational reactor core power not to exceed 3390 megawatts thermal units. And measurement uncertainty recapture uprate was rendered in 2002 which gave them a 1.5 percent increase, and the core power level was not to exceed 3441 megawatt thermal.

Now the uncertainty power uprate which we are discussing now, requests are in the case of 8 percent and the core level will not exceed 3716 megawatts thermal. And as Mr. Marsh said, this is the largest PWR power uprate to date.

Now, some of the major plant modifications are: The licensee upgrading the high pressure turbine and rewinding the generator and provide the associated auxiliaries; installing higher capacity generator output circuit breakers; disconnect switches and reworking on the bus; main transformers and modifications, and; replace and upgrade the control valves for the heater drain system, and; stake the condenser tubes.

And the time table for the EPU implementation is intended plants implement this Waterford 3 EPU in one increment. And completion of the plant modifications necessary to implement the EPU is planned prior to the end of the refuelling outage, which is commencing the spring of 2005.

With the approval of this license amendment request, the plant will be operated at the new power starting in cycle 14.

Some of this table giving the comparison of operating parameters. And as it was pointed, there is a slight increase in the hot leg temperature and the cold leg temperature, it drops. And the RCS flow increases slightly pound-mass per second.

And on the secondary site, the steam generator pressure drops and the flow increases. Further data on this will be provided by the reviewers.

CHAIRMAN WALLIS: So it's the increase in the flow as well, that's the one I didn't find in the documentation. There is something peculiar in the documentation. It says that this change in temperature was equivalent to an enthalpy change going through the core, which was 9 percent. But that's not true. If you look at the steam tables, it just doesn't work out. So maybe the licensee is going to explain all that to us.

MR. KALYANAM: I am sure.

MR. MIRANDA: Could I attempt to answer this question? My name is Sam Miranda from the Reactor Systems Branch.

And this question came up before just where this power increase is coming from. And I did a few calculations to see where it is coming from. And basically it's a change in the cold leg temperature increasing the delta T through the core. That accounts for the 8 percent increase in power. And there's also an increase in steam flow and a change in the feedwater temperature.

And if you do the delta H calculations of feedwater, FOP -- the steam FOP at the new steam pressure, that's also the 8 percent increase in power.

CHAIRMAN WALLIS: Sam, you didn't say anything about the RCS flow rate?

MR. MIRANDA: The RCS flow rate, there is a small change there but mainly that's due to the density change in the cold leg.

CHAIRMAN WALLIS: Well, I think if you calculate the enthalpy change for the hot leg/cold leg, you're lucky to get about four something percent just from the enthalpy change. So we're going to revisit this. Do you have different steam tables from mine, though, something just doesn't work out. It's not just the enthalpy change in the RCS fluid. It's also the flow rate you have to use. I think this flow rate may do it, just looking at it.

MR. MIRANDA: It's deceptive to look at just the flow rate because the flow rate is the thermal design flow rate, and that can change depending upon, you know, how they want to use it in their thermal-hydraulic calculations as opposed to the RCP rated flow rate.

If you just look at the volumetric flow rate and take the density changes, there is an overall change in the flow rate of about 2.9 percent of which about 2.4 percent is strictly due to the change in density in the cold leg. And the rest would be --

CHAIRMAN WALLIS: And so we'll revisit page 105 of the SER sometime, this enthalpy --

MR. MARSH: Yes. We want to explain to you, too, as best we can what's going on in the core. You know, where's the power happening in the core and the fuel itself. So it's not just an RCS loop, it's also what's happening to the flux profiles, what's happening to -- why don't we make sure that the licensee really addresses that for you as well.

Okay. Kaly.

MR. KALYANAM: The staff approach for the review was as Mr. Marsh said, this the first PWR EPU to follow Review Standard 001. We replaced the Standard Review Plan and acceptable core and methodologies. We developed 20 or 25 requests for additional information. And altogether we had about 30 supplements. And we have done audits and independent calculations in selected areas and the reviewers will discuss that in later detail.

And principal areas of review. Okay. I have listed them.

The vessels and internals.

Okay. The metrics which we are referring to is the Review Standard metrics and we have covered all of them. I'm not going to go line by line, but basically vessels internals, piping integrity, steam generator integrity and so on.

And we have --

CHAIRMAN WALLIS: How about the fuel?

MR. KALYANAM: The fuel comes --

CHAIRMAN WALLIS: The fuel is going to produce more power?

MR. KALYANAM: Pardon?

CHAIRMAN WALLIS: The fuel produces more power, so presumably you had to review what happens to the fuel. It gets hotter or --

MR. KALYANAM: Yes.

CHAIRMAN WALLIS: -- heat distribution is different and so on.

MR. KALYANAM: Okay. I'm sure we'll be able to address it in their respective sections.

CHAIRMAN WALLIS: What is it that limits the operators? Is it the fuel?

MR. KALYANAM: I think Sam or --

CHAIRMAN WALLIS: Or was it accident analysis?

MR. KALYANAM: What? Can you answer?

MR. SICARD: This is Paul Sicard. I'm the lead safety analysis engineer for the Waterford uprate.

Now the question is what is a limit as far as the power. From a core and fuel analysis point of what we saw as a limiting event was the performance related tube, the small break LOCA ECCS analysis.

CHAIRMAN WALLIS: Thank you.

MR. KALYANAM: And this is the continuation of the principal areas of review.

And the order of the NRR presentation after the licensee presentation will be as shown here. We have the reviewers from all the branches. And if there is any question that comes up, you know we have the experts in those areas to answer your questions.

And the few open items that Tad Marsh referred to, let me briefly discuss them. There are four issues or topics that are on a success path and close to resolution.

One is submittal by the licensee on the alternate source term is under review. The draft SE which you have and you have seen, the flux test and the issue of the EPU amendment will be contingent on the issue of the alternate source term amendment.

And the reactor vessel internal degradation monitoring program we had some discussions with the licensee and we are on a success path there.

And there was an issue on the three second time delay between the steam generator tube rupture and loss of offsite power. And there also we are very close to the resolution.

And, you know, these items will be resolved before the license is granted.

And the last one is accounting the instrument uncertainty for the tech spec parameters, but are influenced by the EPU. That's one other issue that we are on a success path and close to resolution.

With that, I will ask Jim Medoff to come.

MR. MARSH: Just building a little bit on that last one, that's not really the methods reissue that you and I talked about. This is another accuracy issue associated with this petition, which we'll describe.

DR. RANSOM: One question that I have is I would like to see a pressure schedule for this system because you have a higher flow rate through the core, so a higher delta P across the core, apparently, and some of the steam generator tubes are plugged as well which means the delta P is increased across there. So the horsepower to the pumps must have to increase. And I'm wondering if that's been looked at?

MR. BARKOW: Just a correction. This is Herb Berkow. I'm the Project Director for Region IV plant.

The licensee's presentation is next.

MR. KALYANAM: I'm sorry. The licensee's presentation comes.

MR. MARSH: But I hope we get at your question. If not us, then the licensee. Okay. That's pressure around the reactor, what's going on when the flow drops, horsepower requirements for the reactor.

Okay. Mr. Chairman, we'd like to turn it over to the licensee for his presentation.

CHAIRMAN WALLIS: Move on. Thank you. Thank you.

MR. MARSH: Thank you.

MR. MITCHELL: Good morning. I'm Tim Mitchell. I'm Engineering Director at the Waterford 3 plant. I've been in this position since about August of last year. Prior to that one piece of my past experience was as Operations Manager at Arkansas Nuclear One for the Unit 2 power uprate. So I've seen power uprates also from the operations side. And I feel like that has given me a perspective coming in as Engineering Director at Waterford to look at this and follow up.

In this presentation, Mr. Chairman, we will answer your questions. We'll answer all the questions, but we'll make sure that we get to the ones that have been introduced so far.

We have a number of people here to support our presentation, people from Westinghouse, Enercon and Entergy. I will be introducing the primary members here.

We've built this presentation to cover a number of items, some not effected by power uprate, but they're areas of interest for the industry. So we will try to address more than just what has been effected by power uprate.

I am Tim Mitchell, again giving the introduction.

Safety analysis will be presented by Paul Sicard.

And each of these presenters will give a little bit about their background when they come up.

Risk considerations will be given by Mr. Jerry Holman.

Engineering plant impacts by Mr. David Viener.

Then the Operations Impacts. First training and procedures by Mr. Gene Wemett. And then testing, Mr. David Constance.

And then we'll to the conclusions.

We have a lot of data to present. We will present it as efficiently and answer your questions as we can.

This h as been a significant project for us with significant resource amendment. We think that has helped our product. It has been over three years of significant dedicated resources, and it's been a multisite effort, not just Waterford, but all the Entergy nuclear sites have contributed resources and expertise to this effort.

We feel one of the benefits for Waterford is it has improve our design basis. We've had a strong focus while we went through this on margins. We've eliminated some longstanding margin issues and have plans to address more.

Focused oversight and rigor has been a key element of managing this project. We have a director level project lead, Mr. Ted Leonard. Design and review committees have been used to provide oversight throughout the process so that we have additional rigor or oversight at the end to make sure that the product that is being provided to the plant is the best possible.

We've had some assessments, including corporate lead assessments. We started the effort with a large assessment to make sure that we learned from the industry and in particular the Arkansas Nuclear One Unit 2 upgrade. So we started on the right foot.

We had several other assessments. We had a big one last October to review our readiness. It was a 12 member team. Eleven people on that team had previous upgrade experience, four were from outside Entergy. And then we do periodic assessments of our engineering quality also to make sure another depth of review of done, to make sure the fire quality is good.

We've accounted for industry experience. We've applied it where applicable and we have had a rigorous -- and we appreciate that rigor because we feel that it has given us a better product as well.

And as previously mentioned, this submittal was prepared for the draft Review Standard RS-001 for our efforts.

A high level description of the plant, most of this has already been presented, but we are a combustion engineering NSSS pressure water reactor. So we did enter commercial operation in 1985, and Kaly has already presented the rest of the information on the slide, so I won't go through it again

MR. SIEBER: You have two steam generators.

MR. MITCHELL: That is correct.

MR. SIEBER: And how many total tubes and how many are plugged?

MR. MITCHELL: Do you have the actual data, Alan?

MR. HARRIS: I'm Alan Harris with the engineering department at Waterford.

There are normally 9,350 tubes per steam generator. And number one steam generator, 571 tubes are plugged. And in number two steam generator, 484 tubes. That's a total of 1,055 tubes.

Of those that are plugged, only 429 were plugged due to actual indications. The other 626 were preventively plugged early in plant life or prior to commercial operations due to concerns with vertical support ware at the bat wings.

Does that answer your question?

MR. SIEBER: Okay. Thank you.

DR. FORD: Could you go back one slide, please? This whole presentation relates to the power uprate, of course. I understand that you're considering going for license renewal at some time in the future. To what extent did your analyses for power uprate take into account this future license renewal?

MR. MITCHELL: We in all cases protected our options to go for license extension, and we do plan on going for license extension. The current schedule would be roughly the 2008 time frame to be prepared to go forward with that license renewal.

So we have every intention of proceeding with license --

DR. FORD: So in the back of your mind when you're going through these analyses, the changes influx for instance, corrosion of various types but also entered into your thinking?

MR. MITCHELL: That is correct.

Okay. I'll go through a little introduction of the project team consisting of Entergy, Westinghouse, Enercon and Siemen's-Westinghouse. And as already mentioned, we have a number of people from Westinghouse and Enercon here with us today.

In closing my introduction, we plan to show you that we've done a thorough and rigorous project and that we are making the plant better as a result of this project, and it is safe. The staff review has challenged us and it has improved our project.

And we thank the ACRS Subcommittee for

their time to be able to present this to you.

Thank you. I'll turn it over to Paul Sicard, who will go over our safety analysis.

MR. SICARD: Good morning. My name is Paul Sicard. I'm the lead safety analysis engineer for the Waterford 3 extended power uprate project.

I started work at Waterford in 1988, and I've been doing safety analysis work for Entergy since that time. And I'm here to discuss the safety analysis work that had been done to demonstrate that Waterford will continue to operate safely under extended power uprate conditions, and that we meet the required acceptance criteria for this.

And my discussion is going to be focused on the analytical side of safety analysis, the final safety analysis report section, chapter 15 for example. But I want to also stress that Waterford has kept a focus on operational safety as part of our uprate project, and we have kept our operations department very involved in the project, as Tim has said.

Next slide, please.

The scope of what we've looked at has included looking at the fuel impacts, the emergency core cooling system analyses, the analyses of non-LOCA transient events, containment analyses and our radiological analyses. This has been an extremely thorough review. We have basically redone 90 to 95 percent of the analyses that fall into this traditional realm of safety analysis. We have been closely involved with Westinghouse in the development of those computations. And this is a project that we see as greatly improving the strength of the design basis for the Waterford plant in terms of bringing all of this up to date for our power uprate conditions.

Next slide.

Kaly has already gone over the modifications associated with the power uprate. We want to point out that we have not needed to make significant changes to any of the safety systems. There's no change, for example, to the safety injection system associated with the uprate. Most of these changes are related to the power conversion side of the plant. We do have some changes in the control systems and instrumentations, a couple of minor setpoint changes and relatively minor changes to control system setpoints that are associated with the power uprate.

Next slide.

MR. SIEBER: A quick question, and you may not be able to answer but I'm sure somebody will in the course of the day.

I note the steam pressure goes down by about 30 pounds and the steam flow goes up by about 8 or 9 percent. That tells me that the moisture content has to increase. You are not planning, I presume, to change the moisture separator path of the steam generators. And if you don't, then I presume that there will be an increase in erosion/corrosion of the piping and also an increase in the wear rates of the turbine blade. If that's the case, what steps has Entergy taken to recognize that and alleviate it if possible?

You probably aren't the guy?

MR. SICARD: No. I'm not the guy to get into those details here. David Viener, who is our lead mechanical engineer for the project, will be addressing flow accelerated corrosion during his presentation later, or do you want your answer --

MR. SIEBER: I can wait.

MR. SICARD: Okay.

MR. SIEBER: But if he could right is down so that he makes sure he covers it.

MR. SICARD: Okay.

MR. SIEBER: Maybe I can ask a general

question about fuel management.

MR. SICARD: Yes.

MR. SIEBER: You intend to increase power by about 8 percent. Will the cycle lengths remain the same?

MR. SICARD: I will cover that in a slide later, but yes we are going to keep the same 18 month cycle length that we currently operate with.

MR. SIEBER: Do you intend to replace the same number of assemblies at each refueling or a greater number?

MR. SICARD: We anticipate replacing a larger number of assemblies for each refueling. For the upcoming refueling, our fuel cycle 14, we will have 100 new assemblies as part of the reload compared to 92 for the previous one.

MR. SIEBER: Is it your philosophy, I take it, to minimize the increase in final burnup of the fuel by increasing the amount that you --

MR. SICARD: We are looking to stay within our current burnup limits by having larger batch sizes. Also, by having slightly larger batch sizes that allows us to lower the peaking on the fuel such that under operating conditions there will not be a significant difference in the environment seen by the fuel assemblies for uprate versus what the highest peaking assemblies see right now.

MR. SIEBER: Thank you.

CHAIRMAN WALLIS: You also have -- well, I think it's in the staff's, lower gamma fluxes and so on to the internals. Something has happened about the flux distribution in the core?

MR. SICARD: That is basically an artifact of conservatisms in the original analyses. The original analyses were done, you know, with what was viewed as a core design for the early 1980s. Since then we have gone to a low leakage core such that even when power uprate is considered, and we go and we calculate what the fluence is towards the core periphery, it is lower now than in those original analyses.

CHAIRMAN WALLIS: So what's happened is it's not as if it's actually decreased. It's decreased not only because of the analysis --

MR. SICARD: It has decreased compared to the values that it was designed for.

CHAIRMAN WALLIS: Physically it has probably increased?

MR. SICARD: Pardon?

CHAIRMAN WALLIS: Physically it has

probably increased.

MR. SICARD: Physically it has probably increased.

CHAIRMAN WALLIS: And that equates decrease because there's less conservatism?

MR. SICARD: That is correct.

This slide presents some of the operating parameters.

CHAIRMAN WALLIS: Well, this enthalpy change we're talking about comes from using 541, is it?

MR. SICARD: Let me speak to the --

CHAIRMAN WALLIS: I don't understand having this range of temperatures. I mean, you're talking about a specific power. You presumably have a certain temperature?

MR. SICARD: Yes. And when one starts talking about RCS flow, one gets into the situation like the saying of the man with two watches never knows what time it is. Because one has to define which flow it is that you are considering and what are the assumptions that go into those particular flows.

The technical specification minimum flow is not being changed. That's a value of 148 million pounds per hour. The maximum flow assumption that we used in safety analyses is 115 percent of that value.

There is also a nominal flow which we used in order to do analyses, for instance, of fuel burnup and support fuel management and which is input into items such as structural analysis.

A number that was presented in the slides before shows the change in that nominal flow from what had been our docketed operating point under the Appendix K uprate compared to what the nominal flow is that we are docketing right now for our extended power uprate. And a complication in there is the fact that Waterford had a miscalibration of its ultrasonic flow meter which lead to that previous flow that was our docketed flow upon which operating point calculations were built being slightly low. You know, when we discovered this issue, we entered into our corrective action process. We have assessed it for impact on current operations which was truly minimal. But it does result in having to explain this difference in between the flow rate for our Appendix K information as docketed with the NRC versus power uprate.

Now, for the actual physical change due to power uprate, you will see a slight change in the flow because of the increase in density, because of the slight decrease in temperature.

CHAIRMAN WALLIS: Well, what I'm trying to get at is when you increase the power by 8 percent, is 6 percent of that due to temperature change and 2 percent due to flow change or is it a variable and sometimes it's 5 percent 3, sometimes it's 7 percent 2, one or something? There's obviously these two figure in the energy balance. And I couldn't figure out by how much the flow rate had changed in order to make up this energy out.

MR. SICARD: Yes.

CHAIRMAN WALLIS: Presumably there's a range.

MR. SICARD: Yes. From our point of view the major contributor to the increase in delta T will be the increase in the power. We see the input from the increased output of the core being the more dominate factor to increasing what your delta T will be.

CHAIRMAN WALLIS: Should I use 541 when I try to check your calculations, or 543?

MR. SICARD: You should use 543 because that is--

CHAIRMAN WALLIS: Then you have not quite an increase in flow rate, and flow rate is a significant part of the uprate?

MR. SICARD: Pardon?

CHAIRMAN WALLIS: Then the flow rate change is a significant contributor to the uprate. Because 543 you don't get close to it --

MR. SICARD: No. We are able to accomplish this uprate without crediting an increase in the flow. Because we have built this uprate based upon our minimum technical specification flow which has not change for the uprate. So we are having a fire temperature rise across the core that for the same flow rate as what we had previously.

CHAIRMAN WALLIS: That's true. But 2.6 degrees is not enough to give you that. So I just wanted a simple energy balance calculation, that's all I'm looking for because when I do it, it doesn't come up to 8 percent. That's all I'm looking for.

MR. SICARD: We had questions and discussions with the staff on the subject. This has been documented in some of the responses to the request for additional information that we did have from the staff. And, you know, what is confusing here is the fact that we had this error of approximately 3 percent in this nominal flow. Now I need to stress again --

CHAIRMAN WALLIS: Basically what you guys could do is you could prepare a one sheet explanation that will make sense to a sophomore in engineering in terms of heat balance and put it up on the screen sometime today so I can understand it. You've talked around it so much, I still don't understand how the energy balance works. All I need is a simple equation with some numbers that I could go over --

MR. SICARD: Sure.

CHAIRMAN WALLIS: and say, yes, I believe it. That's all I'm looking for.

MR. HOLMAN: This is Jerry Holman from Waterford 3.

And we'll try and put together that type of slide. The other piece of the equation here that I think is missing is the increase in steam flow from the steam generator as a result of --

CHAIRMAN WALLIS: That has nothing to do with what happens in the flow.

MR. SICARD: We do have that information, and it was in our May 12th RAI response, last page of that.

MR. MIRANDA: Excuse me. Name is Sam Miranda.

Again, I'm back with this same question. And referring back to my calculations. And I believe that the 543 degree temperature in my calculations accounts for only five percent of the power uprate. If I go to the 541 degree temperature, that goes up to the 8 percent.

CHAIRMAN WALLIS: Yes, that's right. Yes, that's more like it.

MR. CARUSO: And you should have a table there that--

MR. MIRANDA: Yes, I did a little spreadsheet.

CHAIRMAN WALLIS: Maybe you could share this with us at some time today? Maybe we should move on now, but we'll come back and make this absolutely clear at some point.

MR. SIEBER: The new delta T, the range of it, would lead to a 6 to 9 percent increase in power. So this, by the change in delta T, that accounts for it in my mind.

MR. SICARD: Let me also explain what this 541 to 543 is. This is a gram of the nominal temperature. We have a range for our cold leg temperature technical specification. But a temperature program for the plant, we're at zero power conditions to control around 541 degrees, and that raises -- that is increased to 543 for hot/cold power conditions. And this is consistent with the original design of Waterford 3. Waterford 3 originally was designed with a temperature ramp going from 545 up to 553. And we changed that in 1992 to a flat temperature profile of 545 due to concerns for potential material issues such as the condition steam generator 2. So that is some of the history of the temperature and how it evolved over time.

You know, let me get back to so me of the other--

CHAIRMAN WALLIS: I guess the reason that this concerned me was because there are changes in flow rate that wasn't evident in the documentation. They have some consequences, and they never seemed to be discussed. That's why it interested me was that there are changes in the RCS flow rates and there are some consequences in terms of --

MR. SICARD: The changes in those flow rates are within the bounds of the existing analyses --

CHAIRMAN WALLIS: Well, they be legal, but they still have some effect. And it's interesting to discuss what the effects might be.

MR. CARUSO: Can I ask a question?

MR. SICARD: Yes.

MR. CARUSO: Are you changing anything about the reactor coolant pump operations as a result of this uprate?

MR. SICARD: No. We are not changing any reactor coolant pump operation as a result of the uprate.

MR. CARUSO: And you're not making any hardware changes to the reactor coolant pump?

MR. SICARD: We are not making any hardware changes to the reactor coolant pump.

MR. CARUSO: So if the reactor coolant pump mass flow rate changes, it's entirely because of -- you're not making any changes to the geometry or the reactor coolant system or the pressure drop behavior of the fuel, correct?

MR. SICARD: We are not making any physical changes to the reactor coolant system. You do have some slight change in the hydraulic resistance as the number of tubes plugged increases.

MR. CARUSO: Right.

MR. SICARD: And there are some slight changes associated with the acceleration of fluid through the core due to the higher heat input. Those are relatively minor.

MR. CARUSO: Okay. So any change in the

flow through the reactor coolant pumps is due to the change in the density of the fluid as it's flowing around the loop and as it's heated by the core?

MR. SICARD: Yes, that would be correct.

CHAIRMAN WALLIS: Don't you have some control over that flow rate? You must have. You just run the pump and get whatever flow rate you get?

MR. SICARD: Yes.

CHAIRMAN WALLIS: Then that's another interesting consideration. How do you manage to make it happen?

MR. SICARD: Well, we do perform analyses of the pressure drop within the core and there are, you know, extensive analyses in order to document what the flow rate will be and that it will be within the acceptable criteria.

Would Steve Cybert of Westinghouse want to add anything to that statement. I think Steve would be the best person. Is he there?

CHAIRMAN WALLIS: So I'm trying to figure out how you get the operate. You simply take more steam out of the steam generator and that makes the water colder?

MR. SICARD: Right.

CHAIRMAN WALLIS: And this then has

effects on the flow rate and everything else which somehow works out.

MR. SIEBER: But the primary effect is on the delta T.

MR. SICARD: Yes.

MR. SIEBER: The flow rate really doesn't mean anything.

CHAIRMAN WALLIS: So how do you manage to get the flow rate coming out of the core hotter? You raise the power level?

MR. SIEBER: You lower -- is the way you do it.

CHAIRMAN WALLIS: So, I mean, you seem to be very concerned about regulations, you say everything's within regulations. But I'm just wondering whether the physics works out and you can actually do it. Maybe it'll work out. Maybe when you do this thing it'll happen exactly as you planned.

MR. SIEBER: It does. It works out.

CHAIRMAN WALLIS: Okay. Okay.

MR. SICARD: Steve, you have something you'd like to add?

MR. CYBERT: Steve Cybert, Westinghouse Electric.

As far as we're looking at the numbers,

and on the operating point, Kal, it does show that the T hot will be more closer to like 601.8, so there's a little more there as far as the delta T.

CHAIRMAN WALLIS: That helps me, too. Because I still have the discrepancy of the 601. So if you have 600.2 you might as well get the other numbers to the same accuracy so we can make a simple calculation.

We should move on here. It just to me there's some very simple questions I was asking and it seemed to be difficult to get a very simple answer.

MR. SICARD: We can provide some information on this later today to clarify the issue.

CHAIRMAN WALLIS: Sure.

MR. SICARD: Okay. Getting on to some of the other parameters. You know, one of the objectives that we had in our power uprate is that we did want to maintain a hot leg temperature approximately the same on a nominal basis as what it was before. That is, you know, somewhere around 601 degrees over here. And that is why we lowered what the cold leg temperature was slightly compared to where it is previously in order to not aggravate any materials associated with nominal hot leg temperature.

We have not changed what our nominal RCS pressure is. The steam generator pressure for the full power conditions goes down slightly because of that increase in power and the fact that we have no increased what that hot leg temperature is and steam flow, of course, increases in order to get the increase in power.

One other operating parameter of note is that we have expanded the safety analyses to allow for a slightly more negative moderator temperature coefficient than what we had previously included in our analysis. And now we cover up to a minus 4.2 times 10 to the minus fourth value for the MTC as opposed to a minus 4.0 previously.

CHAIRMAN WALLIS: So your steam flow goes up by 8.6 percent. And that leads you to stiffen the condenser tubes because you're concerned about vibration. So there's a rather small change in flow and you do something with the condenser. The small changes in flow through the core don't lead you to any concerns about what might happen?

MR. SICARD: We have fully analyzed the impact of flow conditions on the core for power uprate. The change in the flow associated with the slight increase in density is well within the bounds of the number that we have based our maximum analyses on. You know, we feel like we have a focus on reactor safety in that we have done the analyses to show that the hydraulic performance of the core is acceptable and that this change is within the bounds that we have established for the acceptable.

MR. ROSEN: Would you go back to the moderator temperature coefficient again?

MR. SICARD: Yes.

MR. ROSEN: Tell me more about that. How long does that last through the cycle an what is its profile?

MR. SICARD: The moderator temperature coefficient is roughly linear through the cycle. It starts out at a value which is fairly small. Our technical specification limit, I believe, is minus 0.02 at start up. Am I recalling that number correctly, Jerry?

MR. HOLMAN: Yes. This is Jerry Holman.

The MTC that Paul referred to is the minus 4 is an end of cycle MTC.

MR. ROSEN: And the beginning of cycle.

MR. HOLMAN: The beginning of cycle is very slightly negative at 100 percent power.

MR. ROSEN: And it remains negative at a 100 percent power throughout the cycle.

MR. HOLMAN: That is correct. Yes.

MR. ROSEN: Does it remain negative at a 100 percent power, I mean does it remain negative at zero percent power through the cycle?

MR. HOLMAN: At zero percent power it is slightly positive at the beginning of cycle.

MR. ROSEN: How positive is that?

MR. HOLMAN: I don't have the exact number.

MR. SICARD: The former limit which hopefully we do not challenge on each core design, is I believe plus 0.5.

Jeff Brown of Westinghouse, do you recall for cycle 14 what our beginning of cycle moderator temperature coefficient is?

MR. BROWN: It's about a minus .3 at full power conditions at beginning of cycle.

MR. SICARD: And do you have the numbers with you for what it is at lower powers?

MR. BROWN: At zero power it's about a plus .5.

MR. ROSEN: And how long does that last through the cycle?

MR. BROWN: Well, it's --

MR. ROSEN: As the boron burns out?

MR. BROWN: Right. As Paul said, it's more a less monotonically a decreasing throughout cycle from the value of minus .5 to the end of cycle value 18 months later of about minus 4. That's delta --

MR. ROSEN: So I would just guess that maybe from those numbers and the monotonic information that it's about 20 percent through the cycle, perhaps, before you go to zero?

MR. SICARD: I'd say a little bit less than that.

MR. BROWN: Well, at full power.

MR. ROSEN: I know, at zero power?

MR. SICARD: At zero power it probably would be about -- my guess is, you're correct, about 20 percent of the cycle.

MR. ROSEN: Thank you.

MR. SICARD: And for the cycle 14 core in particular, you know while we have expanded the range of the MTC in most of the safety analyses to this minus 4.2 value, our actual expected end of cycle MTC for cycle 14, our first power uprate four that we will be starting up in May or June is a minus 3.9 value. So the minus 4.2 is the result of consideration for providing an expanded range to accommodate the uprate fours. But the first uprate four is within the bounds of what we had previously assumed.

MR. ROSEN: And how many effective full power days is the core loaded with for anything on site?

MR. SICARD: Okay. Jeff, do you have your number at your fingertips, number of effective full power days?

MR. BROWN: Yes. It's 510 EFPDs.

MR. SICARD: And I'll compare that to our cycle 13 core which was actually designed for a 524 EFPD cycle.

MR. ROSEN: Thank you very much.

CHAIRMAN WALLIS: While we're talking about flow, the concern with flow-induced vibrations in the steam generator, is that due to the steam flow or water flow?

MR. SICARD: Let me refer that to one of our support staff over here. I think Don Siska from Westinghouse is the best person to answer that question.

MR. SISKA: Yes. This is Don Siska from Westinghouse.

The answer is both the two areas that are most commonly see that flow-induced vibration are the downcomer entrance to the tube bundle, which is essentially saturated flow, maybe slightly subcooled, and also in the upper tube bundle, the horizontal section of tubing which is mainly a high quality steam at that point or mid quality steam.

CHAIRMAN WALLIS: Are you going to cover that later on?

MR. SICARD: That will be covered in David Viener's presentation on the impacts to the plant.

Next slide.

We'll go on and discuss some of the significant aspects of the uprate. As presented on the previous slide, we're trying to maintain approximately the same nominal hot rate temperature. One of the significant aspects is that we are crediting our steam generator atmospheric dump valves, the ADVs, for secondary pressure control for the small break LOCA event. Those are safety related valves that have already been credited as a means of cool down for the plant and we now have also credited them in this particular analysis.

We have adopted the Westinghouse 1999 large break LOCA evaluation model for the ECCS analyses.

We have moved to the Westinghouse CENTS code as opposed to the CESEC code for the evaluation of non-LOCA transients. The FSAR Chapter 15 type events over there. And that is the case of moving to a more moderate code that has increased capability. It has slightly better modeling on the secondary side and the steamline.

And we have also adopted the alternative source term methodology for our dose calculations. And that is something that we have done primarily in response to the generic letter on control room habitability.

I will mention that there is a precedent for crediting the atmospheric dump valves on this role. South Texas Project credits them in a similar capacity.

Next slide.

These are a list of some of the technical specifications of interest for the power uprate. Because we are crediting the atmospheric dump valves in the small break LOCA analyses, we have moved the requirements that we have on them from the licensee controlled technical requirements manual to our technical specifications including the specification of the setpoint for those valves.

We have raised what our minimum boric acid concentration is in the boric acid makeup tank in order to show acceptable shutdown margin. We have also made more rigorous assumptions in that analysis than the original calculations that supported those technical specifications.

We have lowered the maximum liquid volume in the safety injection tank. That was done for large break LOCA purposes. What that does is it increases the volume of the pressurized nitrogen at the top of the tank which drives the safety injection flow into the reactor coolant system with a better delivered guides that flow in faster because of having more of that gas pressure. Because of the lower steam generator pressure associated with our uprate conditions, we have lowered our setpoints on low steam generator pressure to maintain operational margin.

As an enhancement we have moved the controls on minimum containment temperature, which is a parameter credited in the ECCS analysis from the technical requirements manual to he technical specifications. And --

CHAIRMAN WALLIS: Now why did you do that?

MR. SICARD: We had this parameter in the technical requirements manual. And we had a discussion as we were formulating our license amendment on this parameter. And we felt that minimum containment temperature because of it's role in ECCS performance analysis merited under 50.36 being included in technical specifications.

CHAIRMAN WALLIS: The focus has something to do with NPSH?

MR. SICARD: This does not have --

CHAIRMAN WALLIS: It has no impact on it?

MR. SICARD: This has does not have impact on NPSH. We do not credit containment over pressure for our net positive suction head calculations.

And we have also changed our specification for primary to secondary leakage for the steam generator. We have based on discussions with the staff adopted an operational leakage value. This is similar to the operational leakage that is discussed in NEI 97-06. And the industry as a whole is moving based on discussions with the staff to adopting operational leakage values for the steam generator.

CHAIRMAN WALLIS: But the previous slide you mentioned control room habitability. We're going to discuss that later on?

MR. SICARD: Yes. The end of my presentation I have a discussion on the alternative source term, analyses including the results of our control room habitability tests.

CHAIRMAN WALLIS: And will there be some discussion of the remote shutdown panel and accessibility?

MR. SICARD: We had not included --

CHAIRMAN WALLIS: The time to perform operations there and that sort of thing?

MR. SICARD: We have a discussion from our operations support people here on what the operational impact is of power uprate, including the impact on procedures. Does that answer your question.

CHAIRMAN WALLIS: Well, maybe they will cover that then, remote shutdown panel. I didn't find anything about that in the documentation, which is curious. So put that on the list of things to --

MR. SICARD: Somebody has that on the list then.

DR. KRESS: Are you going to talk about your calculations from the control room habitability with the alternative source term?

MR. SICARD: I didn't catch the beginning of your question.

DR. KRESS: Is it on the agenda to go over the calculations that are on the alternative source term --

MR. SICARD: I will present the results of that and fully prepared to discuss that.

DR. KRESS: What code did you use for that?

MR. SICARD: We used RADTRAD.

DR. KRESS: RADTRAD.

MR. SICARD: We have a couple of slides presenting some of the analysis changes associated with our power uprate effort. As noted before, we have expanded the assumption on number of steam generator tubes plugged for power uprate. Currently our analyses support a maximum number of 700 tubes plugged, and we for power uprate plus that number up to 1,000 to give us more margin on that particular parameter.

The next slide.

CHAIRMAN WALLIS: Are you going to discuss the small break LOCA and things like that? Is someone going to do that later on?

MR. SICARD: Yes. I am presenting kind of the generic list of the analysis changes and I have slides later on small break and large break LOCA.

CHAIRMAN WALLIS: Okay.

MR. ROSEN: Did you mention earlier that you were planning to change the steam generators out?

MR. SICARD: No. We do not have any

definite plan for changing the steam generator. Ted Leonard will speak to that.

MR. MITCHELL: Actually, I am Tim Mitchell.

We have initiated studies for steam generator replacement. Those studies indicate that it will be sometime after the 2010 time frame before we would be required. Probably more likely beyond 2012. But we will be monitoring and updating that study after each refueling outage following our inspection scope and what we find. But right now, steam generator replacement is something we anticipate in the future, but it is a number of years off.

MR. ROSEN: What do you think it's impact would be on the EPU depending the plant is granted an extended power uprate?

MR. MITCHELL: That the steam generator replacement would account for the extended power uprate and we would factor in other variables such as did we want to raise T_{hot} after steam generator replacement, those types things. But, you know, none of that design has been started as far as designing the steam generators. But we would expect that all of this power uprate and life extension would be factored into the replacement steam generator uprate.

CHAIRMAN WALLIS: Did you get to the lowest item yet?

MR. SICARD: Pardon?

CHAIRMAN WALLIS: Did you get to the lowest item here yet?

MR. SICARD: No. I was just going to mention that in passing, and we do have a slide on that later, we have changed our analysis on the long term cooling. We previously had credited the lower plenum in the mixing volume as a result of lessons learned or operating experience from the ANO power uprate. We changed what that assumed volume was for the analysis. We submitted such that we no longer credit the lower plenum but instead credit a portion of the upper plenum.

CHAIRMAN WALLIS: Is this making -- is this now a more conservative analysis?

MR. SICARD: Yes. That is a more conservative analysis because that gives you a smaller overall mixing volume under the power upgrade assumptions, which means that you get to the concentration limit sooner.

CHAIRMAN WALLIS: And in the resolution of GSI-185 we were convinced by the staff to accept a well mixed lower plenum. So it just seems to be going on the opposite direction here, but if it's conservative that's okay.

MR. SICARD: It is conservative. And I believe the staff is also going to discuss this analysis.

CHAIRMAN WALLIS: I think they need to because there's a very long discussion in the SER about this matter, and I couldn't quite see how it got resolved.

MR. SICARD: Continuing on. One aspect of our uprate analysis is that we now predict and permit fuel failure for the return to power main steamline break analysis, one of the Chapter 15 analyses. There are two analyses that are done for main steamline break. This is the one for the longer term reactivity control return to criticality. And we now allow a 2 percent fuel failure due to the DNBR departure from nucleate boiling mechanism. There's a precedent in terms of Florida Power & Light and Calvert Cliffs also having fuel failure for that event.

I will point out that we do not have fuel failure for any of the outside containment main steamline break for Waterford. We have fully adopted the method of statistical convolution for assessing the amount of fuel failure for the Chapter 15 events, and we have updated the ANSI standard upon which we base our reactor coolant radioisotopic concentrations.

Let me also point out on this main steamline break analysis, that is based upon a minus 4.2 MPC. And the amount of fuel failure would be significantly reduced and we may not have any if we looked at that based upon the minus 3.9 value that we would actually have for cycle 14.

Next slide presents the analysis changes that are pertinent to the dose analysis. We're adopting the alternative source term methodology. We are changing the primary-to-secondary leak rate technical specification to an operational leakage value, 75 gallons per day, per steam generator.

We have updated the calculation of our atmospheric dispersion factors for use in both offsite dose analyses and for the main control room. We are using ICRP30 dose conversation factors.

And we have expanded the scope of the control room doses that are reported in our final safety analysis report to include all of the non-LOCA transients analysis and the small break LOCA as well as the large break LOCA and the fuel handling accident which are the two events that we currently report for control room dose.

The next slide. This is where are addressing fuels issues related to the operating. And I hope that we will answer the questions that you have related to fuel here.

Our cycle 14 fuel design, there's no change in the fuel mechanical design. It is a standard 16 by 16 Westinghouse/CE fuel design. It is a 18 month fuel cycle. We continue to use Erbia as the burnable poison in that design. We've been using Erbia for several fuel cycles.

Out of the 217 total fuel assemblies in the core, we will have a batch size of 100 fresh assemblies for the upcoming cycle. We have done analysis for the fuel rod corrosion and duty, and demonstrated that we have acceptable performance related to those parameters.

We've asked questions as far as how much power we're getting out of the fuel. On a core average linear heat rate basis, we will have a core average linear heat rate that corresponds to 5.8 kilowatts per foot. That's just slightly larger than the ANO conditions after they're operated at 5.7. And that is not an outlier compared to other PWRs. Prairie Island has a corresponding value, 6.2. Indian Point has a value of 6.6.

CHAIRMAN WALLIS: It says in the SER that the peak linear heat rate is actually reduced. So you must have done something to change the heat generation distribution.

MR. SICARD: Well, the peak linear heat rate that is assumed as the input in the ECCS analysis for power uprate is a value of 13.2 kilowatts per foot which compares to a value in the current pre-rate ECCS analyses of 12.9 kilowatt per foot.

CHAIRMAN WALLIS: So it's actually increased?

MR. SICARD: On that basis it has increased. We have been able to increase what the value is that we can accommodate within the analyses. You know, there are different -- you know, linear heat rate enters into different analyses and with different biases. And I do not want to comment on what's in the SER because I'm not sure of the context in which that was presented. But, you know, looking at this from the ECCS performance analysis our power uprate supports an increase in what that peak linear feet --

CHAIRMAN WALLIS: So should we think that what's happening here is that a power generated in the core is increased by 8 percent everywhere?

MR. SICARD: That would be a simplistic

way of looking at it. What we have, really, is a case where more of the assemblies are sharing the power. More of them are operating closer to the limit.

I'm going to ask Jeff Brown from Westinghouse, who is --

CHAIRMAN WALLIS: So there is a change in the distribution?

MR. SICARD: Yes, you could say there is a change in the distribution --

CHAIRMAN WALLIS: Because in these power uprates that we've seen before when there's a large power uprate, the management of the fuel becomes very important.

MR. SICARD: And --

CHAIRMAN WALLIS: And is often the key to getting the high uprate.

MR. SIEBER: Yes. But at this point you aren't designing in the final design on the long term steady-state cores. You do that reload by reload as you go along. So what you know most about is the transition fuel.

I think a way to look at this, if there were not a EPU, how many assemblies would you typically add each refueling?

MR. SICARD: We had 92 assemblies for

cycle 13, which is currently operating compared to 100 assemblies for cycle 14 our first power --

MR. SIEBER: Okay. So you're increasing it by about 8 percent?

MR. SICARD: Yes.

MR. SIEBER: Which is about the size that you would use.

MR. SICARD: Yes.

MR. SIEBER: So the burnup will stay the same, the enrichment is typical --

MR. SICARD: Yes.

MR. SIEBER: The first cycle enrichments will be the same?

MR. SICARD: The increase in enrichment from cycle 13 to cycle 14 is 0.07 percent. So it is very small.

MR. SIEBER: It's basically the same.

MR. SICARD: Yes, it is basically the same.

MR. SIEBER: Now you're using a low leakage core?

MR. SICARD: Yes, we have a low leakage core.

MR. SIEBER: Okay. So the second and third burn assemblies on the outside, basically?

MR. SICARD: The third burn on the outside, yes.

MR. SIEBER: Yes. Okay. So that's where the power comes from, this additional assembly you said, and it's right over --

MR. SICARD: We're trying to get more assemblies sharing the load --

MR. SIEBER: Right.

MR. SICARD: -- so that they are all closer together in terms of the power.

MR. SIEBER: Right.

MR. SICARD: Let me have Jeff Brown from Westinghouse provide his perspective on this. Jeff?

MR. BROWN: Right. I just want to mention, as Paul said, although the average power in the fuel rods has increased, in fact the peak fuel rod power has remained more or less the same because this increase in batch size, feed batch size, but also the fact that we added a more burnable absorber, the more smoothed the power distribution. And it was one of the goals going in that the peak rod power would not substantially be -- you know, in terms of absolute power, kilowatts per foot, relative to what the thing is. And so we inspect under normal operating conditions to have about the same margins for the fuel limits as we currently do.

MR. SIEBER: Since you volunteered to answer questions, let me ask another that relates to what Mr. Rosen discussed before.

If you had added additional burnable -- you could actually lower the zero power temperature coefficient which is now positive and make it negative, correct, which from an operator standpoint would be a more stable core. And the offset for that is you would have to increase enrichment cycling and those are dollar bills that you're putting in.

Some utility licensees try to keep the moderator coefficient negative in all cases. Would it be a worthwhile endeavor for this plant to do such a thing from the standpoint of operational stability, particularly in cycle life?

MR. HOLMAN: This is Jerry Holman.

That is the balance that we always have to weigh. I should mention, though, that this is not the first cycle that we've seen, the positive MTC at low power. So the operators are used to seeing that and dealing with that type of response.

MR. SIEBER: Is it the practice of Entergy to try to maintain negative temperature coefficients at all times and exceeding it and having it go positive as an exception?

MR. HOLMAN: We look at the balance of those two factors. As you mentioned, the operational impact versus the impact of the fuel and putting the extra enrichment in there.

MR. SIEBER: So the answer is no?

MR. HOLMAN: Our balance would allow us to have a slightly positive MTC as zero power. We've trained the operators to address that and they're familiar with that type of core response.

MR. MITCHELL: This is Tim Mitchell.

And I can speak from our Arkansas Nuclear One experiences with what would turn out to be a similar core post uprate and the effects of positive moderator temperature coefficient on the operators even at low powers is very minimal. So that is something we've trained extensively on. And if we saw problems with that, that is something that we would consider changing our philosophy.

MR. SIEBER: Well, during a transient then coefficient does turn negative someplace in the course of a power transient. On the other hand, it makes for a unusual response from the operator's viewpoint.

MR. MITCHELL: We use a lot of just in time training to make sure that they're prepared for changes in --

MR. SIEBER: Well it always happens just in time.

MR. CARUSO: Who does your core design? Do you do your own core design or do you have Westinghouse do it?

MR. SICARD: Westinghouse does our core design. Entergy does maintain an intrusive role in that process, both in terms of participation from our site safety analysis and reactor engineering and operations groups as well as our corporate support staff located in Jackson, Mississippi which provides core physics supports to all of the Entergy South sites.

CHAIRMAN WALLIS: While we're on this number of first assemblies, so there's a discussion in the SER about maximum heat loads to the spent fuel pool and the decay time required for reactor shutdown before you can transfer the fuel. Presumably you have -- you just have 8 percent more assemblies with the same burnoff as before you're transferring. It doesn't seem like much of an issue, does it? But why is it mentioned in the SER then?

MR. SICARD: Well, David Viener will discuss these issues as part of the --

CHAIRMAN WALLIS: Oh, that's going to come later?

MR. SICARD: -- design input. As far as that ultimate heat sink calculation, that is a case of where the analysis of record was done, you know, back in the start up days and was a very conservative analysis such that when we have updated mass and energy releases that go into that calculation we result in a lower peak heat load on the ultimate heat sink now under power uprate than under the previous.

CHAIRMAN WALLIS: So part of the way you can get this power uprate is because your analysis is now sharper than it was before on several of these matters, it seems to me?

MR. SICARD: Yes. There area number of cases where that is the case, where the calculations as done originally had conservatism in them that can easily accommodate an 8 percent power uprate.

David Viener, would you like to add anything on the subject? He's standing there to say something. Okay.

Are there any other questions regarding fuel or is it okay if I continue on to discuss other aspects?

MR. SIEBER: Well, let me ask just as part of the roadmap through all the presentations, the work that you do comes up with safety limits, right? The work that you personally do?

MR. SICARD: Yes.

MR. SIEBER: Your responsibility, your come up with safety limits. From safety limits somebody goes through a scaling manual process to come to safety systems settings which is what one puts into the instruments to cause reactors to --

MR. SICARD: Yes.

MR. SIEBER: Will someone discuss the methodology that Entergy proposes at Waterford to make safety system settings? And if so, who will it be so that I can --

MR. SICARD: No, we were not going to present too much information on that topic since we only have one of our setpoints, which is changing for power uprate. That is our low steam generator --

MR. SIEBER: My questions is more generic than that. My questions involves the use of ISA RP 67.04 Method 3 which is not allowed by the staff, which you proposed to use. And I want to know where you stand,

MR. SICARD: I think I have the answer to your question, which is that we had proposed the setpoint per Waterford's license methodology originally. There have been some discussions with the staff subsequently on that one setpoint. Based on our discussions with the staff, we have conservatively adjusted that setpoint. We raised that setpoint slightly in order to satisfy the staff's concerns and we can come to an agreement.

MR. SIEBER: Are you still using Method 3?

MR. SICARD: I'm going to --

MR. SIEBER: With an adjustment?

MR. SICARD: I am going to have our lead instrumentation engineer for power uprate Tom Fleischer step in and address this.

MR. FLEISCHER: My name is Tom Fleischer. I'm the lead I&C instrumentation engineer for Waterford 3.

Currently the answer is no we do not. Currently the answer is yes, we do use methods for the other NSSS setpoints at this time. The setpoint that we touched for extended power uprate was derived based on our technical specification basis. We added additional margin to that setpoint per the staff's request which, I hate to admit, makes it equivalent to Method 1.

The reason I'm saying I hate to admit is because the committee right now, ISA 67.04, of which I'm a voting member, currently is having discussions about the use of Method 3.

MR. SIEBER: That's tomorrow, right?

MR. FLEISCHER: Yes.

MR. SIEBER: Okay. The meeting is tomorrow.

Well, the way things stand right now Method 3 is not endorsed by the regulation. And Waterford is not the only plant that's in this situation because others have chosen that pathway. On the other hand, I have an interest in that and I think it needs to be resolved. And as a person with infinite patience, I will wait for the staff to make progress on that. But it's something that I will follow. And I would have objected to the EPU on that basis, had you insisted on using Method 3 without any adjustment. But since you've made an adjustment and the staff's approved that, I guess I will wait until a more generic resolution of the whole issue occurs. It is something that has to happen sooner or later.

Okay. Thank you very much.

CHAIRMAN WALLIS: We're running way behind. And I suggest that you keep going until you finish your presentation and we have a break.

MR. SICARD: Okay.

CHAIRMAN WALLIS: And I hope that happens before lunch sometime.

MR. SICARD: Okay. We have some slides presenting the results of some of our specific analyses. We have revisited our containment analysis for power uprate. Our current containment LOCA pressurization analysis already accounted for power uprate in terms of the mass and energy releases. We generated new mass and energy releases for main steamline break, rerun these analysis using the GOTHIC code, which is our current license code for this. The results show that we meet our 33 psig acceptance limit. There's essentially no change in the LOCA results and the main steamline break results have gone down slightly due to the lower steam generator pressure at full power conditions.

The next slide. As I mentioned, we are transitioning to the use of the CENTS analysis code instead of CESEC for non-LOCA transients. CENTS is a code that has been generically approved by the NRC for CE designed plants, and it has also received plant specific approval also for ANO 2, San Onofre and Palo Verde.

One aspect of our transient analysis is

that we are continuing to credit a three second time delay between reactor trip and the time of loss of offsite power for the steam generator 2 rupture. That assumption had previously been included in the CESAR analysis and is also an assumption which is common for Westinghouse Pittsburgh plants to assume for various Chapter 15 events.

We have basically, as I said, gone through and rewritten all of the safety analysis that go into Chapter 15 of the final safety analysis report. We have demonstrated that we meet the acceptance criteria for those events, be that it may depending on the specific event a no fuel failure acceptance criteria or a fuel failure that supports the limits for the dose calculations.

Next slide presents the results on our limiting pressurization events, which is the loss of condenser vacuum and for a limiting fault event, the feedwater line break. This shows that we continue to meet what those acceptance criteria are.

The next slide, our large break LOCA analysis has been updated. We based upon the 1999 evaluation model. We currently use the 1985 model. Mentioned some of the changes that went into this analysis such as lowering what the maximum liquid level assumes for the safety injection tank is. Our maximum peak clad temperature from this analysis is 2164 which meets the acceptance criteria of 2200.

DR. RANSOM: What was that before?

MR. SICARD: The value currently in our license basis analysis today is 2177.

DR. RANSOM: One thing that hasn't been clear from this presentation is you're getting more power out of the core, you haven't changed the velocity through the core because I think you're arguing you both maintained the volumetric flow constant, which means that -- and the heat transfer coefficient hasn't changed as a result of that or very much. And so it must come from an increase in temperature from the fuel clad to the fluid. And I know you've lowered the temperature of the incoming flow, but not changed the temperature of the outgoing flow. But what happens to the peak power region of the core; it's sort of unclear. It'd be nice to see a picture of the fluid temperature and the clad temperature through the core.

MR. SIEBER: I think you'd have a flatter distribution.

DR. RANSOM: And I'm surprised that you wouldn't increase the peak clad temperature under the loss of coolant accident.

MR. SICARD: Well, for the question of normal operation, Jeff Brown attempted to address that in terms of the lowering peaking on the hot assemblies for power uprate result in a very similar characteristic for the hot assemblies under power uprate compared to the hot assemblies in today's core. And that's because of spreading what the load is amongst more of the assemblies.

Now, for the large break LOCA, we do have an improvement in the performance of this analysis associated with using the 1999 evaluation model and we do see some improvement in terms of improved delivery of the safety injection tank fluid to the reactor fluent system because of that increased vapor volume at the top of the take. Those are the reasons why for power uprate we are able to demonstrate using that change to the safety injection tank and to the evaluation model that the peak clad temperature remains roughly similar.

MR. LEONARD: But the short answer is that the higher decay heat that would drive a higher peak clad temperature in the large break LOCA event is offset by the better model. So we're getting a lower peak clad temperature because we're using the new evaluation model.

DR. RANSOM: I was concerned about the stored energy. The --

MR. LEONARD: Right. That's correct. But the new model offsets that higher decay heat and the stored energy and gives us slightly lower temperature, heat clad temperature.

MR. SIEBER: The model that you're using is not a realistic model.

MR. LEONARD: That's correct. Yes --

MR. SIEBER: If you use the realistic model, your temperatures would be around 1500 or something?

MR. LEONARD: Would be much lower than what we have here, yes.

DR. DENNING: Do you get discharge of the nitrogen into the system? Do you have more discharge of nitrogen in the system or is there something that prevents the discharge?

MR. SICARD: There are limits on the maximum and the minimum amount of nitrogen in the system. And we did not change anything dealing with the maximum nitrogen volume.

Joe Cleary from Westinghouse will have something to add.

MR. CLEARY: Yes. My name is Joe Cleary. LOCA safety analysis, Westinghouse, involved with the Waterford power uprate analysis.

Yes. In the large break LOCA calculation the safety injection tanks do empty their liquid and inject the nitrogen into the RCS. The tanks inject the nitrogen at an RCS pressure of roughly psi or so. And the large break LOCA evaluation model represents the effect of that nitrogen discharge in the injection section of the RCS piping.

MR. SICARD: Does that answer your question?

DR. DENNING: It wasn't clear. But there is a larger nitrogen volume injected then?

MR. CLEARY: Yes. In order -- by lowering the -- the analysis does analyze a maximum SIT liquid level as the most limiting condition, and therefore by lowering that there is slightly more, by that same amount, more nitrogen.

MR. SICARD: Let me move on to the small break LOCA analysis. We have not changed the method for that analysis. Waterford 3 continues to use the S2M evaluation model. We have credited the automatic operation of the atmospheric dump valves on the secondary side for secondary pressure control for the small break LOCA. Previously relied on the main steam safety pressure that control pressure at a higher pressure.

We have a 1040 psia analysis setpoint for the atmospheric dump valves. What this functionally means is that we're able to control the pressure in the reactor coolant system slightly lower which gives increased flow delivery from our high pressure safety injection pumps for this event.

We had historically at Waterford credited the charging pumps in the small break LOCA analysis. Those have been removed from that analysis both for today's conditions and for power uprate conditions. And the results of our analysis show a peak clad temperature of 2019 degrees, which meets the 2200 acceptance criteria.

CHAIRMAN WALLIS: In your SBLOLCA analysis you present lots of the two-phase level in the core. And a minimum two-phase level is about half way down the core for 1,000 seconds or more. To me a two-phase level means the top of a two-phase mixture, so that would indicate that the half top of the core is dry. I don't think that's what you mean, is it?

MR. SICARD: Joe, would you care to answer that?

MR. CLEARY: Yes, that is what -- that the picture is supposed to present. The upper half of the core is dry steam that the cladding is being cooled by steam, heat transfer to steam both convective and radiation.

CHAIRMAN WALLIS: For that very long period of time. It seems surprising to me that you can steam cool for that long period of time.

MR. CLEARY: That amount of coolant recovery is not unusual. It's very similar to other analysis we've been doing with our evaluation model from the very beginning. The p-cladding temperature of 2000, low 2000 is a somewhat typical result for a CE PWR using our methodology.

CHAIRMAN WALLIS: Maybe it's it all right. I remember analyzing TMI, and when that went dry things heated up pretty quickly. Maybe it's all right. I'm just surprised. You got some much of the core dry for so long with that small break LOCA.

MR. SICARD: You have removed the sensible heat before that occurs and your decay heat has gone done somewhat by that point in time. You know, we do have an increase in the clad oxidation associated with the small break LOCA for power uprate which probably is tied to this phenomenon that you are referring to here.

Joe, would you have any further comments?

MR. CLEARY: You've made a good point. The time at temperature is what controls the cladding oxidation and the cladding oxidation did go up but still well below the acceptance criterion level.

MR. SICARD: Right. And if I remember our boiler brethren, they basically look to try to keep the core one-third covered in order to credit the steam cooling for the top part of their cores. You know, our fuel is of a different design, but one would have the same phenomenon to some extent.

CHAIRMAN WALLIS: Some of these plots are in terms of collapsed level, and that's not what you're showing here. You're showing a two-phased level?

MR. CLEARY: Yes, sir.

MR. SICARD: I'll go on, if I may.

On LOCA long term cooling,t his is the boric acid precipitation analysis that is done for the core. And this was analyzed per the approved CE Westinghouse methodology. And with the change in the mixing volume that I had presented in the earlier slide where we assumed part of the outlet plenum but no longer assumed the inlet plenum as the mixing volume, the results of that analysis who that the initiation of hot leg injection in a two to three hour time frame after a loss of coolant accident shows that you meet your solubility limit. We have a four weight percent margin at the three hour time point to that solubility limit. And this is a change which is primarily due to the change in method, change in assumed volume rather than one which is driven by the power uprate itself.

CHAIRMAN WALLIS: This is an area where the staff has not always agreed with you?

MR. SICARD: There have been some discussions with the staff on that. Let's see, Jerry Holman, I believe --

MR. HOLMAN: Yes. We have had some discussions with the staff on concerns that they had. We have come to resolution on those concerns. And I'll let the NRC staff discuss that more in their presentation.

CHAIRMAN WALLIS: What's the ultimate heat sink?

MR. SICARD: The ultimate heat sink aspect of the analysis will be discussed in Dave Viener's presentation.

CHAIRMAN WALLIS: I understand it's

cooling towers?

MR. SICARD: We have a combination of wet and dry cooling towers. Dave, would you care to answer that?

MR. VIENER: My name is David Viener, and I'm the power uprate mechanical engineering lead.

Ultimate heat sink consists of the component cooling water system, aux component cooling water system and the wet cooling tower basins. The component cooling water system uses a set of dry cooling towers. The aux component systems removes heat from the component cooling water system using the wet cooling towers.

CHAIRMAN WALLIS: The condenser water is cooled by normal operation?

MR. SICARD: The condenser is cooled by our circulating water system, which is a once through system cooled by the river.

CHAIRMAN WALLIS: It's cooled by the river? Yes.

MR. SICARD: Yes.

CHAIRMAN WALLIS: So I just wondered why you needed cooling towers when you have one of the biggest rivers in the nation running next door?

MR. VIENER: Well, the plant was

originally designed to use the river, but during original licensing it was determined to have an independent --

CHAIRMAN WALLIS: It case the river dried up, is that it?

MR. SICARD: I understand that happened to Beaver Valley once.

CHAIRMAN WALLIS: The Mississippi probably wouldn't dry up, but it might get diverted under flood.

MR. SICARD: We can address that in our risk considerations portion of the analysis.

Let me go on to the AST dose analysis. Waterford had documented control room dose previously only for the large break LOCA and the fuel handling accidents. While we were in our power uprate project developing analysis in support to it, there was the issuance of the NRC Generic Letter 2003-01 on control room habitability. And as a result of that generic letter, Waterford saw the need to add to its licensing basis for the control doses for other events.

We conducted our trace gas test of the plant in April of 2004, which was after the initial submittal of our power uprate licensing application. And we have made a subsequent related but separate license amendment to adopt alternative source term in order to address the control habitability issues for the plant. That amendment is under staff review and is one of the open items that Kaly had mentioned in his introduction.

We have in those analysis bounded what our control room inleakage is under both modes of operation of our control room. Our control room will go into what we call a recirculation mode on receipt of a safety injection actuation signal or a high radiation signal at the intakes. And that is a mode where you recirculate and filter the air which is in the control room.

There is also a pressurized mode which the operators can select and can put the control room in. And when they do that, there is approximately 200 CFM of filtered intake flow that comes into the control room to pressurize it.

Our analysis have assumed values that bound the measured inleakage. We assume 100 CFM in the recirculation mode. It bounds a 79 CFM measured value and we assume a 65 CFM value in the pressurized mode that bounds a 36 CFM measured value.

DR. DENNING: Can you help us a little bit on that?

When these pressurized area, it's above atmosphere?

MR. SICARD: Yes, it is above atmosphere.

DR. DENNING: But you're assuming that there's still some inleakage even though it's above atmosphere?

MR. SICARD: We have performed the tracer gas test, which is consistent with the guidance of the generic letter and the NEI industry guidance. And, you know the result of that test gave a value of 36 CFM for the inleakage.

Part of the reasoning behind doing that trace gas testing is that there may be certain areas of the control room where the differential pressure may be different than what the measurement is, the isolated rooms that connect up to the control room, for instance. And I would let the staff provide more explanation on the logic of that this afternoon, if I may suggest. But, you know, we have conducted the analysis in order to bound the results that we have over here.

The next slide. One of the concerns for the Waterford dose analysis is that we do have relatively high chi-over-Q values. The atmospheric dispersion values do to the location of these atmospheric dump valves to the control air intake for most of the non-LOCA transient events. One is cooling down the plant with the atmospheric dump valves, so that is the point of the release for the transient. That is why that is of interest for these analysis.

We have assumed a steam generator leakage of 0.375 GPM per generator for steam generators under faulted conditions such as for a main steamline break or a feedwater line break condition. This is the value which is supported by the operational assessments that are done, each reviewing for the steam generator consistent with NEI 97-06. We have assumed the operational leakage value for steam generators that are intact that have not been subject to a large transient. We have assumed a 75 gallon per day limit for the small break LOCA and all the other events assume a 150 gallon per day value for that.

And we have credited the existing operator actions for selecting the preferred control room air intake when the operators go to pressurized mode within the analysis.

CHAIRMAN WALLIS: How close is this proximity that you have?

MR. SICARD: It is approximately 21 feet from the closest atmospheric dump valve to one of our control room remote air intakes.

CHAIRMAN WALLIS: That's not very far?

MR. SICARD: No, it is not. That is what has--

CHAIRMAN WALLIS: So you will be ingesting not just some radioactivity, but steam, presumably?

MR. SICARD: If one --

CHAIRMAN WALLIS: It gets pretty warm in there, like a Turkish bath in the control room.

MR. ROSEN: When you switch to the preferred intake, do you get much more distance?

MR. SICARD: Yes, we have a better geometry with the preferred intake. The chi-over-Q value goes down by a factor of two for that.

MR. ROSEN: How big is the separation? You said it was 21 feet in the non-preferred intake?

MR. SICARD: I do not recall that number. It is more than twice the 20 feet. The other intake is also oriented in a different direction.

This presents the results for the limiting events that we analyzed for alternative source term. This shows that we meet the regulatory limits of Reg. Guide 1.183 of the alternate source term 10 CFR 50.67 and the five rem GDC19 general design criteria requirement on the control room dose.

MR. ROSEN: Usually we put units on tables that were shown to us.

MR. SICARD: I apologize. These are rem TEDE, total effective dose equivalent.

CHAIRMAN WALLIS: What is the requirement --

MR. SICARD: The requirement is 5 rem for all events.

CHAIRMAN WALLIS: So you're getting fairly close to that?

MR. SICARD: Yes, we are. Fairly close on a couple of events.

MR. SIEBER: If you had left the allowable steam generator leakage at 150, you would have been above five in your small break LOCA, I take it?

MR. SICARD: Under the analysis we did if that was the only change we made, yes we would have been above five for small break LOCA. We do have some conservatisms in that calculation. Because of the relatively small time that we had to work with in between the tracer gas testing and wanting to get a submittal into the NRC for that event, we have a relatively conservative release calculation for small break LOCA. We do have the option of going back and performing a more sophisticated analysis of the releases which has the potential of improving that margin.

MR. SIEBER: Okay. Thank you.

MR. ROSEN: On line four you have the steam generator tube rupture, an acronym?

MR. SICARD: Oh. That is for the preexisting iodine spike. One assumes two different iodine spike characteristics for events that do not involve fuel failure of a preexisting iodine spike and an accident generated iodine spike.

MR. ROSEN: So this is sort of with the preexisting?

MR. SICARD: Yes, that is the worse of the two scenarios for the steam generator tube rupture.

So we have demonstrated that we meet the acceptance criteria for the alternative source term and this supports our --

CHAIRMAN WALLIS: Well, let me go back to the last one. You have a fuel failure of 100 percent for the small break LOCA. What kind of a fuel failure are you talking about that's a 100 percent?

MR. SICARD: That is a clad failure. That is meant to be fuel failure, the same as --

CHAIRMAN WALLIS: Just the gas between the clad --

MR. SICARD: Yes.

CHAIRMAN WALLIS: It's not the whole fuel?

MR. SICARD: No, it is not the whole fuel. Because you would not be uncovering the fuel until approximately 15 minutes into the event where the decay heat would go down. You would not be subject to the fuel melt for that event.

CHAIRMAN WALLIS: Well, that's reassuring.

MR. SICARD: And that is an analysis assumption that is consistent with the dose analysis for the small break LOCA that have been done in the industry.

So that concludes my review of the safety analysis aspects. And if there are no further questions, Jerry Holman our manager of nuclear engineering will present the risk considerations.

CHAIRMAN WALLIS: He's going to present after the break. We're going to have a break now until quarter to 11:00. And we'll try to catch up because we're taking twice as long as we scheduled.

(Whereupon, off the record at 10:28 a.m. until 10:45 a.m.)

CHAIRMAN WALLIS: Let's come back into session.

We're looking forward to Jerry Holman's

presentation. We hope that he can get us back on time.

MR. SIEBER: They said it's not risky --

MR. MITCHELL: This is Tim Mitchell. If I could interject one minute. We are ready to talk about the heat balance question as far as how we did and what percentages of delta T if now is an acceptable time?

CHAIRMAN WALLIS: Well, why don't you do that right after lunch when we're in a good mood?

MR. MITCHELL: Okay. We can wait until after lunch.

CHAIRMAN WALLIS: Yes, I think we should go ahead with this now since he's up there.

MR. MITCHELL: Okay.

MR. HOLMAN: Okay. I'll go ahead and get started. I'm Jerry Holman, manager of nuclear engineering. I've been with Waterford for 22 years.

I'm going to discuss the risk impact of the power uprate.

We looked at all the major elements of the PRA model for its impact on power uprate. That includes the initiating event frequencies, success criteria. We looked at the failure rates. We've particular concentrated on operator response times and the human reliability analysis. We quantified the core damage frequency and the large early release fraction. And we also looked at external events and shutdown risk.

DR. KRESS: Now you have your own PRA, I take it?

MR. HOLMAN: That's correct.

DR. KRESS: And through the industry review?

MR. HOLMAN: Yes. We have gone through a owner's group certification process.

DR. KRESS: Yes.

MR. HOLMAN: And addressed those issues.

There are no change in plant operation that would cause any new initiating events to be included into the PRA model.

DR. FORD: What is your basis for saying that?

MR. HOLMAN: There's --

DR. FORD: Your factual basis?

MR. HOLMAN: We've looked at the operation of the plant after power uprate. There is no significant procedure changes, there's no changes in the way the plant is operated, operator actions. So there's no impact on initiating events.

DR. FORD: And materials degradation doesn't come under that sub-bullet?

MR. HOLMAN: No. In fact, what we would look at is in any cases where there might be some additional wear or degradation --

DR. FORD: Right.

MR. HOLMAN: -- we have monitoring programs to ensure that we capture that wear and do preventative maintenance prior to it getting to the point where it would result in any failures or initiating events.

DR. FORD: Well, you mentioned flow-induced vibration. What would happen, you got a higher flow rate going through the steam generator and the steam generator internals will presumably vibrate more and wear more on anti-vibrations bars, for instance.

MR. HOLMAN: Correct.

DR. FORD: What happened if it went so fast that you go through a tube wall within one operating cycle?

MR. HOLMAN: Right. We have Don Siska here, but I think we would not expect to see those types of differences and changes where the wear rate would increase to get failure within that one cycle.

DR. FORD: Well, that was the objective of my question. What's your technical basis for saying that it wouldn't? The reason why we're so sensitive to that is, as you know in the BWRs, the steam dryers, we've had this problem. And no problem, no problem based on analysis there was a problem.

MR. HOLMAN: Yes.

DR. FORD: So what is your technical basis that you're so sure that there will not be a problem within one fuel cycle.

MR. HOLMAN: Right. Don?

MR. SISKA: I'm Don Siska from Westinghouse.

I can speak to the issue of the flow-induced vibration, particularly within the steam generator.

We looked at the higher flow rates and did a much more detailed type of analysis than we had done originally for these steam generators. And all of the stability ratios, if you will, and the critical areas all remained well within the -- below an acceptance criteria such that we would not predict any sort of onset of instability or any kind of significant wear at all, certainly much less than a structural limit of a tube within one fuel cycle. And I believe Waterford does 100 percent inspection of all active tube during an inspection, so we don't anticipate any problems in that area.

DR. FORD: What would the impact be if you were wrong?

MR. HOLMAN: Well, we have had occasions back in the original licensing of San Onofre and St. Lucie 2 where we did have vibration in what we call the diagonal bars or bat wings and actually had a small leak in less than one cycle. However, these were small controlled leaks and the plant was able to shutdown without any significant issues. We subsequently have done plugging in that region. And in some cases put stabilizers in an area to make sure that this doesn't continue to happen.

DR. FORD: Are there other combustion engineering designs similar to yours which are operating at similar conditions to this?

MR. HOLMAN: Similar to the outbreak conditions you mean?

DR. FORD: Yes, correct.

MR. HOLMAN: Well, Palo Verde has very similar designs. The actual support, tube supports in the Waterford steam generator are more robust than at Palo Verde. They have three partial supports at the top of the two bundles as opposed to two. And the supports in the supper two bundle on the vertical grids connect directly to I-beams where at Palo Verde they float. So we would expect at Palo Verde we would have much more vibration problems than would Waterford.

DR. FORD: Okay.

MR. MITCHELL: This is Tim Mitchell on what if we're wrong.

DR. FORD: Yes.

MR. MITCHELL: We do follow the EPRI guidelines on responding to indications of leakage within the steam generators. Those indications would have us shutting down much sooner than the 75 gallons per day limits that we talked about earlier. So it would be something that we would take very seriously and respond to operationally and take conservative action. So it's not anything that we expect, but our procedures are built to make sure that that is evaluated seriously and there is clear shutdown criteria. I don't remember the exact criteria, but it's well below any of analyzed numbers.

DR. FORD: Okay.

DR. KRESS: On your initiating event frequencies, do you use the generic values for that or do you have plant specific values?

MR. HOLMAN: Yes, we use a combination. We start with the generic data. And for those events where we have seen plant specific events, such as loss of feedwater, we roll in the plant specific.

DR. KRESS: So the only way you can assess whether there is a change in frequency is mostly judgment. You just look at the things that might cause the frequency to change?

MR. HOLMAN: That's correct. And when we do model updates, we go back and look at actual history and we will roll any experience into those model updates and changes.

DR. KRESS: Okay.

MR. MITCHELL: This is Tim Mitchell one.

The one thing we did do as a result of industry experience, it was within the scope anyway but we expanded it, was to go look at where the industry has experienced problems with components as a result of changes in power uprates, even just valves operating in a different region than what they did before.

DR. KRESS: That's where I was leading with my question.

MR. MITCHELL: We've tried to look at

those cases and even look at our maintenance practices of what do we need to do from a maintenance standpoint to make sure those aren't issues. But our final catch is we have performance monitoring program within system engineering that after all the testing is done, we'll continue to monitor parameters, especially on the secondary but the primary also, to look for deltas over consistent conditions that we would have seen prior to the update. And we'll go evaluate those as part of our corrective action process if there are any.

We do have some Arkansas Nuclear 1 that tells us that even two or three cycles later you can have problems with things like static water cooling system. So our performance monitoring program will be very detailed and very rigorous at looking at changes and evaluating those changes and looking within industry experience as a guide at what things should we be concerned about as a result of those.

MR. HOLMAN: Okay. We also looked at our success criteria. We ran the CENTS code to do some analyses in order to confirm that the success criteria for power uprate would not change. And we found that it does indeed --

DR. KRESS: Your success criteria was

what, two out of the three pumps?

MR. HOLMAN: That's correct. It would be things like one emergency feedwater pump required to mitigate and prevent core damage versus two or how many flow paths for safety injection.

Okay. The power uprate team did comprehensive reviews of equipment for its impact due to power uprate. We found that all the systems operate within allowable limits. EPU will not overstress any equipment or there was no impact on any of the PRA failure rates as the result of power uprate.

As we've mentioned before, we do have existing monitoring programs that are in place to capture and monitor for any increased degradation or wear. We have a strong incentive to make sure we catch that degradation prior to it actually turning into equipment failures.

DR. KRESS: Do you use CHECWORKS or the --

MR. HOLMAN: We use CHECWORKS for the flow-accelerated corrosion, yes.

Okay. We looked at operator response times. We ran again the CENTS computer code in order to determine times that are available for recovery of offsite power and the time to core uncovery. In general the higher decay heat as a result of a power uprate reduced operator available action times.

The major impact is the PRA model was a reduction in the time to recover from a loss of feedwater and the time to recover from offsite power, a loss of offsite power. Typically what we're looking at is the time to uncover the core here and with the higher decay heat, that is a little bit shorter.

CHAIRMAN WALLIS: This is where you have these reductions from 40 minutes to 2 minutes?

MR. HOLMAN: That was result of more rigorous analyses and looking at different brakes sizes for that range, that's correct.

CHAIRMAN WALLIS: You concluded that two minutes was too short that you'd assumed that they failed?

MR. HOLMAN: In cases where the time frame was too short to credibly have operators take action, we just assumed that that action was taken.

Okay. So this slide shows the impact of the dominate operator recovery actions before power uprate and after power uprate and after power uprate. The time to core uncovery before power uprate coming out of the CENTS analysis was 82.6 minutes. And after power uprate because of the higher decay heat, it's reduced to 68 minutes. That shorter time available translates into a small increase in the failure probability or the nonrecovery probability. So that's an example of the tech 92 that we're talking about for power uprate.

CHAIRMAN WALLIS: You have aux feed. What is this feedwater recovery? You got two sources of feedwater.

MR. HOLMAN: Yes. We have our main feedwater. We have three emergency feedwater pumps, two motor driven and one is a turbine drive EFW pump. We also have a separate pump that we call an auxiliary feedwater pump. It comes off of the main condenser. So those are the type of actions that we would be --

CHAIRMAN WALLIS: So what's being recovered here? Which of those different sources of feedwater is being recovered?

MR. HOLMAN: We'll step through a progression of what the operators would do given a loss of feedwater.

The first thing they would do would be try and start emergency feedwater. If that does not work, they'll go the next thing. If it continues not to work, we've also got an action to depressurize the steam generators and try and use the condensate pump.

So there's a progression of actions.

The only thing that's changing for power uprate is the total amount of time that's available to complete those actions before we reach core uncovery.

MR. SIEBER: This is a side question. You now have declared your atmospheric dump valves as safety related and they're required to be operable above 70 percent power?

MR. HOLMAN: Correct.

MR. SIEBER: For mitigation of a small break LOCA. Was the fact that you now need them, that becomes a new event with a different frequency; is that figured into your risk calculation?

MR. HOLMAN: The credit for the atmospheric dump valve was required for the conservative licensing basis small break LOCA model that has the Appendix K conservatisms.

For the PRA model we're looking more at a realistic small break LOCA. On a realistic analysis basis we do not require that same automatic feature of the ADV. So we did not have to change or in corporate that ADV as part of our success criteria for the PRA model.

MR. SIEBER: But you have some documentation that it establishes the reasoning path where you document that conclusion?

MR. HOLMAN: That's correct. That's part of the CENTS analysis.

MR. SIEBER: All right. Thank you.

MR. HOLMAN: Okay. We quantified the core damage frequency increase as a result of power uprate and determined to be 3.5 times 10 to the minus 7. That's a small increase that meets the Reg. Guide 1.174 guidance.

We also quantified the large early release frequency to be less than one times 10 to the minus 7. So at the end of power uprate our new core damage frequency is 5.9 times 10 to the minus 6.

MR. ROSEN: Now have you had a peer review of your PRA?

MR. HOLMAN: Yes. We did a peer review coming out of the owner's group. For the power uprate model we've addressed all of the major items that came out of the peer review with the exception of three significant ones. Those were all related to the level two analysis model.

For this effort on power uprate we did not use the full level two. We did a simplified alert.

MR. ROSEN: Now you're saying that peer review looked at your power uprate calculations as well?

MR. HOLMAN: No. The peer review was for a previous version of the PRA model that we built the power uprate off of.

MR. ROSEN: And the peer review had no quarrel with 6E to the minus 6 for internal events at Waterford?

MR. HOLMAN: That's correct.

MR. ROSEN: What in your opinion gives a result that low? I would expect it would be twice that or maybe three times of that in a PWR.

MR. HOLMAN: Right. Prior to the latest update, LOCA frequencies, small break LOCA in particular had dominated, had been a significant contributor. The last update revised the initiating event for LOCAs consistent with the latest NRC guidance. And that reduced the core damage frequency.

The other thing is the convolution approach that we take to recovery of loss of offsite power, that was also a benefit.

Some detailed look at the different combinations of recovery of offsite power. So, again, it's a more improved and detailed analysis which has given us that benefit.

MR. ROSEN: While I've interrupted your

talk, let me ask you a related question. Part of the discussion here today will be about the large transient testing and the desire on the part of Entergy to not do the large transient tests at Waterford.

Now in the attachment 5 to the supplement testing, the startup testing supplement rather, there is a statement I want you to help me understand. It's talking about a SCRAM from full power, from the new extended power. It says "A SCRAM or the potential for a SCRAM from a high power level results in an unnecessary and undesirable plant transient cycle on the primary system. And the risk associated with the intentional introduction of a transient initiator while small, should not be incurred unnecessarily."

Now, that statement does not quantify what the word "small" means. And I'd ask you to help me with that. What is your view of the risk of a full power SCRAM?

MR. HOLMAN: We have not quantified that specific transient and the impact of doing that test. I think it was meant to be a more general statement that anyway time you initiate you reactor trip, there is some consequence to that.

MR. CONSTANCE: Hello. I'm David

Constance. And I'm with Entergy, and I'll be presenting testing later on day.

Jerry, we did get some of those numbers in for the event specific risks for turbine trip. I don't recall what the numbers were, but they were indeed in our opinion small but should not be discounted.

MR. ROSEN: What do you mean by small? You mean --

MR. CONSTANCE: Less than ten to the minus 6.

MR. ROSEN: Less than ten to the minus 6?

MR. CONSTANCE: Right.

MR. ROSEN: Okay.

DR. KRESS: Refresh my memory about this Waterford site. What sort of population density does it have around it, do you recall those numbers?

MR. HOLMAN: No, I don't recall those numbers.

DR. KRESS: Is it near a big city.

MR. HOLMAN: Waterford is about 35/40 miles outside -- west of the city of New Orleans.

DR. KRESS: That would be a low population density side.

MR. LEONARD: This is Ted Leonard, the project lead.

The site's situated in a rather low population area. There's a lot of industry on the river, petro-chem industry on the river near the site. Probably the largest town of LaPlace is about five miles away from the plant as the crow flies. New Orleans is like 50 miles away.

CHAIRMAN WALLIS: It's getting further away. It says 35 miles in the SER.

MR. MITCHELL: It probably is 25 miles to the suburbs for sure.

MR. SIEBER: It's a fluid situation.

MR. HOLMAN: Okay. This slide shows the relative contribution of different sequences. As you can see, the risk at Waterford is dominated by total loss of feedwater and station blackout events.

MR. SIEBER: There was question about how much fuel oil that you have to sustain the loop in that. And it says you will increase the capacity of your diesel tanks by the end of next year. What do you plan to do? Install additional tanks or --

MR. MITCHELL: Yes. This is Tim Mitchell.

David Viener will talk about it in more detail during part of his presentation. But we do plan on adding additional tanks to address operator concerns or our concerns about the operators tend to fill the tanks so full with little room to the overflow. Now the overflow is captured, but the fact that after a surveillance we'll have prompt action to go refill the tank each time. And the frequency of doing that, we think we can improve our margin and improve -- or harden ourselves against operator error with respect to things like overfilling the tank.

MR. SIEBER: So you don't plan to put in additional tanks. You just plan to keep it fuller?

MR. MITCHELL: No. I'm sorry. The immediate is we will keep it fuller until we get the additional added, which is by December of 2006. So we are working on pursuing that design right now to add that additional tank.

MR. SIEBER: Will that be an underground tank?

MR. MITCHELL: It will probably be a tank located in our cooling tower areas. Do we have an exact spot picked? There's three spots.

MR. SIEBER: And that single third tank will feed multiple diesel generators?

MR. MITCHELL: Yes. We have a cross connect between the qualified tanks that this third tank will be able to supply both tanks. But, Joe?

MR. REESE: This is Joe Reese with

engineering with Entergy at Waterford 3.

Currently we're completing a scoping study to let an engineering contract on the design of the tank.

The predominate location selected right now is in our wet cooling tower area. And the predominate design would be looking at a safety related seismic tank that would have the ability to feed either diesel generator storage tank.

MR. SIEBER: So it's a safety related tank?

MR. REESE: That's correct.

MR. SIEBER: Okay. Thanks.

DR. KRESS: Could I see your previous slide a moment? Could you tell me, is that the -- did the sequences that contribute to the core damage frequency at the extended power uprate condition, is that what--

MR. HOLMAN: That's correct, yes.

DR. KRESS: Okay. When you do a delta CDF, then do you just look at the dominate sequences in your--

MR. HOLMAN: Yes, we quantified the entire model so we captured all of the sequences.

DR. KRESS: Oh, you capture all of them.

MR. HOLMAN: Yes.

DR. KRESS: Okay. Okay. Thank you.

MR. SIEBER: What is the delta CDF between non-uprate and uprate conditions?

MR. HOLMAN: The delta CDF due to power uprate was 3.5 times ten to the minus 7.

MR. SIEBER: Okay.

MR. HOLMAN: Okay. We looked at external events. There was a slight increase in the fire core damage frequency as a result of the small decrease in available recovery times. We quantified the delta CDF for fire to be seven times ten to the minus ten. There were no other impacts to any of the other external events as a result of power uprate.

We also looked at the --

MR. ROSEN: What is the fire portion of CDF? Not the delta, the total?

MR. HOLMAN: The percent?

MR. ROSEN: Yes.

MR. HOLMAN: I don't have that number off the tope my head. It's --

CHAIRMAN WALLIS: Well, the fire risk I have is 8.15E to the minus six, which is bigger than your internal events CDF.

MR. HOLMAN: The fire risk value that we calculate is based on the very conservative approach in the FIVE methodology. So it's hard to make a apples-and-apples comparison to the internal risk.

MR. ROSEN: But based on what our Chairman just said, it would roughly equivalent --

MR. HOLMAN: Roughly equivalent.

MR. ROSEN: -- to the internal events risk.

MR. HOLMAN: That's correct. And the delta--

CHAIRMAN WALLIS: The delta is minute.

MR. HOLMAN: Right. That's correct.

MR. ROSEN: The change is minute because of this. But an important contributor to fire, the CDF effort is based on the FIVE analysis at Waterford is fire?

MR. HOLMAN: That's correct.

MR. HOLMAN: Okay. We've looked at shutdown risk. There were no unique aspects of power uprate that would cause us to change the risk at shutdown conditions. We looked specifically at maintaining safety functions during shutdown. There were no changes to our shutdown operations protection plan.

We did look specifically at some of the calculations that we have to determine time to boil under shutdown conditions, and have made those updates as a result of the higher decay heat, folded that into operating procedures.

Therefore, overall we looked at all the PRA major elements for its impact on power uprate. There was a minor reduction in the available recovery time for several operator actions dominated by the recovery of offsite power.

Power uprate has a very small increase of the risk, the 3.5 times ten to the minus seven.

So that concludes my presentation on risk considerations. If there are no other questions, I'll turn it to Dave Viener to talk about our engineering impact.

DR. KRESS: You said your LERF calculation was not the full level two, but just the simplified methodology that the NRC uses?

MR. HOLMAN: That's correct. Yes. The simplified LERF.

CHAIRMAN WALLIS: Thank you. And you've gained us a little bit of time.

DR. KRESS: Yes. Thank you.

MR. HOLMAN: Thank you.

MR. VIENER: Good morning. My name is David Viener. I'm the extended power uprate mechanical lead on the project. I've been at Waterford for 14 years, all in the design organization. I'm here to discuss the engineering impacts as a result of the power uprate.

The project team reviewed all plant system, components and structures the plant could safely operate to the extended power uprate conditions. If the design was inadequate, mods were proposed and they were scoped and designed. If the design margins were acceptable, the design basis was clearly updated to demonstrate acceptance for power uprate.

Some of the significant modifications for power uprate includes the replacement of our high pressure turbine steam path, that's due to the increase in volumetric flow as a result of power uprate.

We are rewinding the generator to accept the new electrical load as a result of the thermal power increase.

We are replacing our generator output breakers and switching station and bus work and so forth. That's again is to accept the new electrical load as a result of power uprate.

We are replacing our alpha transformer and increasing cooling in our bravo transformer. Again, to increase the design to accept the new electrical load.

MR. ROSEN: David, your first bullet on that slide, replacing the turbine steam path. Could you be more specific? That's short of shorthand. Tell me in some detail what you're actually doing.

MR. VIENER: The steam path replacement includes a new full reaction rotor, the inner cylinder and flow guides to the turbine. The valves are not being replaced.

MR. ROSEN: Any piping changes?

MR. VIENER: No piping changes at all. Just -- well the nozzles because we're going to a full arc admission machine. Right now we're at a partial arc admission machine. And we're going from that one nozzle to four nozzles. So there will be some machine work at the turbine for that.

MR. ROSEN: So some piping changes, obviously to match up --

MR. VIENER: To match up with the new turbine. That's correct.

MR. ROSEN: But no new valving?

MR. VIENER: No new valving.

MR. ROSEN: The valving will be upstream of those piping changes, is that correct? The existing valving?

MR. VIENER: The existing valving will remain. There's no change to the steam chest at all as a result of the steam path in place.

MR. ROSEN: And what about the position of the valves, the control valves?

MR. VIENER: They are not moved. There's no physical modification at all.

MR. ROSEN: Okay. But they will operate at a different point.

MR. VIENER: That is correct.

MR. ROSEN: Because of the higher steam flow?

MR. VIENER: The higher steam flow.

MR. ROSEN: Now how close to valves wide open are you?

MR. VIENER: We have designed the operating point for the turbine to accommodate a 1000 tubes plugged and also include a one percent valve margin on top of that. So that's should roughly give us about 12 pounds of margin from the steam outlet moving forward with the power uprate. Our design should assure us that we do not operate with valves wide open.

MR. ROSEN: But you're close, it sounds like.

MR. VIENER: We will be close. But our current tube plugging is about 550 on one generator, 450 on the other. We're going to a 1000 on both generators. Accommodating that pressure drop as a result of that, as well as add another one percent of margin on top of that.

MR. ROSEN: So when are you going to -- I guess you'll have the experience of setting those valves as you creep up towards full power? What's your planning there?

MR. VIENER: The valve -- David Constance is maybe better to answer this question.

MR. CONSTANCE: I'm David Constance and I'll be doing the static testing at Waterford.

And two aspects of the turbine control system that we'll be validating during startup is the turbine valve curve, which is the megawatt to valve position curve and also the megawatt to turbine first stage pressure curve; both will be validated during plant startup.

MR. MITCHELL: This is Tim Mitchell.

Valve setup will actually occur prior to rolling the turbine the same time. So the validations will occur after the turbine is on line. But the biggest change with valve positions is going to the full arc versus partial arc. Instead of having three valves full open and one valve throttling, we will have all four valves throttling even at 100 percent power. And I believe the projection is that'll be roughly 80 percent open. Is that close?

MR. CONSTANCE: Yes, sir. Approximately 80 percent open.

MR. SIEBER: I guess the only impact that the governor valve position has is on the governor action on an overspeed. And presuming that the governors have some impact as they tried to close before the throttle valves trips. But typically that's not the deciding factor. And so that's the only safety issue that I can see that comes out of that, other than you may not be able to get the full power. If you don't, that's the way it goes.

CHAIRMAN WALLIS: So you're only changing one stage in the turbine?

MR. VIENER: It's a whole rotor change.

CHAIRMAN WALLIS: It's a whole rotor. It's one stage though?

MR. ROSEN: High pressure.

MR. VIENER: High pressure and is eight stages.

CHAIRMAN WALLIS: You have eight stages in that one. Well, that makes more sense.

MR. VIENER: Right, eight stages in that one.

CHAIRMAN WALLIS: I was puzzled by it. So by a stage you mean eight stages --

MR. VIENER: That's correct.

MR. SIEBER: Five for him in the rotor section.

MR. ROSEN: Now you're also not doing anything to the low pressure end of the turbine? You have two low pressure?

MR. VIENER: We have three.

MR. ROSEN: Three.

MR. VIENER: Low pressure and no changes are required on the low pressure turbines.

DR. RANSOM: Does that mean the power distribution among the high pressure and low pressure turbines, all of the power increase is in the high pressure turbine?

MR. CARUSO: I do not know the balance of the way the power -- you know, between high and low. High takes the majority of it, but --

MR. SIEBER: Since you're getting it by more steam flow, it would be essentially divided between high pressure and low pressure.

MR. VIENER: Yes. I'm not sure of the balance.

MR. SIEBER: Because you've got more steam flow.

MR. MITCHELL: This is Tim Mitchell.

Because of the HP turbine modification, it will be carrying more load.

MR. SIEBER: Right.

MR. MITCHELL: But the LPs will be picking up some portion of that load. I can't either tell you the percentage or the percent change, but it will be distributed over the entire turbine train. However, the HP will be redesigned to be a more efficient rotor and it will take the majority of the increase.

MR. SIEBER: Well, it's not evenly divided anyway. The very first row of blades produces a lot of horsepower compared to everything else.

MR. MITCHELL: That is correct.

MR. VIENER: Okay. We also are planning some changes on our heater drain valves. We are going to be doing some tube staking in our condenser to make sure we do not have tube vibration movements with power uprate.

And we do have some control system and instrumentations which include setpoint, range and scale changes. And results in about four transmitters to be replaced.

MR. ROSEN: What's the material of construction of the condenser tubes?

MR. MITCHELL: The condenser tubes are stainless.

MR. VIENER: Stainless.

Okay. With the higher decay heat, it didn't result in any physical changes to our safety systems with the ultimate heat sink. The system will still be capable of dissipating the heat loads the normal shutdown and accident conditions.

The water sources are still adequate to maintain cooling to the essential plant equipment. And equipment operating times, this will increase post accident which does impact our fuel oil. And I think we did talk about some plans to increase margin at the site on fuel oil.

MR. ROSEN: Let's go back to 41 again, the previous slide.

MR. VIENER: Sure.

MR. ROSEN: What are these transmitter

that are being replaced and the setpoint, range and scale changes. And what instrumentation are you doing that on?

MR. VIENER: I'd like to turn that question to Ralph Schwartzbeck, our BOP lead.

MR. SCHWARTZBECK: I'm Ralph Schwartzbeck with Enercon Services.

The four transmitters that are being replaced are two main steam pressure transmitters and two boric acid makeup level transmitters.

The setpoint changes are basically operating points for those transmitters. We had to recalibrate some of the transmitters to give them increased range of operation. We have to rescale some of the board meters to show with the new operating conditions.

The setpoints that we really did -- one major setpoint was the low steam generator pressure trip that was done in the reactor protective system. But other than that, it was just minor movements around just to make sure the controls worked like for the feed pump turbines and things like that. Just to make sure that they will operate within their design conditions at uprated power.

MR. ROSEN: You said low steam generator

pressure?

MR. SCHWARTZBECK: Yes. That's the only plant protective system setpoint that is being changed. And that was discussed earlier.

MR. SIEBER: That's a pretty big change. You go from 764 to 662. Why are you changing that again?

MR. SICARD: This is Paul Sicard.

The reason why we are changing that value is to provide operational margin for the plant. We are lowering what the full power steam generator pressure is based upon our operating point for the power uprate conditions, therefore we wanted to lower that setpoint such that it was not going to cause any increase in probability of an inadvertent trip.

And we ran some analysis in order to see where it would make sense to push that number looking at various ramp rates and the impact on plant temperature. As a result of that, we adopted the analysis value that is associated with that number that's approximately 100 pounds lower than that in our safety analysis and we're able to demonstrate acceptable performance in the safety analysis based upon that value.

Does that answer your question?

MR. SIEBER: Yes.

MR. VIENER: Okay. Go the fuel slide.

DR. RANSOM: Let me go back to the pumps for a minute. The main coolant pumps. As near as I can, if I'm not wrong, they'll see about a three percent increase in load. And there's been no discussion of what effect that has on the system.

MR. VIENER: The limiting condition on the reactor cooling pump is during startup.

DR. RANSOM: Is what?

MR. VIENER: Is during startup where reactor coolant is actually cooler and higher mass flow as a result during startup and provides more draw on our motors.

DR. RANSOM: Right. The motors will take that and --

MR. VIENER: We're not changing the startup sequencing in the reactor coolant pump motors. Once you get up to nominal T_{cold} temperature, they're fine. They're operate well within the design limits.

MR. SIEBER: Most coolant pump motor failures are when the plant's cold, and in particular from the in rush when you first start the pump. Once you're operating, they'll run for a long time.

MR. VIENER: Okay. On the emergency

diesel generator fuel oil, we are raising the minimum capacity requirement in our storage tank to maintain the seven day supply for our current licensing basis. We do have a commitment to add additional storage. That should be complete by the end of 2006. And Tim described and Joe described what our plans were for that.

MR. SIEBER: Now, there is actually no additional fuel oil consumption caused by the EPU. This was an error that's been around for a long time, I take it.

MR. VIENER: There will be more consumption as a result of EPU because our ultimate heat sink equipment, some of it has to operate a little bit longer as a result of extended power uprate. Therefore, more fuel will be required.

MR. SIEBER: But those are those cooling tower pumps, right?

MR. VIENER: That's the wet cooling tower fans.

MR. SIEBER: Right.

MR. VIENER: And our aux component cooling water pump.

MR. SIEBER: Okay.

MR. MITCHELL: This is Tim Mitchell.

But you're right. There was design and issue with margins that existed for quite some time, and this is predominately driven -- the modification is predominately driven to eliminate really both issues. But the significance of it is is preexisting to EPU.

MR. SIEBER: Okay. Thank you.

MR. ROSEN: This commitment to add the additional storage, that will be completed prior to the EPU?

MR. MITCHELL: That additional storage will be provided prior to December of 2006. Not prior to EP, I'm sorry.

MR. VIENER: On our emergency feedwater system, it was reviewed and our system flow is still capable of mitigating against feedwater demand events.

And our normal and backup condensate sources are still adequate to bring the plant to shutdown cooling conditions.

On our shutdown cooling system, the system still will be capable of achieving cold shutdown in accordance with Reactor System Branch, Branch Technical Position 5-1.

And our refueling technical specification time limits to reduce shutdown flow will remain unchanged as a result of power uprate due to the conservatisms that were in the current analysis.

Fuel pool cooling, power uprate is proposing a 1 and a half percent increase in decay heat for the fuel pool cooling analysis. We reracked in 1008 and the analysis assumed an 8 percent power uprate at that time. This uprate is basically captured in the Appendix K on recapture, margin recapture.

Delay heat removal analysis does bound the capacity of the fuel pool. We will still maintain the licensing basis temperature limits as a result of extended power uprate. And the bounding time to boil analysis will remain unchanged as a result of power uprates.

MR. ROSEN: How is that possible? I mean, if you're putting more fuel into the pool and your assumption in the time to boil analysis is set, you lose cooling to the pool at the worst time, how do you end up with the -- I would expect there would be change of one and a half change?

MR. VIENER: The licensing amendment in 1998 used the ASB 9-2 decay heat and there's a typo in that decay heat equation that was used at that time.

Calculating the decay heats used in that typo provided very conservative results. Extended power uprate easily masked those conservatisms, and therefore the time -- the bounding analysis which is the full core offload, will remain unchanged.

MR. ROSEN: I understood up to the point where you said there was a typo. And the bounding analysis of the EPU remains unchanged because of the typo is taken out or not? I don't understand.

MR. VIENER: No. Well, moving forward we used the correct ASB 9-2 equation.

MR. ROSEN: I see. okay. And the next sentence remains unchanged because you changed the analysis to correct a prior error?

MR. VIENER: That's correct. That's correct.

MR. ROSEN: Okay. But "unchanged," you mean it's not higher than it was?

MR. VIENER: It's not higher than it was docketed before. It was roughly a little less than three ops.

MR. ROSEN: And now we're confident that's right?

MR. VIENER: I'm very confident that's right.

As far as EPU impact on ongoing industry issues concerning containment overpressure, currently Waterford 3 does not credit containment overpressure in the net positive suction head analysis on emergency core cooling pumps. EPU will still maintain that assumption.

As far as EPU has no impact on the safety injection sump performance as discussed in the recently released generic letter.

EPU has not proposed any system change inside containment, as well as our minimum containment sump level and our sump temperature in containment remain really unchanged as a result of power uprate.

MR. SIEBER: What you say on this slide is it doesn't tell the whole story, right? You increased the minimum temperature of containment to make sure you had enough pump suction head?

MR. VIENER: No. No. We do not credit containment pressure at all for the NPSH analysis on the emergency --

CHAIRMAN WALLIS: That's a mistake in something that we got in our literature.

MR. SIEBER: Right.

CHAIRMAN WALLIS: That has given the impression that there was a --

MR. SIEBER: Right.

MR. HOLMAN: This is Jerry Holman.

The change in minimum containment temperature was the result of the large break LOCA ECCS performance. It is not factored into the net positive suction head analysis.

MR. SICARD: This is Paul Sicard.

Let me point out the change is to move the existing requirement from our technical requirements manual to the technical specifications. So it is not a change in any analysis assumption, but merely in how we are enforcing that assumption.

MR. SIEBER: I guess I need some clarification, though. If you increase the temperature of the containment and thereby the potential stored energy there, why would you do it -- for what reason would you do it other than to make sure you had enough pump suction at the sump? I'm missing something here.

MR. SICARD: Okay. This is Paul Sicard.

For the NPSH analysis or prepower uprate conditions as well as post power uprate conditions we do not consider any increase in containment pressure that occurs because of the loss of coolant in the mass and energy release to the containment. That analysis for net positive suction head and pump performance assumes that the containment stays at its initial pressure for the purpose of evaluating the pump performance.

Now, when one gets into the loss of coolant accident, there one does account for the minimum containment response, minimum pressure response. And that is part of the approved Westinghouse LOCA methodology for determining peak clad temperature.

CHAIRMAN WALLIS: So there is an effect of containment pressure on net positive suction head?

MR. SIEBER: Well, it is in a way and it isn't in a way.

CHAIRMAN WALLIS: Two separate calculations.

MR. SICARD: If we had considered --

MR. HOLMAN: There are two analysis.

MR. SICARD: Yes. If we had considered containment over pressure for net positive suction head, that would give us improved margin because that would give you more pressure to assist the pump. We do not consider that additional term for the net positive suction head analysis.

MR. SIEBER: You're not taking credit for the LOCA pressure? You're taking credit for the containment condition? Is that a way to state it?

MR. SICARD: We are taking credit for the containment initial pressure of approximately one atmosphere.

CHAIRMAN WALLIS: That's all.

MR. SICARD: And that is all.

CHAIRMAN WALLIS: That's easy to understand.

MR. SIEBER: Well, yes. The --

MR. VIENER: We follow the reg. guide requirements as far as design and the ECCS pumps. And if I'm not mistaken, it's the containment pressure and the vapor pressure you assume will cancel out. Okay. So all you have is the NPSH required of the pump less the pressure drop from the containment sump to the ECCS pump and the elevation. That's the only factors you credit in the NPHS analysis.

DR. KRESS: And what did you do about the sump screen blockage in this analysis?

MR. VIENER: Power uprate does not impact that sump blockage analysis at all.

MR. SIEBER: Yes, it's the same sump. Same debris.

CHAIRMAN WALLIS: But you still have the problem if there was one with sump screen blockage.

It doesn't go away.

MR. SIEBER: It doesn't get worse even.

MR. VIENER: Yes. We do plan on following the guidelines of the generic letter that was issued. And we have taken some actions and we've got future actions that are upcoming.

CHAIRMAN WALLIS: What kind of insulation do you have on your steam generators?

MR. VIENER: What I'd like to do is introduce Maria Rosa Gutierrez. She's the one that's our lead in this issue.

MS. GUTIERREZ: My name is Maria Rosa Gutierrez. I work at Waterford 3 in design engineering department.

The question was insulation on the steam generators?

CHAIRMAN WALLIS: Yes.

MS. GUTIERREZ: We have reflective encapsulated insulation and also some Nukon blankets.

CHAIRMAN WALLIS: So it's all reflective metal?

MS. GUTIERREZ: No, not reflective metal. The only place we have reflective metal insulation is on our reactor.

CHAIRMAN WALLIS: So you have fiberglass

on the --

MS. GUTIERREZ: Yes.

CHAIRMAN WALLIS: -- steam generators?

MR. MITCHELL: And on the piping.

MS. GUTIERREZ: And on the piping also.

MR. ROSEN: Any calcium silicate?

MS. GUTIERREZ: No, we do not.

CHAIRMAN WALLIS: But you have those 70 truckloads of fiberglass or whatever it is that we were talking about.

MS. GUTIERREZ: I wouldn't say 70 truckloads, but yes we do.

CHAIRMAN WALLIS: Okay. Well, that's another question.

MR. ROSEN: For another time.

MR. SIEBER: Yes.

CHAIRMAN WALLIS: For another time. We'll probably see you again.

MR. VIENER: Okay. Due to operating experience, we looked at vibration pretty in depth. On a steam generator Don Siska talked about we did do extensive evaluations on our steam generator and determined that we should not experience any problems due to vibration.

DR. FORD: Could I just return to this

particular one? When you say "evaluated," you really mean analyzed? You didn't do any experiences or comparison with plant data, is that correct?

MR. VIENER: Let me turn that question over to Don Siska?

MR. SISKA: As far as the tube bundle evaluation, that was a full analytical evaluation, you know building the models and based on test data, coming up with analytical results.

DR. FORD: Can you tell me more about the test data?

MR. SISKA: The test data for the tubes were based on the tests that combustion engineering had done back in the 1970s for that particular tube bundle design. Triangular pitch, you know one inch apart. And comes up with essentially constants that fit into these Connor's equations and such to predict flow induced vibrations.

DR. FORD: And those experiments, that combustion covered conditions that you'll be having under EPU?

MR. SISKA: That's correct. Yes.

DR. FORD: Okay. On the Palo Verde design, the dry design. First of all, is the dryer a safety related component?

MR. SISKA: No, we do not consider it safety related.

DR. FORD: So if there's a loose parts of that and it impacts on the main steam isolation valve, does that not make it a safety component?

MR. SISKA: Well, one could postulate some pieces. I mean, probably the biggest thing would be the dryer bolts. Those are the only thing we've ever seen actually fall apart from there. And in general, those fall down onto the separator deck. But it's not impossible to say something couldn't get into the steam dryer or into the main steamline, but it would seem very unlikely.

DR. FORD: Okay. Now the question at Palo Verde design, it is not exactly the same, is it?

MR. SISKA: The dryer design is exactly the same.

DR. FORD: The dryer? Okay. But the steam flow will be different, won't it, because there's different -- there's only one steam outlet at Waterford and there's three at Palo Verde? So the steam flow will be different?

MR. SISKA: The steam flow up in the upper drum in particular, yes, it has higher steam flows through Palo Verde. The dryer, it's unusual to say, but the actual Palo Verde which runs at a little higher power than the Waterford EPU actually has less dryers because it's a smaller steam drum.

DR. FORD: So if you take the experience that we're unfortunately learning from the boilers where vibrations in the boiling water reactor steam dryers, certain designs of them, gave -- and you can't say therefore in your particular design at Waterford that you could not get unexpected vibrations?

MR. SISKA: I will never say never, sir.

DR. FORD: Because you don't have anything to compare it with, because you don't have data to compare it against?

MR. SISKA: Yes. We actually have two pieces of data. The initial testing that was done on these dryers looked at pressures from 600 to about 1200 psi and 30 to 60 kilopounds per hour, which is within this range. Now, again, that was not done from a structural sense. That was done mainly to determine moisture carryover capabilities. But, you know, it was some rather significant testing.

And then secondly, Palo Verde which has been operating for nearly 20 years with exactly the same design and higher flow rates, in particular the dynamic pressure through Palo Verde's dryers is about

15 percent, 18 percent higher than what we expect at Waterford during EPU. So we would expect that that type of work at Palo Verde would bound anything that Waterford will see.

MR. MITCHELL: One other point. This is Tim Mitchell.

The dryers on a boiler are vastly different than what are in the steam generators. So we have compared it to the best data that we have available to the most stringent experience, which would be the Palo Verde experience as well as the original testing.

DR. FORD: Okay. And you're still discounting that there could be any impact on the operation of the main steam isolation valves if you were wrong? The loose parts coming off and --

MR. MITCHELL: The loose parts from industry experience would be captured within the steam generators. I am not aware of any industry experience at all with dryer problems ending up anywhere other than, as Don said --

DR. FORD: Again, I come back from the boilers. We were told no it could never happen, but it did happen. And that's why we're pushing it.

MR. SISKA: I'll never say never, sir.

MR. ROSEN: Now you did talk about some bolts coming loose. Is that your own experience?

MR. SISKA: Yes. We have gone in there on occasion. There are a total of 16 half inch bolts that hold these dryers together. I believe there's five on each side that hold it to the dryer support -- or excuse me. Three on each side that hold it to the support and then five that hold it to another dryer on each side. So there's upwards of 2,000 bolts in there. And on occasion we find some. We go in there to take some dryers out, and find one missing.

And to my knowledge we've never actually found one that was missing. You know, it probably ended up just getting beat up and it's just a carbon steel, so it probably eventually just turned into sludge.

CHAIRMAN WALLIS: Maybe it was never put there in the first place.

MR. SISKA: That's entirely possible as well.

MR. SIEBER: Look at your tube sheets.

MR. SISKA: Oh, believe me, we do a lot of that.

MR. SIEBER: That would be the first place I would look.

MR. SISKA: Yes.

DR. FORD: And the failure of those bolts by what, fatigue or by what?

MR. SISKA: I have no idea really.

CHAIRMAN WALLIS: They never found them. They have no idea.

MR. SISKA: And the reason there are so many of these bolts in there is not really from a structural standpoint. It's just to try to keep the steal so that you don't get any of the moisture seeping through there without going through the chevrons.

DR. FORD: Okay. Thank you.

MR. ROSEN: But you didn't say anything about the condition of the dryers. You said that the bolts were found loose a couple of bolts, a few bolts out of the 1600 that are in there. Well, what about the condition of the dryers themselves? Had you inspected them?

MR. SISKA: Waterford I know was looking at that effect. That was something that they were looking at doing. I don't know if it was this outage or later on.

MR. LEONARD: This is Ted Leonard, the project lead.

In our last refueling we performed a rather thorough inspection of our steam generator secondary side after we did a chemical cleaning of the steam generators. Our dryers have corrosion, some type of deposits on them. And we evaluated it quite extensively, probably more from an aspect of trying to quantify is there a pressure drop across the dryers. Some of the dryers there was more build up on them than on some of the others. And we couldn't even with a lot of industry help, we couldn't quantify if we would pick up anywhere from three to four pounds more pressure if we took all the dryers out one at a time and cleaned them. We decided to go through the next outage and do an inspection, and go from there.

MR. ROSEN: Well, I'm really not concerned--

MR. LEONARD: But they're not in like new condition, but they're not structurally degraded. They more have some deposits on them.

MR. ROSEN: Were you actually able to get a fiberoptics probe in there or some other method to have a look at them.

MR. LEONARD: It was mainly all the exterior. Took photos.

MR. SISKA: Yes. These dryers are only 12 inches high. So, you know, you can see a good part of them from right underneath.

MR. ROSEN: Although they have deposits on them, they don't show any signs of distress?

MR. LEONARD: No. It was just the deposit, and some of them more than others. I would not -- wasn't -- they weren't all as dirty.

MR. MITCHELL: This is Tim Mitchell.

There was no evidence of any structural issues at all with the dryers.

MR. VIENER: Okay. We also looked at heat exchanger equipment in our secondary system, namely the feedwater heaters, moisture separator and condenser. And as mentioned earlier, the only impact we have is that we do have to perform some tube taking on the condenser. The feedwater heaters and moisture separator, the heater will be fine moving forward with the power uprate.

We do have a vibration monitoring program ongoing. We do have probes on some key piping systems that we're getting baseline data. That will remain moving forward with power uprate. And, you know, if there are some unexpected results, which we don't expect, but if there are we will take compensatory action --

MR. ROSEN: Can you tell me what the extent of that is? Are you looking, for instance, at the feedwater heaters or the condenser tubes? Where do you have the monitoring program probes?

MR. VIENER: We will have a program through our power ascension testing and our power ascension testing lead --

MR. ROSEN: Well, let me tell you where I'm going with that. Would you be able to detect incipient conditions that could lead to failure in key components or are we going to wake up one morning and hear that you've had failures, or are you going to write an LER that says you detected vibration and went and stopped it ahead of time?

MR. VIENER: What I'd like to do is turn that question over to our test lead, David Constance.

MR. CONSTANCE: Hi. I'm David Constance.

Based upon recent operating experience we've extended our vibration monitoring during the extended power uprate startup testing beyond what was committed to in the testing submittal.

Our testing is going to -- our monitoring is going to extend from the reactor coolant system through the entire plant to the switchyard. It's kind of a graded approach. The more important systems will have a higher level of monitoring and closer level of monitoring than the systems that are either less impacted by EPU or have less of a safety impact.

And I do have a backup slide where I can go over that monitoring in detail during my presentation, if you would like.

MR. ROSEN: Yes. I would like to see that.

MR. CONSTANCE: I'll make sure that's prepared.

MR. VIENER: Flow accelerated corrosion. The power uprate effects have been evaluated using our CHECWORKS model. We do not -- we have determined that no component replacements are required as a result of going up with power uprate.

We did increase outage inspection sampling based on the EPU conditions. That's basically to get some additional baseline data that we don't have.

And moving forward, our program will continue to monitor and detect any deviation from predicted wear rates.

On alloy 600, on the reactor cooling system, our reactor cooling hot leg temperature is going up approximately about 0.8 of a degree. Our cold leg temperature is going up -- or going down about 2 degrees. And the impact on crack initiation due to PWSCC that we have determined is negligible as a result of these operating condition changes.

MR. SIEBER: The two degrees on this slide is not consistent with the larger degrees that you show on other slides.

MR. VIENER: Yes. This two degree decrease is basically hot full power at 543, it doesn't include the ramp, not hot zero power spot 41, which is the four degrees.

MR. SIEBER: All right.

DR. FORD: Could you remind us as to what the situation about your inspections for the reactor vessel head?

MR. VIENER: That's a good question. We have Jamie Gobell here to entertain those questions for you.

DR. FORD: Thank you.

MR. GOBELL: I'm Jamie Gobell, engineering for Alloy 600 Entergy South.

And we are following the NRC order, revised order 03-0009 and that is the volumetric inspection of the nozzles. We performed a volumetric inspection of the nozzles last outage. Did not find any indications to make any repairs. We also performed a visual inspection of the bare metal of the top surface.

DR. FORD: And no indications?

MR. GOBELL: No indications. The head is in good shape.

MR. ROSEN: What sort of access have you got on the top for bare metal?

MR. GOBELL: They had blanket insulation up there that we removed and we could put a crawler in or go in with a baroscope. Except for the very center of the head still has some of the metal insulation and we have to lift that and go in with a baroscope to inspect that.

MR. ROSEN: You did do that, because that was at the famous plant I won't mention did not inspect that area because it was hard to do.

MR. GOBELL: Yes, we did the full inspection.

MR. ROSEN: Three sixty around each of the--

MR. GOBELL: Yes.

MR. ROSEN: Good.

MR. VIENER: Okay. In our steam generators, our NEI 97-06 program we continue to ensure true integrity is maintained post EPU.

Grid stability. Short circuit, transient stability and offsite voltage studies were reperformed as a result of power uprate. Our short circuit study determined that our main generator output breakers were marginal and we are replacing those in this -- well, we replaced one in the last refueling outage, and we're replacing the other one in this upcoming refueling outage.

MR. SIEBER: What's the nominal increase in interrupting capability that you expect to put in there? Do you know?

MR. VIENER: What I'd like to do, I have Singh Matharu who does have those details and he can answer that question.

MR. SIEBER: Okay.

MR. MATHARU: My name is Singh Matharu. I'm an electrical engineer at Waterford.

The original breakers that we had were oil circuit breakers with a short circuit interrupter rating of 63 kA. We have now gone to the SF6 type, which now have an excess of 80 kA.

MR. SIEBER: Okay.

MR. MATHARU: The model that --

MR. SIEBER: So that's a pretty substantial increase?

MR. MATHARU: That is correct.

MR. SIEBER: Yes. And they're OCBs?

MR. MATHARU: Excuse me?

MR. SIEBER: You say they're oil circuit breakers?

MR. MATHARU: The original ones were oil circuit breakers. The new ones are SF6.

MR. SIEBER: Okay. Thank you.

MR. VIENER: Okay. In conclusion with the proposed modifications I've described Waterford 3's plant design can safely operate at the proposed extended power uprate condition.

And that concludes my presentation. If there's no more question, what I'd like to do is turn it over to Gene Wemett, he's our assistant operations manager at Waterford.

CHAIRMAN WALLIS: Thanks.

MR. VIENER: Thank you for your time.

CHAIRMAN WALLIS: What I'd like to do is hear this presentation, and then I think it would be a good time to take a lunch break. We'll come back for what remains, which is a rather small amount. And at that time, you can have anything you wish to add, additional information on any of the questions asked this morning. And then you can wrap up and then we'll hear from the staff.

And I assume it'll take maybe 20 minutes, a half an hour up until lunch something like that at most.

Please go ahead.

MR. WEMETT: My name is Gene Wemett, Waterford 3. I'm the assistant ops manager at the plant. And I have been with the Waterford operations since 1980.

The first thing I'd like to do is address the question I was asked earlier that had to do with evaluation of the control room or promote shutdown habitability.

The power uprate had no effect on actual operations habitability at the area of the remote shutdown panel. The only changes to their occurring down there are basically banding of the meters due to the new ranges for power uprate.

CHAIRMAN WALLIS: Does it change any of the times that the operators have to --0

MR. WEMETT: No, sir.

CHAIRMAN WALLIS: -- go there or take action and whatever that you know?

MR. WEMETT: No, sir.

CHAIRMAN WALLIS: It doesn't change anything like that?

MR. WEMETT: That's correct.

On the first slide we have here is the operations oversight slide. We assigned two full time individuals from the operations staff were assigned to the power uprate project.

MR. SIEBER: Sir, could you talk a little louder, please.

MR. WEMETT: Two full time individuals from the operations staff were assigned to the power uprate project from the start. We assigned a third senior reactor operator shift technical advisor was assigned to review power uprate modifications and evaluations. The responsibility that was given to these individuals has been to identify and respond to operations and training issues, identify and coordinate revisions of operations procedures and to support startup test development.

Operations management has received weekly briefings of the project status from these individuals. And that is still ongoing.

Underneath the training, it's in a three phase program. Phase 1 was introduced last year. It consists of seminars on the overall large overview of power uprate effects on plant systems, technical specifications and operations procedures. And that was performed during the 2004 training cycle.

During phase 2 that's presently in progress, which is cycle 1 of 2005, plant modifications is presently being addressed to all the operators.

In cycle 2 of 2005 is phase 3. This full cycle is dedicated to power uprate training. In this we will be training on operations procedures, setpoint changes and technical specifications. During this period of time the crews will all be evaluated on the uprated plant simulator and the changes in procedures and the setpoints and technical specifications.

MR. ROSEN: Now you said operator plant simulator. I take that to mean that the simulator has been modified to model the uprated plant, is that correct?

MR. WEMETT: That's correct. Prior to cycle 2 the completion of the changes that are being brought by power uprate will be in place in the simulator to train the operators.

The operators will be examined. They will have an evaluated session on the simulator with the power uprate. They will also have a written examination that they will also take like procedures and setpoints and technical specifications.

MR. ROSEN: What's the biggest impact you see on operating during normal times?

MR. WEMETT: During normal times?

MR. ROSEN: Yes.

MR. SIEBER: Nothing.

MR. WEMETT: Huh?

MR. SIEBER: Nothing.

MR. ROSEN: Don't answer. Give him a chance at it. Well, I'm sure you can answer.

MR. WEMETT: Well, there were three concerns that I've had, and I think ops shares that.

One was the ability of the secondary plant systems to adequately perform with the increase flow rates that we're going to see with the steam flow and the feedwater flow and condensate flow.

The other is the ability of core cooling for decay heat removal on both normal plant shutdown, shutdown cooling type conditions as well as with underneath accident situations.

And as we go through here, all the information I've received from the individuals that have reviewed the modifications, the power rate that have been with that, I think they have addressed those concerns from an operations standpoint.

MR. SIEBER: You have no hardware changes to the control room, right?

MR. WEMETT: There is one hardware change. It's actually in the PAC system. And I'm going to get to that in this, and I'll explain a little bit. It has to do with atmospheric dump valve.

MR. SIEBER: Okay.

MR. WEMETT: They're going to add one card to a PAC system.

MR. SIEBER: Okay.

MR. WEMETT: And I'll explain that a little bit. They've allowed me to do that.

MR. SIEBER: But your meter readings will be different and the transient times will be different from an operator's standpoint?

MR. WEMETT: The meter reads? What do you mean?

MR. SIEBER: Well, you know, a 100 percent is a different number now.

MR. WEMETT: That's correct. It'll be about 8 percent higher than what we're at right now.

MR. SIEBER: Right.

MR. WEMETT: But it'll look 100 percent power to us.

MR. SIEBER: Yes. It'll still say 100 percent.

MR. WEMETT: All the banding and corrections of the transmitter rescales will be done.

MR. SIEBER: Okay.

MR. WEMETT: All right. One of the things that we have agreed to, all operations personnel will be trained and evaluated on the power operated training that we're giving right now prior to be allowed to take a shift and operate the plant.

This is kind of getting to your point. On the controls and displays, there are very minimal changes that we've seen. One is to allow a more precise setting of atmospheric dump valve. This is the piece I was talking about, a hardware change.

They're adding a card, and what this will allow us to do is perform a more precise setpoint change to the atmospheric dump valve setpoint. And basically what it's going to be, it's an interface with our plant monitoring computer and it's just visual only for indication. And then at the control room will be able to adjust the setpoint. And that setpoint actually provides impacts -- there is a card being added for us to see that. And that's the only hardware that I know of that's in the control room that's being changed at this time.

The other is the main turbine valve

operation, which we talked earlier, is going to be changed from a sequential valve operation to single valve or partial arc admission type control. Our present turbine has that capability and we do do that during turbine valve test, and we go from sequential to single valve. Stroker valves testing, and then we go back into sequential valve. We also startup in single valve and go to single valve.

MR. SIEBER: Again, that's not a hardware change to the nozzle blocks. It's just different settings in the --

MR. WEMETT: This is the valve programming controller. Digital hydraulic program. Correct.

MR. SIEBER: Right.

MR. WEMETT: Technical specifications. Changes to the technical specifications and the operations procedures are changes in parameters due to the higher decay heat, thermal power and secondary flow changes that we're seeing.

There are going to be no new procedure changes to the normal or off-normal procedures.

And the emergency operating procedures there's really no change to the type and nature of the actions that are in those, and there's actually no action.

There is a change that is in there, and they talked about it earlier, and that is just the time frame which is kind of like a parameter change to initiate hot leg injection.

MR. SIEBER: Right.

MR. WEMETT: It's going from two to four hours to two to three hours. And operations feels that's acceptable to be able to do that. That's just based on a larger break loss of coolant accident.

And in conclusion, the power uprate has worked really hard to minimize the impact of the plant operations at Waterford. The result is the changes brought about by power uprate to the units operation are minimal and are found to be acceptable to the operations department.

Our next priority is the post power uprate power ascension testing to the new power level. To address this priority, Operations had assigned a senior reactor operator for whom this afternoon, I assume after lunch, is David Constance. And he'll be taking that up from me.

And that's basically all I have in my presentation. If there's any questions?

MR. SIEBER: Why did you choose link the change in partial to full arc admission to the EPU?

It's not part and parcel of EPU. You could have done that anytime, right?

MR. WEMETT: That's correct.

MR. SIEBER: Why don't you do it now?

MR. WEMETT: Well, actually right now I think the optimum valve position in our type of turbine that we have in this present age, we actually have better efficiency sequential valve than we do with single operation.

MR. SIEBER: Well, when you go to full arc admission the impulse stage efficiency goes down.

MR. WEMETT: That's correct.

MR. SIEBER: On the other hand, the reason why you would want to do it is to minimize the temperature differential around the nozzle block so you don't get cracking. So you either got -- have some symptoms of cracking or that you're willing to trade for a couple of Btus someplace. But a lot of people have changed and decided I'll waste the BTUs and maybe a few kilowatts to avoid damage to the turbine. I'm sort of wondering why you've linked it to the EPU? It's a curiosity, it's not a safety issue.

MR. WEMETT: David Viener can probably answer that a little bit better.

I do know that in the original discussion it was an option, we could go either way.

MR. SIEBER: Yes.

MR. VIENER: I'm not an expert in turbine design.

This is David Viener, EPU lead.

But right now our turbine has a control stage followed by seven stages of reaction. The new turbine is going with all reaction bladding. We're not going to have the control stage.

MR. SIEBER: Oh, really.

MR. VIENER: And that's why we're going to full arc admission.

MR. SIEBER: Thank you. Understand.

MR. WEMETT: All right. Are there any other questions?

MR. SIEBER: Okay. Thank you.

MR. WEMETT: Thank you very much.

CHAIRMAN WALLIS: We've gained some time. I wonder how much time will the next presentation take?

MR. MITCHELL: Fifteen, 20 minutes I believe is a fairly good estimate.

CHAIRMAN WALLIS: We could move ahead with that and then maybe shorten the lunch break. Let's see. Is that agreeable with the Committee? We just move ahead with this one? Let's move ahead.

MR. WEMETT: All right. Then I'll present David Constance.

MR. CONSTANCE: Hello. I'm David Constance. I've been at Waterford for 17 years. I'm a shift technical advisor and hold a senior reactor operator license on the unit. I've been assigned to power uprate full time for the past power. And I'm performing engineering reviews and I'm responsible for testing. And this segment I'm here to talk about testing.

Power ascension testing consists of reactor engineering tests and power verification, transient and baseline steady state data records, plant modification testing -- I'm sorry, post modification testing, one plant maneuvering test from 100 percent to 90 percent to 95 percent, post 100 percent testing, data collection and surveys and vibration monitoring.

Now part of that post 100 percent testing will include a moisture carry over test where we will find out what the impact on moisture carry over has been due to extended power uprate.

MR. SIEBER: Will that be a sodium test, sodium isotope test?

MR. CONSTANCE: Yes, it will be a tracer injection. I don't know what the trace is going to be used.

MR. SIEBER: Okay.

MR. CONSTANCE: The next slide here shows our power ascension profile. You'll find seven power plateaus followed by a plant maneuvering test from 100 percent to 90 percent.

CHAIRMAN WALLIS: How does this fit in with your various shifts or actually in the control room? It doesn't look like it's of the usual division of time. So there's going to be overlap between these ten hours?

MR. CONSTANCE: This testing extends for five days. So it will go through multiple --

CHAIRMAN WALLIS: I know. But your steps, they don't seem to be related to the shifts in the control room in any logical way; that's my question.

MR. SIEBER: No, it's not.

CHAIRMAN WALLIS: It's not.

MR. MITCHELL: This is Tim Mitchell.

It is not tied to a time on shift to make a power maneuver. At this point we do have --

CHAIRMAN WALLIS: But you don't want to be doing something just as one shift is leaving or something.

MR. MITCHELL: That is correct. Turnover times will be observed and adhered to.

MR. CONSTANCE: What we have, is we'll have during refueling outages we go to two operating crews. And both operating crews will be trained on this power ascension.

Next slide.

MR. SIEBER: Does that mean 12 hour shifts?

MR. CONSTANCE: That's correct. Twelve hour shifts.

MR. ROSEN: Is that a real hold at 50 percent power, very short?

MR. CONSTANCE: Right. The hold at 50 percent power is to recalibrate our excore nuclear instruments. It typically only takes a couple of hours. We'll just take that opportunity to collect some steady state data recognizing it's not truly steady state, not the steady state data that we need for -- that we wish for for our other power plateaus.

CHAIRMAN WALLIS: What's that zigzag at the 100 percent? Does that just mean it's continuously 100 percent?

MR. CONSTANCE: No. That's actually meant to represent the plant maneuvering tests from 100 percent to 90 percent. And it is not unrelated in time to the power ascension.

CHAIRMAN WALLIS: Okay. Okay.

MR. CONSTANCE: Next slide.

A low power physics testing remains unchanged for an extended power uprate. So the startup will be the same as a normal refueling, which is still very similar to our initial startup on the unit.

During power ascension following low power physics testing, data sets will be collected very 10 percent from 20 percent to 100 percent. They'll also be collected at seven different power plateaus. Approximately 1000 parameters will be monitored. And the data will be automatically collected, processed and evaluated against predetermined acceptance criteria.

CHAIRMAN WALLIS: So it will be evaluated right then and there?

MR. CONSTANCE: That's correct. All the data will dump to an Excel spreadsheet. It'll be compared to the acceptance criteria.

CHAIRMAN WALLIS: So it's essentially online? There's no delay while you do this evaluation?

MR. CONSTANCE: That's right. There's no delay determining which parameters meet the acceptance criteria.

MR. SIEBER: Is this all stuff that comes from your plant computer or do you install some special instrumentation just for this test?

MR. CONSTANCE: All the data sets come the plant monitoring computer. There will be a subset which will have to be collected manually at each of the power plateaus. That will be a small subset.

MR. SIEBER: By hand?

MR. CONSTANCE: Right.

MR. SIEBER: Okay.

MR. CONSTANCE: Moving on, the Plant Safety Subcommittee will review a results report at each power plateau graded in 68 percent. The results report will include testing results, a list of equipment out of service and the calculation of the plant safety index.

The plant safety subcommittee recommends continued power ascension. And the plant manager, operations manager and test director approval is required to commence or to recommence power ascension.

CHAIRMAN WALLIS: So he recommends continue ascension no matter what?

MR. CONSTANCE: No. Their recommendation is required for continued power ascension.

CHAIRMAN WALLIS: Or not to. Okay.

MR. ROSEN: Who is this Plant Safety Subcommittee? A subcommittee of what? Of who?

MR. CONSTANCE: Of the Plant Safety Committee. We call it the OSRC, they have different names at different plants.

MR. ROSEN: And this is comprised of who are those people? Not by name, but whether they're --

MR. CONSTANCE: Right. We'll have an operations representatives. I'm sorry. An operations representative, a system engineering representative, a design engineering representative, QA representative and at least one other OSRC regular member.

MR. ROSEN: So they're all site people on the subcommittee, right?

MR. CONSTANCE: That's correct.

MR. ROSEN: What about the OSRC, who are those?

MR. CONSTANCE: That is a site Safety Review Committee.

MR. ROSEN: So you just gave me the membership of the --

MR. SIEBER: Onsite.

MR. MITCHELL: This is Tim Mitchell.

Let me correct me. The Onsite Safety Review Committee is a larger group that includes a couple of additional people like projects and I'm not sure I remember the full -- licensing's also on it. Design engineering is on it. So this is a subcommittee that reports to the OSRC on their review of essentially the startup.

MR. ROSEN: And there is no offsite corporate review during this testing?

MR. MITCHELL: During the testing there is not a -- Safety Review Committee is what we call it in the Entergy. They do not review online with the data. They will review what we're doing beforehand and review after hand. But it's not during the actual power ascension profile.

CHAIRMAN WALLIS: Is there going to be an NRC inspector observing what this safety subcommittee does?

MR. CONSTANCE: Of course, we have our NRC resident. And I have not yet spoke to him what his information requirements are. But we'll provide him with any information that he requires at whatever points in the power ascension he desires it.

CHAIRMAN WALLIS: I think it would be

useful to have him around.

MR. CONSTANCE: Right.

CHAIRMAN WALLIS: While you're making these decisions.

MR. ROSEN: Right. We can ask them when they come up, and I'm sure they will point someplace to observe.

CHAIRMAN WALLIS: They will find some reason to be absent or something?

MR. SIEBER: Well, there's a lot of good places for him to be during this phase.

MR. RULAND: If I could just add something? My name is Bill Ruland, I'm the Project Director for PD3.

There's a specific inspection module associated with power uprates. It looks at both the --- some of the modifications that the licensee had and also directs the inspectors to look at power ascension testing, I believe. We'll confirm that for you later.

DR. DENNING: The 92.5 percent, is that the old operating power and so you can do comparisons with the familiar level? And then 95, 97 that's just kind of creeping up; is that the logic?

MR. CONSTANCE: That's correct. 92.5 is

the previous license power level. And the other ones are just intermediate levels that we selected as being prudent.

MR. SIEBER: On slide 61 where will you take your flux maps?

MR. CONSTANCE: The question is where will we take our flux mapping. At each one of those power plateaus, those are largely driven by what we committed to in racked engineering testing. The specific tests that are done at -- the racked engineering tests that are done each plateau. I have somewhere here in my documentation, but I don't have it on the top of my head.

MR. SIEBER: But basically you're going to do three or four?

MR. CONSTANCE: Yes. Many of the normal startup tests that we do during power ascension will be repeated multiple times during this power ascension.

MR. SIEBER: Okay. Good enough.

MR. CONSTANCE: If I can go to my backup slide now on vibration testing.

MR. CARUSO: You're going to have to flip up the mirror. The other way.

MR. SIEBER: Perfect.

MR. CARUSO: Now focus.

MR. SICARD: All these backseat drivers.

MR. ROSEN: That's our job, Paul.

MR. SIEBER: Now you have to lay over this one here.

MR. CONSTANCE: All right. For vibration testing we have a fairly extensive detail vibration monitoring plan that extends from the racked cooling system and all the way through the plant to the transformer yard. We've taken a graded approach based upon the impact of power uprate on that specific system and upon the importance of that system to safety.

Basically what you're looking at is a break up of systems based upon the level of detail of monitoring. So the first set is the main steam and main feed piping that is safety related. For that we're doing a 100 percent baseline inside and outside containment vibration collection using installed vibration monitoring equipment which we've installed full power upgrade. We'll be collecting that data at 92.5 percent, 95, 97.5 percent and the new 100 percent and comparing it to prebaseline data.

For the main feed and main steamlines outside containment that are seismic quality, which is a larger set of main steam main feed piping, we'll be taking data collection using hand held vibration equipment at 100 percent power and comparing it to the pre EPU baseline data. Visual inspections will be performed at 92.5, 95 and 97.5. So for that piping we'll be taking a data set only at 100 percent, the new 100 percent.

For turbine building piping, we will be performing a walkdown of the turbine building at 100 percent power prior to shutdown. The members of that walkdown team are going to be our performance monitoring engineer, civil engineer and two operators. From that walkdown we will identify any areas that may have additional vibration and either film them, take video records of that piping and hand held vibration data. Then we will re-perform those walkdowns with those same personnel at 92.5, 95 and 97.5 percent.

Now for the main turbine feed pump at the racked cooling pump we have permanently installed instrumentation. It's spectral analysis instrumentation. And the data will be reviewed at 92.5, 95, 97.5 and 100 percent power and compared to pre EPU conditions.

For the equipment in the turbine building we will perform rough data collection using hand held vibration equipment at 95 percent and 100 percent. That will be compared to the current data that we have on that equipment from our performance monitoring program.

Since we are crediting the atmospheric dump valve -- we have more reliance on the atmospheric dump valve, we have a plan to collect vibration data on the atmospheric dump valve during a full stroke at normal operating pressure, normal operating temperature with steam.

And the condenser, we are going to perform an acoustic survey of the condenser at 100 percent and compare it -- at the new 100 percent and compare it to pre EPU baseline data which will be collected prior to shutdown.

We also have a valve and loose parts monitoring system on the reactor cooling system. That data will be reviewed at 92.5 percent, 95 percent, 97.5 percent and 100 percent power and compared to pre EPU baseline data.

DR. DENNING: Could you tell me, is that system that's in normal operation, what do you have for monitoring and loose part monitoring during normal operation all the time? Is it this last thing or how much of this equipment is in effect all the time in normal operation?

MR. CONSTANCE: Of this equipment normally that's in service during normal operation, the valve and loose parts monitoring system is always in service and it's an alarm system. So it has preset conditions which will provide a control room alarm annunciation. We also have vibration monitoring installed on the main turbine, on the feed pumps and on the reactor cooling pumps. That's normally installed equipment.

We have installed some sensors for EPU which will remain installed, but you have to go and connect them and collect that data.

DR. FORD: Now you've got all these monitoring systems in place. Is there any way of using that data to determine what might be happening in an unmonitored place like the dryer or the condenser tubes and the steam generator tubes? Is that global to local evaluation?

MR. MITCHELL: This is Tim Mitchell.

I can't tell you that we'd be able to pick up something on a steam dryer in the steam generator. But you can use this data to triangulate and point you in a direction as far as something abnormal that is occurring and where is that occurring.

DR. FORD: That's what I was getting at.

That's what I was getting at.

MR. MITCHELL: So this data, and we have experience within Entergy Nuclear South we're doing that because there were some feedwater vibration issue at Arkansas Nuclear One Unit 2. And we actually did a lot of that with similar type data to be able to point us in which direction. You know, is it a feed reg valve, you know that type of stuff that will help us narrow it down if we see something abnormal.

DR. FORD: Okay. Thank you.

MR. CONSTANCE: Okay. Ready to go to the next slide.

DR. DENNING: Let me ask you another question, and that is would it be prudent to continue to have an expanded monitoring program for a period longer than just the power ascension? I mean like for the first six months of operation or something like that. Have you considered that?

MR. CONSTANCE: Yes, it's been considered. Keith Kunkel is our performance monitoring individual. He's not here today and it is not part of our plan. We're not committing to it now. But we have discussed that at approximately six months, every six months through the next cycle we should do a turbine building walkdown with those same personnel.

MR. MITCHELL: Yes. This is Tim Mitchell again.

And that's something that I was referring to earlier with the performance monitoring program that system engineering does. We have a plan to collect data prior to the outage or pre EPU conditions and then to go through system-by-system methodically identify any deltas after we reach full power conditions.

So the performance monitoring program will be a living ongoing thing that we'll continually look for any deviations and then go evaluate what those deviations might effect on other systems. But we've also scheduled for ourselves an assessment with industry participation for next June or July, I forget which month, to bring them in and get industry experience to look at the data that we're looking at from a performance monitoring standpoint and get their input. Like, for example, ANO 2 will certainly be a part of that because they've gone through this same type exercise.

MR. SIEBER: I note in your chart of planned testing you don't have any provision for a trip from full power. Why is that?

MR. CONSTANCE: The question concerns a

trip from full power testing, and I think I've best addressed with the next two slides where we talk about our testing considerations, what things we considered in selecting the suite of testing that we're going to do for extended power uprate. So, if I may continue.

All right. This next slide is testing considerations. Some of the things that we considered when selecting the suite of testing for post uprate conditions is that the proposed modifications either have no significant impact on transient response or the effect on transient response has been evaluated using a calculational model which is suitable for predicting the effect on plant transient response due to that modification.

We noted that there are no physical changes to nuclear steam supply system, that there are no new interactions that affect system response and that there are no changes to controller algorithms. All changes to controllers are being accomplished through setpoint changes.

MR. SIEBER: However, you would agree that if you trip from higher power level than your previous maximum power level, the forces are greater on structure systems and components like pump seals, hangers, snubbers, dampers that the plant has never experienced before. And that was not apparently one of your consideration?

MR. CONSTANCE: Right. The question concerns the structural integrity of the plant and its ability to endure large transient. I --

MR. SIEBER: Sooner or later you're going to have one.

MR. CONSTANCE: That's correct.

MR. SIEBER: And the question is would you like to have instrumentation available and learn something from it or just have one, you know which is a different kind of thing.

MR. CONSTANCE: Well, the instrumentation that we would have available, we currently have installed. Most of the information that we would want to gain from a transient test we would gain from the data points that are monitored by the plant monitoring computer.

MR. SIEBER: Well, you may want to think about that because the movement of components on skid plates and strain gauges on various structural members of snubbers, hangers and so forth are not permanently installed. So if you're interested in that kind of stuff, you may want to think about that.

MR. MITCHELL: Okay. This is Tim

Mitchell.

We did go through and look at what the effects would be from the higher power level. We've used the LTC code to help us predict how system performances would be. We validated that against past operating experience both at Waterford during transients and at other plants that have gone through extended power uprate. And we believe that we understand what the affects of 100 percent load rejection or whatever the transient would be upon our secondary with the testing that we are doing.

MR. CONSTANCE: Let me continue on with these next two slides, and then I'll come back to your question.

MR. SIEBER: Okay.

MR. CONSTANCE: Where we at? All right.

So our approach to testing is at the post modification testing demonstrates that components and systems will perform as designed. That the power ascension data collection confirm acceptable operation. That the maneuvering test provides further confirmation and that we've used a benchmark calculation model to evaluate postulated transient conditions.

Two other things that we considered when considering a large transient test is one is the limitations of a large transient test. A large transient test is a single test transient test. It demonstrates a single transient and demonstrates that at a single set of initial conditions. The majority of our changes that impact transient response are to control systems where they're changing our control system setpoints so they control at the new operating point. There is no clear maximum or minimum or bounding condition for transient that we could select to know that our control systems will interact properly.

So the approach we used was to utilize the LTC code, which is a computational method that has been used since the early '80s, specifically in the design of control system interactions. Using that, we were not restricted to a single point test. Instead we ran 38 cases from different transient from different initial conditions.

The second consideration that we used other than the limitations of a single point transient test is that the risk -- and you quoted this earlier -- the risk associated with the introduction of a transient initiator, while small, should not be incurred unnecessarily. So the question that we have to answer is will the transient test provide us a specific discrete piece of information that would make our introduction of the transient initiator worth doing.

MR. ROSEN: From our standpoint you've already told us the risk of doing so is small. Less than 1E to the minus six. So we have no nuclear safety risk to do it.

MR. CONSTANCE: That's correct. It is small, but it shouldn't be discounted. It is small, and it's acceptable but it shouldn't be discounted. So it's --

MR. ROSEN: There's no risk argument being made or offered here. It's simply that Entergy believes it's unnecessary.

MR. CONSTANCE: Right. It's not a risk argument. It's an alternate methods argument, that we've used alternate methods to validate that the plant will operate properly during a transient at the new operating point with the new control system setpoint..

MR. ROSEN: That's the side of the glass you're looking at. I'm looking at the other side which says that Entergy offers no argument that it's too risky.

MR. CONSTANCE: That's correct.

MR. ROSEN: You can SCRAM this plant or do a turbine trip from 100 percent full power without encountering any undue risk?

MR. SIEBER: If there was a significant risk, then we would be remiss in allowing the EPU in the first place.

MR. CONSTANCE: That's correct. We're not arguing that it is an unacceptable risk. It is an acceptable risk.

MR. SIEBER: You don't want to do it.

MR. ROSEN: So it's an economic argument, not a risk argument.

MR. SIEBER: Yes, they don't want to do it.

DR. DENNING: I still think there's a safety argument. As a risk analyst I still think that there is a consideration here. And I don't think we want to push too -- there is a cost benefit question here and I don't think you want to ever induce a trip like this unless there is good reason. So there is a cost benefit we really have to consider here. So I wouldn't let them bull you too much here in saying that ten to the minus six means that it's acceptable for us to go ahead to do that.

MR. ROSEN: Well, he didn't say it was ten to the minus six.

DR. DENNING: Yes.

MR. ROSEN: He said it was less than ten to the minus six. Well I maintain there's no risk argument to -- and I'm just recording your own words.

MR. CONSTANCE: Right. We do not intend to forward a risk argument here. We intend to --

MR. ROSEN: So it's an economic argument.

MR. CONSTANCE: Well, we intend to forward an alternate methods argument in that we can gain the same information through an alternate method and we do not need to incur the small but not insignificant risk. The risk was on the order on eight times ten to the minus seven. So it was less than ten to the minus six.

MR. SIEBER: That's insignificant.

MR. ROSEN: We have to sit and listen to a lot of stuff that's not all that thrilling, but this stuff is interesting and we'll come back to it. We'll come back to it, I'll guarantee you later today when the staff presents. So I would suggest that maybe you don't go away.

MR. CONSTANCE: Okay. I will certainly be around.

CHAIRMAN WALLIS: Well, eight times ten to the minus seven may seem small, but it's not small compared to the ten to the minus six for a CDF we have already, it seems to me. A significant perturbation on your CDF for the year, isn't it? Or is it not?

MR. MITCHELL: This is Tim Mitchell.

We did look at it and we tried to evaluate what the risks were. And I agree that the risks are small. But there is, as stated, some amount of risk even if it is small, and in this case we concluded we were not going to get any significant value out of doing a large transient test.

CHAIRMAN WALLIS: Let's take this up with the staff this afternoon.

MR. ROSEN: Oh, yes, we will take it up with the staff.

CHAIRMAN WALLIS: I think that Steve will probably do that.

I'd like to take a break. And since we are behind, would the Committee agree to come back here at 1:15. Take 45 minutes for lunch. So we'll take a break until 1:15.

(Whereupon, at 12:30 p.m. the Subcommittee was adjourned, to reconvene this same day at 1:17 p.m.)

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

1:17 p.m.

CHAIRMAN WALLIS: Let's come back into session.

We'll finish the Entergy presentation and then we'll hear from the staff. And I believe Entergy is going to answer a few of the questions we had this morning that didn't get covered.

MR. SICARD: Yes. This is Paul Sicard from Entergy again.

CHAIRMAN WALLIS: Quiet please.

MR. SICARD: There were questions retarding RCS flow and the role of the increased density versus temperature rise in the power uprate. We have prepared a slide to try to address that, which we have on the screen right now comparing the current prerate conditions with the conditions for power uprate. And this comparison shows what the mass flow numbers are that correspond to those two different conditions and the corresponding enthalpy rise. This shows that out of the 8 percent uprate from those initial conditions over there to the uprate conditions that three percent of that eight percent is due to the mass flow component and approximately five percent is due to the enthalpy rise associated with those change in conditions. And we hope that this illustrative calculation does answer the question regarding how we are achieving the increased power through the core.

And I will point out again that these are nominal flow values. That the technical specification minimum flow requirement of 148 million pounds per hour is not being revised for power uprate. And that these mass flows are in the middle of the range in between that minimum flow and the 115 percent maximum flow value that we use in analysis where a maximum flow is called for.

So, I hope that this answers any questions or if not, we will entertain them either now or subsequent to the meeting as you desire.

CHAIRMAN WALLIS: Thank you.

So you have an enthalpy change, enthalpy rise change of 3.6, I guess, which I agree that sounds much more reasonable to compare with my calculations.

In the SER it says the average core enthalpy rise goes from 81.5 to 88, which is quite different from your numbers in the 70s. And it seemed to be far too big a change. So something is inconsistent about the staff's enthalpy numbers to yours and mine.

MR. SICARD: I would suspect that the

staff numbers that they are reporting there are based upon the minimum flow rate rather than a nominal flow rate.

CHAIRMAN WALLIS: Well, these are BTUs per pound. They've based on temperature. And I don't see how they could ge so different. So there's something to be sorted out between your numbers and the staff's numbers for enthalpy change. And they're getting all their eight percent out of the enthalpy change and none of it out of flow rate, which again is not consistent with what you have. So there's something very different about what you're saying and what the staff is saying about something which is so simple that it just needs to be corrected, I'm sure.

MR. SICARD: And noted. And I would have the question of is that based on the minimum flow which is not changing. But --

CHAIRMAN WALLIS: But you're still not going to get 88 BTUs per pound delta H without a much bigger temperature rise. Even 541 I think doesn't do it. But anyway, the staff can sort that out.

Thank you. That's been very helpful.

MR. SICARD: Okay. I will turn this over to--

CHAIRMAN WALLIS: Will you put this in the record so we have a copy of this.

MR. CARUSO: I have a copy on this computer. Just leave it on the computer and I'll have a copy of it.

MR. SICARD: Okay.

CHAIRMAN WALLIS: Thank you.

MR. SICARD: I will turn this over to Tim Mitchell for concluding remarks.

MR. MITCHELL: Again, I am Tim Mitchell.

There was a flow accelerated corrosion question this morning early in the presentation which we said we'd get to it later. And we did present some information on flow accelerated corrosion, but I wanted to confirm. I don't even remember where the question came from. But the effects on the secondary from a flow accelerated corrosion standpoint are very minimal, and we can go into more detail if you would like. Okay.

First, I'd like to thank you for this opportunity for us to come talk to you. We believe that this power uprate project, like I started off with, has improved Waterford as a plant, that it's safe for us to go do and that we're actually improving our design basis as part of it.

We appreciate the staff's challenges. I

believe they have challenged us in a number of areas and approved our product as a result.

And I want to thank the Committee for this opportunity to present again.

This does conclude our presentation. We're available for any other questions. But I thank you for the time. That's it.

CHAIRMAN WALLIS: Thank you.

Can we now move on to the staff's presentation?

CHAIRMAN WALLIS: I think we're waiting for the computer, is that what we're doing?

MR. KALYANAM: Sorry about that.

My name is Kaly, I am the Project Manager. And we are going to start the presentation from the staff side.

And the first presenter we have is Jim Medoff who is the reviewer for the vessel. Jim?

MR. MEDOFF: Good afternoon, Committee members. My name is Jim Medoff. I'm the materials engineer with the Materials and Chemical Engineering Branch of NRR. I was responsible for reviewing the reactor vessel integrity and reactor vessel internals integrity issues and to assess the impact of the EPU on the integrity of these components.

Basically as part of my review we used Matrix 1 of the Review Standard RS-001 and my review responsibilities fell under sections 2.1.1 through 2.1.4.

The first area of interest that I looked at was the impact on the 10 CFR Part 50 Appendix H withdraw schedule for the facility. And what we determined as part of the uprate is that the latest capsule report for the facility had a new withdraw schedule in it and the withdrawal schedule did not include the impact of the uprate on the withdrawal time for the final capsule for the vessel. They've already pulled two capsules, they're required to pull one more in accordance with their delta RTNDT for their limiting material.

We determined that 10 CFR Part 50 Appendix H requires you to follow ASTM standard E185-82 in terms of the withdrawal schedule criterion. And the final capsules to be pulled at a time between one and two times the projected end-of-life fluence for the vessel --

CHAIRMAN WALLIS: Can we take down this transparency projector which is --

MR. ROSEN: This thing in front of it.

CHAIRMAN WALLIS: This thing in front.

MR. MEDOFF: What we determined is the projected final withdrawal for the third capsule will continue to be withdrawn in accordance with the ASTM standard, and therefore we concluded that the impact of the uprate did not impact conformance with the ASTM standard in terms of the withdrawal time. And we found that to be acceptable.

Section 2.1.2 of the impact requires us to look at the impact upper shelf energy assessment for the vessel and on the P-T limits. I'll get into the upper shelf energy first.

Basically the staff uses the Charpy impact upper shelf energies as a measure of the remaining ductility in the vessel after you irradiated. And it requires that the upper shelf energy for the limiting vessel material remain above 50 foot pounds Charpy impact absorbed energy at the end-of-life of the plant.

The Waterford 3 reactor vessel is plate limited. It's a low copper vessel and has sufficient remaining margin even under the uprated conditions and we made sure that we got approval of their fluence methodology and fluence calculations by Dr. Lambros Lois, who is my counterpart in the Reactor System Branch of NRR.

We calculated an end-of-life upper shelf energy of 71 foot pounds. And this jived with what the licensee calculated under the uprated conclusions, and that satisfies the 50 foot pound criterion in the rule, so we found that to be acceptable.

MR. SIEBER: That's 40 years into the life?

MR. MEDOFF: They're under a current 80 year design basis, so it's 32 effective full power for 40 year license life.

MR. SIEBER: Okay.

MR. ROSEN: And 80 percent capacity.

MR. MEDOFF: Capacity factor is what they're using.

MR. SIEBER: But that's a lot of margin anyway.

MR. MEDOFF: Right. They have --

MR. ROSEN: I don't suppose the Entergy management would be real happy with 80 percent, but nevertheless it's plenty of margin.

MR. MEDOFF: They have to make that call. I can't force them to do it.

MR. ROSEN: We've had this debate before.

MR. MEDOFF: Right.

For the pressure temperature limits, they did not propose new pressure temperature limits for the EPU application. However, in a previous license amendment application they did submit new heat up and cool down curves for the unit. And what I did was Tom McLennan in my branch was the reviewer for that license amendment. And what I did confirm was that the license amendment did include the upgraded fluences to establish the P-T curves and therefore, we concluded that his approval was based on the upgraded conditions was acceptable.

The next one. The next slide us we look at in 2.1.3 of the Matrix tells us to look at the impact under 10 CFR 50.61 PTS assessment. Again, it's limited by a copper material. And the criterion for the limiting shelf plate is 270 degree F in accordance with the rule. And we calculated a RTPTS or adjusted reference temperature value of 49 degrees F. And this has a wide margin in the --

CHAIRMAN WALLIS: It's amazingly low.

MR. MEDOFF: It's because it's a low copper vessel.

CHAIRMAN WALLIS: How does it get to be so low?

MR. MEDOFF: Low copper.

CHAIRMAN WALLIS: The low copper?

MR. MEDOFF: Usually the plants have -- low copper materials have better RTPTS values, lower value.

So there's not much of an affect on the RTPTS value by the upgrade. So we concluded that it was acceptable against 10 CFR 50.61 criteria.

Okay. The next slide. And we also looked at the impact on the structural integrity of the RV internals. Currently the ASME code, which is invoked by 10 CFR 50.55a requires visual inspection of these components. But there is some -- we may anticipate all of the Dresden/Quad City steam dryer issue, that some of these power uprates may impact some cracking in the component failure. So we looked at the impact on the structural integrity of the RV internals.

When the applicant came in with its application it basically assessed them on the gama radiation. And if you Matrix 1 of the Review Standard, there's a footnote on section 2.1.4 and it invokes a couple of industry topical reports in assessing void swelling and irradiated-assisted stress corrosion cracking. And we used the Westinghouse topical as our guideline, our topical report for this. And Westinghouse establishes a threshold on cracking of one times ten to the 21 neutrons per square centimeter. And the energy is .1 MeV on the neutrons.

What we did was we asked them a question -- a request for additional information on what the fluences would be for their internals. And they came back with something of the order three to five times ten to the 22 neutrons per square centimeter. And since that's above the threshold, the applicant is willing to give us a commitment on participating on the EPRI studies on internals and to implement the activities that result from them. And they're going to send in an inspection plan for review and approval. We're ironing out the wording for the commitment, but that will be resolved before the SE gets written.

DR. KRESS: Where do they stand on inspecting their upper head?

MR. MEDOFF: On nickel alloy components?

DR. KRESS: No, just the upper head.

MR. MEDOFF: The upper head?

DR. KRESS: Yes.

MR. MEDOFF: I think if I'm not mistaken, Entergy indicated that they just at their outage just did a bare metal visual and the volumetrics and didn't find anything.

But we're going to iron out the exact wording of that commitment before the SE gets written.

CHAIRMAN WALLIS: So at the present moment it's a conditional component ironing this thing out before you issue the final SER, is that it?

MR. MEDOFF: Well, we incorporate the commitment into the SE, so we're going to have to alter a little bit. But pending the final wording that we work out with Entergy, but that will go into the final SE.

CHAIRMAN WALLIS: So if they don't meet some requirement, it's okay to then join some imitative?

MR. MEDOFF: Well, the way the initiatives work, and Materials and Chemical Engineering Branch encourages the industry to go out and do industry initiatives studies on degradation and cracking of vessel and internals components. And for PWR, the EPRI/MRP is the organizations that's initiating the studies on these components. We've already had a number of assessments come in from the MRP on nickel alloy cracking. And I think they're starting to initiate the studies on the internals and with the intent down the road that they would submit something to us on what they're recommending for inspections on a plant initiative basis for internal components. And then we would look those over and have dialogues with the EPRI/MRP to work out what a final approved program would be. And that's sort of the way we've done this for the BWR VIP with the boilers and we're trying to initiate something similar with the MRP.

Are there any other questions on the vessel and the vessel's internal components? Dr. Wallis is pondering them. Any further questions.

CHAIRMAN WALLIS: That's okay. You can go ahead.

MR. MEDOFF: Thank you very much.

Mr. Bob Davis will now address what the impact of the EPO on the leak before break analysis and the nickel alloy components integrity.

MR. DAVIS: My name is Bob Davis. And I'm with the Engineering Materials Chemistry Branch in the Piping Integrity and NDE Section. And I reviewed the portion of the application that deals with reactor coolant pressure boundary materials and leak before break.

The increase in hot leg temperature only being .8 degrees will have a minimal impact on the Alloy 600. I think somebody asked about the upper head. I believe they're scheduled to, in accordance with the order, inspect their reactor pressure vessel head this spring. I think other than maybe a small relaxation from the order on coverage on their nozzles, they are complying with the order for the bare high susceptibility. So this small temperature increase really doesn't do anything to change that. And, of course, a decrease in temperature is obviously advantageous as far as PWSCC goes.

So the staff concluded that the increase in temperature will have only a minimal impact on crack initiation and growth.

I did a gentleman this morning from Westinghouse mention that the temperature increase in the hot leg was actually 1.6 degrees rather than the .8 degrees. So I think I will have to somewhere we'll have to address that.

I think somebody this morning asked a question and got a response, and the hot leg temperature is a little bit more. Even at 1.6 degree increase that will have a negligible impact on increased susceptibility to PWSCC. They have a fairly aggressive program. They've replaced some of their nozzles already on their hot leg piping and their initiatives are to replace a lot of their 600 with Alloy 690 using Alloy 52 and 152.

CHAIRMAN WALLIS: With these questions about what the temperature change actually is, is someone going to find out what it actually turns out to be so that after the EPU has been implemented we can find out what it actually is?

MR. DAVIS: Yes. And part of my question based on what the gentleman said this morning from Westinghouse is the range. The .8 plus or minus, point .8 plus or .8 plus or minus two and at what point would they really need to come back and talk to us if it was greater than a certain number?

Okay. Any other questions.

DR. FORD: Could I ask, it's more of a general question than this specific one, to what extent does the staff take into account emerging issues with respect to cracking in this case for the primary water site in a PWR? And I'm thinking specifically in terms of the effect of ripple loading, which might occur because you've got increased flow rates and the effect that that would have on thermal fatigue of some of these pipings. And it recognizes an emerging issue because it's not in the rules, it's not in bulletin, etcetera, right now. But at what point does the staff become involved in addressing those emerging issues?

MR. DAVIS: On that issue I don't have an answer for.

MR. TSAO: This is John Tsao from Materials and Chemical Engineering Branch.

To respond to your questions, the staff is working with the industry to come up with some sort of resolution of the issues, particularly we are looking at the PWSCC, the primary water stress corrosion cracking and leak before break. Right now the EPRI, industry are trying to come up with some type of inspection and enforcement guidelines. And the staff also is trying to find out if we need some type of generic communication to make sure that PWSCC is not a potential degradation.

DR. FORD: Thank you very much.

And the reason why I bring it up is that when you talk about thermally induced ripple loading in piping, it falls between the cracks of the ASMI corrosion fatigue evaluations and MRP stress corrosion. It's between the two ends of the spectrum and it's not addressed. And yet when you look at, for instance, socket welds in these systems where you have eddies associated with a socket weld, you could have a potential decrease in the integrity of those components.

But from your answer, this is ongoing. It is not covered in this particular item because there is not enough information, is that correct?

MR. DAVIS: Well, the PWSCC is what I would be familiar with. And we are, as John mentioned, there are a lot of ongoing issues and discussions with industry. As far as the other issue you brought up, I'm not aware.

DR. FORD: And as you point out, this is not specific to Waterford. It is a generic EPU topic.

CHAIRMAN WALLIS: It only occurs at EPUs?

DR. FORD: Well, it occurs when you increase the flow rate and now you're starting to put in thermal fatigue issues, which are dominate in for instance socket welds.

MR. MEDOFF: Dr. Ford?

DR. FORD: Yes.

MR. MEDOFF: So far for the cracking of the nickel alloy components, Mechanical has been looking at fatigue aspects and the Materials Branch has been looking at PWSCC. We haven't considered ripple loading, we will raise the issue with my management and see what will be taken from there for you. And we'll get back to you.

DR. FORD: Okay. Thank you.

MR. DAVIS: Any additional questions on Alloy 600?

Okay. I also review the section on leak before break. And the operating conditions under the uprated conditions will not alter the conclusions of the previous leak before break analysis for Waterford 3. It's still valid.

Are there any additional questions?

I'll turn it over to John Tsao.

MR. TSAO: I'm John Tsao from the Materials and Chemical Engineer Branch. I reviewed five sections; coding system, flow accelerated corrosion programs, steam generator tube inspections, steam generator blowdown systems and chemical and volume control systems.

I will be talking about only two systems here; flow accelerated programs and steam generator tube inspections because they are more significant in terms of power uprate.

For the flow accelerated corrosion programs, this morning there was some issue as to how much you increase. I have this backup slide.

The FAC program measure the wear rates in terms of mils per year. And these are the changes that would be due to power uprate conditions.

Also, I want to show you another slide that gives the effectiveness of the FAC program. This is provided by the licensee. And as licensee said, it is more in the -- they used CHECWORKS. It's a computer program that considers hydrodynamics, heat balance, temperature in particular.

As you can see the predictive method is conservative considered to actual measurement.

DR. FORD: I'm sorry. Could you explain that?

MR. TSAO: Okay.

DR. FORD: It looks as though it's equally scattered around the one to one line. So why are you saying it's conservative?

MR. TSAO: Well, for example, you can see -- let's see.

You can see just for example, this point here the measurement is about 300 mils. The predict value, let's say, from here to here is about 240 mils. So what it says is that the methodology will predict that the tube wall thinner than measured, therefore it also indicated that the licensee may need to do some monitoring or replacement of that pipe.

DR. FORD: But equally there are points on the other side which are not, what you call it --

MR. TSAO: Well, that's true. Yes, that's correct. But as you know this is only a prediction.

Predictions, hopefully -- well, from the data point you can see they are scattered toward the conservative side. And also the FAC program according to EPRI is that it's a process. In other words, the licensees would go out, make an inspection, UT or ultrasonic measurements or the pipe thickness and then they will come back and they input that data into the computer code so that to make sure there is a certain accuracy in their predictions.

Also predict that the -- in the prediction method they include some safety factors.

DR. FORD: It seems to me as though there's a huge amount of scatter around that one-to-one line. And so the question immediately arises as to what is the impact of that in terms of could you get a through wall erosion event taking place when you had predicted it would not have done so?

MR. TSAO: It could.

DR. FORD: Did you go through that sort of "what if" argument? I mean if you look at that data base, you don't really have too much confidence in CHECWORKS.

MR. TSAO: Well, I wouldn't say they would be relying on CHECWORKS per se. The licensees, not only Waterford but other licensees, you know they include other factors. For example, other industry experience. You know if some plants have some problem with FAC water lines, then they will consider --

DR. FORD: I recognize that.

MR. TSAO: Right.

DR. FORD: But this particular EPU is putting a lot of basis on CHECWORKS to manage this problem. And if this a general observation as to how good CHECWORKS is, my confidence is a little bit shattered.

MR. TSAO: I should point out that Waterford is not unique. I did the review for license renewal, and I also asked questions. And this is type of plot that, you know, other licensee has shown me.

DR. FORD: Yes, I know.

MR. TSAO: In other words, I don't think that licensee is depending solely on what prediction is. They also, you know, include other experiences and inspections. Not only the inspections for the fact, but there are other SME code inspections they have to perform.

DR. FORD: I'll ask again. Did you go through the "what if" scenario?

MR. TSAO: I have Kris Parcziewski from my branch to elaborate on this.

DR. FORD: With that amount of uncertainty in your modeling capability and therefore your management capability, do you not feel uncomfortable?

MR. TSAO: No.

DR. FORD: No?

MR. PARCZIEWSKI: Kris Parcziewski from the Chemical Engineering Branch.

To answer your question, those points are predicted. CHECWORKS predicts but in addition there is a correction factor for each individual line which is here at the top right hand side, line correction factor which indicates that it is corrected for each individual line all the points predicted in the line are corrected by this line correction factor. And the line is defined as a portion of the system which has the same chemistry but not necessarily the same temperature. If I answer your question.

So all those points are already corrected. Ideally, if they were ideal, they would lie in the 45 degree line, the middle line. However, obviously, there is some scatter.

DR. FORD: I understand the physics --

MR. PARCZIEWSKI: Yes.

DR. FORD: -- of the erosion process. It's highly dependent on ph. High dependent on temperature. Highly dependent on corrosion potential and all of those things are interacting. So that if you're a little bit off on your definition of one of those parameters, then you're going to get a big change. So I can understand why there is a scatter there because you're not able to define your system adequately enough, and therefore that's the physical origin of your LCF. But I still feel uncomfortable about that huge scatter and how you use it in management from their point of view and in terms of regulation from your point of view.

MR. TSAO: Okay. For regulation, basically there's no regulation on FAC program.

DR. FORD: That's what worries me.

MR. TSAO: The FAC program is instituted because of the bulletin. Back in the '80s it was result of Bulletin 87-01 where Surry had a --

DR. FORD: Yes, sure.

MR. TSAO: -- a rupture. And Generic Letter 89-08 that required the licensees to institute some type of program, FAC program. And then the industry, you know, with EPRI guidance come up with this program. And so --

DR. FORD: I understand all that. I'm just looking at what the history has been since then.

And, you know, a few months ago we had fatalities in Japan because of this phenomenon, which was not managed well. And you know if this is supposed to be the state-of-the-art of prediction of management and therefore regulation, I just don't feel comfortable.

MR. TSAO: Okay. Speaking of the Japanese, again from my understanding is that Japanese did not inspect, you know, the last 20, 30 years.

DR. FORD: Correct.

MR. TSAO: Where here under FAC program the licensees will have to inspect at least they say 50 to 100 inspection points for their large bore piping and small bore piping they probably sometime inspect 100 percent. And so there's a constant inspections going on to make sure that the --

DR. FORD: I understand that.

MR. TSAO: Right.

DR. FORD: All I'm pointing out is everyone bows to CHECWORKS and says yes, yes that's the best thing that's around. And I'm just questioning it. Is it adequate?

MR. HOWE: This is Allen Howe.

And I'd just like to add in at this point that we understand the question and we will be happy to get back with you with a response on that.

DR. FORD: Thank you.

MR. TSAO: Okay. Next slide.

Next slide I will be talking about is the related to steam generator tube inspections.

This morning you also raised about the question that -- sorry.

Next slide. The power operator will effect the anti-vibration tubes for locations. What it does at the increase of feedwater flow will cause the tube to vibrate a little bit more. And the possible degradation is where the anti-vibration bar, they call the bat wings on top of that square shape, hitting the supports.

Now, we have the requirement in tech spec that we have the leakage requirement, which the licensee has reduced to 75 gallons per day of a steam generator. This is pretty significant in that the normal primary to secondary leakage limit is 150 gallons per day. And Waterford is willing to go down to 75 gallons per day. And that it is very good limits to detect any potential leakage. Because 75 for tech spec translate into administrative limit. Control probably would be at even lower. Therefore, if there's any leak, you know they would probably go into a special administrative control actions additional monitoring. So that's one area that is going to help Waterford.

The second one is in tech spec requirement any flaws cannot exceed 40 percent through wall, through a tube's wall. For the wear indication usually the average is about 5 percent per cycle. In other words, the crack growth for tube wear type of indication usually it grows five to ten percent. So I remember you mentioned the possibility whether the crack can grow in one cycle and through wall. And that is not likely.

DR. FORD: Why do you say that?

MR. TSAO: Because crack grows -- every crack grows for tube wear is about five to ten percent. So even if you have, let's say, 39 or 38 percent crack --

DR. FORD: Maybe I'm misunderstanding. That statement there and from what I've understood about the situation, you're looking at two distinct degradation mechanisms. One is tube wear.

MR. TSAO: Right. Yes.

DR. FORD: And the other one is cracking. Two entirely different atom degradation mechanism.

MR. TSAO: Okay.

MR. MEDOFF: And they may be

interconnected, but they don't necessarily have to be. And so I'm trying to sort the two different degradation mechanisms and trying to understand how your control criteria of make it 75 gallons per day, and you're saying that's great. I just don't follow why is 75 gallons per day adequate when you've got two different wear mechanisms operating under different rate limiting steps? Why is it an adequate regulation and manager?

MR. TSAO: Okay. You talk about the two separate. Cracking. IDSCC, inside diameter stress corrosion cracking.

DR. FORD: Yes.

MR. TSAO: And then PWSCC. Okay.

DR. FORD: Sure.

MR. TSAO: And then this tube wear it's a -- I would say it was kind of pitting. You would say pitting or some type of mechanical metal-to-metal contact the cause.

DR. FORD: Sure.

MR. TSAO: Okay. Now the 75 gallons per day it lower the threshold for licensee to do certain administrative controls, and that is a big plus. Because normal plant it is 150 gallons per day. So there, you know -- because this is -- this leakage limit is defense-in-depth. Wherever there is a crack--

DR. FORD: I'm hearing all the words. I'm looking at what's on that paragraph there and what I've read in the SER.

MR. TSAO: Right.

DR. FORD: I'm seeing at least two different atomistic degradation mechanisms. I'm seeing NEI 97-06, which takes into no account the mechanism I'm aware of. And then I'm looking at 75 per gallons per day. And I'm having a problem of interconnecting all of these things that are on that graph and trying to relate them to what is the danger that I might expect to have a thorough wall hole regardless of the mechanism in one fuel cycle. And I don't have the data and I haven't seen the analysis.

MR. TSAO: The bottom line is that they have a very good leakage limit. Regardless if they pipe break or anywhere, they have 75 gallons per day that would make sure that would make them to shutdown, they have a shutdown if it goes up to 75. Some of the plants they don't shutdown until 150 gallons per day.

Now as for NEI 97-06, that is the industry guidelines that provide a descriptive guidance for them to do inspections and to do certain controls.

DR. FORD: Okay. You sound as though you're defending the licensee rather than questioning the licensee. You're saying that they can do this. And this is good for them.

MR. TSAO: Well, technically -- in fact, I raise the question that their current tech spec is 720 gallons per day. And I questioned them. And then I kind of twist their arm, so to speak, and they come down to 75. And so I wouldn't defend them if --

DR. FORD: Okay.

MR. TSAO: In other words, I'm very happy they come down to 75. I'm very surprised. And actually I give, you know, a pat on back on that in terms of tube degradation and terms of controlling any potential leakage.

DR. FORD: Okay. Thank you.

MR. TSAO: Okay. This is pretty much straightforward and this ends my talk.

DR. FORD: Is someone going to tackle this question about the flow induced vibration in the dryer? Is that going to be discussed by yourself, well obviously not yourself, but is that going to be covered later on?

MR. TSAO: Speaking of flow induced vibration, I not review that section, but this morning someone asked a question about loose parts.

DR. FORD: Yes.

MR. TSAO: Even if the bolts on a dryer are forced down into the steam generator, usually the licensee, including Waterford, they have the secondary site inspection and they usually go through a foreign object search and retrieval, the FOSR. And what they do is they stick a optical camera down the secondary site and they go down to a tube sheet to find any loose parts. Also loose parts can be detect by the bobbin inspections.

DR. FORD: Are you happy that you could never get a loose part into the main steam isolation valve, which was stated this morning?

MR. TSAO: Right. Now I have not heard the cases of going to a main steam valve. Usually if there are loose parts, it falls down --

DR. FORD: Usually.

MR. TSAO: Into bundles.

DR. FORD: Always?

MR. TSAO: I have not heard -- I have heard of the loose parts come from regular internals that flow into the steam generator on secondary side. And then there are some feedwater gaskets that falls into steam generator site. But I hadn't heard of loose parts in the main isolation valve.

MR. MANOLY: Good afternoon. I'm Kamal Manoly, the Section Chief in the Mechanical Branch in NRR. And the lead reviewer for the Waterford power uprate at an audit at Dresden in Chicago looking at the work being done by Dresden/Quad on their dryers. So I know this topic is dear to your hearts, and we're still working on that aspect of it on the boilers.

So if you have any questions beyond what I got from him, I'll take notes and we'll get back to on that, because I don't have benefit of the questions discussion with the licensee.

As typical we look at the -- there is some overlap between our work and the Materials Branch work. We focus primarily in the vessel internals on the stress analysis and the fatigue usage factors. And small loose vibration concentrations. But, obviously you heard the Materials focus is different than ours.

The same thing we do for the steam generator components and the electrical pump. Obviously, and the pressurizer and supports, structural supports also we look at that, too. And balance-of-plant piping and supports and the safety related valves and we saw what we focus on in that area.

Next slide.

We look at the methodology and the loads that they used, that they're consistent with the design basis, the stresses and the fatigue and the agenda and the codes that they're committed to under SER. And also look at the functionality of the valves and their impact on the EPU based on the findings from the Generic Letters 89-10, 95-06 and 96-06 for the pressurization of segments of piping.

Next slide.

Okay. The next slide addresses the NSSS and BOP piping and supports. We talk about the EPUI evaluation that incorporates the approved leak before break methodology for elimination of the primary loop pipe breaks in the original design basis. So that's a change from the original design basis for the facility. And now that everything breaks out in the branch piping, the largest branch piping from the main steam and feedwater and otherwise.

Finite element analysis for the revised loads. Understand that the change in temperature obviously, as we all know, was very small in terms of effect on the stress allowable. But apparently they were doing that as part of the upgrade of their design basis documents.

I guess until earlier today I was under the impression that they meet the ASME limits for all the allowables on all lines, except look at this bullet on that slide. Due to EPU the licensee discovered that the component cooling water shutdown cooling, heat exchanges at the piping was operating at a higher temperature than they initial thought. The design basis is 175 degrees. They have done evaluations for operability up to 225, which means that they don't quite meet the ASME limits above 175. So my understanding is that they will have to start by 50.59 utilizing Generic Letter 91.18 and supplement the one with the nonconformance that they have to ultimately correct to meet the code allowance. Because when they start the 175 for that system, they will be exceeding the ASME code limits.

The last slide is about flow induced vibration. And I guess we have three bullets there.

One relates to the testing and instrumentation on the feedwater at critical locations to monitor during power ascension. And they would be meeting the OM3 standards for monitoring of vibration.

The concern about flow induced vibration, obviously on the dryer, is raised several times. And

I think the vigor lies on the applicant on the work or on the operation of experience to Palo Verde, which has more power than their plant after the power increase. And I considered that operation of a plant for many years probably is far more proof than just testing for -- you know, limited testing. So we know what Palo Verde's experience is and their dryers are bigger, I believe, than Waterford dryer. So we did not feel that there was real issues.

I just heard that during the licensee's presentation that they found that some bolts had broken off at Palo Verde and that's an aspect, I guess, we're going to have to think about.

DR. FORD: What was also brought up this morning was that Palo Verde is not the same design of the steam in the upper plenum, because they have more than just one steam exit point.

MR. MANOLY: I see. I know that the boiler are much larger, because you have four steamlines and the interplay between the four steamlines has a lot to do with the loads on the plates. So the issue is not as exacerbated as the boilers. But I think there's a lot of reliance here on the Palo Verde experience. And the concern about broken bolts is that they go, you know, where they're not desired to be. So I think we still need to think about the significance of that in terms of operability.

On the steam generators, the analysis shows that they meet the stability ratio below .8. So the limit is one, and they basically also said that the steam generators are more robust than the Palo Verde. So I wouldn't expect that they would have an issue there.

So that's basically the section on the Mechanical part. If you have any questions, I'll be glad to take it.

MR. ROSEN: Well, I think you hit on a couple of good issues, Peter. And I wonder if we could have a little more information at the full Committee on this, especially on the reliance on the Palo Verde experience which may or may not be applicable, I guess.

MR. MANOLY: My understanding is that their dryer is bigger than the Palo Verde dryer.

MR. ROSEN: But from our experience in talking about the BWRs and specifically the problems addressed in Quad and how that translates to the rest of the fleet, there was discussion about the differences in configuration are very important.

MR. MANOLY: Yes.

MR. ROSEN: And so I would draw from that the same conclusion here; that the differences in configuration between Palo Verde and Waterford may also be very important. So using Palo Verde as a stocking horse for Waterford may or may not be appropriate. We need a more fundamental look at this than just simply saying well it's kind of like Palo Verde and they haven't had a problem. Not very substantive.

MR. MANOLY: Well, yes. The power at Palo Verde is higher than at Waterford after the power uprate.

MR. ROSEN: Well, yes. But the question really is about forcing functions for vibrations.

MR. MANOLY: Yes, I understand.

MR. ROSEN: Not just because the power is higher doesn't necessarily mean that the flow induced vibration is.

MR. MANOLY: But the geometry I understand of the dryer at Waterford is very similar but it's larger dryer. So --

MR. ROSEN: Maybe we could have some pictures of Palo Verde's dryers and the Waterford dryers.

MR. MANOLY: Okay.

MR. ROSEN: And at least quality of discussion about where the --

CHAIRMAN WALLIS: I'd like to know also because this morning some of the speakers seem to say it was the same, these were the same dryers. They'd also been tested at CE over a wider range of flow rate and pressure. So maybe we could get this more definite; are they same, are they not the same, have they been tested or not been tested, has something similar been tested or the same? You know, get it absolutely straight.

DR. FORD: And also I the other aspect I think, Graham, is this whole question what's going to happen to the loose parts which are created if it does fail or is it just a no nevermind?

MR. ROSEN: Well simply because the loose parts that were talked about here were found down on the top of the tube sheet doesn't necessarily mean that's where they'll always go.

DR. FORD: Exactly.

MR. ROSEN: I mean, they may go down the steamline.

DR. DENNING: But that's probably an analyzable condition.

DR. FORD: Absolutely, but there hasn't

been, that's the point. We don't know it's been asked.

MR. MANOLY: It was not supported --

MR. ROSEN: We're a little bit sensitive on this issue because of history.

MR. MANOLY: Right. Any additional questions?

CHAIRMAN WALLIS: So we've agreed that before the full Committee you're going to have a --

MR. MANOLY: A comparison, I guess, between the --

CHAIRMAN WALLIS: A more definite comparison?

MR. MANOLY: Yes. The Palo Verde dryers and--

CHAIRMAN WALLIS: Maybe besides that you could actually provide my colleague here with a written document which actually has pictures of things so that rather than have the full Committee have to go through all the details so that somebody here can go by an certify --

MR. MANOLY: Yes, that's possible.

CHAIRMAN WALLIS: -- that he has seen drawings, and indeed they are the same or they are not, or whatever.

MR. MANOLY: Yes. That's more efficient I think. Okay. Thank you.

CHAIRMAN WALLIS: Thank you.

MR. STUBBS: Okay. Good afternoon.

My name is Angelo Stubbs. And I'm a reviewer with the Plant Systems Branch. And the review that we performed was for the balance of plant size, plant systems.

Go the next slide. Okay. We'll start off with the scope.

We followed the Review Standard and there's a detailed breakdown of the things that's included in our review scope in Matrix 5 of the Review Standard. I'm going to summarize here things that were in our scope of review. And that included the secondary plant systems; that was the secondary plant waters systems, circulating water systems, the steam heat water, condensate, the ultimate heat sink and cooling water systems, the main turbine and protection from pipe failures, floods, and internally generate missiles.

Also the spent fuel pool cooling and cleanup system, the emergency feedwater system, fission product control and waste management systems and the emergency diesel generator fuel oil storage and transfer systems.

So for our review what we did was we began by looking at what things in the uprate would impact the balance of plant systems. And there were things that we thought of that were of major concern. One, the increase in decay heat associated with the EPI operation. The second was a modification that they were making on the main -- on their pressure turbine. And the third was there could be changes in system operating parameters, that is the pressure, the temperature. There's an increase flow, steam flow by 8.5 percent.

Okay. Next. Okay.

I'm going to start off by talking about the turbine. The change that was made to the turbine was the physical modification of high pressure turbine. And that modification included installation of new high pressure turbine rotors with reaction rating, I think they talked about that earlier. And including the inner cylinder, stationary blades and inlet flow guide.

The EPU evaluation was performed for that, and what we found was the maximum rotor speed following the reactor trip will still be less than 120 percent rates speed, so it will continue to provide adequate protection against overspeed, turbine overspeed.

Okay.

DR. RANSOM: Was the entire high pressure and turbine replaced or did they just put a new rotor in it?

MR. STUBBS: Okay. No -- okay. Go back to the last one. The changes that were made was in the turbine speed paths was in addition to the turbine rotor there was also inlet flow guides, steam sealing components that were replaced.

DR. RANSOM: How many stages around the high pressure turbine?

MR. STUBBS: Does somebody want to -- I don't recall.

MR. VIENER: This is David Viener from Entergy.

There's eight stages.

DR. RANSOM: Pardon?

MR. VIENER: Eight reaction stages.

DR. RANSOM: Eight stages?

MR. VIENER: Eight stages.

DR. RANSOM: So you changed all the staters and the rotors I guess in that?

MR. VIENER: That is correct.

MR. STUBBS: Okay. As I already mentioned, as far as we're looking at it to see that the overspeed protection, the overshoot would stay within the design and the results were we still maintained the overspeed to be less than 120 percent.

CHAIRMAN WALLIS: And 120 percent is okay because of what? Why is 120 percent okay?

MR. STUBBS: Well, 120 percent is the design overspeed that's currently water turbine. The trip -- I think the trips are at 111, the control is at 111 or 111 and a half. And there could be some overshoot.

There was study done to confirm that 120 -- that the 120 percent wasn't exceeded at the EPU. That's the current overshoot for the current turbine and its design overshoot that the plant is designed for in terms of the turbine protection system.

MR. SIEBER: There actually should be very little change in what speed you achieve because --

MR. STUBBS: Right.

MR. SIEBER: -- at a lower pressure, you actually have less stored energy and you're getting all of the additional output from higher steam flow, which doesn't contribute to the overspeed.

MR. STUBBS: Right. And the reason we

looked at it is because you're actually making physical changes and what we might do to change to inertia in the turbine, we just wanted to make sure that that was not --

MR. SIEBER: And those factors are going to be small.

MR. STUBBS: That's right, it turned out to be small.

MR. SIEBER: Yes.

MR. STUBBS: Okay.

DR. RANSOM: What happens on loss of load in terms of overspeed.

MR. STUBBS: In terms of loss of load?

DR. RANSOM: Right.

MR. STUBBS: It still protects -- it's still protect that same overshoot. The control will --

DR. RANSOM: Shut down?

MR. STUBBS: Particularly at 111 percent and even after that, the overshoot will maintain it --

MR. ROSEN: Does this turbine have electrical overspeed and mechanical overspeed both?

MR. STUBBS: Yes.

MR. ROSEN: So what are the setpoints for the electrical overspeed protection and the mechanical overspeed protection?

MR. STUBBS: I believe one is 111 and the other is 111.5.

MR. SIEBER: Unless you have governor valve action.

MR. SCHWARTZBECK: Yes. Ralph Schwartzbeck with Enercon Services.

The electrical overspeed is 103 percent and the mechanical is 111 percent.

MR. ROSEN: So the first thing that happens is the control valves try to control it, right?

MR. SIEBER: Right.

MR. SCHWARTZBECK: Yes. They close down.

MR. ROSEN: If they don't control it, then you get electrical overspeed trip?

MR. SCHWARTZBECK: Yes.

MR. ROSEN: If that doesn't come in, you get a mechanical overspeed trip at 111. And if that doesn't control it, then you just --

MR. SIEBER: Run. Get out of the way.

MR. ROSEN: Well, then the turbine's designed to -- if you have a loose part, it has to be a very big one to come through the casing. And if so--

MR. SIEBER: Yes. They usually keep everything inside.

MR. ROSEN: Yes, it's usually contained. But not always and the orientation of the turbine is looked at vis-à-vis safety related equipment and so on.

MR. SIEBER: Right. And other turbines.

MR. STUBBS: Okay. We'll move on.

Okay. The next area that we looked at was spent fuel pool. And the reason for this was because there's increased decay heat associated with the EPU, so the fuel being offloaded to the spent fuel pool could -- if it was offloaded at the same time would have higher decay heat associated with it.

There was a question this morning concerning why there was discussion in the SE, the extent of the discussion in the SE on this. And the reason is we did our initial review of this and what we saw was that the current analysis, there was very little margin between the calculated peaks and the pool limits. So as a result of that, we asked for additional information from the licensee, and they provided that information. And we wanted to be assured that we weren't exceeding the pool temperatures.

In the inlet what happened, what we found out was or the way this is being controlled is they're using administrative controls to control the amount of decay heat that's actually in the spent fuel pool at any given time after the offloads so that they be control the decay heat to be below the heat removal rate available from the spent fuel pool cooling system.

This way they ensure that they stay below the temperature limits of the pool and they ensure -- by staying below the temperature limits and having the decay heat within -- below -- really at about the same but slightly below what was used in the previous analysis, the time to boil remains down by the current analysis.

CHAIRMAN WALLIS: What does "administrative control" mean? Does it mean that you unload the stuff slower or something, or you unload --

MR. STUBBS: Okay. Administrative controls, in this case it sets offload limits for the total amount of fuel that could be in the fuel pool for any given time after the reactor is shutdown.

The tech spec requires 72 hours before you can start offloading fuel. In this case here it's controlled so that the maximum heat load in a pool will be -- for the normal offload will be 29 million BTUs --

CHAIRMAN WALLIS: So you might wait longer to offload, is that what you might do?

MR. STUBBS: Yes.

MR. SIEBER: That's one thing.

MR. STUBBS: Well, the rate at which you offload --

CHAIRMAN WALLIS: Or offload at a slower rate?

MR. STUBBS: -- may be slower. The one thing, you can wait longer and begin to offload later. That's also an option. But if you begin to offload at 72 hours after shutdown, you know, the rate of -- at some point you're going to get to the point where you would be approaching the maximum heat load and your offload would have to be slowed so that you don't exceed that maximum heat load allowable.

MR. ROSEN: Is that the licensee's answer to that question?

MR. STUBBS: What?

MR. ROSEN: That you control the rate of offload?

MR. VIENER: This is David Viener, again from Entergy.

And Angelo described it perfectly.

CHAIRMAN WALLIS: Sot his increases your time that you have to take to reload and everything?

MR. VIENER: No. What we would do is control how many assemblies that we can offload based on time after shutdown to control the amount of heat that we can put in the pool.

MR. ROSEN: Well, I would say that's sort of surprising. I think that may be the first time I've heard that, that a plant is so limited with respect to spent fuel pool heat rejection capacity.

MR. MITCHELL: Yes, this is Tim Mitchell.

There is typically a tech spec limit on like at a 100 hour point on how many assemblies you can have offloaded.

MR. ROSEN: Yes, I understand.

MR. MITCHELL: And it's really not that we're going to slow down the offload, is that we might either have to stop the middle because we have a certain number of assemblies until we reach some hour point post shutdown or you would start later, which is more likely.

MR. ROSEN: Is that something you do now?

MR. MITCHELL: That is something that we do now -- actually our current outage schedules have not challenged it, so we haven't had to. But I have seen it done at other plants within our system where there is a specific evaluation and depending on things like late temperature or cooling temperature that has to be done on a per cycle basis to determine --

MR. ROSEN: It sounds like it's a pretty marginal design to me.

MR. VIENER: We've had administrative controls in place prior to even this submittal.

CHAIRMAN WALLIS: So this might increase your outage time? You got elements to unload and you've got to do it slower?

MR. MITCHELL: At this point we wouldn't expect to increase our outage time. But there may be a point where outage times if they are improved, could be effected by it. It would be something that we would have to evaluate.

CHAIRMAN WALLIS: So you increase the power of the reactor, but then you increase your outage times, so your net energy production stays the same?

MR. MITCHELL: No. My answer actually was right now it would not effect our current outage time.

CHAIRMAN WALLIS: But it seems that it might.

MR. MITCHELL: It might if we shorten the outage.

MR. ROSEN: Shouldn't you be increasing the capacity of this heat rejection capability here instead of being so marginalized?

MR. SIEBER: That's controlled by the river temperature, right?

MR. ROSEN: Is it the river temperature that's controlling it or your heat exchanger size and pumping capacity?

MR. VIENER: It's controlled by our heat removal component cooling water system and the size of our heat exchanger.

MR. ROSEN: It sounds pretty marginal, as I said.

MR. SIEBER: It's down south.

MR. VIENER: Yes, we're talking that we can remove a partial offload at approximately five days after shutdown. This is if we start to offload at about 72 hours, then it becomes critical because the decay heat is very high in the core three days after shutdown. But the system can remove the whole partial offload of 106 assembles assumed within about five days.

MR. LEONARD: This is Ted Leonard.

And that's using all the worse case design assumptions? And a train of cooling?

MR. VIENER: That is correct. That is following the Standard Revenue Plan criteria of a single failure which we lose a train of cooling.

MR. STUBBS: The analysis was performed with a single failure and also bounding. I'm looking at the last offload which would fill the pool to capacity, so it bounds all their offloads in the future.

CHAIRMAN WALLIS: Okay. So we'll move on.

MR. STUBBS: Okay. Another area that the decay heat also effects -- the increased decay heat also effects is the alternate heat sink in terms of the long term cooling. So EPU evaluation were performed and the results showed that wet and dry cooling tower has sufficient capacity to accommodate post-LOCA heat loads and sufficient water volume is to continued to be available either in the one basin to meet the 30 day heat removal criteria.

The conclusion that we drew for alternate heat sink is pending resolution of how the licensee account for measurement of certainty, which is one of the issues I think that was introduced earlier in the introduction.

CHAIRMAN WALLIS: So this 30 days is if the cooling towers aren't used at all, they just cool with the water basin, is that what that means?

MR. STUBBS: Excuse me. Can you repeat that?

CHAIRMAN WALLIS: Is the 30 day heat removal criteria, that means you just use the water in one basin, you don't actually cool it with a cooling tower?

MR. STUBBS: Well, if the water in one basis is sufficient to meet that.

CHAIRMAN WALLIS: That is just a pool, isn't it?

MR. STUBBS: Huh?

CHAIRMAN WALLIS: A basin is a pool?

MR. STUBBS: Yes. Yes.

CHAIRMAN WALLIS: A big basin is a pool.

MR. STUBBS: Yes.

CHAIRMAN WALLIS: And it means that you just draw in that water without cooling that water over the cooling tower, is that what it means?

MR. STUBBS: No. You still utilize the cooling tower, but --

CHAIRMAN WALLIS: So it operates from the cooling water, is that what it's making up?

MR. STUBBS: Yes.

CHAIRMAN WALLIS: Okay. How about the river? The river doesn't count for all of this?

MR. STUBBS: Well, to meet their 30 day requirement, their primary heat sink is a wet cooling tower basin.

CHAIRMAN WALLIS: Well, why aren't they allowed to use the Mississippi?

MR. SIEBER: They need two.

MR. TATUM: This is Jim Tatum from the Plant Systems Branch.

The criteria that we look at, we rely on seismically qualified capability for the design basis, and so that's why the licensee has to rely on the cooling tower. The cell that they're relying on is seismic category one. And the intake structure, I believe, is not seismically qualified.

CHAIRMAN WALLIS: I see.

MR. ROSEN: Now as a matter for follow up, these places where the staff conclusion is incomplete, is it planned that they'll come back to the full Committee and give us a --

MR. STUBBS: Yes. Right now we're working on -- I think Kaly mentioned this morning, resolution. We think we have a path to resolution for the measurement uncertainty. And as soon as that's resolved --

MR. ROSEN: Well, there are a couple. The other one is the AST, alternate source term. And there are several other things that we've talked about as being pending resolution. It seems to me we're getting a little ahead of ourselves here where the staff isn't done with the licensee and yet they're at Subcommittee.

MR. BERKOW: This is Herb Berkow.

As Kaly indicated this morning, we have agreement, conceptual agreement with the licensee on these three issues. And they will be resolved before we come to the full Committee.

MR. ROSEN: And you'll give us a brief of how they were resolved?

MR. BERKOW: Yes.

MR. ROSEN: Okay.

MR. BERKOW: We will.

MR. STUBBS: Okay. Another area, again it was a result of the increase in the decay heat, we reviewed the impact on the emergency feedwater system. And the initial water source for those are the condensate storage pool with the backup source being the cooling tower and basin. The evaluations so that increased demand for the emergency feedwater for the plant will continue to be met at operating conditions, at the plant operation of operating conditions.

Okay. And the final one which we looked at was the emergency diesel generator fuel oil storage and transfer system. And because of the increased decay heat, this required that some of the equipment for decay heat removal operates for a longer period of time. And that results in an increased demand on the turbine in the four to seven day range and a slight increase in the fuel oil requirements.

The licensee's current fuel -- the current fuel oil levels did not support the seven day operational requirements once the uprate was factored in. It was only -- they were only supplying six and three quarter days for the fuel oil supplier. So the licensee has proposed change their tech spec to increase the minimum required volume in the fuel oil storage tank to meet the seven day criteria. And we reviewed that and we found that the new tech spec requirement added enough additional fuel to satisfy seven day post -- seven day operation.

And as they mentioned this morning, there's also a commitment to add additional fuel oil storage capabilities to the plant by December of 2006.

Is there any other questions?

CHAIRMAN WALLIS: Does that bring it to the end of your presentation?

MR. STUBBS: That would be the end of my presentation.

CHAIRMAN WALLIS: I'm trying to look ahead to the rest of the day here. Someone's going to talk about LOCAs and transient and -- that's the next time, huh?

MR. STUBBS: Rich Lobel is going to talk about containment systems.

CHAIRMAN WALLIS: That includes LOCAs and various transients?

MR. STUBBS: Yes.

CHAIRMAN WALLIS: Okay. Not from the Appendix K standpoint.

Well, I think we should take a break.

Thank you very much for your presentation.

MR. STUBBS: Okay.

CHAIRMAN WALLIS: Five minutes to 3:00 we need to be back.

(Whereupon, at 2:41 p.m. a recess until 2:56 p.m.)

CHAIRMAN WALLIS: Come back into session, please.

We're now going to complete the NRR presentation.

MR. KALYANAM: I have one question. Before Rich Lobel goes, we have two experts, one of the FAC CHECWORKS program, the other one on the steam generator tubes. So we had some questions before the break, and I'm sure they'll be able to provide their response to that. Is that okay.

DR. FORD: Well, I've been bagging on the head about this FAC business. I understand it perfectly. The other members might enjoy having a presentation on that.

MR. KALYANAM: Okay. Either way is fine.

CHAIRMAN WALLIS: If it's something we're going to enjoy, I think we should do it.

MR. ROSEN: As many times as possible.

MR. SIEBER: That's one time.

MR. KALYANAM: I have Ken Karwoski from EMCB

MR. KARWOSKI: I guess I understand this morning there were questions from the steam generator two integrity standpoints some questions about whether or not the power uprate, what effect it would have on wear and cracking along the length of the tubes as a result of the increased flow through the steam generator. And then there may have also been a question about the adequacy of the 75 gallon per day leakage link.

In terms of the effect of the power uprate on the increased flow through the steam generator, there is a potential effect on the amount of wear that can happen at the various support locations, whether it be at the vertical straps, the diagonal bars or at the egg crate supports. There could be an effect on the wear.

In addition, Waterford has exhibited stress corrosion cracking at a number of locations along their steam generator tubes. Both of those mechanisms could be effected by the power uprate. However, the change in the conditions in terms of the flow, the temperatures and the pressures across the steam generator tubes are relatively small and well within the bounds of what exists at other plants. And it's been our experience at the other plants which have uprated power that these small changes have negligible increases in corrosion rates, negligible increases on wear rates. And by "negligible," I mean that it's well managed from one inspection to the next; that when they go in and do an inspection after a power uprate or after an interval, that they still have tube integrity. That the tubes have adequate regulatory margin --

CHAIRMAN WALLIS: This is where? On the inside of the tubes you're talking about?

MR. KARWOSKI: On the outside.

CHAIRMAN WALLIS: Are the tubes rattling and wearing.

MR. KARWOSKI: Rattling and wearing. And that happens at almost every --

CHAIRMAN WALLIS: These fluid interactions are a little hard to predict, aren't they?

MR. KARWOSKI: Actually, they're quite reliable. I mean there are some instances where some tubes, and this is usually in the life of a steam generator, where some tubes will wear quicker than others because of the placement of the anti-vibration bars or the diagonal straps in the case of Waterford.

So some tubes may wear more than others, but in general these phenomenon are very predictable. Plants leave wear scars in service, and in general they're very predictable. The wear rates tend to be very low and they're left in service for many cycles before they exceed the tech spec.

MR. ROSEN: Do they tend to decrease in rate because they kind of wear off whatever the contact point and that's it?

MR. KARWOSKI: That has been the experience, and I can't comment on the combustion engineering data, but I know that that's definitely been the experience at Westinghouse design steam generators. But the wear rates decrease with time because of the contact issue point.

MR. ROSEN: Now the question is brought up how about the effect of vibration, vibrational stresses on the kinetics of stress corrosion cracking?

MR. KARWOSKI: Once again, you know, it is possible that that would increase the rate of cracking, may even change the initiation of cracks. But it's been our experience that any change that does occur: (1) It's not readily measurable, and; (2) that it can be managed within the normal frequency of in service inspections. And certainly if there is a change, we will detect that as we review the annual reports that the plant sends in regarding their inspections. And we would expect them to take corrective action, and that would be something we would followed up. But in general we have not observed that. And in the case of Waterford, it's been their practice that when they find a crack, they plug that crack on detection. It's not like some of the other plants which leave cracks in service and try to manage cracks that --

MR. ROSEN: My questions on those two issues.

MR. SIEBER: The displacements are extremely small and the number of cycles is extremely large. So if there is going to be failure, it would show up fairly early, I would expect.

MR. KARWOSKI: That would be for like the cycle type of fatigue failure.

MR. SIEBER: Right.

MR. KARWOSKI: In this case it's more just the wearing of the tube, which it can be low cycle--

MR. SIEBER: But that's not fatigue failure.

MR. KARWOSKI: No, that is not fatigue. Yes, that's correct.

MR. SIEBER: Right. It's just wearing out.

MR. KARWOSKI: That's just wear.

DR. FORD: Jack, there's a problem discussed earlier on. It's not trangranular fatigue, cracking you see.

MR. SIEBER: Right.

DR. FORD: And therefore it's not covered by the ASME 3 code or anything like that. Similarly it's just stress code in cracking that's been accelerated.

MR. SIEBER: But wear phenomenon is covered by the ASME code.

DR. FORD: Yes.

MR. KARWOSKI: Through the plugging limits and what not and through the plant technical specifications.

DR. FORD: Right.

CHECWORKS?

MR. KARWOSKI: I think Louise Lund was going to talk about CHECWORKS.

DR. FORD: Maybe if I could just state what my problem was, Louise, and that would make it more efficient for you to answer it.

MS. LUND: Should I introduce myself first for the record?

DR. FORD: Yes.

MS. LUND: I'm Louise Lund. I'm the Section Chief for the Steam Generator and Integrity and Chemical Engineering Section, NRR. And, anyway, I was asked to come over and discuss the FAC program.

DR. FORD: My concern was that the way that they're using CHECWORKS right now, it is primarily a prioritization tool as to where you're going to look in the carbon steel piping. From the measures that were shown this morning, it's apparent that CHECWORKS is not good on one-to-one correlation. Therefore, it's quite possible that you may use CHECWORKS to say that I should not look at that pipe because of the particular operating conditions of that pipe, but I should look at this pipe. But in fact that pipe there might well be eroding at quite a large rate, but you wouldn't look at it for one, two, three cycles. In that time you could go through wall. So that was essentially my worry that you're using a model which is not precise to make prioritization decisions.

MS. LUND: Right. And I just want to say off the top, you know we have a very active interest in the FAC programs. Specifically we've had generic letters or generic correspondence that has asked industry to put together these type of programs which manage FACs and also have these predictive methodologies. However, it's not a case of just using the predictive methodologies blindly and looking at information on one line or another; there's a number of things that inform the decision as far as what's inspected and how it's inspected. Because it is a tool, but it's not a blind tool in that particular way. And, in fact, this gentleman I believe is from Waterford and he was mentioning, we had a kind of offline discussion about it and that's why I asked him to come up here and help discuss this, and specifically for Waterford.

I also wanted to say that for these FAC programs, I think that we have an interest in looking at them through power uprate and license renewal in that we ask that the licensee provide information on their most susceptible lines with their measures versus their predicted and whether it gave them information such that they could replace the lines, you know, in a timely manner. Because that's really what we want to know is, is it giving you the information at the time that you need it in order to make the decisions you need to make good decisions about running your plant.

So that's the kind of questions we ask. We do not do a re-review of their CHECWORKS data. We do not take all their raw data and subsequently do an audit of it. Okay. So I just wanted to kind of clarify what it is that we do, you know, in our review process. Usually through a request for additional information we usually will ask them for the most susceptible lines.

MR. ROSEN: We call that a performance-based regime?

MS. LUND: Right. Right. And when we put out that generic letter where we asked the licensees to put together a FAC program and also have these predictive methodologies, we did inspections of those programs at that time. Okay. In fact, to make sure that these programs were in place and in fact doing what we thought that they were doing. Okay.

Now, I now in license renewal, true license renewal we've been asked to come and give a presentation to the ACRS on FAC and FAC programs. And we've actually been in contact with CHECWORKS user script to ask them to come in and help present this information such that you can look industry-wide at how well these FAC programs are working, specifically with the CHECWORKS program and give you a lot of sense -- instead of looking at just one graph, kind of get a sense for generically how this is working and where it may be challenged in certain ways or another, because they think that they have a very good story to tell.

Now maybe if you could introduce yourself, and then also explain how programmatically it's a much lighter look at how you choose the lines and -- because there's a surrogate aspect to it where, you know, if you see something you look at other things that are like that. There are a lot of things that go into the program that don't rely on just this measurement.

So, anyway --

MR. ALEKSICK: Good afternoon. My name is Rob Aleksick. I'm with CSI Technologies representing Entergy today.

Real quick about my background. I've had the opportunity to be involved with flow accelerated corrosion since 1989 and in particular have modeled or otherwise addressed approximately 20 EPU efforts in the last two years.

Dr. Ford made a very good point earlier when he said that the graph that we looked at did not display a very good correlation between the measured results and the predicted results out of CHECWORKS. Programmatically -- well, let me back up a second. That is certainly true in the example that we looked at. That is not always the case.

CHECWORKS models are on a per line or per run basis. The run --

CHAIRMAN WALLIS: Could we go back to that graph that we saw? The graph was a plot of thickness versus predicted thickness.

MR. ALEKSICK: That's correct.

CHAIRMAN WALLIS: Because if you looked at amount removed versus predicted amount removed, it seems to me the comparison will be even worse.

MR. ALEKSICK: That's correct. In fact --

CHAIRMAN WALLIS: That's what you're really trying to predict is how much is removed.

MR. ALEKSICK: Yes, that is true. And my point is that in some subsets of the model, the one that we looked at here which was high pressure extraction steam, the correlation between measured and predicted is not so good. And in some subsets of the model, the correlation is much better.

CHAIRMAN WALLIS: It looks to me that in some cases it's predicting no removal whereas in fact there's a lot of removal. So the error is percentage wise enormous?

MR. ALEKSICK: Yes, exactly. Exactly. Some runs results are imprecise and some more precise. And we look at both accuracy and precision. Programmatically we account for that, that reality, by treating those runs that have what we call well calibrated results, i.e., precise and accurate results coming out of the model that are substantiated by observations, we treat those piping segments differently programmatically than we do areas where the model is less good. If the model results do not correlate well with reality, different actions are taken primarily increased inspection coverage to increase our level of confidence that those systems can continue to operate safely.

In addition to the CHECWORKS results many other factors are considered to assure that the piping retains its integrity, chief among these are industry experience as exchanged through the EPRI sponsored CHUG group. Plant experience local to Waterford in this case. And the FAC program owner maintains an awareness of the operational status of the plant so that, for example, modifications or operational changes that occur are taken into account in the inspection of the secondary site FAC susceptible piping.

DR. FORD: And my final question on this particular subject was given the uncertainties in the model, changed by this performance based aspect that you just talked about, is there any way that you can come up with a quantification of the risk associated with a failure of a specific pipe?

MR. ALEKSICK: There's currently no accepted methodology to quantify that risk, no. However, it is accounted for primarily on a judgment basis through industry experience and information exchange through the EPRI CHUG group.

DR. FORD: Okay.

MR. MITCHELL: Yes, this is Tim Mitchell.

Just to give you a feel for how we're addressing for this upcoming refueling outage, we have increased our scope for a couple of reasons. One to get additional data and we always do more than just exactly what CHECWORKS supports. So you're always out validating and getting more data to be able to help predict where do you need to be looking. But in addition, we're taking some additional points to make sure we have good baseline data for the next cycle to ensure that those points give us a good indication going forward after the EPU.

The analysis for flow accelerated corrosion shows very minimal changes as a result of power uprate. But we are taking seriously our inspection program and expanding it for this upcoming outage to ensure that we know what's happening not just what we're predicting.

MR. ROSEN: Let me roll that back now,

Tim. Can you tell me like for the last three or four outages have you done some actual replacement of piping based on predictions of FAC from the CHECWORKS code or have you never replaced anything? What are you seeing at Waterford?

MR. MITCHELL: I can give you non-Waterford data better than I can give Waterford to ponder.

MR. CHOWDHURY: My name is Prasanta Chowdhury and I'm working with Entergy design for last 20 years.

I was involved with FAC also for several years in the past.

It's not the CHECWORKS model that determines what replacement is to be done. We base it on actual measurement we take during the refuel outage. So we also project based on actual measurement that what will be our future projected thickness in next refueling outage. So you can survive until next cycle. And then we do some evaluation based on our criteria that makes the stress criteria -- or based on the code requirement. Like make all the equation.

Now code allows to go thinning in local area but the FAC is a local thinning. So we do some local thinning evaluation to make sure that it goes to the next cycle.

Does that answer your question?

MR. ROSEN: No.

MR. MITCHELL: Did we replace any piping in the last three outages?

MR. CHOWDHURY: I don't recall. I don't recall. But we did extensive modification on extraction steamline in the past. But it changed to crack piping or stainless steel piping or chrome moly, which is more corrosion resistance piping. I don't answer your question --

MR. ROSEN: You say you have made extensive modifications --

MR. CHOWDHURY: In the past.

MR. ROSEN: -- you changed to chrome moly?

MR. CHOWDHURY: Several years back, yes.

MR. ROSEN: Okay.

MR. CHOWDHURY: So whatever we did, see the corrosion of thinning, we took it out and made modifications.

MR. ROSEN: Yes, well, that's typically the plant's response. If you find substantial thinning, then you just don't go back and put in carbon steel back in the same place.

MR. CHOWDHURY: Right.

MR. ROSEN: Because what happened before will happen again.

MR. CHOWDHURY: I mean we have also made a procedural entry into this FAC that anytime we do a replacement, we use a better corrosion resistant material or EPRI guidelines.

MR. ROSEN: Okay. So you're saying you have made those kinds of modifications.

MR. CHOWDHURY: Yes. But still we are ongoing and doing things. If we see something we need to change, we change it.

Does that answer your question, sir?

MR. ROSEN: It's a little better. Not a 100 percent.

MR. CHOWDHURY: Okay.

MR. ROSEN: I would prefer something, and maybe for next meeting you can come back with some real data that there are 11 locations that you changed in the last five years or something.

MR. CHOWDHURY: Yes, we can do that. Because I don't have the data with me. I can get in touch with the FAC program engineer and get those information. Thank you.

CHAIRMAN WALLIS: That would be excellent.

DR. FORD: Thanks very much indeed. I

appreciate it.

MR. KALYANAM: Next we have the Containment Systems group Richard Lobel.

MR. LOBEL: Good afternoon. My name is Richard Lobel. I'm with the Probabilistic Safety Assessment Branch but in the Containment System area.

Next slide, please.

I wanted to talk about the review of the analysis that were done for the containment accident analysis. This slide lists the areas that were looked at. Basically the analysis of containment response to a LOCA both the mass release and the containment response and the containment response to a main steamline break, both mass and energy into the containment and the containment response and subcompartment analysis also, which is a type of LOCA.

Next slide.

CHAIRMAN WALLIS: You mean that PSA Branch actually does this sort of thermal-hydraulic analysis?

MR. LOBEL: We're the orphan section. We go to the branch meetings but don't understand what they're talking about, because it's all acronyms dealing with risk and we just sit there and listen. But that's where they put us.

The mass and energy for the LOCA was

calculated using NRC approved Westinghouse methods, Ceflash for the blowdown and Flood 3 for reflood and Contrans for the long term mass and energy release.

The calculations for LOCA were previous approved by the staff and the license amendment issued, I think in Amendment 165 that had to do with changing the number of operable fan coolers. And I think that was issue around 2000. So the mass and energy release and the containment response for LOCA haven't changed for the Waterford EPU because the analyses were initially done at EPU conditions.

A subcompartment is defined in the SRP, for those who are familiar, as any partially or fully enclosed volume within the primary containment that houses a high energy piping and limits the flow out of that volume so that the subcompartment pressurizes faster than the global response to the containment. And the item of interest is the structural integrity of the walls of the subcompartment.

The license reexamined this and found that there was significant margin to any limits. And used approved methods.

The main steamline break analysis was done using the NRC approved code, SGNIII that was approved back with CESAR and calculates the mass and energy release from a ruptured steamline into the containment.

The containment response to both the LOCA and the steamline break were calculated with the GOTHIC code. The staff back in this Amendment 165 had approved GOTHIC 5 for use by Waterford and the licensee went to the more recent version of GOTHIC, GOTHIC 7. The staff had reviewed GOTHIC 7 on another docket and found it acceptable with some limitations or restrictions that had to do with modeling of heat transfer. The licensee used the code in a way that didn't use any of the model that we found unacceptable. So the calculations done with GOTHIC 7 were benchmarked to GOTHIC 5 calculations and found to be very close.

CHAIRMAN WALLIS: So you accepted the calculations made by the applicant?

MR. LOBEL: Yes, we didn't do --

CHAIRMAN WALLIS: You didn't any confirmatory calculations?

MR. LOBEL: No, because of the fact that the change wasn't all that much in terms of containment and the licensee used methods, mass and energy methods had been used for decades now for analysis and CE designed plants. And like I said, GOTHIC 7 we reviewed on another docket and the licensee was asked to verify that they were using the code consistent with that review, and they answered that they had. So it really didn't qualify for analysis that required an independent audit.

The environmental qualification analysis the licensee stated that the containment pressure and temperature for EPU conditions were bounded by the existing plant accident profile except for the time at elevated temperatures, which was slightly longer. And the licensee confirmed that the electrical equipment was still qualified for the longer time and the containment flood level remained unchanged.

MR. SIEBER: It would seem to me that with respect to the scored energy contained in fluids, they would be equal to or perhaps slightly lower than the current conditions at the plant. And the only thing that's different is the decay heat of the core.

MR. LOBEL: Yes.

MR. SIEBER: And so whatever differences you see are the result of the, perhaps, ten percent higher level of decay heat, which would tell me everything stays about the same.

MR. LOBEL: Yes. Basically these codes -- because typically when we do an audit calculation, we ask the licensee -- which we didn't do in this case. When we do, we ask the licensee for his mass and energy calculations. So really this is just a heat balance check.

MR. SIEBER: That's right.

MR. LOBEL: And a check of the heat transfer models and that kind of stuff accounting for the inventory of liquid, what's condensing on the walls and what's falling in the sprays and what's in the sump, and all that.

MR. SIEBER: Right. Right.

MR. LOBEL: So it's basically true.

There were slight differences in the calculations, some assumptions, but really not --

CHAIRMAN WALLIS: But you could almost estimate the change in pressure by a global energy balance -- or put it into the containment and see what happened. And you've come fairly close in terms of an increment.

MR. LOBEL: Yes.

MR. SIEBER: That's why it's small.

CHAIRMAN WALLIS: Yes.

MR. LOBEL: Next slide, please.

CHAIRMAN WALLIS: So you do it on the back of an envelop confirmatory calculation.

MR. SIEBER: Yes.

CHAIRMAN WALLIS: That's what I would do.

MR. SIEBER: You would not even need the whole envelop.

MR. LOBEL: These are the results of the calculations for the LOCA. Like I say, these were done for a previous license amendment that the staff approved. And the next slide for the steamline break. Let me just point out there should have been change to the slide. The numbers for the pressure and temperature are very slightly different than what I have here. This was from the licensee's original submittal and they made a modification, which didn't make it onto the slide.

The pressure, I think, was 41.87 instead of 41.83. So not really significant.

CHAIRMAN WALLIS: These temperature acceptance limits are so different because steam has a different effect than water or something on --

MR. LOBEL: On a LOCA in the main steamline break?

CHAIRMAN WALLIS: On equipment, is that what it is or was it --

MR. LOBEL: Yes. We asked the license about this and the licensee claims that the acceptance level they've always used for main steamline break is this high temperature, which is an environmental qualification temperature. So we did ask the licensee well how does that address the issue of structural integrity of the containment. And the licensee came back in response and said that they had looked at that and they were calculating a temperature below the structural temperature.

CHAIRMAN WALLIS: Well, did the containment sprays come on during all this?

MR. LOBEL: Yes.

MR. SIEBER: Yes.

CHAIRMAN WALLIS: So why is the steam break inherently different from a water steam break?

MR. LOBEL: Well, typically the --

CHAIRMAN WALLIS: Everything is wet and soggy no matter what, isn't it?

MR. LOBEL: Well, typically the enthalpy of the break is higher and the timing is different for the steamline break.

MR. SIEBER: More mass.

CHAIRMAN WALLIS: But the environment is wet and soggy in either case, and the temperature is very different in the two cases. I can't understand why equipment qualification or whatever should be so different.

MR. LOBEL: Well, I can't answer what the basis for that limit is. Maybe the licensee can. But I'm sure it's based on --

CHAIRMAN WALLIS: Don't you set the acceptance limit?

MR. LOBEL: Pardon?

CHAIRMAN WALLIS: Doesn't the agency set the acceptance limits rather than the licensee?

MR. LOBEL: Well, we set the criteria, but no the licensee typically sets the value because it depends on the design of his containment and any equipment in his containment. So --

MR. SIEBER: Generally the EQ profile, you have a lot of electrical equipment in containment and each one has an EQ profile that it has been tested to.

MR. LOBEL: Right.

MR. SIEBER: So you look at the most restrictive of those, and that becomes the design acceptance form below which you must keep the containment response to a steamline break.

MR. LOBEL: It's a very conservative calculation. For instance, the staff guidance allows the licensee to take credit for what's called revaporization where some of the liquid that is condensed goes back into steam again and takes some energy out of the system. But Waterford didn't take credit for that.

DR. RANSOM: Are these results for LOCA a large break LOCA?

MR. LOBEL: Yes. That's typically limiting for containment.

MR. SIEBER: What's that, the LOCA? Steamline break?

MR. LOBEL: Well, for a LOCA, the large break LOCA is typically limiting for containment.

MR. SIEBER: That's right.

MR. ROSEN: The previous slide.

MR. SIEBER: Okay.

MR. LOBEL: In general, some licensee predict that the steamline break is a higher temperature and --

MR. SIEBER: Yes. I thought that generally the case, that there's more energy release from a steamline break than a LOCA.

MR. LOBEL: Yes.

CHAIRMAN WALLIS: Well, the SER is full of all kinds of transients that were analyzed. And there is nothing of interest in any of that, is that right? It's just these few that are the limiting ones that we worry about?

MR. LOBEL: For the containment, yes.

MR. SIEBER: It depends on who --

CHAIRMAN WALLIS: Well, for anything else. I mean, for any other criteria, all these other transients that are in the SER, that presumably you're not going to talk about, were not interesting because they never challenged any limits?

MR. LOBEL: Well, not containment limits.

DR. DENNING: Radiological. Some of them are radiological.

MR. LOBEL: This review concentrates on the structural capability of the containment.

CHAIRMAN WALLIS: Just on containment. All those other things that were in the SER that we're not going to discuss perhaps?

MR. LOBEL: Well, I think they're going to be discussed after I'm done. We have people here to discuss them. But it's not something I review.

CHAIRMAN WALLIS: Maybe they just summarize in a minute or two or something all these events. We're going to get to that next, are we?

MR. LOBEL: Yes.

CHAIRMAN WALLIS: Okay. So are you finished?

MR. LOBEL: I'm finished.

CHAIRMAN WALLIS: Thank you very much.

MR. KALYANAM: Next we have Sam Miranda from the Reactor Systems Branch.

CHAIRMAN WALLIS: We still have about half of your slides to go through, is that real? I'm just looking at the schedule and the mass of slides here.

MR. KALYANAM: And hopefully Sam will be able to skip quite a few of them.

CHAIRMAN WALLIS: Okay. Thank you.

MR. MIRANDA: My name is Sam Miranda. I work in the Reactor Systems Branch as a technical reviewer. And could I have the next slide, please?

Our review areas are listed in the following slides. They're based on Matrix 8 of the Review Standard-001.

Okay. At this point in general, I could summarize the review areas as those accidents or transients that are sensitive or effected by the power uprating or have been analyzed using different methods. In the case, the principle change in the non-LOCA accidents was the transition from CESEC to CENTS.

As part of our review we have also done an audit of several key analyses, a detailed review both in-house and at Westinghouse's offices in Connecticut. And we concentrated on these accidents for various reasons.

For example, the loss of feedwater analysis is a loss of heat sink event which would be effected by the power uprating.

The feedline break analysis is one of the more complicated non-LOCA events which requires a detailed model of the secondary side.

Steamline break analysis in this instance, we noticed that there was a change in the licensing basis for the steamline break. Besides using the CENTS code, there was -- the licensee was reporting a fuel failure for the inside containment steamline break with loss of offsite power and where they had not been doing so in the past in the FSAR.

Furthermore, this fuel failure was due to incipient centerline melting. And we discussed it with the licensee and they agreed that in the future that there would be fuel management and shutdown margin available to prevent centerline melting of fuel. However, they do predict two percent fuel failure due to clad damage.

We also looked at the small break LOCA and long term cooling, and Dr. Len Ward, my colleague, will discuss this in further detail after me.

MR. SIEBER: As far as long term cooling is concerned, it seemed to me that was where one of the shortfalls was, slightly. And the question is do you retain a coolable geometry for the long term?

MR. MIRANDA: I didn't get the first part of your question.

MR. SIEBER: Well, it seemed to me that one of the questions was the capability to do long term cooling. And my question is does Waterford retain coolable geometry for the long term period, which is 30 days plus?

DR. WARD: Yes. I'm Len Ward from the Reactor Systems Branch. I'm going to talk about that right after this discussion in about ten minutes.

MR. SIEBER: Okay. All right.

DR. WARD: And it's in regard to boric acid precipitation where you can block the entire core with boric acid.

MR. SIEBER: Okay.

MR. MIRANDA: Yes, we have a detailed discussion on that coming up.

These are some results of our calculations we did. We did the details reviews, we did the audits and Len Ward also did some independent calculations.

And this is a brief summary of those results. And he'll be going into this in further detail later.

As you can see, we have the fuel clad failure of 2 percent in the steamline break.

For the large feedline break, one of the concerns is RCS over pressurization. And the licensee predicts a peak pressure of 2753 psia and our staff calculations predict 2709 psia.

The next slide.

CHAIRMAN WALLIS: And that 3000 parenthesis, that's an acceptable?

MR. MIRANDA: That is the limit for this event, yes.

The loss of condenser vacuum, we also got good agreement between the submittal and our independent calculation, as well as the small LOCA. We were predicting within half a foot of core uncovery.

Next slide.

CHAIRMAN WALLIS: And that's okay to have the core -- the top half of the core uncovered for over 1,000 seconds is okay? Maybe I've forgotten this kind of thing, but it seems sort of surprising to me to have it uncovered for so long.

MR. MIRANDA: Yes. This morning there was a peak clad temperature reported for this break of

2018.

CHAIRMAN WALLIS: Right. That is presumably because it's climbing up steadily during all that time and it's dry.

MR. MIRANDA: These slides I'm going to go through very quickly. I have them in case anyone wants to ask questions or discuss them, but basically what these are are a checklist or a worksheet that I was using to be sure that all of the events were addressed. And for a power uprating submittal, not all the accidents really need to be reanalyzed. You have to look at the ones that are effected by the power uprating and the ones that are effected by changes in methodology. And there are a lot of accidents that are bounded by others. And you need to be careful about reviewing the ones that are bounded by others to be sure that you're comparing apples-and-apples, that the same criteria apply for these events. And that's where the ANSI Condition II, III and IV come in. And this is an expansion you might consider of Matrix 8 of the Review Standard where I'm looking at these events to be sure that claims of one accident bounding another really are valid.

So that's the rest of the slides.

CHAIRMAN WALLIS: Why do you need to

consider so many things? I mean, presumably very few of them turn out to be significant?

MR. MIRANDA: Exactly. And some of them -- many of them are not analyzed.

CHAIRMAN WALLIS: But you knew from previous experience before the uprate that many of them didn't come close to challenging the system.

MR. MIRANDA: Yes.

CHAIRMAN WALLIS: Yet you still have to go through it all again for a relatively small change in power?

MR. MIRANDA: Just to be sure that it was looked at, yes. And a lot of them, as you'll see, they're not even analyzed. They're bounded.

MR. SIEBER: Is that because of the way the Review Standard is written?

MR. MIRANDA: Yes. The Review Standard covers all of these, that's right.

MR. SIEBER: What's your opinion of the Review Standard the way it is right now easy to use, difficult to use, does it make more work for you, does it have a value added to it?

MR. MIRANDA: I have used it. I do think it has a value added. I think it's too long. But I use the parts that I find useful, and the parts that

I found useful were the Matrix 8.

And, frankly, I think the Review Standard should be used as a guide to revise the Standard Revenue Plan, which need revision anyway. So this is a good starting point for the revision, and we should rely mainly on the Standard Revenue Plan which should have provisions in each Standard Revenue Plan section to deal with situations such as upratings. If you're looking at uprating, consider decay heat, consider power level, consider so on.

MR. SIEBER: It seemed to me that it did allow the staff to produce pretty good SER. To me it's one of the best that I've seen.

MR. MIRANDA: Thank you.

If there are no more questions, I'd like to have Dr. Len Ward come up and discuss the independent calculations and the long term cooling.

DR. WARD: My name is Len Ward. I'm in the Reactor System Branch. And I just wanted to show you some calculations that I did, some audit calculations. The large feedline break. We looked at the limiting small break LOCA and I looked at post-LOCA long term cooling, and that's dealing with boric acid precipitation.

And we picked these because when you have increase in power like that, small breaks will uncover deeper, they'll be exposed longer, you're really taxing the ECCS. And this limiting small break I'm going to show you is controlled by the high pressure safety injection safety only, one HPSI pump.

Post-LOCA long term cooling is important because you're putting in borated water into a system that's boiling. You're building up boric acid. And once you reach the solubility limit, you'll get precipitation. So clearly what's CE/Westinghouse does is they would provide a guidance document to the EOPs to their customer, and they would recommend a time to switch to simultaneous hot and cold side injection. And that is initiated to control the boric acid and prevent it from building up. And I'll show you the results of some of some the calculations that we did and --

CHAIRMAN WALLIS: You're going to have a much higher concentration of boric acid, too?

DR. WARD: That's right. That's right. The source is higher, the power is higher. I'll get into it, but basically our calculations showed that -- I couldn't reproduce the results, and the reason was there was an error in it. But we fixed it and I'll get into the details later.

CHAIRMAN WALLIS: There was an error in your calculations?

DR. WARD: No. There was an error in their calculation.

CHAIRMAN WALLIS: Oh, okay.

DR. WARD: I was asked to speed this up, do you want me to jump to the small break LOCA and the boric acid --

CHAIRMAN WALLIS: Because yours may be one of the more interesting presentations.

DR. WARD: Okay. Let me ask the Chairman here, or the Committee, do you want me to talk about feedline break -- okay. I mean, it's up to you.

CHAIRMAN WALLIS: These are important.

DR. WARD: Okay. The large feedline break, basically I verified their peak pressure and to get to the bottom line here, they really overwhelmed this, they did it to death. They assumed the feedline break was at the bottom of the tube sheet so that they expelled all the liquid from the system in about 20 second due to break. Now clearly, you know, it's a boil off problem if you put the break up at the actual location. You're going to have a heat sink for a longer period of time and you're not going to probably use your heat sink while you're at full power. But I consider this analysis pretty much beat to death, and so I didn't want to emphasize this too long because I'd like to get to the small break because of Dr. Wallis' concerns.

But the staff calculation are the circles. And this is the cold leg pressure. And the I calculated a pressure within 50 pounds pressure. And basically what happens, as the next slide will show you, when you put the break at the bottom of the tube sheet, you basically drain the generator in about 20 seconds and so you degrade the heat transfer, you have full power. Because you don't have full heat transfer, the pressure goes up. And you hit -- the safety valve opens, you get a trip. And the pressure decreases and it slowly increases again later on because the other generator, because of the conservative assumption they made on aux feed, they really delayed that. You start to pressurize again a little bit at the end. But I was more focused on that initial pressure and wanted to confirm that peak pressure. Because this is an event that challenges the design pressure of the plant.

Now, I mentioned small break LOCA.

DR. DENNING: Len, did you all assume looking at water levels in the vessel and fuel failure?

DR. WARD: No, I didn't look at that. I'm just looking at the thermal-hydraulics. I'm looking at peak pressure. I didn't look at -- or anything like that. Well, I didn't get into that.

DR. DENNING: But this is the case, isn't it, where there's two percent clad failure?

DR. WARD: You know, I can't remember. No, I don't think so.

DR. DENNING: It's a different case?

DR. WARD: I don't think so.

MR. SICARD: This is Paul Sicard.

The feedwater line break is a pressurization event. It does not challenge the DNBR. There is no fuel failure for that event.

DR. RANSOM: Were these independent calculations or were they using methods that --

DR. WARD: And I'd better mention that I didn't have six months to set up RELAP5. We didn't have a Waterford plant deck. So I used a model that I had put together, that I had developed about 15 years ago. I'm going to document that calculation as part of this submittal that the staff will get. It's very similar to what you saw on AP1000. It's basically the same model, but I put drift flux in there. It's got--

and thermal dynamics. It solves a network, a nodalization network simultaneously for pressure and system flow rate, semi-implicit. The drift flux model has been benchmarked against a lot of the data that you've seen at low pressure as well at intermediate pressures. It's got all of the required Appendix K models in there; Henry-Fauske, critical flow. There's a pump coastdown model.

I could probably spend an easy hour describing it, but I would rather wait so that you could see -- you'll see the documentation on this later on when I document it. But you may have seen most of the model documented in the AP1000 submittal, the work that I did on that plant.

CHAIRMAN WALLIS: Why is there no credit for accumulator injection?

DR. WARD: That is a conservative assumption they made, and I'll show you. The primary system pressure for this break decreased below the SIT accutation pressure of about 580, but they didn't credit it for this break.

The most limiting small break -- when you have fairly low capacity HPSI pumps or HPSI pumps that are SI pumps that CE has, their classic 2700 megawatt plant Millstone/Calvert Cliffs, low capacity HPSI pumps, 200 pound accumulators. So because of that you get these long uncoveries. So this kind of uncovery transient that you're seeing is very typical of a CE type plant.

But I wanted to mention that that this calculation is still conservative. And there is no credit for the accumulator injection. If they took credit for that, you would have terminated the transient earlier and the P clad temperature a 100 to a couple hundred degrees lower.

Now remember, too, we're assuming the decay heat is 20 percent higher and there's a diesel failure, which means you're only taking credit for three-quarters of one high pressure pump.

The actual power distribution is TOC skewed. When you expose the core for a small break, you want to look at a shape with a peak in the top because that'll heat up the worse. And this shape happens to be -- it's not a shape that's going to set for decay heat. It's a shape that was chosen from a transient analysis that would be momentary. The actual decay heat shape will be less skewed because you've been operating, you know, for months with that kind of power shape.

So I just wanted to list some of the

conservatisms in the analysis.

If we look at the pressure transient for this break, this is an 0.055 square foot break at the bottom of the discharge leg, and that's about a three inch break. So it's pretty small.

When the break opens, the system depressurizes, you lose the subcooling and you'll establish a pressure plateau just over 1,000 pounds. And that's because the break is too small to continue to depressurize and so you have to rely on heat removal through the generator.

The secondary side is sitting at the relief valve setpoint. Actually, it's the ADV valve in this case, and this is a good thing that CE did. They qualified their ADVs to open at a lower pressure. And so what does that do? That lowers the system pressure from up here around 1200 down here, and that means during this 1200 second tier, you're going to get more injection into the system. So from a safety standpoint, that was a good thing to do.

Now this is an Appendix K calculation, of course, so there's 20 percent more decay heat.

This primary system is a giant U tube. And the break in the cold leg, the fluid levels drained down to the elevation of the break critical flow of liquid going out of the system. Now once the level drops down below the bottom of the cold leg, you're going to get steam out. And so for the remainder of the transient, it's a simple boiling pot. You've got a head of water supporting a two phase mixture on the core lower plenum side. And because of the steaming rate going out the break, that that flow is greater than the steaming rate in the core it depressurizes. But at these higher pressures, the high pressure pump cannot match boil off. So I'll show you the level. The level is decreasing. And it's a race so the pressure falls low enough so that the high pressure injection can now match the decay heat boil off and then the level will recover again.

And you can see the pressure. Small break is a pretty simple transient. It's just a hydrostatic fluid balance. The only mass in the system for the majority of this event from 600 seconds out to an hour is in the downcomer and in the core and lower plenum. And to get steam elsewhere in the system, there's no spacial variation in pressure. It's probably a tenth of a psi pressure difference between the upper plenum and the core. So you don't need a lot of cells to model that. And that's why with the calculation I did, it's basically got two volumes in the primary system. But I have a drift flux model to calculate the level swell.

And that's probably the single most important parameter that one --

CHAIRMAN WALLIS: What does it matter because if the top's dry, who cares what's happening to the swelling below it?

DR. WARD: Well, I mean that's the point, though. But you want to calculate the amount of liquid mass that's in the core. You're voiding the core --

CHAIRMAN WALLIS: What I'm worried about, though, that dotted line at the top which says top of the core.

DR. WARD: Right, right here.

CHAIRMAN WALLIS: It's exposed for 1500 or 2000 seconds or something.

DR. WARD: Right. And I guess, that's from--

CHAIRMAN WALLIS: That's the worse.

DR. WARD: When you look at that, that's kind of alarming, isn't it?

CHAIRMAN WALLIS: It is. Yes.

DR. WARD: But let's look at the reason why that is. We've got 20 percent more decay heat than is actually there. If you decrease the power by 20 percent, that's just like increasing the capacity of the high pressure pump by the same pump.

If you increase the flow rate from the pump by 20 percent of a 12 and a half foot core, you're going to increase that level by another two and a half feet. It's going to be up here. And the temperature is going to drop by 500 degrees.

Now, the accumulator came on right about here, but they didn't credit it. And that would have jumped the level up anyway. And they could have credited that and we have accepted it. But they wanted to make this conservative because you want to show the most limiting small break in this range is the one when the system depressurized on that previous plot, the primary system pressure hangs up just above the accumulator pressure. So the only thing that's controlling this break is HPSI flow, and at about this point here the system has depressurized enough. So three quarters of one high pressure pump is now exceeding the boil off and it's slowing filling back up.

So now there is two-phase nucleate boiling in the bottom. And as long as the plant's tripped, that's okay. The clad temperature is probably within ten degrees of the sink temperature. But up here now we've got steam in this part.

CHAIRMAN WALLIS: That's 40 minutes for that time for when it's exposed?

DR. WARD: It's exposed for -- yes, the peak is probably somewhere right about here.

CHAIRMAN WALLIS: Yes. But TMI --

DR. WARD: TMI drained completely.

CHAIRMAN WALLIS: -- was destroyed long before 40 minutes.

DR. WARD: Yes. If this two-phase level drops probably another foot, half a foot, it's going to go over 2200 degrees. I mean with Appendix K assumptions, they're probably at the limit -- they probably can't drop that level too much more, like a half a foot.

CHAIRMAN WALLIS: It's the fact that the top's dry that --

DR. WARD: This is steam cooling now. You can cool a rod with steam.

MR. SIEBER: It's not dry.

CHAIRMAN WALLIS: But you could drop the level to zero, you still haven't changed what you're doing to the top of the core.

DR. WARD: Then you're not producing any

-- there's no boil off. There's no steam flow. It'll heat up very -- it'll melt.

CHAIRMAN WALLIS: Okay.

DR. WARD: So we're taking credit -- you have --

CHAIRMAN WALLIS: So you need the depth to make the steam.

DR. WARD: Right. If the two-phase level is at the top, you're boiling at a 100 pounds per second of this thing. If it's down here just above the middle, it's about 60 pounds per second. Okay.

CHAIRMAN WALLIS: Okay.

DR. WARD: And so 60 pounds per second of steam flowing up the top of that rod is enough. The heat transfer coefficient is about 25 BTUs per hour per square foot per degree F. And that includes convection and radiation. The THTF test down at Oak Ridge shows that thermal radiation to steam represents about 20 to 30 percent of the heat transfer. So it's pretty significant.

If they didn't credit that, the temperature would be over 2200 degrees. But they benchmarked against the G2 bundle uncovery data and all the THTF data, we reviewed that. And they did a good job.

I mean, so this core is uncovered for this long, this is not best estimate. If this was a best estimate CSAU calculation, I'd have a lot of heartburn with this because I don't think they can calculate the two-phase level over that period of time within a half of foot out of 12 feet. But this has one HPSI pump, three quarters of one pump, it's got 20 percent more decay heat and they are also the steam super heats right at the two-phase surface. And if you look at G@ data and THTF, it really doesn't super heat for about six inches to a foot because you've got this froth and it's throwing bubbles and it's closer to Tsat there. So they don't credit that.

So, yes, it's a little alarming to see something like this, but remember it's Appendix K. If they made all best estimate assumptions and they only had one HPSI pump, the two-phase level would be somewhere up here. Temperatures would probably be around 1500.

So I guess what I'm saying is, yes, there's still margin there. You're getting this response because of the conservatism in Appendix K, and there's that margin.

MR. SIEBER: It goes beyond that. It's self imposed conservatism --

DR. WARD: Well, plus the accumulator, that's right, because that would even lower further.

MR. SIEBER: Right.

DR. WARD: They could take credit for accumulator injection.

MR. SIEBER: Right.

DR. WARD: Because for that break size and larger ones, accumulators are coming on. And the accumulators are overwhelming the system. And the accumulators are there not for large breaks, but for small breaks, probably more so I would say. It keeps the small breaks really low temperatures. Okay. So accumulators are a good thing. They're your friend. But they didn't credit it.

So that in itself, you know, I can say -- I can stand up here and say it's a conservative calculation. You know, it's alarming to see a core exposed like that for a three inch break but it's that way for a reason and it's prescribed in the law. And they have met that.

The next thing I looked at was the post-LOCA long term cooling. And when I did that I couldn't reproduce their results. And it turned out that when I assumed -- now the mixing volume for mixing boric acid in their model with the core and the upper plenum below the elevation of the bottom of the hot leg. And when I assumed that that was true liquid, I matched their result. Let me show what I'm talking about here, maybe if I could illustrate it.

MR. ROSEN: It would be better right side.

DR. WARD: Their mixing volume is basically the core region and the fluid level up to the bottom of the cold leg. They're about the same, they're off set by half a foot, but it's right there.

What they assumed -- I calculated a void fraction of 35 percent average at about three hours. I put that in, and I precipitated it about an hour. They're getting about four hours. So this initiated some discussion with the vendors --

CHAIRMAN WALLIS: Yours sounds worse. Yours sounds worse.

DR. WARD: Yes. I calculated an hour. They corrected their model and put in 35 percent void fraction and got basically the same thing. Let me show you what that looks like.

Now this is the calculation I did --

CHAIRMAN WALLIS: They have one where it turns around.

DR. WARD: Right. Well, I'll show you that in a minute. Well, I'll get to that second, but let me go through this first.

This is just pumping in borated water and it's building up. And when you do that, they calculated, you know, over four hours. And this is my calculation but it also reproduced theirs. But this is with the error. If you assumed the void fraction is 35 percent liquid, this is a steam void, then it precipitated in an hour.

CHAIRMAN WALLIS: So what appears in the documentation that we saw --

DR. WARD: You see this curve right here and then you see between three and four --

CHAIRMAN WALLIS: It's the wrong curve?

DR. WARD: Yes, it's the wrong curve. Between three and four hours they initiate hot and cold side injection, so when that happens -- all you need to do is inject in excess of the boil off at about 25 GPM you will -- you'll turn it over and it will -- with their high pressure injection pump, it was asymptotically reach a value somewhere down --

CHAIRMAN WALLIS: Now you're saying they have to do this before an hour instead of the four hours?

DR. WARD: No. You can't switch before two hours because --

CHAIRMAN WALLIS: So --

CHAIRMAN WALLIS: Because when you split half the injection between the hot and cold side, at that point if you switch any earlier than two hours, you'll uncover the core, you can't match the steam rate.

CHAIRMAN WALLIS: So you're saying you're going to plug up the core?

DR. WARD: Well, no. I'm just saying that they need -- you know --

MR. SIEBER: They're overheat.

DR. WARD: What'll happen is if you precipitate, yes, it'll block the core. I'm not going to guess what's going to happen, but you'll fill the core up with boric acid salt and it will block the core. And then it will heat up and something else will happen. So it's a long term cooling -- that's why you don't -- that's why you want to switch to simultaneous injection at some time enough earlier so that you can control it.

CHAIRMAN WALLIS: Can you do it with the real mixing volume?

DR. WARD: No, you can't do it this way. They assume the pressure in the upper plenum is 14.7 which is basically the containment pressure. And with that volume, it won't work. So what I had done is some calculations to look what I would call basically an envelop of where they need to be in for us to be -- for this to work.

And so what I did -- but what I did, I did a calculation where I calculated the mixing volume. Now the mixing volume will grow with time. It'll start off in the core, this is a large break LOCA, and it will grow as the steaming rate drops and the loop pressure drops. You'll get more and more two-phase in the system.

What I did is I calculated a two-phase mixing volume that includes the core and the upper plenum. And as it grew, I took credit for that increase in the mixing volume until it got up to within about a half foot of the hot leg and then I didn't let it get any bigger because the steam that's disengaging the two-phase surface and collecting in the upper head, it's got to go somewhere. Where is it going to go? It's going to go out the hot leg, so that defines a pressure to drive steam around the loop and it won't let the two-phase go any higher. So I held it at that point.

And even if I did that, if I assumed 14.7 in the upper, I'm still precipitating at about an hour. It didn't help very much. But if you assume now that your upper plenum pressure is 20 pounds pressure, which is what CD has done; they have changed from 14.7 to a 20 psi limit, and they are using a mixing volume that is no greater than to a region near the top of the hot -- if you do that now, you will precipitate at somewhere in the neighborhood of near four hours. So if they switch to simultaneous injection in the two to three hour time frame, you know, this envelop suggests they're okay.

Now, they just finished doing these calculations in the last week and I haven't seen them, but I talked to them on the phone. They're in the envelop.

One of the things that we're going to have to do is review -- they're going to submit their containment analysis. They used GOTHIC. It's a licensed methodology, too, and they ran it in a minimum containment pressure mode where they maximize the heat transfer on the surfaces, maximized -- made all the assumptions pertinent to minimizing the pressure. And they calculated at 4 hours 21 psia, right? So, you know, I eager await that calculation to take a look at it. And they're also going to document their boric acid calculations that they did that's consistent with my values at 20 pounds.

So the bottom line is they had to make some -- they corrected the error. There is still margin remaining to support this power uprate.

And I wanted to mention some of the other things that would show that this is still conservative.

The two-phase level is up into the -- it's up into the hot leg region to the top of the hot leg. I mean, the two-phase level after about two hours is up in this region here. And there's a large volume there. And that's not considered. They were able to show the four hour precipitation limit with that without crediting the hot legs. And I think the hot legs are going to increase the mixing volume. That's about another couple hundred cubic feet.

The other thing is this is a large break LOCA. The steam that's coming off the core is in entraining liquid and it's throwing out in the hot legs in the generator. So it's removing liquid with boric acid in it, so it's not really concentrating, at least it's not going to concentrate at that level.

So did I show that? So anyway, I guess --

CHAIRMAN WALLIS: So if they had somehow vented the containment and hadn't gotten this pressure, then they would plug up the core?

DR. WARD: Then you let the containment door open and you stayed 14.7, I guess you'd have a problem.

MR. SIEBER: Nothing would come out.

DR. WARD: You know, I mean, containment doors don't open that readily, so --

CHAIRMAN WALLIS: Where did this 20 psia number come from?

DR. WARD: They did it. It was a calculation that I had done that showed that it works. They did a GOTHIC minimum containment pressure calculation to show that they can justify 20 psi with that. And that's a licensed methodology run to minimize containment pressure, maximize condensation on the walls, maximize energy removal, I think. Well, all four --

CHAIRMAN WALLIS: Sounds like NPSH all over again.

DR. WARD: Well, it does, doesn't it. It's--

CHAIRMAN WALLIS: Well, this is interesting. I'm very glad that you did some independent calculations which lead you to find an error, and then that you cleaned up the mess created by the error.

DR. WARD: Right.

CHAIRMAN WALLIS: Helped to.

DR. WARD: And I think, you know --

CHAIRMAN WALLIS: Then the end of the story seems to be happy, we think.

DR. WARD: Right. I couldn't say it any better. And I guess we --

CHAIRMAN WALLIS: How many other calculations you need to do independently.

DR. WARD: Excuse me.

CHAIRMAN WALLIS: How did you know to do this one?

DR. WARD: Well, you know, I just -- you know, you pick one.

CHAIRMAN WALLIS: Yes.

DR. WARD: The plant power levels going up--

CHAIRMAN WALLIS: You picked one which was important.

DR. WARD: Yes. I mean, there's 8 eight percent power increase. I mean, you're going to build up boric acid a lot faster, the sources are higher concentration. I mean, you're going to get there quicker.

And I consider this is important because this phenomenon is consistent with any break size in the cold leg where the system will not refill, so it boils. If you -- if the break size is small enough and eventually the high pressure injection system or the ECC fills the system, you'll disperse the boric system throughout the system. But this a break size probably down in the neighborhood of two-tenths of a square foot or larger where they never refill. And so all you need is a break. I can't have as many HPSI pump-- the full -- that's all. You're going to be in this region.

So it's important that the guidance that CE gives -- excuse me. Westinghouse gives their customer is a switch time to assure: (1) when they switch you've got enough injection so the core won't uncover but it's early enough so that you can control the boric acid. And that's important. That's why I wanted to look at this calculation.

MR. SIEBER: Let me ask a question about that from an operator's viewpoint. The time that you're predicting there, really depends on the way you do your calculation and the assumptions that you make.

DR. WARD: That's right.

MR. SIEBER: Now the operator isn't going to sit there looking at his watch saying no, it's going to be time in 15 minutes to switch my injection mode. He has to look at other parameters. What does he look at to tell when it's the right time to make that change?

DR. WARD: Well, he has that -- and it's a large break, he has no other indication except a time. And he's got to adhere to that. Hopefully, there's usually one hour or more for him to do that. They would be told at -- if they're told to switch to simultaneous injection at 2½ hours, no later than 3½ hours, that two hours the guidance will say prepare to line up the system because as early as but no later than X you will be in simultaneous injection. And my experience at Northeast Utilities when I was working with the SRO there when we were modifying the procedure, those guys follow it exactly.

MR. SIEBER: I know.

DR. WARD: This is a LOCA. In post TMI days, now that was my experience at Northeast, that this SRO is real sensitive to what that procedure says. And he's not going to touch those pumps and he's going to do whatever it says. And he's going to do when it says it.

MR. SIEBER: Yes, there's no doubt that

the operator 99 percent of the time will do what he's told to do.

DR. WARD: Right.

CHAIRMAN WALLIS: On the other hand, it's not clear to me that what the analysis tells him to do is going to match to the way the plant's responding at a given time because of all these conservatisms and assumptions and everything that are built into this. And I'm having a little difficulty reconciling all of that to what does the operator really do.

DR. WARD: Okay. Well, assuming he follows his procedure, what -- within this envelop if he follows it, if he was late by half an hour or an hour, my gut feeling is -- I haven't done any entrainment calculations, I haven't included the mixing in the hot legs.

MR. SIEBER: Right.

DR. WARD: You know, we were trying to get there so we could have this meeting.

CHAIRMAN WALLIS: You ought to put in some uncertainties and you ought to show what's the spread of likely results.

DR. WARD: Okay. Well --

CHAIRMAN WALLIS: And suppose he that he injects at a time --

DR. WARD: There's 20 percent more decay heat to secure, so if you get rid of that, it's going to give you another 30 minutes. If you take credit for entrainment, my guess is -- now that's going to move it out at least another half an hour. I mean, I can't speak -- I haven't done that calculation, but --

MR. SIEBER: He's probably hoping for shift change.

DR. WARD: Yes.

MR. SIEBER: Let the other guy do that.

DR. WARD: Well, I don't want to go there. But, I mean, there is conservatisms in this, too. There isn't as much as there was before.

CHAIRMAN WALLIS: This is going to be resolved unequivocally by the time of the full Committee meeting?

DR. WARD: They have committed to document everything they have done.

CHAIRMAN WALLIS: Is that going to resolve everything unequivocally?

MR. SIEBER: Well, but this isn't unique to the EPU condition, right? This will occur in any plant that does this configuration?

DR. WARD: Well, that --

CHAIRMAN WALLIS: There will be a lot more boric acid now.

DR. WARD: We're getting ready to send a letter out. We're going to mention that we found a nonconservatism in a vendor's model, please review your long term cooling analysis and, you know, show us that your model remains acceptable.

CHAIRMAN WALLIS: But this is work in process?

DR. WARD: Right now.

CHAIRMAN WALLIS: Less than three weeks before the meeting, or two weeks before?

DR. WARD: Well, their calculations are done. They haven't documented them yet. And I'm expecting to get them -- well, hopefully before the SER goes out. I mean, there will be a reference. The project manager can address that.

MR. KALYANAM: Before February 2.

MR. SIEBER: Can you hear that? You need to talk into a microphone somewhere.

MR. KALYANAM: Okay.

MR. SIEBER: Pick one. You can talk into his tie, if you want to.

MR. KALYANAM: I was saying that we have the next meeting here on -- the full meeting on February 10th. Before that we would -- unless these calculations will be dockets.

CHAIRMAN WALLIS: Okay. So there's no uncertainty in management decisions. There may be in engineering, but there's never uncertainty in management decisions.

MR. KALYANAM: I think we work in unison.

DR. WARD: Thank you.

DR. RANSOM: I think it's very good to see calculations like this. The only difficult I guess I have with it, it's not TRACE, it's not TRAC, it's not RELAP5, but yet another methodology that presumably has not been benchmarked and --

DR. WARD: Well, it has. I've benchmarked it against LOFT, Semiscale, SO-710D is a Semiscale test that has a long term core recovery.

MR. BROWN: Well, the point is I don't believe you've documented that and --

DR. WARD: Well, you haven't seen it, but I'm going to give it to you. I mean, there's only so much I can do in a month, you know. If I could break into three people --

MR. BROWN: Why are we developing TRACE when you can do this?

DR. WARD: Well, we didn't have a plant -- we did not have a Waterford -- we don't have plant decks for every plant, so we got to do the best we can. The best I could do is I have a methodology that I -- I mean, I did hand calculations, too, to verify minimum levels and peak pressures, but I wanted to see the transient. And if I've matched separate effects data for two-phase level swell over a full range of pressures and heat up data, I'm going to run that. In lieu of doing nothing, I think what I have done verifies their analyses. I've predicted the break spectrum with that code for Millstone running a .5 square foot, .2 square foot, .05 -- I mean, a small break is something easy to model. It's a boiling pot.

You don't even need to do a momentum balance. And you can take the liquid mass, balance them hydrostatically, off set the fluid levels by the steam flow, which is decay heat in the loop, and you're going to get the same thing that TRAC or RELAP gets, only I'm going to get it in 15 seconds and I'm not going to wait for five hours for the answer. And I can run maybe 15 or 20 of these.

DR. RANSOM: Well, is the NRC going to make this a part of their inventory of codes to use and methods?

DR. WARD: Well, no. We haven't talked about that. But anybody that, you know, in the branch that wants to use the code, you know I will show them how to use it.

DR. RANSOM: That's the only problem I have with it, is --

CHAIRMAN WALLIS: Well, Vic, this isn't going to be licensed based on his calculations.

MR. BROWN: No, I understand that. But you use it as an audit.

DR. WARD: I mean, my calculation gave me enough comfort it says that limiting 055 square foot break, I didn't feel comfortable. When I saw that, I was going like whoa.

CHAIRMAN WALLIS: It's not a code, is it? It's just a one node --

DR. WARD: Well, no, it's three volumes. There's one on the hot side, there's one on the cold side, there's a pressurizer that's not equilibrium because of that over pressurization event. I compare it against the MIT pressurization tests that Pete Griffith did very nicely. A whole slew of level swell tests.

I mean, the most important parameter for a small break to govern, to judge its performance is two-phase level swell. And there isn't a level swell test out there that I haven't run. And I have run --

CHAIRMAN WALLIS: Now when you get more and more boron in there, doesn't the drift flux change?

DR. WARD: Good question. I guess the density changes.

CHAIRMAN WALLIS: Well, the interfacial properties change when you got all this gop in there.

DR. WARD: That's right. I didn't --

CHAIRMAN WALLIS: It concentrates at the interfaces, it changes whether or --

DR. WARD: You're right.

CHAIRMAN WALLIS: -- not the bubbles are glommery. And I think the drift flux is going to change as you get more and more boron concentrating. Do we have any basis for knowing what it is?

DR. WARD: I have not done that calculation. And that is a good --

CHAIRMAN WALLIS: I would think it would froth up more as you --

DR. WARD: I think it would tend to retard the steam velocity and it would froth it up. It would swell more even in this small break --

CHAIRMAN WALLIS: Are there those studies of level swell with concentrated boron --

DR. WARD: I've seen none in that area.

I mean, I'd like to see.

CHAIRMAN WALLIS: There should be.

DR. WARD: I haven't seen any tests that says here's the mixing volume. Those don't even exist.

CHAIRMAN WALLIS: Yes. But you're assuming you could take a drift flux correlation for pure water and apply it to boric acid, which is almost on the point of precipitating?

DR. WARD: Well --

CHAIRMAN WALLIS: It's like taking --

DR. WARD: That's a good question.

CHAIRMAN WALLIS: It's like taking your first correlation for boiling water and applying it to boiling milk. And you know what happens when you boil one or the other.

DR. WARD: Yes. Yes.

Well, if this saving grace, there's Appendix -- there are conservatisms in there that say, you know, I believe it's in the envelop but I have not done that calculation with boric acid in there.

CHAIRMAN WALLIS: I don't think you can believe anything about boric acid unless you --

DR. WARD: I mean what test data would I compare it to?

CHAIRMAN WALLIS: You have to have a test.

DR. WARD: Right. I mean, you have a good point. I mean, I didn't think of that. I guess that's one of the good things about standing up here and talking with you, too. You get some good input, right?

CHAIRMAN WALLIS: And how long does it take to resolve something like that?

DR. WARD: Gee, I don't know. I mean --

MR. ROSEN: Oh, probably a year or two.

DR. WARD: I mean, I'd like to see some test data on what is the mixing volume? What does it look like? What does the debris from the sump do when it's in there? I don't know what that --

CHAIRMAN WALLIS: There's probably more mixing in the lower plenum than they assume.

DR. WARD: No mixing in the lower plenum.

CHAIRMAN WALLIS: There probably is.

DR. WARD: I think there is.

CHAIRMAN WALLIS: Because at psi 184 it's a completely --

DR. WARD: Right. I think it will mix down there, because it's heavy, it's going to drain --

CHAIRMAN WALLIS: Well, you've also got jets coming in through the colander. You got a colander down there? Maybe not in this design.

DR. WARD: That's right. Well, there's a -- there's a flow skirt. But, yes, there's a big lower head. There's about ten, fifteen feet in the lower plenum.

CHAIRMAN WALLIS: Well, there's some jets of liquid coming in. It's not just a big --

DR. WARD: Yes, it's coming -- no.

CHAIRMAN WALLIS: It goes through something like --

DR. WARD: It goes through a flow skirt and then it's directed upward into the core. But your --

CHAIRMAN WALLIS: You have a problem I think though with drift flux through a concentrated boric acid mixture. Maybe it throws it up more, which would be better, wouldn't it?

DR. WARD: Yes. I think it would swell up faster and it would mix it out into the hot legs and--

CHAIRMAN WALLIS: And it might actually carry over more, which would be worse.

DR. WARD: Could be. And the entrainment, don't forget there's an entrainment mechanism, too, that's throwing liquid out in the hot legs even before the two-phase level gets up there. So it's not really going to concentrate in my opinion in the first hour because if you look at the reflood test, for every pound of steam exiting the core, there's two to three pounds of liquid flying out of there. And I assume that that all stayed in the core.

CHAIRMAN WALLIS: Well, what shall we do with this? When you have -- you have to have a drift flux to get the swell here.

DR. WARD: Right. Right.

CHAIRMAN WALLIS: And that's very important for cooling core.

DR. WARD: Well, in this case --

CHAIRMAN WALLIS: It's not so important for the boron concentration, because you're just pulling it off.

DR. WARD: Provided the two-phase -- I don't -- it's going to be a cooling problem if the two-phase level drops back into the core.

CHAIRMAN WALLIS: But if the two-phase level rises, then you're boiling it off faster and you're concentrating faster. You have more heat transfer. It rises, it covers more of the core. You get more boiling.

DR. WARD: That's right. That's right.

CHAIRMAN WALLIS: And so it will

concentrate faster?

DR. WARD: You're right, it'll concentrate a little faster provided there's no such thing as entrainment.

CHAIRMAN WALLIS: I'm quite sure you'll resolve this issue.

DR. DENNING: Graham, I would agree. I mean, I think that it's really very interesting work. I'd be curious whether the applicant has a comment at this point. But how do we go forward with this issue as it currently stands? You know, it's just too up in the air.

DR. WARD: Well, we plan, as I mentioned, we're going to issue a letter shortly and we're going to ask them to re-review -- to look at this model and tell us -- you know, demonstrate that your model --it remains applicable. And there will be a laundry list of other things that will be addressed.

CHAIRMAN WALLIS: Someone going to respond to this drift flux question?

DR. WARD: Well, that's another question on the list.

CHAIRMAN WALLIS: But we know that putting contaminants in water easily changes the drift flux.

DR. WARD: Yes. I haven't looked at that, to be honest with you. I have not done that.

MR. ROSEN: When did you plan to come back to the full Committee? I mean --

MR. CARUSO: Two weeks.

MR. ROSEN: That's what I thought.

CHAIRMAN WALLIS: And the management has stated everything is going to be resolved.

MR. ROSEN: Two weeks is hardly time for us to finish up our business here, go home, change clothes and come back.

CHAIRMAN WALLIS: Well, we can write a letter which says you got to resolve this issue.

MR. SIEBER: Well, this issue is not Waterford EPU specific.

DR. WARD: Yes, it's not specific to it.

MR. ROSEN: It also applies to Waterford.

DR. WARD: Well, it does.

MR. SIEBER: That's right.

MR. ROSEN: And we're asked to --

MR. SIEBER: And we have a couple of those.

MR. ROSEN: -- recommend a license change --

MR. SIEBER: We got two of those now. We got the instrument issue, too.

MR. ROSEN: We got the what?

MR. SIEBER: Instrument issue, too, that needs to be resolved and they're both industry wide.

CHAIRMAN WALLIS: Well, I think this is a case history of where the staff by actually doing its own analysis begins to review features which it wouldn't review if it just reviewed what someone else has done.

MR. SIEBER: That's right.

CHAIRMAN WALLIS: And it indicates how important it is to do this sort of thing.

MR. HOLMAN: This is Jerry Holman from Waterford 3.

We've talked with Len quite a bit about these issues. We agree he's got some good concerns and things that we need to look at. Overall, however, we believe there are still some remaining conservatisms in the calculations to show that we're still conservative with the power uprate.

You are correct that this is not just a Waterford 3 power uprate issue, it's more a generic issue that applies to all the plants. And we'll be looking forward to finally resolving this in a generic basis and approving the model.

CHAIRMAN WALLIS: What concerns me is that this may be fairly long discussion. If we get into satisfying ourselves that this issue is resolved, it may take an hour or two. We can't do that at a full Committee meeting. We have to have another Subcommittee meeting. We can't take the full Committee through all the details of something like this. There isn't time to do that.

DR. WARD: No. Maybe you could take the approach that if you look -- although there are some weaknesses, and we recognize that there are other weaknesses in this method. But if you look at the model collectively, are there enough overwhelming assumptions that would ease your conscious a little bit. And that's where I'm at. But, you know, you mentioned the effect on drift velocity, and that's something that I want to look at. Because now you've spiked my interest in it.

CHAIRMAN WALLIS: Well, you could do interesting tests. You could two vertical tubes, you could put distilled water in one, you can put boric acid about to precipitate in the other --

DR. WARD: And see what it does.

CHAIRMAN WALLIS: -- and bubble or boil, whatever.

DR. WARD: Right.

CHAIRMAN WALLIS: One may go way up here and one may just go up there.

DR. WARD: Yes.

CHAIRMAN WALLIS: Then you can say --

DR. WARD: Right.

CHAIRMAN WALLIS: -- there's obviously a big change or there isn't. But that takes time. You can't just do that overnight. Maybe you need a rest, so you can do it over night.

DR. WARD: It's something to consider, certainly.

DR. DENNING: So where are we, Graham?

CHAIRMAN WALLIS: I'm not convinced. I'm just waiting for -- I don't know what they're going to do. Something is going to happen between now and the full Committee --

DR. WARD: Well, they're going to document their calculations.

CHAIRMAN WALLIS: Well, how do we know? We don't want to go to the full Committee meeting with something which is half baked.

DR. WARD: Well, maybe there's something that--

MR. HOLMAN: This is Jerry Holman again from Waterford.

As Len showed and pointed out, there are some remaining significant conservatisms in the model, namely the entrainment, the mixing volume, those types of things that we believe shows there's still margins available for this issue.

MR. SIEBER: I think the difficulty you have is that we're faced with recommending the acceptance of the SER that the staff wrote, and in the next two weeks they're not going to revise that SER. So I'm not sure what it is we're going to do in two weeks.

I think the work that's been done has been very good. I just don't think that you can finish in time.

DR. WARD: Yes, I don't think I could address that one.

MR. SIEBER: So, we have to decide what we're going to do next.

CHAIRMAN WALLIS: Well, ideally, we'd like to give you more time to get the story together.

MR. SIEBER: Yes.

CHAIRMAN WALLIS: And say that we don't want to come to the full Committee until everything is up and done, in which case we have to put it off for a month or something. And we're already putting off things and we have nothing to do in February if we put this off, too. That's okay, I suppose. We go home earlier. There is a real question about whether or not you should bring something like this to the full Committee.

DR. WARD: Well, maybe there's some sensitive -- there's some calculations that I can do to show the sensitivity to it and maybe if it shows that you need to get out into the time where it's after you had switched to simultaneous injection where it becomes important, that it would help alleviate the concerns somewhat. But, you know, that's an approach. I mean, I can do -- obviously, I'm not going to do any tests, but we can do some calculations. And I can get together with Westinghouse and maybe do a literature search and take a close look at it and see what's out there and see what we can do. I mean, there's a lot of stuff in the chemical industry that might be useful that, you know, I haven't tried to look into.

MR. SIEBER: On the other hand, if we all rush to get done, the chances of making an error or overlooking something becomes greater. And I don't want to be in that situation.

CHAIRMAN WALLIS: Well, maybe you should do an independent study of some of the other things.

MR. ROSEN: Especially some things that are coming up in the near term.

CHAIRMAN WALLIS: No, I mean some other aspects of this application.

MR. ROSEN: Oh. Yes.

DR. WARD: Okay.

CHAIRMAN WALLIS: We're going to move on the rest of the presentation and we're going decide what to do with this one.

MR. SIEBER: Thank you.

CHAIRMAN WALLIS: Let's hear the rest of what the staff has to say.

Do we need a break or not? Can we last? We're going to be behind, but do we keep going? Shall we try keeping going and see where we get? Just take breaks as you have to, okay?

MR. KALYANAM: Michelle Hart from our Containment and Accident Dose Assessment Section.

MR. SIEBER: You have to talk to the microphone.

MR. KALYANAM: Okay. The next speaker is Michelle Hart from our Accident Dose Assessment.

MS. HART: Hi. I'm Michelle Hart. I'm in the Probabilistic Dose Assessment Branch. I did the design-basis accident dose analysis review.

The regulatory requirements for this plant, because they are not an alternative source term for the EPU when they first submitted it, we looked at then versus 10 CFR Part 100 and GDC-19. And the review was conducted in accordance with the applicable SRP sections as noted in Matrix 9 of the Review Standard.

The licensee's analyses followed all applicable guidance. Any differences were justified and found acceptable by the staff. And we did perform confirmatory dose analyses, although the acceptance is based on their analyses.

The design-basis accidents that were evaluated for radiological analyses are the following on this slide. It's the Chapter 15 type design-basis accident analyses. And there is one draft SE open item, it is the control room habitability. Why that was an open item is when they originally submitted the EPU control room dose analyses in their original submittal, they only looked at the LOCA and the fuel handling accident and compared it to GDC-19 for whole body and thyroid. And they noted that the unfiltered inleakage assumption for the control room was not based on testing, but they would be doing testing and they would update it as necessary.

When they came back with the tracer gas test results, the analyses in the original submittal did not bound the results. So they decided to submit a separate full scope alternate source term application. They did this in July of last year. And it's been supplemented through October of this past year as well.

All of the control room dose analyses in the AST were for all of the accidents in the Chapter 16, not just the LOCA and the fuel handling accident, included all of them. And it supplants all of those -- the only two that were in the EPU, which were the LOCA and the fuel handling accident. And so that the control room unfiltered inleakage assumptions bound -- that would bound the tracer gas testing.

And the ASTU review is currently undergoing. I have finished most of the review and it is scheduled for completion by the end of March. Actually, by the middle of March. And I don't see any technical issues at this time that would prevent its approval.

DR. KRESS: Are you reviewing the chi over Q values?

MS. HART: Another person in our branch is reviewing those. They did have new chi over Q values for the control room, and those have been reviewed, yes.

DR. KRESS: And they look like they're okay for that --

MS. HART: They look like they're okay. There is the ABV release point, which was not looked at previously in their current FSAR because they only looked at the fuel handling accident and the LOCA, and that was not a release point. Those ADVs are r close to the control room intake. We have evaluated that and determined that the valve, even though it's very high, is reasonable and they take care of that by selecting a more favorable intake at two hours into the accident, for most cases.

DR. KRESS: You have a special code you use for those that takes care of the building wakes and the close in?

MS. HART: ARCON 96 is the control room code that is used. And it does take account of building wakes. It is not -- the models break down under ten meters. It was not benchmarked under ten meters, the distance between the intake and the release point.

DR. KRESS: Okay. And these were closer than ten meters?

MS. HART: There is one release point that is, yes.

DR. KRESS: But the alternate release point is a little further?

MS. HART: That is correct. That is correct.

CHAIRMAN WALLIS: Well, this is going to be resolved by March the 10th.

DR. KRESS: I think she said it's already --

MS. HART: Yes. The alternative source term amendment is under review right now. It's a separate amendment. It includes offsite and onsite control room.

CHAIRMAN WALLIS: So the approval by February 10th should be contingent upon this working out okay?

MS. HART: Yes. The EPU is not found acceptable with respect to term habitability with the current information in the EPU submittal itself. In that the EPU would not be able to be implemented until the AST is also implemented.

DR. KRESS: The site dose calculation uses the worst two hours?

MS. HART: That's correct. The offsite.

DR. KRESS: Does the control room do that also?

MS. HART: No. The control room is for the 30 day extent of the accident, or if it's a shorter accident for the shorter time period. So it's the entire duration.

DR. KRESS: It's the entire duration?

MS. HART: Right.

Next slide.

The exclusionary boundary and low population zone doses with the EPU submittal comparing it to the 10 CFR Part 100 does meet that dose criteria and all of the dose criteria within the SRP sections of Chapter 15.

The control room doses are not yet found acceptable for the EPU, the AST which does use the EPU conditions is under review and will be approved in the near term.

DR. KRESS: What kind of leakage containment do they have for the site dose? One percent, one tenth of a percent for that?

MS. HART: I can't recall off the top of my head. I'm sorry. Do you remember, Paul?

MR. SICARD: Yes. This is Paul Sicard.

The containment leakage that is assumed is

0.5 volume percentage per day for the first day and 0.25 after 24 hours.

DR. KRESS: Yes, that accounts for the pressure that you get.

MR. SICARD: That is correct, that accounts for the pressure.

CHAIRMAN WALLIS: So you're sure that everything's going to be okay?

MS. HART: Until it is absolutely --

CHAIRMAN WALLIS: You don't know?

MS. HART: -- issued, we don't know that for sure.

CHAIRMAN WALLIS: So this is a little like the previous matter?

MS. HART: It is an open item, yes.

CHAIRMAN WALLIS: Okay.

DR. DENNING: Let me pursue that just a little bit. When is the earliest that it could be closed?

MS. HART: It is now aiming at March, the middle of March.

DR. DENNING: The middle of March. So does that mean if the ACRS doesn't review this until the middle of March, it doesn't make any difference as far as the moving forward?

DR. KRESS: We have reviewed things based on what the staff tells us and what the preliminary results are and say that pending closure of these items, satisfactory matter, that we approve the SER. We've done that before.

DR. DENNING: Yes. Where I was headed, Tom, was really the previous issue. I mean, I wouldn't have any problems with this particular issue. The previous issue is the one that we're going to have a hard time dealing with it two weeks.

MR. SIEBER: Right.

CHAIRMAN WALLIS: Well, this seems to be based on understood physics, this alternative source term, I hope.

DR. KRESS: Well, we've had extensive hearings on the alternative source term. And we have agreed in the past that it is an appropriate thing to use.

DR. DENNING: You know there's another element of it, too. And that is whether it's five rem in the control room that they get, or 10 rem in the control room, that's not going to make a whole heck of a lot of difference to the world. If you melt down the core, it's a different issue. Not that -- and also, we know that there's a lot of conservatism in these methods anyway. But it's just what are the implications in the long term.

DR. KRESS: Well, I feel good about the fact that they actually measured in the inleakage use and the tracer gas. You have to repeat that measurement at particular intervals or is it a one time thing?

MR. SICARD: This is Paul Sicard.

Right now there is not a definite time period that has been established for periodic testing of the tracer gas testing. That is an item which is being worked on by NEI on a generic industry basis. And when there is agreement on how to proceed on that periodic testing, such as the frequency, Waterford will be consistent with that generic industry approach.

DR. DENNING: I'm still curious as to how with positive pressure they're getting inleakage, although you can get it with wind pressure, I guess, on the building. But it still is curious to me that if they really go to a positive pressure, that they're seeing inleakage.

DR. KRESS: I think you hit on it. It's a delta P --

DR. DENNING: It's a delta P with the

wind?

DR. KRESS: -- at various local positions. And that could vary inside and outside.

MR. SIEBER: You've got a lot of rooms surrounding the envelop and some of them are pressurized and some are vacuumed.

DR. DENNING: And some aren't.

MR. SIEBER: And it's a matter of delta P.

CHAIRMAN WALLIS: I think there may be duct switch may have a different pressure from the environment, too, go through that.

DR. KRESS: Yes. And they may have --

MS. HART: They have noticed in previous in previous testing that there's been pressurized ducts that have been pressurized higher than the control room itself, and that's actually what caused the pressurization in the control room, helped the system itself pressurize the control room. So that's what one of the issue that started off the whole issue with control room habitability and unfiltered inleakage and the testing and started us off on that whole route.

CHAIRMAN WALLIS: It was also a big issue that they do a test. Of course they prepare for the test and everything is fine. But as you know when sort of you're weather proofing your house and you're weather proofing and a few weeks later there are leaks.

DR. KRESS: Well, that's why I asked them about the frequency.

CHAIRMAN WALLIS: Right. How often do they test?

DR. KRESS: Well, they're going to wait for NEI guidelines on that.

CHAIRMAN WALLIS: Oh, wait for NEI. Okay.

MS. HART: Are there any more questions on the design-basis accident analyses?

Thank you.

MR. KALYANAM: Okay. The next presenter is Paul Prescott, and he will discuss our test program.

MR. PRESCOTT: Good afternoon, gentlemen. My name is Paul Prescott. I'm with the Plant Support Branch of NRR.

Up to this point ACRS has heard the licensee's and staff's reasons for granting the EPU. Underlying the safety conclusions is the fact that SSCs are installed correctly. A large part of this is that they undergo required post-maintenance tests and that all tech specs surveilliances have been completed.

We challenged the licensee and the technical branches to ensure that they have considered the need for any specific testing. This includes any larger scale testing beyond routine post-maintenance tests.

A specific area considered in SRP 14.2.1 is large transient testing per RG 1.68.

Next slide, please.

Per the SRP, the licensee may propose alternatives to certain testing. The most justified exclusion to EPU testing is for large scale testing. Typically this is the main steamline isolation valve closure and the generator load reject tests.

The alternate method argument related to analytical methods, that is the method chosen by the licensee.

In accordance with SRP 14.2.1 the staff reviews the proposed EPU test program to adequate demonstrate the performance of SSCs important to safety, checks the performance of SSCs impacted by the EPU related modes, and reviews the integrated effect of the EPU modifications.

Next slide, please.

As you may be aware, Waterford 3 was the first EPU that was conducted using the guidance developed with SRP 14.2.1. However, it was not truly the first EPU for large transient testing that was considered by our group. Duane Arnold, which recently came for license amendment, I applied the principles behind this to review their license amendment to defer their large transient testing.

The next slide, please.

CHAIRMAN WALLIS: So even if there were really good arguments for doing large transient testing, you'd have to fight your precedent of having approved 12 EPUs without requiring it? You'd have to then presume they give really good reasons why something was different about Waterford, even if there are good reasons for doing LTT?

MR. PRESCOTT: Not necessarily. I mean, we still look at each one, at least I do. I still look at each one individually.

CHAIRMAN WALLIS: You have to say what's different about Waterford?

MR. PRESCOTT: What's different about each one.

CHAIRMAN WALLIS: Yes. But then they're going to come back and say you allowed 12 which covered the range, why are you picking on us.

MR. PRESCOTT: Again, this wasn't -- that's not truly how we look at it. I look at it as each one comes in, I review it for the SRP.

CHAIRMAN WALLIS: Yes.

MR. PRESCOTT: I consider what's happened in the past and apply that to the review. I think I'm justified in doing that. The SRP gives me that guidance, as a matter of fact, to consider operating experience. And this could be applied, you know, as an example of a similar PWR that had done a power uprate to a similar extent.

MR. CARUSO: How does the fact that they put together ANO 2 properly tell you that they put together Waterford properly?

MR. ROSEN: What do you mean put together? You mean built it?

MR. CARUSO: Build it, made the modifications of ANO 2 correctly. How does the fact that that was done correctly at ANO 2 tell you that it was done correctly at Waterford 3?

MR. PRESCOTT: All right. One of the big discussions that we've had in the past is what gives me assurance, what gives us, staff assurance of the plant's adequacy for the modifications that they performed for the power uprate.

I believe that guidance is there in 50.59, in the post-maintenance tests that are performed per the regulations. And then our tech spec surveillances that are required to assure operability of systems important to see. That's what I base that on.

MR. CARUSO: Are there any startup tests or surveillance requirements that would require an integrated assessment of whether all these systems that are individually tested will actually work the way they are expected to operate?

MR. PRESCOTT: To assist us in that review, we break down the EPU really into two separate parts; that is the low power physics testing portion of it and then power testing that's done 80 percent and above. So you kind of break it down in steps. And as the licensee as stated previously, the low power physics testing portion, there was no impact on that. So now that really leaves me with what modifications were done for the power uprate and what post testing or analytical methods that they propose to use.

MR. CARUSO: So how does this tell you that it's all going to work in an integrated fashion?

MR. PRESCOTT: Again, I believe that the post-maintenance tests are adequate and the analysis that have been approved by the -- not just approved but reviewed by the staff give assurance that the plant will perform at uprated power.

MR. ROSEN: Yes, but those are just words. I mean, the post-maintenance test, I assume you mean post-mod tests as well?

MR. PRESCOTT: That's correct.

MR. ROSEN: The modification that they've done, the principle one, is on the high pressure end of the turbine.

MR. PRESCOTT: That's correct.

MR. ROSEN: You can't test that at zero power or low power because there's not steam flow. The idea of the initial startup tests was to test that component, that whole series of components out through the turbine with a turbine trip from full power.

MR. PRESCOTT: Right. But you have to look at what the modification is. The modification is the replacement of a HP rotor. The HP rotor was there previously.

MR. ROSEN: And that's why I questioned to move out the valving and all of that. And I got answers that said it's mainly the steam path and not the valving. But you're still talking about the principle component for which the turbine trip test is done at full power; that is the response of the turbine to the shut off of steam.

MR. PRESCOTT: That's correct.

MR. SIEBER: Yes, but none of that is safety related.

MR. ROSEN: Oh, I know it's not safety related.

MR. SIEBER: And it doesn't effect the --

MR. ROSEN: No, wait a minute. Wait a minute.

MR. SIEBER: -- safety aspect of the point.

MR. ROSEN: I know it's not safety related. We've shown hundreds of times, if I could find one example I could find a 100, where non-safety related components have impacts on the plant. And, in fact, the turbine of course is treated, in some respects, as a safety related component with the turbine missile strike probability analyses and all the rest.

So to just say it's not safety related doesn't really inform me a whole lot. I mean, it's true, but it doesn't inform me a whole lot, nor does it provide a basis for the decision making.

MR. PRESCOTT: That's correct.

MR. ROSEN: I still want to know what the substantive basis is for not requiring the test at full power, the new full power, just as the staff did at the original full power. And so I probed this morning is it a risk basis? No. Turbine trip and the SCRAM that results is not a risky situation. We're told that it's a very low risk, so it can't be risk. So it's purely economic. So the staff must be responding to a licensee's economic pressure incentives, and I don't think that's appropriate. I think you need to --

MR. PRESCOTT: I don't think that's the staff intent here. The staff looks at-- we don't narrow the purview of the review to safety -- just important to safety equipment. We look at the overall scope --

MR. ROSEN: Well, that's right.

MR. PRESCOTT: -- of the EPU that was performed. And, again, you have -- at least I -- we ask the staff to ask themselves what would it gain you if you asked for the test to be performed. And so far when we were writing -- obviously, when we were -- as you know, this SRP is relatively new. You know, we developed it within the last couple of years.

And as we went around -- and there was a DPO involved with this also questioning whether or not large transient testing should have been performed. And there's also a requirement that we go back and look at the other sites that had performed large transient testing at a later date to review whether or not they should perform it.

When we -- again, it's not just my opinion, it's the staff's opinion. They have to come forward with a technical justification as to why the test should be performed. Is there something new --

MR. ROSEN: Well who -- the staff must come forward with a technical justification as why the staff -- the test should be performed, is that what you just said?

MR. PRESCOTT: There has to be a basis to ask for them to perform the test.

MR. ROSEN: Well see now, that's precisely why the Review Standard was changed and the SRP was changed to reverse the burden of proof. That's the way it was, but shouldn't be now. The idea at least was that intended was that the licensee should come forward with a justification that people can agree to for why the test should not be performed; otherwise the test should be performed. And I think what you've done is taken on the licensee's burden, and it's not necessary.

The licensee in his application should carry that burden. I don't think they have. And I don't think you should have agreed to it.

MR. JONES: This is Steve Jones in the Plant Systems Branch, Acting Section Chief.

We did look at this from the perspective of what is the basis for not performing the test, the large transient tests in particular, general load reject and mainsteam isolation valve testing. Those tests perform certain functions or at least the initial test program had certain design criteria that they were intended to demonstrate. And in this case, they didn't really have anything to do with the turbine performance.

What we did consider is: The extent of the modifications associated with the power uprate and the overall change in power of the plant; the operating experience this plant has had; what analytical models they could use to evaluate transient response to the plant in an integrated fashion, and; how those models were benchmarked.

When we looked at Waterford, this is just barely over the threshold for an EPU, 108 percent and we only consider EPUs above 107, a percent of original license power. And then we're looking at the modifications were largely outside of the areas that would effect integrated response in those two large transients tests in that the turbine response is fairly independent and then the other factors like the feedwater heater drain valve response is also relatively small effect on the transient response of the plant to those types of tests.

Also, in this case the licensee had models that considered how each controller performed. And in this case the controllers were, as the licensee mentioned this morning, the algorithms of the controllers weren't changed, just the setpoints. So they were able to change that in their model and model the response. And those models have been benchmarked to both Waterford's experience with those types of transients that already have occurred from their 100 percent of their current licensed power, and also operating experience at the -- at a similar CE and NSSS plant, ANO 2 at a higher than original license power from a power uprate condition, effectively.

And on that basis we concluded that there would be very little information gained from a large transient test.

MR. CARUSO: Can I ask a hypothetical? Suppose Entergy decided to build Waterford 4, and they decided to build it just like Waterford 3? Would you expect them to perform this test at the startup of the new Waterford 4 plant?

MR. JONES: Yes.

MR. CARUSO: Why?

MR. JONES: One of the principle reasons would be that Waterford 3 has already essentially gone through the tests from what's 93 percent of their uprated power level. They just haven't done it at 100 percent. And then --

MR. CARUSO: Well, why would you require Waterford 4 to do the test?

MR. JONES: Because there are a series of new components that have never been -- never responded to a transient and may have other problems.

MR. CARUSO: But they would say well we tested these components in the factory. This pump worked, this control circuit behaved properly, we did the individual tests before we even started up the plant pumping water, opening the valves that all the valves worked, the turbine was tested in the factory, the overspeed was tested, the control valves were tested. Why do I have to run one of these tests?

MR. JONES: New plants have a lot of experience with things like foreign materials being left inside components. And that's not going to --

MR. CARUSO: And operating plants don't?

MR. JONES: Within the scope of the area that of the plant that plant systems is concerned with, these modifications don't have any credible likelihood of introducing those types of foreign materials that would change a transient response.

MR. CARUSO: They don't do maintenance during outages?

MR. JONES: Every plant does. Then we would be talking about every plant doing transient testing coming out of each outage. I think what we're looking at is the delta and whether or not the extent of the modifications has a credible likelihood of introducing some type of new interaction that can't be detected by the normal post-modification testing of that individual component.

What we see at Waterford was a lot of setpoint changes that are non-disruptive to the controllers. And then the only really invasive mods are downstream of the steam inlet valves to the main turbine or pretty upstream with regard to the feedwater heat drains. But from what I understand of that modification, that's not a mod that's actually invasive to the valve either. That's mainly a controller setup.

CHAIRMAN WALLIS: It may happen by itself anyway --

MR. SIEBER: Well, it certainly will happen.

CHAIRMAN WALLIS: -- after operating for a while.

MR. ROSEN: At 2:30 in the morning.

CHAIRMAN WALLIS: And the only question is is whether you'd rather do it that way or do it now. For the first time.

MR. JONES: For the first time, that's I think the key.

What we're expecting is that the response will be very similar to the last time it happened based on what we've just discussed. And we're using the criteria that were laid out in the Standard Revenue Plan for determining that.

DR. RANSOM: Well, to some degree is the ascension to power test a test of this type because if any problems are encountered, I presume they shut it down, you know, and restart the test after they've resolved whatever problems are encountered?

MR. JONES: Certainly a large majority of the test systems that Plant Systems Branch are concerned with are tested during the normal operating and power ascension portions, and the maneuvering transient that's included in their power ascension test.

DR. RANSOM: One thing I'm curious about on the turbine and the generator, isn't it rotated before they begin this power ascension testing? How do they do that?

MR. PRESCOTT: Put it on turning gear.

MR. SIEBER: Rotate it.

DR. RANSOM: Drive it in some way?

MR. PRESCOTT: Yes.

MR. SIEBER: Oh, yes. The turning gear.

MR. PRESCOTT: Yes. The turning gear.

MR. SIEBER: There's a motor on it.

DR. RANSOM: Well, I would say that this uprate given, as you suggests, it's borderline percentage wise, but it is not borderline in the sense that to the extent to which modifications have been made or are being made. As we said the high pressure turbine will be upgraded and replaced, generator's going to be rewound, associate auxiliaries will be changed, higher capacity main generator output circuit breakers, disconnect switches and bus work will be installed, control valves for the heat drain system will be either upgraded or replaced, atmospheric dump valve controls, we heard a little about them, will be replaced.

MR. JONES: I believe no. The atmospheric dump controls --

MR. ROSEN: They're going to be modified?

MR. PRESCOTT: To a finer setpoint.

MR. ROSEN: The setpoint changes.

MR. PRESCOTT: Yes, sir.

MR. ROSEN: Okay. Well -- lower steam generator trip pressure setpoint, reheat system safety valves will be modified, condenser modifications will be performed staking the condenser.

I mean, that's a long list of stuff. And my feeling about all that stuff is it has to work as an integrated whole. And the only way to know that is to do an integrated test, the large transient test at the new EPU. And I wouldn't expect that to be done the day the instant you get there, but at a reasonable time after you get to the EPI conditions and after you've taken steady state data, and at a time convenient to the system and the plant when management and all the control systems, the proper control systems are in place, additional resources as necessary both people and equipment. And it would seem to be that that would be an appropriate time to take it rather at some undetermined time in the future decided by the plant, not by the plant management.

MR. MITCHELL: Yes. This is Tim Mitchell.

I guess I feel like we are testing each of those components you listed. And we are doing LTC code predictions on their performance. But things like turbine valves, which would be the primary concern I believe with everything along the turbine train, are they capable of moving and closing, you know we will demonstrate that they are capable of moving and closing or opening as part of the power ascension profile, plus the maneuvering from 100 percent power to 90, to 95 also shows our ability to move those valves from the new 100 percent power plateau.

So to me we are testing the plant.

MR. ROSEN: Individual, I agree. Individual here, individual there. But your reliance on calculations and analyses to predict the transient response of a plant from full power at the extended power conditions is purely analytical. And I don't think we would have ever accepted that in the past. And I see no reason to do so in the future.

You can continue to address this subject and provide more documentation, but I've been through all of the stuff that's been provided, I think, both by the staff and the applicant. And I don't think you've carried the burden. My reaction to it is well, if that's the best you can say, why don't you just do the test and get it over with.

CHAIRMAN WALLIS: Steve, I'm not sure that this Subcommittee is going to take the position one way or the other. I don't know how the members feel about this, but we may turn out to be evenly split.

MR. ROSEN: Well, that may very well be. That may very well be. And I was just feeling my burden to let the applicant and the staff know.

CHAIRMAN WALLIS: Well, I'm saying if we're going to go to the full Committee, it would be good if we could go with a recommendation. You know, we've actually gone through the arguments and as a Subcommittee we recommend that they do or do not do these tests.

MR. ROSEN: Well, we could take a soft vote if you want. I felt my burden was to say how I felt.

CHAIRMAN WALLIS: Yes, I think you should. I think that's very good that you did.

DR. DENNING: I mean if we're going to get to a soft vote, then I'd like to talk a little bit more about it. Because my feeling is --

CHAIRMAN WALLIS: Well, I thought we'd talk about it after they've finished their presentation.

DR. DENNING: Sure. After. Absolutely.

CHAIRMAN WALLIS: When we start asking ourselves whether or not we should go to the full Committee and what are the issues and so on.

MR. JONES: This is Steve Jones in Plant Systems. I just wanted to bring up one more point.

We have accepted in the past when during initial startup tests when plants have had inadvertent trips at lower power levels then initially plans, we have accepted those as satisfying the startup test requirement.

MR. ROSEN: Up to that power level, not extrapolated beyond that power level?

MR. SIEBER: No, extrapolated.

MR. JONES: I mean, we've accepted those as satisfying the generator load reject tests for 100 percent power if it occurred at 80 percent power.

MR. PRESCOTT: And we also accepted for initial startup of plants, we also accepted as logic for not performing certain tests at other plants that were being constructed afterwards with the same vintage or the same make, they're not performing a certain test based on a test performed at other plants.

MR. ROSEN: I understand.

MR. PRESCOTT: So NRC has long --

MR. ROSEN: I understand that you've told me that you've accepted it at other plants and at lower power levels in the past.

MR. PRESCOTT: Yes.

MR. ROSEN: We're talking about the future, not the past here I thought. And so I would prefer to talk about the future. And given the fact that either you make a change here with the past or you use the past essentially forever as prologue. In other words, we give every licensee the signal that they may rely on the past precedent of not requiring this. Their burden has been reduced effectively to zero, when in fact their purpose -- the change of the standard was to transfer the burden to the licensee. It was not the staff's job to argue with the agency reviewers that the licensee could waive transient testing, which was part of normal startup programs. It was not the staff's job to do that. It was the applicant's job to do that. To make that case convincingly.

MR. PRESCOTT: And then the SRP covers that. It gives them the option of supplying us information analytically or performing the test. It doesn't weigh the option for them.

MR. RULAND: Let me add about Duane Arnold. As you probably are aware, Duane Arnold when we approved their power uprate, they had a license condition that required them to do large transient testing.

Recently they came in for a license amendment to eliminate that license condition. And the staff basically said to the licensee -- but we haven't issued this license amendment by the way, yet. That they hadn't performed sufficient justification to eliminate large transient testing at this point.

So what I'm arguing is that the staff has shown that we're applying this as the Review Standard has suggested on a case-by-case basis. And in fact, at least at this stage in Duane Arnold they haven't provided us sufficient justification to justify eliminating the large transient testing. So that's just an example.

MR. ROSEN: Well, I appreciate that.

MR. PRESCOTT: And there was a significant RAI associated with this EPU at trying to address large transient testing.

CHAIRMAN WALLIS: Can we perhaps move on and revisit this later?

MR. PRESCOTT: Finally, this is just to give a little more background on some of the things that we take a look at, and we also take a look at operator training and familiarization, any changes that were done to the ELPs and the benchmarking of analysis codes and models as extra consideration for whether or not large transient testing.

Next slide, please.

Finally, this is just a conclusion slide to give an overall view of that SRP 14.2.1 has options available to a licensee for ways of justifying large transient testing and testing in general. And that there have been 12 domestic LWRs or light water reactors that have implemented staff approved EPUs.

CHAIRMAN WALLIS: But at Duane Arnold you are requiring?

MR. PRESCOTT: No, it's a licensed condition right now that's on there to perform the testing. They're doing their power uprate in phases and they haven't reached the phase yet where they're required to do the testing --

CHAIRMAN WALLIS: There have to be LWRs

where you have required large transient testing.

MR. PRESCOTT: I'm sorry.

CHAIRMAN WALLIS: You said there were 12 were you have not required large transient tests. Are there other ones where you have required large transient tests?

MR. PRESCOTT: No, sir.

CHAIRMAN WALLIS: No. So this is 12 of 12?

MR. PRESCOTT: Yes.

CHAIRMAN WALLIS: There's no example where you have required them?

MR. PRESCOTT: No, sir.

And that's it.

MR. HOWE: This is Allen Howe. Let me just clarify something.

Duane Arnold has a license condition which requires them to do large transient testing. As the context here, they haven't gotten to the point yet where they would need to do it, and they've submitted an application for removal of that license condition. But, in fact, you could say the answer is that Duane Arnold has been required or has a requirement to do large transient testing.

CHAIRMAN WALLIS: Can we move into the

next item now?

Thank you very much.

MR. KALYANAM: The last presenter of the day will be Martin Stutzke to talk about the probablistic safety assessment.

MR. STUTZKE: Good evening, gentleman. I'm Martin Stutzke from the Probability Safety Assessment Branch. Unlike the two members of my branch previously, I'm an actual PRA analyst.

MR. ROSEN: Rather than an orphan in the PRA group, right?

MR. STUTZKE: I look at them as my foster children.

MR. ROSEN: Well, that's nice.

MR. STUTZKE: We're reviewed the risk evaluation that Waterford submitted to us, primarily for two reasons. One, we want to make certain that the risks are acceptable. And two, we want to determine if special circumstances exists as defined in the Standard Revenue Plan Chapter 19 Appendix D. Special circumstances are items that could rebut a presumption of adequate protection that's provided by meeting current regulations.

The point behind this is that the Waterford EPU application is not a risk-informed application. So strictly speaking RG 1.174 does not apply. However in the course of developing the Review Standard RS-001 there, the staff has concluded in fact that special circumstances may exist for all EPUs, and hence we do a review for that purpose.

One of the things that's different when you're looking at the risk of a nonrisk-informed application, the focus on adequate protection means we tend to look at the overall risk. We're not so concerned about the change in risk, the delta risk calculation, although you will see that we have in fact looked at them.

Next slide, please.

The review scope basically consists of examining the internal events, the following types of external events.

Internal floods. The license has a conservative screening approach that's used.

Internal fires where they've relied on EPRI methodology, the fire induced vulnerability evaluation approach.

Seismic events or where they've relied on seismic margins analysis.

The so called HFO events; high winds, external floods and other external events where they've used NUREG-1407 screening. 1407 is the IPEEE submittal guidance.

Their Level 2 PRA which is basically a LERF calculation based on NUREG/CR06595.

A qualitative assessment of shutdown risk based on questions out of the Standard Review Plan Chapter 19.

And we've also examined the PRA quality. I should point out with concern to PRA quality, the Review Standard is basically -- I looked at Regulatory Guide 1.174, the SRP Chapter 19 and section 19.1. As you know for Regulatory Guide 1.200 has been issued for trial use, which talks about industry peer reviews and the ASMI PRA standard. I will confess that I looked at this, but you will not see that I referenced it. It is not the basis of my decision of adequate quality for this license application.

Next slide.

The overall results are as shown on the slide. I did not have them up on this slide because the internal floods and internal fires, in fact, are conservative approaches. In fact, I went ahead and added them up over lunch. The total core damage frequency is about two times ten to the minus five per year, that's including all the internal events and external events.

The change in core damage frequency is on the order of four times ten to the minus seven per year. When you do compare that to Regulatory Guide 1.174 you find they're in Region III, which means it is a very small increase in risk.

DR. KRESS: Did you look at late containment failures at all?

MR. STUTZKE: No, sir. No, sir.

MR. ROSEN: Say again what Region III is?

MR. STUTZKE: Region III equates to a very small change in risk.

MR. ROSEN: You mean that's what's allowed?

MR. STUTZKE: Yes.

MR. ROSEN: It's not no change?

MR. STUTZKE: It's not no change.

MR. ROSEN: Right.

MR. STUTZKE: The language is very small. Region II is small.

MR. ROSEN: Allowed?

MR. STUTZKE: Right. And Region I is not allowed.

With respect to their internal events PRA, I focused on several things. One had to do with the frequency of loss of offsite power because the power of the plant was being increased and we had an event in August of 2003 that blacked out large amounts of power in this country, we needed to have a look at the loop frequency. In fact, the licensee's approach to estimating loop frequency is to take a list of offsite power events, loss of offsite power events that have occurred and screen out those that clearly don't apply to their sites such as snow or ice or things like that. Even though I'll note that it apparently supposedly snowed in New Orleans a couple of week ago.

MR. ROSEN: For the first time, and in south Texas.

MR. STUTZKE: And in south Texas.

MR. ROSEN: Eight inches in my back yard.

MR. STUTZKE: It's amazing how probability sometimes come true.

MR. ROSEN: That was once in a 100,000 years.

MR. STUTZKE: I look at that loop frequency and compared it to work that the Office of Research has recently done in support of the staff's action plan on grid related issues. And the Waterford frequency is in fact higher. I'll also point out that Waterford operates in a regulated environment and there's no intention to become deregulated. Office of Research and NRR has tentatively reached a conclusion that regulation versus deregulation does have some influence on the likelihood of loss of offsite power. I like that.

In addition, I looked at success criteria. We've talked about that earlier today. The fact that that the deterministic conservative calculations require or the atmospheric dump valves to mitigate small LOCAs. The PRA calculation, realistic calculation indicated that those valves were not needed to mitigate the LOCA.

My conclusion goes all the way back to the Commission's PRA policy statement, the third bullet says "PRAs should be as realistic as practicable." So in fact when I use a realistic one, the licensee used a realistic calculation. He determined that the valves were not necessary, and hence there was no change to their success criteria between the pre and the post EPU plants.

I think our branch continues to wrestle this as we find indications where one applies the traditional deterministic approaches and reaches one conclusion and comes in with a PRA calculation that may refute this.

In addition, the licensee recalculated operator response times using the CENTS code. They're pre-EPU PRA appears to be a mixture of some plant specific analyses, some generic analyses and some good old fashioned engineering judgment. What you found in some cases that when they calculated using CENTS, the operator had more time than before, even though the power level had gone up. So I asked them to do a sensitivity calculation where they left the loop recovery probabilities the same and they changed only the human errors in the model. And in fact the change in core damage frequency only went down by ten to the minus nine. So it's a negligible effect. So in fact they adjusted the pre-EPU PRA to account for the correct times out of CENTS, and then they bumped up the power level and recalculated those. And I think it's a reasonable calculation.

For seismic risk, in NUREG-1407 Waterford was classified as a reduced scope plant. The licensee has stated that an increase in power level is not expected to affect equipment survivability or response. There's no change in the safe shutdown passways using the seismic margin analysis.

For HFO events, they were screened out in IPEEE; there's no way that an increase in power level will increase the frequency, the current frequencies of HFO events. So there's no contribution from them.

For shutdown risk, the Standard Review Plan Chapter 19 contains four questions to help us to decide if impacts on shutdown risks could be important. The questions are as follows:

Will the changes affect shutdown schedule? As you see indicated here, the answer is no.

Will the changes affect the operator's ability to respond? And remember we're talking about responds to events while the plant is in fact shutdown. The licensee maintains a shutdown operations protection plan that maintains a variety of important functions. And they would propose to control the plant using the same way.

The third question is will the changes affect the shutdown equipment reliability? Again, the answer is no.

Or would it affect the availability of equipment or instrumentation used for contingency planning? And again the conclusion was no.

So the fact that all of the questions resulted in no lead me to the conclusion that the proposed EPU had no or small impact on shutdown risk, and we didn't pursue it any further.

With respect to PRA quality, you'll see dates and times of when the licensee submitted their IPE and IPEEE and when the staff accepted them. As stated earlier this morning, the licensee had an owner's group peer review in January of 2000. My impression is the licensee maintains a living PRA program, and I think this is true for all the Entergy plants. You can see there's been several PRA updates, the latest being in June of 2003. They maintain their PRA as quality records.

I would say in my experience that's about half of the plants do that, actually maintain these as formal engineering calculations like that.

So in order to confirm the quality of the PRA, I looked at the resolution of the IPE, IPEEE and peer review findings. They have addressed all but three of the category A findings from their peer review, and all but 19 of the category B findings.

To give you a flavor of what this means is most of the category A findings pertain to the Level 2 PRA. For the EPU they didn't use their existing Level 2 PRA. Instead they used NUREG/CR-6595 and so it's not necessary to resolve the questions. There's some comments on model documentation and things like this.

So the conclusions are, the PRA has technical adequacy. I think it's modeling the post-EPU plant reasonably so we can have some confidence in its results. The risks are acceptable because, in fact, the licensee meets the Regulatory Guide 1.174 guidelines even though they didn't need to. And we have seen nothing in our review that indicates the proposed EPU creates special circumstances, so we have no reason to rebut a presumption of adequate protection based on my review.

Questions?

CHAIRMAN WALLIS: The CDF for this plant is low enough that it's more adequate protection compared with the average plant.

MR. STUTZKE: That's right.

DR. KRESS: Besides it's a large dry containment.

MR. STUTZKE: It's a large dry containment.

DR. KRESS: Those are two pretty good things to --

MR. STUTZKE: Yes.

CHAIRMAN WALLIS: So does the staff have any kind of summary to present. It's on the schedule here.

MR. RULAND: Just one thing I owe you from this morning's meeting had to do with what our procedures said concerning the inspector witnessing of initial power ascension testing.

Our inspection procedure, which is specifically called power uprate, and this inspection procedure requires the inspector to witness initial power ascension after they implement the changes that were made for the power uprate and to witness a review test of any major plant tests. So those are what the guidance we give our inspectors.

Secondly, you've heard of course a number of our technical staff stating that this the first time that we've completely used our RS-001 Review Standard.

CHAIRMAN WALLIS: Right.

MR. RULAND: And as part of that program we're going to solicit from the technical staff for not only this power uprate for PWR, but for the next BWR power uprate review, to take that input from the technical staff to see how we need to revise it, if any. I suspect there's a number of changes that we're going to make as the staff actually used the Review Standard. So that's also part of our process, and we intend to do that.

But that concludes our presentation. I think Allen, you got some closing remarks.

MR. HOWE: Yes. Thank you, Bill. This is Allen Howe.

And first of all, I'd like to say that we appreciate the opportunity to come before the ACRS and to present the information related to the Waterford 3 extended power uprate.

The staff has done an extensive review on this process. When we came in today we identified a couple of open items that we have conceptual agreement on the resolution of them. We need to nail down some of the details, and we are going to be working diligently to do that.

In addition, during the course of the dialogue today I took some notes, and I know that others took some notes on some other items that were of interest that we should be prepared to discuss at the ACRS full Committee. And we will be working to manage that and assure that we address those issues at the time that we come before the full Committee.

Thank you.

CHAIRMAN WALLIS: Thank you very much, staff.

Is it appropriate, Ralph, we come off the record at this time?

MR. CARUSO: I think so.

CHAIRMAN WALLIS: So we don't need the transcript anymore. Thank you.

MR. MITCHELL: Chairman Wallis, I do have some FAC data that was requested.

CHAIRMAN WALLIS: Let's go back on for these bits of factual data.

MR. MITCHELL: Okay. The flow accelerated corrosion, going back on the question of past outage history. All of the items I'm going to talk about were predicted either by CHECWORKS or by our program itself. As I think everybody's probably aware, CHECWORKS does not do small bore, so we rely on our program to do small bore.

In refueling 10, which would have been three outages ago, we did some weld buildup on stainless steel overlay that was predicted by the program. This is not CHECWORKS either. That's outside the bounds of CHECWORKS.

RF 11, the next outage --

MR. ROSEN: Well, where did you do that weld overlay? What system? You didn't say.

MR. MITCHELL: It's a cross under piping on the turbine.

RF 11 extraction steam elbow, a 20 inch. That was based on a CHECWORKS prediction from the previous outage. And we went in and replaced that with chrome moly.

Then in RF 12 there are two two inch main steamlines that replaced based on data that we had collected in previous outages in this predictions. But those were not -- but those are small bore, they weren't CHECWORKS. And that's it.

MR. ROSEN: So some cross under piping was built up?

MR. MITCHELL: That's correct. One 20 inch elbow.

MR. ROSEN: One 20 inch elbow was replaced with chrome moly.

MR. MITCHELL: Right. And two --

MR. ROSEN: That's a small bore piping.

MR. MITCHELL: And then two lines of small bore piping.

MR. ROSEN: In the main steam system?

MR. MITCHELL: That's correct. And again, all of those were predicted.

MR. ROSEN: All of those were predicated, but not necessarily by CHECWORKS.

MR. MITCHELL: Just one was even in the

scope of CHECWORKS, that's correct. So the one that CHECWORKS had an opportunity to predict, it did predict. But that's the only one in the last three outages that was within the scope of the CHECWORKS.

MR. ROSEN: Thank you.

CHAIRMAN WALLIS: Okay.

MR. MITCHELL: That's all my FAC data. We could discuss some more on the boron precipitation question that Dr. Ward presented if you would like, but I'll leave that up to the Committee.

CHAIRMAN WALLIS: Well, you didn't have any info when he was talking and maybe you should, since that looks as if that might be a very important issue.

MR. MITCHELL: We have looked at it and Joe's going to talk about it in more depth, but in summary we have gone back and done the calculations. Those calculations have supported our position, that's even with the conservatisms that Dr. Ward described. And those conservatisms more than bound any open issues with the calcs. Those calcs will be QA'd next week, I believe. If that's not correct, Joe, please correct that. But I'm going to turn it over to Joe and let him talk about it as well.

MR. CLEARY: Yes. What we plan to do is

expand the calculation that we've done today to address Len's concern to include as quantitatively as possible or semi-quantitatively some other conservatisms that we haven't discussed in the meeting today and also some of the ones that we have.

We would start off that recalculation by attempting to implement into the calculation the affect of the increase in the boric acid density on the phase separation model that will determine the void fraction in the mixing volume.

CHAIRMAN WALLIS: Now, do you have a basis for doing that?x

MR. CLEARY: To be honest, we do not have a basis at this point in time. The intent of the calculation would be to show that hopefully over a wide range of void fractions after accommodating -- relaxing these other conservatisms, we would have a bounding result that would cover any expected impact that a more detailed and therefore time consuming evaluation of the effect of boric acid --

CHAIRMAN WALLIS: Well, when you boil a mixture close to saturation, the vaporization concentrates this substance on the interface and you will probably will tend to precipitate boric acid on the interface of the bubbles. So you now have a mixture which is not homogeneous. It has interfacial characteristics which are different from the bulk and which may actually involve precipitation of this soluble.

MR. CLEARY: I can't argue --

CHAIRMAN WALLIS: That would change the -- it seems to me, that would change the drift flux or have the potential to change the formability of the drift flux and quite a few other of the hydraulic characteristics of this mixture, the same way that you boil certain things in the kitchen, when you boil candy and so on, when you start to get conditions where you're going to change the structure of the stuff, you begin to get very different boiling behavior of that material.

MR. CLEARY: I agree. And that's why the purpose of these calculations would be to show that once we start relaxing these very conservative assumptions we would remain far enough below the solubility limit that these effects would not significantly enough change the answer to lead to the expectation of boric acid precipitation.

In the longer time frame, there are test data out there that can be brought into the evaluation. The MHI has done tests on the Backus facility. The Finnish have done some tests that the NRC staff is aware of that can help bring more factual information to bear on the issue.

CHAIRMAN WALLIS: So these tests would include boiling of boric acid solution near the limit of solubility.

MR. CLEARY: That's correct.

CHAIRMAN WALLIS: And the resultant drift flux or whatever it is that's necessary to calculate the void fraction?

MR. CLEARY: At this point I don't know the extent of the instrumentation that was in these facilities to know what could be brought to bear on trying to benchmark current models --

CHAIRMAN WALLIS: Now, is this something that can be done in two weeks?

MR. CLEARY: What I'm describing, bringing in the results of these test studies, they certainly cannot be done in two weeks. Again, the intent of the work we would propose doing in the next two weeks is to show that once we relaxed the very conservative assumptions, that we would lower the maximum concentration recalculate well below the solubility limit to give a high degree of confidence that in the long term on a generic basis Waterford as well as other Westinghouse and GE-designed NSSSs would not have a problem.

CHAIRMAN WALLIS: What would concern me about going to the full Committee with this is that you have this analysis, it looks important enough that it would have to be examined very carefully and critically. We'd have to probably have some written material we could study. And this would be -- certainly it would have to occur at the Subcommittee level. We couldn't expect the full Committee to digest new technical material which they hadn't had a chance, no one had a chance to fully critique.

So I wonder if we should go to the full Committee with something like that?

MR. MITCHELL: I guess it is important to note that this is not a Waterford issue, that it is a generic issue that we will be pursuing pushing to resolution.

CHAIRMAN WALLIS: You may have created a generic issue, yes.

MR. CLEARY: I believe the staff has recognized that it is a generic issue and the draft SER talks about pursuing it on a generic basis. Albeit this is before Len Ward's consideration of the affect of the void fraction on the mixing volume. But in general, the staff had these issues which they were planning to pursue on a generic basis.

MR. SIEBER: Well, it's not particularly helpful for Entergy or any applicant to believe that an issue becomes a generic issue and therefore they should get their application approved because this issue moved to some other category. And it could well be that the applicant would want to move rapidly to resolve it, at least in their case, so that the EPU would move forward. You know, just making it a generic issue doesn't help.

MR. CLEARY: I could expand on it a bit more, the type of work we can do within the two week time frame.

MR. SIEBER: When you get to the end of the two week time frame, you're going to have a calculation that's probably not been reviewed, is not QA, not part of the application, not reviewed and reviewed by the staff, not a part of the SER. And I'm not sure how we can deal with that. I mean, there's more that has to be done than I think is possible to do in two weeks.

MR. RULAND: Clearly, Jack, at this stage, you know, I think the staff needs an opportunity to go back and talk to the applicant, talk to our management and get back to you very rapidly about what we see as our approach out of this problem.

MR. SIEBER: Promptly.

MR. RULAND: And promptly. Yes, sir.

MR. SIEBER: I'm not saying that anybody did anything wrong. I congratulate both the staff and the applicant for reaching the point that they've reached. It's just that I think that we need to resolve it and document it to a greater detail than you can do in two weeks.

CHAIRMAN WALLIS: I think really from my point of view, the desirable process would be for you folks and the staff to work hard on this and come back to the Subcommittee.

MR. SIEBER: Yes.

CHAIRMAN WALLIS: And when we're satisfied, we can say it's ready to go to the full Committee.

MR. SIEBER: right.

CHAIRMAN WALLIS: I don't see that happening between now and February 10th. This will upset the management that wants to get something out of the way of the ACRS by the February meeting, but I don't quite see how we're going to do that. That's the feeling I have. Maybe my colleagues have a different feeling about it.

MR. SIEBER: I agree.

MR. ROSEN: Are we on the record still.

CHAIRMAN WALLIS: We're still on the record. We can go off the record, if you like.

We stayed on the record because we were getting input from the applicant. If we have ceased getting input from the applicant and the staff, then I think we should go off the record and discuss among ourselves.

Are we really ready to go off the record now? In that case, I'll thank everybody who has contributed to it. Thanks very much.

And go off the record.

(Whereupon, at 5:36 p.m. the Subcommittee was adjourned.)