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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

November 30, 2005

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

SUBCOMMITTEE ON POWER UPRATES

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WEDNESDAY,

NOVEMBER 30, 2005

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

MEMBERS PRESENT:

RICHARD S. DENNING, Chairman

THOMAS S. KRESS

VICTOR H. RANSOM

JOHN D. SIEBER

GRAHAM B. WALLIS

ACRS STAFF PRESENT:

RALPH CARUSO, ACRS Staff

ACRS CONSULTANTS PRESENT:

GRAHAM M. LEITCH

SANJOY BANERJEE

NRC STAFF PRESENT:

JAMES BONGARRA, NRR
ROBERT DAVIS, NRR
BARRY ELLIOT, NRR
RICK ENNIS, NRR
RAY GALLUCI, NRR
MICHELLE HART, NRR
CORNELIUS HOLDEN, NRR
STEVE JONES, NRR
KRZYSZTOF PARCZEWSKI, NRR
ROGER PEDERSEN, NRR
DEVENDER REDDY, NRR

ENTERGY/GE STAFF PRESENT:

VINCENT ANDERSON
RICO BETTI
MICHAEL DICK
JIM CALLAGHAN
JOHN DREYFUSS
JIM FITZPATRICK
JERRY HEAD
BRIAN HOBBS
PAUL JOHNSON
CRAIG NICHOLS
PEDRO PEREZ

ENTERGY/GE STAFF PRESENT:

PAUL RAINEY

BRUCE SLIFER

CHRIS TABONE

CHRIS WAMSER

ALSO PRESENT:

PETER JAMES ATHERTON

JOE HOPENFELD

RAYMOND SHADIS

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P R O C E E D I N G S

8:31 A.M.

CHAIRMAN DENNING: The meeting will now come to order. This is a continuation of a meeting of the Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates.

I'm Dr. Richard Denning, Chairman of the Subcommittee. The Committee Members in attendance are Dr. Graham Wallis, Dr. Tom Kress, Dr. Victor Ransom, and Mr. Jack Sieber. ACRS Consultants in attendance are Dr. Sanjoy Banerjee and Mr. Graham Leitch.

The purpose of this meeting is to discuss the extended power uprate application for the Vermont Yankee Nuclear Power Station. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC Staff, the Vermont Yankee licensee, Entergy Nuclear Northeast 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 November 14 and November 28, 2005.

Portions of this meeting may be closed to discuss proprietary information. However, let me say that we don't really expect that to happen today as it did yesterday. So we think that today's meeting will be open, at least the vast majority of it will be open.

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. It is especially important today for people to speak up into the microphones because the meeting is being broadcast via conference call link. The conference call will allow stakeholders to listen to the discussion today, but we will not be taking comments over the phone.

If it becomes necessary to close the meeting to discuss proprietary information, stakeholders on the conference call will begin to hear recorded music and a message explaining that the meeting is closed until the meeting returns to open session.

We received several requests from members of the public to make oral statements today and they will have the opportunity to make those comments this afternoon. Other interested stakeholders can submit written comments to the ACRS at the NRC's Washington, D.C. address or by email to Mr. Caruso at the address listed on the agenda. These comments will be provided to all of the Members before the meeting of the Full Committee on December 7, 2005.

This is the second of two ACRS Subcommittee meetings that will consider the Vermont Yankee power uprate request on November 15 and 16. The Subcommittee met in Brattleboro, Vermont. The Full ACRS is scheduled to consider this application on December 7, 2005 in Rockville, Maryland. And that meeting will also be open to the public.

We will now continue with the meeting and I call upon Mr. Ennis of the NRC staff to continue.

MR. ENNIS: Thank you. My name is Rick Ennis. I'm the Project Manager for the Vermont Yankee Extended Power Uprate, EPU, in the NRC's Office of NRR.

We have a lot of things on the agenda today I want to brief here. Yesterday, Dr. Denning requested that we try to fit a presentation into the agenda sometime today concerning debris loading on the emergency core cooling system, ECCS, suction strainers. Entergy and the NRC Staff had some discussions yesterday afternoon and it was decided that Entergy would be willing to do that presentation today. However, due to the short amount of time to prepare, we request that that will be done some time after lunch today.

My suggestion is that we try to fit it into the agenda after the Plant Systems presentation which is Topic 14. That runs from 12:45 to 1:45 and so we can potentially start at 1:45.

CHAIRMAN DENNING: Could we have it at the beginning of that because Dr. Banerjee is going to be leaving shortly after that.

DR. BANERJEE: Three o'clock.

CHAIRMAN DENNING: Okay, it sounds like it would work either way.

MR. ENNIS: Something else we could offer up and it is potentially if the Subcommittee feels that further discussion on electrical engineering topics isn't necessary, we could opt to potentially shorten that and drop it out. We did talk about station blackout during the meeting in Brattleboro, so that's just something we could offer.

CHAIRMAN DENNING: As a place to cut back.

MR. ENNIS: Cut back.

CHAIRMAN DENNING: Jack, do you have a comment on that?

MEMBER SIEBER: Yes, as far as -- part of that was reliability issues and when we were in Vermont I did get and the Subcommittee got a pretty good explanation as to what the licensee has done to respond to the current reliability issues that affects that plant plus a lot of other plants across the country. So my guess is that unless other Members object, that is something that we could drop out.

CHAIRMAN DENNING: Good. Let's plan it that way, assuming we need --

MR. ENNIS: That's actually, the licensee had a topic, station blackout and grid stability as Topic 10, and then the Staff had 11. That would free up about 45 minutes there, if we could drop those and just move everything else forward.

CHAIRMAN DENNING: Well, the problem is that that happens in the morning.

MR. CARUSO: I think we can do that. I think the Subcommittee can do that.

CHAIRMAN DENNING: That means we get to plant systems earlier.

MR. CARUSO: Well, then we can do sump screens after plant systems, maybe at lunch?

CHAIRMAN DENNING: Does that mean that we get into plant systems in the morning, if we do that?

MR. ENNIS: Well, let's see. If we moved everything up 45 minutes, then maybe we could do the sump screens right after lunch?

CHAIRMAN DENNING: And we'll do plant systems before lunch?

MR. ENNIS: Let me see. Yes, we should be able to do that.

CHAIRMAN DENNING: Let's plan along those lines then, that we will drop the station blackout and bridge stability and electrical engineering. Both of those?

MR. ENNIS: Right, drop topics 10 and 11.

CHAIRMAN DENNING: Ten and 11, yes.

MR. ENNIS: And go to plant systems after human performance, right before lunch and start the sump strainers right after lunch.

CHAIRMAN DENNING: That sounds good.

MR. ENNIS: Okay, the only other statement I want to make is I wanted to note that the topic regarding debris loading on the ECCS strainers is discussed starting on page 121 of the Draft Safety

Evaluation and that issue was resolved largely through the licensees responsible to 9603. And that's all I wanted to say.

With that, I turn it over to Entergy, unless there's any other questions.

CHAIRMAN DENNING: You can proceed.

MR. NICHOLS: Good morning. My name is Craig Nichols. I'm the Project Manager for the Power Uprate at Entergy Vermont Yankee. I'm pleased to be back again today to continue our discussions on our extended power uprate application.

Our first topic today is flow-accelerated corrosion and PT curves. With me today I have Mr. Jim Callaghan, the Manager of Engineering Design at Entergy Vermont Yankee; Mr. Jim Fitzpatrick, Senior Lead Engineer at Vermont Yankee, and our Flow-Accelerated Corrosion Program Engineer; and Mr. Pedro Perez, the supervisor for Radiological and Fluence Group at Arriva.

I'd like to turn it over to Mr. Callaghan for the presentation.

MR. CALLAGHAN: Good morning. As Mr. Nichols identified, I'm Jim Callaghan, Design Engineering Manager Vermont Yankee and this morning I'll be presenting a short overview of the flow-accelerated corrosion program at Vermont Yankee and the potential EPU impact. I'll also be giving a very short presentation on PT curves.

Next slide.

Vermont Yankee uses a programmatic approach to monitor FAC, flow-accelerated corrosion. The program was developed using the guidance from General Letter 89-08 and NSAC-202L. CCECWORKS and EPRI software tool is used to predict FAC wear, planned future inspections and organized inspection data.

MEMBER WALLIS: How does this predict that FAC depends upon? How does it depend upon the velocity of the fluid?

MR. CALLAGHAN: The CHECWORKS model takes into account a number of parameters, velocity, material --

MEMBER WALLIS: It is linearly or is it square or cube? Or does it depend on the velocity.

MR. CALLAGHAN: The wear goes up proportional to velocity.

MEMBER WALLIS: Proportional to velocity.

MR. CALLAGHAN: Yes.

MEMBER WALLIS: Is this an empirical thing? There's no theory behind it? So it would increase then?

MR. CALLAGHAN: Yes, it will increase. And I'll get into that.

Additionally, the program ensures that any FAC operating experience events are evaluated for applicability to VY and incorporated in the VY program as necessary.

Next slide.

Vermont Yankee typically inspects between 25 and 35 large bore components each refueling outage. This inspection scope is determined by use of the CHECWORKS tool, past VY inspections, engineering judgment and industry operating experience.

Repeating inspections in the condensate and feedwater system over the last 15 to 20 years have identified minimal flow-accelerated corrosion wear in these systems. Those are the two systems that are most impacted by EPU.

MEMBER WALLIS: Where does the material go?

MR. CALLAGHAN: Pardon me?

MEMBER WALLIS: The flow-accelerated corrosion actually wears out the pipe, doesn't it?

MR. CALLAGHAN: That is the phenomenon, it wears out the pipe.

MEMBER WALLIS: Where does the material go?

MR. CALLAGHAN: Basically, what we're seeing right now is very little wear.

MEMBER WALLIS: It turns into rust or something? Where does that appear in the system?

MR. CALLAGHAN: I'm not sure.

MEMBER WALLIS: It forms and then it's taken out when you renew the --

MR. CALLAGHAN: That is true. But again, our indications are we see very minimal wear, especially in the condensate and feedwater system.

MR. LEITCH: Have you had to replace any?

MR. CALLAGHAN: I'll get into that. We have a significant amount of flow-accelerated corrosion resistant piping at VY. In fact, our extraction steam system which is a major industry issue for flow-accelerated corrosion was originally FAC-resistant material.

Additionally, the next three slides --

MR. LEITCH: Is that 2 percent chrome piping there?

MR. CALLAGHAN: Different types. We have some of the one and a half percent chrome, 2 and a half percent chrome. In fact, we use stainless steel, too. It's all FAC-resistant material.

MR. LEITCH: Is that original?

MR. CALLAGHAN: That was original in the extraction scheme system.

MEMBER KRESS: I'm never quite sure what the word minimal means in these bullets.

MR. CALLAGHAN: And Mr. Fitzpatrick can get into it, but what we're seeing in the condensate and feedwater system in these inspections is within the tolerance of the UT equipment data which is plus or minus .004 inches.

MEMBER KRESS: That helps a lot.

MR. CALLAGHAN: So sometimes it's plus, sometimes we'll gain material; sometimes we've lost material is basically what we're seeing.

The next three slides, again, Vermont Yankee has replaced a number of systems since 1970 with flow-accelerated corrosion-resistant materials.

First slide is equipment. We have replaced all 10 of our feedwater heater shells with resistant material. We've also done our low pressure turbine casings. The next page identifies some large bore piping. The majority of our two-phase flow piping at Vermont Yankee has been changed out to FAC-resistant material which keeps our concerns to a minimum and basically lowers the amount of inspections we did. We started, we did a number of -- a larger number of inspections when we first started the program, based on replacing materials and based on our results, that's where we've gotten down to the 25 to 35 large bore components right now.

The next slide shows our small bore piping. Again, a number of these pipings were replaced proactively based on operating experience at other industry facilities.

Next slide.

EPU impact. Vermont Yankee has completed and updated systems susceptibility review for flow-accelerated corrosion which documented that no new systems were needed to be added for the FAC for EPU. Those no new systems are equipment because right now if a system was identified in our program, the whole system is in the program. So it did not include any additional piping or components.

As you can see in this slide, flow and temperature does increase from EPU. Oxygen and pH level contents are not expected to change significantly to impact any FAC. In fact, the temperature increase in some places lowers the wear rate in the flow-accelerated corrosion, based on where the temperature is on the curve.

So right now what we're doing to determine our inspection scope going forward, we're using bounding analysis, using the 25 percent potential increase in the feedwater line. It's proportional to the velocity, so we are looking at our inspection data that we have up to date and trending that we do right now for CLTP, we're increasing that by 25 percent to see where we should inspect.

MEMBER RANSOM: Do you know the basis for being proportional to velocity? You would think it would be proportional to velocity squared which is the dynamic pressure and that represents dynamic forces.

MR. CALLAGHAN: Mr. Fitzpatrick?

MR. FITZPATRICK: The CHECWORKS formulation is 8 or 9 inputs and the mass transfer, it actually takes care of the geometry of each component. Velocity is an input to that. It is a squared term or it depends on the geometry, but you've got temperature effects, material effects and the net effect is a smaller increase than just -- if just the velocity increases 25 percent, the wear rates probably will increase less than that.

Typically, from other EPU studies, the increase in wear rates projected the maximum has been about the proportion of velocity increase.

MEMBER RANSOM: Is this built into CHECWORKS?

MR. FITZPATRICK: CHECWORKS will end up with -- the 25 percent is the number we're using to trend existing data. We trend data from measurements and we have a predicted model over here that does the most susceptible components to inspect. We've been working down that list.

MR. CALLAGHAN: So the CHECWORKS model will take the new velocity into effect. So there's really two parts of how we do this. We use the CHECWORKS model as a tool to get the susceptibility, the highly susceptible areas. We also use our trend data from our actual inspections where we're going out and we use the two of those, along with, as I said, operating experience and engineering judgment to determine where we're going next with our inspections or do we have to go back to the same spot for our inspections.

DR. BANERJEE: What is the mechanism of corrosion here?

MR. FITZPATRICK: For the single-phase systems, it would be -- Jim Fitzpatrick. For the single-phase systems, it's chemical. The oxide in typical FAC, single-phase FAC, the oxygen in the oxide goes in solution and iron goes free and the process keeps repeating itself.

DR. BANERJEE: So there's an oxide layer and that oxygen in some way disassociates into the --

MR. FITZPATRICK: Yes.

DR. BANERJEE: And then is it a wear problem which is velocity related that the iron is sort of eroded off or does it go into solution?

MR. FITZPATRICK: It goes into solution, but you've got flow continuous in a line. It would just become a steady state.

DR. BANERJEE: Also, it just dissolves?

MR. FITZPATRICK: It goes --

DR. BANERJEE: Without the projective oxide layer.

MR. FITZPATRICK: Yes, and more oxide forms and the process repeats itself.

DR. BANERJEE: And the velocity is just mass transfer rate is affected by the --

MR. FITZPATRICK: Mass transfer is different for each, like an elbow, a straight piece of pipe, pipe downstream of an orifice.

DR. BANERJEE: Sure.

MR. FITZPATRICK: Also, our BWR oxygen levels, 30 to 50 ppb, PWRs are down below 10 and the threshold for starting to have FAC is down around 10. So most PWRs won't have a problem with single-phase FAC in the condensate and feedwater systems.

DR. BANERJEE: What are your velocities like?

MR. FITZPATRICK: Average velocity in the feedwater system is approximately 15 feet per second.

DR. BANERJEE: So you see more of this where high turbulence exists?

MR. FITZPATRICK: Highest velocities are the feedwater reg valves and it's like 30 feet per second for the valves. We've monitored it both upstream and downstream of that for a number of years.

DR. BANERJEE: Okay.

MEMBER SIEBER: I guess my impression is that the flow-accelerated corrosion is a contest between corrosion and erosion, both mechanisms are going on at the same time and the influence of velocity determines which of the phenomenon is the predominant one, whether it's erosion or corrosion. And that's why the function that you get when you plot historical wear rates for a plant are not exactly proportional to the velocity or the velocity squared somewhere in between.

MR. FITZPATRICK: Because of the other factors involved.

MEMBER SIEBER: Right.

MR. CALLAGHAN: Jim Callaghan.

MR. LEITCH: Your inspections are done only at refueling outages or can they be done --

MR. CALLAGHAN: Yes, done at refueling outages.

MR. LEITCH: So you have some confidence then that once you reach EPU power levels, the flow-accelerated corrosion will not be aggressive enough that you'll have any problem mid-cycle?

MR. CALLAGHAN: No, we do not believe that, based on our running 32 years, the inspections we've done, the very low or minimal corrosion we have seen in the systems, and again, I reemphasize, we have changed out, replaced all our two-phase flow systems with FAC-resistant material. So we've done -- we've been doing this for the last 25 years, replacing material.

MR. LEITCH: It looks like the feedwater piping has the largest flow increase there, and also the largest temperature increase. Is the feedwater piping FAC-resistant piping?

MR. CALLAGHAN: No, the feedwater system is not FAC-resistant piping. That's why --

MR. LEITCH: It's just carbon steel.

MR. CALLAGHAN: Carbon steel. Single-phase.

MR. LEITCH: Which helps.

DR. BANERJEE: Do you have a problem with crud in the fuel, cobalt which is transported on and off and spreads around the system?

MR. CALLAGHAN: I do not believe so.

DR. BANERJEE: So you have no radioactive cobalt going around your system?

MR. CALLAGHAN: Not a significant amount, if we have any. I'm not --

DR. BANERJEE: So you have no seals which are stalite and things like that?

MR. CALLAGHAN: I would have to ask someone else.

MR. NICHOLS: Craig Nichols. We do have some components that retain, that are still stalite valve seats, etcetera.

DR. BANERJEE: So you still have those?

MR. NICHOLS: We still have stalite.

DR. BANERJEE: So there is some cobalt crud that goes on the fuel, comes off and spreads around the system?

MR. NICHOLS: There is a minimal amount of that.

DR. BANERJEE: It's not a major problem?

MR. NICHOLS: It's not a major or significant issue for Vermont Yankee.

DR. BANERJEE: For some BWRs it is, and flow effects are significant.

So you don't expect any flow effects on radionuclide transport around the system?

MR. CALLAGHAN: No, we do not. Getting back to EPU impact, this is Jim Callaghan. Another data point for determining future inspections is the CHECWORKS model as I identified. And we are updating that CHECWORKS model with our recent outage inspection data and the parameters for EPU to start selecting our components for our refueling 26 which is in 2007.

Currently, the program identifies a 50 percent increase in the amount of inspections we will do for the next three refueling outages.

Next. In conclusion, Vermont Yankee expects minimal changes in actual FAC-wear rates due to EPU. This is based on significant amount of the flow-accelerated corrosion resistant material in place, minimal wear rates identified through previous inspections and the flow increase from EPU which could be significant, 25 percent, but based on what we're seeing already, 25 percent of very little is still very little.

MR. LEITCH: The previous slide said a 50 percent increase --

MR. CALLAGHAN: In the number of inspections.

MR. LEITCH: In the number of inspections. Now how does that relate to the number of places where CHECWORKS says you ought to look?

MR. CALLAGHAN: I'll let Mr. Fitzpatrick answer that.

MR. FITZPATRICK: The 50 percent -- I was asked to come up with some long-term planning for budget and be prudent. We're estimating a 50 percent increase in scope for the next three outages, so at least we'll get more data. We'll use the CHECWORKS predictions to inspect more components, do repeat inspections on components that we already have data for, and develop a level of confidence under EPU operation.

MR. LEITCH: So in the three outages, will you have looked at every place where CHECWORKS says you might have a problem?

MR. FITZPATRICK: If the model correlates. It's statistical. It says these are susceptible and ranks them and then we go down and put inspection data in. It factors the inspection data into the correlations and says here's your new wear rate and theoretically, if you get enough data, it will match in the end. It's a planning tool. It's an empirical tool. It's not deterministic.

MR. LEITCH: I'm just concerned in this area about relying too heavily on your past experience. These added flow rates can cause the problem to accelerate in a nonlinear fashion. Some places have had these come on pretty fast.

MR. FITZPATRICK: We'll be looking at the highest length locations and the highest velocity locations in the next three outages. If we have low wear rates, we really can't detect them. You can't detect any real wear until you get some time between them.

MR. LEITCH: Yes, okay. We just, which I'm sure is clear to you, we spend an awful lot of time talking about nuclear safety. This is that, but it's also an industrial safety problem. We can hurt people this way and I just want to emphasize that and it sounds like you guys are right on top of it.

MR. CALLAGHAN: We understand that, and that's why we're increasing our inspection scope in a logical way.

Okay, to go back to conclusions, Jim Callaghan again.

Again, there's no impact. EPU had no impact on the flow-accelerated corrosion program, methodology or scope and as I said really the one significant change is the amount of inspections we plan to do programmatically over the next three outages and beyond if we see anything. But right now, that's the expectation of the program.

That's the conclusion of my flow-accelerated corrosion presentation.

CHAIRMAN DENNING: Okay, you can go on to PT. Pressure-temperature limit curves. This is a very short, one slide. Current license thermal power, fluence calc and PT curves was updated in 2003. The curves were based on a peak neutron fluence of 1.24 times 10^{18} neutrons per centimeter squared. The calculations done for EPU fluence calculation, the fluence rate, the flux did increase by 26 percent. Calculating the EPU actual peak fluence, you can see on the slide it came out to 3.18 times 10^{17} which is obviously bounded by the current PT curves in our tech specs which is 1.24 times 10^{18} neutrons per centimeter squared.

Just for information did throw what the current license thermal power fluence is up there. You can see it's 2.99 times 10^{17}.

CHAIRMAN DENNING: This is integral through plant lifetime? Is that what those fluences are?

MR. CALLAGHAN: Yes.

MEMBER WALLIS: Integral through what?

CHAIRMAN DENNING: Through plant lifetime.

MEMBER WALLIS: Oh, I was wondering how time came into it. It's integral over the whole lifetime.

MR. CALLAGHAN: Yes, it is.

CHAIRMAN DENNING: What about internals and their embrittlement? Is that an issue that represents a safety concern or concern? Obviously, internals are going to see a significant increase in fluence.

MR. CALLAGHAN: I would like to ask Mr. Rico Betti, VY's Senior Structural Engineer.

MR. BETTI: I am Ricco Betti. The interesting thing about the fluence evaluation that we had done was that our original fluence evaluation and numbers that we had for designed for our internals was much higher than those that were calculated in our updated fluence calc.

We updated a fluence calc and we hadn't done it for quite a few number of years and we had some old, pretty conservative numbers in our fluence evaluation, so our internal evaluations for flow evaluations or effects on the internals was based on higher, original GE values from 1970s, late 1960s and when we had GE update our fluence evaluations it turns out most of the fluence estimates on internals and walls, etcetera dropped. That's the short of it.

CHAIRMAN DENNING: Because of major conservatism in the initial calculations, even though clearly the flux is probably substantially higher?

MR. BETTI: That's right.

CHAIRMAN DENNING: Are there any components where embrittlement is a limiting, life limiting and they have to be replaced because of embrittlement?

MR. BETTI: No.

CHAIRMAN DENNING: No.

MEMBER KRESS: These integrated fluence values, are they both with the new flux calculations or is this CLTP, the old one with the old flux?

MR. BETTI: No, they're both with the new --

MEMBER KRESS: Both with the new.

MR. BETTI: Flow calc.

MEMBER KRESS: I don't understand why the flux increases by 26 percent, that the fluence doesn't increase by 26 percent.

MR. BETTI: I'll turn that back over to Jim.

MR. CALLAGHAN: I can ask Mr. Perez to --

MR. PEREZ: Hi, I'm Pedro Perez. The reason for that is, that's an integrated amount over a four-year life of the plant. The first 33 year integration is the lower fluence rate and then the remainder is at a higher. So the net effect is not --

MEMBER KRESS: Is not 26 percent.

MR. PEREZ: Right.

MEMBER KRESS: Because it's not over the whole time.

MR. PEREZ: Exactly.

MEMBER KRESS: Thirty years at the lower.

CHAIRMAN DENNING: Another way to look at is you're increasing power by 20 percent, so that's automatically increasing the fluence by 20 percent, plus you have to flatten the core. And when you flatten the core you're raising the outer edges which most influences the vessel wall.

MEMBER KRESS: That's why it fluxes 26 percent instead of 20 percent.

MR. CALLAGHAN: Any other questions?

CHAIRMAN DENNING: No other questions, thank you.

MR. CALLAGHAN: Thank you very much.

(Pause.)

MR. ENNIS: This is Rick Ennis. We have a presentation now by the Materials and Chemical Engineering Branch. First up will be Barry Elliot.

MR. ELLIOT: Thank you. My area of discussion is going to be the reactor pressure vessel integrity and the internal integrity.

I'll start off with the reactor pressure vessel. The Staff looks at radiation embrittlement and its impact on integrity. The three areas we look at in evaluating a reactor vessel integrity is the surveillance program, the effective upper-shelf-energy of the materials in the beltline of the reactive vessel, and the pressure temperature limits.

With respect to surveillance program, the regulation that is here is the Appendix H, established rules for -- that all licensees must use and to monitor radiation embrittlement. There are two choices. You can have a plant-specific program where the capsules are irradiated within the existing vessel, or you can have an integrated surveillance program where it could be a host reactor providing data to the plant.

In this case, for Vermont Yankee, they're part of an integrated surveillance program which is used for the entire BWR fleet. This program was approved for Vermont Yankee in a letter dated March 29, 2004. In this program, the monitoring of the weld and the plate material will be used -- that Vermont Yankee will use the data from the Susquehanna Unit One Surveillance Program.

We've looked at, as part of the EPU, we've looked at the impact of fluence on the surveillance program and the existing program is adequate for Susquehanna to give radiation monitoring data throughout the license of the plant.

CHAIRMAN DENNING: Was there an issue with the initial number of specimens available and that's why it went to an integrated surveillance program?

MR. ELLIOT: The integrated surveillance program was established many years ago for the BWR fleet. Some plants were missing data and some plants didn't have good data. So they decided to use an integrated approach where they would look for, at each vessel and look throughout the entire fleet surveillance program and pick out particular capsules that would be used for each vessel. It turned out that the Susquehanna surveillance material was very good for Vermont Yankee. So that's how we wound up there.

MEMBER SIEBER: That's based on the metallurgical constituency of the capsule compared to the vessel.

MR. ELLIOT: That's right.

CHAIRMAN DENNING: So welding materials were similar?

MR. ELLIOT: Welding materials and the plate materials are similar at Susquehanna to Vermont Yankee and that's why it was chosen to be the host plant.

MEMBER SIEBER: How do you overcome the fact that Susquehanna is a lot newer plant and therefore has --

MR. ELLIOT: Susquehanna has a higher leaf factor.

MEMBER SIEBER: That's true.

MR. ELLIOT: And so they get more

radiation per time for their capsules than Vermont Yankee. So they're going to have much higher fluences earlier than Vermont Yankee.

MEMBER SIEBER: Have they caught up yet?

MR. ELLIOT: I don't know if they caught up yet, but --

MEMBER SIEBER: It's sort of a race.

MR. ELLIOT: I know that when the capsules are going to be withdrawn and they're going to be withdrawn at certain radiation levels which are the levels that will be useful for Vermont Yankee.

MEMBER SIEBER: So in the meantime, Vermont Yankee actually had its own capsules, right?

MR. ELLIOT: Yes. And --

MEMBER SIEBER: It's not like you don't have any data.

MR. ELLIOT: No, no. We have one surveillance capsule that they withdrew. That's good data. It's very important and we've made them commit to keeping the capsules in the vessel. They can't take those capsules out. If these are backup capsules that if something happens at Susquehanna, we have something from Vermont Yankee that we can fall back on.

The second issue that we address in vessel integrity is the upper shelf energy and this is a ductility question for the vessel. This is a very good vessel. Let me tell you why. This was built by Chicago Bridge and Iron, this vessel. And the weld material here is shielded metal arc weld. Most of the vessels in the United States were fabricated using submerged arc weld. And in the submerged arc weld process the electrode is covered with a copper coating and the copper coating is what causes all the embrittlement. These people have used -- Chicago Bridge and Iron used shielded metal arc weld which doesn't have the copper coating, so this plant has very low copper. That's why you saw in the previous projection, they can go to very high fluences and it doesn't matter to them because the copper is so low. They just don't have a problem.

And in fact, for the upper shelf Entergy, I estimated that they would state even with the higher EPU conditions, their upper shelf energy is still above 50 foot pounds. That's Appendix G requirement. If you go below 50 foot pounds, then you have to do some more analysis, but their materials are so good that they just won't have that problem.

The same thing with the pressure temperature limits. I don't want to redo what was just done a minute ago, but they're very low copper. It's plate limited because the copper is so low, so this vessel, the PT limits can last a very long time.

In conclusion, the licensee has adequately addressed changes in neutron fluence resulting from EPU conditions in the reactor vessel.

The next area I'll talk about is the integrity of the reactor internals and core support materials. The BWR fleet has also a sort of integrated inspection program and where they have put together reports and inspection programs for all of the reactor vessel internals.

We reviewed those programs and they are adequate, except for two. We decided two of the programs were inadequate. One was the program for the top guide grid beams. The top guide grid beams are susceptible to irradiation assisted stress corrosion cracking. The criteria the Staff uses for determining whether it's susceptible is if the fluence exceeds 5 times 10^{20} neutrons per centimeter squared, in the area the material is susceptible.

For uprate conditions, the only internal component that will receive this type of fluence is the top guide grid beams. In response to a Staff RAI, the licensee has adjusted its top guide grid beam program and it's now, we'll be doing periodic inspection of the top guide grid beams and that's where we're at. They will start that after they start power uprate.

And then yesterday, the other area, of course, is the steam dryers. Yesterday, you heard a presentation, I'm not going to go through anything as deep as that. The steam dryers program at the time we wrote this SER was not in place, so as a minimum we requested that the licensee do inspections as three refueling outages following the power uprate and this will give us an idea of whether or not there's any problem that we've missed.

I just want to point out this is more than is required by the GE seal, seal 644 rev. 1, would only require two outages. And then you can go to less frequently, I think every other outage. So they're doing a little bit more here and based on these results, we will know what to do in the future.

Finally, in conclusion, licensee has identified appropriate degradation management programs to address the effects of EPU on the reactor internals and core support materials.

Thank you.

MR. ENNIS: Next up, we have Bob Davis.

MR. DAVIS: I'm going to be talking about the reactor coolant pressure boundary barrels for the flow pressure temperature mechanical loading for most of the reactor coolant pressure piping systems. These do not increase for the extended power uprate. If there are any increases they're very, very minor.

MEMBER KRESS: Does that include thermal transients, fatigue thermal transients?

MR. DAVIS: Those are assessed where necessary and I'll -- for example, for the main steam and I'll get into that in just a second.

Some of the systems were considered generic and in accordance with the topical report that we approved. And other systems required plant specific evaluations. Which systems required plant specific evaluations and which systems were considered generic, some of that is proprietary, so I can't discuss all of that here.

The plant specific evaluation process was done consistent with Appendix K of the ELTR1 which is the generic guidelines for GE, BWR, EPU. And that was reviewed and approved by the Staff.

The major system that we looked at was the reactor recirculation system and for Vermont Yankee, all of this material has been replaced with Category

A material per NUREG 0313 which is a low carbon 316 stainless steal which is resistant to intergranular stress corrosion cracking.

We also inquired as if there were any flaws in the recirculation system that Vermont Yankee is currently monitoring and there are no flaws that they are currently monitoring in the reactor recirculation system.

For the main steam and feedwater systems inside the containment, there will be an increase in flow which -- with the feedwater, I think the gentleman from the licensee just discussed that in an earlier presentation.

These increases in flow in the main steam and the feedwater which are over 20 percent were evaluated for compliance with the code of construction requirements under the EPU conditions. So it meets the 1967 B311 requirements.

And as far as for the transient conditions, I'll have to defer that question to someone -- they did evaluate that in transient conditions, so the main steam and feedwater still will meet the requirements. If you need any more in-depth information on that, I'll have to refer you to somebody. And B31 addresses those issues.

MR. LEITCH: This plant is on hydrogen water chemistry?

MR. DAVIS: They do have a water chemistry program and Chris will talk about their chemistry program in the next presentation.

MR. LEITCH: Now you mentioned the reactor recirculating system, but what about other systems adjacent to the reactor, RHR, core spray, reactor water cleaner?

MR. DAVIS: Well, for all those, they were either considered generic to the topical report or they were evaluated -- and all those others, all the systems other than main steam and feedwater, there's really no increase or very slight increase in pressure, temperature or flow. I believe the recirc. system, I think the flow is less than 2 percent. The pressure is very minimal and it's all new. It's all new IGSCC resistant material.

MR. PARCZEWSKI: My name is Kraysztof Parczewski, talking about three areas where you could produce one effect. There are protective coating and organic materials, flow-accelerated corrosion, interactive water cleanup system.

The flow-accelerated corrosion, I've prepared a presentation, is limited to the amount of material provided to us in our submittal. You heard presentation with quite a bit of presentation of the material on the flow-accelerated corrosion. So to listen to my presentation is basically repetition of what has been presented before.

Now my protective coating, after DBLOCA, some of the coating inside the containment may fail, generating debris which will be carried by moving fluids and deposited on pump strainer inducing NPSH of the pump. The licensee determines the generation of this debris and its effect by EPU.

There are two types of material which are recognized by the licensee. Protective coating consisting of inorganic zinc is an epoxy top coat and organic material consisting of carbon-based paint chips.

Using the methodology from the report, NEDO-32686, the licensee determines about 85 pounds of protective coating could be stripped by the post-LOCA jet. This value is bounding and is unchanged after EPU.

The effect of EPU organic material was assessed by the test, performed by Argon Research Laboratory. They simulated the LOCA environment and found the strained approach velocity and suppression turbulence were very, very low and did not change after EPU. There was no change in NPSH therefore.

They concluded that the effect of damage protective coating on plant performance is not affected.

MEMBER WALLIS: Can you tell me more about the physical nature of these chips? Are they fine, very fine particles? Are they flakes or what are they?

MR. PARCZEWSKI: That's right. They're very, very fine and there is not enough force to deposit it on the strainer.

MEMBER WALLIS: Are they hydrophobic or hydrophilic or anything? Is there a chance that they would pick up air and have air attached to them?

MR. PARCZEWSKI: I'm sorry?

MEMBER WALLIS: I just wonder if they're just chips or they're chips with maybe air bubbles attached to them or something, when everything is all stirred up in the initial --

MR. PARCZEWSKI: Actually, I don't know this information.

MEMBER WALLIS: I mean if they had air attached to them, they might not sink.

MR. PARCZEWSKI: Very, very few of them

are deposited on the strainer. I don't know the mechanism.

MEMBER WALLIS: That's sort of assuming that they sink, that they're not attached to air bubbles or anything else like that.

DR. BANERJEE: That also assumes that the turbulence level is low.

MR. PARCZEWSKI: The turbulence level is very low.

MEMBER WALLIS: But that is an assumption.

MR. PARCZEWSKI: This, this probably prevents it from --

MEMBER WALLIS: Also, they could be attached to the other fibrous material before they get to the pool? I just don't know. There's sort of an assumption that they're all on their own at the bottom of the pool. It seems to me a bit of an assumption because there are ways in which they could attach to something else.

DR. BANERJEE: What is the sludge material?

MR. PARCZEWSKI: Beg pardon?

DR. BANERJEE: What is the sludge which is there which is cleaned up?

MR. PARCZEWSKI: It's usually aquatic

different materials.

DR. BANERJEE: How does that arise?

MR. PARCZEWSKI: It is corrosion products.

DR. BANERJEE: >From where?

MR. PARCZEWSKI: >From the piping.

DR. BANERJEE: So there is quite a substantial amount of sludge that's removed every -- shot down or whatever. Where does this come from? How is this affected? And is that going to be affected by the EPU?

MR. PARCZEWSKI: Well --

DR. BANERJEE: Is it going to go up?

MR. PARCZEWSKI: It is probably affecting EPU because the particles --

DR. BANERJEE: What is their origin? I couldn't understand where this sludge came from. Maybe someone can enlighten me.

MEMBER WALLIS: Does FAC has something to do with it?

MR. ELLIOT: Excuse me --

DR. BANERJEE: You clean it out --

MR. ELLIOT: I just read Kryz' slide and what he's trying to tell you, I think, here is that the analysis that they've done in the past is applicable for EPU condition. That's his conclusion.

There is a generic program going on right now about the strainers and all of the issues you're talking about are part of that review.

DR. BANERJEE: Is this going to be dealt with by somebody else?

MR. PARCZEWSKI: At the present moment, this particular program Bob mentioned is an on-going program. We don't have the final results.

DR. BANERJEE: What I'm asking about is that when you deal with what ends up on the strainers, there is, of course, things that come from the insulation, right? There are paint chips or whatever comes from these coatings, much of it is unqualified. The third thing is sludge which is present there already, which they clean out every now and then, whatever frequency.

MR. PARCZEWSKI: Yes.

DR. BANERJEE: I'm asking where does that sludge come from?

MR. PARCZEWSKI: I cannot answer the question. I can provide you --

DR. BANERJEE: That would be nice. Somebody should answer that question. I would like to know what effect the EPU might have on that sludge, if any.

MR. ENNIS: This is Rick Ennis. I think Craig Nichols might have some information to provide.

MR. NICHOLS: Craig Nichols from Entergy Vermont Yankee. As we have a session this afternoon on debris and strainers and stuff, Entergy would be glad to discuss that during that presentation.

Is that acceptable?

CHAIRMAN DENNING: I think we can move on this point, recognizing we'll come back to it. Thanks.

MR. CARUSO: Can I ask one question? Does the Staff intend to apply the lessons learned from the resolution of the GSI 191 issue which is currently aimed at pressurized water reactors? Does the Staff intend to apply that information to boiling water reactors as well?

MR. PARCZEWSKI: The specific information of the gels wouldn't apply to BWRs because there is no chemistry. It's pure water. In the case of PWR, you have water calcitant, some other material, so this is a completely different issue.

MR. CARUSO: I guess my question is more programmatic question because you said that there would be -- the Staff would be considering what came out of that program and looking at boilers.

MR. ELLIOT: No, I don't think that was our intent.

MR. CARUSO: That was not your internet?

MR. ELLIOT: No.

MEMBER SIEBER: It was my understanding the boilers came first as far as examining sump capacity and sump clogging and then the PWRs came later which is the GSI 191 issue. The boiler issue is closed to my knowledge. And for each plant individually, in the PWR issue, still subject to the Generic Letter response.

MEMBER KRESS: Do you have buffer material to control the pH of your suppression pool?

Do the BWRs buffer their suppression pool to control the pH?

MR. PARCZEWSKI: No.

MEMBER KRESS: That's only PWRs?

MR. PARCZEWSKI: Yes.

CHAIRMAN DENNING: Okay, let's continue with the presentation.

MR. PARCZEWSKI: Now should I make a presentation on flow-accelerated corrosion?

CHAIRMAN DENNING: Go ahead.

MR. PARCZEWSKI: The rates of flow-accelerated corrosion are affected, but several operational parameters some of which will be -- will change after EPU. These parameters are flow velocity, temperature, moisture and oxygen content.

After EPU, the licensee will determine new values for these parameters and introduce them into the revised predictive coding CHECWORKS, making it applicable for predicting flow-accelerated corrosion wear rates after EPU.

CHAIRMAN DENNING: Has Staff reviewed CHECWORKS and they're comfortable that it --

MR. PARCZEWSKI: This right here is CHECWORKS. I am going to give you an example of change in flow velocity after EPU. It's quite considerable. Usually, it's about 24 percent increasing. So will be reflected on wear rates. Temperature will similarly change.

So really, basically the program, the predictive program will be updated and use to predict wear rates after EPU.

My final presentation will be reactor water cleanup system. The most significant changes in reactor water cleanup system is performance after EPU are due to high flow caused by high feedwater flow after EPU.

Flows with the system, usually within .8

one percent of feedwater flow. Obviously, there's feedwater is reflected in the flow in the water, reactor water clean up system.

MR. LEITCH: There is no increase in flow in the reactor water cleanup system.

MR. PARCZEWSKI: Yes, it does increase.

MR. LEITCH: Reactor water cleanup pumps are not changed in any way are they?

MR. PARCZEWSKI: No, very small changes. This change in most cases is significantly small and no modification of system operation is needed. Very small indeed.

Slight increase of system pressure. Slight increase in system pressure and lower temperature, increase in ion concentration and increase in water conductivity. The only significant change in plant operation will consist of more backwash of filter demineralizer and keeping the control bar in slightly more open position to compensate for the increased water, feedwater pressure.

In addition, the licensee verified for all pipes and components, the pressure and temperature rating will remain unaffected because of negligible changes in system process parameters and no instrumentation set forth needs to be adjusted. So basically the changes are very small after EPU.

DR. BANERJEE: Can I ask you a question?

MR. PARCZEWSKI: Yes.

DR. BANERJEE: Going back to the generation of these coatings in the DBLOCA, post-LOCA jet, there is going to be more energy discharged because the plant is running at a higher power and generating more power as well. And post-LOCA as well.

MR. PARCZEWSKI: Yes.

DR. BANERJEE: Now do you believe that it's reasonable to assume that nothing will change post-LOCA, even though more energy has to be discharged?

MR. PARCZEWSKI: Well, there are changes, but they are very small ones.

DR. BANERJEE: But the jet must carry with it ultimately more energy?

CHAIRMAN DENNING: Why is that, Sanjoy?

DR. BANERJEE: More power is being generated.

CHAIRMAN DENNING: No, but that doesn't affect the jet, the LOCA jet. It's the same condition.

DR. BANERJEE: The quality of everything

inside is different, right? There's a higher quality. So the quality means there's energy. Energy is related to the latent heat of vaporization here. So it has to have power.

MEMBER WALLIS: It depends on where the break is.

DR. BANERJEE: It depends to some extend, but it's not obvious to me that it should be the same. I haven't looked at it in detail, but I don't see that it's obvious that it has to be the same.

Is it related just to the discharge rate? Is the discharge going to be the same quality, the same energy, the same flow rate?

Is it break related? There's no affect of upstream conditions?

CHAIRMAN DENNING: Well, I think this is a good question. I don't know whether someone from Entergy or the Staff wants to address it. This isn't obviously the right group to address that, but it is an interesting question.

DR. BANERJEE: They subscribe to this conclusion.

MR. ENNIS: I think Michael Dick from --

MR. DICK: This is Michael Dick with GE. The answer isn't, and part of the beauty of the constant pressure power uprate is is that there is either no effect or very minimal effect. I can give you a couple of examples.

One, for the recirc line breaks, it's not affected by power uprate and the fact is that these limiting breaks occur down at the lower end. You're going to have the most mass and energy rate release. It's going to be down at towards the natural circulation part of the power flow map. That's where you get the maximum sub-cooling.

The other is as far as with the main steamline breaks, those aren't changed. We're not having to change -- we're not changing the pressure, okay, in the main steam system and so then that that break flow is going to be based on either -- for inside containment, it's going to be assuming instantaneous break is on the choke flow of the pipe which is a function of the pipe size, which of course, isn't changing.

And of course, the major issue is the pressure is not changing so the choke flow, so the break flow doesn't change either.

MEMBER KRESS: Just lasts longer.

MR. DICK: Yes, yes.

MEMBER KRESS: But by the time you get

near the end of it, you've already wiped out what stuff you're going to wipe out.

MR. DICK: Sure. It's that initial impingement that really is going to be driving the material.

MEMBER WALLIS: The bigger effect is whether or not the paint has aged and it becomes easier to strip, you'll see a much bigger effect than any of these other conditions you're talking about.

MR. DICK: My understanding, Dr. Wallis, that's one of the subjects we're going to talk about this afternoon.

DR. BANERJEE: So the contention is that the discharge rate is the same, but it lasts longer. So the initial pulse which is supposed to do most of the damage is of the same magnitude, but the tail goes on longer to take the energy out ultimately.

And you have to have -- what goes in has to come out.

MR. DICK: Absolutely, absolutely. The course then that you're depressurizing in that and that's very low energy.

DR. BANERJEE: So it's just that the energy deposited for a longer period of time, but the pulse of energy that comes out first which is the most intense is of the same magnitude.

MR. DICK: Sure, sure.

DR. BANERJEE: That's the argument.

MR. DICK: Sure, and you can see that kind of in a broad picture. Sure, there's more energy, but you look at the overall containment response, okay as far as the pressurization, but the power uprate itself only causes the peak containment pressure to go without .2 PSI, I believe it's 41.6 to 41.8 between current license power and EPU power level. So I'm saying yeah, that increase in overall containment pressure is a function of yes of the uprate itself, but that effect is very minor.

CHAIRMAN DENNING: Tell me again as far as you're saying the amount of energy. Clearly, there's more stored energy than fuel.

MR. DICK: Sure.

CHAIRMAN DENNING: But what about the enthalpy in the water and steam. Is there really any significant --

MEMBER WALLIS: It's less. You have a higher quality for the same volume, you have less. Same volume system, with the high quality in the reactor, you have less stored energy in terms of --

DR. BANERJEE: Well, you have it as steam.

MEMBER WALLIS: But that's less. Same volume.

DR. BANERJEE: It doesn't condense. When it condenses it has more.

CHAIRMAN DENNING: Okay, I think that -- Rick, I'm wondering -- I think we are done now with this presentation and I was wondering if maybe, although we had promised that we were going to not do the electrical engineering, since we really have until 10 and as long as Ralph doesn't beat me over the head, I would propose that we do the station blackout portion of the electrical engineering presentation or have we lost everybody?

MR. ENNIS: I would have to check as we turned the reviewer loose and told him he didn't have to do his presentation. So I'll have to check to see if he's available.

MR. ENNIS: The other thing, Entergy was going to talk about station blackout too, so I'm not sure --

CHAIRMAN DENNING: Which one we'd prefer or if we want both.

MR. ENNIS: We talked about a lot of it during the last meeting in response to the engineering inspection.

MEMBER WALLIS: I have a question.

CHAIRMAN DENNING: Well, you may ask a question then.

MEMBER WALLIS: I think as part of his presentation, either yours or the previous one, I was reading the SER and there was a statement that the steam separators would maintain their structural integrity under EPU conditions. This isn't the dryers, this is the separators. Underneath the dryers is these things that separate and this seemed to have no basis. Just a statement. Is this based on tests at high quality or something? Is there some basis for the statement that there's no problem with the steam separators handling the higher quality? Where did that come from?

MR. DICK: This is Michael Dick with GE again. Yeah, the steam separators for Vermont Yankee application were instrumented both at the prototype plant for the 205-inch vessel which is Monticello. And there was also instrumentation done during the initial start up testing of the VY plant.

If I remember correctly from our analysis, that the predicted stress level on the separators is at EPU conditions on order of about 1 ksi against our original criteria, GE criteria which is 10 ksi.

The second issue is that these separators, the model that is installed at Vermont Yankee, these were tested under full flow conditions before they started to be implemented in the 1970s throughout the fleet and they were tested at flow rates that are well in excess of the flow rates that each one of the separators -- and that was 129 separator elements for the Vermont Yankee head and separator assembly.

MEMBER WALLIS: So there's no vibration problem?

MR. DICK: We don't believe there's any vibration problem. That's the basis for our conclusion.

MEMBER WALLIS: Your 1 ksi. That's assuming steady conditions.

MR. DICK: Yes.

MEMBER WALLIS: No shaking.

MEMBER WALLIS: I was just curious about what the basis was for this statement. It's because of GE's tests, right?

MR. LEITCH: I had a question in this area about hydrogen water chemistry. Is this plant on hydrogen water chemistry? And will there be any impact on a hydrogen consumption rate to sustain proper protection?

MR. DICK: This is Michael Dick with GE again. Vermont Yankee has both hydrogen water -- they're what we call a low hydrogen injection plant because they have both hydrogen water chemistry and Nubble metal coating, so effectively, the rate of hydrogen injection will increase with the proportional to the feedwater flow rate in order to maintain the same PPM concentration of hydrogen in the feedwater system, okay, which of course goes through the vessel. So yes, there is a very, very slight -- well, effectively, there's a 20 percent or 22 percent increase in hydrogen consumption and I don't have the actual VY's injection levels, but for low hydrogen injection plants, that injection rate is a factor of 10 to 20 lower than the systems were originally designed and analyzed to be able to inject and not have problems with normal operational doses in the plants.

MR. LEITCH: So presumably the plant has the capability to increase it by 20 to 22 percent/

MR. DICK: Oh absolutely. That's something -- I believe that is -- and once again, I plead a little bit of ignorance. I don't have the exact VY value they're injecting now, but typically that would be on the order of say 1 to 2 SCFM and so then it would go up 20 percent. So effectively going from 2 to 2.2 SCFM. That's a very, very low hydrogen injection rate.

MEMBER SIEBER: Actually, it probably wouldn't go up 20 percent because the ingress of oxygen in the system is based on all these pressures which really don't change that much and so the flow rate doesn't, feedwater flow rate doesn't make all that much difference. It's how much oxygen gets into the system that needs to be dealt with with the hydrogen you inject.

So it will go up, but probably not even 20 percent.

MR. DICK: Yes, but the issue is conservatively it would go up because I believe the VY doesn't have ECP probes and so they're doing their injection rate analytically.

MEMBER SIEBER: All right.

MR. DICK: So you just basically conservatively inject, sure.

MEMBER KRESS: That instrumentation you talked about on the separators, does it still exist?

MR. DICK: No sir.

MEMBER KRESS: It's not --

MR. DICK: Yeah, that would have only

been, that would have been installed only for the initial start-up test program.

DR. BANERJEE: Where is the hydrogen injected and how does it mix?

MR. DICK: It's injected into the feedwater system.

DR. BANERJEE: And it mixes as the flow goes down into the core?

MR. DICK: Yes. The feedwater lines go into spargers.

DR. BANERJEE: Right.

MR. DICK: Okay. Which is a sparger into the annular region between the shroud and the --

DR. BANERJEE: So it mixes in the down -- as it goes down?

MR. DICK: Yes sir.

DR. BANERJEE: And the high velocity of the mixing as effective? Because I think once the hydrogen gets into the core, then it's effectiveness after that goes down, doesn't it?

MR. DICK: Well, sure. That's why it's a feed and bleed system.

DR. BANERJEE: So is the increased velocity going to have a shorter transit time, adequate mixing in the down columns?

MR. DICK: Well, no, because our core flow rate isn't changing with the power uprate.

DR. BANERJEE: So the transit time is still the same?

MR. DICK: Yes sir.

DR. BANERJEE: And the mixing you expect is good. These are issues which have arisen in other BWRs with regard to mixing of the hydrogen and the down columns.

MR. DICK: I believe that's been analyzed. I just don't have the information.

DR. BANERJEE: All right.

MEMBER WALLIS: How does the piping vibration monitoring program work? We talked about steam line and instrumenting that. Does the feedwater line have high velocities and so on? There's something referred to as a piping vibration monitoring program. Do you have strain gauges spread around the plant or something? Or someone is listening? What's happening?

MR. NICHOLS: As part of the program, we have both accelerometers installed in accessible areas such as the dry well and high radiation areas and also plant walk down.

MEMBER WALLIS: Is it already there?

MR. NICHOLS: It's already there installed, yes sir.

MEMBER SIEBER: I thought vibration monitoring is done with portable instruments. You do pumps and valves and that tells you the pump is good, if you've worked on it and you've aligned it right and it's not going to tear itself apart through operation. So the only permanent installation is generally in high rad areas or hard to get to areas.

CHAIRMAN DENNING: Is Entergy willing to give their station blackout presentation at this time?

MR. NICHOLS: We can do that.

CHAIRMAN DENNING: Let's do that for the next 15 minutes.

(Pause.)

You can go ahead and start whenever you're ready.

MR. NICHOLS: We just have to load it up.

CHAIRMAN DENNING: Yes.

MR. NICHOLS: Good morning. I have with me Mr. Paul Johnson, principal engineer in our Design Electrical Department. And Mr. Paul Rainey, Senior Consultant in our Mechanical Fluid Systems Group.

Station blackout is referred to as the loss of all off-site power to the Vermont Yankee switch yard. The loss of both on-site, the two on-site alternating current diesel generators and the Vernon tie alternate AC source which requires a restart due to the presumed regional blackout. That's fed as part of a diverse grid system, but under the regional blackout, it is assumed that that is also lost. Therefore, there is a loss of all on-site and off-site AC sources.

The analysis performed meets the Reg. Guides and NUMARC 87-00. Vermont Yankee is an 8-hour full coping plant with a 2-hour, AAC meaning a loss of alternate occurring power for two hours until the AAC source, the vernon hydrostation is brought back.

MEMBER SIEBER: And what does that give you, the battery charger?

MR. NICHOLS: No, that's the equivalent of one diesel generator. So we would have power for pumps, valves, core cooling systems.

A coping study that's performed includes reactor level control using our high pressure coolant injection system, reactor pressure control with a safety relief valve. It's been determined that there is sufficient inventory in the condensate storage tank, that the battery capacity is sufficient for that two-hour period until the battery chargers can be realigned after the restoration of AC power.

The peak torus temperature remains below 185 degrees during the whole of the event, meaning there's no need for credit and containment over pressure for NPSH. The loss of ventilation for the control room and the emergency core cooling systems has been evaluated and that there is sufficient air or in our case, nitrogen, available for operating the SRVs and necessary loads.

CHAIRMAN DENNING: With regards to the torus temperature, is it the duration? Why is it that the torus temperature remains below that whereas in some other scenarios it doesn't? It's a matter of how long we have to follow it?

MR. NICHOLS: It's the amount of decay heat, depending on the event, whether it's assumed that appendix K conditions, etcetera, and what you have available to mitigate that.

CHAIRMAN DENNING: Now when you get power back from -- when you get the vernon -- is that what I mean? The -- no, the hydro. When you get the hydro back, how much -- how long do you have to rely on that? You say it's an 8-hour plant. Does that mean then that in 8 hours it's assumed that other sources of electricity are made available?

MR. NICHOLS: That's correct.

CHAIRMAN DENNING: And is that what -- in the period after the hydroplant comes on, how many RHRs are you working as far as heat exchangers?

MR. NICHOLS: I'll ask Mr. Rainey to address that.

MR. RAINEY: I'm Paul Rainey. What we do is run one RHR pump in the torus cooling mode and that basically we put that on once we get power back.k

CHAIRMAN DENNING: Yes, and now if you continued that forever and you've got no more AC power back, would the torus temperature then rise above the 185?

MR. NICHOLS: No.

CHAIRMAN DENNING: No?

MR. RAINEY: No, that peaks at approximately three hours.

CHAIRMAN DENNING: Peaks that early?

MEMBER SIEBER: In effect, you get one full safety train back.

MR. NICHOLS: That's correct.

MEMBER SIEBER: Either one.

MR. NICHOLS: Right.

CHAIRMAN DENNING: What I'm trying to figure out is what's the difference between that and the LOCA as far as where the heat is going? Where is the heat going?

MR. RAINEY: The LOCA dumps the majority of the heat right at the beginning.

CHAIRMAN DENNING: Yes.

MR. RAINEY: During a station blackout where you're doing a controlled heat removal, via the SRVs, we're not dumping all the --

CHAIRMAN DENNING: So you don't have the dump of all the original --

MR. RAINEY: Not right at the beginning.

MEMBER WALLIS: So eventually it has to go somewhere.

MR. RAINEY: Yes, and then we have torus cooling on and we're removing the heat.

MR. NICHOLS: It's also performed at nominal conditions meaning not 102 percent appendix K power that's which the LOCA is.

CHAIRMAN DENNING: Uh-huh.

MEMBER WALLIS: Can you start the plant based on just the vernon supply?

MR. NICHOLS: No.

MEMBER WALLIS: You need to have the --

MEMBER SIEBER: The tech specs would --

MR. NICHOLS: We'd be fed by the off-site power supply and have to have the diesel generators available.

MEMBER SIEBER: Two alternate sources.

CHAIRMAN DENNING: So the 102 percent could be enough to make the difference here?

MR. NICHOLS: There's other conservative assumptions required in the appendix K LOCA calculation.

CHAIRMAN DENNING: That are not in there.

MR. NICHOLS: That are not in the station blackout.

CHAIRMAN DENNING: That's probably a large part of where it is, then. Okay.

MEMBER WALLIS: It's a realistic calculation.

MR. NICHOLS: This table provides the time line for the restoration of the vernon hydro or alternate AC source in the 2-hour period, at time zero, the station blackout when the regional grid blackout occurs. As required by procedure, the hydrostation is notified within 10 minutes.

MEMBER WALLIS: But there's nobody there.

MR. NICHOLS: Right.

MEMBER WALLIS: They're notifying Wilder or something.

MR. NICHOLS: That is correct. And that's why we conservatively use the additional 90 minutes within the 100 minutes.

MEMBER WALLIS: If you drive from Wilder to Vernon in good conditions it takes you about 60 minutes. The best you could do would be an hour, unless you broke the speed limit.

MR. NICHOLS: But that's using the worse case assumption that it would have to be someone from Wilder. There are two other stations that have personnel assigned at Bellow Falls and Vernon. There are people assigned to Vernon, they just may be out on assignment.

They may be at Bellow Falls. They may be at other areas that are closer to Vermont Yankee. We also assume the off-hours condition potentially.

MEMBER SIEBER: How far away is Vernon from the Vermont Yankee plant?

MR. NICHOLS: It's within two-thirds of a mile.

MEMBER SIEBER: You can train somebody at Vermont Yankee to start it.

MR. NICHOLS: I don't necessarily want to go there, but it's not an Entergy-owned facility. They have a commitment to restart that under a contract within 90 minutes.

MEMBER WALLIS: Do they need emergency power at Vernon to get it started?

MR. NICHOLS: They already are a black start facility. They've got water.

So once the vernon hydro is started, the orders are given to realign the power and provide the 4 kV power from that station to the Vermont Yankee emergency bus.

CHAIRMAN DENNING: Now your batteries have to last for two hours.

MR. NICHOLS: That's correct.

CHAIRMAN DENNING: What's the difference between the demands on the batteries for EPU versus current?

MR. NICHOLS: I'll ask Mr. Johnson to address that.

MR. JOHNSON: The battery load for station blackout is less than the analyzed accident load by a fair amount, so we expect that the station batteries would last well beyond two hours.

CHAIRMAN DENNING: Yeah, but can you answer the question though was what's the real difference in demand? Is it 20 percent higher or is it some place in between 20 percent higher and --

MR. JOHNSON: I would guess that if the station blackout demand is 20 percent less, so the accident demand would be about 20 percent higher in that ballpark.

MEMBER SIEBER: Well, you're actually still moving the batteries' power instrumentation moves some valves and basically don't do much else and if you don't change the instrumentation, change the number of valves and the type, the load shouldn't change very much.

MR. JOHNSON: It's not a significant change.

MEMBER SIEBER: Right.

CHAIRMAN DENNING: There are no pumps going off the batteries?

MR. NICHOLS: No, not available during this time because the AC power is gone, so you're not operating those breakers, etcetera, so we're relying on the high pressure coolant injection which is free from AC power.

CHAIRMAN DENNING: Okay. I understand.

MEMBER SIEBER: A lot of plants will have turbine lube oil as a DC powered motor. Typically, those are run off of separate battery system than the emergency batteries.

MR. JOHNSON: We have turbine auxiliaries off of our safety-related station batteries and we assume that they operate for a short time --

MEMBER SIEBER: Enough to bring a turbine down.

MR. JOHNSON: And they are considered in the station blackout, loading scenario and the accident loading scenario.

MEMBER SIEBER: Okay.

MR. NICHOLS: The conclusion for the Vermont Yankee station blackout at EPU conditions is that the Vernon hydrostation will be available within the 2-hour period which meets the criteria for the 2-hour AAC that the station blackout coping period of 2 hours is satisfied, given the parameters for the plant and the capabilities that remain in the plant. And that the plant remains in a safe condition during that 2-hour period and the full 8-hour required station blackout period.

CHAIRMAN DENNING: Now as far as the 2-hour period is concerned, it looks to me like, as you pointed out, there just is very little difference in demand. As you get into the 8-hour period, is there a significant difference or is it really, as Jack was saying, it's almost the matter that you're refeeding the charger to the batteries. Do you have significant additional things that AC power is required for in that 2 to 8-hour period than the 0 to 2-hour period in the 2 to 8-hour period?

MR. NICHOLS: For the AC power?

CHAIRMAN DENNING: Yes.

MR. NICHOLS: The AC power comes back at the 2-hour mark.

CHAIRMAN DENNING: Yes, okay.

MR. NICHOLS: And then we can transition it to depressurize, go to -- I'm sorry, start the torus cooling mode because we've been running HPCI and exhausting steam. We can turn on the cooling systems, run those off the now powered 4 kV buses.

CHAIRMAN DENNING: So there really is a difference in demand in that period because of the higher -- or isn't there? You just run the RHR the same way you would and the suppression until the temperature gets higher, but it's not reaching the limit?

MR. NICHOLS: Correct. And the limit we're talking about here would be necessarily the limit for NPSH protection.

CHAIRMAN DENNING: Yes, gotcha.

MEMBER WALLIS: This Vernon tie is

underground, is it?

MR. NICHOLS: The feed from the Vernon tie --

MEMBER WALLIS: Underground and goes directly to some emergency bus?

MR. NICHOLS: Actually comes into a transformer on our station.

MEMBER WALLIS: It's above ground now?

MR. NICHOLS: The transformer is.

MEMBER WALLIS: I'm just thinking of some common event like a very severe ice storm which caused the grid problem could also cause some problem with the Vernon tie.

MR. JOHNSON: The transformer, this is Paul Johnson. The line runs underground from the Vernon station to a pad mount transformer which sits on the ground. All of the cables are enclosed.

MEMBER WALLIS: All enclosed.

MR. JOHNSON: And then it goes via underground duct bank directly to us.

MEMBER WALLIS: Unless there's some common weather cause that's going to affect both, could affect the arrival of a first --

MR. JOHNSON: That's correct.

CHAIRMAN DENNING: And the important thing is also they're not affected by EPU. I mean this is a question that's already been resolved as far as the NRC is concerned.

MR. NICHOLS: That's correct.

MEMBER WALLIS: It really is independent of EPU altogether, isn't that --

CHAIRMAN DENNING: Almost.

MR. NICHOLS: As noted, the only change is what the plant is doing before the --

MEMBER WALLIS: Except that the temperature was slightly higher and the suppression --

MR. NICHOLS: That is correct.

MR. LEITCH: You were not affected at all by the August 2003 grid?

MR. NICHOLS: That's correct. That came basically to the border of Vermont and New York and had very slight impacts, just over the border into Vermont and then going straight down through Mass., but did not -- the plant remained on line.

MR. LEITCH: Have you ever experienced loss of off-site power?

MR. NICHOLS: Yes.

MR. LEITCH: And what about -- but not station blackout?

MR. NICHOLS: That is correct.

MEMBER WALLIS: How old is the plant? Does it go back to the other Northeast blackout?

MR. NICHOLS: No, that was just prior to construction.

MEMBER WALLIS: There was a Northeast blackout which affected --

MR. JOHNSON: 1965.

MEMBER WALLIS: As long ago as that?

MR. JOHNSON: There were two. One in '64 and one in '65.

MR. NICHOLS: The plant started in '68 time frame.

CHAIRMAN DENNING: Thank you very much and we will now go into recess until 10:15.

(Whereupon, the proceedings in the foregoing matter went off the record at 9:58 a.m. and went back on the record at 10:17 a.m.)

CHAIRMAN DENNING: Go ahead.

MR. WAMSER: Good morning. My name is Chris Wamser. I'm the Manager of Operations at Vermont Yankee. On my left is Chris Tabone. Chris is the lead Ops Training Instructor for the License Operator Continuing Training Program, and on my right is Craig Nichols, whom you have met several times.

This morning we want to talk to you about

EPU impacts on operations. Specifically, we have four areas we want to talk about. One is essentially what is regarded by the Operations Department as the most obvious or prevalent impacts to them on a day-to-day basis as a result of the EPU.

The second will be operations training that has been done and will be done going forward to support EPU and power ascension testing. The third is operations procedures -- abnormal and emergency operating procedure impacts as a result of EPU. And, lastly, operator actions and timelines that are impacted by EPU.

On a day-to-day basis, the most obvious impacts from EPU on the Operations Department are the fact that the plant will be required to operate three reactor feed pumps versus two currently to maintain the new 100 percent power level. That is a level of redundancy that has changed as a result of power uprate.

To support that, the plant has modified the recirc system and added an automatic runback feature. That runback feature essentially automates what is now a manual operator action under a similar transient. For example, currently, we run all three condensate pumps to maintain 100 percent power.

If a condensate pump is lost currently, we procedurally have a manual action for operators to reduce circ system flow to reduce power to support running, continuing to operate the plant online. So that feature is only automating what is currently a manual action.

The second impact to operations that we will see is the additional rod pattern adjustments that will be required as a result of a smaller flow window to operate the plant at the new 100 percent power level.

MR. LEITCH: I had a question about who basically calls for the rod pattern adjustment. Do you have a position called a reactor engineer that does this?

MR. WAMSER: We do have a reactor engineer. The reactor engineers are very closely related. They work closely within the Operations Department. Although they are not part of the Operations Department, they work with us. They follow core performance, and they provide recommendations to us on when we should do rod adjustments and rod pattern exchanges.

The reactor engineering group, it's worth noting, routinely trains with Operations Department for significant events such as startup and plant shutdowns, other testing related to reactivity. So we have a good working relationship with them. We also have a reactor engineer on call 24 hours a day, specific point of contact. In case something were to occur during off hours, we have that protocol established.

MR. LEITCH: Do they have their own --

MEMBER SIEBER: You don't have anybody on shift. No reactor engineer on shift.

MR. WAMSER: That's correct, yes. We do have a technical -- a shift technical advisor on shift.

MR. LEITCH: Do the reactor engineers have a training program specifically designed for those? You mentioned, Chris, that they train with the operators, but are there some facets of training that they have, some qualification? How does one get to be a reactor engineer? is basically my question.

MR. WAMSER: I cannot speak with confidence on the exact detail of the reactor engineer training program. John, can you help me?

MR. DREYFUSS: I can. John Dreyfuss, Director of Engineering. The qualification for reactor engineering is a position-specific qualification in our engineering training program. One of the key aspects of that qualification, besides all of the specific tasks that the individuals have to perform -- operating the transverse in-core probe system, other typical reactor engineering functions at a BWR. They also do go through the General Electric station nuclear engineering course as well.

MR. LEITCH: So before a guy is one of these folks that are standing the duty at home, they're on call, he has been through the General Electric station nuclear engineer's course?

MR. DREYFUSS: That's correct.

CHAIRMAN DENNING: Graham, could you speak into the microphone?

MR. LEITCH: Yes, okay. Yes. Do you want me to repeat that? I was just asking -- I was just saying, then, that before someone stands the duty as a reactor engineer, whether in the plant or at home, he has been through the General Electric nuclear engineering course, and I received an affirmative answer in that regard.

MR. WAMSER: We emphasize, you know, the full qualification for all personnel onsite doing anything. Engineering programs have specific qualifications for all of the various engineering tasks that fall under their areas, similar to the way Operations has training programs that require qualifications before we can go out and operate the plant appropriate to a specific position.

MR. LEITCH: Now, I have the perception that, as a result of EPU, the work of the reactor engineer is somewhat more complex. There are more bundles operating closer to the limit. There are different parameters to keep the -- all of the various acronyms -- the MAPLHGR and everything -- in line.

And this becomes -- in my mind, I think it already is -- a very sophisticated function and quite complex. Do you see EPU as adding to the complexity of the reactor engineer's work?

MR. WAMSER: I don't believe there is really any new tasks that the reactor engineers are responsible for. The core is the same. The way we manage it is going to require us to do, as mentioned, rod pattern adjustments more frequently.

But the task, any particular task involved, and whether it's daily surveillance of thermal limits or planning/coordinating future power reductions to accommodate rod pattern adjustments or rod pattern exchanges, those tasks are within their current skill and qualification group. To me, it's --

the impact is one of management, not task-specific.

MEMBER SIEBER: Now, the operators are qualified to do a rod pattern adjustment on their own without supervision from a reactor engineer?

MR. WAMSER: We have guidance on how to -- you know, essentially, if we need to reduce power, we have guidance saying, you know, if it's something short of requiring an automatic or a manual plant trip power reduction, we have a rod pattern that's provided to us. It is updated as needed. The operators routinely use it, both on shift and in the training arena.

Chris and I can both attest that that is a standard action in simulator training. As some event occurs, the crew is required to reduce power to some value. And this is how we do it -- maneuver it with recirc flow, we pull out our rod pattern sequence, and we work through it and put the plant in a stable condition.

Jerry Head, would you like to speak to the other tasks related to management of the core?

MR. HEAD: Yes. I'm Jerry Head, Manager of Nuclear Engineering Analysis. As I discussed some yesterday, part of what you're hitting on is correct in that it's possible to get a power update core design that is more difficult to manage from the standpoint of reactor engineering as far as thermal limits and things like that.

We have been very conservative in the design of these cores, in part because, you know, it's a new thing for us, right? You don't want to take out margin that you had in the past if you can avoid it. And so -- unfortunately, he's not here right now, but Bob Vita, one of the guys that works for me actually, is a former reactor engineer at VY.

He worked very closely with us in the operations and the reactor engineering staff at VY in the design of the cores for this power uprate, to ensure that we provided as much margin as we comfortably could to preclude having any extreme difficulty for the reactor engineers in the management of that cycle.

When you get into the tail end of the cycle where we're actually starting to -- I call it run out of gas, where you've actually got to make those rod pattern adjustments fairly frequently, that is the point in the cycle where we'll have the most difficulty. And we've looked at that a number of different ways to make sure that we weren't trying to give the reactor engineer something they just could not live with.

You know, everything we could do from, you know, verifying GE's methods, as we discussed yesterday, with our own, and to ensure that we're, you know, making their job as easy as we can. I was a reactor engineer once, too, and I've had a core that was a pain in the neck to operate, and I wouldn't want to do that to anybody.

MR. LEITCH: Toward the end of the cycle, how frequently do you picture these rod pattern adjustments being made?

MR. HEAD: I can't recall in calendar time. You know, it -- we've got the frequency -- and I wish Bob was here. He'd have this answer off the top of his head. We're looking at 2,000 megawatt days per ton on the average for those sequence exchanges. But towards the end it drops down to like 1,500, and I can't even tell you what that is in calendar days. Every couple of weeks I think at the tail end of the cycle we'll be making those moves.

MR. WAMSER: I think that's accurate. It could be every two weeks or so at the very end of cycle.

MR. LEITCH: So it's a significant increase from your present operating regimen?

MR. WAMSER: That's correct.

MR. HEAD: And those things, again, are -- you know, would -- they're not infrequently-performed tests and evolutions in that sense, but it's something that we do -- you know, we train the guys on, we look real hard at the predictive tools the reactor engineers have now to go through cases and see how they believe the core is going to behave as they go through those evolutions. It's a whole lot better than it was in my day.

And, again, we look at it from an offline method with CASMO/SIMULATE to make sure that we're not seeing anything different. And, you know, we typically go into these things with pretty high confidence of how it's going to behave, and we're generally pretty successful there.

MR. WAMSER: And we have full confidence that we will be able to predict when we need to make those adjustments, ensure we're scheduling for those and accommodating the manpower requirements. I mentioned startup and shutdown sequences earlier, and, you know, it is standard operating procedure that reactor engineering is on shift 24 hours a day with Operations while we're maneuvering the plant.

MEMBER SIEBER: What criteria do you use

to set the nominal end of life for a given fuel cycle?

MR. WAMSER: That is beyond my area of expertise. Mr. Head?

MR. HEAD: Because we operate a fleet of plants, we typically trying to schedule our outages for the plant so that they don't overlap, because we share resources between those. And so that's what -- you know, it's a calendar date on when we're going to plan that outage, you know, for the two-year cycles. So we're looking at ones, you know, almost three years down the road, how much energy we're going to put in that core. That target date sets the nominal energy we put there.

MEMBER SIEBER: Yes. The criteria is: do you have excess reactivity, or are you moving on borrowed time so to speak when you get to the end of life?

MR. HEAD: We typically design the cores with the option to coast down. If we run well enough in a cycle, we design into them the ability to perform, you know, a coast down, because --

MEMBER SIEBER: But you don't --

MR. HEAD: -- from a fuel cycle economics perspective.

MEMBER SIEBER: -- typically coast down.

MR. WAMSER: I would say typically we do.

MR. HEAD: Typically we do.

MEMBER SIEBER: Okay. So you're --

MR. WAMSER: Typically we do. In preparing for a power uprate, this particular last cycle was different. We have more energy in the core, but that is not typical. And I would say once we --

MR. HEAD: If we run well, we coast.

MEMBER SIEBER: And so that kind of operation sort of exacerbates your peaking factors a little bit, because you're really depleting the core. And say you get bigger differentials in fuel element --

MR. HEAD: Yes. And the flip side of that, too, it works the other way as well sometimes. You know, the core that we just shut down, you know, when we were doing the design work for it, we had anticipated power uprate. And so that had enough energy in it to do a power uprate.

MEMBER SIEBER: Right.

MR. HEAD: And so we carried excess reactivity over that we had to deal with from -- it bid us some shutdown margin areas. We ended up with, you know, excess reactivity that we had to deal with, and the peaking that you get from that as well. So it's a -- one of those things you have to balance in the design process.

MR. WAMSER: And there is also the management part of it at the end of the cycle, to say that the work of managing and maintaining power at some point becomes, you know, too difficult so to speak for operation in the reactor engineering group. And that's when we decide, okay, we've done everything we can do. We're X number of days from our shutdown, and we're going to coast from here.

MR. HEAD: In reality, if you recall, Chris, we actually shifted this last outage to burn a little bit more out of that core, because it was going to give us some difficulties.

MEMBER SIEBER: Well, you know, the philosophy as to how you manage the end of life is -- it has some pros and cons. Obviously, you pay money for the neutrons, and so the more neutrons you can get and use for the dollars that you spent the better off you are.

On the other hand, core becomes more difficult to manage at the end of life, and I just need to assure myself that the Operations Department has enough input into the system, so that it doesn't allow the core designer to design difficulty into the operator's job.

MR. WAMSER: That's an interesting point, and at Vermont Yankee I can say that the operations perspective is strongly -- strongly influences what we're doing with core design. The reactor engineering group -- and, actually, Jerry mentioned by name, Bob Vita has been the lead for the last couple of cycles in developing the core design.

He works with the Operations Department, and we review and approve core design information as well as we work with him throughout the operating cycle to coordinate power reductions and rod pattern exchanges. So we have a strong voice in reactor engineering, how they do business, and our approval of planned evolutions is required.

MEMBER SIEBER: Okay. To me, that's important.

MR. CARUSO: Are you licensed to operate with reduced feedwater temperature?

MR. WAMSER: Say again.

MR. CARUSO: Are you licensed to operate with reduced feedwater temperature?

MR. WAMSER: No.

MR. NICHOLS: We are not.

CHAIRMAN DENNING: Continue.

MR. WAMSER: Okay. Moving on, other impacts that will be observed by Operations on a routine day-to-day basis -- the slight reduction in operator action times for certain events. We'll talk about that in more detail in a later slide, but that is obvious to them.

The balance of plant modifications that have been done prior to and as part of EPU preparations have served to improve plant performance and component reliability. And from an operations perspective, I think it's worth noting that the systems that we're going to be asked to uprate the plant with have been modernized significantly over the last several operating cycles.

We have an electronic pressure regulator that is, in my opinion, the envy of the industry in terms of its performance, which we have upgraded recently. We have our feedwater level control system. Our feed heater level control systems have all been upgraded. Our recirculation system controls have all been upgraded. I have a brand-new high pressure turbine, brand-new high pressure feed heaters down at my condensate demilitarized system. I have a brand-new control system down there to operate that system to ensure plant chemistry is maintained.

So from an ops perspective, we've got -- been given a lot of good, new, modern equipment to run this facility with, and when we go into power uprate to have high confidence in the ability of this equipment to support plant operations.

MR. LEITCH: Chris, could we talk a little bit about the condensate pump and feedwater pump situation that you mentioned? Right now, you normally run all three condensate pumps, but only two feed pumps.

MR. WAMSER: That's correct.

MR. LEITCH: And as I understand it, when the -- when one of the -- when there's a low suction pressure at the feed pumps, you trip both feedwater pumps simultaneously, is that the present --

MR. WAMSER: We currently have offset trip set points for feed pumps on suction pressure. We have a staggered trip sequence.

MR. LEITCH: Staggered trip. Okay. Now, with EPU, you're changing that arrangement a little bit, as I understand it.

MR. WAMSER: We are augmenting it. We have installed a logic system such that with any condensate pump that trips there will be an automatic trip of the bravo reactor feed pump immediately, concurrently with that.

MR. LEITCH: It's always the bravo, right?

MR. WAMSER: It's always the bravo.

MR. LEITCH: Yes, okay. And then, is there a sequential trip of the other two pumps in low suction pressure?

MR. WAMSER: Those trip -- suction pressure trips will remain.

MR. LEITCH: Okay.

MR. WAMSER: Sequential, right.

MR. LEITCH: Sequential, yes.

MR. WAMSER: So we have not undone the logic system trip.

MEMBER SIEBER: But you're getting a runback at the same time.

MR. WAMSER: Correct. Power above X percent, the runback will be armed. If at that point EPU conditions and condensate pump trips, or, for that matter, feed pump trips, but a condensate pump trips we will have an automatic trip of a reactor feed pump, bravo reactor feed pump.

The protection for the other feed pumps will remain. There will be low suction trip logics that still remain. Do not anticipate that that would be challenged, and that's the reason for introducing the new trip.

MEMBER SIEBER: Will you be cutting back on recirculation for --

MR. WAMSER: Recirc system flow will be reduced at the same time.

MEMBER SIEBER: So that's going down and power level is going down. And so you're sort of in the horse race as to, does everything get under the wire at the right time.

MR. WAMSER: Right.

MEMBER SIEBER: Okay.

MR. WAMSER: Next slide, please.

In the area of operations training, I think it's worth emphasizing a couple of things. First, the bulk -- the overwhelming majority of systems that have been modified, the hardware modifications were installed in the Vermont Yankee plant in the spring 2004 refueling outage.

Prior to that, as part of our normal practice, we have modified the simulator that the operating crews train on to reflect those modifications and provided training on those modifications to the operators before the equipment was installed in the plant. That is a typical process for us, and it has served us very well.

So we make the investment in modifying the simulator. We train the operators on that in the simulator. It serves two purposes. It is certainly to make the operators familiar with the new equipment. It also provides an opportunity to do some online validation of procedures that have been developed to support the new equipment.

MR. LEITCH: Now, some instrumentation has to be rescaled for an EPU.

MR. WAMSER: That's correct.

MR. LEITCH: If I look at the simulator right now, that instrumentation has been rescaled.

MR. WAMSER: That's correct.

MR. LEITCH: In the real control room, has that instrumentation been rescaled?

MR. WAMSER: Yes. It's all there.

MR. LEITCH: So it's all --

MR. WAMSER: It's all there.

MR. LEITCH: It's all there, okay.

MR. WAMSER: And that's actually going to my third bullet here, which says, "What gives me great confidence going forward, as we approach the actual power ascension testing, is that the equipment that will be used for power ascension testing has been in service for approximately two years at this point.

So the operators' confidence and knowledge of these systems, the controls, anything that has been modified, it is not new to them the day we decide to -- that we receive approval and commence power ascension. So they will have very good working knowledge and experience on this equipment.

Additionally, the operators have received simulator training on power uprate conditions. The core model on the simulator has been updated, and that has gone well. Feedback from procedures associated with that was incorporated into procedures that we will use when we actually go into power ascension.

The fourth bullet -- power ascension testing and transient testing -- we'll be trained using our just-in-time training program, just prior to actual commencing of the power increase. That is a typical process that has served us very well also is for a special evolution or something of this nature, which is a special test, to ensure that the training is as fresh as possible we will perform that training just prior to performing the evolution.

So operators have real recent experience implementing the procedures, looking at their controls, understanding what the supporting team will be doing during the ascension testing.

I think it's worth noting here that this is not an operating crew doing this by themselves. We're going to have a significant level of resources from engineering supporting the power ascension testing, evaluating the data as it is received for acceptance criteria.

Additionally, in addition to the training, we'll be providing extra management oversight 24 hours a day, seven days a week, during the power ascension to ensure that the crew has not only a test team working for them, but they have management oversight to ensure that any issue or any road block that is encountered can be clearly resolved before proceeding.

MR. LEITCH: And I guess there are two tests that you're -- two dynamic tests, let's say, that you're going to do -- the tripping of the condensate pump and the tripping of the reactor feed pump.

MR. WAMSER: That's correct.

MR. LEITCH: So the crews that are going to participate in that, you indicated they would be trained just in time. But the other crews would also, I take it, be trained for those kind of evolutions?

MR. WAMSER: I anticipate all operating crews are going to be trained. All operating crews will be trained on the modification that we're talking about, which is the logic of the condensate pump and feed pump trips. For power ascension testing, I anticipate all operating crews will receive that training. The duration of the testing is such -- is such that essentially all operating crews are going to get exposed to it during their normal rotation of shift work.

So it would be prudent to provide that training to all of the operating crews. In addition to that, although we have high confidence in the outcome of those tests, the transient tests -- the tripping of a condensate pump and tripping of a feed pump -- we will train the operating crews for both eventualities -- successful outcome and unsuccessful outcome -- so that they are clearly trained on the "what if" of if a condensate pump trip results in a loss of feed or a feed pump trip results in a reactor SCRAM.

MR. LEITCH: Reactor SCRAM, yes. Thanks.

MR. WAMSER: Next, please.

In the area of operating procedures, essentially abnormal and emergency operating procedures, some items to discuss. Between the setpoint changes and some hardware changes associated with the EPU, there have been changes made to several abnormal operating procedures.

Additionally, the site will be adopting a new steam dryer integrity procedure. Steam dryer monitoring will clearly be part of the power ascension testing. But based on GE SIL, we have developed a steam dryer integrity off/normal procedure, which we'll be implementing and will remain in place after power ascension testing is complete.

In the area of emergency operating procedures, there are no new emergency procedure actions or strategies. The only impact has been a minor revision to emergency procedure graphs due to EPU as a result of decay heat load change.

MEMBER SIEBER: Well, let's explore that just a little bit. You know, for example, the ATWS EOP, all of the actions the operators must take, which occur pretty quickly after the onset of the ATWS event, are speeded up under EPU conditions. Are you practicing to the new dynamics of the progress of an accident like that? For example --

MR. WAMSER: Absolutely. And --

MEMBER SIEBER: -- standby liquid control has got to go in faster.

MR. WAMSER: Absolutely. And the timeline kind of gets into the next slide, but that's okay. The thing I want to emphasize, because, clearly, the committee has had much discussion on ATWS, and, obviously, a concern, and, you know, it's a concern for any operator as well. I mean, fundamentally, a lot has to go wrong to get there.

But in that area, I think it's worth emphasizing that our practice has been that on a failure to SCRAM event to immediately inject SLC and not wait to observe oscillations. We are a detect-and-express plant -- that is true -- Option 1 delta. However, it is prudent to use the system that is used to shut down a reactor when you have obvious evidence that the plant has not shutdown as expected.

So by training and practice, we have for years injected SLC immediately. We do not wait to observe oscillations, and essentially we hope we never see them. But that --

MEMBER SIEBER: On the other hand, water level control is important in an ATWS event, too.

MR. WAMSER: That is certainly true.

MEMBER SIEBER: And it's different than other accidents.

MR. WAMSER: That is true. Absolutely.

MEMBER SIEBER: And so the operators

are --

MR. WAMSER: Why don't we --

MEMBER SIEBER: -- not to pick it up in this reduced amount of time.

MR. WAMSER: Why don't we trip over -- slip to the next slide here, and we'll talk further on that.

MEMBER SIEBER: All right.

MR. WAMSER: In the area of operator actions and timelines, there are no new operator strategies. That is to say that the procedures and the general flow-through procedures has not changed. There are no new EOPs. There are no new legs in the EOPs. There are no new steps in the EOPs.

The time it takes to do any discrete task has not changed as a result of EPU. It doesn't take longer to inject SLC before or after EPU. The time required has changed. Operations --

MEMBER SIEBER: So you've got to do it sooner.

MR. WAMSER: Say again.

MEMBER SIEBER: You've got to do it sooner.

MR. WAMSER: That is correct. And in that area, Operations and Training has received information from PSA Group on time-critical steps and has reviewed that. And, essentially, what we determined was anything that was required to occur within 30 minutes warranted our review.

And when we went through that review, we identified anything that required action 10 minutes or less that we wanted to specifically validate whether that had changed or not as a result of EPU. And where they had changed, we used the Operations Department and the Operations Training Group to validate the ability to implement and meet the new timelines.

So the examples that you raised, which are injecting SLC, is a significant one. That time duration has gone down. I know that in subsequent discussion under PSA some specific detail will be provided to you on what the time was and what it is now.

But I'm telling you that we have seen that information, we have validated our ability to meet that information -- things like inhibiting our automatic depressurization system, which is a key action for us, injecting SLC, taking action to maintain the main condenser as a heat sink, maintain MSIVs, main steam isolation valves open.

MEMBER SIEBER: Well, you know, the

operator doesn't have a lot of time, even under the current license power. And so you've got an EPU, and he has less time, which to me raises the possibility of having a cognitive error on the part of the operator doing the wrong thing or doing nothing.

And with everything happening faster --

MR. WAMSER: Well --

MEMBER SIEBER: -- you've got to deal with --

MR. WAMSER: -- you're absolutely right. And this comes to the core of, how do we perform training? How do we determine what is the appropriate thing to train on? How frequently do we train on it, and how do we emphasize it? And what you're describing is something that has a significant issue.

It has a -- Chris would know all the right words. But, essentially, you look at the difficulty, the significance of an action or an event, and the outcome. And you use that as part of your systematic approach to training in determining how often is it required to train this, and you ensure that your training program supports that. So --

MEMBER SIEBER: And you feel confident that it does?

MR. WAMSER: I am absolutely confident.

I am a product of our training program. I still have a senior reactor operator's license, and in the area of ATWS I would say -- I'm not certain if I've ever gone to training on my routine training program and have not seen an ATWS. I mean, we practice this religiously over and over and over and over.

So I have high confidence that we clearly understand what the procedure directs. I have high confidence that operators can perform it. And I absolutely agree that it's time critical actions, and we fully appreciate that. And I will admit that we are aware of the time difference.

MEMBER SIEBER: Yes.

MR. WAMSER: You know, it is obvious to operators, to they appreciate the significance of that.

CHAIRMAN DENNING: Well, we're going to get into those time differences a little later.

MR. WAMSER: That's correct.

CHAIRMAN DENNING: Okay. I think we --

MEMBER SIEBER: Yes, why don't we move on.

MR. LEITCH: The standby liquid control pumps are keylock switches.

MEMBER SIEBER: Who's got the key?

MR. LEITCH: I know that in the simulator usually the keys are in the switches.

MR. WAMSER: In the plant, the key is in the switches.

MR. LEITCH: The key is in the switch?

MR. WAMSER: Absolutely.

MR. LEITCH: Very good. You don't want to spend some time looking for the keys.

MEMBER SIEBER: You have it safeguarded very well, I see.

(Laughter.)

MR. WAMSER: We know it's important.

MR. LEITCH: A couple of questions about your emergency operating procedures. I don't think it has changed with respect to EPU, but do they take you down a logic path that indicates under what circumstances you use drywall sprays? There's been some concern for a while about when they should be used and the possibility of collapsing the drywall liner and those types of things.

MR. WAMSER: Yes. We have clear -- and similar to the discussion on ATWS, containment pressure and accident mitigation essentially, you know, let's face it, any accident, any break, feed line, steam line, reactor vessel, recirc loop, you know, we see that in containment parameters. So it is another area that we practice routinely in the simulator managing and mitigating accidents and transients related to leaks inside containment.

We have procedure guidance related to net positive suction head, maintaining net positive suction head to the ECCS pumps. In all areas of the emergency operating procedures, operators -- number one, the procedures are symptom-based, so you don't have to understand what broke to get you there. You just need to know something is broke.

And it is an area where training and experience is key, because we have multiple parameters that we're monitoring, and we have guidance on managing those parameters. And so we do not take action based on one parameter necessarily at the exclusion of all others. We have to understand overall what's going on in the plant, understand what our priority is, to effectively implement the emergency operating procedures.

In the area of containment pressure and net positive suction head for the ECCS pumps, we do have guidance in the operating procedures that would say any leg that would require me to depressurize or reduce containment pressure, i.e. spray of the drywall and/or torres, would direct me to look at what containment pressure is, what is the temperature in the torres, what are the net positive suction head requirements for that pump, and make a determination of, number one, whether I do it or not, but also how far do I go before I terminate sprays.

MR. LEITCH: Okay.

MR. WAMSER: So that guidance exists. That's correct.

MR. LEITCH: Okay. Thank you.

CHAIRMAN DENNING: Okay. Thank you, all.

I think, then, we'll move on to the next presentation.

MR. WAMSER: Okay. Thank you.

MEMBER SIEBER: Thank you.

MR. BONGARRA: Good morning. My name is Jim Bongarra, and as the slide indicates I am with -- well, actually, it doesn't indicate properly anymore. We've had a change in organization here recently. I'm with the Division of Inspection and Regional Support. I'm with the Operator Licensing and Human Performance Branch now, so that's -- this slide was made up just before we --

CHAIRMAN DENNING: Engineering Psychologist sounds like a really difficult job to me.

MR. BONGARRA: It becomes more and more

difficult as we go on, it seems.

(Laughter.)

MEMBER SIEBER: It sounds like you couldn't make up your mind what you wanted to be.

(Laughter.)

MR. BONGARRA: I'd like to think that it's the best of both worlds in a sense.

MEMBER SIEBER: There you go. Perfect.

MR. BONGARRA: What I'd like to -- what I had planned to talk to you about this morning for about a half hour or so are really two areas. One was the -- basically, the process, to review with you the process that the staff uses to review and evaluate the human performance aspects of licensing power uprates, and the results of the staff's evaluation of Vermont Yankee's request for their extended power uprate.

I must say that the gentleman that preceded me this morning, they touched on a good number of items that I was going to talk about. And I don't know whether you wish me to continue with -- in that line or --

CHAIRMAN DENNING: Let's try to focus on your evaluation of, like, the time -- you know, the assessment of there are clearly reductions in time. How did you determine that those reductions in time really were still -- reduced amounts of time for performing activities was still adequate?

MR. BONGARRA: Okay. Well, I think I can probably go to -- I'll skip the process, then, and, Rick, if we could go to -- well, maybe Slides 6 and 7 I think is where I talk a little bit about the times.

Essentially, we looked at what the licensee submitted to us in terms of their justification and description for what time reductions were actually taken as a result of the EPU. And I guess from, if you will, a deterministic standpoint, it certainly appeared to us that, yes, there were reductions in time available to take certain critical operator actions, but, in essence, two things seemed to have occurred.

One, that essentially for a number of actions that were affected there seemed to be a -- the actions themselves were straightforward for the most part, and some of them were not really time-sensitive. For example, there was one task that changed essentially, but the operator essentially had I believe it was 40 minutes or so to -- to take the action. So we didn't consider that as a real time-critical action.

Now, with regard to the actions that were described previously, again -- and I think I'm kind of going to move to Slide 7 here -- essentially, under the ATWS scenario there was a reduction in time available for operators to initiate automatic depressurization. And I think it was from, as the slide indicates, 6.2 minutes to 5.4 minutes, which was a reduction in available time to take that action of a little less than a minute.

But, again, according to the licensee's description to us, the time that the operators actually take to initiate this depressurization is about one and a half minutes. So there is -

MEMBER WALLIS: But does that one and a half minutes include the time it takes them to figure out what they have to do? There's a lot of difference, and you have to -- before you actually take an action, you have to be sure that's the right action. How long does it take for them to do that?

MR. BONGARRA: I am not certain exactly whether that was a factor involved in the actual operation of that -- or in the actual time estimate for that action. And perhaps one of the --

MEMBER WALLIS: I would think that's why you got into the psychology part of it. Actually doing something may be the easiest part of the whole action, but figuring out that you're sure that's what you need to do may take you longer.

MR. BONGARRA: Let's ask the applicant to comment on that.

MR. TABONE: This is Chris Tabone from Entergy. Those estimated times were basically from T zero of the event, so that did include the time to determine what action needed to be performed, plus the time it actually took to take the actions.

CHAIRMAN DENNING: Can you give us a feeling for this ATWS scenario? It's just what the operator is seeing and how he knows that he has to perform the depressurization?

MEMBER WALLIS: How does he know he has an ATWS?

MR. BONGARRA: I guess in my understanding of -- essentially of an ATWS, this is -- this is an event, first of all, an ATWS event, as I understand it, that is not a new event to the operators. What is new essentially is the time that is allowed now for the operator to actually initiate the depressurization.

So what I'm simply saying here from my understanding of this event, we're not looking at, number one, a new event. We're looking at basically an event that has been, as a routine process within EOP training, an event that would be trained on as a -- in a routine fashion.

What has changed is the amount of time that the operator has to take that specific action, and there are certain steps that you take by memory on receipt of the SCRAM signal. I mean, the first few steps you don't even have to break out a procedure. I mean, the operator memorizes the first few things he does.

And one of the things on an ATWS, I mean, you would get a signal that you're supposed to SCRAM. One of the first things you do is look at your APRMs and say, "Whoops, they're still -- they're not down scale." So --

MEMBER SIEBER: You don't say "whoops."

(Laughter.)

MR. BONGARRA: I would say "whoops."

(Laughter.)

And then, I think we had the licensee tell us that immediately upon receipt of a SCRAM signal, and the APRMs not downscale, they go with SLC.

MEMBER SIEBER: Why don't we have an operator go through what you see, what you do, for the first -- for the steps you have to memorize.

MR. WAMSER: This is Chris Wamser, Operations Manager at Vermont Yankee. The ATWS scenario is very self-revealing, as you've already indicated. The receipt of automatic alarm indicating a SCRAM will come in. At Vermont Yankee -- I'm not certain that this is typical in the industry, I expect it is.

But the enunciator windows associated with SCRAM conditions are red as opposed to white for all other alarms in the control room. So it is extremely self-revealing when a SCRAM condition comes in. The operator actions of verifying control rod movement, which is something Vermont Yankee can do, which is not typical at all plants, we have a full core display showing all control rods and at what notch position they're at.

So it's a very large, essentially three by three, picture of whether the control rods are moving or not. So that is essentially -- essentially, you can imagine looking at that screen up there. That's my full core display, and up to the upper right are my alarms associated with the SCRAM. So it's self-revealing. I have a SCRAM condition.

I look at the full core display, are my control rods moving or not. I look at my APRMs, my power range monitors, have they moved off of 100 percent, have they gone down scale or not. Tells me whether the SCRAM was successful or not.

If at that point you don't have indication that the control rods are moving, you're going to back up that SCRAM by manually SCRAMing reactor use in the two control rod SCRAM pushbuttons.

MEMBER WALLIS: So we have gotten a few seconds into the event, have we?

MR. WAMSER: Yes.

MEMBER SIEBER: Yes, right. Five seconds maybe.

MR. WAMSER: Right. From there, for an operator, if that manual SCRAM were to be unsuccessful, we then use our alternate rod insertion and recirc pump trip logic manual pushbuttons, to manually depress those, as another method to back up the SCRAM function, which would be expected to essentially support the SCRAM going to completion.

After that, rolling the reactor mode switch to the shutdown position introduces another SCRAM through reactor. At that point, we've gone through most of the initial operator actions. For Vermont Yankee there is a step to commence lowering.

We have an automatic setdown on reactor

water level, a pushbutton that we depress, and at that point, really, amongst all of this is these conditions' success or lack of success are being reported from the reactor operator to the control room supervisor.

The control room supervisor is essentially only a couple of feet behind the reactor operator. He has broken out the procedures appropriate, which are the failure to SCRAM or ATWS procedure. And at this point, he is following operator actions.

The next order is essentially to do the first bullet up there, which is inhibit the automatic depressurization system from operating. That is an order to a different operator to do that, and essentially the next step is to direct the operator to insert or inject SLC -- if he hasn't already done it, is inject SLC.

So at that point --

MEMBER SIEBER: And these are your memorized steps.

MR. WAMSER: That's correct.

MEMBER SIEBER: These are the steps that all operators memorize, and that gives them a chance to get out the procedure book.

CHAIRMAN DENNING: Is it correct that this

-- is there an error on that slide? It should be inhibit instead of --

MR. WAMSER: That's right. It should be inhibit ADS, not --

CHAIRMAN DENNING: And when would ADS occur automatically in this?

MR. WAMSER: It's the 5.4 minutes.

CHAIRMAN DENNING: Is that --

MR. WAMSER: Depending on plant parameters, an extended low low -- reactor low level conditions, for example.

CHAIRMAN DENNING: I'm just wondering, but that's -- that's what determines that he has to make that action within 5.4 minutes, is if he doesn't then there must be some probability that it will happen without the inhibit.

MR. WAMSER: I'm sorry. I didn't catch that whole question.

CHAIRMAN DENNING: The 5.4 minutes is determined by -- there is some possibility if he does not inhibit within 5.4 minutes that it will automatically depressurize. Is that true?

MR. WAMSER: That's correct. I don't have the exact details of that specific timeline, but, in general, what taking that action is doing is to ensure that the system does not automatically open the safety relief valves and depressurize their reactor.

It's in anticipation of the fact that this procedure is going to direct us to reduce reactor water level to have the effect of reducing power. So the automatic actuation of that system will be based on what we call a reactor of low low level condition for a time period of two minutes. And at that point, when we -- the time to get to the low low condition, plus two minutes, is when this system will automatically depressurize this.

So inhibiting it is in anticipation of the fact that there is specific operator actions that will reduce reactor water level, and we fully expect we will reduce it below that trip setpoint, as a matter of choice, to reduce reactor power by removing or lowering the water level in the core.

CHAIRMAN DENNING: But, again, the 5.4 minutes is a critical time, and the -- with some uncertainty in it. But it's the possibility that it could automatically depressurize right after that.

MR. WAMSER: Yes.

MEMBER WALLIS: This is 5.4 minutes from time zero?

MEMBER SIEBER: Yes.

MEMBER WALLIS: So he's doing other things during those 5.4 minutes. He doesn't have all of the 5.4 minutes to worry about this 1.5-minute action. He's doing other things, which are stacking up, isn't he?

MEMBER SIEBER: But the idea of going through the scenario is to demonstrate what the operator actually is doing.

MEMBER WALLIS: Yes. Well, I'm concerned that what you mean by saying he's got 6.2 minutes -- do you mean he has got to do it by 5.4 minutes from time zero, when you say he's got 5.4 minutes? Or do you mean he's got 5.4 minutes from the last significant action he took?

MEMBER SIEBER: No, from time zero.

MEMBER WALLIS: Time zero. So there are other actions all stacked up in that time.

MEMBER SIEBER: No.

MEMBER WALLIS: So this 1.5 minutes is part of a whole series of actions.

MEMBER SIEBER: No, not really. Not really.

MR. WAMSER: It is the first --

MEMBER SIEBER: That's not what he said.

MR. WAMSER: -- action that is directed.

MEMBER WALLIS: So it really does have five minutes to do that one.

MR. WAMSER: Right. I detailed essentially the immediate operator actions for a SCRAM or a failure to SCRAM condition. Procedurally, the first step directed is that first bullet there -- initiate or -- I'm sorry, inhibit automatic depressurization system.

DR. BANERJEE: When do they have to start lowering the water level?

MR. WAMSER: They have to -- that is a priority as well. We have -- the action that is taken, essentially, were in three legs -- power suppression and reactor water level control and pressure control. By practice, we go down the power leg and ensure that the SLC system is injecting, as I described, commencing to lower power -- I'm sorry, lowering level to lowering power is the next concurrent step.

DR. BANERJEE: So the first step is to -- to -- what is the first step, inhibiting the -- or, no, there are some other steps before.

MR. WAMSER: I guess what I would refer to as immediate operator actions to back up the SCRAM or get the SCRAM to go to completion. All right.

DR. BANERJEE: Okay. Thank you.

MR. WAMSER: Those are not necessarily detailed in the procedure. Those are by training and other procedures. Those are trained immediate operator actions for SCRAM condition. Once we get into the actual ATWS procedure, the first step is to initiate -- I'm sorry -- inhibit ADS.

And at that point, we -- then, the procedure branches down into three concurrent legs that we work through -- controlling key parameters, power level, and pressure.

MEMBER WALLIS: This next one is initiate a SLC system, given main condenser failed. He has to first find out what's the status of the condenser?

MR. WAMSER: Yes. This is a little bit simplistic, unfortunately. But fundamentally -- and it's not a fault of this slide, it's just the complexities or the nature of how these events could progress. If a failure to SCRAM event occurs, and I do not have a loss of the main condenser, i.e. the main steam isolation valves stay open, then there is no immediate threat to containment.

And the time required for that task, specifically to inject SLC, is different. It's less.

MEMBER WALLIS: It's not really the main

condenser failing. It's the steam valve staying open, which is fortunate, isn't it?

MR. WAMSER: Right. The way it's written there is --

MEMBER WALLIS: There's all kinds of ways --

MR. WAMSER: The way it's written up there is the way, you know, PSA writes these things. But -- and I support PSA, but --

(Laughter.)

But the idea is, you know, today the plant is operating, and I have a main generator, and I have a main condenser in service. If a SCRAM condition occurs by itself, that is not anticipated necessarily to result in the isolation of the main condenser. The main steam isolation valves are not necessarily going to close.

The worst case scenario, so to speak, the most challenging scenario for the containment, is that they do. And for that we have to have prompt operator action to get SLC going. If -- you know, essentially if you consider the fact that if I had a failure to SCRAM event, and the main condenser stays available as a heat sink, if the plant, for example, were to settle out at 20 percent power, I have 20 percent power going to the main condenser, I have a circ water system removing the heat from that, and I have more time available to mitigate that accident.

MEMBER SIEBER: You could do that forever.

CHAIRMAN DENNING: Do you have data from simulator training that says I -- we've run through this in the simulator a hundred times and -- and the operator has failed to do it only one time out of a hundred, or something like that?

MR. WAMSER: We have data, probably not in the format that you're looking for. But, for example, in development of licensed operator examinations, the development of critical tasks is related to things like this, of what are time-critical elements. And pass/fail criteria is developed and implemented based on things like this

So when Chris Tabone develops an examination for an operating crew that we do annually, it does have critical time elements associated with it, and those time elements are based on expectations like this. So we have that kind of data that says, what has our operator performance been in meeting time-critical tasks of a variety of types.

CHAIRMAN DENNING: Were those exams in simulator or in --

MR. WAMSER: Yes.

CHAIRMAN DENNING: Okay.

DR. BANERJEE: You effectively have a decision tree here, don't you, the timelines associated with it?

MR. WAMSER: Yes.

DR. BANERJEE: Do you have that decision tree documented in that form somewhere? Or is it -- did we get it? Is it one of those things that was on the -- well, that was sort of a huge chart, right?

MEMBER WALLIS: I was a bit lost in that. It was okay for a while, but then when you've got all of these different --

DR. BANERJEE: It looks so complicated. Plus, it was on one sheet, so you couldn't display it easily. But maybe -- is that the decision tree we are talking about, the --

MEMBER WALLIS: It had all sorts of arrows going to seven and five and four and --

MR. WAMSER: Yes. Yes. The emergency operating procedures flowcharts are decision trees. And I mentioned in my discussion earlier that monitoring of all of the various plant parameters is required, reporting of those plant parameters is required, and that information has to be processed to determine, in some cases, what is the -- what is the priority for the operating crew to mitigate an accident.

And that is a normal part of the procedure development and of the training of operators, and the examination of operators.

DR. BANERJEE: Now, associated with those decisions there is some probability that the right decision will be made or the wrong decision will be made.

MR. WAMSER: That's correct.

DR. BANERJEE: There are outcomes associated with that.

MR. WAMSER: That's absolutely correct. And we're transitioning here from the procedures that operators use to mitigate transients/accidents and into the PSA world, what are the results of incorrect decisions or incorrect actions. And I certainly am not the PSA expert, but I would say that not all wrong decisions or -- I guess not all wrong decisions necessarily equate to increased core damage frequency.

DR. BANERJEE: Sure. I mean --

MR. WAMSER: They put you on a different path to outcome. Simply stated, a transient or an accident that requires an operator to use a high pressure source of injection, and if he is unsuccessful doing that, essentially if he doesn't know how to operate, for example, the outcome could be that the crew depressurizes the plant and uses low pressure injection.

You know, exactly how PSA uses that mathematically to determine the core damage frequency, I'm sure there is a value associated with that, but it doesn't necessarily mean that core damage occurs.

MEMBER SIEBER: One of the distinctions that you could think about is that BWR emergency procedures are more symptom-based than they are event-based.

MR. WAMSER: They are definitely symptom-based.

MEMBER SIEBER: Whereas the pressurized water emergency procedures are more event-based than symptom-based. And if they are symptom-based, that means the operator sees this and does that, and -- which is a pretty straightforward way to deal with things. And it doesn't necessarily make the operator analyze the action. He is just responding to indications that he is getting that tells him the condition of systems.

For example, when you discuss in this the loss of the condenser, you are really saying, "I lost my heat sink." Okay? And that is one of the legs of an event tree that says, you know, this is a bad way to go, and here's the mitigating strategy for that. There is all kinds of other ones that aren't as significant, and so the emergency procedures, while they will deal with them, don't deal with them in the terms that it does with a bad outcome.

CHAIRMAN DENNING: Let's move back to the presentation. And let's move fairly quickly through it from this point on, if you would.

MEMBER WALLIS: Well, we might still ask some questions.

CHAIRMAN DENNING: Oh, absolutely. That's our business.

MR. BONGARRA: Well, let me pick up, then, with -- basically, then, let me go to the next slide, which is Slide 8, and that's control room alarms and displays. This gets back to the beginning of the presentation, which I didn't provide to you, which basically tells you essentially, or would have told you, what areas that we take a look at and are sensitive, essentially, to power uprate.

And one of the areas, of course, is human system interfaces, controls, alarms, and displays, and essentially in their application for power uprate, the request for power uprate, they told us that -- essentially that the EPU will affect these particular items, indicators, main steam line flow indicators, feedwater flow, etcetera, and they committed, basically, to make modifications to the instrumentation.

From our standpoint, it's important that they emphasize the fact that they are using not only Operations' input, but they are factoring in human factors engineering expertise as well. So there's a level of confidence here that the changes that will be made to these instruments essentially will have oversight by the human factors engineering discipline.

CHAIRMAN DENNING: Now, wait a second. To my knowledge, I -- either these changes have already occurred, or at least they are available in the simulator, and I guess let's go back and do that. The fact that they told you they're going to use human factors review doesn't necessarily give me any comfort that we really identified where there might be potential problems.

Are there any potential problems here with -- that require additional human factors review, or is it just a matter you're going to change indications on these displays and stuff?

MR. WAMSER: It appears that question is focused to Entergy. Chris Wamser, Manager of Operations. These are very good examples. Actually, the first two bullets up there -- main steam flow indicators and feed flow indicators all needed to be replaced as a result of the new operating range or the upgraded operating range.

The human factors associated with that is that those indicators happen to be mounted side by side, and the human factors aspect of that is to ensure that at steady-state conditions the indicators are installed such that essentially it's a balanced bar graph type display. At steady-state operations, the feed flow indicators and the steam flow indicators all look horizontally to be the same value.

So the effect of that is that we can quickly tell if something is out of normal. If we see one of those indicators change, it is out of sync with the other five.

CHAIRMAN DENNING: Is this consistent with your current --

MR. WAMSER: It is -- it is consistent. It is as installed -- as I described it, it is as installed, and it is consistent with our previous installation.

CHAIRMAN DENNING: Right. Proceed.

MR. BONGARRA: Again, commitment was made to train operators on the modifications as well, and the required changes and training will be made before the uprate is implemented.

Next slide, again, is related to human system interfaces. Specifically, one of the areas we're concerned with, too, in our review is safety parameter display system, TMI action item here.

Again, with regard to the SPDS, the licensee committed to review the analog and digital inputs to the SPDS, including any changes that might be needed to the SPDS. As indicated on the slide, they either will or have reviewed already changes to EOP curves and limits, for instance, that were discussed earlier. And, once again, a commitment was made to train the operators before the EPU was implemented.

Next slide has to do with operator training program and the control room simulator. Again, I think that Entergy did a very thorough job in describing this earlier. I won't go over all of the items on this slide, but let me just emphasize the fact, too, that one of the commitments we look for in our review is the fact that ANSI Standard 3.5, which is Nuclear Powerplant Simulators for Use in Operator Training and Examination, is used essentially to make sure that the simulator changes are made in accordance with essentially the guidance in that standard.

So we are pretty confident that the fidelity, if you will, of the simulator after these changes are made will indeed remain high fidelity.

I guess that brings me, really, to the conclusions of my presentation here. And, again, we didn't go over all of the slides, but my -- our opinion anyway that the licensee has accounted for all the effects that the proposed EPU would have on available time for operator actions.

They have taken or they plan to take, before EPU implementation, appropriate actions to ensure that operator performance isn't adversely affected by the proposed uprate. We feel confident that Vermont Yankee will continue to meet applicable NRC requirements that are related to human performance, and we conclude that essentially the licensee's proposed EPU is acceptable with respect to the human factors issues.

CHAIRMAN DENNING: Okay. Any questions?

MEMBER WALLIS: Yes, I have a question.

CHAIRMAN DENNING: Go ahead.

MEMBER WALLIS: Regarding the probability of error --

MR. BONGARRA: The probability of error, sir?

MEMBER WALLIS: Right. We got a document, a GE document, that for some reason is labeled "proprietary." But it gave tables of the current times available for certain actions, and the CPPU times. And it gave estimates of the human error probability for the old -- current power and the CPPU power, the upgrade power.

Did you look at those, and are they credible?

MR. BONGARRA: I'm afraid I'm going to -- I'm going to have to defer that. I'm not sure -- I'm going to have to defer that to the probabilistic risk assessment group. I must say I'm not --

MEMBER WALLIS: You didn't look at those?

MR. BONGARRA: -- I'm not familiar with the document that you're referring to.

CHAIRMAN DENNING: Yes. Marty Stutzke will have to answer that question.

MEMBER WALLIS: He will answer that? The thing that surprised me in some of the tables -- and, again, this seems to be labeled proprietary, so I don't think I can give you any numbers or anything --

MR. BONGARRA: Is there a date on that document?

MEMBER WALLIS: -- is how high some of these probabilities are for certain actions, which presumably can't be important.

MR. BONGARRA: Do you have a reference as far as a supplement number or --

MEMBER WALLIS: Well, this is CG NEDC-3309-DP.

MR. BONGARRA: All right. I guess if it's --

MR. DICK: This is Michael. Is that -- is there any underlining on that text? I don't believe so. So that -- that information itself is not proprietary.

MEMBER WALLIS: So it's not proprietary?

MR. DICK: No, sir. I'm just trying to find --

MEMBER WALLIS: I guess when I see it -- a 73 percent probability of failure in action, I just wonder why the action is even performed. It just seems to be such a high number. I mean --

CHAIRMAN DENNING: Marty is back here in

the audience. Let me just make sure that he feels comfortable that he knows what --

MEMBER WALLIS: Do you want to address that? So this was operator reopens MSIVs and restores condenser for containment heat removal, something like that. We're going to have a question for him.

CHAIRMAN DENNING: Yes. He knows a question is coming, so --

MEMBER WALLIS: He is going to face that question.

CHAIRMAN DENNING: Yes.

MEMBER WALLIS: Okay. Thank you.

CHAIRMAN DENNING: Very good. Thank you very much, and let's move on to the plant systems presentation.

MR. REDDY: Good morning. I am Devender Reddy, the ATWS Systems Engineer, Plant Systems Branch.

The scope of BOP includes internal hazards, fission product control, component coding, and the decay heat removal systems. Also, it includes power conversion systems, risk management, and other auxiliary systems.

The NRC staff focused its review efforts on auxiliary systems which include spent fuel pool cooling system, service water and ultimate heat sink, auxiliary cooling system, and condensate and feedwater system.

The NRC staff's review and experience in the past has indicated that these systems are most challenged by power uprates. With regard to the spent fuel pool cooling, the fuel pool cooling system merely consists of non-safety-related normal fuel pool cooling system and also a standby fuel pool cooling system which is safety-related system.

The staff's review focused on the standby cooling system and its capability for both batch offload as well as the full core offload. The goal is to maintain the pool temperature below the current license limit of 150 degrees.

And the licensee's analysis and the staff's review confirmed that with current administrative controls the pool temperature will be maintained below 150 degrees for both the batch offload as well as full core offload.

CHAIRMAN DENNING: Now, the full core offload is the limiting condition here?

MR. REDDY: Yes.

CHAIRMAN DENNING: And the -- when you say "administrative controls," does that mean that they have to move fuel out of the pool into dry storage to be able to do this? Where does the administrative control --

MR. REDDY: Well, actually, that's not the case to the extent I know of. But administrative control applies to installing the gates for batch offload like, you know, up to six days, install the gates for full core offload after 10 days. There is that administrative control.

And for the power uprate, actually the gates will be closed after seven and a half days, in order to maintain the pool temperature 150 -- below 150 degrees. Whereas for the full core offload, the administrative control will be -- the gates will be closed after 11 days.

MR. JONES: This is Steve Jones. I'm Acting Chief of the Balance of Plant Section. Just to clarify, the plant -- as a BWR, it has the reactor cavity, a couple of gates that separate the cavity from the spent fuel pool. The licensee is crediting the capability of RHR to remove a portion of the decay heat for the first several days of the outage, and then the fuel gates would be installed, and then rely solely on the spent fuel pool cooling system.

CHAIRMAN DENNING: Thank you.

MR. REDDY: Next slide.

With regard to the service water system and ultimate heat sink, this the ultimate heat sink, and the service water takes water supply from where we were. The system was evaluated and it was determined that the current service water system has adequate cooling capacity for EPU operation.

And the staff reviewed licensee's evaluation and is satisfied with the assumptions and design limits of their analysis. In case a service water system is not available, there is an alternate cooling system which will be available to supply cooling water to the essential components for safe shutdown.

And with regard to the alternate cooling system, during original licensing for Vermont Yankee loss of one of them was postulated. Therefore, it led to the design and implementation of the alternate cooling system. The alternate cooling system has a design capacity of seven days of water supply.

As I mentioned earlier, if service water system becomes unavailable due to failure of the one due to fire or flooding in the intake structure, the alternate cooling system will be relied upon for supplying the cooling water to the essential components for safe shutdown.

Further, during ACS operation, cooling tower in the deep basin will serve as heat sink. The licensee performed inventory and new operator loss analysis, and confirmed that at least seven days of cooling capability will be available for EPU operation.

MR. LEITCH: Did you review those calculations? That sounds like the licensee did it. There's no comment there about your opinion of their calculations.

MR. REDDY: We reviewed the -- what do you call, the results that they submitted. We did not review the calculation itself, but we -- we reviewed the information provided by the licensee -- the import conditions and other assumptions.

MR. LEITCH: So you didn't verify the calculations at all?

MR. REDDY: The calculation itself, no, we did not look into the calculation. But they support a lot of information to the calculation.

Also, the modification to the service water system, motor-bearing oil coolers has been made to recover service water flow to the coolers. This modification preserves the inventory of the cooling tower basin.

Now, regarding the condensate and feedwater system, based on the information submitted by the licensee, the staff is satisfied that Entergy has adequately evaluated and addressed the impact of the EPU on the capability and reliability of the condensate feedwater system to provide feedwater to the reactor for EPU operation.

However, based on those modifications that are being made to the design and operation of the condensate feedwater system, the staff was concerned about reliable operation of the system at EPU conditions.

Therefore, the staff imposed a license condition to confirm acceptable performance of the condensate and feedwater system at EPU full power operation. This information was conveyed to the ACRS Subcommittee on 15th of November in Vermont.

Now, talking about the license condition, briefly, the license condition consists of tripping a condensate pump at the EPU full power. And for testing and/or analysis, the licensee is to demonstrate that the plant will respond as designed to loss of a reactor fuel pump.

In summary, the staff finds the proposed

EPU to be acceptable with respect to BOP area based on staff's review of licensee's analysis and also licensee performance of testing of the CFS -- that's condensate feedwater system -- prior to commencing full power EPU operation.

So this --

MR. LEITCH: I'm confused as to the nature of this commitment, that you can trip the condensate pump without SCRAMing the reactor. Suppose the reactor does SCRAM. Then, what can be done? I mean, they have to make some changes. In other words, does this have to have a successful outcome? What is the safety issue here? Isn't it just a reliability issue?

MR. REDDY: Well --

MR. LEITCH: Why should the NRC care if the plant SCRAMs I guess is basically my question.

MR. REDDY: Well, our position is in order to approve the power uprate we want to have what they call the successful operation of the test or some kind of justification that, you know, it does not trip the reactor once -- you know, when the condensate pump is tripped.

CHAIRMAN DENNING: But your concern is you don't want to have the impact on the plant of multiple plant trips.

MR. REDDY: Yes.

CHAIRMAN DENNING: That's the safety issue.

MR. REDDY: Yes, that is the safety issue.

CHAIRMAN DENNING: You don't want to have multiple plant trips.

MR. REDDY: Right. Multiple and, you know, frequent trips, you know.

CHAIRMAN DENNING: Yes.

MR. JONES: This is Steve Jones again. The concern was the unnecessary challenge to safety systems. I think our concern was more focused on the condensate pump because there was a potential there for a total loss of feed event. This was more of a secondary concern, and we -- the condition does allow analysis in lieu of testing, just to demonstrate that the expected hydraulic response to the system remains within the capability of the plant to withstand without a reactor trip.

MR. LEITCH: But I don't understand the force of this commitment. In other words, say they do this test, trip the condensate pump and the reactor SCRAMs. Are we, therefore, requiring that they back down to the original power level? Are we saying make some changes and try it again? Or what's the force of the commitment?

MR. JONES: Okay. By analysis it would be just to show that the reactor water level would essentially maintain within the band that would prevent a reactor trip. If for some reason they are unable to show that, yes, then we'd be looking for a modification prior to I guess ascending back to the EPU power level.

CHAIRMAN DENNING: Now, I missed this. I thought there was a commitment that -- for a test. Isn't there a commitment for a test?

MR. JONES: There's a commitment to trip a condensate pump.

CHAIRMAN DENNING: Yes.

MR. JONES: As a test.

CHAIRMAN DENNING: As a test.

MR. JONES: The feed pump trip can be performed either via analysis or a test.

CHAIRMAN DENNING: Okay. But with regards to the condensate pump, if it fails, then what are the implications? Do they then have to do some changes to the way they do their runback? I think when we discussed this in Vermont there was some indication that, if it did fail, that there could be changes in the procedure made in the way they do the runback, and that, you know, they could then demonstrate that -- with the new change that they would be able to do it.

Do you want to make a comment on that?

MR. NICHOLS: Yes, just one clarification. For the --

CHAIRMAN DENNING: State your name, please.

MR. NICHOLS: Craig Nichols from Entergy/Vermont Yankee. Clarification is for the condensate pump trip test, the required test, the criteria is that there not be a loss of all feedwater. There's not -- the condition is not that there not be a SCRAM. There has to not be the loss of all feedwater.

And as we spoke in Vermont, we would make adjustments to controls, setpoints, etcetera, to be able to satisfy that condition. It is the reactor feed pump follow-on, which is either by analysis or a test, for the avoidance of the plant trip.

CHAIRMAN DENNING: Okay. Continue.

MR. REDDY: Well, if you don't have any questions, this concludes the BOP review -- that is, balance of plant systems review. And at this point, if you don't have any questions, I'd like to move on to the fire protection system.

CHAIRMAN DENNING: Are there any questions on -- further questions on this? Obviously, this is an important area.

(No response.)

Then, go ahead with the fire protection.

MR. REDDY: All right. Actually, I'm presenting this on behalf of the Fire Protection Branch and Ray Galluci. He's the one who prepared it, and if there are any questions he will be responding to those.

The goals of fire protection program -- number one, fire will not prevent performance of necessary plant safety functions. Number two, fire will not significantly increase the risk of radioactive release. The NRC staff's review focused on effect of increased decay heat to ensure fire protection of the SSCs -- the structures, systems, and components -- and ensure that safe shutdown can be achieved and maintained.

The fire protection program acceptance criteria is based on 10 CFR 50.48 and Draft GDC-3. Also, the specific review criteria is based on the review standard for power uprates -- that is, RS-001.

Regarding the evaluation of the fire protection, the NRC staff verified that the licensee examined the five elements of fire protection program, demonstrating no effect on any of these five elements.

As verified by the NRC staff, the licensee demonstrated that fuel integrity is maintained, and there are no adverse consequences on the reactor pressure vessel integrity or the attached piping. The licensee also identified minimal, if any, impact of the power uprate on the plant's post-fire safe shutdown procedures.

Next one.

NRC also verified that the licensee properly demonstrated that fuel cladding integrity and containment integrity are maintained, and that sufficient time is available for the operator to perform necessary actions.

So, in summary, the staff concluded that the licensee has adequately accounted for the efforts of the increased decay heat. The fire protection program will continue to meet regulatory requirements following implementation of the proposed power uprate. Therefore, the staff finds the proposed EPU acceptable with respect to the fire protection.

CHAIRMAN DENNING: This may be a question for Ray.

MR. REDDY: Sure.

CHAIRMAN DENNING: And that is, it isn't obvious how a power uprate really is going to lead to problems in the fire protection program. Are there examples of where power uprates do have systems related problems that arise because of the power uprate?

MR. REDDY: Ray is there.

MR. GALLUCI: This is Ray Galluci. Pretty much it's a delta type of analysis, and the only examples in there are not specific for any fire scenarios, other than showing that some operator response times, etcetera, that have to meet Appendix R conditions may be decreased but still stay within the Appendix R limits.

So pretty much what you're looking -- asking is accounted for in the licensee's Appendix R evaluation.

CHAIRMAN DENNING: Thank you.

MR. REDDY: Do you have other questions.

MR. JONES: This is Steve Jones. I did want to step back and address the comment regarding the alternate cooling system. In that case, the licensee used the same model that was used during the previous licensing basis evaluations for that cooling tower and basin system.

So in that respect we didn't look at the methodology details. Our review was focused on the assumptions and design limits that were used associated with that, including this modification that the vendor discussed regarding capture of the oil cooler.

MR. REDDY: RHR service water --

MR. JONES: Right. The RHR service water cooler flow and diverting that back to the basin as opposed to letting that escape from the based inventory.

MEMBER SIEBER: Is that close enough to a water source that you could use a fire truck to make up to it?

MR. JONES: Certainly. Yes, I mean, it is an available site, but the licensing basis was maintained as a seven-day inventory with no makeup.

MEMBER SIEBER: Okay. But you could make up to it.

MR. JONES: Yes.

MEMBER SIEBER: Okay.

CHAIRMAN DENNING: Even beyond seven days, is that the question?

MEMBER SIEBER: Yes.

CHAIRMAN DENNING: Yes.

DR. BANERJEE: In the public comments that we had at Vermont, there was somebody who made some comments related to cable tray separation or something. Is that issue here or not?

MR. ENNIS: This is Rick Ennis. I'm not aware of any current cable separation issues at the plant.

CHAIRMAN DENNING: I wonder if Entergy could reply to that as well. Are you aware of any issues with cable tray separation?

MR. NICHOLS: There are no active issues related to cable tray separation --

CHAIRMAN DENNING: Thank you.

MR. NICHOLS: -- at Vermont Yankee.

CHAIRMAN DENNING: Thank you.

MEMBER SIEBER: Well, Vermont Yankee is an Appendix R plant. And so it has to comply with Appendix R, including whatever exemptions they sought when Appendix R was imposed.

CHAIRMAN DENNING: Okay.

MEMBER WALLIS: But that wouldn't be affected by the power uprate.

MEMBER SIEBER: No.

CHAIRMAN DENNING: Okay.

MR. REDDY: Thank you very much.

CHAIRMAN DENNING: Thank you very much.

I think we are done, then, for this morning. Right?

Okay. We will now go in recess until 12:45.

(Whereupon, at 11:43 a.m., the proceedings in the foregoing matter recessed for lunch until 12:49 p.m.)

CHAIRMAN DENNING: Vermont Yankee is going to make a presentation related to the residual heat removal and core spray suction strain. I want to make it clear that the purpose of this is --

(Whereupon, the foregoing matter went off the record briefly.)

CHAIRMAN DENNING: Let me say again that the objective here is obviously not related to the adequacy of the current design but, rather, to look at the uncertainties associated with debris calculations of the strainers as they relate to MPSH overpressure credit in the upgrade.

And so you can keep the presentation fairly short. And then I know that a couple of the staff members have questions. Any time you're ready, you can start.

14. PLANT SYSTEMS

MR. HOBBS: Okay. Good afternoon. My name is Brian Hobbs. I'm the Entergy engineering analysis supervisor for the Vermont Yankee power uprate project. With me to present this module on RHR and Core Spray Suctions Strainers are Mr. Enrico Betti on my right and Mr. Bruce Slifer on my left.

Just a couple of key points about this presentation. First of all, we believe we have a conservative set of design assumptions for our existing ECCS pump strainers.

They are some of the largest strainers in the BWR industry. They were installed to take into account items such as debris. And we have a conservative debris loading assumption that we'll be talking about today. And the bottom line relative to power uprate is that it really does not have much effect on some of the assumptions in our design of our ECCS suction strainers.

I would like to turn it over to Mr. Enrico Betti.

MR. BETTI: Good morning. This is Enrico Betti from Entergy.

The topics we're going to touch on today are the residual heat removal and core spray suction strainer arrangement. I'll give you a depiction of what our strainers look like at Vermont Yankee, a little talk about the stacked disc strainer design.

A little background on how VY developed our debris quantities used for the design of the strainers and what debris quantities we use in our MPSH analysis. We want to talk a little bit about how we came up with our debris head loss correlation through testing. And, finally, we'll give a discussion on our strainer design and the prevention of air ingestion being drawn into the strainers.

If you look at this screen here, this is the Vermont Yankee torus. The reactor vessel sits in here. You see each of the downcomers. You can see the header, the pipes that drop 96 outcome of pipes drop into our torus pool.

And, Brian, could you show us the RHR strainers? These sets of modules here and here are the RHR modules. These latter two are our core spray modules.

When we did this project, we set out to provide some margin in MPSH. We sized these modules to provide basically the largest modules we could get into our torus. And that was with a large hole that we cut into our torus to install the --

MEMBER WALLIS: The core spray outlet is

at one end of that thing?

MR. BETTI: That's right.

MEMBER WALLIS: And there seem to be some discs. Do they extend all the way down to the bottom of that cylinder or what is below them?

MR. BETTI: Yes. We'll --

MEMBER WALLIS: You're going to show us that?

MR. BETTI: Yes. We'll discuss the construction of the discs and how they work. If you look at this overview, too, you'll see that not only was the degree of head loss a concern because our old strainers were small cans that came right off these fittings, these new ones have extremely low head loss fittings that were part of the design, a ram's head in this case, which is a custom-made fitting made out of two long radius elbows. And this is reducing off of fear for minimizing any kind of piping losses.

Next slide. What you see here, Graham, is a close-up of the RHR strainer. You've got a picture of a half of this, one of our RHR strainers. Here's the ram's head, which is especially made to split teeth below lead loss. And then that folds into a flange section of strainer. This strainer section is around eight feet long. And then there's a small bend. And we have another section of the strainer.

This is the support. The supports are right in line with our torus ring girder so that the hydrodynamic loads and shocks that come down here are all transferred directly into the line of the supports on our torus.

Since we had reasonable margin right in this plane. So we kept any added load from hydrodynamics right in this plane. That was a key design.

I'll touch on these strainer designs, but let me go over briefly. This strainer inside consists of a 24-inch stainless steel pipe, half-inch thick. And there's a series of holes drilled in the machine in that pipe such that the holes in this end are bigger than the holes in this end. The purpose there is you have the core pipe.

Over that, we have a set of perforated plate. And there's a one-inch gap between these intersections of the strainer where the perf plate is in the inside pipe and outside of those, you have these stacked discs. The holes on the inside are tuned such that the debris loading in these strainers happens evenly.

The other idea of these kinds of strainers is that you're going to have a big area around these stacked discs. And as these initially start filling up with new car, and you end up with the geometry that's a pretty large area.

If they get full of debris, then the velocity, approach velocity, going through that debris is going to be through the circumscribed area of the strainer. And that's accounted for in the way we analyze the debris loading and head loss of these units.

Next slide, please. What you have here -- and we wanted to include this a little bit -- is a look at the RHR, a section of the RHR strainers. There's the ring girder in the background. Here's the downcomers.

And this is some water levels that were mentioned in some comets that we get on these calculations. I just want to point out that the levels on these drawings for minimum water level are the levels that we assign for strainer design. They're not our actual minimum water levels post-LOCA.

We made it a difference because we wanted to assure that we have some tolerance in the design versus the actual water levels. That was to take into account any kind of construction or problems that we had during installation. So these design values -- and Bruce will talk to that in a little bit -- are quite a bit lower than our post-LOCA minimum water level.

Okay, Brian. What you see here is the core spray suction strainer. I think that was a 14-inch, but it's got an elbow reducer up to the 24, comes into the same kind of design.

Here you have 2 sets of 24-inch core pipes. And then outside that you have a 26-inch area of the strainer diameter here and then this 47-inch OD discs.

Okay, Brian. Again, here's a shot of the core spray. And because the geometry in the piping and location had to be a little different to facilitate the fittings and the elbows, the submergence of this strainer is a little bit different than the RHR. And Bruce will talk to that in a minute, too.

I didn't have a lot of time to put these slides together. And this is a shot out of one of our calculations on these strainers. And these strainer designs were a PCI prototype 2 was the basic design here. PCI, EPRI did a lot of testing on this unit right down here.

MEMBER WALLIS: Between the gap on the two, I didn't quite understand. The 24 to 26 inches, what's in there? Nothing?

MR. BETTI: The core tube of the strainer is 24-inch pipe.

MEMBER WALLIS: Right.

MR. BETTI: And then the --

MEMBER WALLIS: So it's OD?

MR. BETTI: It's the OD. And then there's a series of holes in that pipe that --

MEMBER WALLIS: Right.

MR. BETTI: -- make an even flow into that pipe. And outside that pipe is a 26 area where that would be the bottom of the notched portion of the strainer.

So there's one inch of annulus flow area between the outside of the pipe and the smaller section of the disc. That would be the inner disc.

Then you have an open hollow section of perforated plate that goes 47-inch OD.

MEMBER WALLIS: So what is in that inch? There's nothing there? I don't understand.

DR. BANERJEE: Just show the diagram, please.

MEMBER WALLIS: Between 24 and 26. What

is there there?

MR. BETTI: Yes. The core pipe runs in here. So there's an annulus open area of perforated plate. It causes a -- that's a secondary seal. That's where the debris is caught.

MEMBER SIEBER: There's water.

MR. BETTI: There's water in there, right.

DR. BANERJEE: The debris is caught on the faces of those plates, isn't it? The debris is caught on the faces of those plates, which are perforated.

MR. BETTI: That's right.

DR. BANERJEE: I'm also trying to understand the design. This shows how the plates are put on the pipe, but what does a plate look like?

MEMBER WALLIS: Also what's between the 24 and 26? There's another tube that's 26 inches diameter?

DR. BANERJEE: Maybe a better diagram.

MR. BETTI: Yes. I'm going to show you a section of this.

MEMBER WALLIS: This is part of the test now, to see if you can draw it.

MR. BETTI: If we're looking at a section of the -- this outer ring of the torus, which is made up of these cylindrical discs that are all welded, all this area is made out of perforated plate, eight-inch holes, 40 percent open flow area.

MEMBER WALLIS: That's all one thing, then.

MR. BETTI: That's all one welded unit.

MEMBER WALLIS: There are some structural braces in here.

MR. BETTI: Yes, but they are full of holes that hold those units up.

MEMBER WALLIS: Okay. So there are holes all around that.

MR. BETTI: Yes. And then inside here, there's this core plate in that core pipe.

MEMBER WALLIS: Okay.

MR. BETTI: And that has two functions. It forms the structural component that holds the strainer up, but it also has engineered holes in it to allow flow from here to get into the pipe. And then the hole sizes are designed such that there is even flow to the debris bed.

So debris collects out here like this.

MEMBER WALLIS: Right.

MR. BETTI: That's the design of the strainer.

MR. CARUSO: And where's the center line

of that?

MR. BETTI: The center line of the pipe is here.

DR. BANERJEE: How big are the holes in the pipe?

MR. BETTI: They vary from like somewhere around like ten square inches down to something smaller?

DR. BANERJEE: And the holes in that outer shell?

MR. BETTI: This is all an eighth inch perf by 40 percent open flow area. It's all stainless.

MEMBER RANSOM: How big are the holes in the inner pipe

DR. BANERJEE: They vary. They vary depending upon the position.

MEMBER RANSOM: They look smaller than an eighth of an inch.

MR. BETTI: Oh, they're much bigger. They're a large area, like ten square inches, six square inches, that --

MEMBER RANSOM: No bigger particles than an eighth inch are going to get in there and then --

MR. BETTI: Right. This is a PCI patented design strainer. This is design-tested at EPRI when we bought these rights.

CHAIRMAN DENNING: It's done that way to give a constant deposition of debris across the whole strainer. That's why there's a variability in the whole socket.

MR. BETTI: That way the approach velocity anywhere on the strainer designs is the same. So as strainers get longer, each unit has to have the specific patent of holes because they attach together and you want to have the same flow through the whole length of strainer. So they're custom-designed holes in the inner tube.

DR. BANERJEE: I guess when the strainer doesn't have any debris on it, you want to ensure that the flow to each of those one-eighth inch holes is the same. So they distribute the big holes in such a way because it's a manifold problem. Through Bernouli's equation, you have to change the hole sizes to give you an even flow.

Once you start to build up the debris, it doesn't matter because then the main pressure drop is through the debris. The initial conditions have to be set to be uniform. And that's the reason to do it.

MEMBER RANSOM: Is this also designed so

the big pieces of debris would be caught on the outside of those discs?

DR. BANERJEE: Anyway, I think that that's a nice picture.

MR. BETTI: All right. If there's no more questions on this slide, we can --

DR. BANERJEE: Do you have data circumscribed area somewhere --

MR. BETTI: Yes, the next slide.

DR. BANERJEE: -- or is that the next one?

MR. BETTI: That one I did make up for this meeting. All right.

So these are the maximum design flow velocities that we used in the strainer design for short-term and long-term post-LOCA conditions. What you see here is the strainer flow, then the strainer area, the approach velocity of these strainers based on their perforated plate area, which we just described, and then the approach velocity based on area and approach velocity based on the circumscribed area of these strainers.

Now, these are the inputs that we use into the program evaluations we use for debris head losses, these --

DR. BANERJEE: I have a question here,

maybe for clarification. The circumscribed area, does that include the thickness of the plates or does it not? That's the first question.

MR. BETTI: Yes, it does.

DR. BANERJEE: But there is no flow through that outer or is there a flow through it? Are there holes --

MR. BETTI: Yes, there is.

DR. BANERJEE: -- at the top of the plate as well?

MR. BETTI: There are.

DR. BANERJEE: There are holes everywhere?

MR. BETTI: Holes everywhere.

MEMBER WALLIS: There's much less flow through that than there is through the gap.

DR. BANERJEE: Right, right. So, in fact, there are holes everywhere.

MR. BETTI: That's right. There are holes everywhere, right.

DR. BANERJEE: Okay. The second question is when you talk about the approach velocity, that is not the approach velocity into the gap, right?

MR. BETTI: Right.

DR. BANERJEE: But it is approach velocity normal to the gap.

MR. BETTI: That's true.

DR. BANERJEE: So what is the significance of that approach velocity when it comes to entrainment and transport to the strainer because when you talk about the approach velocity being 0.039, that's not significant to what is coming to the strainer? The approach velocity really is .111 or .058 depending on how much strainers you have.

From the viewpoint of turbulence in the main tank and what is being transported to the strainer, it's the near field which matters. It's not the approach velocity normal to that. That's always puzzled me enormously.

CHAIRMAN DENNING: Show us on the figure where the approach velocity is because I'm not sure that you answered --

DR. BANERJEE: He hasn't answered.

CHAIRMAN DENNING: -- correctly on --

MR. BETTI: I haven't answered his question yet, no, but --

DR. BANERJEE: He understands it, though.

MR. BETTI: I understand his question.

CHAIRMAN DENNING: Okay. Now, where is the approach? I thought you did a circumscribed area.

MR. BETTI: Yes. The approach velocity

based on the perforated plate area would just be the strainer flow divided by the areas described right there. That's the approach --

DR. BANERJEE: Which is what you have shown there.

MR. BETTI: That's right. And then if we calculated the approach velocity based on a cylinder that matched that plate location there, that's what we call the approach velocity based on the circumscribed area.

CHAIRMAN DENNING: Right, and which is this velocity.

MR. BETTI: We just calculated both of them here.

CHAIRMAN DENNING: Right. Oh, I'm sorry. There's the -

DR. BANERJEE: Yes. I was just saying that for --

MR. BETTI: His question is an interesting question. It's one that we wrestle with. You know, in a turbulent torus, is it more important that we consider this or is this more important in attracting specifically a paint particle to the strainer?

DR. BANERJEE: I would maintain --

MR. BETTI: And so the way that we did it in the report that we had docketed on this, we actually did that by close observation of the testing.

DR. BANERJEE: Well, the testing was with a single strainer, right?

MR. BETTI: It was with a single strainer.

DR. BANERJEE: So you got the obvious answer, which is completely wrong.

MR. BETTI: Well, I don't think so because the testing showed that the particles had to come right up onto the plate that we tested to stick to the plate.

DR. BANERJEE: Yes, but, I mean, I don't want to argue. I think it's fairly obvious that if you have a single strainer, you never have a circumscribed situation. And the approach velocity is never into the gaps. You basically made a problem which has an approach velocity of 0.02 or 0.039.

By definition, if you make a stack, that's a different matter. In your paint chips, you never made a stack. You just had a single strainer that you looked at.

MR. BETTI: Yes. We can talk a little about that testing later.

DR. BANERJEE: Yes. So I think --

MR. BETTI: I understand your point. I

just think that we spent a lot of time studying the films from that paint testing to make observations to see were there paint chips being drawn in through the circumscribed flow or were they being drawn in simply because we put such a high concentration of paint.

We'll talk about that. We found it more to be as a, you know, you need a lot of turbulence to keep the paint afloat. And then you need to get that paint chip close to the strainer so it gets drawn in.

So it is more of a macro look at it. We could have addressed it, you know, in a couple of different ways. Certainly the answer would have been cleaner. We wouldn't have had to match the films if the answer was paint doesn't go to the strainers at either approach velocity.

That would have been a nice answer engineering-wise, but we had to do more work to establish that that wasn't the case that we could use that cylindrical test information to come to --

DR. BANERJEE: I think the concern is that all your work, experimental work, that I have seen -- there may be others -- in the reports are all with single discs so that when you stack the discs and you start to have flow into a stacked disc, it is the approach velocity of the circumference which matters.

MR. BETTI: Yes, not a new question. So I understand.

DR. BANERJEE: And when you have a single disc, it's a completely different approach velocity. So I don't see the applicability of any of your experiments to the case at hand.

In fact, the pressure dropped, the entrainment, none of which is applicable to a stack of strainers. You're talking about a single strainer which is completely exposed.

MR. BETTI: EPRI did testing on stacked disc strainers. And they did testing on the NUREG correlations for stacked disc strainers to assure that the NUREG correlation that we used for this circumscribed and then perforated plate area arrangement was valid. Okay?

So the stacked disc was tested at EPRI. On the previous slide, that was the standard stacked disc. What I was trying to depict is that our stacked disc and the standard stacked disc arrangement has been tested.

The reason that we set out to do some more testing, some specific debris head loss testing, was more of the issue of we're designing bigger strainers but lower approach velocities. And even though the materials had been tested, we wanted to make sure. We wanted to find out what nuances were involved with lower approach velocities and a large amount of paint chips. Those were the key.

So we had additional testing done on the head loss correlations, but you're correct in saying that that head loss correlation, we were concentrating on the correlations themselves because so much testing had already been done with the stacked disc arrangement at EPRI.

DR. BANERJEE: Well, first of all, the EPRI -- we haven't seen the EPRI test. That would be a valuable thing to take a look at.

MR. BETTI: Okay.

DR. BANERJEE: Like all these tests, when we have looked at them in more detail, almost everything we have seen in the past is, let's say, highly disputable. And I've found it very difficult to understand any of the tests which have been done, including the ones which were done at Los Alamos.

The second aspect is that the correlation, which I think you also refer to as semi-theoretical, is, in fact, neither theoretical nor semi in any way. To call it theoretical is just incorrect. There's no basis in theory for that correlation, which there have been notes written on as well.

That correlation is also suspect. So it would be very interesting to see what evidence EPRI has gathered to support that correlation.

MR. BETTI: You're calling into doubt the NUREG correlation that was accepted by the NRC.

DR. BANERJEE: It may or may not be accepted. The fact remains that when we have reexamined this correlation, it has had severe problems interpreting some of the very recent data that has been taken.

MR. BETTI: I just don't --

DR. BANERJEE: Have you seen the most recent data?

CHAIRMAN DENNING: Now, which data are you referring to, Sanjoy, Los Alamos?

DR. BANERJEE: Los Alamos data. So we would like to see the EPRI results, look at it, and see how well this correlation bounds it. If it's in a stacked disc as well, is the data taken in a situation where the gaps have filled up? And so it's completely circumscribed.

MR. BETTI: Well, they did it both ways. They did the relationship between unfilled and filled. They made sure their correlation worked through that

--

MEMBER WALLIS: Once the gaps fill up, the strainer really stops functioning as a very good strainer. And it's filled. And that's it. And anything else has to go on the outside.

MR. BETTI: It still functions as a strainer.

MEMBER WALLIS: But it doesn't function very well because it's lost all its area. It's lost most of its area.

DR. BANERJEE: And the approach velocity is --

MEMBER WALLIS: Anyway, you're going to go on.

MR. BETTI: Yes. All right. So at Vermont Yankee, we designed our strainers for our conservative suppression pool debris loads. We were using the NUREG correlations that were validated through testing.

We did some minor modifications of that testing based on the LNC chuck testing that we did in this test facility to account for VY's debris combinations and approach velocities.

And then when we get this test data, then that information is correlated to head loss in our suppression pool by just adjustments in viscosity and the --

MEMBER WALLIS: You had 50 percent of the finds are retained or something like that?

MR. BETTI: Right. Take the --

MEMBER WALLIS: The other ones go right through?

MR. BETTI: Right.

MEMBER WALLIS: They normally go through the reactor and come back again?

MR. BETTI: Yes.

MEMBER WALLIS: And they get called the second time around?

MR. BETTI: Right. That's based on testing, too.

MEMBER WALLIS: Do you only assume 50 percent of them in your --

MR. BETTI: They do. And in a minute, we'll talk to that number, Graham. And I think you will feel a little differently when you see how much of those finds we use in our test and how much of the finds that we have in our --

MEMBER WALLIS: The other thing I didn't see was -- well, there's a time effect. In all of this Los Alamos test, there's a mysterious time effect.

And then there was also this thin bed effect, which can form anywhere. You can get a matrix and then some time later you get a thin bed on top of it or something. And there were all kinds of warnings about you have to be able to calculate it. I didn't see anything about a thin bed effect in your analysis.

Is that because you couldn't figure out how to do it or just assumed it's homogeneous and --

MR. BETTI: You might have to -- I don't know what you mean by a "thin bed."

MEMBER WALLIS: Well, I'm not going to say what I mean, but Los Alamos says there's a thin bed effect, which was actually found in BWRs a long time ago.

MR. NICHOLS: To be clear here, you're referring to the recent testing done as part of the --

MEMBER WALLIS: They came here and talked to us. And they said at any place in this bed, you know, you've got a mixture of fiber and fines. So you could get a thin layer of fine material, which has a much higher pressure drop than it would have, which was dispersed in everything else.

MR. BETTI: Okay. Now I understand.

MEMBER WALLIS: It's like the mud that the beaver puts on the dam that seals it up.

MR. BETTI: That's right.

MEMBER WALLIS: That's what they were concerned about.

MR. BETTI: And when we did our head loss testing, there were those effects. And that fact is into the calculated head loss as recorded. In other words, if you take a stack of debris and you try to correlate it real well and drop it real fine into a pipe, it doesn't disperse homogeneously. And the strain of loss is really a function about how all that debris stacks up.

MEMBER WALLIS: That's right.

MR. BETTI: And there's a lot of randomness in those. So if you take an ideal correlation for debris head loss and assume that everything stacks up randomly and you get this really fine correlation through that method and then you say, "Well, gee, now I'm going to change my slides by four percent. So, therefore, my head loss is going to change by .07 percent," I say hogwash. And I've always said hogwash because we ran a series of tests.

And when you look at one of these strainers, when they have debris on them, they're anything but homogeneous. And then you take a cylinder and you put it in a pool and you take these kinds of low approach velocities when the paint chip and other component settling velocities can be as high as .2 feet per second. You end up with most of your debris at the top of the strainer or areas away from the flow. All right?

So what our approach was -- and this is something that I have just bounced up and down on when anybody says, "We're going to start employing one of these correlations to change our head losses" -- to put the debris in the most conservative combinations that we think you can get on any of these strainers.

MEMBER WALLIS: Most conservative is usually to put all of the fiberglass on first and put all of the sludge on top.

DR. BANERJEE: I also noticed that you ran a --

MR. BETTI: But what I was getting at is that when we ran these tests with these size strainers, that you would end up with not a full debris bed but patches of debris and patches of opens. Okay?

So your head loss is more a correlation about how many open areas you have versus what your debris loss is through your correlation. So when we are said and done with these correlations, what we maintain is we establish from this test with a conservative concentration of debris, we establish the head loss for the VY strainers. And that's the head loss we maintain.

We don't go back and say, "Okay. We only got 75 pounds of sludge, not 700 pounds of sludge, like we assume here."

And so they say, "Well, gee, that's great. Sludge causes most of our head loss." Therefore, instead of, you know, one foot, now we have .2 feet.

We say, "No." A head loss is what we establish during those tests. And we keep those head losses in our MPSH calculation.

DR. BANERJEE: Let me go back. If I understand how you did these calculations, you used a computer program called H-loss, right?

MR. BETTI: Yes.

DR. BANERJEE: And this was run for you by a corporation called ITS?

MR. BETTI: Yes.

DR. BANERJEE: What you did, if I understand it, is that you zoomed because you had to zoom ascertain porosity or a solid density. It was .2 if I look at the results. Those were based, if I understand it correctly, on some experiments we have done with single strainers.

The situation that you have there is very different because what you've got is a stacked set of strainers into which the material is accumulating. And when it eventually builds up to the edges there, then this amount of debris which is stopped between those plates acts as a filter. No test that I saw looked at any situation like this to know what the true density might be.

As the fine particles go through this fiber bed, which is stuck on these strainers, the density could well be higher or lower. I have no idea.

MR. BETTI: That's right.

DR. BANERJEE: I'm simply saying I just don't know.

MR. BETTI: Right.

DR. BANERJEE: Secondly, in the head loss correlation, which is the NUREG 6224, the tuning parameter is SV, the surface area per unit volume, which is what they tune to fit experiments basically. And by tuning it sufficiently, you can fit any experiment.

But the problem that arises is that

between experiments, you get very different SVs to fit the data. So almost every experiment has a different SV. Okay?

Now, I actually looked for your value of SV, which was used. And I couldn't find it. I went over your reports with a fine-toothed comb. So that must have been an input parameter to tune against the experiments, which may have been done by ITS. It would be very interesting to know what SV they used because there is data now on typical SVs for fiber and particle mixed beds, which compact more and more as you go.

And those are pretty thick beds now you're talking about, thick because they're about an inch, like this. They're deep. I don't know how deep they are. But you could well have very different densities through that bed --

MR. BETTI: Yes, but that's --

DR. BANERJEE: -- from the ones that zoomed to the calculation.

MR. BETTI: The densities used in our calculations --

DR. BANERJEE: .2.

MR. BETTI: Yes, but that was based on the measured density from the --

DR. BANERJEE: Was measured on a single strainer.

MR. BETTI: Single strainer, exactly.

DR. BANERJEE: It was very different from that situation.

MEMBER WALLIS: As long as presumably the gap doesn't fill up very much, they may be okay.

MR. BETTI: That's right.

MEMBER WALLIS: As long as the pressure --

DR. BANERJEE: The gaps are only one-inch.

MEMBER WALLIS: No. As long as the pressure drop is very low, it doesn't compress the bed. And lots of the effects that we worry about don't occur.

MR. BETTI: Yes. I think it says it in the report that we docketed when we originally designed these strainers, we designed them not to fill up, but --

MEMBER WALLIS: They get pretty close at the limit.

MR. BETTI: Yes. And because of the approach velocities for lower, the density ended up being lower. So, therefore, we did get a little bit of external buildup of the debris.

DR. BANERJEE: Well, but even if you do

get half an inch buildup on each side, you're still going to close that gap.

MEMBER WALLIS: Right.

MR. BETTI: But, in reality, you put one of these strainers in a pool with this kind of strainer drop and you take this discussion and you look at the bottom of these strainers, you're going to find that the bottom of the strainer has got holes all over it.

In reality, the pressure drop is just going to be a function of the amount of open area in the bottom of the strainer. So it's not as theoretical as you think. And I think that we have a conservative design that's going to give us a very, very low pressure drop. And that's --

DR. BANERJEE: You're saying the stuff falls down from the bottom?

MR. BETTI: Yes. It falls down from the bottom.

DR. BANERJEE: The bottom of the pool?

MR. BETTI: Yes. It only collects on the sides. And there's a lot of open areas on the bottom of these strainers.

DR. BANERJEE: This isn't up against the wall somehow? I thought you showed us --

MR. BETTI: Can we go back to the slide?

DR. BANERJEE: It was resting on a wall or something.

MR. BETTI: No. We'll look at that, at the section.

MEMBER WALLIS: It actually falls off the strainer as it builds up?

MR. BETTI: Yes. I mean, it would build up in this quiet area over here, but there would be very little debris in the areas over here.

MEMBER WALLIS: It's a self-cleaning strainer?

MR. BETTI: No. I think it's just the fact that when there's any turbulence or any moisture in the water in the front end, debris kind of collect in the quiet areas in the back end. So it's going to concentrate the debris collection on one side.

So if we say size the strainers, which we did, to take all the nukon without going into the gaps and we assume it all builds up evenly; in fact, it does build up evenly, gravity in dead areas, concentrate some of the material so there's a lot less for the other areas.

It's not like the strainer is designed and there's an infinite amount of -- I mean, some of these plants designed for feet of nukon material. And we design basically to have a thin coat of material for all our strainers.

DR. BANERJEE: The issue I suppose would be that as the top got full of debris, which I agree would happen, then the flow would drop through it. And you'd start to get much higher flow through the bottom, --

MR. BETTI: Right.

DR. BANERJEE: -- which would ultimately clog up again.

MEMBER SIEBER: It's the approach velocity that controls how much adheres.

DR. BANERJEE: You going to get a lot higher approach velocity at the bottom.

MEMBER SIEBER: As time goes on.

DR. BANERJEE: As time goes on.

MR. BETTI: That's a geometry problem, but there is a bigger gap in approach velocity because, like you say, when you fill those gaps, you have quite a large reduction in area.

DR. BANERJEE: Sure.

MR. BETTI: But, then again, if you don't fill the bottom gaps because you dump four inches of strainer in the quiet areas at the top area, you still end up with a larger effect of working area of your strainer.

DR. BANERJEE: Well, I think the first thing that we should do is take a look at these EPRI experiments because we didn't have access to those at the moment and see what strainer behavior was, what mix they used, and what sort of -- did they use fibrous material as well as particle?

MR. BETTI: Yes. Fibrous and sludge, yes.

DR. BANERJEE: And sludge. So that would be a good point to start.

MR. BETTI: The only thing new here is the high paint chip quantities. We're going to talk to that because the basis for high paint chips was something we're going to get into in a little bit.

CHAIRMAN DENNING: Would you go ahead and proceed, then?

MR. BETTI: Thank you.

CHAIRMAN DENNING: And let's move more quickly now through.

MR. BETTI: All right. We included a slide that was design debris low quantities for the torus in here. You'll see line 1, we have nukon insulation. That was the URG allowed you to do basically the zone of influence.

We took the approach where we took on one whole research system. We took the lazy approach, where we just used the whole research system and get to use half our nukon and assume that that was blown off in a jet.

We had when we did this testing a lot of TempMat that was on our temporary mat insulation. A lot of that since has been removed, but we don't take that out of our correlation. That's been replaced with RMI insulation.

We still have some RF flex insulation in our drywell. You'll note that we assumed in this that we had -- in addition to some of the URG-recommended values, that we included 622 pounds of sludge from our torus. And what --

DR. BANERJEE: That's not in your source term here. It says much lower than that. I have this report, which is your source term here.

MR. BETTI: Yes.

DR. BANERJEE: And it seems that what you did was 159 plus 50 plus 27 and you took 150 from the drywell. So I don't see how you got that 772 number. This was not consistent with your report, which I have in front of me, which is on VY. It's called "Debris Source Terms for Sizing of Replacement Residual Heat

Removal and Core Spray Strainer, VY C1677."

MR. BETTI: One, six, seven, seven?

DR. BANERJEE: Yes. The numbers are 159 plus 50 plus 27 plus 150. And the 150 came from the drywell.

MR. BETTI: That's true. Let me explain it a little bit. I don't know what before you were talking about. I'll clarify that a little bit.

When we set up the design test cases in the debris loading for the design of the strainers, these are the numbers on the board that we used. Okay?

Six seventy-seven was then -- after that, that calc was written. And those numbers were put in there that reflect more realistic sludge factors.

But the debris head loss correlations that we maintain in our MPSH calculations are those that are developed in VY C1924. Our 808 calc uses the debris head loss calculations in 1924. Those head loss calculations in 1924, the basis of those, is the debris quantities that we put in the design spec and that we tested it at Alden.

So there's a 1677 calc that tries to put together what a realistic head loss would be and sludge loading for our plants, but, as I started to say in this conversation, we maintain the values from 1924. And these are the values that went into the 1924 calculation.

DR. BANERJEE: Do we have 1924?

MR. BETTI: I think you got that one, yes.

DR. BANERJEE: Here the basis is very clear. You say you have an 18-month fuel cycle. And based on the debris, the sludge that has been removed, on the second, you give 159 pounds of dry sludge.

MR. BETTI: Right, right.

DR. BANERJEE: And, as a conservative measure, you add 50 pounds of sludge to that.

MR. BETTI: Right.

DR. BANERJEE: And 27 pounds are added after that to provide some operational flexibility, which gives you 6 months additional time between torus cleaning.

MR. BETTI: That's right. And then --

DR. BANERJEE: So I can follow this logic very clearly, what you said.

MR. BETTI: That's right. Right.

DR. BANERJEE: But it's not incredibly conservative or anything. You just are doing something which is roughly right.

MR. BETTI: Roughly right, yes.

DR. BANERJEE: There's not a huge --

MR. BETTI: And that was based on, like you say, a sludge quantity of around 50-59 pounds per --

DR. BANERJEE: One fifty-nine pounds because you don't clean every refueling cycle, seen every second.

MR. BETTI: Yes, but it was 50 some odd --

MEMBER WALLIS: Fifty-three pounds a year it says here.

MR. BETTI: Fifty-three pounds a year, right, and --

DR. BANERJEE: So the refueling being every 18 months, and you say every second refueling cycle you're cleaning.

MR. BETTI: Right. So that was based on the first time we did this cleaning and the guys started canting, somewhat decantoring the debris in the bottom of the torus.

We hadn't painted our torus at that point. We had old paint, a little bit of rust, et cetera. And that was the quantities we came up with.

So what we did for the strainer design specification that determined the quantities for testing was increased those values so that we were testing a conservative potential sludge load. Okay?

In 1924, we -- in the spec, VY S049, you'll see a bunch of debris load cases that are based on these sludge quantities based on the split fractions of each of the pumps.

Then at Alden, they ran the test on those equivalent debris quantities. Then the VYS --

DR. BANERJEE: I guess we have this in the report that I need to look at, look at the basis of how you did it. It's 1924? I've got it. We'll look at it.

MR. BETTI: So what I'm saying is that --

DR. BANERJEE: I'll check.

MR. BETTI: -- 1924 we use as the basis, then. Those head losses are then what is used in our 808 calculation. All right?

DR. BANERJEE: Now, the report, the head loss calculations, is it documented in that one that used H-loss, then?

MR. BETTI: Yes.

DR. BANERJEE: That was the ITS study?

MR. BETTI: Right. It's I think the 1924 calculation. Bruce should have a copy of it with --

DR. BANERJEE: Yes. Nineteen twenty-four, we have that.

MR. BETTI: That was actually --

DR. BANERJEE: Do we have that?

MR. BETTI: It was --

DR. BANERJEE: Well, I'll check it out.

MEMBER WALLIS: Make sure it's on that internet thing we have access to.

DR. BANERJEE: Yes. Nineteen twenty-four is there.

MEMBER WALLIS: It is there? Okay.

CHAIRMAN DENNING: Let's move forward, then, please.

MR. BETTI: Thanks, Bruce.

All right. Now, the thing that kind of made our plant unique in this regard at the time was a high quantity of paint assumed to end up in our torus.

We had contracted with CDI and GE to kind of look at our paint and determine what was qualified, what was unqualified. What they basically said was, "Gee, we have to get in there. And we have to do -- you would have to do some testing, look at this paint, make sure if it's qualified or unqualified."

Because we had a deadline for compliance with 9603, the decision was made to treat all top coat painting in our drywell and torus as unqualified until we proved it to be qualified.

That ended up with basically about 75,000 square foot paint that ended up in our torus. And that was the assumption that was used to develop the paint loadings that we used in our paint debris testing at all.

Then what we did is because we knew we were doing settlement tests, we tried to get a very light paint. We tried to get a paint that was representative of our paint, thin, in a size that would have the least tendency to sink.

So those were the characteristics that we picked for the paint. We had a bounding amount of paint. We picked the paint that was the same long variety that we used until we tried to pick thicknesses, dimensions, et cetera, densities that would give us the most buoyant effect to the paint so that it had the most likelihood of being dried. All right.

DR. BANERJEE: I have here the sludge, but it doesn't seem to be that much, the number. Is there something weird in how I should interpret these?

MR. BETTI: Yes, because each of those --

DR. BANERJEE: It says "Sludge 91.5 pounds." Is this for per strainer or something?

MR. BETTI: Yes. It's per strainer based on split fractions and flow and conditions for each of the strainers. So depending upon the condition you're talking about, if you say you dump a total of 700 pounds of sludge to your torus and you have three pumps, one core spray, two HR pumps running, there will be a distribution of that debris to the strainers. And then we have a short-term strainer loading and then a long-term strainer loading. In certain periods, they often turn on pumps.

DR. BANERJEE: I guess we need to go through this in detail.

MR. BETTI: We can do that.

CHAIRMAN DENNING: Continue.

MR. BETTI: All right. To give you an example on the sludge, in 2004, we did another sludge removal. That was 75 pounds after 6 years. And, again, we're assuming 772 pounds in our test data. So I'm just trying to emphasize here that our testing is done at very conservative values and our head losses were done with very conservative values.

Next slide, please. That concludes the discussion on the debris. And we have Bruce Slifer we're going to turn it over to for a little discussion on the issue of submergence and air ingestion.

MR. SLIFER: My name is Bruce Slifer. I'm with Vermont Yankee.

We'll talk about some of the testing that has been done to determine if there's any potential for formation of an air core vortex in air ingestion through these strainers.

There are a couple of tests that were conducted which give some indications of the conditions under which this type of phenomena might occur. The first series of tests that I want to discuss are the Alden Research Lab tests that were documented in NUREG CR-2772.

Those tests were done with a strainer, which is basically a strainer that was typical of the strainer designs in place at the time. These tests were done in 1982. And this strainer configuration was a codicle strainer, much shorter in length than the kinds of strainers we're talking about that are installed at Vermont Yankee today. But they still do give some kind of indications of the potential for vortex formation.

The diameter pipe was two feet, which is in --

MEMBER WALLIS: Horizontal pipe? Horizontal?

MR. SLIFER: Yes, it was horizontal. The orientation was --

MEMBER WALLIS: So as is the distance of both the top of the pipe. Is that what it is?

MR. SLIFER: I'm sorry? I didn't --

MEMBER RANSOM: The submergence? Is that the --

MEMBER WALLIS: It's from the top of the --

MR. SLIFER: Submergence is from the center line of the pipe to the top of the pool. The flow rate was 12,000 gpm maximum, which is much higher than the flow rates we see in our strainers. The calculated Froude number was .8. And under those conditions, they concluded that there was no air core vortexing; therefore, no air ingestion.

Next slide, please. Much more typical or, I should say, applicable to Vermont Yankee's situation today was EPRI testing of the PCI stacked disc prototypes. Again, the diameter of the core tube is two feet.

They did a test where the submergence was one and a half feet, which left the top portions of the disc exposed and at a flow rate of 10,000 gpm, again with a flow rate much higher than we see typical of our strainers, calculated Froude number 1.11. There was no vortex observed. In the next slide, we'll show you a picture of that.

So this is the picture of that particular test with a ran between 5,000 and 10,000 gpm, with the upper portion of the disc exposed. It's a bubble formation in the pool, but there was no vortex indicated and no air ingestion in this test.

Next slide, please. Now, specifically for Vermont Yankee, we have, of course, two different types of strainers. There's a core spray strainer. We had a maximum flow rate of 4,600 gpm, submergence of 4 feet, which is the basis that we use in our calculation of available MPSH based on the suppression pool levels after a LOCA.

Our calculated Froude number based on the core tube by an order of two feet is --

MEMBER WALLIS: Is this a different Froude number than you had in the previous slides were based on this?

MR. SLIFER: That was based on two feet.

MEMBER WALLIS: I had a lot of trouble with these different Froude numbers. The Froude number in the EPRI report is based on the submergence, and yours here is based on the tube diameter.

MR. SLIFER: Well, it's based on diameter and its submergence. Both the diameter is important for the extermination of the flow velocity.

MEMBER WALLIS: The velocity. Well, you take velocity over the square foot of GD or you take velocity over square root of GS.

MR. SLIFER: GS.

MEMBER WALLIS: That's this definition here?

MR. SLIFER: Yes.

MEMBER WALLIS: What does it say based on a few cord, then?

MR. SLIFER: Well, because the second part is the lot based because of --

MEMBER WALLIS: The loss is based on the gauge, but the Froude number is based on S.

MR. SLIFER: It's based on S and D.

MEMBER WALLIS: Yes. But based on velocity, it's V over squared of GS.

MR. SLIFER: Correct.

MEMBER WALLIS: So it's really what I would call based on --

MR. SLIFER: Well, the reason I did this, because the second problem that I show here is based on the circumscribed surface area that we talked about earlier.

MEMBER WALLIS: I see. Okay.

MR. SLIFER: So that affects your approach velocity.

MEMBER WALLIS: That's irrelevant. That's based on the velocity of the surface area.

MR. SLIFER: Correct.

MEMBER WALLIS: Okay.

MR. SLIFER: Again, based on the testing that was done and those low values for approach velocity and the low Froude number, in that submergence, there would be no vortex formation.

MEMBER WALLIS: You know, there's a basic problem here that what happens depends both on the Froude number and the ratio, S over D, and this other geometry of the strainer.

So just using Froude number alone isn't a good enough criterion.

MR. SLIFER: Both Froude number and submergence.

MEMBER WALLIS: I think you may be okay if you use both of them here. If you have bigger submergence and a smaller Froude number, --

MR. SLIFER: Correct.

MEMBER WALLIS: -- that's okay. If you've just got one of them, it's probably not all right.

MR. SLIFER: Well, this is really based on both. It has the --

MEMBER WALLIS: What concerned me was when you had this fully loaded strainer which was sort of one inch below the surface in the minimum level. That's disappeared now, has it?

MR. SLIFER: Yes. I'll get to that point.

MEMBER WALLIS: So that's old hat? That's no longer valid?

MR. SLIFER: That's true.

MEMBER WALLIS: Okay. Because which report was that? Was that the 1677 or was that more up to date than that? That was 1920, wasn't it?

MR. SLIFER: I believe it was 1920. I think, as Rico explained --

MR. BETTI: Yes. I explained it. I wanted to make sure that our strainers were designed with some margin And the calculation there may have had some weak spots, but we knew we had significant margin.

And based on EPRI tests, et cetera, these Froude numbers, we really didn't think we had an air ingestion --

MEMBER WALLIS: That's where I have a

little trouble because you said you had this Froude number based on I think a 5-foot or a 1.5-foot submergence. And then you applied it to what looked like a .2 feet submergence.

MR. SLIFER: Right.

MEMBER WALLIS: It didn't make any sense.

MR. BETTI: To clarify, that's not .2 feet because the strain is 47 inches in diameter plus .19 feet.

MEMBER WALLIS: So that's not down to the axiom?

MR. BETTI: It's down to the axiom.

MEMBER WALLIS: All right.

MR. BETTI: And the velocity of our strainer is quite a bit lower than the velocity of that test. So that's the difference.

MEMBER WALLIS: I think it's not just the vortex you're worried about because the floating debris, the Armaflex floats around and presumably gets drawn --

DR. BANERJEE: It's the Armaflex moving.

MEMBER WALLIS: -- to the region of the strainer, which if you had a drawdown like this, you would actually draw down the Armaflex into the --

MR. SLIFER: I think we've got the next

slide.

DR. BANERJEE: Because you argue that the Armaflex never gets to -- it wouldn't get to the deeper one, to the CS one.

MR. SLIFER: Basically if you used the minimum values of the suppression pool you would expect after a LOCA with the debris floating on top of the surface, the submergence to the top of the debris bed would be 1.8 feet to 3.3 feet for the strainer. So the debris would be quite a difference above the top of the debris bed.

MEMBER WALLIS: The top, very top, of the --

MR. SLIFER: Very top of the debris bed.

MEMBER WALLIS: Top to the --

MR. SLIFER: The top of the debris bed.

MR. BETTI: So what we are theorizing here is that .1 percent velocity, which is going to draw the foam insulation down to 3.3 feet of water. I'm not a fluid expert, but I wouldn't think so.

DR. BANERJEE: Well, it's more the problem with the CRS, rather than the RHR. The concern is because they are closer to the surface.

MR. BETTI: The velocity is lower, yes.

MR. SLIFER: Again, the Froude number is

--

MEMBER WALLIS: Now, what concerns me a bit here is that we have seen all these reports. And some of us have read them. I think Sanjoy and I have read them. And there seems to be a series of them that develop.

Sometimes one is replaced by another. And what you're telling us today is different from what is in the report. So all we have is some sort of oral presentation to go on. We don't have the sort of final word written down so we can really look at it and say, "Yes, we believe it."

DR. BANERJEE: Yes. The reason is it's something maybe that is very explainable, but, for example, your case 2B is the worst case for your RHR. There your slide number is 490-something. And here you're putting 722. Which is right? We don't know.

MR. SLIFER: I guess all I can explain to you is it's based on specific part flow. So this is a fraction evaluation that needs to go into the strainer loading.

If we had X quantity of debris in the strainer, it's only a portion of that that would get to the debris --

DR. BANERJEE: This is the total.

MR. SLIFER: For one strainer.

MR. BETTI: For one strainer.

MR. SLIFER: There are scenarios working in conjunction with that debris loading.

DR. BANERJEE: But, anyway, it's confusing. If after reading this report, I don't understand what you have done, then other people would also be confused.

MR. SLIFER: Nobody would be confused who was involved with the 9603 process for a number of years and went through these large design changes and the acceptance of that methodology. None of us would be confused.

DR. BANERJEE: But there was to be a final document, right?

MEMBER WALLIS: You have to convince somebody else. That's the problem. You may be sure, but you have to have some sort of argument which somebody else can follow.

It seems to me that probably you've got a good story here. I think probably, probably you have a good story, but it isn't really --

DR. BANERJEE: I'm not convinced about the paint chip business, frankly, because that's a matter of timing. If you look at the story in your reports, the argument, really, is that early in your LOCA, the level of turbulence is very high. But paint chips are all entrained and everything, whatever.

But then your approach velocity is, look, because these things haven't clogged. Okay? So it's only late in your LOCA that --

MR. SLIFER: Yes.

DR. BANERJEE: But your core doesn't calculate buildup, you see?

MR. SLIFER: Right, but we could.

DR. BANERJEE: You could.

MR. SLIFER: I mean, we could bound your assumption and say that for the minute and 66 seconds that the high turbulence phase happens, how much paint could get -- you know, bound your paint. How much would get there? What would your head loss be for that event?

DR. BANERJEE: Well, yes. The first thing is the assumption that high turbulence only lasts for 60 seconds. When you have a LOCA coming into this drywell and turning this thing off, I mean, any turbulence calculation you are likely to do is not going to last for the 60 seconds. Even the decay of turbulence would take much longer.

But, leaving that aside, the worst case

here turns out to be the IB, where you've got the LOCA going on and on for a long period of time and keeping on stirring it up from the viewpoint of the paint chips.

That's also documented because you sort of say that your level of turbulence is high for -- I don't know -- many hundreds of seconds, see? So that begins to look like the limiting case.

I'll give you the references. It's your own report.

MR. SLIFER: What I have here is our submittal, which was from one of our reports, which was the one we gave the most scrutiny --

DR. BANERJEE: Right.

MR. SLIFER: -- to make sure that it was written right. And this is page 16 of 32. And this is our December 29, 1999 submittal for what we did for the testing. This is BBY 99-164. What it says, the section strain, it says, "At a medium pool turbulence level, like for an IBA, most of the paint debris settled to the floor and little remains suspended where it could be ultimately deposited on the strainers.

It was only at high debris turbulence. And then when you shut off the pumps and you had the high approach velocity using the circumscribed area that you could get debris to come to the strainers. If you had the high turbulence, neither nukon nor the paint could stick to the strainers because the turbulence velocities were much higher than the approach velocities.

DR. BANERJEE: Yes. I understand the argument.

MR. SLIFER: In the intermediate, we could not keep the paint suspended. So I don't --

DR. BANERJEE: Yes. But the turbulence level is arbitrarily set as high, medium, low. What does that mean to begin with? But, leaving that aside, your approach velocity always for these strainers is based on your circumscribed case because, really, what is bringing the paint to the outside of this is the flow into those gaps. You know, as soon as you come near to that, that's what the velocity is.

MEMBER WALLIS: It's unlikely to go out again once it gets in.

DR. BANERJEE: Yes. What does it do?

CHAIRMAN DENNING: We're going to have to bring this discussion to a close pretty quickly. So why don't you take your last couple of slides?

MR. SLIFER: This is my last slide, I

believe. There was a question raised at some point about the potential for not keeping the suction lines full. I think that may have been oriented on an assumption perhaps if you --

MEMBER WALLIS: Only if you have a very low level.

MR. SLIFER: Yes, very low level and a horizontal run. But, of course, there is a vertical drop from our strainer down to the pumps, which are located on another floor. So those are seven feet and eight and a half feet.

And, again, since there's no air vortices, the suction lines are kept full. And the static head is not degraded.

CHAIRMAN DENNING: Talk to us, then, about if you know the numbers, the head losses you're predicting through the debris in comparison with the six psi that is associated with the overpressure credit.

MR. SLIFER: Our debris head loss is on the order of half a foot. So we're talking less than a couple of tenths of a psi.

DR. BANERJEE: But, of course, if they get plugged up, it can be very high.

MR. BETTI: That is based on the strainer design head losses, not based on calculated debris loss.

MR. SLIFER: I guess we have to --

CHAIRMAN DENNING: What was that again? Say that again.

MR. BETTI: It's based on the bounding debris quantities used in the strainer specifications that we put here, like we don't take credit for sludge reductions, new --

MEMBER WALLIS: Do you take credit for that?

MR. BETTI: We do take the credit for the maldistribution.

MEMBER WALLIS: Because that is an experiment?

MR. BETTI: That is an experiment.

MEMBER WALLIS: So you're not really using this NUREG correlation? You're using the experiment?

MR. BETTI: Correct.

DR. BANERJEE: And the experiment is a single strainer, not for a stack.

MEMBER WALLIS: An experiment assumes -- well, then in your experiment you've got nonuniform distribution. So you've got less head loss than you would have gotten if you had used the correlation, I expect, because a correlation assumes uniforms, which would be more conservative.

Anyway, I just don't know how we resolve this because it seems to be an ongoing discussion here. And then we have to go on.

MR. HOBBS: Well, this is Brian Hobbs.

I think keeping in mind the purpose of this meeting is to discuss the effects of power uprate, we believe we have a conservative debris quantity used for our head loss design of our strainers and that the design criteria are not affected by power uprate. That's sort of the gist of our presentation today.

MEMBER RANSOM: Has there been any effort to reduce the debris sources, getting rid of some of the insulation types in Vermont Yankee?

CHAIRMAN DENNING: We had a little bit of that in the introduction, didn't we?

MR. BETTI: Yes, I think that. I mean, we had some TempMat in there that was temporary insulation. And that has been replaced with RMI insulation, one.

I think the biggest improvement we had was -- I mean, the sludge source was primarily as a result of old paint and problems with paint in our torus.

When we installed the strainers, we blasted.

So one of the key issues, real issues, that you have in strainers is a combination of nukon and sludge. Those are the two real culprits. And the nukon alone isn't going to hurt it, if it's nukon and sludge.

And effectively what we do now is we have programs in place -- and I can let ops. talk to that -- to keep things extremely clean. And so we're not going to get a lot of sludge coming out of our containment in there. And then, two, as witnessed after 6 years of operation with our new paint in our torus, we pulled out 75 pounds of debris.

So I think that's the key to focus on is that we would like to get very little head loss. And, two, we use a conservative amount of nukon transported to our torus. That's a third safety feature.

MR. NICHOLS: Enrico, what you're saying is that while we still retain those in our design of the strainer calculation, designed head losses, we actually improved on that for what would actually happen in the plant, which provides another set of margin for what really occurred.

MEMBER RANSOM: I had one other question. On your picture, what is that current open area on the end?

MR. NICHOLS: It's not. It's a closed area on the end, probably a piece of plywood, something that's --

MEMBER RANSOM: This is part of the strainer material closing the end.

MR. NICHOLS: Closing the end on our strainer is a stainless steel plate with stiffeners, just a solid plate.

MEMBER RANSOM: Just a solid plate on the end?

MR. NICHOLS: Solid plate on the end, right.

CHAIRMAN DENNING: Well, thank you very much. We appreciate your flexibility in being able to make this presentation on such a quick request. And we're ready now to move on to the source terms and radiological consequences.

15. SOURCE TERMS AND RADIOLOGICAL CONSEQUENCES

MS. HART: Hi. I'm Michelle Hart. I'm with the NRR staff. I'm a health physicist. And I had the task of looking at the source terms and radiological consequences analysis for the Vermont Yankee extended power uprate.

Next slide. I used the EPU review

standard matrix 9 to do my work. And my SEM was put into that safety evaluation section 2.9.1 and 2.9.2. For the source terms for the radwaste systems analysis, the licensee did look at the radiation sources and the reactor coolant accident for the constant pressure power uprate conditions and then do continue to meet the requirements.

For the design basis accident radiological consequences analysis, the licensee submitted a separate alternative source term amendment request. And that was reviewed and approved as amendment number 223 on March 29th of 2005. The dose analyses did assume the proposed EPU conditions, 1950 megawatts thermal, which is 102 percent of the operated power.

They followed the regulatory guidance unless they justified it. And all the design basis accidents do meet 10 CFR 50.67 criteria and the more specific criteria in the standard review plan.

MEMBER WALLIS: They meet the criteria, but the margin has gone down presumably because of the bigger source term.

MS. HART: It's hard to make that one criterion. They did do some additional things. They took some additional credit for removal in the containment as well when they went to the new source term.

MEMBER WALLIS: So they used a different calculation procedure than before?

MS. HART: Yes, right. Right. And if you look at the next slide, this is the changes that they made in that alternative source term amendment. Most of the changes were made in the LOCA.

For BWRs, the standard assumption is that it is the tech spec leaking rate from the drywell for the entire duration of the accident. They justified reducing that after 24 hours to half of that leakage rate.

MEMBER KRESS: Isn't that what they always do?

MS. HART: BWRs.

MEMBER KRESS: BWRs?

MS. HART: That's not a standard, no.

MEMBER KRESS: PWRs are.

MS. HART: PWRs, yes. Yes, PWRs, that's a standard assumption, the reduction.

MEMBER KRESS: It's because you get a lower pressure.

MS. HART: Right, right. And that's how they justified this reduction for the BWR. They also took credit for the use of the SLC system, running that after the accident to keep the pH level in the suppression pool above seven so that you would not have re-evolution.

MR. CARUSO: So that means that there is boric accident released into the containment following a Loca as part of the design mitigation.

MS. HART: That is correct. That is a change that they made in their alternative source term amendment.

MEMBER WALLIS: So they do change the suppression pool pH, but doesn't the SLC system have a low pH? I thought someone set a -- it's an acid, isn't it, a low pH?

MS. HART: It's an acid.

MEMBER KRESS: Yes. You generally the suppression pool --

MEMBER WALLIS: There's no buffer.

MEMBER KRESS: -- pH to be higher. That could be basic or neutral. I don't understand this.

CHAIRMAN DENNING: Yes. But that's also surprising. Do you mean in any LOCA they're now going to operate the SLC system?

MS. HART: That's correct.

MEMBER WALLIS: So we could have chemical effects in the pool that we didn't think about before?

MEMBER KRESS: I don't know what chemicals are in SLC. I always thought it was boric acid.

MS. HART: It's sodium pentaborate.

MEMBER KRESS: Sodium pentaborate.

MS. HART: Correct, yes, sodium pentaborate.

MEMBER WALLIS: It's a buffering thing?

MS. HART: It's a buffer, yes. They're buffering.

MEMBER WALLIS: So it does go to a high pH, then.

MS. HART: It goes above seven.

MEMBER WALLIS: Right. So it's not acidic?

MS. HART: It's not acidic.

MEMBER WALLIS: So it has all the things that BWRs have and all the chemical effects that --

MEMBER KRESS: Sodium pentaborate is not what PWRs use, but --

MS. HART: No.

MEMBER WALLIS: They use something like that as a buffer.

MEMBER KRESS: They use a pH buffer, yes.

MEMBER WALLIS: They don't use it for the boron. They don't use it for the boron. They use a sodium something for a buffer, but it's boric acid they use.

But wait a minute now. This stuff goes into the suppression pool with every LOCA?

MS. HART: That is what they have assumed, yes. They have special procedures that if they know that a LOCA has happened, that they will inject that within -- I can't recall the exact time, but it was within a certain time frame. It's I think a couple of days before they absolutely need to have it to make sure that they don't have iodine re-evolution.

MEMBER WALLIS: And this affects all the stuff we were talking about half an hour ago.

DR. BANERJEE: It depends when it's injected, I guess.

CHAIRMAN DENNING: Let's make sure that we're not misinterpreting. Is there any misinterpretation here as to what is happening? Is indeed in every LOCA now you would operate the SLC system? Is that a true statement or not?

MR. PEREZ: Okay. This is Pedro Perez.

Basically the way I look at it, there's only one design basis LOCA. And with that event, which is a high release of source term from the core, we will inject the sodium pentaborate within two hours to keep the suppression pool pH, of course, the recirculation, above 7 for 30 days.

CHAIRMAN DENNING: Based on what do you decide that you had a large release of radionuclides?

MR. PEREZ: On the drywell high range monitor readings.

CHAIRMAN DENNING: And do you know how high? I mean, the silliness of what we are getting ourselves into here is that the reality is in the large LOCA, you have a trivial release of iodine.

And we play this game of design basis source terms for a certain purpose. And if we're injecting SLC inappropriately and getting at the questions of chemical reactions in the suppression pool and all this kind of stuff just because of a regulatory conservative inconsistent way that we treat design basis accidents, we have led ourselves down the wrong pathway.

So it does require in coincidence before you would operate the SLC an indication of the substantial amount of iodine release or could it be just a gap release and we would wind up injecting something? Is that clear or not?

MR. PEREZ: Again, this is Pedro Perez.

The indication would be over 500 rankine per hour in the drywell, which is extremely high compared to the normal. So you will have a very large gap release. And basically this is primarily from the noble gases.

CHAIRMAN DENNING: Would a gap release give you this?

MR. PEREZ: Yes, sir.

CHAIRMAN DENNING: Yes? It would give you this? The gap release would give you this?

MR. PEREZ: Yes.

MEMBER WALLIS: So this happens with quite a few LOCAs.

MR. PEREZ: It will be basically the design basis source term to assume a significant level of damage in the fuel itself, starting with the gap release and then a subsequent overheating of the fuel, releasing your halogens and more of the radionuclides.

MEMBER WALLIS: This is in the design basis accident?

MR. PEREZ: Yes, sir.

DR. BANERJEE: How many fuel rods would need to be damaged? What sort of core damage is needed?

MR. PEREZ: Again, Pedro Perez.

The AST application follows regulatory

guide 1.103, where you have the prescribed release for actions and timings. And we're talking about basically 100 percent of the gas, noble gas, activities released within I think 30 seconds. The start is 30 seconds.

CHAIRMAN DENNING: All this artificial design basis accidents calculation that we do, well, we're not going to solve this problem today. Please continue.

MS. HART: In addition, they took credit for iodine removal by the drywell sprays, both for the particulate and the elemental form of iodine, and also took credit for iodine deposition in the main steam lines for any leakage that would go past the main steam line isolation valves.

CHAIRMAN DENNING: This is all --

MEMBER WALLIS: Part of those sprays that bring down the pressure?

MS. HART: That's correct.

MEMBER WALLIS: I thought they needed it for MPSE.

MR. PEREZ: Based on the iodine.

MEMBER WALLIS: It's another one of these glitches in the design basis accident definition or something?

MS. HART: I'm not sure I understand the question.

MEMBER WALLIS: Drywell is best operated when you calculate these other calculations we have seen for the pool temperature?

MR. PEREZ: Yes. This is Pedro Perez.

Yes. The same drywell sprays that are credited for removing the iodine particulates, these are the same that assumed that have the maximum condensation, if you would, of the condensibles that minimize the pressure that's credited in the containment overpressure calculation.

CHAIRMAN DENNING: Continue.

MS. HART: Yes. They also continued to -- they looked at the rest of the design basis accidents that do apply to BWRs, the main steam line break, the fuel-handling accident, and the control rod drop accident. For none of the accidents did they assume control room isolation. They assumed just normal intake as they are unfiltered in leakage.

Next slide. To go further into the SLC system pH control to credit the use of the system, they discussed the reliability of the system. They also discussed the procedures, compensatory measures, and training. And there was also a review done of the suppression pool buffering adequacy by injecting that sodium pentaborate.

And for the new justification for the crediting iodine deposition in the main steam piping and in the condenser, they looked at the seismic rug in this, the alternate leakage treatment pathway. And they also discussed and we found acceptable elemental and particulate iodine removal methodologies and assumptions.

That concludes my presentation. Do you have any further questions?

CHAIRMAN DENNING: No. Thank you very much.

16. HEALTH PHYSICS

MR. PEDERSEN: My name is Roger Pedersen. I'm a senior health physicist in the former Plant Support Branch, the former Division of Inspection Program Management, Office of Nuclear Reactor Regulation.

I looked at the health physics aspects of the Vermont Yankee EPU. Most of the health physics issues associated with extended power uprate were addressed and closed out in the review of the GE topical report. There are a few specific examples which were the topic of my review.

The stroke of my review focused on first verifying that the conclusions in the topical report were still applicable to the Vermont Yankee application and then focusing on those areas where the increasing source term, particularly N-16 gammas in the steam side of the plant and some gas issues, might impact both occupational doses and public doses of the EPU.

Well, there's also an issue with regard to post-accident access to the plant, the lessons learned from Three Mile Island, item 2.B.2 if you're familiar with the lessons learned task force designation.

The topical review, as I said, addressed the adequacy of the shield design for typical plants. It does acknowledge that certain areas may have higher dose rates depending on the plant-specific design.

So part of my review was to verify that the radiation zoning designations -- it's in the current FSAR of the plant -- did not change. And the licensee did verify that.

So that indicates that the dose ranges in those normally occupied spaces of the plant during normal operation are not significantly impacted.

CHAIRMAN DENNING: What are your assumptions as far as what basically the source term is under normal operation conditions? Is it assumed that it's proportional to the power?

MR. PEDERSEN: Yes. That was the assumption. As a first approximation in most of the areas, there are some cases where that is not true, particularly with N-16 on the --

CHAIRMAN DENNING: Yes. You're going to talk about N-16 a little bit more?

MR. PEDERSEN: Yes.

CHAIRMAN DENNING: Okay.

MR. PEDERSEN: The design basis accident or the post-accident access to vital areas of the plant issue was actually addressed by the licensee in the AST submittal that Michelle spoke of a minute ago.

In switching to the alternate source term, the licensee included the post-accident access to vital area evaluation with the other design basis accidents. And they evaluated the doses to individuals doing missions out in the plant to mitigate the course of an accident at the EPU power rate, even though this was a pre-EPU analysis that they did. And they demonstrated that they do meet those criteria in the 737 2.B.2. That issue was included.

In terms of public doses, the significant issue that we focused on was the compliance with 40 CFR 190, which is an EPA regulation. It's also referenced in 10 CFR 2013.01E, which is a design basis of 25 millirem per year to a member of the public. It's a public dose constraint, if you will, as opposed to the 100 millirem per year dose limit that we have in 10 CFR part 20.

The N-16 issue, the elevated N-16 from the power uprate, does impact that dose off site, particularly from sky shine off the turbine components, the turbine building, condenser, and steam line in the turbine building.

You look like you had a question. I'm sorry.

CHAIRMAN DENNING: Yes. As far as is most of the dose coming from noble gas release from --

MR. PEDERSEN: No. At this point it's N-16.

CHAIRMAN DENNING: It really is N-16, --

MR. PEDERSEN: Yes.

CHAIRMAN DENNING: -- not a sky shine kind of thing?

MR. PEDERSEN: Yes. Even though the concentration of N-16 coming out of the reactor, starting into the steam line, the concentration is constant, there is a 20 percent increase in production plus a 20 percent increase in steam flow. So the concentration is constant.

There is actually a reduction in the decay time. The 20 percent higher flow rate results in the N-16 getting to the turbulent components faster.

So the 7.2-second half-life comes into effect. So there is actually more than a 20 percent increase in the N-16 decaying in the turbine and the condenser. The shine, the scatter off of the atmosphere above the plant to the dose receptor off site, sees that, sees that increase.

I have to apologize for this slide. There's an error in it. If you would ignore the 20.2-millirem per year there? That is an erroneous number. It actually included the non-N-16 direct shine off to the off site, most limiting off-site location twice. It double added that.

So if you would just ignore that number and read that slide or the third bullet to that slide with the pre-EPU dose is 15 millirem per year, 13.4, the resulting from N-16, increases to not 20.2 but 18.6 millirem per year from radiation and sky shine. There was a revision to the slide that didn't get fully implemented, and I apologize for that.

MEMBER RANSOM: It increases to what?

MR. PEDERSEN: 18.6 is the total.

MEMBER RANSOM: 18.6 is total, yes.

MR. PEDERSEN: From total direct radiation and sky shine to the most limiting location off site, not the 20.2. That was an error. In addition to the N-16, there is some shine from other components on site, rad waste tanks and --

MR. CARUSO: Can I just ask, 15 was composed of 13.4 from N-16 shine plus 1.6 of everything else?

MR. PEDERSEN: The 15 millirem per year is the current annual off-site dose from the direct radiation and shine, N-16 shine. 13.4 of that currently is from N-16 shine.

MR. CARUSO: Okay.

MR. PEDERSEN: So that 15 will increase to 18.6 millirem per year.

MR. CARUSO: And of the 18.6, how much is --

MR. PEDERSEN: 16.9.

MR. CARUSO: 16.9.

MEMBER KRESS: Is that calculated at the nearest point on the boundary?

MR. PEDERSEN: The most limiting, yes, the most limiting point on the boundary. Now, interestingly enough, 40 CFR 190, the EPA regulation is actually to an actual member of the public.

MEMBER KRESS: Which may or may not be that point.

MR. PEDERSEN: May or may not be that point. But the licensee didn't take credit for that in their calculation.

MEMBER WALLIS: Where is this member of the public?

MR. PEDERSEN: Excuse me? Yes, I can't point it out on a map, but it's the most limiting location according to the analyses the --

MEMBER WALLIS: Trying to get highest dose?

MR. PEDERSEN: It is my understanding it is not too far from where the nearest member of the public actually lives. There is a residence right on --

MEMBER RANSOM: And that's all year? There's no fraction --

MR. PEDERSEN: Yes. They didn't take any residency factor into consideration for that dose factor.

MEMBER SIEBER: It's on the

owner-controlled area fencepost. That's the closest point.

MR. PEDERSEN: Yes. Now, I have to point out that these calculations are based on the licensee's current off-site dose calculation manual methodology. It's a calculational dose, as opposed to a monitored dose, a measured dose.

That methodology is based on an empirical relationship that they determined by measuring the dose at this location and correlating that to the steam line ramp monitor readings. So the dose is a calculation that uses the steam line rad monitor reading as a basis for running through the algorithm of the dose.

Now, subsequent to me finishing my review and writing the safety evaluation, there has been a question raised about that methodology. And we, the NRC region I inspection program, are looking at their off-site dose calculation manual closer.

There was an on-site review two weeks ago. And there are a couple of unanswered questions at this point. So there should be a star next to this. We didn't open an item here. We don't have an unresolved issue in the review at this point, but that's pending the licensee being able to resolve the open questions from the inspection that is outstanding at this point.

MEMBER SIEBER: Did you look at items that are part of post-accident radiological conditions, like post-accident sampling kinds of things, leakage from equipment under recirculation?

MR. PEDERSEN: The post-accident access, the 2.B.2 items, --

MEMBER SIEBER: Yes.

MR. PEDERSEN: -- those vital areas that are defined --

MEMBER SIEBER: Right.

MR. PEDERSEN: -- in NUREG 0737, --

MEMBER SIEBER: Right.

MR. PEDERSEN: -- yes, those are the locations that an operator needs to access in the plant to mitigate the course of the accident.

MEMBER SIEBER: And they should be accessible?

MR. PEDERSEN: They should be accessible. And those criteria --

MEMBER SIEBER: Are they?

MR. PEDERSEN: -- it refers to GDC 19, which this is not a GDC plant. So there's a GDC 11 that comes in there. But yes, they demonstrated a level -- they calculated the 11 vital areas that they identified are accessible within the dose criteria 737 2.B.2.

MEMBER SIEBER: Okay. Thank you.

MR. PEDERSEN: My final slide is the conclusion that's in the safety evaluation. The staff concludes that the EPU proposal meets the requirements in 10 CFR 20. And, again, that's with an asterisk: assuming that there is a satisfactory resolution to the outstanding questions concerning the off-site dose calculation manual, 10 CFR 50, appendix I, and NUREG 0737, item 2.B.2.

The staff finds that the licensee's proposal is acceptable with respect to radiation protection and ensuring that occupational radiation exposure will be maintained as low as reasonably achievable.

CHAIRMAN DENNING: Thank you. Break time. What we're going to do, we're going to have five extra minutes. So 2:45

(Whereupon, the foregoing matter went off the record at 2:26 p.m. and went back on the record at 2:46 p.m.)

CHAIRMAN DENNING: And we're now going to get into one of my favorite subjects, probabilistic safety analysis.

MR. NICHOLS: Today to make the presentation on probabilistic safety assessment for the extended power uprate, we have Mr. Vincent Anderson, manager of the Risk and Reliability Group at Erin Engineering and Jerry Head, the manager of Nuclear Engineering Analysis for Entergy Nuclear, Northeast.

Vincent.

MR. ANDERSON: Good afternoon. I'll be giving an overview of the risk assessment for the VYEPU.

The approach taken to the VYEPU is the same as done in past EPU risk assessments that you may have seen, and the results are the same, very similar to the past studies.

This first slide gives an overview of the status of the VYPRA program. The internal events risk models at Vermont Yankee are a Level 1 and a Level 2 PSA, Level 1, as you know, being core damage frequency, Level 2 release frequency.

The external events analyses at VY were developed as part of the individual plant examination of external events in 1998, and as you know, cover internal fires and seismic and other external hazards. Internal fires were done with the EPRI FIVE methodology, and seismic was done with the EPRI seismic margins methodology, and the other external hazards were done as a comparison against the NRC standard review plan with the IPEEE guidance of NUREG 1335, I believe.

CHAIRMAN DENNING: Are there any intents to upgrade the internal fire's PRA?

MR. ANDERSON: Jerry would probably have to answer that.

CHAIRMAN DENNING: Yeah.

MR. HEAD: Entergy as a corporation is looking right now in the 0805 potential that's coming out. We're looking at that across the fleet and trying to make a determination which direction we'll go. I can't give you an answer right now how we're going to land as far as which plants we're going to take down that path and what that timetable will be, but I think those decisions are due by the end of the year.

MR. ANDERSON: As you know, the NRC's phased approach to risk regulation, utilities are now considering the other aspects of the risk profile and how they're going to proceed on them in the next number of years.

So next slide.

So the PSA that was used for the risk assessment is an up to date PSA. It reflects the current plant configuration. There was an NEI peer review performed for the VYPRA in 2000. All the A and B facts and observations have been resolved. Those are what are termed the higher priority facts and observations.

The VYPSA is maintained and routinely updated. It has been updated, I believe, five or six times since the IPE submittal. The scheduled updates are performed on a two cycle schedule per procedure.

Next slide.

CHAIRMAN DENNING: Is the PSA used for operational purposes? Do you have it basically on line, and do you use it when you make changes in configurations?

MR. HEAD: That's correct. All of the configuration risk management practices that we have for normal operational and maintenance activities are covered using this model.

MR. ANDERSON: The big ticket items for the impacts due to EPU on the PSA come from hardware changes that are made, procedural changes, plant configuration changes and obviously the increased power level.

Comparing the modifications of the VYEPU with the PSA models, these are essentially the impacts. There are no new accident sequences identified. The EPU does nothing that would change the way accident sequences are modeled or how they progress other than certain timing issues.

There are no significant impacts on the following: initiating event frequencies. The turbine trip initiating event frequency was the only one that was adjusted to predict or to bound any future increase in turbine trip frequency to running the third feedwater pump. That's just a predicted adjustment in the PSA model. Obviously future operating experience will actually determine what the real frequency of a turbine trip is.

Of the success criteria in the PSA, there was only one that required modification due to the EPU, and that was the requirement of an additional safety valve for ATWS over pressure protection.

The hardware changes as part of the EPU resulted in no impacts on the PSA. They are typically like for like replacements or enhanced components, newer components, and in fact, the future may hold that they operate more reliably than the previous equipment did.

And the procedural changes also did not warrant any changes to the PSA. Any changes to procedures were so minor that they had no impact on human error probabilities. The procedures are the same. They just are minor changes to reflect minor set point changes, et cetera.

CHAIRMAN DENNING: But that doesn't mean that the HRA probabilities haven't been modified.

MR. ANDERSON: That is a correct statement.

The other impact is due to the changes in timing due to the increased decay heat load on post initiator operator actions. Post initiator operator actions are those obviously that are performed in response to an initiator. The PSA obviously has pre-initiator operator errors, but those are obviously not impacted by the EPU.

There's approximately 60 or so post initiator actions in the PRA, and those were investigated for changes, their probabilities, due to decay heat load changes, and obviously not all of them are impacted by changes in decay heat load. Only some fraction of them are.

MEMBER WALLIS: Now, these, you say slight decrease in time.

MR. ANDERSON: Yes.

MEMBER WALLIS: And then I went to this GENEDC 3309TP, and sometimes for certain actions the time changes by what looks like a small amount, but the probability, the human error probability, goes up much more than you would expect for that small time increase. It must have something to do with ---

MR. ANDERSON: That could be true.

MEMBER WALLIS: -- how long it takes to do the action or something.

MR. ANDERSON: Yes, that is true.

MEMBER WALLIS: There are some remarkable changes of where the time changes by 20 percent, but the error goes up like three times.

MR. ANDERSON: Yes, right. Yep, yep, you're probably getting to those faster actions.

MEMBER WALLIS: Right.

MR. ANDERSON: A small change in time --

MEMBER WALLIS: The fact that you have a slight decrease in time doesn't mean that it's a slight change in the probability of error.

MR. ANDERSON: Correct., yep, yep.

MEMBER WALLIS: Okay.

MR. ANDERSON: Yep, that is a true statement. Some of these --

MEMBER RANSOM: The probabilities have been taken into account then?

MEMBER WALLIS: He's going to get to it, I suppose.

MR. ANDERSON: What was that question? Do you want me to --

MEMBER RANSOM: Just whether or not the change in the probability in the occurrence had been factored in.

MR. ANDERSON: Oh, definitely, yes.

MEMBER WALLIS: Because it's part of the PRA, isn't it?

MR. ANDERSON: Yes, yes. The human error probabilities were recalculated based on the changes in the timing.

MEMBER KRESS: So one times ten to the minus three is three times ten to the minus three.

MR. ANDERSON: Right, or an action that was -- a one percent failure could go up to a five percent.

MEMBER WALLIS: Is this GE document the basis for your probabilities that you use for human errors?

MR. ANDERSON: I must say I don't know what GE document you're referring to.

MEMBER WALLIS: It's one of the things that you guys put on file for us to read.

MR. HEAD: I believe that the GE document and the PSA model both use the same root document for a source for those numbers. I believe those human error probabilities were calculated as part of the PSA update and then lifted and put in the GE document, I believe.

MEMBER WALLIS: It says that they're referring to a general -- so CPPU? It's not specific to Vermont Yankee.

MR. NICHOLS: I believe that is our submittal document.

MR. NICHOLS: Oh, is that it? Okay.

MR. ANDERSON: So that would be plant specific numbers. It's plant specific numbers.

MEMBER WALLIS: You have plant specific, yeah.

MR. ANDERSON: Yeah, there's an EPU risk assessment that includes human error probability changes. It's a thick document.

MEMBER WALLIS: I was surprised that I couldn't -- some of these human error probabilities were as large as 73 percent. Does that seem right?

MR. ANDERSON: Very few of them would be

that, but yes.

MEMBER WALLIS: Very few, but there is one in that table --

MR. ANDERSON: Yes.

MEMBER WALLIS: -- which is 73 percent, which seems --

MR. ANDERSON: Yeah, I know the one. When you mentioned it earlier, that's reopening the MSIVs during an ATWS scenario.

MEMBER WALLIS: That's right.

MR. ANDERSON: Yeah. The VYHRA, human reliability analysis, was updated in 2000 to include operator interviews, and so the operators were interviewed for all, not all, but a large fraction of the actions, and I believe that action requires an estimated 15 minutes to complete it.

MEMBER WALLIS: That's why. They don't have much more margin.

MR. ANDERSON: No, you don't have much margin, and it's a complex action. It's installing jumpers, and then you actually have to reopen the MSIVs, equalize them on both sides, yeah.

CHAIRMAN DENNING: But ATWS is a low probability event. So that even though --

MR. ANDERSON: Exactly.

CHAIRMAN DENNING: -- it's a high human error here --

MR. ANDERSON: Right, exactly.

CHAIRMAN DENNING: -- it doesn't make that much difference to the rest.

MR. ANDERSON: That is a correct statement. We are talking about changes in the short time frame actions for ATWS, and those are where the actions, the human error probabilities are more influenced compared to others, but in the grand scheme of things, ATWS is six or seven percent of the overall CEF profile. So you're getting minor changes in your overall CEF profile because ATWS is such a low frequency accident scenario.

And I guess we'll go to the next slide.

For example, since we're talking about ATWS, I put up a few of the ATWS actions right here, and you've seen them before. These are the faster moving operator actions. They're not necessarily the dominant actions in a PRA. Obviously the slick one would be the more important one of the ATWS actions here, but in the grand picture of actions in the PRA, that's probably only maybe the fifth or sixth most important action in the PRA. The others are probably way down there on the list.

The timing, as you'll see, dropped 45 seconds or so out of five or six minutes, and that's the allowable action time that the PSA determines based on thermal hydraulic runs and assumed Q times and end times of what the PSAs are concerned with, and the time that the operator actually has to perform that action is well within that.

For example, inhibiting ADS maybe a minute and a half to actually do that with the feedback back and forth among the operators, and yet he still has over five minutes to do it.

CHAIRMAN DENNING: Yes. Now, in coming up with the realistic estimate for the time to do that action, how is that really done?

MR. ANDERSON: That goes back to the 2000 human reliability analysis update and the interviews with the operators and training staff at that time. So PRA engineers would sit down with operating staff over the course of a couple of days and go through scenarios and EOPs and ask them are they trained. When was the last time they trained on this? Are they familiar with this action? How long does it take to do it? Is it a priority for you? All of those sorts of things.

CHAIRMAN DENNING: That was mostly though in interviews as opposed to, again, simulator demonstration?

MR. ANDERSON: Mostly interviews, but I believe -- and I may be stretching it here by telling you -- I believe simulator observations were performed as well as part of that, but I do not know that answer right now.

MR. HEAD: Our typical process within Entergy is to look at the simulator evaluations of various events. As part of that process on the update, we've not --

MR. TABONE: Excuse me. This is Chris Tabone from Entergy.

These are some of the ones that are listed there. Those quicker ones during the ATWS were the ones we did do during -- in the simulator with a crew and a stopwatch.

MEMBER WALLIS: What sort of probability did you come up with for these?

MR. TABONE: These guys are on the order of one to two percent failure rates. They both depend on the complexity of the action and the timing. I've got numbers scribbled down here.

For example, initiation of SLICK is about a 5E to the minus two failure rate that goes up to about an 8E to the minus --

MEMBER WALLIS: So it's one in 20 or something.

MR. TABONE: Yeah, it's one of those things, those type of numbers for the fast moving actions.

MEMBER WALLIS: And this is something that says realizes he has an ATWS. Is this an action?

MR. TABONE: That is part of the calculation.

MEMBER WALLIS: He has to realize he's got one before he does any of these things.

MR. ANDERSON: Right. The human reliability analysis typically divides up a recognition that there is an abnormal event. The diagnosis time frame, then the execution, and then uses a Gaussian distribution to come up with the likelihood that he completes all of that within his five minutes or 15 minute time frame.

Next slide.

MEMBER WALLIS: So if it's a clean ATWS, he's probably okay. If it's something unusual about it, and one problem going back to TMI was that there were two things wrong. The symptoms got sort of mixed up.

MR. ANDERSON: Right.

MEMBER WALLIS: And that's where you worry about something here. If it's straightforward ATWS, that's probably okay, but if it's something else happens to be going on at the same time, then it gets confused.

MR. ANDERSON: That is true, and the methodology that VY uses, which is called EPRI 6560L, it handles that on a broader level by assigning us stress factors.

There are other methodologies that actually get into very fine details of what you described. What do the procedures look like? What do the indications look like? Are there double "not" statements, all that sort of thing?

The methodology for the EPU was primarily the quantitative risk assessment of the Level 1 and Level 2 internal events, and the Level 2 being the LERF methodology, the LERF risk metric.

Have you got a question?

MEMBER RANSOM: No, I'll ask it the next slide.

MR. ANDERSON: And then the other two aspects were external events and shutdown events were handled on a qualitative basis by looking at the results of the IPEEE, looking at the conclusions for fire, for example, looking at the dominant sequences for fire and making an assessment of how EPU would impact those.

For example, fire is primarily dominated by fire induced equipment failure combinations and less so by any changes in operator actions and the same with seismic. It's overwhelmingly dominated by past industry studies, by seismic induced failures. Random and human failures are a small percentage of the seismic risk profile.

And then shutdown events is primarily impacted by the changes in the boiling time of the flooded up levels, and those are already long times of operator actions such that any changes of ten percent or 15 percent over the course of six hours or ten hours doesn't make any quantifiable change to a human error probability calculation.

So the next slide.

And these are the final conclusions. The delta DCF was calculated three to the minus seven in the very small risk range of reg. guide 117, and LERF was right at the border of very small and small and delta LERF of 1E to the minus seven. And that's --

MEMBER WALLIS: A change in two weeks?

MR. ANDERSON: I hope not.

MEMBER WALLIS: Two weeks ago the numbers were bigger.

MR. ANDERSON: Oh, was that the containment over pressure estimate?

MEMBER WALLIS: I don't -- oh, maybe that's where it is. Maybe I'm confused.

MR. ANDERSON: And that's unfortunate because the containment over pressure --

MEMBER WALLIS: Bigger numbers than these.

MR. ANDERSON: Well, yeah. Well, if we were to do it without being forced down the path of coming up with one, the delta risk for containment over pressure probably would be zero.

MEMBER WALLIS: Now, does your PRA then include that sequence? It includes the probabilistic analysis of the temperature of the pool and the probabilistic analysis of the failure of containment with the small hull and --

MR. ANDERSON: No.

MEMBER WALLIS: -- NPSA test not in the --

MR. ANDERSON: That is -- that is not in this risk assessment.

MEMBER WALLIS: It's not in this.

MR. ANDERSON: If we were to put it in

there, we would put it in here on a less bounding approach than we did three weeks ago, yes, and then it wouldn't change these numbers.

MEMBER WALLIS: But it would change the other one because for the other ones --

MR. ANDERSON: Yes.

MEMBER WALLIS: -- you had to assume something.

MR. ANDERSON: Yeah, and we just went with what people wanted to hear. Throw it in there and assume it goes away. NPSH goes away if you've got a hole, but you require a lot of things rather than just a hole.

MEMBER RANSOM: Now, these numbers include credit for containment over pressure, or do not?

CHAIRMAN DENNING: They're realistic.

MR. ANDERSON: This is realistic analysis. so yes. So the thermal hydraulic calculations here do calculate what the containment pressure is, but the issue about containment over pressure on NPSH, those scenarios, that threshold was never met because you only meet that limiting NPSH in design basis assumptions of the 85 degree pool temperature, 102 power, two sigma decay heat, all that stuff, which the realistic PRA doesn't do that.

So we never get to that, needing that requirement for --

MEMBER WALLIS: You never get to it. I thought there would some probability of getting to it.

MR. ANDERSON: Yep, yep. There's probability, yeah. If we would have to --

MEMBER WALLIS: You folks said this business about if you were realistic the pool temperature is so much lower.

MR. ANDERSON: Right.

MEMBER WALLIS: And so on, but there must be some probability of --

MR. ANDERSON: There probably is. We could probably look at the --

MEMBER WALLIS: So there's probably some finite probability.

MR. ANDERSON: There's probably some finite little hair, exactly. That's a true statement, and we would have --

MEMBER KRESS: You would have to have a pretty sophisticated uncertainty analysis.

MR. ANDERSON: Not to throw out a quick number, but I'll throw out. It's probably E to the minus nine, E to the minus eight sequence, you know.

MEMBER KRESS: Are you talking probability or frequency?

MR. ANDERSON: Frequency of an accident, I guess, you know, yeah.

MEMBER WALLIS: You'd have the hottest day in Vermont in two centuries or something.

MR. ANDERSON: Yeah, you'd have to have that. You'd have to be running at 102 percent power. We'd have to have the pool at its minimum tech. spec. level, all those things together, and then have to have the accident in question.

MEMBER WALLIS: But the pool never gets anywhere near that temperature when you're starting. It never gets up to 90 degrees or whatever it is when you're starting, before anything else.

MR. ANDERSON: Yeah, my guess would be that's a true statement, but I don't know. Chris, do you have anything?

It probably never got to --

MEMBER WALLIS: Have they ever got to 90 degree full temperature?

MEMBER SIEBER: Well, you have to shut down.

MEMBER WALLIS: Right.

MR. WAMSER: During certain system surveillances, operational testing of the high pressure coolant injection and the reactor core coolant, those systems which are quarterly tests do put us above the 90 degree range, but we have short duration allowed for that.

MR. ANDERSON: Right, for that short period.

MEMBER WALLIS: In normal operation it doesn't happen.

MR. ANDERSON: Absolutely not.

CHAIRMAN DENNING: Do you have any leaking SRVs?

MR. WAMSER: No, and we have no recent history of leaking SRVs at Vermont Yankee.

MEMBER WALLIS: And if you did, you'd fix it.

MR. WAMSER: That's correct also.

CHAIRMAN DENNING: What's the CDF itself? I've forgotten.

MR. ANDERSON: The CDF was in the range of 7.8E to the minus six per year for the base CDF and went up to about eight-ish E to the minus six per year, and that's right in the middle of the pack of the BWR Mark 1.

CHAIRMAN DENNING: I understand why we look at delta CDF, delta LERF. I mean, that's getting to be part of this risk informed kind of environment we're in, but there is a difference between looking at an up rate and delta CDF and LERF and a constant power where you have changes.

The reality is that just the fact of increasing power by 20 percent increases the inventory by 20 percent, and means that if our delta CDF had no change at all, the latent cancer fatality risk increases by 20 percent, and the early fatality risk probably increases by more than that, and so I think we have to be careful not to kid ourselves into thinking that we get off by looking at these --

MR. ANDERSON: Risk metrics.

CHAIRMAN DENNING: -- risk metrics that are poor measures, in some cases poor measures of risk itself; that there isn't an inherent change in risk that's associated with the up rate, and I think that our responsibility is to be sure that that risk still is an acceptable risk.

And of course, we're starting out with a low risk anyway to start off with.

MR. ANDERSON: That is true.

CHAIRMAN DENNING: But I think that the question of how appropriate CDF and LERF are as measures when we're talking about changes in power becomes more questionable than it does when we're talking about changes in configuration at a fixed power.

I have some questions about -- I know it's illegal for us to now go back and look at the risk study that was done for the NPSH, but I had questions about that anyway because I really didn't understand the two configurations that are discussed, and we look at the difference between them.

But in the words that describe the configuration, it just didn't make sense to me. Can you explain that to me again?

MR. ANDERSON: Right. I agree. Was it the word "available"? I think there was some --

CHAIRMAN DENNING: Well, I don't know. You can explain the two configurations, what they really --

MR. ANDERSON: So the base configuration is the PRA with the EPU adjustments to the PRA. So we're starting by that.

CHAIRMAN DENNING: Right.

MR. ANDERSON: And it also has in it initiation of emergency containment venting defeats ECCS due to MPSH issues. That's already in the base model.

The next configuration does one simple change, and that is the addition of the probability of containment isolation failure or a preexisting leak, either one of those, and the probability is determined in various ways. And that was inserted as a failure of ECCS in the sequences, and it was done across the board to all sequences, and there was no additional mitigation of those probabilities to say really what's the likelihood that I'm going to be at 90 in the pool or I'm going to be at whatever.

MEMBER WALLIS: Given to all of these ECCS sequences?

MR. ANDERSON: Yes, it was.

MEMBER WALLIS: But you don't need --

MR. ANDERSON: We don't need it for all the sequences, yep.

MEMBER WALLIS: You only need it for the big ones.

MR. ANDERSON: You only need it for the big ones, yep.

MEMBER WALLIS: So that's vary strange.

MR. ANDERSON: Yeah, that is true.

MEMBER WALLIS: With the least likely ones.

MR. ANDERSON: Right.

MEMBER WALLIS: So you're erring way on the way.

MR. ANDERSON: Right, and that's the double edged sword of trying to take bounding approaches. You know, there's the one side. You take a bounding approach just to show things aren't significant with respect to some criteria, but then you also are forced to start saying that's proper assessments right there. That's just ridiculous to assign it to every single sequence, but it was intended to be a bounding assessment.

CHAIRMAN DENNING: Any other questions about PRA? No?

Thank you very much.

MEMBER KRESS: Well, I guess I do have one. Does your PRA have capability of doing parameter uncertainty, Monte Carlo type?

MR. ANDERSON: It does now.

MEMBER KRESS: It does?

MR. ANDERSON: Yes, and that was performed for that conservative containment over pressure assessment. Parametric uncertainty analysis wasn't performed at the time of this EPU risk assessment a couple of years ago, but you know, based on knowledge of what the parametric uncertainty analysis is at VY and at other plants, the mean propagated uncertainty probably only changed by ten percent, and it wouldn't bounce you out of the very small risk category.

MEMBER WALLIS: I'm sorry. He left you off. I'm trying to digest what you just told me. When you make this change, you sort of say that there's a containment leak.

MR. ANDERSON: Yep.

MEMBER WALLIS: And you said it defeats all of the ECCS?

MR. ANDERSON: Yep, yep.

MEMBER WALLIS: So none of the ECCS works?

MR. ANDERSON: Correct.

MEMBER WALLIS: Then why is the effect so small?

MR. ANDERSON: There are other systems. There's alternating --

MEMBER WALLIS: There must be.

MR. ANDERSON: Yeah, and there is also --

MEMBER WALLIS: So you're really saying we don't need ECCS at all.

MR. ANDERSON: Excuse me. Excuse me. Low pressure ECCS. Those are also low pressure systems.

MEMBER WALLIS: Low pressure, right. It's the recirc. It's not the high pressure.

MR. ANDERSON: So if we're on high pressure accident sequences.

MEMBER WALLIS: Okay.

MR. ANDERSON: Yeah, those are only LPCI and course --

MEMBER WALLIS: It's just a recirc.

MR. ANDERSON: Yeah. Thank you.

MEMBER WALLIS: You're going to make it all clear for us now.

MR. ANDERSON: Thank you goodness.

MR. STUTZKE: Hi. I'm Marty Stutzke from PRA Licensing Branch A in the Division of Risk Assessment. That's under our new reorganization. You see my old affiliation there.

Yeah, I find it interesting that all of the questions are deferred to the PRA, which is always at the end of the day.

In anticipation and maybe some lessons learned, my next slide is my summary.

(Laughter.)

MR. STUTZKE: It seems like we always get cut off, but the basic summary here is that I feel that the licensee has adequately modeled the risk impacts in his PRA. The risks are, in fact, acceptable because the Reg. Guide 1.174 --

MEMBER KRESS: What is your reaction to Rich's comment that LERF and 1.174 ought not really be applied to power up rates?

MR. STUTZKE: Well, my reaction is we probably need to look beyond that. I think we need to be looking at perhaps late sequences, late releases, as you had indicated, perhaps the use of conditional containment failure probability.

It's true the sorts of issues that you're dealing with in power up rates aren't well captured by PRA. It's almost beyond the methodology's capability to do in any reasonable fashion.

MEMBER KRESS: Unless you go to full Level 3.

MR. STUTZKE: Unless you go to full Level 3, in which case you would be so overwhelmed by the uncertainty that you wouldn't show much delta.

MEMBER KRESS: Well, maybe you ought to deal with the uncertainty, too.

MR. STUTZKE: Right.

MEMBER KRESS: Well, let me ask you another question about that second bullet. One of the principles in 1.174, well, two of them; one of them is that the plant should comply with all of the other body of regulations when they're dealing with one area where --

MR. STUTZKE: That's correct.

MEMBER KRESS: -- you're changing it. How do you know that's true?

MR. STUTZKE: That's the traditional deterministic analysis portion that the other branches do.

MEMBER KRESS: That's the inspection and the assessment?

MR. STUTZKE: Inspections to enforce the regulations like this. For example electrical-mechanical, they worry about compliance with regulation.

MEMBER KRESS: So that's what they're doing when they're --

MR. STUTZKE: That's right.

MEMBER KRESS: -- going through the SAR.

MR. STUTZKE: In other words, out of the five key principles of risk informed decision making, my branch looks at number four: what's the impact on risk?

MEMBER KRESS: Right, but the other people look to see if they meet these other --

MR. STUTZKE: Right. We rely on the other people to do their assessment as well.

MEMBER WALLIS: And there is no regulation about NPSH.

MR. STUTZKE: There's no regulation that prohibits crediting over pressure.

MEMBER WALLIS: That's why you say it conforms to the regulations.

MR. STUTZKE: That's right.

MEMBER WALLIS: There are reg. guides though. They're not regulations.

MR. STUTZKE: But those aren't regulations. They are one acceptable way of complying with regulation.

All right. Let me jump to the second slide to remind you of kind of the game rules of the risk evaluation here. First of all, the EPU submittal is not risk informed under Reg. Guide 1.174. The licensee didn't submit it that way, and therefore, our review is altered in some respects.

Of course, we're using the EPU review manual, RS001, and it tells me licensees need to perform risk evaluations to demonstrate that the risks are acceptable, but it doesn't define what acceptable risk is in this review standard, and to determine if special circumstances exist, that could potentially rebut the presumption of adequate protection provided by the alliance complying with the existing regulatory requirements.

Okay. We have definitions or examples of types of special circumstances in the standard review plan, Appendix D. Okay? For example, compromising defense in depth, things like that. And in fact, SPR-19, Appendix D, one of the examples of a potential special circumstance is power up rate. Okay? So that's why we do these sorts of reviews.

But realize we're using the PRA, the risk evaluation to drill down into the EPU to see if we could find something that could potentially be a problem. And the fact is after all of the EPUs we've looked at in PRA space, we don't tend to find very much risk, and I think it goes to the questions that Dr. Kress was saying earlier. It's almost as if PRA is incapable of finding the actual risk to the way we currently practice it.

We would need to extent a full Level 3 or something like this. So my feeling is it would be unusual for me as a risk analyst to find something in EPU that one of the other technical branches wasn't on top of already. In other words, we would confirm and say, well, how bad could it really be in risk based, like that.

Okay. Slide 4.

It's interesting. I was struck when VY was making their presentation. They didn't look at my slides, and I didn't look at their slides, but you'll see the same information here, like this. So they've done a full power Level 1 PRA. Realize their internal events model is a linked event tree approach. It's a support state approach implemented in the risk man software.

MEMBER WALLIS: So you're describing now what they did, not what you did?

MR. STUTZKE: Right.

Seismic margins method, EPRI-5 methodology for fires, the so-called hypho-related risk based on reviewing, again, standard review plan requirements.

They do have -- they didn't take the credit probably that they should. They have a full Level 2 PRA. It's not just a simple large early release frequency calculator.

MEMBER KRESS: Does that mean it has fission products in it?

MR. STUTZKE: Yeah. It goes all the way out to release fractions.

MEMBER KRESS: Okay. That's nice to know.

MR. STUTZKE: That's impressive. You

don't usually see people take the effort to maintain this type of model anymore.

So on Slide 5, again, as they had previously noted, they made a small increase to the turbine trip frequency. This is to account for the fact that the post EPU plant requires three out of three reactor feedwater pumps, whereas the pre-EPU plant only required two out of three.

Okay. So a trip of a single feedwater pump may cause a partial loss of feedwater, but that's bend in the PRA under turbine trip. When they say loss of main feedwater, they mean total loss of main feedwater.

I looked to see why there were no other changes to the initiating event frequencies like this. One of the things I noted was the turbine bypass capacity has decreased under EPU. They're generating more power, but they haven't added any valves like this.

Well, the fact is that they don't use turbine bypass to avert reactor trip above I think it's about 30 percent or so. So it has no influence on it.

One of the big questions is what is the impact of LOOP frequency, loss of off-site power frequency like this. As you've heard earlier, the licensee is making and has made extensive hardware modifications to maintain reactive load, rewinding the main generator, a large capacitor bank, et cetera, et cetera.

They already have actions to preserve grid stability in place, and some of those actions may necessitate lowering power as they need to.

Finally, I looked at the LOOP frequencies in their PRA study, and I compared it to the recent LOOP frequency data estimated by the Office of Research. These are frequencies research had generated in response to an NRR user need following the August 2003 northeast blackout, and in fact, the more recent research data indicates a lower LOOP frequency than the licensee was currently using. So I think they've bounded it pretty well like that.

On Slide 6, no impact on LOCA frequencies. One that I had probed them about concerns inadvertent open relief valves, IORB sequences, and the reason is that elsewhere in the submittal they talked about the possibility of flow induced vibrations inducing inadvertent open relief valves or causing stuck open relief valves.

So I had posed an RAI for them and said, you know, the gist of it was how come it's discussed in this one section and the PRA is rather silent on it.

And they provided these explanations to me: no change in the seating force on the pilot valves; any possible flow induced vibrations wouldn't be transmitted actually to the valves, and so forth and so on.

I think notably if the valves were, in fact, leaking, they would detect it, and if necessary, shut the plant down to fix it. So it wouldn't degenerate into a true inadvertent open relief valve initiating event like this.

I looked at all the other hardware modifications. There's nothing they're doing to support systems that would cause me to believe they would change the frequency of support system initiating events. No change in internal flood frequencies, again, because they're not changing any of the hardware; they're not changing how they inspect it or how often.

As I was pointing out, the internal floods are part of what they call the internal events PRA. It's not a separate study. It's enveloped in there.

Okay. As far as accident sequences, they did what I considered a rather extensive set of MAAP runs to assess the impact of the proposed EPU on the Level 1 PRAs, 60 MAAP runs. That's quite a lot. I was impressed by the amount of effort they put into it.

Of course, one can debate whether MAAP is a good code or a bad code and for various reasons that are well beyond me, but they have a tool and they used it, and I think that's noteworthy like this.

CHAIRMAN DENNING: And basically they used to determine success criteria?

MR. STUTZKE: Success criteria and timing of operator actions that drive the PRA, and I'll explain about how that's used in some detail.

They did add an extra spring safety valve, which changed the ATWS success criteria. Again, I asked about the reduced turbine bypass capacity. It doesn't affect the success criteria for ATWS like this.

The last bullet, we've already talked before about the credit for containment accident pressure to maintain a positive suction head. Realistic evaluation indicates that they don't need the credit, that MPSH would be adequate without it.

As you're aware, they have done some

sensitivity studies. I've done some sensitivity studies trying to get around the modeling uncertainty on this. Following my return from Vermont a couple of weeks ago, we framed some additional questions, requests for additional information. We had discussed this with a licensee, and I think formally they were sent out like yesterday or today or so.

So I'm awaiting their response to my formal questions.

MEMBER WALLIS: Does this give what I was looking for earlier, which was sort of probability? They said the realistic evaluation shows it's not needed. But is there some tale of the uncertainty distribution where in one case out of 1,000 you might need NPSH?

MR. STUTZKE: Well, it's true, but you would be talking about uncertainties that PRA analysts don't normally deal with. You're talking about the uncertainty --

MEMBER WALLIS: That's good for you to deal with.

MR. STUTZKE: The actual uncertainty in the calculation of available net positive suction head, for example, the friction factor is unknown. The strain of loading is unknown.

MEMBER WALLIS: Temperatures and everything.

MR. STUTZKE: Like that. When a PRA analyst does these, we use realistic assumptions. In other words, we don't deliberately add conservatism, but as raising up the decay heat or things like that.

And we define a definition of core damage. Normally it's peak center line temperature exceeds some value or the core is uncovered with no hope of refiling it, some success criteria like this such that one may make a thermal hydraulic calculation. We can determine yes or no, was that definition of core damage reached or not. So it's very black and white for us. We don't really look at the uncertainty in the PRA calculation.

MEMBER KRESS: There's two parts to this uncertainty. There's the uncertainty in the actual net positive suction head you're going to get as a result of the debris build-up and the pressure drop and stuff, and then there's the uncertainty in the actual pressure in the containment.

Now, the PRA could be used to get that second part.

MR. STUTZKE: That's right.

MEMBER KRESS: And it looks to me like it would be a relatively easy uncertainty analysis if you had the data to do the other part and then overlap the two uncertainties.

MR. STUTZKE: Well, I don't know that I would say it's easy. I'm unaware that anybody has tried to calculate the uncertainty in the pressure response.

MEMBER KRESS: Well, you've got the models.

MR. STUTZKE: It's true, and you would have to run the models. You'd have to make many MAAP runs in Monte Carlo fashion.

MEMBER KRESS: You'd have to hook it up to a Monte Carlo.

CHAIRMAN DENNING: But PRA has not treated phenomenological uncertainties in that way, and again, there are kind of two kinds of uncertainties here. There's a variability, but I don't think that's what really is the element here. I think it really is phenomenological uncertainty in the ability of our models to predict those phenomena, and we just don't address it.

If we did address them, it would probably appear in the uncertainty in the risk number rather than in the -- if you looked at a CCDF, it would be in the uncertainty in the CCDF, not in the shape of the CCDF, although the two -- it can reflect back into the mean probability, the mean risk that we deal with typically, but it's complex, and there is some work being done along these lines on treatment of phenomenological uncertainties, but there's no PRA that has really treated that in the past, that kind of treatment.

MEMBER KRESS: The only place I want to use the PRA is to find the uncertainty in the pressure that you're going to get in containment, and I think you could deal with that very nicely. It's a blow-down, LOCAs, and you may have to put in some probabilities of leakage and stuff like that, but that's what I want to use the PRA for.

And then you say, now, we've got this other aspect of the flow through the ECCS system and the spray system and the debris build-up and whether or not the uncertainties in the LOCA generating debris and getting there. That's another -- I don't think you can use the PRA for that, but you've got models for it, and I think you could --

CHAIRMAN DENNING: How did you say you were going to use the PRA to give you a pressure? You use the code to give you pressure.

MEMBER KRESS: Well, you use something like the blow-down models that are in the codes.

MEMBER SIEBER: I would actually prefer not to see PRA used in this, but I think that the fourth bullet here is extremely important with regard to preserving things like defense in depth and independence of barriers and so forth, and if a realistic deterministic evaluation would show that containment accident pressure credit is not needed for MPSH and that an appropriate phenomenological and sensitivity studies were done, again, in a deterministic way, then you could preserve the concepts of defense in depth and so forth and use that as the basis for allowing a power upgrade to the extent that it would be allowed under the conditions that are there.

I'd prefer that approach.

CHAIRMAN DENNING: Yes, and I'd like to ask Entergy if there's anybody that could speak to that. Have you considered that approach of the realistic analysis with some consideration of uncertainties on this NPSH problem?

Because it certainly is one that gives us a lot of difficulty,a nd I think that the direction that Jack is going is one that is very appealing, and

I'm just wondering whether you've given thought to that.

MR. NICHOLS: Well, we've given thought to it. This is Craig Nichols from Entergy.

Since it's not allowed to do a realistic LOCA, et cetera, by rules, we cannot do that. We have done that in sensitivity space and provided that information to the staff for their use, and I believe as we showed in our earlier presentation, such treatment that way in realistic space in almost every domain shows that, as stated here, COP would not be needed.

MEMBER WALLIS: You showed us a little table, and it just said taking this temperature, this temperature, and so on, and then the full temperature was 169 rather than one -- but that was only a few cases, and what would really help me, and it's along the lines Jack is saying, is if you could go through putting all of the uncertainties, and then you would say realistic evaluation with the consideration uncertainties shows that the probability that the containment accident credit will be needed is one in ten to the minus six or something. Then we can make an independent judgment about, well, okay, we don't need it with PRAs and everything.

MR. NICHOLS: I think now I understand what you're asking for.

MEMBER WALLIS: It looked as if that would be the case.

MR. NICHOLS: A uncertainty treatment --

MEMBER WALLIS: But you didn't go that far. I mean you were still conservative in some other respect.

CHAIRMAN DENNING: Well, recognize, again, we're not asking you for anything here. We're just exploring what you've done. You know, there's no direction or request from us.

MR. NICHOLS: We do understand the request or the --

CHAIRMAN DENNING: But we're just curious whether you've done it --

MR. NICHOLS: -- the curiosity.

CHAIRMAN DENNING: -- and whether you had any data that would have helped us along those lines.

MR. NICHOLS: We have done some work in that area. I don't believe that we're ready to present it now.

MEMBER WALLIS: Well, I think the staff did something, too. The staff looked at uncertainties and then this NPSH problem, too, and sort of said, well, there were so many conservatisms that it won't be needed, but it was not done in a very complete and quantitative way.

CHAIRMAN DENNING: Well, let's pretty Marty a little bit because he came up with success criteria that he used in his analysis, and I'm curious. Could you talk to us about those success criteria that you used there?

MR. STUTZKE: Well, let me speak generally how PRA analysts divines success criteria. When a PRA analyst talks about success criteria, normally it's a very clear-cut situation. For example, one has a three-train system and I want to know do I need one out of three pumps working or two out of three pumps working.

Okay. That is a big difference. Okay? It's unlikely that I would miss something or it would have enough phenomenological uncertainty in the thermal hydraulic calculation that I could ever change my opinion between one out of three versus two out of three pumps.

I would remind you that a lot of the IPEs and certainly when I first got into the business, we never ran codes like MAAP to determine success criteria. It was a back-of-the-envelope calculation.

Okay?

That was adequate because we couldn't have been that far off. That was the judgment like this.

When you deal with the issue of credit for containment accident pressure, you know, now you're pushing some of the cherished beliefs of PRA analysts that we can't divine success criteria like we do and we need to do a lot more work.

You know, my feeling, let's -- the other thing I would say is let's don't get confused between a PRA versus a probabilistic propagation of uncertainty. Right? That's something that anybody can do. It's just a function of random variables, and I apply the appropriate distributions and I calculate it.

MEMBER WALLIS: But it really does apply in a PRA. When you've got to make a decision is it successful or not, this thermal hydraulic uncertainty really does come into that decision if you did the whole Joe.

CHAIRMAN DENNING: We don't do the whole Joe.

MEMBER WALLIS: But you don't do it. You don't do it. You can't.

MR. STUTZKE: No.

MEMBER SIEBER: It's the definition of what does working mean. You know, sometimes it works, sometimes it doesn't.

MEMBER KRESS: The reason I suggested the PRA for one part of it is because you've got the frequencies and the LOCAs built into it, and it's not the probability long term. Well, it's probably -- it's an initiating event times the probability.

MR. STUTZKE: So to answer Dr. Denning's question, how did I come up with the success criteria? I assumed them. I said if this is true and this is true and this true, I can develop a model, and this is the delta CDF.

CHAIRMAN DENNING: And the criteria you used, if I remember it, was that RHR availability within four hours or something like that. Is that --

MR. STUTZKE: Suppression pool cooling. The assumptions were whenever I needed to have some sort of accident sequence that dumped heat into the Taurus (phonetic), okay, and I needed to be able to run either low pressure or core spray pumps, and there was a hole in the containment so that I had no over pressure, and the suppression pool cooling wasn't started in four hours. That seems to be a difference between my analysis and what the licensee had done because I understand the suppression pool needs some time to get heated up before we actually create the problem within PSH, whereas in their analysis it just goes off the core damage basically. It's one of the reasons why they got such a large delta CDF as compared to I did because they made different assumptions in the sensitivity analysis.

The idea is --

MEMBER WALLIS: Ten times as much as you did, didn't they?

MR. STUTZKE: Yeah, ten times as much. It has caused me considerable lost sleep over the last couple of weeks trying to understand why did they get such a big number like this.

CHAIRMAN DENNING: Well, we heard a lot of it right here as to why the numbers are bit.

MR. STUTZKE: Yeah, but again, it's an idea that let's make some assumptions and do a PRA calculation, and the idea is that if the delta CDF, you know, the change in risk is small enough, you gain some level of comfort with that result. That's the idea.

Okay. I presume I will be back to speak to the full committee on containment accident pressure later on. So let's --

MEMBER SIEBER: That would be a good assumption.

MEMBER WALLIS: So you're going to lose some more sleep before then.

(Laughter.)

MR. STUTZKE: Either that or I need to find a new job.

MEMBER SIEBER: No, just lose some sleep.

MR. STUTZKE: Yeah, but I'll table it now because the licensee hasn't formally responded to my RAIs, and I'm in the process of revising safety evaluation now.

Okay. So on Slide No. 8 --

MEMBER WALLIS: Wait a minute. Let's go back. They're in the process of responding to your RAIs and all of this is going to be finished by next week or not?

MR. ENNIS: This is Rick Ennis.

As I had mentioned yesterday, the intent is to be able to discuss this as full committee at least verbally. We don't think we have time to fully revise the SE and issue it again.

MEMBER WALLIS: But these RAIs are going to be responded to by next week?

MR. ENNIS: We had requested that they be responded to by Friday, this Friday. And we have drafts on a computer here now, responses to those.

MEMBER WALLIS: I don't think it would be good to come to the full committee with too many of these loose ends, the RAIs not responded to and things like that.

MR. HOLDEN: Yeah, this is Corney Holden.

I think the other point that we made at the start, the SE right now, we've drawn a conclusion on the SE in that we've asked for additional information and risk and will include that, and that will supplement what we already have.

CHAIRMAN DENNING: What they said was based upon the PRA work that the staff had done, they've concluded the acceptability in that.

MR. STUTZKE: That's correct.

CHAIRMAN DENNING: And that this was not then dependent upon resolution of those RAIs.

MR. STUTZKE: Right. I haven't decided yet, nor have I discussed with my management, but you know, the PRA evaluations that I did, the scoping analysis may disappear from the safety evaluation altogether. We may rely on the licensee's work, review it, and consider that it's acceptable.

MEMBER WALLIS: That's surprising. I

mean, the fact that you did this confirmatory analysis I think helps us. It would be a pity if it all disappeared.

MR. STUTZKE: That's why I need to discuss.

CHAIRMAN DENNING: Okay. Continue.

MR. STUTZKE: Okay. On Slide No. 8, there's no changes to the failure rate data that the licensee is using in their PRA. It seems reasonable because as long as operating ranges, limitations on equipments are being observed.

There was a change in the probability of stuck open relief valve, SORV. I apologize. This is not worded very clearly. In fact, right now it's nonsense.

The idea is this. As you increase decay heat and you have a reactor trip of some sort, the valve chatters more. It opens-closes, opens-closes, opens-closes, right? And it will do that more often, extended power uprate conditions than not, and so every time you challenge the valve to open, you fail to reseat it and create an accident sequence.

The licensee had looked at several ways of doing this. One was just adding up 20 percent to the failure probability of the valve, being 20 percent decay heat. At the lower end, they will say, "Well, the valve reliability, if it sticks open, it will stick open on the first demand. So there's no change."

They actually looked at a number of MAAP runs for transients and counted the number of relief valve cycles and came up with this 15 percent. So I think they've got it reasonably bounded here.

I'll point out stuck open relief valve sequences don't contribute notably to their risk at all.

CHAIRMAN DENNING: What does a realistic model look like for a stuck open relief valve as far as the data is concerned? Do they stick open on the first one or do they stick open on the tenth one or is it --

MR. STUTZKE: Well, that's the problem. Some people believe if it fails it will fail the first time, but once it gets exercised, it can recede. Other people believe it's a matter of wear. So it wants to stick open on the last cycle.

I've seen people try to apply binomial distribution to it and say it has got a constant probability of demand, and so I count that up, and you get a range of answers in there.

MEMBER WALLIS: And if it leaks, it leaks whether a PWR, and you probably build up boron, but you don't in this case.

MR. STUTZKE: No, you won't.

I mean, when I say "stuck open," I mean stuck open enough to create small LOCA or medium LOCA.

MEMBER WALLIS: Well, I know. I was thinking of TMI again. The stuck open probably was related to the history of that leaking valve over a period of time.

MR. STUTZKE: Yes.

CHAIRMAN DENNING: You're saying the sticking open was? I'm not sure that's true.

MEMBER WALLIS: I think it was. It had been leaking more and more over a period of time, and I think that -- well, it's a red herring.

CHAIRMAN DENNING: It's a different argument.

MR. STUTZKE: Human reliability. I was intrigued this morning and this afternoon when you gentlemen were discussing human reliability with other people and was very glad that Dr. Apostolakis is not sitting here to interrogate me this afternoon.

But I wanted to try to --

MEMBER KRESS: He'll get his chance next

week.

(Laughter.)

MEMBER SIEBER: He will be next week.

MR. STUTZKE: It's inevitable, right?

I wanted to give you a little explanation of how timing of operator actions is used to determine their probability of occurrence like this and, therefore, to give you some idea of changes of timing driven by the extended power uprate and what that really means in here and to try to remind you of some features.

I, like most PRA analysts, develop a time sequence of an event. So we'll say at time zero the event occurs. At time one there's some compelling signal that the event has actually occurred, enunciated responses, things like this. The compelling signal, that is what tells the operator go do something. So now he's reached some point in his procedural space telling him to do things.

At some later time, we'll call it T2, it's what I'll call the point of return. If they take action after that time it's of no avail. T3 then would be some time when a bad consequence occurs as a result of the failure like this.

So the total time frame from T0 to T3,

that's what you get out of a thermal hydraulic calculation, a MAAP run. The examples that were being discussed this morning, that's the 6.2 minutes available time to inhibit ADS being reduced down to 5.4 minutes. So that's an actual thermal hydraulic calculation like this, although I will point out in the early days of PRA we used to do those by paper and pencil, 60 minutes to half an hour, things like this.

The time from we'll call it the point of return to the bad consequence, that's the implementation time. That's the time it takes the operator to physically get out of his chair, go up to the board, figure out which control to operate, push the button, and do what he needs to do.

Okay. For in control room actions, that time does -- implementation times tend to be very short, right, unless the control room is physically big. I've not been in the Vermont Yankee control room. I've been into several, for example, at N Reactor where the control room is about 30 meters long, and it's a hike to get from one end to the other, and the implementation time is important like this.

So the time between the compelling signal and this point of no return is called diagnosis and decision making time. I call it thinking time, the fancy name "cognitive time."

So now the operator perceives something is amiss. Okay? He needs to overcome his shock. He needs to figure out what's going on like this. He needs to recall his training and decide out of all the things he knows, what's the appropriate thing to do?

In the case of this inhibit ADS, it would appear that he's got about four minutes to sit and think about what he needs to do until the time he actually needs to do it.

Well, that four-minute time is called the available time, and that is one of the inputs into the calculation of the cognitive error probability. I say one of the inputs because the human error probability not only depends on time, but other sorts of factors, the man-machine interface, psychological stress, work load, training procedures, things like this.

All of these factors are put into an HRA quantitative model to generate the final number. One of the questions that was raised this morning is what about simultaneous actions. During an ATWS there's a lot going on in a very short time, the need to inhibit ADS, the need to inject slicks, the need to lower water level down to tap, to reduce the power.

HRA people tend to think of those as operator burdens, and they are treated by certain performance shaping factors, notably the workload performance shaping factor. So if he has multiple concurrent actions going on, we as a higher performance shaping factor -- it's basically a multiplier onto a basic probability. So it just scales it up like that. Okay?

In addition, each one of these human actions may be modeled separately. It appears they're on separate basic events in the model, and HRA analysts are very careful to worry about the dependency among those actions, the idea being, for example, if he fails to inhibit ADS, maybe he doesn't understand what's going on, and so he will fail to lower the water level and fail to inject slicks. He's got a total brain loss. He's confused. Okay?

And HRA people try to handle that with a dependency analysis.

As far as Vermont Yankee goes, they did a large amount of work on the human reliability, probably more than I've seen for a while. For example, they looked at the man-machine interface to decide whether those performance shaping factors would be affected, and the answer was no like that.

So, in other words, they're considering the change in display, the span of instruments and things like this, the training in order to handle the new plant.

They went down and they looked at their post initiator human actions, their 59 in their model, and they recalculated 41 of the probabilities like this. They had employed a screening method that was based on primarily importance measures. They looked at combinations of Fussell-Vesely importance measures and risk achievement worth.

Then they also had another one that said any human action that had less than 30 minutes available time we will reassess like this.

MEMBER KRESS: How did they know what value of, say, Fussell-Vesely or RAW to cut off and say, "We'll not deal with those below that"?

MR. STUTZKE: It appears to me they picked the magic numbers out of 50.69, the Fussell-Vesely of .005 and the risk achievement worth of two. So I asked them in RAI. I said give me all of the human errors, even the ones you screened out, and I want to look at them and see whether I agree that they should be screened out or not.

And so I looked at all 59 of them and

agreed with their assessment because the ones they threw out aren't affected by the timing tremendously.

Realize whenever you start the screening process on importance measures, basically you're trying to save yourself some analysis time. Let me calculate 41 instead of 59.

MEMBER KRESS: Not much difference there, is there?

MR. STUTZKE: Well, my feeling now is with tools like EPRI's human reliability calculator, it's just as easy to do 59 rather than to defend why I picked these 41s, you know. You can save yourself an RAI, things like that.

So anyway, I go and looked at what they threw away and convinced myself that it looked pretty good, and then they recalculated these probabilities to handle the shorter available response times, and that's all put into the model.

As I had said before, they looked at the dependencies. They reassessed the dependencies in the model. It appears to be almost an analysis, complete new analysis from scratch rather than just presuming what they had done before was okay. So I feel that they've done a pretty good job with looking at the human reliability.

The thing that I would point out in all of this, when we go back to the time lines, we have an uncertainty of how much available time there really is, phenomenologically and things like this. There's an uncertainty in how much time it takes the guy to respond, implementation time.

So by necessity then you've induced an uncertainty then in the available time. Okay? So I don't know whether I have got four minutes available to think or three and a half minutes or whatever it is.

On top of that, now I put that number into something called a time response correlation or time reliability correlation, depending on who you want to call, but the idea is that on the X axis it says here's the available time, and on the Y axis it says here's the magic probability of failure, right?

These curves are a dime a dozen. Right? If I put five HRA analysts in the room, I would have eight curves. Okay? There's not a large consensus on it. It's one of the sore points with Professor Apostolakis. It's like why do you use this NUREG and why don't you use ATHENA.

Well, that's just another NUREG, and you know, which one is the right one to use? And the fact is there's not good consensus among the community as to what the appropriate thing is, the point being that when you see a small change in time, say --

MEMBER WALLIS: But can I ask you this one that I was referring to, the GE-3309TP? Is that a good one?

(Laughter.)

MR. STUTZKE: I'd have to look to see what they actually did, which number they had, but no matter which, you know, I feel like you're damned if you do and damned if you don't. No matter which book I pull out of my bookcase, somebody will say I should have used that one. Okay?

MEMBER KRESS: George will say that now.

MR. STUTZKE: You will see in VY unfortunately I didn't have a chance to present it, but I have done a sensitivity to the human reliability method, and I pulled them out from over about a 20-year span, and you'll see the number doesn't change that much.

Well, one of the reasons is that the time response correlation is derived out of simulator data that industry did, EPRI did a long time ago, right? That the only way to get this curve is empirically, and then one can argue whether it fits to a Weibold distribution or a log normal, which is one of the big screaming arguments that you hear in this.

But the fact is you're dealing with a pretty sparse set of data, and you're trying to extrapolate it or interpolate it to situations where maybe it doesn't apply like this.

Now, the result of this is tremendous uncertainty in the results of the PRA like that.

Okay. Next slide.

Okay. This shows you the impact of the extended power uprate on core damage frequency by comparing it to the Reg. Guide 1.174 risk acceptance guidelines. You notice the guidelines are actually the stair step function. The bottom step, the bottom tread there is the region of very small change in risk, and that's where the black dot is, and that's where they come out.

For the middle step we have small changes in risk. Well, if it's in Region 2, it may still be acceptable. Okay? When you get into the Region 1, that's when we really begin to worry. Okay?

With respect to this review of the extended power uprate, if their risk metrics had landed in Region 1, I would begin to question adequate protection. That's kind of my personal trigger, although there are no hard and fast rules on this, but you can see clearly from the risks that they've actually calculated here that they're in the very small regime.

MEMBER KRESS: Now, that's the risk of internal events?

MR. STUTZKE: Yes, sir, that's what I wanted to point to. In fact, that dot moves up diagonally to the right because there's risk from external events in the base model, and there's a delta risk due to external events that they're not quantifying. There's also risk due to shutdown and low power event, okay, like that.

MEMBER KRESS: So you sort of have to guess how far it goes.

MR. STUTZKE: That's right.

The other thing I'll point out is these are not hard and fast boundaries between the region. They're fuzzy. Okay?

CHAIRMAN DENNING: You know, in this case, I think the external events, you know, they're unlikely to be significantly changed here.

MR. STUTZKE: That's correct.

CHAIRMAN DENNING: And the low power for the arguments they made. So it's not as obviously a deficiency as we see in some cases of application of 1174 where there really are things that could significantly affect like fire risks and stuff like that. I don't see that here.

MR. STUTZKE: yeah, that's correct, and we'll talk about what's missing in a few other slides here.

Okay. As far as to the impact on the Level 2 PRA, again, the licensee had done a number of MAAP runs to support their EPU. No changes in the Level 2 success criteria. The actual modeling of accident progression, the BIN categorizations like this, basically the results of the delta LERF number they calculate is being driven by the delta CDF from the internal event, from their model like this.

They did look at some small changes in timing to see whether it made any difference or not, and it doesn't appear to be very strong. So when you plot this up against the risk acceptance guidelines, you have what I'll guess personally -- I'll say what a regulator hates to see. Now we're on the cusp here. Okay? I've got some sort of guideline, and I am smack dab right on top of that guideline, but I know my guideline is fuzzy and I know that this dot is fuzzy, too.

My point is I'm still acceptable. Okay? Region 2 is still acceptable under certain conditions like this, but now you can see I'm getting closer to the boundary. So what's the impact on LERF from external events?

And now I may be actually pushing it a little bit. So we need to consider the external events in some detail. They hand run the EPRI 5 methodology, the fire induced vulnerability evaluation, basically went back and looked at it again to see if changes needed to be made to it.

As you know, what you're doing in the EPU, it doesn't change the drivers to the methodology. For example, you're not physically changing the fire protection system. You're not adding combustible loading, things like this. So the frequency of fires shouldn't change. The plant responds won't change noticeably.

Now, five is a semi-quantitative result, but the CDF it calculates is not as good a fidelity as the CDF from the internal events. It's kind of gauge to tell you, gee, which room really is the problem point like this. It's a ranking methodology almost in my mind.

So they didn't determine any

vulnerabilities when they relooked at their five study, and I think that's a reasonable conclusion.

For the seismic PRA study, nonselect 14, they've used the EPRI seismic margins method. That was part of their IPEEE response, and I dug into this a little bit following our meeting in Vermont, motivated by questions that Bill Sherman had asked like this.

When the IPEEE submittal guidance came out, NUREG 1409, Vermont Yankee was identified as a focus scope 0.3G plant. What does that mean?

Okay. We have to realize that NUREG 1407 assigned every power plant in the country to one of four categories. You either had a 0.5G review level earthquake. Those were the plants in California. You had a reduced scope set of plants. Those were like Crystal River or Turkey Point down in Florida where they don't have a large seismic hazard, and everything else was poured into the 0.3G category, everything.

Okay. That 0.3G category is called a review level earthquake, okay, and it is loosely related to the seismic hazards at the site, but if you read 1407, Appendix A, it explains why it's not directly tied into risk. It's not like I'm saying, gee, the frequency of an earthquake of 0.3G is below ten to the minus six. That's a false interpretation of this number.

Okay. By comparison, the operating basis earthquake at VY is 0.07Gs. A shutdown earthquake is two times that or .14G.

The focused scope means that they're limited when relay chatter was evaluated to review relays that weren't in the USIA 46 program like that. Relays are important here because that's the containment isolation signal that may impact over pressure potentially.

But when you look at the seismic risk, things that drive seismic risk like changes to structures so that you have turbine building colliding with the reactor building things, nothing is happening. They're not modifying the structures; they didn't modify the equipment mounting.

Specifically I looked up the HCLPF values, high confidence of low probability of failure, for reactor coolant system in containment, and they're greater than the 0.3G screening criteria. It means these are very rugged systems. It's not likely that an earthquake would simultaneously create a LOCA and fail the containment.

So as a result there's no new

vulnerabilities that have been identified arising from the EPU concerning seismic risk.

On Slide 16, the shutdown risk evaluation, again, it's a qualitative assessment, and the licensee pretty well discussed it earlier today. We don't create any new initiating events. No reason to suspect that the frequency of already identified shutdown initiating events would increase.

There are some small changes to the core boil down times for the post CPU because the decay heat is a little bit higher.

Should shutdown cooling fail, the plant has redundancy and diverse systems, low capacity decay heat removal systems, but because the capacity is smaller, they may be precluded if you were to lose them shortly after shutdown, but again, this seems to be a minor effect like this.

And, again, some small reductions in available operator action times. Again, as I pointed out, if you have four hours to respond and the delta is ten minutes, it's almost no change at all like this.

Again, you control outage risk and attract configurational risk in general. They have computerized risk monitor that they will maintain like this.

Okay. Slide 17 is the discussion of the PRA quality here. Basically the quality is okay because the PRA has been based on their IPE and IPEEE submittals, which the staff has already accepted some years ago.

They did have a peer review owners group back in November of 2000. All of the Category A and B findings have been resolved. I actually looked at those findings to see what the problem was and what action they had taken to resolve them, and pretty well agree with them.

I'll point out I've been involved in two of the pilot programs for Reg. Guide 1.200, which was our PRA quality reg. guide that endorses the ASME PRA standard, and the nature of the facts and observations that I read for Vermont Yankee were very similar to what I observed in those pilot programs. Okay?

So their PRA quality is as good or as bad as most everybody else's is in the industry, in my opinion, like this.

In addition, the staff, as you know, maintains SPAR models that drive the significance determination process, notebooks. The staff had actually gone up and benchmarked the PRA against the

SPAR model in May of 2003.

I'd asked RAI specifically on this because it appeared the core damage frequency changed by, I guess, a factor of two over a couple of months, and I was kind of perplexed about why that happened, and they were modifying their PRA in result to this benchmarking model.

Okay. So I think we have good agreement, that they've been responsive. My opinion is their PRA is of adequate quality to drive the sorts of risk evaluations they need to document the CPU like this.

Yes, there are things that could be improved. I was encouraged to hear them thinking about fire PRAs and getting away from the EPRI FIVE. I would encourage them. I think that's the right way to go.

CHAIRMAN DENNING: Can I add my agreement with that, not that it will influence them? But I certainly would like to see them influenced that direction.

MR. STUTZKE: We need all the support we can get here like this. I think personally methods like FIVE and seismic margins, they were good at the time, but we can do better now, and there's no excuse not to do any better now. We have the computer tools, so let's use them. But a personal opinion of mine, although I'm certain most of the people that I work with would agree wholeheartedly.

Okay. So the conclusions are, again, my second slide that I had showed you earlier. I think they've done a good job of modeling and addressing the risk impacts within the limits of the PRA. They're clearly in compliance with Reg. Guide 1.174 acceptance guidelines. There's nothing I've been able to identify as a special circumstance so far that would question a presumption of adequate protection at this time.

Further questions?

CHAIRMAN DENNING: Any questions?

MEMBER KRESS: Good job.

CHAIRMAN DENNING: Yes, I agree. Good job. Thank you very much.

MR. STUTZKE: Thanks.

CHAIRMAN DENNING: Thank you.

Okay. Mr. Shadis, are you ready to talk to us?

PARTICIPANT: Do you want to make a presentation to us? Is there anyone else who wants to make a presentation?

Any other public comments?

CHAIRMAN DENNING: Please make sure you speak into the mic and identify yourself.

MR. HOPENFELD: My name is Joe Hopenfeld. I'm a consultant to New England Coalition.

I'll be very, very brief because I spoke for half an hour a couple of weeks ago. Let me repeat my concern.

First, very simple. What happens to a damaged dryer that is exposed to DBA loads? I'd like to remind you, and I think it was mentioned here by Entergy, that these plants were designed to withstand DBA. So it's true the computer codes that were used 40 years ago are a little bit different than the computer model that we're using today.

And based on my experience with PWRs, you'll find new things, new loads under DBA condition that you didn't see before. Obviously they have not at that time considered it a dryer that contains certain distribution of cracks of unknown size and unknown location.

That issue should be addressed, and I haven't heard it discussed, only very briefly.

The second issue, and I can go through this very, very quickly, has to do with the iodine spike or iodine releases. We heard this presentation in the afternoon, and I haven't heard anything said about the iodine uncertainty.

There is a generic issue that is unresolved. When you operate with EPU, under EPU conditions, the flow rates are higher. So the concentration of iodine is lower, and if you remember or you can go back to the database and you'll see when the concentration is lower, there's a potential for a much higher iodine spike, and I'm not talking factor of two or three. I'm talking an order of magnitude.

So are we asking ourselves are we meeting the 10 CFR 100 or the 10, what is it, 50.69? That issue hasn't been even touched on, and I think we have to assure ourselves that under the EPU conditions you meet the requirement, the legal requirements.

And what I would like to remind you, that the database on which the iodine spike is based on, it's purely empirical, and it is not -- you cannot extrapolate the directive to the way I understand it was done. It wasn't described in the presentation today, but from reading the SER, I believe that they're just plain extrapolated directly, and I think that issue should be addressed because you cannot assure yourselves that we meet the criteria.

Now, I don't know how far are we for the

5 REM or whatever it is in the control room. The numbers were not presented. They were not in the SER. So I don't know how far we are, but I've looked at some numbers in other plants, and there was no order of magnitude cushion in there. They were very, very much closed.

So you really have to look at it. It's not an academic issue if you really want to meet the legal requirements. It's not a safety issue, but it's an issue that should be addressed.

The last one has to do with the delta P across the screen, and one thing that bothered me a little bit, we have some experiments at Los Alamos. We have some experiments at VY. We have some experiments at EPRI, and for a person that, you know, is kind of removed from that, it's very difficult to see how all of that matches together.

In addition to this, I keep hearing the word "conservatism." However, the conservatism that you're talking about is based on data which was obtained in '96 by weighing the sludge in the pool. But now what happens to all the sludge that you have during blow-down? What happened to all of the crud and the rust that you get in the drywall that's coming down there?

But more important than that, the SER states that the conductivity of the coolant is different, and obviously the particle size, particle distribution is going to be affected by the pH.

So it's not really a conservative kind of approach. That's ridiculous, but conservative approach would be to take a one-eighth of an inch fiberglass and put it on the screen and take a spray gun and shoot it with particles. That would be conservative, and then work yourself back.

There's no modeling at all. There's absolutely no understanding how these pieces come together. They just -- they're somewhere there, but you know, there's some insight.

Well, I have absolute zero insight as to how these things go together. So I know you have a lot of flow area, and that's good, but that clearly is not sufficient.

Now, with regard to another comment I made last time, it had to do with flow acceleration and corrosion. I think answers were clear. The gentleman that was sitting here asked the question, and the question was answered with regard to velocity and the fact that you're going to increase the scope of your inspection probably will take care of it, but it is a potential problem because you're running 100 feet or 200 feet per second with some particles in there. So basically, these are the four issues that I am sort of repeating myself.

CHAIRMAN DENNING: Do we have any questions?

Let me ask one question, and that is with regard to your first concern, which is in additional accident loads, it looked to me like as far as local loads that they really aren't changed very much, and I was wondering whether, you know, it was EPU or whether it's -- that even though the power is up, the blow-down looks awfully similar, and I was just wondering was there a particular accident scenario that was of concern to you that would --

MR. HOPENFELD: Well, I think I just went on a gut feeling that we are talking about increasing power. I know you're going to be choked on one side, but as it was pointed out, you're going to run in for a long period of time.

Really the question is: are you going to excite some new vibrations in that dryer during that different conditions? And you've got to address that. Because if you do, there was a case. I forgot where it was in Florida. I just don't remember the case, where we did have, I think, a valve on the main steam line lifted and excited very, very strong vibrations.

So you've got to look at it. You just can't say it's not there. How different it is, I mean, the flow is choked, and I don't know what the peer does to it, but I think you have to realize really again going back to what the calculations tell you.

The calculations we had 40 years ago are not that good, again, based on the PWR. If you go into more detailed modeling, you may find out.

I don't know how the temperature is affecting it. Temperatures may not be different, but the natural frequency of the dryer may change, too. So how to hold that thing together, somebody has got to look, and I haven't even heard it mentioned to you running into PRA and CDF, but you've got to address the physics first.

CHAIRMAN DENNING: Thank you very much.

PARTICIPANT: Are there anymore comments?

MR. ATHERTON: My name is Peter James Atherton. I'm here primarily representing the interests of the public.

And I have a few comments I'd like to make, and I'll start out with an overview that has me concerned, and that is the present state of NRC safety culture.

I was involved in a 2206 petition on a BWR in which the response ultimately, which went to the Commissioner level, was that -- and this was put in writing -- was that there was their opinion that there would not be an accident at a boiling water reactor, and therefore, the safety concerns that I addressed at that time were not considered to be significant.

And if that's a prevailing attitude within NRC as a result of this higher management posture, I have concerns about, you know, how this propagates into a safety culture. I realize it's obvious to me that you have engineers from General Electric and Vermont Yankee are quite competent, and they do the design work in trying to make the plant function at a higher power level, be it more efficient so to speak, which is, you know, what an engineer tries to do for money making purposes, and so they do have some control over the equipment that they operate and handle, design and use for all practical purposes.

They, however, don't have control over some things like environmental issues and disgruntled employees, and the unmentionable, the terrorist act. And these can have an effect upon the operation of the plant in a negative way.

And so I'm concerned about the safety culture that NRC propagates in this manner to people that I've interacted with.

Another overall perspective is safety margin. I used to work with the Nuclear Regulatory Commission and the old Atomic Energy Commission in the 1970s, and there was significant safety margin, and I can't give you specific numbers to it, that plants were designed to, probably because of the unknown more than anything else.

What hasn't been made obvious to me at least in the presentation that I was permitted to be at yesterday and today was exactly what an acceptable margin is at least from a percent perspective, whether it be temp. to pressure or whatever, and the design of an equipment that would be considered acceptable.

For instance, I saw what appeared to be in a conflicting manner. I went over the areas of the submissions that the members of the public were permitted to have in the closed sessions, and I noticed, for instance, over pressure protection was cited to be 1328 psig and the limit established by some standard was 1375. That's getting very close to the limit in that area, and I just wondered what is acceptable.

CHAIRMAN DENNING: One thing you should recognize is that the ASME standard itself has a great deal of conservatism in it that we recognize. So it's not just that that's a safety limit.

MR. ATHERTON: I know, but why is it that NRC has not developed or devised a standardized safety margin for this, that or the other to which then either an exemption would have to be granted if the licensee or the utility or the plant owner, whatever they are nowadays, doesn't meet it as opposed to just coming up with something that creeps up on that limit? That's the point I'm trying to make.

And that perhaps would tend to approach the safety culture point of view from NRC's perspective.

I have a general question. I was involved with the weapons side of the nuclear fence, and at one of the sites that I was involved with they're doing kind of a retroactive look at to what radiation releases were from that site to the general public, and what has not been made clear to me through my participation over a matter of years with that group is what is an acceptable radiation release to the environment where an epidemiological study could provide some significant determination as to whether the public was adversely affected.

The health physicists have proposed a ten rem standard per year, if I recall correctly, and I was just perplexed because I was unaware of anybody who had a standard that they were going to use to cut off whether or not it would be worthwhile studying the adverse effects of radiation on the public or whether a study should take place.

And so I was interested in some feedback in that area at some point in time. If we are permitting 25 millirem per year radiation release to the general public as an acceptable limit and the public is not being significantly affected by ten rem per year release, why the conservativeness?

If it is, then that's a significant gap, from 25 millirem to ten rem by, you know, several orders of magnitude, and this is an issue that I think needs to be addressed in one way or another.

With regard to the issues that the public was shut out on, the computer codes, I'm obviously not able to determine separately as a member of the public whether these computer codes are properly verified by testing or some other means to determine that what they actually say in particular with particular inputs and with particular assumptions or what tests reveal fall within that range.

And so I have questions as to, you know, the applicability of these codes to this particular uprate.

At the beginning of the licensing of this nuclear power plant, Vermont Yankee, they had to have in those years, the late '60s and early '70s, a failure modes and effects analysis, which is a rudimentary way of determining what the design criteria would be.

Nobody has addressed this failure modes and effects analysis to what specific accidents were looked at, what they came up with back then and then what the power uprates' effects are going to be upon that today, and I would ask why.

I would also concerning probabilities, and I have asked this on a number of occasions and I to this date haven't received an adequate reply. We have probabilities. In the early days it was failure rates. In order to predict how long a piece of equipment would operate, we had simple probabilities that we would use to determine that. It has now become a field of its own.

When I asked the question that to me would help put this probability scenario into perspective, I go back to TMI, for instance, and I will say: the Three Mile Island accident Unit 2 in 1979, what was the probability that that accident occurred in the manner in which it occurred? What would be the probability of that happening?

And probably a year later I got some feedback from somebody who was a manager today who was involved with those earlier computations at that time,a nd I'm going to say this, although he gave it to me in a private manner. He said the probability of that accident happening was close to ten to the ninth or one over ten to the ninth. Excuse me.

That's -- you know; yet it did happen, and we're using numbers of Reg. Guide 1.147 has ten to the fourth, ten to the fifth. We're not looking at the failure rates of steam dryers. What's the probability that a steam dryer's failure rate is going to be such that what happened at Quad Cities or what is happening at other plants would have happened?

And what is the probability, if we're looking at probabilities, what is the probability that that failure rate is going to occur with the beefed up design at Vermont Yankee?

And what would be the potential

consequences if it did occur?

And I haven't seen people look at this situation from that point of view.

I had an occasion when I was requested to do so to look into the seismic criteria at Vermont Yankee, and not from the NRC, but from the output from another agency it appeared that the 24-year maximum probable earthquake was in the neighborhood of .3G's ground acceleration.

And when I looked at the criteria that Marty Stutzke, if I'm pronouncing his name right -- he has indicated that the plant was designed to something like .07G, an operating basis earthquake. I'm assuming that's a ground acceleration, and the safe shutdown earthquake to .14G versus the maximum probable earthquake over a 2,400-year period being .3G, and I'm saying why. What happened to the design, you know, for the maximum probable earthquake?

And then he goes forth and describes the fact that it looks like the main coolant system would be able to withstand something greater than point, G, which makes that point somewhat moot at least probabilistically, but then I happen to know that the stand alone devices, the structures, the things like water tanks, storing lots of water, hundreds of thousands of gallons of water, pipes, underground pipes, cooling towers to the extent that they're not independently seismicly qualified; would they be capable of withstanding this maximum earthquake?

And I haven't seen a response to that.

I also was involved with a Taurus (phonetic) problem at another BWR in which the Taurus apparently either jumped or was fearful of it having moved in some way, shape, or form during a blow-down incident that this plant had. And there was sufficient concern that -- this was only a few years ago, in the neighborhood of five or five to six, seven years ago -- and there was sufficient concern with this situation such that during the refueling outages they put saddles on the Taurus to try to keep it from moving and thereby keep it hopefully intact.

I haven't heard this subject addressed at Vermont Yankee, and I don't know what the situation is like there.

This same plant also had a core shroud problem, a cracked core shroud. Whereas foreign countries that I know of with the same type of problem have replaced the shroud, this plant chose to patch it, and I understand that there are other plants, and if I'm correct, Vermont Yankee also has a patch on a core shroud.

I haven't heard that addressed and what the effects of that patch would be with the uprate and how that patch has operated over the course of the time that it has been in place.

And I got the impression from Mr. Stutzke being up here that he had some requests for additional information out to the licensee and presumably there is going to be a final presentation to the full committee, and I can't help but get the impression that this safety issue is being time constrained, and that in the rush to get answers towards the end, they have scheduled something ahead of time which, I believe, as you mentioned, sir, there might be too many loose ends at that time.

I'm just curious as to why these loose ends would not be, let's say, properly addressed at least by this point in time rather than have it go forward to the point where the full committee would have to deal with this.

And so I get the impression as an outsider that time management is more important than safety, and I could be wrong, but this is a concern to me as a member of the public. And I would ask that perhaps you look into that situation as to why we still have outstanding issues in a matter that's coming to the full committee for hearing and whether maybe that full committee meeting maybe wouldn't be proper to postpone that until these issues were properly addressed.

And I thank you for permitting me to make these comments.

CHAIRMAN DENNING: Thank you very much.

MR. ATHERTON: Are there any questions?

CHAIRMAN DENNING: Any comments, questions?

(No response.)

CHAIRMAN DENNING: Thank you.

Are there any other members of the public that want to make a presentation? Yes, please.

MR. SHADIS: Good afternoon. My name is Raymond Shadis. I'm representing New England Coalition.

Thank you for the opportunity to comment. I'll try to make this quite brief. As I remarked to one member of the committee earlier today, there's too much to say. So I'll be brief. We will try to provide some additional written comments, and I'll try to do that in outline form so that they're accessible and usable for your purposes.

I would like to comment, and I hope that the committee in its review will comment on the process. There are all of the technical specifics, and there are a number of things that jumped out today, but largely the great concern here is with the process.

From October, beginning of October forward, it really seemed as if the technical review was being driven by a calendar that was set for reasons other than technical review. We suddenly had proposed dates for ACRS to review this project, and a last minute rush of RAIs and SER and, you know, we're really not done with that process yet.

And it does seem to be backwards, that all things considered, if safety were the first concern, that that first concern for safety would have it that as the technical issues were resolved, the calendar would then be set in accordance with anticipating the end of resolving those issues, not the other way around.

So there's that comment. Also, one thing that popped out today, earlier today, was the segmented licensing actions that have gone forward in support of EPU. In June of -- yeah, I think it was in June, late spring of 2003, we have copies of NRC staff correspondence wondering if it is valid for this licensee to separately submit their ARTS MELLA (phonetic) application, their AST application, and the extended power uprate application, and whether or not for legitimate consideration they should not all have been submitted together.

When we had a presenter from NRC today talking about the alternate source term credit for dry well spray capture of Iodine 131, one of the committee members put their finger right on it because, hey, wait a minute. We're taking credit for using this spray system. On the other hand, we have some constraints about not using it. You know, this is among one of those many little issues that's got to be floating around in the mind of an operator.

Comes the time when you are under accident constraints, and had AST and the EPU been handled together in one application, people might have meshed those two concerns and properly addressed them, and I guess our concern is how many other technical issues are floating out there where there is conflict and contradicting information that is bouncing around among these three different applications.

And I just very quickly want to comment on one other item that you have all been asked to consider by the State of Vermont initially, and that is the State of Vermont in requesting an independent engineering assessment of Vermont Yankee as prerequisite to upgrade stated that in their letter of request, their belief that the ACRS would consider any such examination in the course of its review of the uprate.

And I know that you've gone there, given that you scheduled that into the two meetings that you held in Brattleboro.

I just want to give a little background on the origin of that engineering team inspection that NRC offered as a substitute for the independent engineering assessment that was requested by the Vermont Public Service Board. This is SECY Letter 040071, dated April 29th, 2004, and this letter spells out the proposed program for the engineering team inspection. It is entitled "Proposed Program to Improve the Effectiveness of Nuclear Regulatory Commission Inspections of Design Issues."

And this is from William Travers, Executive Director of Operations. And Mr. Travers reports that in order to better understand the degree to which NRC inspections and licensee self-assessment efforts have been effective in identifying design issues, the staff reviewed the last three years of data from the reactor oversight process, and here's what he says. And I think it's interesting; it's instructive.

"Of the 17 greater than green design engineering issues that fell within the scope of this review, 11 were NRC identified, two were licensee identified, and four were self-revealing." Love it.

"Of the 11 NRC identified issues, seven involved issues that had previously been recognized by the licensee, but whose significance the licensee had not recognized. Three of the NRC identified issues were associated with fire protection, an area not typically covered in NRC design inspections. Only one of the NRC identified issues was identified as a result of an NRC design inspection."

And it takes me back to parochial school when we had to do all of the taking away and putting back of numbers in any sequence. If we had the blackboard up here, we could come down and understand that of 17 greater than green design engineering issues, only one was identified as a result of an NRC design engineering inspection.

So does the program need improvement is the question they were trying to answer, the question they were struggling with.

Now, the scale of the independent engineering assessment requested by the State of Vermont was for four people, four weeks, or about 640 hours of inspection time, and in this letter with respect to the proposed engineering team inspection, Mr. Travers reports, "Overall, the prototype inspection module is more resource intensive and would require about 700 hours of direct inspection versus the current allocation of approximately 500 hours for the safety system design inspection."

And it doesn't take very long in thinking about it before one realizes that the inspection that was done wrapped in the routine periodic design basis inspection, the one that yielded one finding in 17, that same inspection.

So where Vermont was asking for inspection on the scale of 640 hours, here we have NRC proposing to give them 200 hours of specialized inspection added to the normal 500 hours that they do. The 500 hours is taken off the board, and what is put back on is 700. So basically a net gain of 200 hours.

On July 1st, 2005, SECY Paper 050118 was issued by Luis Reyes, Executive Director, and again, it is instructive, and it goes eventually right to this EPU review, my humble opinion.

The results, and he's speaking now about four pilot inspections that were done, and Vermont Yankee was one of those pilot inspections. "The results of the pilot inspections appear to indicate that latent design and engineering issues mostly of very low safety significance persist at operating reactors. The pilot inspections resulted in 29 inspection findings."

And to Vermont Yankee, the next page, "the staff has reviewed the results of the Vermont Yankee inspection and has concluded that the current power uprate inspection procedure should be enhanced. In addition, a process should be developed to better integrate the inspection and NRR technical review process for power uprates and other important license amendment requests. These conclusions are based primarily on the identification of several issues during the Vermont Yankee inspection. These issues included the acceptability of the licensee's power uprate submittals with respect to station blackout rule, motor operated valve testing, certain operator response times, and certain assumptions in accident analyses. The staff believes it unlikely that these inspection identified issues would have been identified by subsequent NRR technical reviews because" -- and this echoes the last two days because I heard this, and this is parenthetical and I'm interjecting this.

Over the last two days, I heard NRC staff say again and again "the licensee says," "the licensee reports," "the licensee tells us," "the licensee has it in their application."

"The staff believes it unlikely that these inspection identified issues would have been identified by subsequent NRR technical reviews because the NRR technical reviews rely primarily on licensee submitted documentation."

And this I could have written myself. "The staff, therefore, believes that a detailed inspection is a good complement to the NRR technical review in this area."

Finally, there is a table included in Attachment 2 of that letter, and it yields that Vermont Yankee was accorded a total of 910 hours of direct inspection. This is an addition of 410 hours not to the nominal 500 that's part of the vanilla periodic inspection.

So what the State of Vermont asks for was a very special inspection to confirm the conditions of the plant, to provide some indication of future plant reliability, to confirm, I think -- maybe I'm putting a little interpretation on this -- to confirm NRC's assumption that their normal inspection regimen provides sufficient assurance that the plant is in conformance with its design basis.

And what they got instead was a warmed over portion of their normal inspection regimen with a topping, if you will, and definitely not what they requested.

I will be submitting written comments because there is additional material with respect to the contrast between the scale and the scope and the purposes of the requested independent engineering assessment and what NRC finally gave us, which was the engineering team inspection, and I will persist in that until I convince you gentlemen to reject the notion that these two are somehow equal.

Finally, just a couple of quick points. A number of the presentations that were given, there was an admission or it could be easily derived that safety margins, while they may not have been or may not be eroded beyond what regulation provides for, are nonetheless eroded, diminished, and where this is a matter of public concern, it is truly disconcerting to see all of those diminutions at almost every turn and facet stack up.

In terms of a trend, you would have to say, as far as a safety trend, it is a negative trend that has been incorporated in this application.

Earlier today one of the NRC presenters referenced the off-site dose calculation manual and referred to the numbers for fenceline dose as a result of the shortened time of passage for N-16 through the loop and resulting shine in fenceline dose.

And I don't remember the exact numbers he used, but it looked to me like he was saying the base fenceline dose from which Vermont Yankee was moving was about 15 MR per year, and that after uprate, they were looking at about 18.6. I think those were the numbers he used.

And this is an issue that we reviewed because the State of Vermont has an agreement with Vermont Yankee in which Vermont Yankee agrees to comply with state regulation of 20 MR at fenceline, 20 MR per year, and when we first looked at the proposed uprate, the numbers we got went beyond the 20 MR.

but then what happened very quickly was that at Vermont Yankee they reached back into some NRC guidance which permitted them to adjust the calculated dose at fenceline, and what it is is a quality factor which they now applied on the difference between skin dose and air dose or between -- turn that around -- between air dose and skin dose, between rads and rems.

And whereas this has been traditionally treated as a one-one equivalency, there's now in place a .71 quality factor. So I'm not arguing with the numbers they gave you, but if it's 18.6, they arrived at that by applying for and taking credit for and using this .71 quality factor.

To the citizen walking by, what that looks like is a 29 percent discount in order to facilitate uprate. What wasn't mentioned is that we're now looking at the deployment of dry cask storage, and whatever little incremental dose can be expected from that will, of course, be added. That is now a matter of some contention.

The same thing is true, of course, in terms of the alternate source term and control room habitability issues. NRC offered its licensees the option of applying certain source term credits many years ago and Vermont Yankee never saw the need until they got ready to apply for extended power uprate, and then suddenly that long list of credits that was hung on the screen here when NRC staff did their presentation popped up.

And so it essentially is a 40 percent discount of what would have been dose at the control room under accident conditions, and in order to facilitate uprate.

These are but two examples out of many that are available, and we'll write you until you really won't want to open the envelopes, but these are two examples out of the many that are available of the way that the safety margins have been eliminated.

And you know, we spoke in Brattleboro at least to some small degree about the removal of the old things that we used to rely on for redundancy, of defense in depth, of the individual integrity of individual safety systems. So, you know, we'll be bringing those to you, and I do thank you.

I have a couple of quotes for you. I love these little quotes. EPA Chairman Ruckleshouse once said about risk assessment, and it could be as well applied to the PRAs, that it was like capturing an enemy combattant, and if you tortured him long enough, you'd get him to say anything.

You know, we see that over and over. At my hotel room this morning, I lingered over a Christa McAuliff tribute, and that was the 1986 Challenger disaster. You know, PRA just didn't hack it there, and PRA I don't think would have predicted that since we began extended power uprate modifications at Vermont Yankee, we have had two generator trips and two scrams, and we have had reverberations throughout the system, recirc pump trips, various trips during one of those.

So bringing you those concerns. Any questions, gentlemen?

CHAIRMAN DENNING: Thank you very much.

MR. SHADIS: Thank you.

CHAIRMAN DENNING: We appreciate your input.

Okay. I would like to thank all of the contributors. I think that this has been an excellent meeting. I'd like to particularly thank Entergy for excellent presentations, their willingness to make modifications in their presentations, the staff also for excellent presentations. I thank the public for their comments.

And with that, I think we will adjourn.

(Whereupon, at 4:59 p.m., the meeting was concluded.)

CERTIFICATE

This is to certify that the attached proceedings before the United States Nuclear Regulatory Commission in the matter of:

Name of Proceeding: Advisory Committee on Reactor Safeguards Subcommittee on Power Uprates

Docket Number: n/a

Location: Rockville, MD

were held as herein appears, and that this is the original transcript thereof for the file of the United States Nuclear Regulatory Commission taken by me and, thereafter reduced to typewriting by me or under the direction of the court reporting company, and that the transcript is a true and accurate record of the foregoing proceedings.

Lindsay Barnes

Lindsay Barnes
Official Reporter
Neal R. Gross & Co., Inc.

Entergy Vermont Yankee
Extended Power Uprate

Presentation to the
Advisory Committee On Reactor Safeguards
Extended Power Uprate Subcommittee
November 30, 2005

1

Flow Accelerated Corrosion
Topics

- Program Overview
- EPU Impact
- Conclusion

2

Entergy

Flow Accelerated Corrosion

Overview

- o Programmatic Approach to Monitor FAC
  - Program Meets Generic Guidance
    - o Generic Letter 89-08
    - o EPRI NSAC-202L
  - Uses EPRI CHECWORKS Software to Predict FAC Wear, Plan Inspections, and Organize Inspection Data
  - Evaluates and Incorporates FAC Related Industry Operating Experience for Applicability to VY

3

Entergy

Flow Accelerated Corrosion

Overview

- o Typically 25 to 35 Components Inspected Each Outage
- o Repeat Inspections in Condensate & Feedwater show Minimal FAC Wear
- o Significant Amount of FAC Resistant Piping
  - Extraction Steam System Piping Originally Constructed Using FAC Resistant Material
  - Replacement of Degraded Components With More FAC Resistant Materials

4

Flow Accelerated Corrosion
Replacements With FAC Resistant Materials

Entergy

- Equipment
  - All Feedwater Heater Shells Replaced with FAC Resistant Material
  - LP Turbine Casings Replaced with FAC Resistant Material

5

Flow Accelerated Corrosion
Replacements With FAC Resistant Materials

Entergy

- Large Bore Piping
  - Moisture Separator Drains Downstream of Level Control Valves
  - Heater Drain Piping Downstream of Level Control Valves at new Feedwater Heaters
  - Feedwater HP Flush and Feedwater Pump Recirculation Lines Connecting to Condenser
  - Turbine Cross Around Lines

6

Flow Accelerated Corrosion
Replacements With FAC Resistant Materials

Entergy

- Small Bore Piping
  - Main Steam Drains From HPCI and RCIC Turbine Steam Supply Lines in Rx. Bldg. to Condenser
  - Main Steam Leads Continuous Drain Through Restriction Orifice To Condenser
  - AOG Steam Supply Drain Lines To Condenser
  - Turbine Bypass Valves First Seal Leakoff Lines
  - High Pressure Feedwater Heater Vent Lines

7

Flow Accelerated Corrosion
EPU Impact

Entergy

- No Additional Systems Have Been Added to the FAC Program Due to EPU
- EPU Flow and Temperature Changes
  - Maximum Flow Increases 24.6% in Feedwater
  - Maximum Temperature Increase of 18.4°F in Final Feedwater
- Bounding Estimate of Changes in FAC Wear in Single Phase Systems to be Proportional to Changes in Flow Velocities for EPU

8

Entergy

Flow Accelerated Corrosion

EPU Impact

- Updating CHECWORKS Models with Recent Outage Inspection Data and EPU Parameter Changes for Performing Component Selection for RFO 26
- Currently Planning For 50% Increase In The Number Of Inspections Performed For The Next 3 Refueling Outages To Monitor Potential Changes Due To EPU

9

Entergy

Flow Accelerated Corrosion

Conclusion

- Minimal Changes in Existing FAC Wear Rates Expected with Implementation of EPU
- No Impact on FAC Program Scope or Methodology
- Increased Inspections Planned For Next Three Refueling Outages

10

Pressure Temperature Limit Curves EPU Impact

- Fluence (> 1 Mev)
  - CLTP Fluence Calculation and PT Curves Updated in 2003
  - PT Curves based on peak neutron fluence of 1.24×10^{18} n/cm^2
  - Fluence Calculation Updated for EPU
    - Increase RPV ID Fluence Rate (Flux) by 26%
  - RPV ID Surface Integrated Peak Fluence
    - CLTP - 2.99×10^{17} n/cm^2
    - EPU - 3.18×10^{17} n/cm^2
- TS PT Curves remain bounding for EPU operation

11

Entergy

Station Blackout

- Loss of Offsite Power to VY Switchyard
- Loss of Both Onsite AC Diesel Generators
- Vernon Tie AAC Source Requires Restart due to Regional Blackout
- Meets RG 1.155 and NUMARC 87-00
- 2 Hour Coping Duration for Restoration of AC Power Via Adjacent Vernon Hydro Station

1

Entergy

SBO Coping

- Rx Level Control by HPCI System
- Rx Pressure Control by SRVs
- Sufficient CST Inventory
- Battery Capacity Sufficient for 2 Hours
- Peak Torus Temperature < 185 F
- Loss of Ventilation Evaluated
- Required Air (N_2) Available
- PCIS Maintained

2

Entergy

SBO Timeline

- SBO Occurs – Time 0
- Vernon Hydro Notified by REMVEC to Blackstart - < 10 Minutes
- Vernon Hydro Staffed and Ready to Blackstart - < 100 Minutes (from t=0)
- Power Restored to Vernon Tie Line and Vermont Yankee 4 kV Bus Re-energized - < 120 Minutes From t=0

3

Entergy

Conclusions

- Vernon Hydro Available Within 2 Hours
- SBO 2 Hour Coping Analysis
- Plant Remains in a Safe Condition for the SBO Duration and Recovery

4

Entergy

System Impact Study

- o System Impact Study Performed by ISO-NE
- o Scope of Analysis Included all of New England and its Interfaces
- o Improved VY Fault Protection Systems
- o Northfield 345 kV and Ascutney - Coolidge 115 kV Lines Rerated
- o 60 MVAR Capacitor Bank Added for Voltage Support

5

Entergy

Operator Training, Procedures and Actions

Operational Impacts

- Operation of all (3) Reactor Feedwater Pumps
  - Recirc Runback/Pump Trip
- Additional Rod Pattern Adjustments
  - Reactor Recirculation Flow Window Reduced
- Slight Reduction in Operator Action Times for Certain Events
- Balance of Plant Modifications Improve Plant Performance and Component Reliability

1

Entergy

Operator Training

- Simulator was Modified to Support EPU
- Training on Modifications
- On-going Training With Modifications Installed for the Past 2 Years
- Operating Crews Were Trained at EPU Conditions
- Power Ascension / Transient Test Training Prior to Performing EPU

2

Entergy

Operator Procedures

- Some Abnormal Procedure Changes Due to EPU
- New Steam Dryer Integrity Procedure
- No New Emergency Procedure Actions or Strategies
- Minor Revisions to Emergency Procedure Graphs Due to EPU

3

Entergy

Operator Actions / Timelines

- No New Operator Strategies
- The Time it Takes to Perform Required Actions Did Not Change
- Operations and Training Completed Time Validations for Time Critical Actions
- The Time Required to Perform Certain Actions has Decreased
- Operator Actions Remain Within the Allowable Time Windows

4

Probabilistic Safety Analysis
VY PSA Overview

Entergy

- o Internal Events
  - Level 1 (Core Damage Frequency)
  - Level 2 (Release Frequency)
- o External Events (IPEEE Study)
  - Internal Fires (EPRI FIVE Method)
  - Seismic (EPRI SMA Method)
  - Other External Hazards (NRC SRP Review)
    - o Winds, Ext. Floods, Transportation, etc.

1

Probabilistic Safety Analysis

Entergy

- o Reflects Current Plant Configuration
- o NEI Peer Review in Y2000
  - All Category A & B Facts and Observations Resolved
- o VY PSA Maintained and Routinely Updated to Reflect Current Plant Configuration and Operating Experience

2

Probabilistic Safety Analysis

Potential PSA Impacts Due to EPU

- o Hardware Changes
- o Procedural Changes
- o Configuration Changes
- o Power Level

3

Probabilistic Safety Analysis

EPU Impacts

- o No New Accident Sequences Identified
- o No Significant Impact:
  - IE Frequencies
  - Only One Success Criteria Change (1 additional SSV for ATWS)
  - Due to Hardware Changes
  - Due to Procedural Changes
- o Slight Decrease in Time Available for Some Post-Initiator Operator Actions

4

Probabilistic Safety Analysis
ATWS Operator Actions

Entergy

ACTION	CLTP	EPU
Operator Inhibits ADS	6.2 min.	5.4 min.
Operator Initiates SLC (MSIVs Isolated)	6 min.	5.3 min.
Operator Bypasses MSIV Low Level Isolation Interlocks	4 min.	3.4 min.

5

Probabilistic Safety Analysis
Methodology

Entergy

- Level 1 & 2 Internal Events (Quantitative)
- External Events (Qualitative)
- Shutdown Events (Qualitative)

6

Probabilistic Safety Analysis
Conclusions

- Very Small Risk Increase (CDF)
  - $\Delta CDF = 3E\text{-}7/ry$
- Small Risk Increase (LERF)
  - $\Delta LERF = 1E\text{-}7/ry$
- No Significant Risk Impact from External Events and Shutdown

7